SCIENTIFIC INQUIRY INTO
HYDRAULIC FRACTURING
IN THE NORTHERN TERRITORY

DRAFT FINAL REPORT APPENDICES

DECEMBER 2017

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These Appendices of the draft Final Report support and refer to the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory draft Final Report*. There is also an Executive Summary of the draft Final Report. Each document has been published separately, but together they form the totality of the draft Final Report.

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Appendix 1 Terms of Reference

Background

On 14 September the Northern Territory Government announced a scientific inquiry into hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory (the **Inquiry**) under the *Inquiries Act (NT).*

Definitions

For the purposes of this document:

"Associated Activities" means:

a. the acquisition of ground or surface water for hydraulic fracturing;
b. the mixing of water, chemicals and proppant to create hydraulic fracturing fluid;
c. the return of injected fluid and water produced from the unconventional reservoir to the surface after hydraulic fracturing, and subsequent transport for reuse, treatment or disposal; and
d. the reuse, treatment and release of wastewater generated by hydraulic fracturing.

"environment" means land, air, water, organisms and ecosystems and includes:

a. the well-being of humans;
b. structures made or modified by humans;
c. the amenity values of an area; and
d. economic, cultural and social conditions.

"environmental impact" means any change, or potential change, to the environment.

"environmental risk" means the chance of something happening that will have an environmental impact, measured in terms of the environmental consequences and the likelihood of those consequences occurring.

"hydraulic fracturing" means the injection of fluids under pressures high enough to fracture the gas bearing formation where the fluid is comprised of water, chemicals and proppant.

"unconventional reservoir" is a reservoir where the gas bearing formation is shale.

Terms of Reference

The Inquiry will:

1. assess the scientific evidence to determine the nature and extent of the environmental impacts and risks, including the cumulative impacts and risks, associated with hydraulic fracturing of unconventional reservoirs and the Associated Activities in the Northern Territory;
2. advise on the nature of any knowledge gaps and additional work or research that is required to make the determination in Item 1, including a program for how such work or research should be prioritised and implemented, that includes (but is not limited to);
    a. baseline surface water and groundwater studies,
    b. baseline fugitive emissions data,
    c. geological and fault line mapping, and
    d. focus areas for baseline health impact assessment,
3. for every environmental risk and impact that is identified in Item 1, advise the level of environmental impact and risk that would be considered acceptable in the Northern Territory context;

4. for every environmental risk and impact that is identified in Item 1,
    a. describe methods, standards or strategies that can be used to reduce the impact or risk; and
    b. advise whether such methods, standards or strategies can effectively and efficiently reduce the impact or risk to the levels described in Item 3;
5. identify any scientific, technical, policy or regulatory requirements or resources that are in addition to the reforms being implemented through the existing environmental reform process that are necessary to reduce environmental risks and impacts associated with the hydraulic fracturing of unconventional reservoirs to acceptable levels; and
6. identify priority areas for no go zones.

When the Inquiry makes a determination under Item 1 about whether or not there has been an impact or risk on economic, cultural and social conditions, the Inquiry will not only consider the impacts and risks of hydraulic fracturing and the Associated Activities, it will also consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry. This may be undertaken through a social impact assessment or similar activity.

Methodology

In the course of delivering the Terms of Reference, the Inquiry will:

1. advise the timeframe for the Inquiry prior to 1 January 2017;
2. develop and implement a stakeholder engagement program, which will be publicly released prior to 1 January 2017 and which will include opportunities for the public to give written submissions and meet with the Inquiry in Darwin, Katherine, Tennant Creek and Alice Springs (and potentially other communities) prior to and following:
    a. the release of an Interim Report on the Findings of the Inquiry; and
    b. the release of a draft Final Report on the Findings of the Inquiry;
3. have regard to issues raised in the course of implementing the stakeholder engagement plan that relate to the Terms of Reference;
4. subject to any request for a submission or any part thereof to be kept confidential, make all submissions to the Inquiry publicly available;
5. have regard to relevant domestic and international reviews and inquiries regarding the environmental impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the Associated Activities; and
6. consider the principles of ecological sustainable development and the precautionary principle.

Appendix 2 Final list of issues

1 Water

Water quality

Groundwater

- There may be a risk of groundwater contamination as a result of:
  - induced connectivity between hydraulically fractured shale formations and overlying or underlying aquifers;
  - surface spills of chemicals, flowback water or produced water into near-surface groundwater;
  - leaky wells as a result of poor design, construction, operation or abandonment practices or as a result of well degradation over the life of the well;
  - reinjection of flowback water, produced water or treatment brines into a groundwater aquifer;
  - induced connectivity between different groundwater systems as a result of seismic activity caused by hydraulic fracturing or reinjection of water; and/or
  - changed groundwater pressure regimes from hydraulic fracturing activities.

Surface water

- There may be a risk of impacts on surface water quality as a result of the following types of incidents:
  - on-site spills, including as a result of extreme weather events such as cyclones and floods;
  - spills that occur during transportation of chemicals to or from the site during the development and production phases;
  - spills of flowback water, produced water or brines produced by water treatment; and/or
  - inputs of sediment from erosion of road and pipeline corridors.

Water supply and distribution (quantity)

- There may be a risk of adverse environmental impacts as a result of reduced water supply due to the large amounts of water being extracted for use in hydraulic fracturing.
- There may be a risk of changes to the timing and/or quantity of surface water flows because of the discharge of produced water, which may be significant particularly in arid to semi-arid landscapes.
- There may be a risk to surface water and groundwater flow processes as the result of possible seismic activity caused by hydraulic fracturing or reinjection of water.
- There may be a risk of surface disturbance affecting surface flow paths and altering infiltration.

Aquatic ecosystems and biodiversity

- There may be a risk of adverse impacts on aquatic ecosystems and biodiversity, including groundwater dependent ecosystems. This may result from changes in the quality and/or quantity of surface and/or groundwater available to them.

Amenity values

- There may be adverse impacts on general amenity values such as in national parks, rangelands and recreational fishing areas. This may result from changes in the quality and/or quantity of water available.

Public health

- There may be adverse impacts on human and livestock health due to changes to water quality, supply and distribution as a result of hydraulic fracturing and the associated activities.

Aboriginal people and their culture

- Natural water bodies are central to traditional land use and many sites of significance to Aboriginal people relate to water. A reduction in either water quantity or quality may impair the traditional use and/or value of the sites.

Economic

- Changes to water quality, supply and distribution may have an adverse impact on industries that may coexist with the onshore unconventional gas industry, such as agriculture, pastoralism, fishing and tourism.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

2 Land

Terrestrial ecosystems and biodiversity

- There may be a risk that hydraulic fracturing and the associated activities will have an adverse impact on terrestrial ecosystems and biodiversity in the Northern Territory. Specifically, there may be a risk of:
  - biodiversity loss on a local and regional scale as a result of areas being cleared for roads, pipelines and drill pads or as a result of spills;
  - biodiversity loss and reduced ecosystem function due to habitat loss and fragmentation;
  - adverse impacts on terrestrial ecosystems, including fauna and flora, as a result of changes to water quality and availability;
  - biodiversity loss and ecosystem function due to the spread of weeds;
  - impacts on biodiversity and greenhouse gas emissions due to changed fire regimes;
  - adverse impacts on fauna as a result of increased noise and light from gas operations;
  - loss of biodiversity due to inadequate knowledge of biodiversity assets leading to inappropriate planning of regional development;
  - disruption of surface water flows at the landscape scale by road and pipeline infrastructure;
  - loss of locally important or sensitive sites due to inappropriate location of infrastructure within a development area; and/or
  - increased human activity, roads and pipelines acting as barriers and corridors for faunal movement and the drinking of wastewater.

Soil health

- There may be a risk that the chemicals used in the drilling and hydraulic fracturing process will have an adverse impact on soil health, including as a result of spills of flowback water.
- There may be a risk that there will be compaction of soils underneath production pads or along pipelines.

Aboriginal people and their culture

- The landscape, terrestrial ecosystems, plants and animals are central to traditional cultural values. Adverse impacts to these things may have an adverse impact on Aboriginal cultural values.

Seismic activity

- There may be a risk of seismic activity caused either by the hydraulic fracturing process or the reinjection of wastewater into the ground.

Subsidence

- There may be a risk that the drilling and hydraulic fracturing process causes land subsidence.

Economic

- An adverse impact on terrestrial ecosystems may be a risk to industries that co-exist with the onshore unconventional gas industry, such as agriculture, pastoralism, fishing and tourism.

Amenity values

- The Panel recognises that the Northern Territory has iconic wilderness values as a core part of the Australian outback. There may be a risk that the development of the unconventional gas industry will have an adverse impact on the outback experience (for example, tourism) through infrastructure development (for example, the construction of pipelines and processing plants) and increased traffic, noise and light (from flaring).
- There may be a risk of solastalgia.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

3 Air

Public health

- The possible health risks associated with the release of gases from the hydraulic fracturing process are discussed below in '1.4 Public health'.

Climate change

- There may be a risk that greenhouse gases, including hydrocarbons (methane and ethane) and carbon dioxide, will be released during hydraulic fracturing and the associated activities. Emissions may be from sources such as wellheads, pipelines, compression stations and final use. The potential contribution of hydraulic fracturing and the associated activities to the burden of greenhouse gas emissions will be assessed by the Panel.

Amenity values

- There may be a risk that there will be adverse impacts on amenity values, such as in national parks and rangelands, due to gaseous emissions and flaring.

Air contamination

- There may be a risk that soil contaminated by spills of fracking fluids or wastewater becomes airborne as dust, causing harm to the environment and to human health.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

4 Public health

Drilling and fracking chemicals

- There may be a risk that chemicals used during the drilling and hydraulic fracturing process are harmful to humans and livestock. Further, there may be a risk that those chemicals come into contact with humans or livestock via groundwater or atmospheric pathways. While the concentrations of potentially harmful chemicals in the water are low, the actual amount of chemicals can be significant and may pose a threat to the water supply if not properly managed.

Hydrocarbons and BTEX

- There may be a risk that hydrocarbons associated with the extracted gas come into contact with humans or livestock via groundwater or atmospheric pathways. This may include

aromatic hydrocarbons such as BTEX, which have featured prominently in some risk assessments relating to flowback water from petroleum and unconventional gas extraction activities in the US. The addition of BTEX in drilling and fracking fluids is prohibited in the Northern Territory.

Radioactive substances

- There may be a risk that naturally occurring radioactive materials from underground come into contact with humans or livestock as a result of the drilling or hydraulic fracturing process.

Mental health and wellbeing

- There may be a risk that the mental health and wellbeing of persons could be affected by an unconventional gas project. These factors could include increased costs of living associated with changing property values, access to social services, business failures, increased traffic, effects on the natural environment and concerns about the amenity of the local area, including solastalgia.

Diesel fumes

- There may be a risk of emissions from plant and equipment, such as diesel fumes from drilling equipment and pumps, and from off-site increases in road traffic.

Physical safety

- There may be a risk that physical safety may be compromised by factors associated with hydraulic fracturing, including road transport accidents.

Aboriginal health

- There may be a risk that as a consequence of the possible impacts described above, the physical and mental health of Aboriginal persons and communities, as a group that is especially vulnerable and disadvantaged, is particularly affected (that is, the 'gap' is increased and not decreased).

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

5 Aboriginal people and their culture

Land ownership

- There may be a risk that hydraulic fracturing or the associated activities will disrupt traditional practices that connect Aboriginal landowning groups with their country and underpin recognition of their ownership of that land.
- There may be a risk that there is inadequate or inappropriate consultation with Aboriginal landholders in obtaining access to their lands and/or permission to carrying out any onshore unconventional shale gas development.

Benefits

- There may be a risk that the development of the industry will occur without short and long term benefits flowing to local Aboriginal communities.

Culture, values and traditions

- There may be a risk that the above and/or below ground disturbance associated with drilling and hydraulic fracturing of onshore shale gas formations will have an adverse impact on Aboriginal culture, values and the traditions that connect landowning groups with their country and sustain community cohesion.
- There may be a risk that access to and the use of traditional lands will be denied or restricted by the presence of any onshore unconventional shale gas development.
- There may be a risk that sacred sites and cultural landscapes are degraded and damaged both above and below the ground.

Community wellbeing

- The development of the onshore unconventional shale gas industry may have an adverse impact on the wellbeing of Aboriginal communities.
- There may be a risk of solastalgia caused by any onshore unconventional shale gas development.
- There may be a risk that any onshore unconventional shale gas industry causes community division in respect of those who may benefit from any industry and those who will not.

Aquatic and terrestrial ecosystems

- The development of the unconventional gas industry may have an adverse impact on aquatic and terrestrial ecosystems important to Aboriginal culture.

Aboriginal health

- There is a risk of an exacerbated adverse impact on Aboriginal health, taking into account the particular vulnerabilities and disadvantage of that population.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

6 Social impacts

Housing and rents

- There may be impacts on local housing, which may decrease or increase rents and house prices as a result of an increased population.

Insurance

- There may be a risk that there will be an increase in insurance costs and liabilities of landowners, occupiers, and traditional owners.

Health services

- There may be impacts on the local health system (hospitals, health services and so on) as a result of an increased population, including that there may be increased health services in remote communities as a result of industry's presence.

Education

- There may be an impact on the local education system as a result of an increased population.

Infrastructure

- There may be an impact on infrastructure, such as roads, as a result of increased traffic.

Livelihoods

- There may be an impact on livelihoods.

Long term benefits

- There may be a risk that the development of the industry will occur without short and long term benefits flowing to the local community.

Community cohesion

- There may be an adverse impact on community cohesion and resilience. That is, there may be a risk of social division being created between those who benefit from the development of any onshore unconventional shale gas industry and those who do not.

Crime

- There may be an increase in crime.

Employment

- They may be an impact on local employment and skill levels.
- There may be negative impact caused by an influx of FIFO employees.

Business

- There may be an impact on local business opportunities.

Amenity

- There may be a risk that the amenity of people will be adversely impacted by hydraulic fracturing and its associated activities.

Social licence to operate

- There may be a risk that no social licence to operate an onshore unconventional shale gas industry exists.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

7 Economic impacts

Distribution

- There may be a risk that any economic benefits will not be shared by the regions that are directly affected by the industry and/or will not be shared equitably between the gas companies, the government, and the community.

Property values

- There may be a risk that there will be a decrease or increase in existing property values.

Other industries

- There may be a risk that there will be an adverse impact on other businesses, such as tourism, fishing, agricultural and pastoral businesses.

Energy security

- There may be an impact on the energy security of the Territory.

Employment

- There may be an impact on employment in the Territory.

Net impacts

- There may be a risk that any economic benefits will not outweigh economic detriments.
- There may be an opportunity cost of investing in an onshore unconventional shale gas industry rather than in renewable energy.
- There may be a risk of residents leaving a particular region because of the presence of an onshore unconventional shale gas industry.

Management

- There may be a risk that, if not properly managed, any economic benefits will result in 'boom and bust' economic activity.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

8 Land access

Consultation

- There may be a risk that gas companies do not consult adequately with land owners, occupiers, or traditional owners, in gaining access to the land for exploration and extraction purposes.

Consent

- There may be a risk that gas companies enter the land without obtaining the consent of the landowner, occupier, or traditional owners, causing conflict.

Conditions

- There may be a risk that gas companies and landowners, occupiers, and traditional owners, do not negotiate mutually beneficial conditions associated with any agreement permitting access.

Compensation

- There may be a risk that compensation paid for access and/or disturbance to land will not be adequate.
- There may be a risk that if there is an incident in the exploration, extraction or production of any gas, the land may not be properly remediated or the land owners, occupiers, or traditional owners may not be adequately compensated.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

9 Regulatory framework

Failure to protect the environment

- There may be a risk that the regulatory framework does not adequately protect the environment (water, land, and air) from risks associated with hydraulic fracturing and its associated activities.
- There may be a risk that the regulatory framework does not ensure adequate, or any, remediation and/or rehabilitation of any environmental damage caused by hydraulic fracturing and its associated activities.
- There may be a risk that the cost of any remediation and/ or rehabilitation of environmental damage caused by hydraulic fracturing and its associated activities is not passed on, either in whole or in part, to the entity that caused the harm, but is passed on to the public.

Land access

- There may be a risk the regulatory framework does not appropriately balance the rights of landowners, occupiers, and traditional owners, with those of gas companies.

Public health

- There may be a risk the regulatory framework does not adequately mitigate public health risks associated with the onshore unconventional shale gas industry.

Aboriginal culture and communities

- There may be a risk the regulatory framework does not adequately protect Aboriginal culture, values, traditions and communities from risks associated with the unconventional shale gas industry.

Social impacts

- There may be a risk the regulatory framework does not adequately mitigate the social risks associated with the onshore unconventional shale gas industry.

Economic impacts

- There may be a risk the regulatory framework does not ensure that any economic benefits are appropriately distributed between the gas companies, the Government and the local community.

Compliance and enforcement

- There may be a risk of inadequate monitoring or enforcement of compliance with the regulatory framework. This may arise from, for example, inadequate resourcing of the regulatory agency, inadequate expertise, or inadequate training.
- There may be a risk that sanctions provided for in the regulatory framework are inadequate or are not utilised by the regulator.
- There may be a risk that the cost of complying with the regulatory framework is too high for industry and the industry becomes uneconomic.

Access to justice

- There may be a risk that access to justice by the public is denied or restricted by the regulatory framework.

Complexity

- There may be a risk that the regulatory framework developed is too complex.
- There may be a risk that given its complexity, any regulatory framework that is developed is rushed and inadequate.
- There may be a risk that there is inadequate information about the long term risks associated with hydraulic fracturing and its associated activities to develop a suitably robust regulatory framework.

Regulatory capture

- There may be a risk of 'regulatory capture', whereby the regulatory body becomes inappropriately aligned with industry and becomes reluctant to regulate against the interest of any onshore unconventional shale gas industry.
- There may be a risk of the perception of regulatory capture which may have a tendency to undermine confidence in both the regulatory body and the Government.

Political risks

- There may be a risk that the Government is perceived to be subject to undue influence by the gas industry thereby leading to a loss of public confidence in the Government and the democratic process.
- There may be a risk that, given the short term nature of the political cycle, the long term consequences of any onshore unconventional shale gas industry cannot be appropriately regulated.

Cumulative risks

- There may be cumulative risks associated with some or all of the risks identified above.

Appendix 3 Risk assessment matrix

Chapter 7 Water

Environmental value 1: water quantity

Environmental objective 1: to ensure all surface and groundwater resources are used sustainably

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Excessive extraction from surface water	*Likelihood* - low, lack of permanent surface water in Beetaloo Sub-basin and other semi-arid and arid regions. *Consequence* - medium. *Risk* - low.	Prohibit use of surface water for shale gas hydraulic fracturing in the NT ***(Recommendation 7.5).*** Develop WAPs for the Beetaloo Sub-basin region that specifically exclude use of surface water for onshore shale gas development ***(Recommendations 7.5 and 7.6).***	Low
Excessive extraction from groundwater - regional impacts	**Northern Beetaloo Sub-basin:** *Likelihood* - low. *Consequences* - medium. *Risk* - low. **Southern Beetaloo Sub-basin:** *Risk* - cannot be assessed, lack of detailed knowledge on recharge rates in the region.	Develop and undertake a strategic regional environmental and baseline assessment (**SREBA**), including a regional groundwater model, for any prospective onshore shale gas basin before any production licences are granted for shale gas activities in that basin, commencing with the Beetaloo Sub-basin (***Recommendation 7.4***). Ensure sustainable extraction limits on the basis of the outputs from the regional numerical groundwater model ***(Recommendations 7.6*** and ***7.15***). Develop WAPs for the northern and southern regions of the Beetaloo Sub-basin and determine water allocations once there is better knowledge of the groundwater resources (***Recommendation 7.6***).	Low for northern Beetaloo Sub-basin. Not able to be determined for southern Beetaloo Sub-basin.
Excessive extraction from groundwater - local impacts	*Likelihood* - low of an unacceptable aquifer drawdown further than 1 km from the gas company bore fields. *Consequence* - medium, if aquifers are drawn down excessively this could reduce the effectiveness of bores used by pastoralists and communities. *Risk* - low.	Develop and undertake a SREBA, including a regional groundwater model, for any prospective onshore shale gas basin before any production licences are granted for shale gas activities in that basin, commencing with the Beetaloo Sub-basin (***Recommendations 7.4***). Develop WAPs for the relevant region that include adequate controls over the rate and volume of water extraction by gas companies, and implement a default buffer zone of 1 km between gas company bores and other bores (***Recommendation 7.7***). Require gas companies to monitor local drawdown and 'make good' any excessive drawdown (***Recommendation 7.7)***.	Low
Unacceptable changes to surface or groundwater flows from felt seismic activity caused by hydraulic fracturing	*Likelihood* - low, little evidence for hydraulic fracturing causing felt seismic activity, except in areas of active faults. *Consequence* - low. *Risk* - low.	Require monitoring of the extent of hydraulic fracturing and if needed, reduce the pressure used for fracturing (see discussion at Section 5.10 and ***Recommendation 5.8***). Require monitoring of seismicity during hydraulic fracturing and terminate if induced earth tremors exceed 0.5 on the Richter scale (see discussion at Section 5.10 and ***Recommendation 5.8***).	Low
Unacceptable changes to surface and groundwater flow from seismic activity caused by reinjection of wastewater	*Likelihood* - low, evidence that this practice has cause seismic activity in US but no evidence for flow changes. *Consequence* - low to medium. *Risk* - medium.	Prohibit reinjection of wastewater until comprehensive investigations are undertaken to show that no seismic activity will occur (***Recommendation 7.8***).	Low

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable changes to the surface water flow characteristics due to planned or accidental discharge of wastewaters	*Likelihood* - low to medium, based on historical data from the US. *Consequence* - low. *Risk* - low.	Prohibit the discharge of onshore shale gas hydraulic fracturing wastewaters (treated or untreated) to any surface water body (***Recommendation 7.16***).	Low

Environmental value 2: surface and groundwater quality

Environmental objective 2: to maintain acceptable quality of surface and groundwater

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable groundwater contamination from leaky production wells	**Wastewater (salts and chemicals)** *Likelihood* - very low, little evidence of faulty contemporary wells. *Consequence* - medium, will depend upon the behaviour of contaminants in the groundwater (dispersion, transport, degradation). *Risk* - medium. **Methane** *Likelihood* - low to medium, methane leakage more likely than leakage from bores of contaminated flowback or produced water. *Consequence* - low, little evidence that methane contamination of groundwater is harmful. Methane in water is considered non-toxic, but a possible explosion risk in drinking water bores or storage tanks if dissolved concentration exceeds 28 mg/L. *Risk* - low.	Ensure that all wells to be hydraulically fractured are constructed to at least Category 9 or equivalent, and tested to ensure well integrity before and after hydraulic fracturing, with the results certified by the regulator (***Recommendation 7.10***). Require all relevant information about hydraulic fracturing fluids, flowback and produced water be publicly disclosed (***Recommendations 5.5*** and ***7.9***). Establish a default 'no go zone' of 1 km between well pads and water supply bores (***Recommendation 7.10***). Require real-time groundwater quality monitoring around each well pad (***Recommendation 7.10*** and ***7.11***). Develop specific guidelines for human and environmental risk assessments for all onshore shale gas developments (***Recommendation 7.3)***. Require monitoring of methane in domestic and stock-watering bores closest to well pads. Require venting if concentration in water exceeds 10 mg/L (see discussion at Section 7.6.1.2 and ***Recommendation 7.10***).	Low (wastewater) Low (methane)
Unacceptable groundwater contamination due to leaky abandoned wells	*Likelihood* - low, likely to be little produced water present and gas pressure will be greatly reduced at end of production life. *Consequence* (wastewater) - low, since very low volumes of wastewater will be involved. *Risk* (wastewater) - low. Consequence (methane) - low. *Risk* (methane) - low.	Ensure world leading practice well integrity construction and decommissioning standards are applied and enforced by the regulator (***Recommendations 5.1, 5.3*** and ***7.10***).	Low (wastewater) Low (methane)

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable groundwater contamination due to spills of hydraulic fracturing chemicals and wastewater: on-site spills	*Likelihood* - medium, spills are typically small volume; the likelihood of the contaminants penetrating to the aquifer is low for most of the Beetaloo Sub-basin. *Consequence* - medium, contamination could result in health issues for humans and stock using the aquifer for drinking. *Risk* - medium.	Require the EMP for each well pad to include an enforceable wastewater management plan and spill management plan to be approved prior to the commencement of hydraulic fracturing (***Recommendation 7.11***). Require use of enclosed tanks for wastewater in preference to open ponds, and each well pad to be covered (for example, with a geo-membrane or clay liner) to reduce the infiltration of spills to aquifers (***Recommendation 7.11***). Require real-time monitoring around each well pad (***Recommendations 7.10*** and ***7.11***).	Low
Unacceptable surface and groundwater contamination due to off-site spills of hydraulic fracturing chemicals and wastewater from road and rail transport	*Likelihood* - medium, accidents are likely, particularly for road transport. *Consequence* - medium, contamination of surface waterbodies could occur and result in adverse effects on aquatic ecosystem; in case of groundwater, will depend on where the accident/spill occurs and permeability of overlying soil/rock horizons at that location. *Risk* - medium.	Review adequacy of transportation of hazardous goods regulations (see discussion at Section 7.6.3.2). Conduct a review to determine whether there is a need for restrictions on the transport of hydraulic fracturing chemicals and wastewater during the wet season, particularly on unsealed roads (***Recommendation 7.12***). Review the benefits of rail transport for some or all of the hydraulic fracturing chemicals and other consumables required by the shale gas companies (***Recommendation 7.12***).	Not able to be determined
Unacceptable groundwater contamination due to off-site leaks of hydraulic fracturing chemicals and wastewater from pipelines	*Likelihood* - low, pipelines will be buried. *Consequence* - medium, will depend on volume of the spill, type of wastewater and potential for contamination of groundwater. *Risk* - low.	Ensure adequacy of construction guidelines and their enforcement.	Not able to be determined
Unacceptable contamination of groundwater aquifers due to reinjection of treated or untreated wastewater into other aquifers	*Likelihood* - undetermined, cannot be assessed without detailed site-specific information and computer modelling. *Consequence* - medium, if surface aquifer is contaminated. *Risk* - undetermined.	Prohibit reinjection of wastewater until detailed investigations are undertaken to determine whether or not the risks associated with this practice can be managed to acceptable levels (***Recommendation 7.13***).	Not able to be determined
Unacceptable groundwater contamination due to induced connectivity between hydraulically fractured shale rock formation and overlying aquifers	*Likelihood* - remote to very low, provided that the hydraulic fracturing does not intersect with a fault. *Consequence* - medium. *Risk* - low.	Require submission of details of known fault locations and geomechanical planning for hydraulic fracturing by gas companies to the regulator (***Recommendation 7.14***).	Low

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable groundwater contamination due to changed groundwater pressures	*Likelihood* - low due to very large distance between shale formation and aquifers. *Consequence* - medium. *Risk* - low, provided that the fracturing operations avoid the proximity of existing faults.	Require submission of details of known fault locations and geomechanical planning for hydraulic fracturing by gas companies to the regulator (***Recommendation 7.14***).	Low
Unacceptable contamination of surface waters due to the intentional discharge of partially treated or untreated wastewater	*Likelihood* - low, provided that this practice is prohibited. *Consequence* - medium, if during wet season when dilution is available and depending upon the concentrations of contaminants released. *Risk* - low.	Discharge of shale gas hydraulic fracturing wastewater (treated or untreated) to drainage lines, waterways or temporary stream systems should not be permitted (***Recommendation 7.16***).	Low
Adverse effects of linear infrastructure (roads, pipelines) on the quality and distribution of surface water across the landscape	*Likelihood* - medium, unlikely there will be problems with pipelines provided they are buried. *Consequence* - low to medium, depending upon how they are designed and constructed. *Risk* - medium.	Ensure that there is a landscape scale approach to the design of any infrastructure to minimise the possibility of flow disruption or concentration of flows and that all roads and pipeline corridors are constructed to comply with relevant guidelines, such as the International Erosion Control Association's Best Practice for Erosion and Sediment Control and the Australian Pipeline Industry Association Code of Environmental Practice 2009 (***Recommendation 7.17***).	Low

Environmental value 3: aquatic ecosystems and biodiversity

Environmental objective 3: to adequately protect ecosystems and biodiversity that are dependent on surface water or groundwater

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Excessive extraction from surface waters	*Likelihood* - low, given the lack of permanent surface water in Beetaloo Sub-basin and other semi-arid and arid regions. *Consequence* - medium, if volumes and flow regimes are altered. *Risk* - medium.	Prohibit use of surface water for onshore shale gas hydraulic fracturing in the NT (***Recommendation 7.5***). Develop WAPs for the Beetaloo Sub-basin region that specifically exclude use of surface waters for onshore shale gas development (***Recommendations 7.5*** and ***7.6***).	Low
Excessive extraction from groundwaters	*Likelihood* - low, for surface GDEs since none known in Beetaloo Sub-basin, undetermined for subterranean ecosystems (stygofauna). *Consequence* - undetermined for subterranean ecosystems. *Risk* - undetermined, lack of detailed knowledge of impact of subterranean fauna (stygofauna).	Undertake a SREBA of the Beetaloo Sub-basin, including a baseline study of surface and subterranean ecosystems (***Recommendation 7.4***).	Low for surface GDEs but undetermined for subterranean ecosystems
Unacceptable contamination of surface waters (aquatic ecosystems)	*Likelihood* - low. *Consequence* - medium. *Risk* - low.	Discharge of shale gas hydraulic fracturing wastewater (treated or untreated) to drainage lines, waterways or temporary stream systems should not be permitted (***Recommendation 7.16***). Store chemicals and wastewater in lined containment structures or tanks within bunded areas. Effectively manage accidental spills from well pads, road tankers or pipelines (see discussion at Sections 7.6.3.1, 7.6.3.2 and 7.6.7, and ***Recommendations 7.11*** and ***7.12***).	Low
Unacceptable contamination of groundwaters (groundwater-dependent ecosystems)	*Likelihood* (leaky wells) - low, little evidence of faulty contemporary wells leaking solutes. *Likelihood* (spills) - medium. *Consequence* -undetermined, impact of contaminants on surface GDEs and subterranean fauna unknown. *Risk* - undetermined.	Undertake a SREBA of the Beetaloo Sub-basin, including a baseline study of surface and subterranean ecosystems (***Recommendations 7.4, 7.18*** and ***7.19***). Undertake an ecological risk assessment of shale gas hydraulic fracking wastewater toxicity to stygofauna (see discussion at Sections 7.2.3, 7.7.1 and ***Recommendations 7.4, 7.18*** and ***7.19***).	Undetermined

Chapter 8 Land

Environmental value 1: terrestrial biodiversity and ecosystem health

Environmental objective 1: to ensure there is a low risk of impact on the terrestrial biodiversity values of affected bioregions and to ensure that the overall terrestrial ecosystem health, including the provision of ecosystem services, is maintained

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable location of shale gas developments within a region	*Likelihood* - high, due to lack of region-wide biodiversity knowledge. *Consequence* - high, significant threat to species that might occupy highly restricted ranges in development area. *Risk* - high.	Undertake a SREBA for all affected bioregions prior to any onshore shale gas production. (***Recommendation 8.1***). Exclude onshore shale gas development from regions identified in the SREBA as having high conservation value (***Recommendation 8.1***).	Low
Unacceptable increase in the spread or impact of weeds	*Likelihood* - high, given experience with onshore gas developments elsewhere. Consequence - high, given severe potential impact on conservation and production values. *Risk* - high.	Undertake baseline assessment of all weeds on a permit area prior to any onshore shale gas exploration (***Recommendation 8.2***). Undertake ongoing weed monitoring to inform any necessary weed management measures (***Recommendation 8.2***). Ensure gas companies have in place prior to entering a petroleum title area, a weed management plan that is consistent with all relevant statutory weed management plans and any relevant threat abatement plans made under the EPBC Act (***Recommendation 8.3***).	Low
Unacceptable increase in the spread or impact of exotic invasive ants	*Likelihood* - medium, given that such species are established elsewhere in northern Australia and are readily spread by vehicles and machinery. *Consequence* - high, major impacts on native species if introduced. *Risk* - high.	Implement hygiene measures for vehicles and machinery (see discussion at Section 8.4.2.2 and ***Recommendation 8.3***).	Low
Unacceptable increase in the impact of feral animals	*Likelihood* - low, because onshore gas development is unlikely to have a significant impact on feral animal populations. *Consequence* - low, as any increased impact of feral animals is likely to be local only. *Risk* - low.	Require gas companies to be aware of regional feral animal management obligations and programs (see discussion at Section 8.4.2.3).	Low
Unacceptable changes to fire regimes	*Likelihood* - medium, increased human activity and hence sources of ignition. *Consequence* - high, given the ecological importance of fire and its role in GHG gas emissions. *Risk* - high.	Establish regional fire management plans, which include requirements for baseline data, monitoring for any increase in fire frequency, and implementation of management actions as appropriate (***Recommendation 8.4***).	Low

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable loss of native vegetation	*Likelihood* - high, given that substantial areas will be cleared of vegetation. *Consequence* - low, because only small proportion of the landscape will be cleared, and fragmentation and edge effects are likely to be limited. Risk - medium.	Identify any threatened species likely to be affected by cumulative effects of habitat loss and fragmentation and manage accordingly (***Recommendation 8.5***). Minimise vegetation clearing (***Recommendation 8.6***). Progressively rehabilitate cleared areas (***Recommendation 8.7***). Implement offsets to compensate for local vegetation and habitat losses (***Recommendation 8.8***).	Low
Roads and pipelines as ecological barrier or corridors	*Likelihood* - medium, given impacts of past construction of roads and pipelines. *Consequence* - medium, given ecological importance of run-on/ run-off dynamics in flat, semi-arid landscapes. *Risk* - medium.	Require gas companies to identify critical habitats during corridor construction and select an appropriate mechanism to avoid detrimental impact upon them (***Recommendation 8.10***).	Low
Other impacts on wildlife	*Likelihood* - low, given management procedures already in place. *Consequence* - low, given that any impacts will be local only. *Risk* - low.	Implement existing management procedures (***Recommendation 8.10***).	Low

Environmental value 2: landscape amenity

Environmental objective 2: to ensure that the perception by residents and tourists that the NT is a place of largely unspoiled landscapes is not diminished

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable landscape transformation	*Likelihood* - medium, given experiences with onshore gas developments elsewhere. *Consequence* - high, given the extremely high importance of the NT's unspoiled landscapes. *Risk* - high.	Ensure that gas companies minimise the surface footprint of each development and ensure that well pads are at least 2 km apart (***Recommendation 8.15***). Ensure that the infrastructure within development areas is not visible from public roads (***Recommendation 8.15***).	Low
Unacceptable increase in heavy-vehicle traffic	*Likelihood* - cannot be assessed, lack of predicted traffic information. *Consequence* - uncertain. *Risk* - uncertain.	Assess the impact that all heavy-vehicle traffic associated with any onshore shale gas industry will have on the NT's transport system, including: • forecast traffic volume and roads used; • the feasibility of using the existing Adelaide to Darwin railway line to reduce heavy-vehicle road use; and • road upgrades. Develop a management plan to mitigate such impacts (***Recommendation 8.16***).	Low to medium

Chapter 9 Greenhouse gases

Environmental value 3: climate change

Environmental objective: to limit the emissions of methane and greenhouse gases to the atmosphere

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Excessive upstream fugitive emissions of methane	*Likelihood* - high, given that methane emissions occur mostly on a continuous basis but with some episodic releases. *Consequence* - low, given that upstream methane emissions (from any new shale gas field) will contribute a very low proportion of net global methane emissions. *Risk* - medium.	Introduce the US EPA New Source Performance Standards of 2012 and 2016 (***Recommendation 9.1***).	Acceptable[1]
Abnormal fugitive emissions of methane during upstream production and processing	*Likelihood* - high, in the absence of monitoring and appropriate action. *Consequence* - low, given that upstream methane emissions (from any new shale gas field) will contribute a very low proportion of net global methane emissions. *Risk* - medium.	Implement a code of practice or other guideline for the ongoing monitoring, detection and reporting of emissions from gas fields and wells upon production commencing (***Recommendation 9.2***). Implement baseline monitoring of methane concentrations for at least one year in advance of production commencing (***Recommendation 9.3***). Implement baseline and ongoing monitoring by the regulator, to be funded by the industry. Measurements and their interpretation to be undertaken by an independent third party (***Recommendation 9.4***). Monitoring results should be published on a continuous real-time basis (***Recommendation 9.5***). Implement investigation if emission concentration limits are exceeded to identify the source(s) of the excess levels, and 'make good' provisions must be implemented where necessary. Such investigations and implementation must be the responsibility of industry. All methane exceedance events must be reported to the regulator and the information made public (***Recommendations 9.5*** and ***9.6***).	Acceptable
Excessive emissions of lifecycle greenhouse gas	*Likelihood* - high, given that GHG emissions occur mostly on a continuous basis but with some episodic releases. *Consequence* - low, given that GHG emissions (from any new shale gas field) will contribute a very low proportion of net global GHG emissions. *Risk* - medium.	Focus risk reduction on reducing upstream methane emissions as there is little opportunity to reduce GHG from the downstream stage (see discussion at Section 9.6).	Acceptable

1 The Panel assessed all GHG risks as 'medium', making it necessary to consider how these risks can be further mitigated. Given the assessed likelihood and consequence ratings cannot be reduced to a lower category, the assessed risks will remain medium. As the consequences are assessed as 'minor' or 'moderate' (they are not assessed as 'severe' or 'catastrophic'), it is not necessary to formally invoke the precautionary principle as the conditions precedent have not been met (see Chapter 4). Nevertheless, the precautionary principle has been considered and applied where appropriate.

The Panel believes that implementation of the additional mitigation measures specified in the recommendations contained in Chapter 9 will result in lower levels of emissions of methane and GHG and allow any new onshore shale gas field in the NT to achieve an acceptable level of risk for methane and GHG emissions.

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Excessive emissions of methane from abandoned wells	*Likelihood* - high, given that methane emissions from abandoned wells occur mostly on a continuous basis but with some episodic releases. *Consequence* - low, given that methane emissions from abandoned wells will contribute a very low proportion of net global methane emissions. *Risk* - medium.	Mandate a code of practice setting out minimum requirements for the abandonment of all onshore shale gas wells in the NT. The code must be enforceable and include a requirement that: • wells undergo pressure and cement integrity tests prior to abandonment, with any identified defects to be repaired prior to releasing the well for decommissioning; and • testing must be conducted to confirm that the plugs have been properly set in the well. (***Recommendation 5.1***) Provide a bank guarantee or bond to the regulator to ensure necessary funds are available to decommission wells or facilities in the event an operator is no longer a going concern (***Recommendation 14.19***).	Acceptable
Other (supplementary) risks may prevent lower levels of methane emission performance from being achieved	N/A	The action framework in **Table 9.10** to be implemented to manage and/or mitigate any supplementary risks that may prevent the achievement of lower levels of methane emissions (***Recommendation 9.7***).	Acceptable

Chapter 10 Public health

Environmental value 1: to prevent adverse impacts on public health by exposure to chemicals in contaminated water and air

Environmental objective 1: to assess and manage health risks associated with contaminated surface and groundwater

The risk estimates and risk mitigation measures for this objective are identical to those associated with water quality in Chapter 7.

Environmental objective 2: to assess and manage human health risks associated with the specific chemicals used in, or likely to result from, hydraulic fracturing processes

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable human health effects caused by hydraulic fracturing and geogenic chemicals in flowback water	*Likelihood* - low, for hydraulic fracturing chemicals, unknown (at this time) for geogenic chemicals. *Consequence* - medium, if inadequate knowledge of the concentration or presence of more toxic chemicals compromises the estimation of health risks via a formal HHRA. *Risk* - low.	Require gas companies to prepare a site-specific HHRA that: • uses contemporary knowledge of the chemicals proposed to be used specifically in formulating fracking fluids for operations in the NT; and • provides further details of the chemical composition of flowback and produced water specific to the geological features of the NT sites proposed for shale gas development, along with the proposed methods of treatment and/or disposal of this water (***Recommendation 10.1*** and ***10.2***).	Low - for hydraulic fracturing chemicals Unknown - (at this time) for geogenic chemicals

Environmental objective 3: to ensure human health risks associated with airborne emissions from gas wells and associated infrastructure are acceptable

Risk	Preliminary risk assessment	Mitigation measure	Residual risk
Unacceptable impacts on the health of nearby communities from volatile or gaseous chemicals emitted from well heads, storage ponds, processing facilities or pipelines	*Likelihood* - medium for methane. Low for VOCs but highly dependent on the distance between source and potentially exposed humans. *Consequence* - low for methane (relatively non-toxic gas). Medium for toxic gases and VOCs (such as NOx, BTEX), especially where associated with gas combustion events (flaring). *Risk* - low to medium.	Require a high standard of maintenance to ensure well head assemblies and pipelines are not leaking, coupled with regular monitoring to detect point source leaks. (***Recommendations 5.1*** to ***5.4***). Establish appropriate setback distances to minimise risks identified in HHRA reports, including potential pathways for waterborne and airborne contaminants. In the absence of local information, a default minimum setback distance of 1.6 km (based on US data) should be used (***Recommendation 10.3***).	Low
Unacceptable impacts on the health of nearby communities from dusts and/or diesel exhaust fumes from shale gas site preparation activities	*Likelihood* - medium, but likely to be of relatively short-term impact during the pre-production phase of well head and facility development. *Consequence* - low to medium, depending on controls over equipment movements and/or dust suppression measures. *Risk* - low to medium.	Establish appropriate setback distances (based on scientific evidence) to protect landowners and local communities. In the absence of local information, a default minimum setback distance of 1.6 km (based on US data) should be used (***Recommendation 10.3***).	Low to medium

Environmental objective 4: to ensure the human health risks associated with potential impacts on wellbeing are acceptable

The assessment of this objective is primarily covered in Chapter 9, together with the assessments contained in Chapters 11 and 12.

Appendix 4 Panel meetings

Date	Location
8 December 2016	Sydney, NSW
8-9 February 2017	Sydney, NSW
11 March 2017	Darwin, NT
5 May 2017	By telephone
2 June 2017	Melbourne, Vic
18 July 2017	Canberra, ACT
6 September 2017	Melbourne, Vic
25 September 2017	Melbourne, Vic
9 October 2017	Brisbane, QLD
9 November 2017	Melbourne, Vic

Appendix 5 Stakeholder meetings

Location/Date	Organisation	Representatives
DARWIN, NT		
20 February 2017	NT Department of the Chief Minister	Ms Jodie Ryan, Chief Executive Officer Ms Rachel Bacon, Deputy Chief Executive Officer
	Frack Free Alliance, Darwin	Ms Belinda Quinlivian Mr Chris Naden
	Lock the Gate Alliance (NT)	Ms Naomi Hogan, Northern Territory Coordinator
	Environmental Defenders Office (NT) Inc	Mr David Morris, Principal Lawyer and Executive Officer
	Environment Centre Northern Territory	Mr Drew English, Chair Ms Shar Molloy, Director
	Frack Free Alliance, Darwin Rural	Ms Pauline Cass
	Northern Territory Chamber of Commerce	Mr Brian O'Gallagher, Acting Chief Executive Officer Mr Greg Ireland, President
	Australian Petroleum Production and Extraction Association	Mr Matthew Doman, Director, South Australia/Northern Territory
	Origin Energy Limited	Dr David Close, Chief Geologist and Unconventional Exploration Manager Ms Stephanie Stonier, Corporate Affairs Manager (Northern Australia)
	Central Petroleum Limited	Mr Richard Cottee, Managing Director and Chief Executive Officer
	Pangaea Resources Pty Ltd	Mr Todd Hoffman, Geoscientist
	Santos Ltd	Mr Bill Ovenden, Vice President, Exploration and Subsurface Mr Tom Baddeley, Manager, Government and Community Relations Mr Che Cockatoo-Collins, Aboriginal Employment Adviser
KATHERINE, NT		
21 February 2017	NT Department of the Chief Minister	Mr John de Koning, Regional Executive Director
	Amateur Fishermen's Association of the Northern Territory	Mr Warren de With, President
	Katherine Town Council	Mayor Fay Miller Deputy Mayor Toni Tapp-Coutts Alderman Peter Gazey
	Victoria Daly Regional Council	Mayor Brian Pedwell
	Don't Frack Katherine	Ms Kerrie Mott Dr Errol Lawson
	Jawoyn Association Aboriginal Corporation	Mr John Berto, Chief Executive Officer
NHULUNBUY, NT		
22 February 2017	NT Department of the Chief Minister	Mr Jim Rogers, Regional Executive Director
	East Arnhem Regional Economic Development Committee	Representatives from the following organisations: Gumatj Aboriginal Corporation, Miwatj Employment and Participation Ltd, Dhimurru Aboriginal Corporation, Rio Tinto, East Arnhem Regional Council, and the Australian Department of Prime Minister and Cabinet

Location/Date	Organisation	Representatives
TENNANT CREEK, NT		
22 February 2017	Tennant Creek Regional Economic Development Committee	Mr Greg Marlow, Chair Mr Steven Edgington, Regional Executive Director, Barkly Ms Josephine Bethel, Secretariat
ALICE SPRINGS, NT		
23 February 2017	Arid Lands Environment Centre	Mr Jimmy Cocking, Director
	Public Health Association Northern Territory; Doctors for the Environment	Dr Rosalie Schultz
	Alice Springs Town Council	Mayor Damien Ryan Councillor Jade Kudrenko Mr Rex Mooney, Chief Executive Officer
	Chamber of Commerce, Alice Springs/Tennant Creek	Ms Kaye Eade, Executive Officer Mr Martin Glass
	Central Desert Regional Council	Ms Cathryn Hutton, Chief Executive Officer
	Frack Free Northern Territory Alliance	Ms Lauren Mellor, Coordinator Ms Marli Banks
DARWIN, NT		
24 February 2017	Northern Land Council	Mr Murray McLaughlin, Media and Policy Manager Ms Rhonda Yates, Manager, Minerals and Energy Branch Mr Michael O'Donnell, Principal Legal Officer Mr Greg McDonald, Senior Project Coordinator
	Northern Territory Farmers Association	Mr Simon Smith, President Mr Tom Harris, Director
	NT Department of Primary Industry and Resources	Mr Alister Trier, Chief Executive Officer
	NT Department of Environment and Natural Resources	Ms Joanne Townsend, Acting Chief Executive Officer
	Amateur Fishermen's Association of the Northern Territory	Mr David Ciaravolo, Executive Officer
ALICE SPRINGS, NT		
30 March 2017	Aboriginal Areas Protection Authority, Alice Springs	Board meeting
DARWIN, NT		
31 March 2017	Northern Territory Cattlemen's Association	Annual General Meeting and Industry Conference
DARWIN, NT		
2 April 2017	Amateur Fishermen's Association of the Northern Territory	Annual General Meeting
TENNANT CREEK, NT		
11 May 2017	Central Land Council	Full Council meeting
KATHERINE, NT		
31 May 2017	Northern Land Council	Full Council meeting
NEWCASTLE WATERS, NT		
4 July 2017	Traditional Owners and Northern Land Council	Ms Gay English, anthropologist Mr Ian Harris, Project Officer Borroloola/Barkly Region, Northern Land Council
MARYFIELD PASTORAL STATION, NT		
5 July 2017	APN Pty Ltd Hayfield-Shenandoah	Mr John Dyer and Mrs Val Dyer Mr Justin Dyer and Mrs Sally Dyer Mr Nick Dyer

Location/Date	Organisation	Representatives
HAYFIELD PASTORAL STATION, NT		
6 July 2017	North Star Pastoral Pty Ltd	Mr Colin Ross, Managing Director North Star Pastoral Pty Ltd Mr Warwick Giblin, Managing Director, OzEnvironmental Pty Ltd
BRISBANE, QUEENSLAND		
17 July 2017	Centre for Coal Seam Gas, University of Queensland	Professor Andrew Garnett, Director Ms Helen Schultz, Project Officer (Research & Strategy), Dr Sue Vink, Principal Research Fellow, Centre for Water in the Minerals Industry Associate Professor Nicole Gillespie, Business School Dr Katherine Witt, Research Fellow, Centre for Social Responsibility in Mining, Sustainable Minerals Institute Associate Professor John Steen, Business School Professor Ray Johnson, Chair, Well Engineering and Production Technology Professor Brian Towler, Chair in Petroleum Engineering Professor Jim Underschultz, Chair in Petroleum Hydrodynamics
	Queensland Gas Company	Mr Spencer Roberts, Smart CSG and Transformation Manager, Shell Australia Ms Lucy McKee, Technology and Planning Manager, Development, Shell Australia
BRISBANE, QUEENSLAND		
24 July 2017	Agforce	Dr Dale Miller, General Manager, Policy Mr Daniel Phipps, CSG Project Leader with Agforce
	Queensland Farmers' Federation	Dr Georgina Davis, Policy Advisor, Resources
DALBY, QUEENSLAND		
25 July 2017	Queensland Gasfields Commission and landholders affected by the CSG industry	Ms Jane Walker, Regional Engagement Officer, Queensland Gasfields Commission Mr Stuart Hayllor Mr Brad Robinson, Feedlot Manager, Mort and Co Mr Tom and Mrs Michelle O'Connor
	Western Downs Regional Council	Mayor Paul McVeigh Mr Ross Musgrove, Chief Executive Officer
	Former Commissioner of the Queensland Gasfields Commission	Mr John Cotter
ROMA, QUEENSLAND		
27 July 2017	Queensland Gasfields Commission	Ms Katrina MacDonald, Regional Engagement Officer
	Former Mayor of Roma	Mr Rob Loughnan
	Former Councillor	Mr Scott Wason
MILES, QUEENSLAND		
27 July 2017	Origin Energy Ltd	Dr David Close, Chief Geologist Mr Tim Ogilvie, Regional Manager (Western Downs) Ms Natasha Patterson, General Manager, Communities and Access
	Miles State High School	Mr Stephen Hardy, Head of Department - Senior
TENNANT CREEK, NT		
15 November 2017	Northern Land Council	Full Council meeting, Tennant Creek

Appendix 6 Departmental briefings

Date	Presenters	Description
DARWIN, NT		
8 December 2016	**NT Department of Primary Industry and Resources** Mr Alister Trier, Chief Executive Officer Mr Ian Scrimgeour, Director, Northern Territory Geological Survey	Presentation on Northern Territory gas resources, basins and energy demand.
ADELAIDE, SA		
	Nuclear Fuel Cycle Royal Commission Consultation and Response Agency Ms Madeline Richardson, Chief Executive Mr John Phalen, Director, Engagement **Department of State Development** **South Australian Government** Mr Barry Goldstein, Executive Director, Energy Resources Division Mr Michael Malavazos, Director, Engineering Operations, Energy Resources Division	Overview of the South Australian Nuclear Fuel Cycle Royal Commission Consultation and Response Agency.
DARWIN, NT		
8 February 2017	**NT Department of Environment and Natural Resources** Mr Des Yin Foo, Director, Water Assessment	Presentation on water, focussing on climate change and major aquifers in the Northern Territory.
	Department of the Environment and Energy **Australian Government** Mr Anthony Swirepik, Director, Bioregional Assessments, Office of Water Science	Presentation on bioregional assessments.
	Department of Natural Resources and Mines **Queensland Government** Mr Bill Date, Chief Inspector, Petroleum and Gas Inspectorate Mr Ian Heiner, A/Executive Director, Coal Seam Gas Compliance Unit	Presentation on the Queensland experience with unconventional gas, focussing on land access issues and the Gasfields Commission.
DARWIN, NT		
9 February 2017	**NT Department of Primary Industry and Resources** Mr Jop van Hattum, Senior Director, Petroleum Technology and Operations	Presentation on technical overview of hydraulic fracturing for shale gas.
	NT Department of the Chief Minister Ms Jodie Ryan, Chief Executive Officer	Presentation on the economy of the Northern Territory.
DARWIN, NT		
11 March 2017	**NT Department of Primary Industry and Resources** Mr Jop van Hattum, Senior Director, Petroleum Technology and Operations	Presentation on the Petroleum Act and the Petroleum Environment Regulations.
BRISBANE, QUEENSLAND		
17 July 2017	**Queensland Gasfields Commission** Ms Ruth Wade, Commission Chair Ms Carolyn Collins, General Manager Mr Liam Jeory, Policy and Engagement Director Mr Murray Cornish, Communications Director	Presentation on the Commission's powers and functions.
	Gas Industry Social and Environmental Research Alliance (**GISERA**) and Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) Dr Damian Barrett, Research Director, Onshore Gas (Energy Business Unit) Mr Dan O'Sullivan, Deputy Director Dr Andrea Walton, Research Scientists (Social Science), CSIRO Dr Rod McCrea, Research Scientists (Social Science), CSIRO	Presentations on community wellbeing and resilience.

Date	Presenters	Description
CANBERRA, AUSTRALIAN CAPITAL TERRITORY		
18 July 2017	**CSIRO/GISERA** Dr Damian Barrett, Research Director, Onshore Gas (Energy Business Unit)	Presentation on the Beetaloo Basin Water Study quantifying baseline characteristics of groundwater within the Beetaloo Sub-basin.
	NT Department of Environment and Natural Resources Ms Karen Avery, Executive Director, Environment Policy and Support	Presentation on the Northern Territory environmental reform agenda.
CANBERRA, AUSTRALIAN CAPITAL TERRITORY		
19 July 2017	**Department of Industry, Innovation and Science Australian Government** Mr Bruce McCleary, General Manager, National Radioactive Waste Management Taskforce Mr Angus Cole, Manager, Community Consultation, National Radioactive Management Taskforce	Presentation on the Radioactive Waste Management Project community consultation and engagement.
	Department of the Environment and Energy Australian Government Mr John Higgins, Director, Knowledge and Technology Division Mr Matthew Whitfort, Assistant Secretary, Knowledge and Technology Division Mr Andrew McNee, Assistant Secretary, Environment Standards Division	Presentation on human health risks, environmental exposure conceptualisation and environmental risks of chemicals used in coal seam gas extraction.
	Department of the Environment and Energy Australian Government Mr Anthony Swirepik, Director, Knowledge and Technology Division Mr Matthew Whitfort, Assistant Secretary, Knowledge and Technology Division	Presentation on combined geological and bioregional resource assessments.
	Department of the Environment and Energy Australian Government Ms Gayle Milnes, Assistant Secretary, Domestic Emissions Reduction Division Mr Rob Sturgiss, Assistant Secretary, International Climate Change and Energy Innovation Division	Presentation on Australia's current emissions data, its emissions reductions target and whether the supply of high-quality gas to the east coast could assist in meeting this target.
	Department of the Environment and Energy Australian Government Mr Brenton Philp, Assistant Secretary, Energy Division Mr Dwayne Purdy, Director, Energy Division	Presentation on the National Energy Policy, including energy security issues, the role of gas and the National Electricity Market, the Northern Gas Pipeline and future opportunities.
BRISBANE, QUEENSLAND		
24 July 2017	**Department of Natural Resources and Mines Queensland Government** Mr Warwick Squire, Acting Executive Director, Coal Seam Gas Compliance Unit, Mineral and Energy Resources Mr Lyall Hinrichsen, Acting Executive Director, Resources and Energy Policy Mr David Rynne, Chief Economist Mr David Wiskar, Executive Director, Water Policy Mr Keith Phillipson, Director, Office of Groundwater Management Mr Jon Thomas, Manager, Petroleum Assessment Hub Dr Steven Ward, Acting Manager, Coal Seam Gas Compliance Unit Mr Peter Lee, Executive Petroleum Inspector, Petroleum and Gas Inspectorate Mr Hamish Butler, Director, Petroleum and Gas Unit **Department of Environment and Heritage Protection Queensland Government** Mr Mark Venz, Executive Director, Petroleum, Gas and Compliance	Presentation on recent gas exploration and infrastructure development and its economic contribution to the State. Information was provided on gas sector policy and the legislative framework, particularly with regard to petroleum and gas tenure, land access, water policy and planning and groundwater impact assessment. Presentation by the Department of Environment and Heritage Protection, which administers the *Environmental Protection Act 1994* (Qld) on environmental policy, regulation, compliance and enforcement in Queensland.

Date	Presenters	Description
BRISBANE, QUEENSLAND		
28 July 2017	**CSIRO/GISERA** Dr Damian Barrett, Research Director, Onshore Gas (Energy Business Unit) Mr Dan O'Sullivan, Deputy Director, GISERA Dr Neil Huth, Lead Researcher, Agriculture and Food, CSIRO Dr Sarah Lawson, Senior Research Scientist, Reactive Gases Team Leader, Oceans and Atmosphere, CSIRO Dr Melita Keywood, Research Scientist, Oceans and Atmosphere, CSIRO Dr Cameron Huddlestone-Holmes, Senior Research Scientist, Energy, CSIRO Mr James Kear, Research Team Leader, Hydraulic Fracturing, CSIRO	Presentations on scientific research in respect of communities living in gas development regions. Topics included groundwater and surface water management, biodiversity, land management and socioeconomic impacts. Technical presentations were provided on hydraulic fracturing technologies and well decommissioning.
	Department of Natural Resources and Mines **Queensland Government** Dr Sanjeev Pandey, Acting General Manager, Office of Groundwater Impact Assessment	Presentation on the role of the Office of Groundwater Impact Assessment.
ADELAIDE, SA		
7 September 2017	**Department of State Development** **South Australian Government** Barry Goldstein, Executive Director, Energy Resources Division **Department of the Premier and Cabinet** **South Australian Government** Michael Malavazos, Director, Engineering Operations, Energy Resources Division	Overview of South Australia's approach to best practice for upstream petroleum industry regulation with regard to the *Petroleum and Geothermal Energy Act 2000* (SA). The approach to monitoring compliance of regulated activities and surveillance classifications were discussed.

Appendix 7 Public hearings

Location/Date	Organisation	Representatives
ALICE SPRINGS, NT		
6 March 2017	Alice Springs Town Council	Mayor Damien Ryan Deputy Mayor Jamie de Brenni Councillor Jade Kudrenko
	Arid Lands Environment Centre	Mr Jimmy Cocking, Director Mr Alex Read, Policy Officer
	Aloha Therapeutic Massage	Mr Jason Trevers
	Central Petroleum Limited	Mr Richard Cottee, Managing Director and Chief Executive Officer Mr Rolf Schulte, Alice Springs Area Manager Mr David Liddle, Public Relations and Communications
	Drill and Complete Pty Ltd	Mr Ash Chawla, Well Engineering and Project Management
	Central Land Council	Mr David Ross, Director Mr James Nugent, General Manager, Legal Ms Julie Ann Stoll, Mining Manager
	Public Health Association NT; Doctors for the Environment; Central Australian Rural Practitioners Association	Dr Rosalie Schultz
	Central Australia Frack Free Alliance	Ms Marli Banks Mr Dalton Dupuy
TENNANT CREEK, NT		
7 March 2017	Barkly Landcare and Conservation Association	Mr Anthony Cox, President Ms Anne Alison Ms Naomi Wilson Mr Michael Anderson
	Cave Creek Station	Mr Rohan Sullivan
	Seed Indigenous Youth Climate Network	Ms Larissa Baldwin, National Co-Director Ms Vanessa Farrelly
KATHERINE, NT		
8 March 2017		Ms June Tapp
	Big River Station	Mr Daniel Tapp
	Katherine Mining Services Association	Mr Geoff Crowhurst, Chair
	Top Didj Cultural Experience and Art Gallery	Ms Petrena Ariston
	Don't Frack Katherine	Dr Errol Lawson
		Ms Annette Raynor
		Ms Teresa Cummings
	Katherine Town Council	Mr Robert Jennings, Chief Executive Officer
DARWIN, NT		
10 March 2017	North Star Pastoral represented by OzEnvironmental Pty Ltd	Mr Warwick Giblin
	Australian Petroleum Production and Exploration Association	Mr Matthew Doman, Director, South Australia/Northern Territory Mr Keld Knudsen, Policy Director, Exploration

Location/Date	Organisation	Representatives
DARWIN, NT		
10 March 2017	Origin Energy Limited	Mr Ross Evans, General Manager, Exploration and New Resources Dr David Close, Chief Geologist and Unconventional Exploration Manager Mr Alexander Cote, Senior Petroleum Engineer Ms Stephanie Stonier, Corporate Affairs Manager (Northern Australia)
	Lock the Gate Alliance (NT)	Ms Naomi Hogan
	Santos Ltd	Mr Bill Ovenden, Vice President Exploration and Subsurface Mr Che Cockatoo-Collins, Advisor Aboriginal Engagement Mr Andrew Snars, Maranoa Regional Manager Mr Rohan Richardson, Manager Design and Construction Onshore
	Armour Energy Limited	Mr Luke Titus, Chief Geologist
	Amateur Fishermen's Association of the Northern Territory	Mr David Ciaravolo, Executive Officer
	Environmental Defenders Office (NT) Inc	Mr David Morris, Principal Lawyer and Executive Officer
	Environment Centre Northern Territory	Ms Shar Molloy, Director Mr Drew English
	Frack Free Alliance, Darwin	Ms Belinda Quinlivian Mr Chris Naden Ms Melissa Burey
	Northern Territory Cattlemen's Association	Ms Tracey Hayes, Chief Executive Officer Mr Tom Stockwell, President
	Consolidated Pastoral Company	Mr Troy Setter, Chief Executive Officer
		Mr Justin Tutty
		Ms Katherine Marchment
		Ms Merrilee Baker
	Pangaea Resources Pty Ltd	Mr Tim Radburn, Executive Director
	Halliburton	Ms Diana Grantham, Senior Technical Professional Production Enhancement Mr Ian Adams
	Climate Action Darwin	Ms Anna Boustead Ms Grusha Leeman
DARWIN, NT		
31 July 2017	Sully Pty Ltd and MS Contracting	Mr Bill Sullivan Mr Mark Sullivan
		Mr Rob Woods
	Institute for Energy Economics and Financial Analysis	Mr Bruce Robertson
		Ms Jo Vandermark
	United Voice	Mr Pat Honan
DARWIN, NT		
1 August 2017	Lock the Gate Alliance (NT)	Ms Naomi Hogan
	Environmental Defenders Office (NT) Inc	Mr David Morris, Principal Lawyer and Executive Officer
		Professor Melissa Haswell
		Mr Jamie Houldsworth
	Frack Free Darwin	Ms Belinda Quinlivian Ms Melissa Bury

Location/Date	Organisation	Representatives
DARWIN, NT		
1 August 2017		Ms Seranna Shutt Mr Ron Chute Ms Ellen Gapany
		Professor Jenny Davis
		Mr Ron Chute Mr David Forsyth
		Mr Nicholas Milyari Fitzpatrick
	Oilfield Connect	Mr Mark Fraser, Manager
	Terrabos Consulting Pty Ltd	Mr David Armstrong
		Mr Carl Brand representing Ms Rikki Saltmarsh
DARWIN, NT		
2 August 2017	Santos Ltd	Mr Bill Ovenden, Vice President Exploration and Subsurface Mr Tom Baddeley, Manger Public Affairs Mr Paul Wybrew, Senior Environmental Officer Mr Geoff Atherton, General Manager of Drilling Operations Mr Che Cockatoo-Collins, Advisor Aboriginal Engagement
		Mr Tim Forcey
		Ms Billee McGinley
		Mr Christland Kovison Yao
		Mr Paul Sharp
	The Australia Institute	Mr Roderick Campbell, Research Director
	Climate Action Darwin	Ms Grusha Leeman
	Maritime Union of Australia	Mr Thomas Mayor, Branch Secretary
		Mr Justin Tutty
		Ms Katherine Marchment
		Ms Pauline Cass
ALICE SPRINGS, NT		
3 August 2017	Arid Lands Environment Centre Inc	Mr Jimmy Cocking, Director Mr Alex Read, Policy Officer
		Ms Lisa Gray Mr Miles Jennings
		Mr Allan O'Keefe Mrs Marilyn O'Keefe Ms Jasmin O'Keefe
		Mr Jason Trevers
	Central Australia Frack-Free Alliance	Ms Marli Banks Mr Jesse Hancock
		Mr Domenico Pecorari
	Elkedra Station	Ms Amber McBride
ALICE SPRINGS, NT		
4 August 2017		Mr Christopher Hawke
		Ms Dianna Newham Ms Barbara Molanus Ms Ella Newham-Perry
	Arid Lands Environment Centre Inc	Mr Jimmy Cocking, Director Mr Alex Read, Policy Officer

Location/Date	Organisation	Representatives
ALICE SPRINGS, NT		
4 August 2017		Ms Amber Driver
		Ms Kirsty Robertson
		Mr Mark Swindles
		Ms Esther Nunn Ms Gem Walsh
		Ms Heather McIntyre
	RMIT University	Dr Matthew Currell, Senior Lecturer and Program Manager (Environmental Engineering)
KATHERINE, NT		
8 August 2017	Katherine Mining Services Association	Mr Geoff Crowhurst, Chair
		Dr Errol Lawson
	Environment Centre Northern Territory	Ms Shar Molloy, Director
	Vista Gold	Mr Brent Murdoch, Director/General Manager
KATHERINE, NT		
9 August 2017	North Australian Rural Management Consultants Pty Ltd	Ms Teresa Cummings, Corporate Manager
		Ms Carol Randall Mr Andrew Smith
		Mr Annette Raynor
		Mr Daniel Tapp
		Ms Cheryl Birch
	Gasfield Free Communities	Ms Lauren Mellor Ms Vivienne Soebek Mrs Glenys Somers Ms Petrena Ariston Ms Kerrie Mott
		Mr Michael Somers Mrs Glenys Somers
	Origin Energy Ltd	Dr David Close, Chief Geologist and Unconventional Exploration Manager Ms Stephanie Stonier, Corporate Affairs Manager (Northern Australia) Mr Alexander Cote, Senior Petroleum Engineer
		Ms Samantha Phelan
TENNANT CREEK, NT		
10 August 2017	Australian Petroleum Production and Exploration Association	Mr Matthew Doman, Director, South Australia/ Northern Territory Mr Keld Knudsen, Policy Director, Exploration Mr Adam Welch, Senior Policy Adviser
		Mr Raymond Dixon Ms Eleanor Dixon Ms Jeanie Dixon Mr Shannon Dixon Ms Mary James
		Mr Andrew Munckton (by video and conference call)
MELBOURNE, VICTORIA		
6 September 2017	Schlumberger Australia Pty Ltd	Mr Paul McDougall, Australia Onshore General Manager Mr Joe Lima, Director of Environment Sustainability Mr Daniel Kalinin, Technical Manager, Stimulation

Appendix 8 Community forums

Date	Location
6 March 2017	Alice Springs
7 March 2017	Tennant Creek
8 March 2017	Katherine
9 March 2017	Darwin
9 March 2017	Humpty Doo
20 March 2017	Gapuwiyak
20 March 2017	Nhulunbuy
21 March 2017	Ngukurr
21 March 2017	Borroloola
22 March 2017	Daly Waters
23 March 2017	Mataranka
24 March 2017	Timber Creek
27 March 2017	Wadeye
29 March 2017	Hermannsburg
29 May 2017	Yuendumu
30 May 2017	Maningrida
4 July 2017	Elliott
8 August 2017	Katherine
10 August 2017	Tennant Creek
11 August 2017	Alice Springs
11 August 2017	Humpty Doo
12 August 2017	Darwin
22 August 2017	Mataranka
22 August 2017	Jilkminggan
23 August 2017	Daly Waters
23 August 2017	Borroloola
24 August 2017	Ngukurr
25 August 2017	Maningrida
28 August 2017	Hermannsburg
29 August 2017	Yuendumu
30 August 2017	Elliott
30 August 2017	Timber Creek
31 August 2017	Nhulunbuy
1 September 2017	Yirrkala
1 September 2017	Gapuwiyak

Appendix 9 Presentations by the Panel

Date	Organisation	Event	Panel member
30 March 2017	Aboriginal Areas Protection Authority	Board meeting, Alice Springs	Chair and Dr David Ritchie
31 March 2017	Northern Territory Cattlemen's Association	Annual industry conference, Darwin	Chair
2 April 2017	Amateur Fishermen's Association of the Northern Territory	Annual General Meeting, Darwin	Chair
11 May 2017	Central Land Council	Full Council meeting, Tennant Creek	Chair
31 May 2017	Northern Land Council	Full Council meeting, Katherine	Chair
15 November 2017	Northern Land Council	Full Council meeting, Tennant Creek	Dr David Ritchie

Appendix 10 Community updates

Update	Date	Description
1	20 December 2016	The inaugural meeting of the Panel on 8 December 2016, the importance of community consultation and the proposed hearings and consultations.
2	6 February 2017	The visit of the Panel to Moomba, SA, to witness hydraulic fracturing, well drilling and associated infrastructure.
3	13 February 2017	The second meeting of the Panel and the March hearings and community consultation schedule.
4	21 February 2017	The release of the Issues Paper on 20 February 2017, stakeholder meetings and the hearings and community consultation sessions.
5	6 March 2017	The commencement of the first round of consultations.
6	11 March 2017	The completion of the first round of consultations in urban centres.
7	20 March 2017	The postponing of the community forum in Maningrida.
8	27 March 2017	The conclusion of the first round of community forums in regional and remote communities.
9	27 April 2017	A reminder that submissions of the Issues Paper close on 30 April 2017 and discussion of hearings and community forums to hear the views of Territorians. Release of public tender for economic modelling.
10	5 May 2017	Release of public tender for a social impact assessment and management framework.
11	24 May 2017	Award of tender to undertake economic impact modelling to ACIL Allen.
12	28 June 2017	Award of tender for a social impact assessment and management framework to Coffey.
13	5 July 2017	Details of the public hearings to be held across the Northern Territory, in relation to the foreshadowed release of the Interim Report.
14	14 July 2017	Release of the Interim Report and commencement of second round of public consultations.
15	27 July 2017	Announcement that the second round of public hearings are commencing next week.
16	31 July 2017	Announcement of commencement of second round of public hearings.
17	2 August 2017	Release of dates and venues for community forums at Katherine, Tennant Creek, Alice Springs, Humpty Doo and Darwin.
18	4 August 2017	Confirmation by the Chair that the second round of consultations is not the final phase of community consultation by the Inquiry.
19	16 August 2017	Release of dates for community forums at regional and remote communities.
20	21 August 2017	Regional and remote community forum update.
21	6 October 2017	Closing date for submissions is announced for consideration in Interim Report.
22	7 October 2017	Clarification regarding the Australian Broadcasting Corporation's news story on the social impact assessment consultation conducted by Cross Cultural Consultants.
23	16 October 2017	Response to the Australian Broadcasting Corporation's Radio National Story that the Chair *"supported"* calls for an investigation into former Chief Minister Adam Giles's subsequent employment by Hancock Prospecting Pty Ltd.

Update	Date	Description
24	27 October 2017	Release of ACIL Allen's economic impact assessment of a potential onshore unconventional shale gas industry in the Northern Territory, *The Economic Impacts of a Potential Shale Gas Development in the Northern Territory.*
25	7 November 2017	Confirmation of appointment of Indigenous Agreement Solutions by Coffey to undertake on-ground engagement in communities within the Beetaloo Sub-basin and surrounding areas, delaying the release of the draft Final Report, the final round of consultations and the Final Report.

Appendix 11 Media engagements

Date	Activity	Media organisation
3 December 2016	Media event	ABC TV and Radio, Darwin and NT News
7 February 2017	Interview	ABC Radio, NT Country Hour
14 February 2017	Interview	ABC Radio, Darwin
20 February 2017	Media event	ABC Darwin, Channel 9, NT News, Territory FM
21 February 2017	Interview	Territory FM
23 February 2017	Media event	ABC TV; ABC Radio, NT Country Hour; Alice Springs News; Centralian Advocate
28 February 2017	Interview	Territory Q Magazine
6 March 2017	Interview	ABC Radio, Alice Springs
9 March 2017	Written response	Katherine Times
	Written response	Alice Springs News
10 March 2017	Interview	ABC Radio, National AM
	Interview	ABC Radio, Darwin
20 March 2017	Interview	Yolngu Radio
21 March 2017	Written response	NT News
23 March 2017	Interview	ABC TV, Darwin
4 April 2017	Interview	ABC Radio, Darwin
	Interview	ABC Radio, Alice Springs
13 April 2017	Written response	NT News
3 May 2017	Written response	NT News
8 May 2017	Written response	Alice Springs News
25 May 2017	Written response	ABC Darwin
26 May 2017	Written response	Alice Springs News
	Written response	Centralian Advocate
29 May 2017	Interview	PAW Radio
30 May 2017	Written response	Alice Springs News
8 June 2017	Written response	ABC Darwin
14 September 2017	Written response	ABC Darwin
4 October 2017	Written response	ABC Darwin
11 October 2017	Written response	ABC Darwin
13 October 2017	Written response	ABC Radio National
16 October 2017	Written response	ABC Radio, Darwin
31 October 2017	Written response	NT News
8 November 2017	Interview	ABC Radio, Darwin
8 November 2017	Interview	Channel 9

Appendix 12 Submissions

Current as at 9 October 2017

*confidential submission

Submission number	Name or organisation
1	Mr Barry Nicholson
2	Ms Katherine Marchment
3	Ms Monica O'Connor
4	Mr Terry Baldwin
5	Mr Clinton Dennison
6	Mr Mark Edward
7	Mr Lawrence Lyons, Environics
8	Central Australia Frack Free Alliance
9	Mr Robert Adams
10	Ms Harshini Bartlett
11	Mr Daniel Tapp, Big River Station
12	Mr Daniel Tapp, Big River Station
13	Mr Phil Walcott
14	Mr Denny Migl, Sigma Cubed Inc
15	Coomalie Community Government Council
16	Ms June Tapp
17	Mr Barry Nicholson
18	Mr Rohan Sullivan, Birdum Creek Station
19	Mr Blair McFarland
20	Mr Paul Brant
21	Dr Michael Blockey
22	North Star Pastoral, represented by OzEnvironmental Pty Ltd
23	Armour Energy Ltd
24	Mrs Helen Davison
25	Ms Yolande Doecke
26	North Star Pastoral, represented by OzEnvironmental Pty Ltd
27	Mr Phil Cross
28	North Star Pastoral, represented by OzEnvironmental Pty Ltd
29	Mr Gerry Wood MLA, Member for Nelson
30	Origin Energy Ltd
31	Withdrawn
32	Northern Territory Cattlemen's Association
33	Ms Pauline Cass
34	Ms Merrilee Baker
35	Mr Paul Brant
36	Mr David Jagger
37	Ms Eleanor Wilson
38	Mr Mark Sinclair
39	Mr George Kyreakou

Submission number	Name or organisation
40	Mr Daniel Leather
41	Mr Tony Hayward-Ryan
42	Ardent Group Pty Ltd
43	Mr Colin Mellon
44	Ms Amanda Doyle
45	Mr Thomas Lynch
46	Don't Frack Katherine
47	Central Land Council
48	Ms Helen Armstrong, Gilnockie Station
49	Ms Jenny Knight
50	Withdrawn
51	PLan: The Planning Action Network
52	Ms Kelly-Lee Hickey
53	Dr Geralyn McCarron
54	Mr Tony Hayward-Ryan
55	Withdrawn
56	Lock the Gate Alliance (NT)
57	Santos Ltd
58	Santos Ltd
59	Environment Centre Northern Territory
60	Pangaea Resources Pty Ltd
61	Halliburton Australia Pty Ltd
62	Climate Action Darwin
63	North Star Pastoral, represented by OzEnvironmental Pty Ltd
64	Central Petroleum Limited
65	Don't Frack Katherine
66	Withdrawn
67	Ms Annette Raynor
68	Top Didj Cultural Experience and Art Gallery
69	Mr Paul Brant
70	Mr Paul Brant
71	Mr Paul Brant
72	Mr Greg Reilly
73	Mr Jim Sullivan, Cave Creek Station
74	Mr Jason Trevers, Aloha Therapeutic Massage
75	Mr Rod Dunbar, Lexcray Pty Ltd
76	Central Desert Regional Council
77	Mr Tom Measham, Commonwealth Scientific and Industrial Research Organisation
78	Ms Jennifer McFarland
79	Falcon Oil and Gas Australia Pty Ltd
80	Ms Julia Siddall
81	Ms Barbara Molanus
82	Ms Gabby Watson-Scotty
83	Ms Jessica Graham
84	Ms Jasmine Sammut

Submission number	Name or organisation
85	Mr Joseph Costelloe
86	Mr Jim Green
87	Mr Andrew Andrejewskis
88	Arid Lands Environment Centre Inc
89	Mr Tim Forcey
90	Ms Harshini Bartlett
91	Ms Nicole Pietsch
92	Mr John Armstrong, Gilnockie Station
93	Central Australia Frack Free Alliance
94	Prof Madelon Finkel
95	Katherine Town Council
96	Doctors for the Environment Australia
97	Halliburton Australia Pty Ltd
98	Sweetpea Petroleum Pty Ltd
99	Central Petroleum Limited
100	Jemena Limited
101	Australian Pipelines and Gas Association and Energy Networks Australia
102	WL Tinapple
103	Mr Lindsay Owler, Argonaut Resources
104	Mr Bruce Beer, BC & M Beer Pty Ltd
105	Dr Matthew Currell
106	Ms Sue Slater
107	Public Health Association of Australia
108	Mr Warwick Smyth, Geoconsult
109	Dr Steve Mackie, Geosim Consulting Pty Ltd
110	Regional Development Australia Northern Territory
111	Mr Rob Ross, Qeye Labs Australia Pty Ltd
112	Mr Mick Curran
113	Mr Luke Marshall
114	The Norwood Resource Incorporated
115	Mr Alexander Belford
116	Prof John Kaldi, Australian School of Petroleum, The University of Adelaide
117	Dr Andrew Kulpecz
118	Mr Andrew Pedler, Matau Advisory Pty Ltd
119	Mr Ryan Taylor-Walshe
120	Mr Greg Carlsen
121	Mr David Warner
122	Dr David King
123	Dr Kris Waddington, Buru Energy Ltd
124	Mr Ralf Oppermann, OPPtimal Resource Solutions Pty Ltd
125	Mr John Wilson
126	Mr Richard Osbon
127	Mr Michael Micenko
128	Mr John Kopcheff
129	Mr Craig Gumley, Gumley Advisory Services

Submission number	Name or organisation
130	Mr John Heugh, PetroAfrique Oil and Gas Ltd
131	Mr Gregory Meldrum
132	Dr Steve Mackie, Petroleum Exploration Society of Australia
133	Mr Eric Streitberg, Buru Energy Ltd
134	Mr David Adderley
135	Blue Energy Limited
136	Mr Griffiths Weste
137	Mr James Groombridge
138	Mr Mark Fabian
139	Mr Darryl Roy Kingsley
140	Mr Anthony Kress
141	Frack Free Darwin
142	Institute for Energy Economics and Financial Analysis
143	Mr Robert Laws
144	Ms Helen Bender
145	Beyond Zero Emissions
146	Mr Chris Carty
147	Ms Liz Howells
148	Mr Miles Ponsonby
149	Mr Greg Kemp
150	Nation Energy (Australia) Pty Ltd
151	Mr Robert Pearson
152	Mr Justin Tutty
153	Origin Energy Ltd
154	D.R Johns
155	North Star Pastoral
156	Mr Chris Harwood
157	Paltar Petroleum Limited
158	The Australia Institute
159	Mr James Wright
160	Mr Bill Sullivan, Sully Pty Ltd
161	Mr Bevan Warris
162	Imperial Oil and Gas Pty Ltd
163	The Desert Fruit Company
164	Ms Sandy Watters
165	Ms Juliet Saltmarsh
166	Mr Mark Sullivan, Flying Fox Station, MS Contracting
167	Ms Andrea Broughton, Groundwater Solutions International
168	Santos Ltd
169	Mr John Geary
170	Mr Stuart Jones, Petroleum Exploration Society of Australia
171	Lock the Gate Alliance (NT)
172	Mr Alex Ross
173	Mr Simon Molyneux
174	Oilfield Connect Pty Ltd

Submission number	Name or organisation
175	Climate Action Darwin
176	Mr Alex Yeadon
177	1 Territory Party
178	Schlumberger Australia Pty Ltd
179	Dr Liz Moore
180	Mr David Armstrong, Terrabos Consulting
181	Roper Resources Pty Ltd
182	Ms Jean McDonald
183	Prof Melissa Haswell
184	Mrs Frederika Saltmarsh
185	Katherine Mining Services Association
186	Northern Australian Rural Management Consultants Pty Ltd
187	Ms Rachel Tumminello
188	Environment Centre Northern Territory
189	Ms Sharyn Bury
190	Amateur Fishermen's Association of the Northern Territory
191	Ms Charmaine Roth
192	Ms Pauline Cass
193	Ms Gypsy Cass
194	Mr Cameron Fink, Bridgeport Energy Ltd
195	Mr Rebel Cass
196	Mr Titan Cass
197	Mr Robert Bates
198	Mr Michael Harcla
199	Mr Steve Vidler
200	Ms Rose Matyr
201	Ms Emma Burkitt
202	Ms Megan Fleming
203	Ms Jeananne Baker
204	Mr Geoff Baker
205	Ms Bianca-Jade Stevanovic
206	Mr Michael Baker
207	Mr Brian Baker
208	Ms Renee Baker
209	Mr James Donley
210	Ms Mandy Hall
211	Dr Peter Dart, School of Agriculture and Food Sciences, The University of Queensland
212	Mr Lachlan Bestic
213	Environment Defenders Office (NT) Inc
214	Northern Land Council
215	Australian Petroleum Production and Exploration Association
216	Dr Errol Lawson
217	Northern Territory Cattlemen's Association
218	Consolidated Pastoral Company Pty Ltd
219	Mr Justyn Wood, Wood Petroleum Exploration Pty Ltd

Submission number	Name or organisation
220	Pangaea Resources Pty Ltd
221	Halliburton Australia Pty Ltd
222	Oilfield Connect Pty Ltd
223	Ms Grusha Leeman
224	NT Department of Environment and Natural Resources
225	Ms Jill Emerson-Smith
226	NT Department of Primary Industry and Resources
227	Ms Yvonne Werner
228	Mr Bryce McLaren, Buru Energy Ltd
229	SG Interest I, Ltd
230	NT Department of Environment and Natural Resources
231	Schlumberger Australia Pty Ltd
232	Santos Ltd
233	Origin Energy Ltd
234	Aboriginal Areas Protection Authority
235	Alice Springs Town Council
236	Mr Jason Trevers, Aloha Therapeutic Massage
237	Amateur Fishermen's Association of the Northern Territory
238	Arid Lands Environment Centre Inc
239	Australian Petroleum Production and Exploration Association
240	Ms Merrilee Baker
241	Barkly Landcare
242	Mr Daniel Tapp, Big River Station
243	Mr Rohan Sullivan, Cave Creek Station and Birdum Creek Station
244	Central Australia Frack Free Alliance
245	Central Land Council
246	Central Petroleum Limited
247	Climate Action Darwin
248	Consolidated Pastoral Company Pty Ltd
249	Ms Teresa Cummings
250	Don't Frack Katherine
251	Drill and Complete
252	Environment Centre Northern Territory
253	Environmental Defenders Office (NT) Inc
254	Frack Free Darwin
255	Halliburton Australia Pty Ltd
256	Katherine Mining Services Association
257	Katherine Town Council
258	Lock the Gate Alliance (NT)
259	Ms Katherine Marchment
260	North Star Pastoral, represented by OzEnvironmental Pty Ltd
261	Northern Territory Cattlemen's Association
262	Origin Energy Ltd
263	Pangaea Resources Pty Ltd
264	Dr Rosalie Schultz

Submission number	Name or organisation
265	Ms Annette Raynor
266	Santos Ltd
267	Seed Indigenous Youth Climate Network
268	Ms June Tapp
269	Ms Petrena Ariston, Top Didj Cultural Experience and Art Gallery
270	Mr Justin Tutty
271	Withdrawn
272	Origin Energy Ltd
273	Origin Energy Ltd
274	Halliburton Australia Pty Ltd
275	NT Department of Environment and Natural Resources
276	Santos Ltd
277	Withdrawn
278	Withdrawn
* 279	Pangaea Resources Pty Ltd
280	Santos Ltd
* 281	NT Department of Primary Industry and Resources
282	Mr Mark Goldstein
* 283	Origin Energy Ltd
* 284	Origin Energy Ltd
285	Coal and CSG Free Mirboo North – Margaret, Gayle
286	Lock the Gate Alliance (NT)
287	Groundswell Gloucester
288	1Earth Media
289	NT Department of Primary Industry and Resources
290	Tax Justice Network Australia
291	Mr Jason Trevers, Aloha Therapeutic Massage
292	Ms Barbara Molanus
293	Ms Deidre Olofsson
294	Francis Mendes
* 295	NT Department of Primary Industry and Resources
296	Geoscience Australia
297	Mr Rod Dunbar
298	NT Department of Primary Industry and Resources
299	Australian Government Department of Industry, Innovation and Science
300	Imperial Oil and Gas Pty Ltd
301	Ms Eleanor Dixon
302	Australian Petroleum Production and Exploration Association
303	North Star Pastoral represented by OzEnvironmental Pty Ltd
304	North Star Pastoral represented by OzEnvironmental Pty Ltd
305	Mr Mark Swindles
306	Mr Lawrence Lyons, Environics
307	Mr Anthony Kenny
308	Millwarparra Aboriginal Corporation
309	Ms Linda (no surname provided)

Submission number	Name or organisation
310	Mr Phil Cross
311	Dr Matthew Currell
312	Mr John Jenkyn
313	Mr Rob Woods
314	United Voice Northern Territory Branch
315	Mr Bruce Robertson, Institute for Energy Economics and Financial Analysis
316	Lock the Gate Alliance (NT)
317	Prof Melissa Haswell
318	Oilfield Connect Pty Ltd
319	Mr Carl Brand on behalf of Ms Rikki Saltmarsh
320	Mr Tim Forcey
321	Mr Christland Kovison Yao
322	The Australia Institute
323	Mr David Forsyth
324	NT Department of Primary Industry and Resources
325	MS Contracting and Sully Pty Ltd
326	Mr Rod Woods
327	Mr Bruce Robertson, Institute for Energy Economics and Financial Analysis
328	Ms Jo Vandermark
329	United Voice Northern Territory Branch
330	Lock the Gate Alliance (NT)
331	Environmental Defenders Office (NT) Inc
332	Prof Melissa Haswell
333	Mr Jamie Houldsworth
334	Frack Free Darwin
335	Ms Seranna Shutt, Mr Ron Chute and Ms Ellen Gapany
336	Professor Jenny Davis
337	Mr Ron Chute and Mr David Forsyth
338	Mr Nicholas Milyari Fitzpatrick
339	Oilfield Connect Pty Ltd
340	Mr David Armstrong, Terrabos Consulting
341	Mr Carl Brand on behalf of Ms Rikki Saltmarsh
342	Santos Ltd
343	Mr Tim Forcey
344	Ms Billee McGinley
345	Mr Christland Kovison Yao
346	Mr Paul Sharp
347	The Australia Institute
348	Climate Action Darwin
349	Mr Tom Mayor, Maritime Union of Australia
350	Mr Justin Tutty
351	Ms Katherine Marchment
352	Ms Pauline Cass
353	Arid Lands Environment Centre Inc
354	Ms Lisa Gray and Mr Miles Jennings

Submission number	Name or organisation
355	Mr Allan O'Keefe, Ms Marilyn O'Keefe and Ms Jasmin O'Keefe
356	Mr Jason Trevers
357	Central Australia Frack-Free Alliance
358	Mr Domenico Pecorari
359	Ms Amber McBride
360	Mr Christopher Hawke
361	Ms Dianna Newham, Ms Barbara Molanus and Ms Ella Newham-Perry
362	Ms Amber Driver
363	Ms Kirsty Robertson
364	Mr Mark Swindles
365	Ms Esther Nunn and Ms Gem Walsh
366	Ms Heather McIntyre
367	Dr Matthew Currell
368	Katherine Mining Services Association
369	Dr Errol Lawson
370	Environment Centre Northern Territory
371	Vista Gold
372	North Australian Rural Management Consultants Pty Ltd
373	Ms Carol Randall and Mr Andrew Smith
374	Ms Annette Raynor
375	Mr Daniel Tapp and Ms Cheryl Birch
376	Gasfield Free Communities
377	Mr Michael Somers and Mrs Glenys Somers
378	Origin Energy Ltd
379	Ms Samantha Phelan
380	Australian Petroleum Production and Exploration Association
381	Mr Raymond Dixon, Ms Eleanor Dixon, Ms Jeanie Dixon, Mr Shannon Dixon and Ms Mary James
382	Mr Andrew Munckton
383	Ms Dianna Newham
384	Mr Alex Ariston
385	Dr Matthew Currell
386	Dr Errol Lawson
387	Vista Gold
388	Ms Carol Randall and Mr Andrew Smith
389	Australian Petroleum Production and Exploration Association
390	Ms Annette Raynor
391	Ms Helen Clarke
392	Ms Sharon Powell
393	Withdrawn
394	Ms Jo Vandermark
395	Ms Carol Randall and Mr Andrew Smith
396	Ms Annette Raynor
397	Mr Raymond Dixon
398	Mr Jason Trevers
399	Origin Energy Ltd

Submission number	Name or organisation
400	Ms Amber Driver
401	Terrabos Consulting
402	Prof Jenny Davis
403	Mr Michael Somers and Mrs Glenys Somers
404	Ms Samantha Phelan
405	Mr Daniel Tapp and Ms Cheryl Birch
406	Gasfield Free Communities
407	Stygoecologia Australasia
408	Imperial Oil and Gas Pty Ltd
409	Mr Jason Trevers
410	Ms Esther Nunn
411	Arid Lands Environment Centre Inc
412	Territory Frack Free Alliance
413	Dr Errol Lawson
414	Geoscience Australia
415	Mr Richard Creswick
416	Ms Sue McWhirter
417	Northern Territory Environment Protection Authority
418	Consolidated Pastoral Company Pty Ltd
419	NT Department of Primary Industry and Resources and NT Department of Environment and Natural Resources
420	Santos Ltd
421	Australian Petroleum Production and Exploration Association
422	Ms Pauline Cass
423	Ms Heather McIntyre
*424	NT Department of Primary Industry and Resources
425	Ms Andrea Broughton, Groundwater Solutions International
426	Mr Anthony Knapton
427	Pangaea Resources Pty Ltd
428	NT Department of Environment and Natural Resources
429	NT Department of Environment and Natural Resources
430	Withdrawn
431	Ms Carolyn Carttling
432	Ms Evelyn Alberta Bacala
433	Origin Energy Ltd
434	Que Kenny
435	University of Queensland Centre for Coal Seam Gas
436	Urban Development Institute of Australia (NT)
437	Lock the Gate Alliance (NT)
438	Ms Katherine Marchment
439	Core Energy Group Pty Limited
440	Arnhem Earthmoving and Mechanical
441	Blue Energy Limited
442	Central Petroleum Limited
443	Environment Centre Northern Territory

Submission number	Name or organisation
444	Mr Geoff Farnell
445	Australian Government Department of the Environment and Energy
446	Climate Action Darwin
447	North Star Pastoral represented by OzEnvironmental Pty Ltd
448	Mr Roger Heapy
*449	NT Department of Environment and Natural Resources
450	Commonwealth Scientific and Industrial Research Organisation
451	Commonwealth Scientific and Industrial Research Organisation
452	Commonwealth Scientific and Industrial Research Organisation
453	North Star Pastoral represented by OzEnvironmental Pty Ltd
454	Withdrawn
455	Ms Monica Napper
456	Environmental Defenders Office (NT) Inc
457	Ms Charmaine Roth
458	Climate Council of Australia
459	Australian Government Department of Industry, Innovation and Science
460	Schlumberger Australia Pty Ltd
461	Hancock Prospecting Pty Ltd
462	North Star Pastoral represented by OzEnvironmental Pty Ltd
463	Ms Pauline Cass
464	Schlumberger Australia Pty Ltd
465	Australian Petroleum Production and Exploration Association
466	Origin Energy Ltd
467	North Star Pastoral represented by OzEnvironmental Pty Ltd
468	North Star Pastoral represented by OzEnvironmental Pty Ltd
469	Origin Energy Ltd
470	Elengas
471	Northern Land Council
472	NT Worksafe
473	NT Department of Environment and Natural Resources
474	Hancock Prospecting Pty Ltd
475	Bureau of Meteorology
476	Origin Energy Ltd
477	Doctors for the Environment Australia
478	Mr Gerry Wood MLA, Member for Nelson
479	NT Department of Primary Industry and Resources
480	Northern Territory Environment Protection Authority
481	NT Department of Environment and Natural Resources
*482	Australian Government Department of the Environment and Energy
483	Alberta Energy Regulator
484	NT News
485	Mr John Oakley
486	Paul Josif and Associates
487	Ms Carol Randall
488	Ninti One Limited

Submission number	Name or organisation
489	Top End Imports
490	Ms Jean Lewis
491	Engineers Australia Northern Division
492	NT Department of Primary Industry and Resources and NT Department of Environment and Natural Resources
493	Northern Territory Chamber of Commerce and Industry
494	Darwin Major Business Group
495	Mr John Wischusen
496	Mr Gerry Wood MLA, Member for Nelson
497	Mr William Probert
498	Mr Sean Ryan
499	Dr Geralyn McCarron
500	Dr Geralyn McCarron
501	Dr Geralyn McCarron
502	Mr Ben May
503	Mr Gerry Wood MLA, Member for Nelson
504	Ms Marcella Louise Hager
505	Central Australia Frack Free Alliance
506	Jemena Limited

Submissions containing confidential information

Submission number	Name or organisation	
* 279	Pangaea Resources Pty Ltd	Appendices 1, 3 and 6 are commercial-in-confidence
* 281	NT Department of Primary Industry and Resources	Attachments are confidential under s 61 of the *Petroleum Act 1984* (NT)
* 284	Origin Energy Ltd	Attachment does not meet the level of reporting certainty required by the ASX
* 295	NT Department of Primary Industry and Resources	Attachment C is confidential due to the non-disclosure of environmental security bonds
* 424	NT Department of Primary Industry and Resources	Attachment D is confidential under s 61 of the *Petroleum Act 1984* (NT)
* 449	NT Department of Environment and Natural Resources	Submission provided in confidence (content not yet publicly available. Awaiting publication)
* 482	Australian Government Department of the Environment and Energy	Submission provided in confidence (content not yet publicly available).

Appendix 13 Table of correspondence requesting further information

Current as at 9 October 2017

*confidential submission (see Appendix 12)

Date	Recipient	Details	Submission reference
28 April 2017	Origin Energy Ltd	Request for data in relation to petroleum resources, water use and land access and disturbance	272
28 April 2017	Pangaea Resources Pty Ltd	Request for data in relation to petroleum resources, water use and land access and disturbance	* 279
28 April 2017	Santos Ltd	Request for data in relation to petroleum resources, water use and land access and disturbance	232
28 April 2017	Schlumberger Australia Pty Ltd	Request for data in relation to water use and chemical toxicity	231
28 April 2017	NT Department of Environment and Natural Resources	Request for data in relation to water resources and ecosystems	224
28 April 2017	NT Department of Tourism and Culture	Request for data in relation to tourism areas, cultural sites, recreational sites and national parks	No formal response submitted
28 April 2017	NT Department of Primary Industry and Resources	Request for data in relation to petroleum resources and water use	*281
28 April 2017	Halliburton Australia Pty Ltd	Request for data in relation to water use and chemical toxicity	274
22 May 2017	NT Department of Environment and Natural Resources	Request for data in relation to water resources	271
24 May 2017	NT Department of Environment and Natural Resources	Request for data in relation to water resources	278
26 May 2017	Origin Energy Ltd	Request for information in relation to fluid ecotoxicity	Addressed in Submission 272
26 May 2017	Santos Ltd	Request for information in relation to fluid ecotoxicity	280
7 June 2017	Senator the Hon. Nigel Scullion	Request for information in relation to Amendments to Pt IV of the *Aboriginal Land Rights (Northern Territory)* Act 1976 (Cth)	No response received
13 June 2017	Department of Primary Industry and Resources	Request for information in relation to environmental rehabilitation securities	* 295
6 July 2017	Department of Primary Industry and Resources	Request for information in relation to the management of weeds on and around petroleum exploration permits	419
6 July 2017	Department of Environment and Natural Resources	Request for information in relation to the management of weeds on and around petroleum exploration permits	419
25 July 2017	Arid Lands Environment Centre Inc	Request for information on greenhouse gas emissions and methane emissions	No written response received. But see submission 353
25 July 2017	Australian Petroleum Production and Exploration Association	Request for information regarding issues identified in the Interim Report: 1. flowback and produced water; 2. spills; 3. deep groundwater systems; 4. solid waste management; 5. health assessment; 6. traffic; and 7. greenhouse gas emissions.	421

Date	Recipient	Details	Submission reference
25 July 2017	The Australia Institute	Request for information on greenhouse gas emissions and methane emissions	No response received
25 July 2017	Climate Action Darwin	Request for information on greenhouse gas emissions and methane emissions	No written response received. But see submission 446
25 July 2017	Environment Centre Northern Territory	Request for information on greenhouse gas emissions and methane emissions	No written response received. But see submission 370
25 July 2017	Environmental Defenders Office (NT) Inc	Request for information on greenhouse gas emissions and methane emissions	See submission 456
25 July 2017	Northern Territory Environment Protection Authority	Request for information on greenhouse gas emissions and methane emissions	417
25 July 2017	Imperial Oil and Gas Pty Ltd	Request for information on flow back and produced water, spills, deep groundwater systems, solid waste management, health assessment and greenhouse gas emissions	No written response received. But see submission 408
25 July 2017	Lock the Gate Alliance (NT)	Request for information on well integrity and greenhouse gas emissions	See submissions 370 and 437
25 July 2017	Origin Energy Ltd	Request for information regarding: 1. flooding; 2. well integrity; 3. flowback and produced water; 4. spills; 5. deep groundwater systems; 6. solid waste management; 7. health assessment; 8. infrastructure requirements; 9. baseline data; 10. traffic; 11. greenhouse gas emissions; and 12. comments on Section 9.8 of the Interim Report regarding Preliminary Risk Assessment.	433
25 July 2017	Pangaea Resources Pty Ltd	Request for information on greenhouse gas emissions, and methane emissions	427
25 July 2017	Santos Ltd	Request for information on greenhouse gas emissions and methane emissions	420
25 July 2017	Schlumberger Australia Pty Ltd	Request for information on well integrity, flowback and produced water, spills, solid waste management, health assessment, and greenhouse gas emissions	See submissions 460 and 464
31 July 2017	Commonwealth Scientific and Industrial Research Organisation	Request for information on greenhouse gas emissions and methane emissions	450
1 August 2017	NT Department of Primary Industry and Resources	Request for information regarding further input regarding the below matters: 1. well integrity; 2. flowback and produced water; 3. solid waste management; 4. infrastructure requirements; 5. disposal of wastewater into aquifers; 6. storage; 7. discharge into waterways; 8. Amungee well data; 9. greenhouse gas emissions; 10. minimum standards; 11. regulatory capture; 12. cost recovery; 13. compensation; and 14. strategic development.	*424

Date	Recipient	Details	Submission reference
2 August 2017	Consolidated Pastoral Company Pty Ltd	Request for information regarding claims made by Lock the Gate Alliance (NT) that there were water studies around the Beetaloo Sub-basin commissioned	418
2 August 2017	Geoscience Australia	Request for information regarding: 1. future development of each basin; 2. groundwater studies; and 3. recharge rates of the Tindall limestone aquifer.	414
2 August 2017	Australian Government Department of Industry, Innovation and Science	Request for information regarding the objectives of the Royalty Return Scheme	459
8 August 2017	NT Department of Environment and Natural Resources	Request for information regarding the Department of Environment and Natural Resources *Environmental Regulatory Reform Discussion Paper*	*449
11 August 2017	Australian Government Department of the Environment and Energy	Request for information on greenhouse gas emissions and methane emissions	445
14 August 2017	Commonwealth Scientific and Industrial Research Organisation	Request for information regarding research being undertaken by GISERA on groundwater in the Hutton Sandstone aquifer in the Surat Basin	451
18 August 2017	Commonwealth Scientific and Industrial Research Organisation	Request for information regarding groundwater dependent ecosystems	452
18 August 2017	NT Department of Environment and Natural Resources	Request for information regarding flow rate estimates	429
31 August 2017	Australian Government Department of the Environment and Energy	Request for research commissioned in relation to chemicals used in hydraulic fracturing	*482
11 September 2017	NT Department of Environment and Natural Resources	Request for information regarding surface spills and groundwater contamination, and oxygen	481
13 September 2017	Alberta Energy Regulator	Request to discuss the Alberta Energy Regulator's experience with shale gas development and understanding of the regulatory framework within which the regulator operates and which governs onshore shale gas development in Alberta	483
19 September 2017	NT Department of Environment and Natural Resources	Request for an indicative Fire Management Zone Risk and Hazard Map and to provide the outcomes of public consultation administered by Bushfires NT regarding changed fire regimes in the Northern Territory	473
20 September 2017	Northern Territory Environment Protection Authority	Request for information regarding the regulatory framework for the management of spills of chemicals and wastewater associated with hydraulic fracturing	480
20 September 2017	NT Department of Primary Industry and Resources	Request for information regarding the regulatory framework for the management of spills of chemicals and wastewater associated with hydraulic fracturing	492
20 September 2017	NT Department of Environment and Natural Resources	Request for information regarding the regulatory framework for the management of spills of chemicals and wastewater associated with hydraulic fracturing	492
20 September 2017	NT Worksafe	Request for information regarding the regulatory framework for the management of spills of chemicals and wastewater associated with hydraulic fracturing	472
20 September 2017	Hancock Prospecting Pty Ltd	Request for information related to buffer zones regarding Exploration Permit 154 and evidence of compliance with regulation and no significant environmental incidents indicated in a submission to the Inquiry	474

Date	Recipient	Details	Submission reference
22 September 2017	NT News	Request for information regarding associated research gathered from the MediaReach poll referenced in the NT News article *Fracking to Divide Territory Labor* published 31 August 2017	484
24 October 2017	BC Oil and Gas Commission	Request for information in relation to the regulation of the onshore unconventional gas industry in British Columbia.	No formal response submitted

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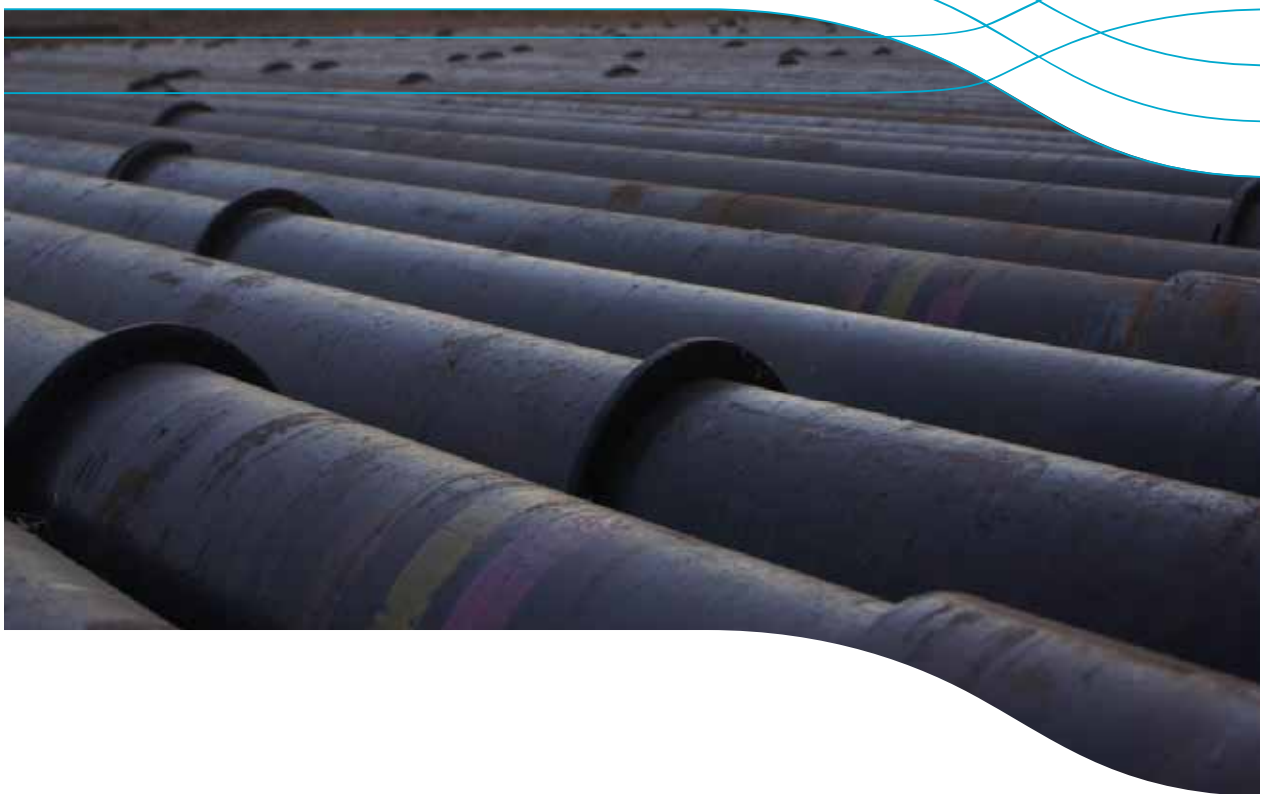
Report into

The shale gas well life cycle and well integrity

Prepared for the Northern Territory Hydraulic Fracturing Inquiry

Cameron Huddlestone-Holmes, Bailin Wu, James Kear and Raman Pandurangan
EP179028
December 2017



Citation

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Acknowledgments

The authors would like to acknowledge CSIRO internal reviewers for their thorough reviews of this document. We also thank members of the Australian onshore gas industry and regulators for their insights in to the topics covered in this report. We acknowedge Wellbarrier AS who provided example well barrier schematics for this report.

We acknowledge the Northern Territory Hydraulic Fracturing Inquiry for commissioning this work.

Executive summary

Shale gas resources are attracting increased attention globally, given their potential as an energy resource. The Northern Territory holds significant shale gas resource potential and, to date, these resources have seen only limited exploration. In December 2016, the Northern Territory Government established the Northern Territory Hydraulic Fracturing Inquiry (**the Inquiry**), an independent scientific inquiry to investigate the environmental, social and economic risks and impacts of hydraulic fracturing of onshore unconventional gas reservoirs and associated activities in the Northern Territory. This report has been prepared for the Inquiry, to provide an overview of the drilling and hydraulic fracturing process employed in the development of shale gas resources. It has a focus on well integrity and the potential for impacts related to well integrity.

This report is based on a review of the literature on well integrity issues and well integrity failure rates for oil and gas wells. The available literature specific to shale gas well integrity failure rates is not extensive; however, the well construction and operation methods used in other oil and gas developments provide an indicator of potential well integrity issues in shale gas development. The well integrity hazards for any shale development will depend on the characteristics of the resource.

The report first provides an overview of concepts around well integrity, and an overview of the drilling life cycle from design to construction, operation and subsequent abandonment, and the associated hydraulic fracturing processes. It then discusses well integrity in more detail, with a review of the potential mechanisms for well integrity issues and the rates of well integrity failure as reported in the literature. Potential pathways for hydraulic fracturing to cause subsurface contamination and to affect well integrity are also discussed. The report outlines the regulatory regime that applies to well integrity and hydraulic fracturing in the Northern Territory, and summarises the regulations in other Australian jurisdictions. It concludes with policy options for managing well integrity risks in the Northern Territory.

Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface. Well integrity is established through the use of barriers that prevent these unintended fluid flows. For shale gas wells, a two-barrier principle is applied, in which at least two independent and verified barriers are in place. Only if both barriers fail will there be a well integrity failure that results in unintended or uncontrolled fluid flow.

The key findings of this study are as follows:

- Well integrity in shale gas wells is a risk that needs active management throughout the well life cycle for the safe, efficient and environmentally sustainable operation of wells.
- The scale of the risk depends on the characteristics of the resource being developed, as for other types of oil and gas wells (shale gas wells are a subcategory of oil and gas well).
- The low permeability and limited overpressures in shale gas resources mean that they are likely to have lower well integrity risks than conventional resources, and this is supported by the limited amount of data available.
- The most plausible pathway for environmental impact over the life of a well is by migration of methane gas up the outside of the well, caused by a loss of integrity of the bond between cement and casing or cement and formation. The rates of gas leakage on a per well basis are likely to be small; however, the cumulative flux of gas from a large number of wells may be significant in terms of greenhouse gas emissions.

- The residual risk is low when risks are actively managed using current leading industry practice based on hazard identification, risk assessment and risk management.

Other findings of this study are as follows:

- Industry and regulators have a focus on maintaining well integrity, and the industry follows several international standards on well integrity management.
- Current leading practice involves the use of well integrity management systems to manage integrity risks across the well life cycle.
- The two-barrier principle is critical to maintaining good well integrity and is standard practice in the industry.
- Gas migration along the outside of the well does not necessarily indicate the movement of other fluids. Methane migration is driven by buoyancy, whereas migration of fluids will require pressure gradients to drive fluid flow.
- Plausible pathways for hydraulic fracturing operations (as opposed to during the rest of the well life cycle) to lead to contamination of shallow aquifers are primarily through impacts on well integrity that may contribute to the migration of fluid along the outside of the well. Casing failures during hydraulic fracturing activities are also plausible, although there is a low likelihood of this occurring in wells that have been properly engineered.
- Catastrophic well integrity failures during shale gas drilling operations are unlikely in a shale gas development because of the low permeability and limited overpressures in shale resources.
- Baseline studies to characterise the environment before shale gas activities commence in an area will provide important data to assist in any future evaluation of possible environmental impacts.
- There has been limited development of onshore gas resources in the Northern Territory; therefore, there is currently a lack of data for well integrity hazard identification and risk assessment. To reduce well integrity risks, it may be useful to have a basin-wide approach to identifying hazards and effective risk management approaches, with collaboration between operators, regulators and other stakeholders, should an onshore gas industry develop. This approach may assist in providing the broader community with transparency about the process for managing well integrity.
- In the Commonwealth, South Australia and Western Australia, the regulations related to well integrity for offshore wells are objective based, and use the 'as low as reasonable practical' principle for managing well integrity risks. These jurisdictions have no or limited prescriptive requirements around well construction, although they do have guidelines for well integrity assessment.
- Codes of practice for coal seam gas well construction and abandonment are mandated in New South Wales and Queensland. Queensland also has a code of practice for other petroleum wells. The establishment of a code of practice or guidelines in the Northern Territory will need to balance a prescriptive approach with the ability to adapt as risks are understood and new technologies become available.
- The long-term integrity of shale wells that have been abandoned using current industry practices is not well covered in the literature. The main risk for abandoned wells is gas migration along the outside of the casing. Gas leakage on a per well basis is likely to be small, but the cumulative flux of gas from a large number of wells may be significant in terms of greenhouse gas emissions. Understanding the risks associated with abandoned wells within the context of the Northern Territory's shale gas resources could lead to the establishment of leading practices, should an onshore gas industry develop.

1 Introduction

This report has been prepared for the Northern Territory Hydraulic Fracturing Inquiry (**the Inquiry**) to provide an overview of the drilling and hydraulic fracturing process employed in the development of shale gas resources. It has a focus on **well integrity**[1] and the potential for **impacts** related to well integrity. During exploration, wells provide access to allow the resource to be characterised, and during production they provide a means for gas to be brought to the surface. As the interface to the subsurface environment, wells are also a possible pathway for unintended release of fluids to the environment, and concerns have been raised about well integrity.[2] Hydraulic fracturing is necessary to allow economic production rates from shale gas resources, because of the low permeability of these resources. The potential for impacts on shallow aquifers from the migration of **hydraulic fracturing fluids** has also been raised as a concern.[3]

The drilling and hydraulic fracturing technologies used in shale gas projects have evolved from those used for conventional petroleum resources, with a great deal of innovation over the past two decades.[4] Drilling for shale gas now typically involves the drilling of multiple wells from a single-well pad, with horizontal extensions increasing the exposure to the target shale formation.[5] To produce shale gas, multiple hydraulic fractures are placed along the horizontal section of the well. The most common hydraulic fracture design in shale gas wells in the United States uses water-based hydraulic fracturing fluids pumped at a high flow rate.[6] The adoption of this technology has been important in the rapid growth of shale gas and oil production in the United States.[7]

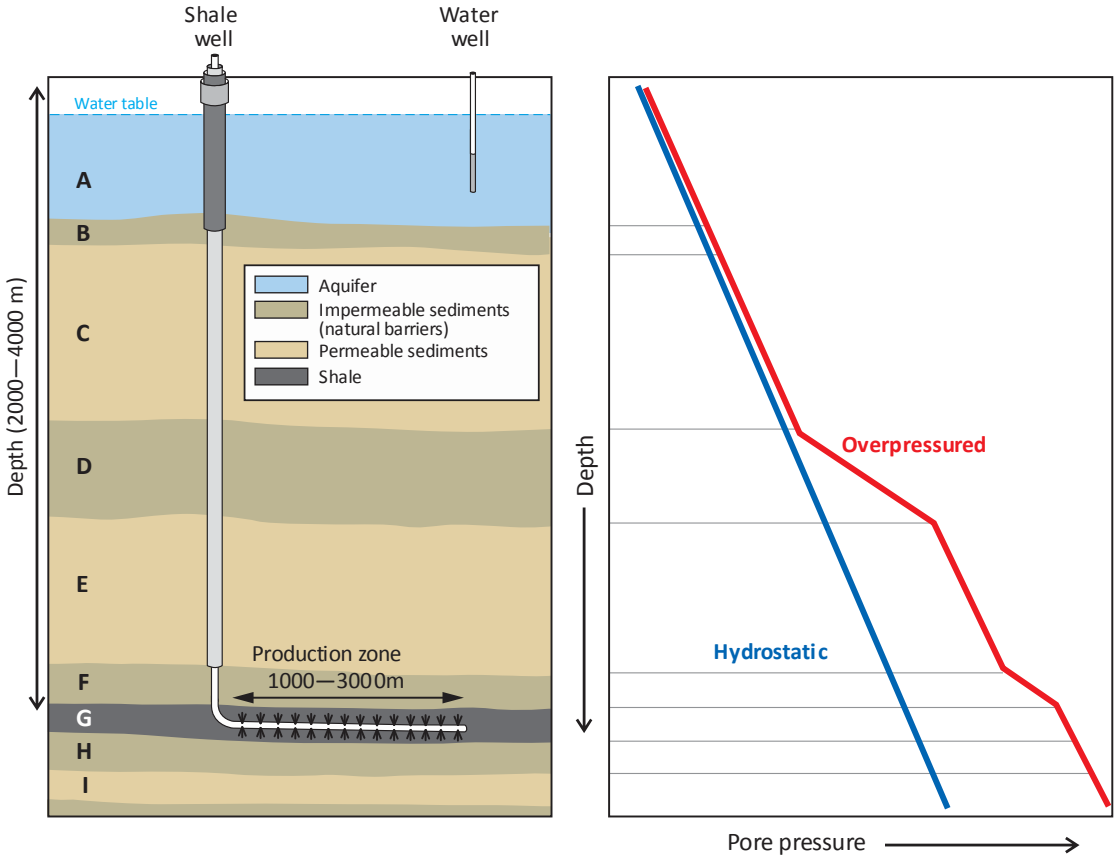
This report first provides an overview of some of the key concepts around well integrity, and of drilling and hydraulic fracturing processes. It then discusses well integrity in more detail, with a review of the potential mechanisms for well integrity issues and the rates of well integrity failure that have been reported in the literature. It also discusses potential pathways for hydraulic fracturing that lead to subsurface contamination. The regulatory regime that applies to well integrity and hydraulic fracturing in the Northern Territory is outlined, together with a summary of regulations in other Australian jurisdictions. The report concludes with a summary of the issues and policy options for managing **risks** related to well integrity.

[1] Terms given in bold in the text are included in the Glossary
[2] Davies et al. 2014; Ingraffea et al. 2014; Jackson 2014.
[3] US EPA Report. Chapter 6.
[4] Golden and Wiseman 2015. p968-974.
[5] Cook et al. 2013. p54-56
[6] Gallegos et al. 2015.
[7] Cook et al. 2013; Golden and Wiseman 2015.

2 Why is well integrity important?

Concerns around well integrity are often raised in regard to shale gas developments. These concerns relate to the potential for the unintended flow of fluid out of, or into, the well, between layers of rock or to the surface via the well. To understand well integrity, it is important to consider how fluids and gases move in the subsurface. **Figure 1** shows a simplified shale gas resource, consisting of the shale layer at the base, with overlying layers of various sedimentary rocks referred to as the **overburden.** This overburden will include layers of different **permeability**; broadly the layers can be classified as permeable (which allow fluid to flow through them) or impermeable (which form a barrier to fluid movement). Some of the permeable layers may be **aquifers**, containing water that is used for agriculture or domestic purposes, whereas others may contain salty water. Hydrocarbons (oil or gas) may also be present in some rock layers.

Figure 1: Simplified shale gas resource. Rock layers A-F are overburden that cover the shale resource (layer G). The graph on the right shows the pore pressures in the rock; the gradient in blue is the hydrostatic gradient. The gradient in red shows the pore pressures in an overpressured scenario, with layers D and F trapping higher pressures below them. Not to scale.



Subsurface vertical water flow

The pressure of the fluids in the rock is called the **pore pressure**, and at hydrostatic pressure, the pore pressure is equal to the weight of the column of fluid above it. The pore pressure increases with depth, as it does in any body of water. When water in rock layers is at hydrostatic pressure, there is no driving force for the water to flow vertically.

In some geological settings, the pore pressure is higher than the hydrostatic pressure. These **overpressures** can occur when there is an increase in the amount of fluid or gas in the rock, or when there are changes to the rock such that the amount of pore space is reduced. If the fluid cannot escape, the result is an increase in pore pressure. Overpressures can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure. In **Figure 1**, layer A contains an aquifer that is connected to the surface. Overpressures cannot form in this layer because the pressure can escape at the surface. The pore pressures in layer E are overpressured, as shown in the graph in **Figure 1**, but the fluid and pressures are held in place by layer D, which is impermeable.

If a well is drilled into a water-bearing layer that is at hydrostatic pressure (layers A, B and C in **Figure 1**), water would only flow up the well with the aid of a pump. This scenario is analogous to drinking a glass of water through a straw – suction has to be applied. If a well is drilled into an overpressured layer (layer E in **Figure 1**), the water will flow up the well unassisted. A common example of this scenario is the artesian water wells drilled into the Great Artesian Basin.

Fluids will not move in the subsurface unless there is a driving force, so an overpressure zone would be required for a fluid to move unassisted vertically up the well.

Subsurface vertical gas flow

Natural gas is predominantly methane, and has a much lower density than water; this buoyancy will drive natural gas to move upwards through the rock unless there is an impermeable barrier in place. Gas resources can only exist if the gas is trapped in the subsurface, otherwise it would have leaked out through geological time. To extract the gas, a well must be drilled to provide a pathway for the gas to flow to the surface. Gas can flow under its own buoyancy, and any overpressure will increase the rate of flow.

Rate of fluid and gas flow

The rate at which fluids or gas move in the subsurface is affected by the size of the flow pathway. The larger the pathway, the greater the rate of flow for a given driving force (overpressure or buoyancy). Friction and surface roughness of the pathway reduce the flow rate; therefore, fluid and gas flow rate will be lower over longer pathways. Another factor is the size of the **reservoir** of fluid or gas, and the permeability within that reservoir. For example, the Great Artesian Basin is a large reservoir with high permeability, and wells drilled into this reservoir have had artesian flows for decades. In contrast, in a small reservoir, the pressures would be quickly depleted and flows would decline. Similarly, in a reservoir with low permeability, the effective fluid or gas flow would be restricted and pressures would drop quickly. Shale gas reservoirs have low permeability by definition, which is why **hydraulic fracturing** is required. The hydraulic fractures increase the volume of the reservoir accessed by a well (the fractures are extensions of the well for practical purposes), overcoming the low permeability.

The role of drilling fluids

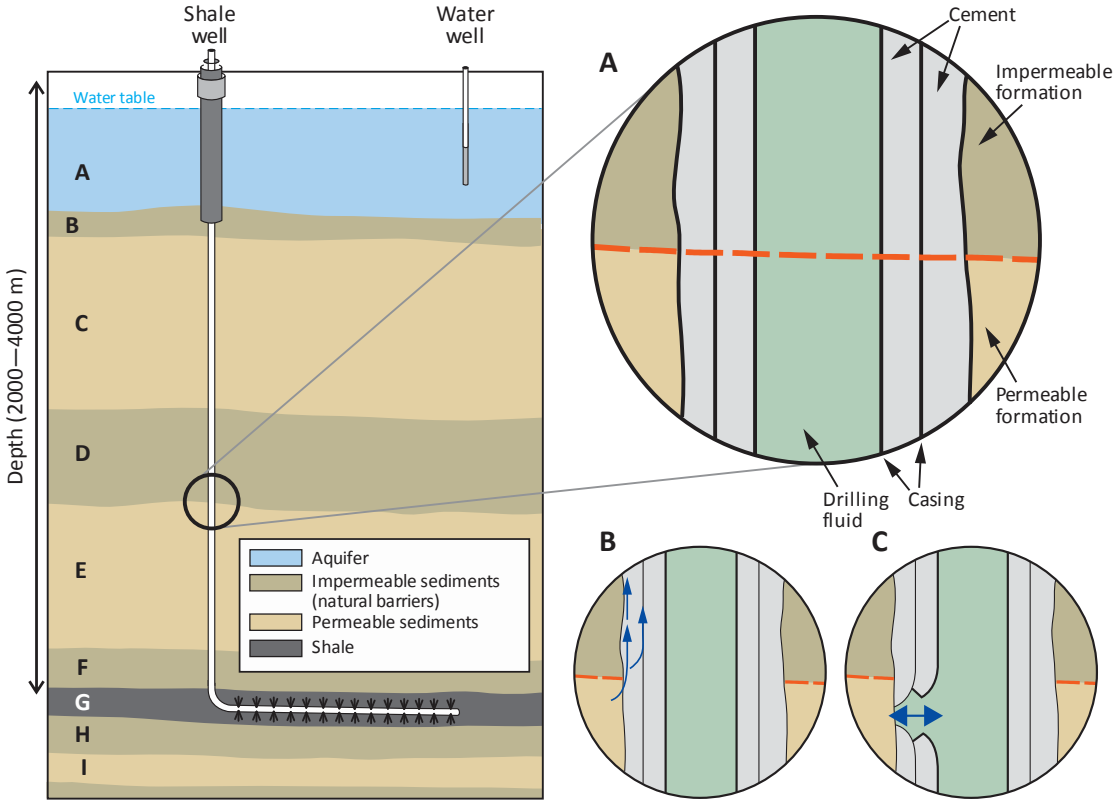
Drilling fluids are usually designed to have a density that balances the pore pressure in the surrounding rock, to prevent formation fluid from entering the well and drilling fluid from being lost to the formation. Drilling fluids also need to lift drill cuttings from the well, prevent **borehole** breakout and lubricate the drill bit. If the drilling fluid density results in pressures greater than the formation pressure, drilling fluid may be lost to the formation. Faults and fractures may also result in losses of drilling fluid. These possible scenarios are well known and are readily identified during drilling operations. A range of engineering practices can be used to manage these losses, including changing the drilling fluid density, using additives that prevent losses and setting **casing** across loss zones.

Well barriers

When a well is drilled, well integrity is established by maintaining the integrity of the natural barriers (the impermeable rock layers) through which the well is drilled. The primary methods of creating well integrity are cementing steel casing into the well, as shown in Figure 2, and controlling the density and pressure of fluids (including drilling fluids during drilling operations) or gas within the well. Problems with well integrity can generally be considered in two broad categories:

- unintended flow of fluids or gases between rock layers or to the surface along the outside of the well (see **Figure 2B**); and
- unintended flow of drilling fluids or hydraulic fracturing fluid from inside the well into the surrounding rock, or from formation fluid or gas into the well (see **Figure 2C**).

Figure 2: Shale gas wells cut through geological layers that form barriers to vertical flow. The casing, cement and management of pressures within the well reinstate this barrier (red dashed line in A). Well integrity problems can occur when the well becomes a pathway for vertical movement or gas or fluid (B), or when the well is breached, allowing fluid to flow in to or out of the well (C). Not to scale.



When considering fluid movement, overpressures contribute significantly to well integrity issues and their consequences. However, high overpressures that would drive vertical fluid movement are not a common feature of shale resources, and the limited data collected in the Beetaloo Basin indicates that this basin has low overpressures.[8] In contrast, the buoyancy and low viscosity of gas means that it is more likely to be able to move along these pathways. In addition, gas may be present in shallower layers of rock as well as the target shale gas reservoir. Gas from any of these sources may move upwards along the well if a pathway is present. The rate at which fluid or gas could flow up a pathway

[8] Close et al. 2016.

will be limited by the aperture of the opening through which it flows. Where the **annulus** between the well casing and the rock is cemented, the size of any opening will be limited.

A loss of well control can result in the unintended flow of fluid into or out of a well. Where there are high overpressures, the risk of fluid or gas flow into the well is higher. An inrush of gas or **formation fluid** into the well can lead to a well **blowout** at the surface. Large overpressures can be a factor in conventional oil and gas resources, and were a contributing factor to the blowout of the Macondo well that led to the loss of the Deepwater Horizon drilling rig.[9] The Macondo well was drilled offshore in water over 1,500 m deep. The well extended around 4,000 m below the sea floor, where it intersected four distinct hydrocarbon reservoirs. These reservoirs were highly overpressured, with pore pressures close to exceeding the tensile strength of the rock, and contained large volumes of gas and oil. The eventual blowout of the Macondo well is believed to have been caused by a chain of failures, starting with a failure of the cement around the casing, followed by a failure of the **blowout prevention** (**BOP**) system and other secondary safety systems. In contrast, shale gas wells are drilled onshore and into resources at a relatively shallow depth below the surface (2,000-4,000 m). High overpressures are uncommon in shale gas resources, and the low permeability in shale resources will limit the volume of any inrush into the well, meaning that blowouts are unlikely.[10] The operational complexity of onshore shale gas wells is also lower than for offshore drilling in conventional reservoirs, particularly those with high overpressures. This comparison highlights the importance of the geology and characteristics such as pore pressure, permeability and reservoir volume in determining the potential consequences of a failure of well integrity.

Hydraulic fracturing fluid movement

Hydraulic fracturing fluid will migrate into the formation when fluid pressures are higher than the pore pressures in the surrounding rock. During hydraulic fracturing operations, a specific zone of the surrounding rock formation is exposed to the high-pressure hydraulic fracturing fluid in order to propagate hydraulic fracture into the formation. The design of the well controls where the hydraulic fracturing fluid can enter the formation. If the well integrity is compromised, hydraulic fracturing fluids may breach the well and flow into other rock layers. Designing a well to withstand hydraulic fracturing pressures is a routine engineering task, and the designs typically incorporate multiple barriers; also, **pressure testing** of the well before hydraulic fracturing ensures that the well is strong enough to withstand hydraulic fracturing pressures.

Hydraulic fracturing injects fluid under pressure into the reservoir rock. Some of this fluid will hold open the fractures, and the rest will flow into the pore space in the reservoir rock. When the hydraulic fracturing operation is complete, the fluid pressures will dissipate quickly and a portion of the injected hydraulic fracturing fluid will flow back up the well. Some hydraulic fracturing fluid will remain in the pores of the reservoir rock layer due to the low permeability. Migration of the hydraulic fracturing fluid left behind in the pore space of the reservoir rock is governed by the same processes as the migration of other pore fluids; therefore, it is unlikely that the fluid will be strongly driven to flow vertically between rock layers.

Summary of the importance of well integrity

This discussion highlights some of the basic geologic and engineering factors that influence well integrity, and the impact of these factors in shale gas resources. High overpressures are uncommon in

[9] National Academy of Sciences, 2012.
[10] Royal Society & Royal Academy of Engineering 2012. p25

shale gas resources, and the low permeabilities in these resources will limit the potential for a blowout and the potential drive for cross formation flow. In addition, the low permeabilities will continue to influence the impacts of well integrity after the well has been abandoned. Pressures within the reservoir will be depleted by production. Restoration of pore pressure in the reservoir is likely to be slow because the low permeability will prevent migration of any high-pressure fluids from outside the reservoir, and processes that might increase pressures from within the shale are subject to a geological timescale. However, some gas will remain in the reservoir and its buoyancy will continue to provide drive for upward flow, should pathways be available.

3 Well life cycle

All wells follow a similar life cycle, regardless of their purpose, with some variations in their design and operational aspects. The well life cycle, as outlined in *ISO 16530-1 Petroleum and natural gas industries - Well integrity - Part 1: Life cycle governance* (**ISO 16530-1**), has the following phases:[11]

- basis of design phase;
- design phase;
- construction phase;
- operational phase;
- intervention phase; and
- abandonment phase.

Figure 1 shows the basic layout of a shale gas well and identifies its key components. The layout and components of a well will vary according to its purpose in the local geology. It is impossible to draw a shale gas well in a way that shows how narrow the well is compared to its length. The diameter of a well is only about 15-25 cm, whereas the length is several kilometres. A useful way of visualising this ratio of diameter to length is to think of the edge marking (around 10-12 cm wide) on a several kilometre stretch of highway.

3.1 Basis of design phase

The basis of well design phase is where the objectives of the well are set and the full life cycle operational requirements are determined, to allow for detailed design of the well in the next phase. Some of the information that is required at this phase includes:[12]

- the location;
- targets – formations and depths;
- well type (that is, **exploration**, production or monitoring);
- well subsurface architecture (vertical, deviated or horizontal);
- geological information, including expected formations, aquifers, faulting and temperatures;
- geomechanical information, including pore pressures, rock strength, in situ **stresses**, **porosity**, permeability and temperatures;
- for an exploration well, data acquisition requirements;
- for a production well, production parameters such as production rates, the composition of the fluids and gasses that will be produced, and the stimulation and testing strategies that will be used;
- potential for planned re-completion or conversion of the well for other purposes (converting an exploration well to a monitor well, for example); and
- the expected operating life of the well.

[11] ISO 16530-1:2017.
[12] ISO 16530-1:2017.

The geology of the resource and the overlying strata that must be drilled through to reach it are important because they determine the depth, thickness and gas content of the target shale horizon. Although shale resources are typically made up of flat lying layers of rock, geological features such as folds and faults are important in determining the geometry of the resource. Igneous intrusions may also cut through the resource, and the design of the well trajectory will need to take these features into account.

Geomechanical properties are important because they describe how rock will respond mechanically (deform or break) as it is drilled through. An open well will fail if the stress concentrations around its circumference exceed the strength of the rock.[13] Geomechanical parameters such as in situ stress, rock strength and pore pressures are important for the design of the casing in the well. These parameters are also important for hydraulic fracture design.

Overpressures in formation fluids are an important consideration for well design and well integrity. [14] If the pore pressure is at the hydrostatic gradient, there is no driving force for fluids to move vertically between layers of rock at different depths, or to the surface. If the pore pressures are above the hydrostatic gradient, they are said to be overpressured and those pressures can drive the flow of fluids vertically between formations to the surface, should a pathway be available. A well with good integrity will be able to control these overpressures. Overpressures develop naturally as a result of a range of mechanisms through geological time, and low to moderate overpressures are present in many shale resources, including the Beetaloo Basin in the Northern Territory.[15] Gas and oil can move vertically owing to their buoyancy and expansion, even without overpressure, but water cannot move vertically without a driving force.

These geological, geomechanical and operational considerations are all important for well integrity. These factors need to be taken into account so that the design of the well reduces risks to its integrity.

3.2 Design phase

In this phase, all aspects of the well are designed in detail, taking into account the overall life cycle of the well and all future operations, through to its eventual abandonment. The design is based on a detailed analysis of data and requirements collected during the previous phase, and includes the following aspects:[16]

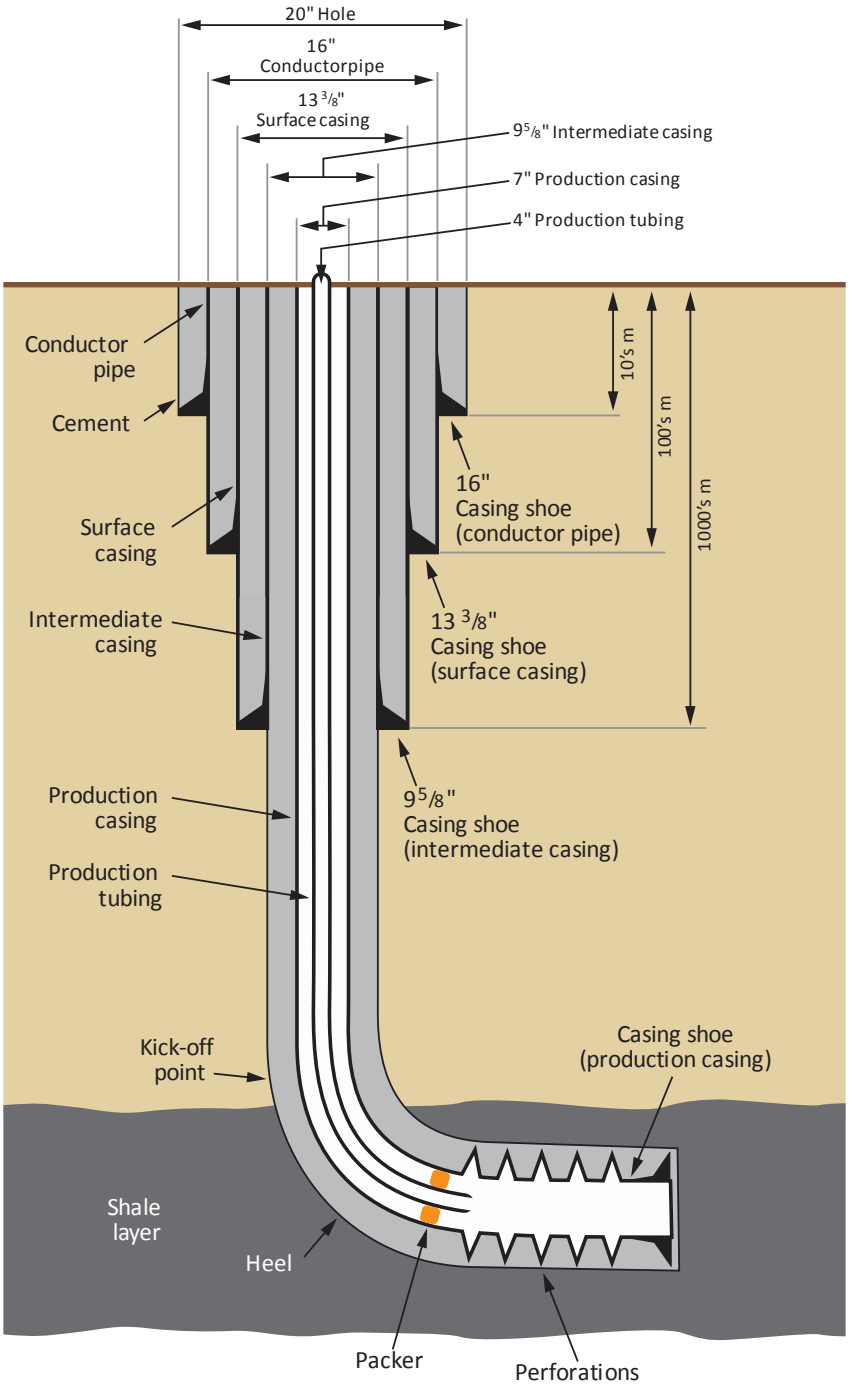
- well design, and specification of materials and equipment (such as casing, cement and completion);
- data acquisition program, including **well logging**, sample collection and well testing;
- well stimulation activities, if required;
- barriers to managing well integrity;
- operating procedures, including risk management and well integrity management; and
- plans for final abandonment of the well.

The design of the casing, cementing and completion are important for long-term well integrity. Casing is steel piping that provides a pressure tight conduit between the shale gas resource and the surface.[17]

[13] Zoback 2007. p3 and chapters 6 to 9.
[14] Zoback 2007. p3 and chapters 6 to 9.
[15] Close et al. 2016; Jarvie 2014; US EIA 2013.
[16] ISO 16530-1:2017.
[17] Hossain and Al-Majed 2015. p433-501

Wellbore casing is a highly engineered product that is designed to cope with anticipated wellbore conditions. International standards cover the manufacture, testing, engineering specification, mechanical properties and performance of the casing.[18] The casing prevents the unintended flow of drilling and hydraulic fracturing fluids out of the well, keeps the well open through weak or broken rock layers, and prevents formation fluids from entering the well and from moving between layers of rock via the well.

Figure 3: General layout of casing in a shale gas well. Casing sizes are specified in imperial units. Not to scale (width is significantly exaggerated).



Casing/hole sizes

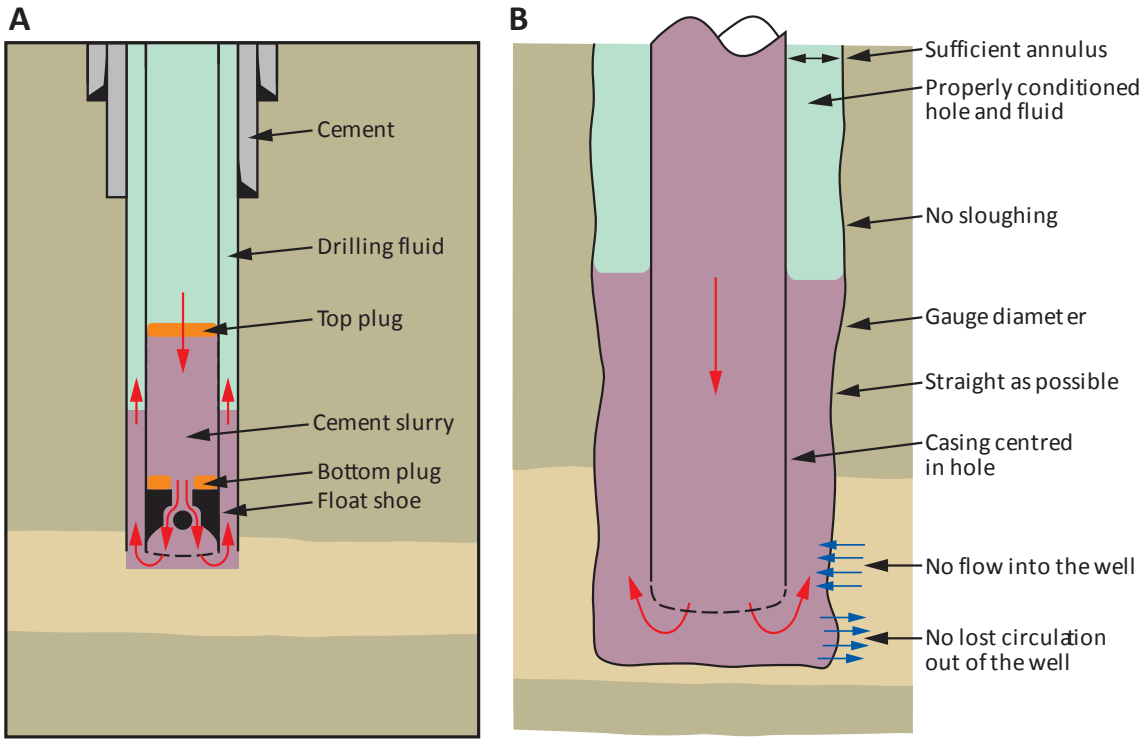
Inches	Centimetres
20	50.8
16	40.6
13 3/8	34.0
9 5/8	24.4
7	17.8
4	10.2

[18] ISO 11960:2014.

Wells are drilled in stages, with each stage cased before drilling proceeds to the next stage, using a smaller diameter drill bit. **Figure 3** shows the general layout and nomenclature for casing used in shale gas wells, indicating that the diameter of the well decreases with depth, as successive casing telescopes inside the previous **casing strings**. The design of casing for a well will need to take into account the depths of layers of rock or aquifers that need to be isolated from each other, the corrosive nature of fluids or gases (such as hydrogen sulphide or carbon dioxide) that may be encountered, the stresses that the casing will be subjected to and the operational requirements of the well. The casing layout, casing material and wall thickness are all parameters that can be varied.

Without cementing, the casing alone is not sufficient to ensure wellbore stability. Therefore, the casing is cemented into the well (**Figure 3**), to provide strength to the well and a seal between the casing and the surrounding rock.[19]

Figure 4: The process for cementing casing into a well. The cement is pumped down into the centre of the well and returns up the outside of the well (A). The well requirements for effective cementing are shown in (B). Not to scale. Modified from Smith.[20]



During the cementing process, a cement slurry is pumped down the centre of the well, and flows up the annulus between the rock formation and the most recently placed casing (**Figure 4**). The cement works with the casing to mechanically couple it to the surrounding rock, creating a hydraulic seal and protecting the casing.[21] Shale gas well cements are usually a Portland cement (of slightly different chemical composition to regular Portland cement) mixed with water and other additives. The additives modify certain properties of the cement, such as setting time, viscosity, density and permeability to different fluids. Well cements are designed, tested and prepared using established procedures to meet

[19] Taoutaou 2010.
[20] Smith 1990.
[21] Hossain and Al-Majed 2015. p503-570

relevant specifications, and they have negligible permeability to formation fluids when cured.[22] The casing and cement work together and are critical to well integrity.

In designing the oilfield cementing process, drilling engineers consider factors such as the depth and design of the well, and the properties of the pore fluids and surrounding rock layers. The cementing process is undertaken in a series of steps that are designed to clean and prepare the well for cement, prevent the cement slurry from contamination with drilling fluid (also known as **drilling mud**) and ensure that the cement slurry is positioned at the intended vertical well location.

Various standards cover the design of wells, the specification of materials and equipment used in their construction, and well operations. As at June 2016, the International Association of Oil and Gas Producers listed over 150 primary standards related to well construction and well operations.[23] Some of these standards are mandatory in various jurisdictions; however, they are mostly used for quality control for operations, and the provision of services and materials in the industry.

3.3 Construction phase

The well construction phase involves drilling and completion of the well in accordance with the design. A focus during this phase is managing the risks associated with drilling and maintaining well integrity.[24] Well control refers to the prevention of 'kicks', which are uncontrolled flows of formation fluids or gases into the wellbore that can reach the surface.[25] A severe kick can lead to a blowout, which is the uncontrolled escape of fluid from the well.

Drilling fluids are an essential component of drilling operations, and are distinct from the hydraulic fracturing fluids used during well stimulation (see Section 4). [26] These fluids provide cooling and lubrication to the drill bit and drill string, lift drill cuttings from the well and are a component of well control. The density of the drilling fluid is increased by the use of additives to counteract any overpressures in the formation, preventing kicks and helping to maintain wellbore stability in uncased sections of the well. If the density of the drilling fluid is too high, drilling fluid may be lost in layers of rock. Additives that create a low-permeability skin on the wellbore can be used to limit these losses.

Casing is installed and cemented in place in a number of stages during the construction phase, as shown in **Figure 3**. Initially, a large-diameter surface casing is set sufficiently deep to protect surface aquifers, and is fully cemented in the ground. Once a well is drilled to either the design depth or a depth where a casing string is required, a steel casing string is run into the borehole and cemented (**Figure 3** and **Figure 4**). The cement fills and seals the annulus between the casing strings, or between the casing string and the formation rock. This process is repeated until well construction is complete.

In each stage, the well is prepared (essentially, cleaned by the circulation of drilling fluid) and cement is then pumped down the centre of the well so that it flows around and up the annulus between the casing and the surrounding rock. The well integrity provided by the cement depends on both the cement slurry design and several other aspects of the well cementing process; for example, preparation of the wellbore, and the condition and centralisation of the casing. Ideally, the wellbore and casing would be prepared for cementing as follows (**Figure 4B**):

- the wellbore diameter should be close to the drill bit size (known as the gauge);

[22] ISO 10426-1:2009.
[23] IOGP 2016.
[24] ISO 16530-1:2017.
[25] Hossain and Al-Majed 2015. p205
[26] Hossain and Al-Majed 2015. p73-139

- the surface of the wellbore should be smooth;
- during drilling, breakouts or **washouts** of the surrounding rock should have been minimised by good design of the drilling mud;
- there should be no formation fluid influx into the wellbore or major loss of drilling mud to the surrounding rock;
- the casing should be centralised, with a sufficiently wide annulus surrounding the casing to allow cement flow; and
- the drilling mud in the hole should be properly conditioned to remove pieces of rock that may slough off the walls of the well.

During the construction phase, components of the well that contribute to the well's integrity are tested to verify that they are performing as designed. Verification is an important element of well integrity management.[27] The integrity of well casing and cement can be tested by pressurising the well, to verify that it can hold the pressures that it may be exposed to over its life. A variety of downhole logging tools can be used to measure the state of the casing and the integrity of the bond between the casing, cement and rock.

For production wells or wells used for formation testing, hydraulic fracturing (also known as well stimulation) activities are undertaken as part of the construction phase. The hydraulic fracturing process itself is described in Section 4.

The final activity in the construction phase is the 'completion' of the well, preparing it for the production of gas.[28] Completion involves the installation of hardware in the well to allow the safe and efficient production of gas from the well at a controlled rate, and many different completion technologies are available. If the well was drilled for other purposes, or if the well is to be suspended, the completion will be designed accordingly. For example, instruments such as pressure meters or temperature sensors may be installed in a monitoring well during the construction phase.

3.4 Operational phase

For production wells, the operational phase will have the longest duration, with some wells producing hydrocarbons for decades. During this phase, the main activities are monitoring the well's integrity and performance, and maintenance. Abnormal pressures in the annulus between casing strings can indicate integrity issues, as can changes in production rates. Wireline logging, in which measurement tools are lowered down the well on a wireline, is generally the only means of checking the integrity of casing and cement down the well. Observations from a sample of wells can be used to indicate the integrity of wells across a field.[29]

3.5 Intervention phase

In some cases a well must be re-entered to perform maintenance, repairs or replacement of components; for surveillance; or to increase productivity.[30] Such interventions are also referred to as '**workover**'. Interventions can be critical to maintaining well integrity, and a range of technologies are

[27] ISO 16530-1:2017; NORSOK D-010.
[28] Hossain and Al-Majed 2015. p679-735
[29] ISO 16530-1:2017. p53
[30] ISO 16530-1:2017.

available for repairing casing and cement.[31] Production wells may be hydraulically re-fractured to extend their production, and the design of such activities needs to be commensurate with the design of the well and its current condition, allowing for any corrosion or other deterioration.

3.6 Abandonment phase

The **abandonment** phase is the final phase in the well life cycle; in this phase, the wells are decommissioned, **plugged and abandoned**. The goal of plugging and abandoning the well is to ensure the integrity of the well in perpetuity, effectively re-establishing the natural barriers formed by the impermeable rock layers that were drilled through to reach the resource.[32] Once a well has been abandoned, there is little prospect of re-entering the well for any purpose. Monitoring may be conducted after the well has been abandoned, to confirm that **plugs** have been properly set in the well. The well's ongoing integrity should not be dependent on long-term monitoring,[33] although such monitoring may be conducted to confirm the effectiveness of abandonment practices. The aims of abandonment are to: [34]

- prevent release of formation fluids or well fluids to the environment (including aquifers);
- prevent the flow of **groundwater** or hydrocarbons between different layers of rock; and
- isolate any hazardous materials left in the well.

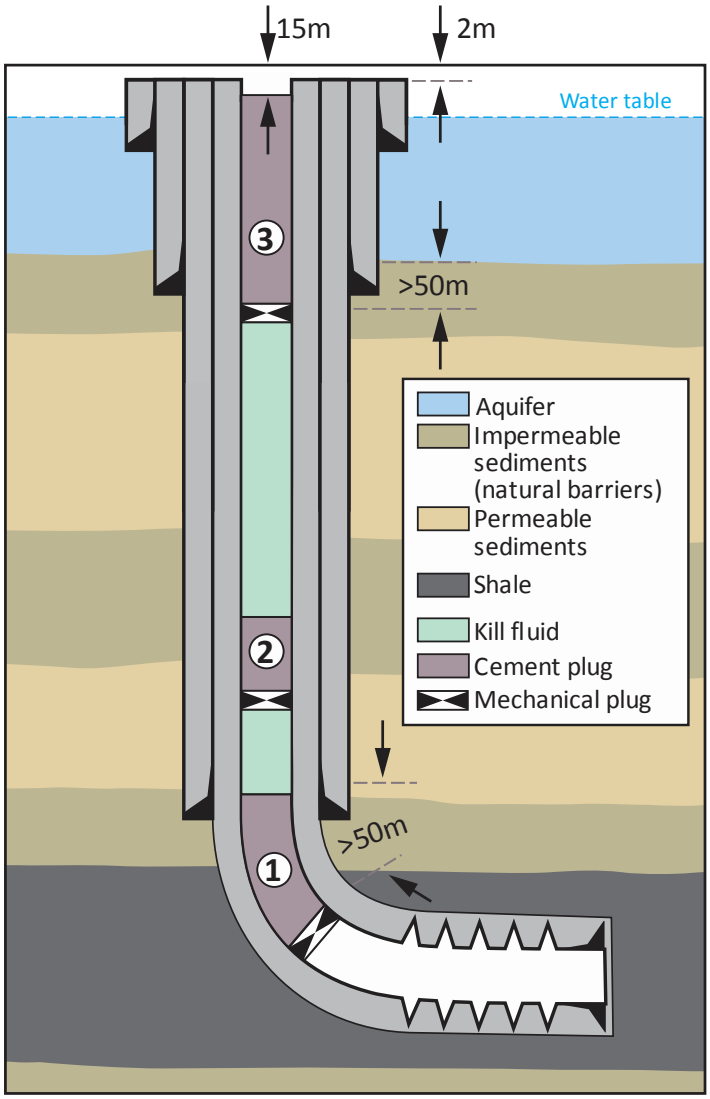
The method of plugging and abandoning a well involves confirming the well's integrity to ensure that there will be no movement of fluid into or out of the well, and placing barriers in the well to prevent the vertical movement of fluids between rock layers. A schematic of an abandoned well is shown in **Figure 5**. The plugs typically comprise cement with mechanical plugs or retainers. To provide long-term integrity, the cement (or other barrier material) must:[35]

- not shrink;
- be able to withstand the stresses in the wellbore;
- be impermeable;
- be impervious to chemical attack from formation fluids and gases;
- be able to bond with steel casing and rock; and
- not cause damage to the casing.

The design of well abandonment must be considered during the design phase of the well.[36] For example, the casing material that will be left in the well must be compatible with the objectives of abandonment.

[31] Ansari et al. 2017; Durongwattana et al. 2012; Roth et al. 2008.
[32] ISO 16530-1:2017; Kiran et al. 2017; NORSOK D-010.
[33] ISO 16530-1:2017.
[34] ISO 16530-1:2017.
[35] NORSOK D-010. p96
[36] ISO 16530-1:2017.

Figure 5: An abandoned well, showing the cement plugs that are placed in the well to prevent vertical flow of fluids. Numbers indicate order of placement of the cement plugs. Not to scale.



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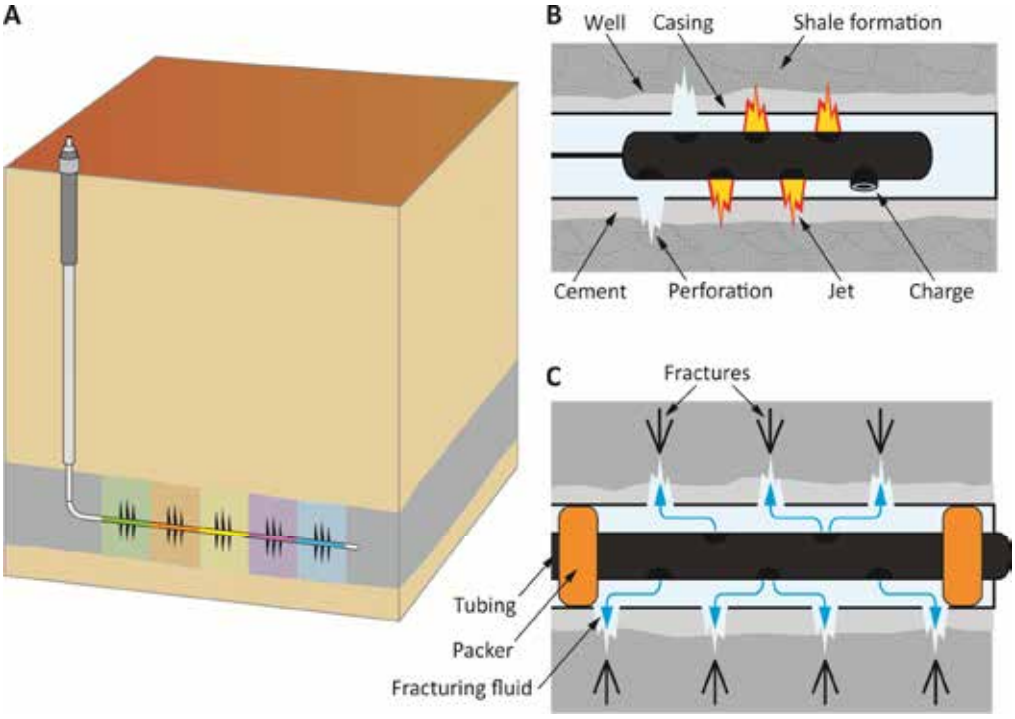
4 Hydraulic fracturing

Hydraulic fracturing is a stimulation technique that is used to increase the production of oil and gas from **unconventional resources** such as oil shales, by the injection of a hydraulic fracturing fluid at high pressure into a cased wellbore. Hydraulic fracturing of a shale gas or shale oil is usually conducted over several intervals (called 'hydraulic fracture stages') along the **production zone** of the well (**Figure 6**). Hydraulic fracturing of each stage treats a discrete volume of the reservoir. This staged approach allows for more control of the hydraulic fracturing process.

It is generally not possible to hydraulically fracture the whole well in one step. Most hydraulic fracturing treatments in shale oil and gas wells take place in the relatively long (up to several km and usually at least 1-2 km long) horizontal or nearly horizontal section of the well that follows the rock layers that contain the most concentrated hydrocarbon resource, and that has mechanical properties that allow for successful fracture treatment. Although vertical wells may be fractured for testing purposes, it is now uncommon to use a large number of vertical production wells to exploit shale gas or tight gas resources, because vertical wells cannot access a large enough volume of the reservoir. The number of fracture stages in a single well has increased over time in unconventional fields in North America. Moreover, a single well may have more than one horizontal branch or 'lateral', and each of these can have a large number of fracture stages. In 2009, 10-12 stages would have been considered typical, with spacing of around 200 m; in contrast, in 2017, it is common for 40-100 fracture stages to be placed in a single lateral, with spacing of about 15-30 m between clusters.

Figure 6: Hydraulic fracture stages. Hydraulic fracturing is typically conducted in stages; each coloured zone in (A) shows a different stage. For each stage, the casing must be perforated (B) to allow the hydraulic fracturing fluid to access the shale formation. Hydraulic fracturing is then conducted in each stage within a short section of the well that has been isolated, in this case using packers (C). Various technologies can be used for staged hydraulic fracturing. Not to scale.



The hydraulic fracturing fluid is predominantly a mixture of water, **proppant** (usually sand) and a small percentage of chemical additives (typically less than 1%). The zone to be fractured is perforated using shaped charges, and isolated using mechanical plugs or other devices before the hydraulic fracturing fluid is injected into the isolated wellbore zone. Because the hydraulic fracturing fluid is contained within the isolated wellbore zone, the pressure builds up until it exceeds a threshold known as the breakdown pressure. Once the hydraulic fracture fluid pressure exceeds the breakdown pressure, it fractures the rock, resulting in 'hydraulic' fractures. The direction in which the hydraulic fracture propagates depends on the orientation of in situ stress in the reservoir, with growth mainly occurring in a direction perpendicular to the minimal **principal stress**. At larger depths, the overburden (vertical) stress due to the weight of the overlying soil or rock is typically greater than the horizontal stress, implying that hydraulic fractures are usually vertically orientated. Once the hydraulic fracture has initiated, further propagation is controlled by the fluid flow. Some of the hydraulic fracturing fluid drives hydraulic fracture growth; the rest is injected or lost into the formation (a process known as 'leak-off'). The surface area of the hydraulic fracture increases as the fracture grows, thereby increasing the fluid loss into the formation. The hydraulic fracturing fluid injection rate is therefore calculated to propagate hydraulic fractures to the desired size, given the expected fluid loss into the formation.

Proppant is added to the hydraulic fracturing fluid to hold the fractures open at the end of the treatment. At the start of the simulation, the hydraulic fracturing fluid is injected without any proppant, to initially open a fracture wide enough to allow the proppant to travel along the hydraulic fracture; this is known as the '**well pad**'. As the hydraulic fracture propagates into the reservoir, proppant is added to the hydraulic fracture fluid in such a way that the correct proppant concentration along the hydraulic fracture is reached at the end of the treatment. Finally, the wellbore is flushed to remove any residual proppant, leaving behind a proppant-filled fracture that acts as a conductive channel through which oil and gas can flow into the wellbore.

After hydraulic fracturing treatment is complete, a portion of the hydraulic fracturing fluid will flow out of the wellbore in a process known as '**flowback**'. The experience in the United States is that the amount of hydraulic fracturing fluid that returns to the surface as flowback water from shale gas reservoirs is typically 10-30%.[37]

The advent of **horizontal drilling**, which exposes the wellbore to a larger part of the reservoir formation, has made it possible to extract oil and gas from reservoirs that were previously considered uneconomical. In the United States in 2015, it is estimated that almost 50% of crude oil production and 70% of natural gas production was from hydraulically fractured wells.[38] Hydraulic fracturing uses a significant volume of water, with a typical shale gas well consuming 13-24 million litres of water during stimulation activities. The Barnett Shale in the United States, for example, used about 243 billion litres of water over its production history, and hydraulic fracturing as a whole used about 116 billion litres water annually in the period 2012-2014. [39] More than 50 million tonnes of proppant (90% is silica sand) are used in the US annually for hydraulic fracturing operations. In 2017, about 4000 tonnes per well is typically used. The trend in the United States is for faster drilling, more hydraulic fractures per well and more wells drilled from each well pad.[40] However, any eventual shale gas well and hydraulic fracture designs in the Northern Territory would be governed by a number of factors including specific geology, available technology, well location and market forces.

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[37] US EPA Report.
[38] US EIA 2016a; US EIA 2016c.
[39] US EPA Report.
[40] US EIA 2016b.

5 Well integrity

Well integrity is a fundamentally important aspect of well operations throughout the life cycle of a well. Maintaining well integrity is critical for the safe and effective operation of wells, and to protect the environment.

Well integrity is defined in several international standards, recommended practices and guidelines:

- Norsok Standard D-010 *Well integrity in drilling and well operations* (**Norsok D-010**) defines well integrity as the "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well*".[41]
- The Norsok D-010 definition is also used by Oil & Gas UK's *Well life cycle integrity guidelines*.[42]
- **ISO 16530:1 2017** defines well integrity as "*containment and prevention of the escape of fluids to subterranean formations or surface*".[43]
- *Hydraulic fracturing – well integrity and fracture containment, ANSI/API recommended practice 100-1* (**API 100-1**) defines well integrity for onshore wells that will be hydraulically fractured as "*The quality or condition of a well in being structurally sound with competent pressure seals (barriers) by application of technical, operational, and organizational solutions that reduce the risk of unintended subsurface movement or uncontrolled release of formation fluid*".[44]

API 100-1 further describes well integrity as *"the design and installation of well equipment to a standard that:*

- *protects and isolates useable quality groundwater,*
- *delivers and executes a hydraulic fracture treatment, and*
- *contains and isolates the produced fluids"*.[45]

ISO 16530:1 2017 also provides a more complete description of well integrity:

> *"Well integrity refers to maintaining full control of fluids within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment."*

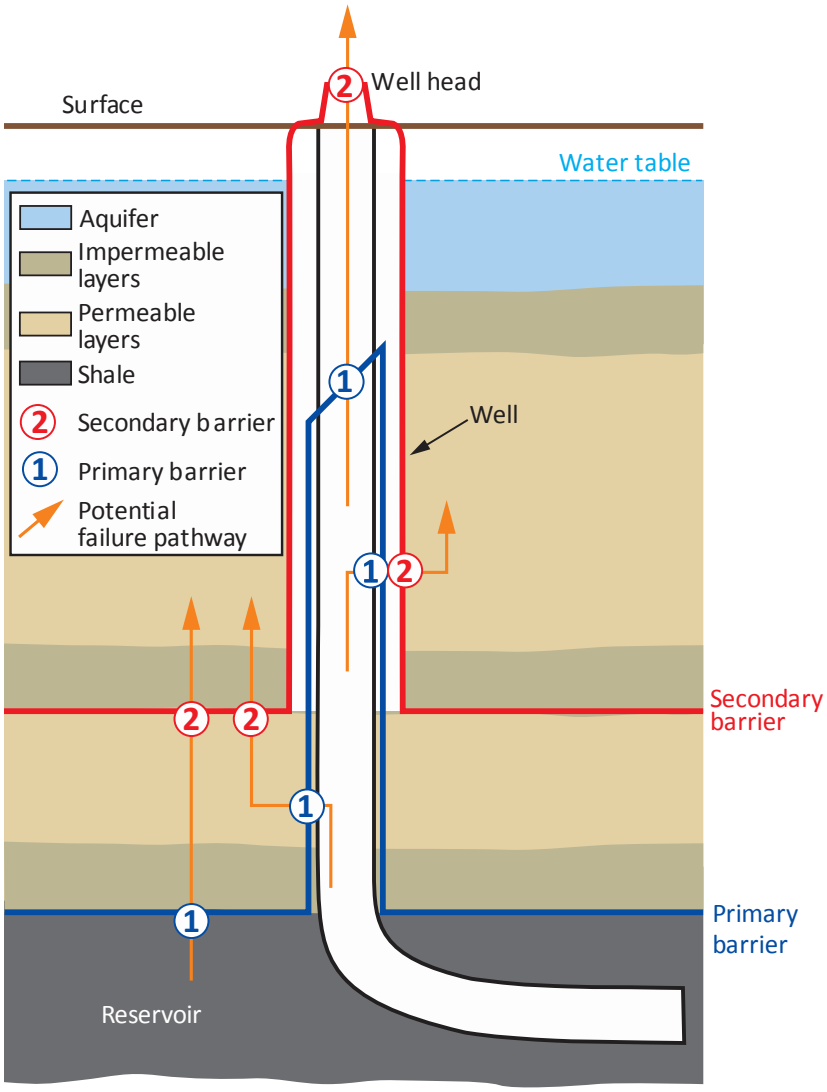
This definition is particularly useful because it introduces the concept of **well barriers**. A fundamental concept in well integrity, well barriers are defined in ISO 16530:1 2017 as a "*system of one or several well barrier elements that contain fluids within a well to prevent uncontrolled flow of fluids within or out of the well*".[46] Well barriers normally comprise several components and practices that work together to contain fluids; they include physical or hardware barriers, operational barriers, human barriers and administrative barriers.

Physical and hardware barriers are the components that are most tangible. They include impermeable formations, drilling fluids, casing cement, casing strings, **packers**, **well heads** and valves, and blowout

[41] NORSOK D-010.
[42] Oil & Gas UK 2016.
[43] ISO 16530-1:2017.
[44] API RP 100-1.
[45] API RP 100-1.
[46] ISO 16530-1:2017.

preventers. **Figure 7** shows the basic principles of the barrier concept, with the elements combining to form a "top hat" barrier that separates fluid in the reservoir and the well from the external environment and the surface. In this figure there are two barriers: a primary barrier in blue and a secondary barrier in red. The use of a two-barrier system, with two independently verifiable well barriers, is common practice in the industry. The second barrier gives a level of redundancy, providing protection should the primary barrier be compromised.

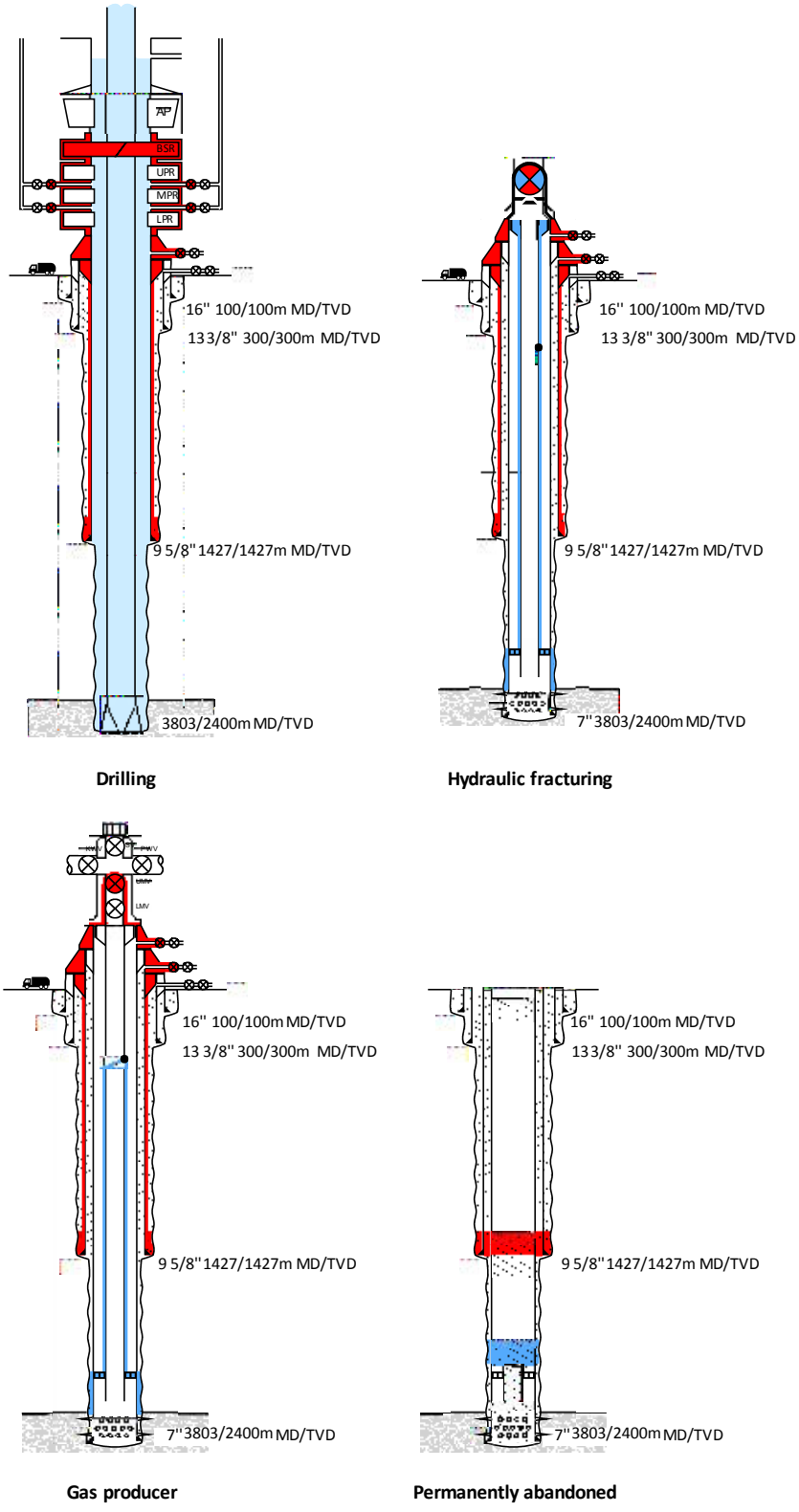
Figure 7: The two-barrier concept, showing the two barriers to various pathways for fluid flow out of the well.



Many different elements make up a well barrier, all of which need to be verified to confirm well integrity. **Figure 8** shows examples of the two-barrier system throughout the well life cycle. The principle is maintained; however, the barriers and barrier elements vary to suit the risks and operational requirements of each phase. Well barrier design will vary between wells, influenced by the design of the well, the characteristics of the resource being drilled and the risks identified.

A **well integrity failure** occurs if all barriers have failed and there is a pathway for fluid to flow into or out of the well. In a two-barrier design, both barriers need to fail for a well integrity failure to occur. A barrier failure will not result in a loss of fluids to or from the environment provided that the second barrier is intact.

Figure 8: Examples of the two-barrier system during different phases of the well lifecycle. The primary barrier is shown in blue and the secondary barrier in red.[47]



[47] Supplied by Wellbarrier AS, Norway, https://www.wellbarrier.com/.

Well integrity issues can be caused by any of the following:

- a **well breach**, including failure of **cement sheaths**, plugs, bonds, casing, and downhole and surface sealing components;
- a hydrological breach, fluid movement between geological formations – including formations not targeted for exploitation; and
- an environmental breach. contamination of or water balance impact on water resources – fluid leaks at surface and causes contamination of water sources.

Various potential impacts on environments can result from poor oil and gas well integrity, such as:[48]

- **impact on groundwater**: contamination of shallow and deep aquifers could be a risk associated with oil and gas well drilling and production activities due to poor well construction;
- **localised hydraulic connectivity between isolated aquifers along a well trajectory**: this can occur because of failed casing, poor cementing or generally poor well construction, decommissioning or abandonment practices; and
- **fugitive gas emissions**: localised gas leakage to both the atmosphere and into aquifers from oil and gas wells can occur because of equipment failure or poor well construction and abandonment practices.

5.1 Well barrier integrity failure mechanisms

This section discusses mechanisms for oil and gas well barrier failure in major phases of a production well life cycle. It also briefly discusses the likelihood of these failure mechanisms occurring, and the consequences and the mitigation measures required if they should do so.

5.1.1 Failure mechanisms associated with oil and gas well drilling

Drilling, the first step in constructing a well, presents a number of potential risks to well integrity. During drilling, the primary well barrier is the drilling fluid pressure exerted on the rock formation surrounding the well. The secondary well barrier includes the drilling blowout preventer, casing and cement, well head and cap rock formation.[49]

Drilling fluid density or mud weight is vital in maintaining well integrity before the casing is cemented. A safe mud weight range (or window) is determined by a lower bound (defined by the **formation pore pressure**) and an upper bound (defined by the formation **fracture gradient**). If the mud pressure is less than the formation pore pressure, formation fluid may enter the well. Uncontrolled influx of large volumes of hydrocarbons may lead to a blowout at the surface, which may in turn have a significant impact on the environment. In shale gas resources, blowouts are unlikely because high overpressures are uncommon in such resources, and the low permeability will limit the volume of any inrush into the well.[50]

Low mud weight can also result in wellbore instability (breakout or washout; that is, enlargement of borehole size). This is not a direct risk to well integrity in terms of containing and controlling the flow of wellbore fluids. However, the significantly enlarged wellbore may result in poor displacement of mud

[48] Bore integrity review, CoA.
[49] NORSOK D-010.
[50] Royal Society & Royal Academy of Engineering 2012. p25

during cementing and therefore a poor-quality cement sheath behind the steel casing, which may lead to loss of well integrity.[51]

If the mud weight is greater than the formation fracture gradient, drilling fluid may enter the surrounding formations or reservoirs. Most drilling fluids currently used in Australia are water based, generally comprising a mixture of water, clays, fluid loss control additives, density control additives and viscosifiers.[52] If large volumes of drilling fluid are lost into overburden or the reservoir (in particular, into shallow aquifers), this can significantly affect the environment.

To reduce risks of blowout or massive loss of drilling fluid during drilling, formation pore fluid pressure along the well trajectory is estimated. The estimate is based on data from nearby oil and gas wells or a **seismic survey** before drilling. Leak-off tests are conducted to ensure the integrity of casing and cement, and to determine the formation fracture gradient. A functional BOP will significantly reduce or eliminate the risk of environment contamination due to blowout. Because of the low permeability of shale gas reservoirs, significant hydrocarbon blowout from shale gas reservoir is unlikely during drilling.

5.1.2 Failure mechanisms related to casing and cementing

Well integrity can be lost though casing and cementing issues such as channels or voids in the cement; gaps between the formation and the cement, or the cement and the casing; and pore adhesion. These issues can be caused by poor placement of the cement, leakage through casing connections, degradation of the cement sheath and corrosion of the casing.

If channels of drilling mud remain in the annulus, they may provide a **preferential flow** pathway for fluid to migrate inside the cement sheath.[53] If a build-up of compacted drilling mud (also referred to as filter cake) is left on the well surface before cementing, it could dehydrate after the cement sets, resulting in an annulus at the interface of the formation and the cement. Furthermore, cement can shrink during setting, resulting in a **microannualus** (a fracture between the cement and the casing or formation) along the interface between the cement and the casing, or between the cement and the formation rock. **Figure 9** shows photographs of a drilling mud channel in the cemented annulus due to incomplete displacement of the drilling mud and the inner casing being off centre, and of a cement sheath core containing shale fragments recovered from an old well due to poor hole cleaning.

A good cement sheath is a solid that has a low permeability (measured in microdarcies) and **hydraulic conductivity** (that is, in the order of 10^{-6} m/d),[54] and that bonds to the casing and formation surfaces. Such a sheath prevents fluid from migrating within or through the sheath. However, downhole pressure and temperature can change because of operations in the well's history, such as casing pressure tests, well production and shut-in, and reservoir hydraulic fracturing stimulation. These operations lead to changes in well pressure and temperature, which in turn can induce radial deformation of the casing and failure in the cement sheath. This can lead to debonding on the interfaces between the cement sheath and the casing or formation, creating migration pathways through radial fractures (**Figure 10**) and microannuli.[55]

[51] Cook and Edwards 2009.
[52] Cook et al. 2013.
[53] Bonett and Pafitis 1996.
[54] Parcevaux et al. 1990.
[55] Goodwin and Crook 1992; Watson et al. 2002.

Figure 9: A) Incomplete displacement of drilling mud, the resulting drilling-mud channels, and the off-centre inner casing;[56] Used with permission from the Society of Petroleum Engineers. B) Photo of a sidewall cement core containing shale fragments in the cement sheath, indicating poor hole cleaning before cementing the casing.[57] Used with permission from Elsevier.

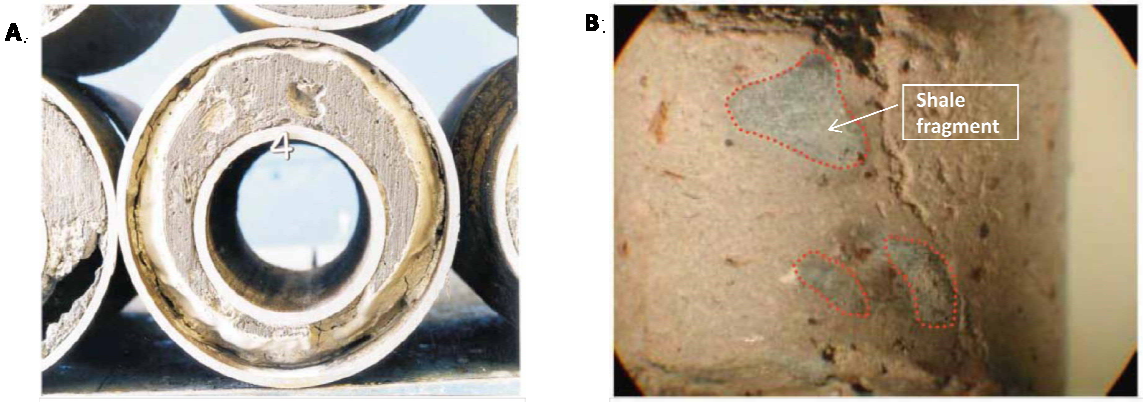


Figure 10: Cement sheath failure, resulting in cracks developing from pressure cycling on the internal casing.[58] Used with permission from the Society of Petroleum Engineers.

The impact of the cement sheath and bond failure on well integrity will depend on the extent of such failure along the wellbore and on specific geological conditions. For example, one study in the Gulf of Mexico found that there was no breach in isolation between formations with pressure differentials as high as 97 MPa (14,000 psi), provided there was at least 15 m (50 feet) of high-quality cement seal between the formations.[59]

Failure mechanisms related to corrosion of casing and chemical breakdown of the cement are discussed in Section 5.1.4.

The risks of the well integrity being compromised due to well casing and cementing can be mitigated by:

- setting the surface casing well below the base of the aquifer system;
- designing a cement slurry that is appropriate for the geological and geochemistry conditions;

[56] Watson et al. 2002.
[57] Duguid et al. 2013. p5666
[58] Watson et al. 2002.
[59] King and King 2013.

- completing the coverage of the hydrocarbon bearing formations with cement in the well annulus;
- selecting materials for casing and other well barrier components that are compatible with the geochemistry environment;
- applying good industry cementing practice; and
- using wireline logging tools to check the quality of cement sheath and bonds on the interfaces and mediatory cementing.

5.1.3 Potential impact of hydraulic fracturing on well integrity

Fluid may migrate via pathways within or external to a production well, stimulated by hydraulic fracturing. These pathways may be created or enlarged by the high cyclic pressures exerted on the well during hydraulic fracturing operations. This section briefly discusses the aspects of hydraulic fracturing that could affect well integrity. These aspects are:

- casing failure induced by hydraulic fracturing; and
- cement sheath and cement bond failure induced by hydraulic fracturing.

Casing failure induced by hydraulic fracturing

High pressures associated with hydraulic fracturing operations can damage the casing and lead to a breach of the seal between formations or aquifers. The production casing through which fracturing fluids are pumped is subject to higher pressures during fracturing operations than during other phases in the life of a production well. Therefore, to maintain integrity, the well and its components must be strong enough to withstand the stresses created by the high pressure of hydraulic fracturing fluid, otherwise a casing failure may result. If casing failures are undetected or are not repaired, they could serve as pathways for fracturing fluids to leak out of the casing. Casing failures during hydraulic fracturing operation or shortly following the operation have been reported in Australia and the United States.[60] In the Northern Territory, the Baldwin 2HST-1 well experienced a shallow casing failure during hydraulic fracturing in 2012.[61] The hydraulic fracturing fluids were retained in the well as a result of the multiple casing design, and the well was subsequently abandoned. The US Environmental Protection Agency (EPA) reported mechanical barrier failures of 3%, but did not indicate whether the hydraulic fracturing fluid was contained by secondary barriers or escaped the well.[62]

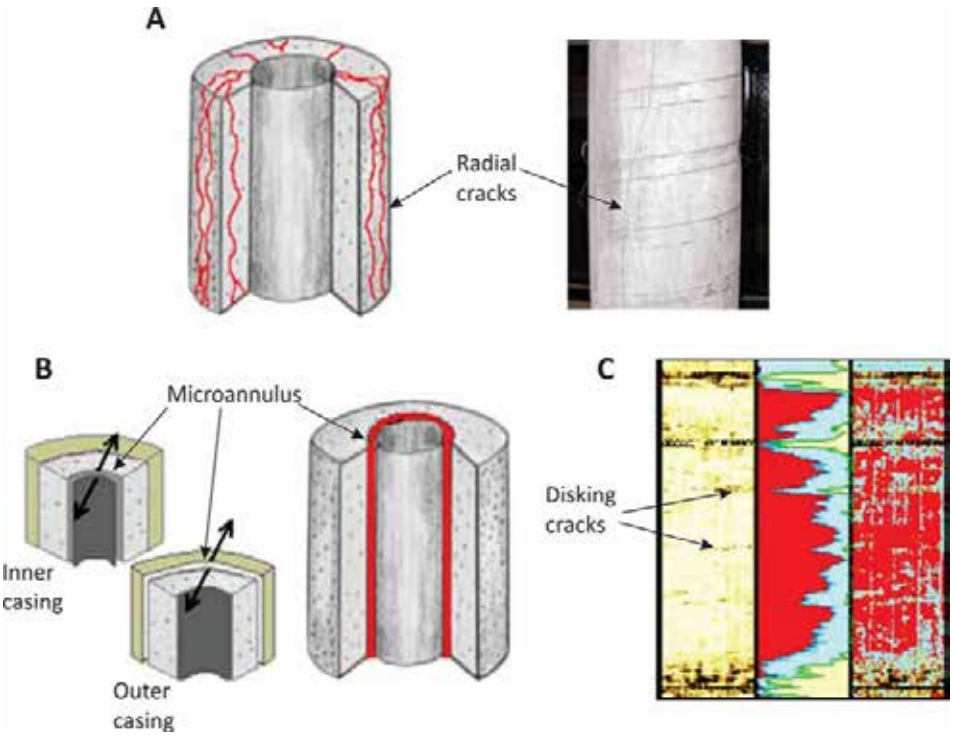
Cement sheath and cement bond failure induced by hydraulic fracturing

Cycling of pressure associated with staged hydraulic fracturing operations can damage the cement sheath behind the casing, which in turn can lead to debonding on the interfaces or tensile failure of the cement sheath. **Figure 11** illustrates potential damages to the cement sheath from the high cyclic well pressures.[63] Although a small area of debonding may not lead to fluid migration, it has been found that a microannulus is usually present after perforating or immediately after hydraulic fracturing pumping begins.[64] Maintaining a good bond during hydraulic fracturing can be problematic because the hydraulic fracture fluid pressure can also cause the microannulus to propagate. If this propagation is extensive along the wellbore, it could be a conduit for fluid or gas migration. Migration of gas (in

[60] Johnson et al. 2002; US EPA 2015.
[61] DPIR submission 226. p48.
[62] US EPA Report. p6-70
[63] Lecampion et al. 2011.
[64] Behrmann and Nolte 1998.

particular methane) is more likely than the migration of fluid, because the bouyancy of the gas provides a larger driving force for migration through the microannuli.[65] As an example of this mechanism, carbon dioxide (**CO_2**) migration to the surface along a microannulus in a CO_2 **injection well** was recognised as a plausible cause for observed leakage from a CO_2 injector.[66] Fluid migration along a microannulus may also be responsible for some of the sustained casing pressure often observed in production wells. [67]

Figure 11: Types of damage that could be encountered in the cement sheath: A) radial cracks, B) microannulus on the interface with the casing and formation rock, and C) disking cracks in a well log.[68] Used with permission from Elsevier.



The data available suggest that methane migration along the microannulus is the most common integrity issue. The source of a methane leak detected at the surface could be the shale reservoir or other methane-bearing strata in the overburden, including shallow biogenic methane sources. However, the rate of methane leakage along any potential microannulus is likely to be low because of the limited aperture and long length of this pathway and the limited driving mechanism.[69]

5.1.4 Potential fluid migration pathways in decommissioned and abandoned wells

As outlined in Section 3.6, the goal of abandoning a well is to ensure well integrity in perpetuity, re-establishing the natural barriers to the vertical movement of fluid (gas, oil or water) that existed before

[65] Dusseault et al. 2000.
[66] Loizzo et al. 2011.
[67] Loizzo et al. 2011.
[68] Lecampion et al. 2011.
[69] Rocha-Valadez et al. 2014.

the well was drilled. Cement plugs are placed in the well (**Figure 5** and **Figure 12**), creating a barrier to flow within the well, and the combination of casing and cement creates a barrier.

For a leak to occur in an abandoned well, whether the leak is to the surface or cross flow subsurface between different geological formations, three elements are needed:[70]

- a source formation where hydrocarbons or other fluids exist in the pore space;
- a driving force between the source formation and the surface (in the case of leakage to surface), or between different geological formations (in the case of subsurface cross flow); such driving forces could be a difference in pressure, temperature, salinity or buoyance; and
- a leakage pathway between the source formation and surface, or between different geological formations.

Figure 12 shows a schematic of potential leakage pathways along an abandoned well. Well leakage or failure has been attributed to poorly cemented casing or hole annuli, casing failure and abandonment failure for abandoned wells.[71] Also, preferential pathways for fluid flow that have been identified are interfaces between cement and formation rock or casing, and casing and cement plug for abandoned wells.[72] In the cement sheath, migration of fluid could also occur through fractures, channels and the pore space. In the latter case, fluid flow would occur only when the cement sheath was degraded or did not form properly during the cementing process.[73]

For shale gas wells abandoned using current practices, if any of these leakage pathways were to develop, they are unlikely to allow large fluid flow rates. The small cross-sectional areas and long vertical lengths of the pathways will limit flow. Also, shale gas resources are unlikely to have large driving forces for flow once production is completed because they will generally be depressurised. The characteristically low permeability of shale gas resources will also limit the amount of gas available to flow along a well.

The National Petroleum Council (**NPC**) in the United States is an oil and natural gas advisory committee to the Secretary of Energy that comprises industry and non-industry members. A working group of the NPC made certain observations about abandonment practices:[74]

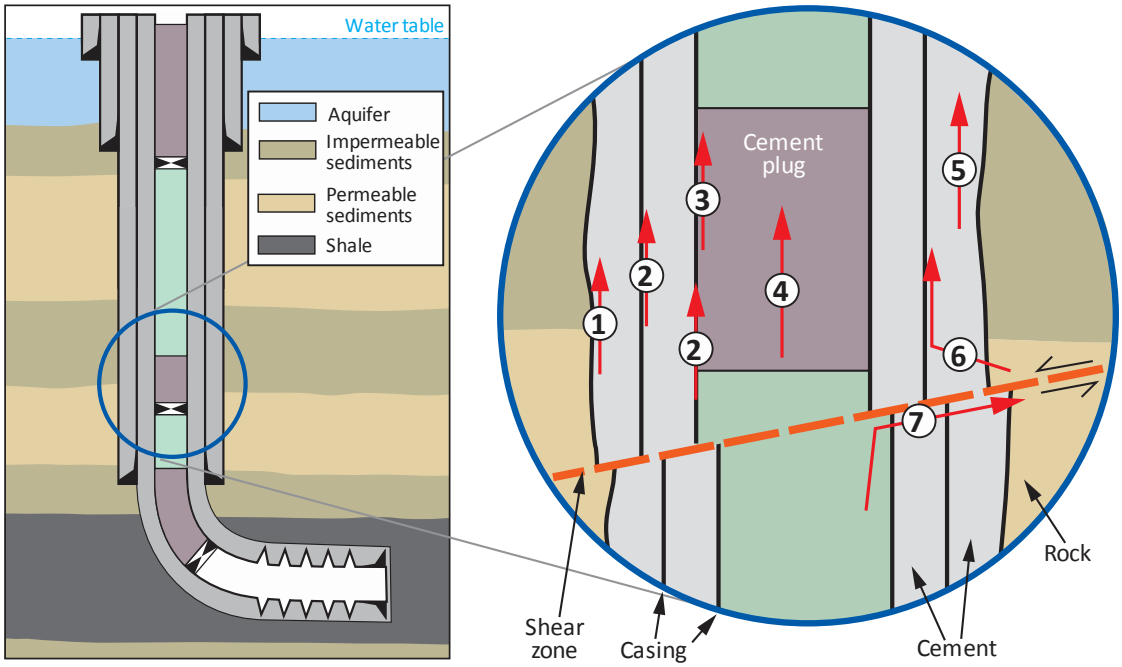
- the underlying technologies used have not seen significant progress since the 1970s, and there is room for innovation;
- abandonment is a cost for oil and gas companies, and any benefits may not be valued by the companies;
- companies are likely to minimise costs while meeting the minimum standards imposed by regulators – this contrasts with well integrity management during the rest of the well life cycle, where maintaining safety, production and operating efficiency are clear benefits to industry.[75]

The composition of fluids in the reservoir and formations that the well passes through will influence the durability of the casing and cement. Saline groundwater may corrode the casing, and the presence of CO_2 or hydrogen sulphide (**H_2S**) may also affect the casing and cement. The composition of shale gas is similar to that of natural gas in conventional reservoirs. Shale gas is typically a dry gas that contains 60-95% by volume methane and nitrogen, with ethane, propane, noble gases, oxygen and CO_2. The gases CO_2 and H_2S are referred to as sour gases because they can create an acid environment. CO_2

[70] Watson 2004.
[71] Watson and Bachu 2009.
[72] Gasda et al. 2004.
[73] Zhang and Bachu 2011.
[74] NPC North America 2011.
[75] Smith et al. 2016.

concentrations are typically in the range 0-10% by volume.[76] H_2S can occur naturally in some resources, typically at trace concentrations. H_2S generation as a result of hydraulic fracturing activities has also been reported.[77]

Figure 12: Routes for fluid leakage in a cemented wellbore: 1) between cement and surrounding rock formations, 2) between casing and surrounding cement, 3) between cement plug and casing or production tubing, 4) through cement plug, 5) through the cement between casing and rock formation, 6) across the cement outside the casing and then between this cement and the casing, 7) along a shear through a wellbore. After Davies et al.[78]



Durability of casing

Corrosion attacks every metal component, including casing, at all stages in the life of an oil or gas well.[79] Casing damage and loss of well integrity due to corrosion have been widely reported.[80] The cement quality, and cement sheath and bonding integrity are critical in protecting the casing from external corrosion. Factors that will expose the casing to corrosive fluids (if present) and therefore start the process of corrosion are degradation and failure in the cement sheath, and de-bonding of the interfaces along the casing and rock formation.

The impact of CO_2 corrosion on low-alloy steels has been studied extensively at pressures relevant for oil and gas transport (up to 1 MPa CO_2 pressure). A comprehensive review by Choi et al on corrosion of well-casing materials under high pressure for wet and supercritical CO_2 is relevant to geological storage of CO_2.[81] The review found that the corrosion rate of carbon steel under high CO_2 pressure without protective iron carbonate ($FeCO_3$) – that is, in the early stage of exposure – can be as high as about

[76] Speight 2013.
[77] Pirzadeh et al. 2014.
[78] Davies et al. 2014.
[79] Brondel et al. 1994.
[80] Bazzari 1989; Vignes and Aadnoy 2010; Watson and Bachu 2009.
[81] Choi et al. 2013.

20 mm/year. The corrosion rate can decrease to low values (~0.2 mm/year) in long-term exposure because of the formation of a protective film or scale of $FeCO_3$ on the steel surface.

Corrosion rates depend on the type of steel used. Rates are higher for mild carbon steel (~0.1-1 micrometre/year in favourable conditions such as high pH, and up to 1 mm/year in the case of chloride-induced localised corrosion) than for stainless steel or steel coated with corrosion-resistant material (fractions of a micrometre/year).[82]

A relatively long-term experimental study (up to 1,000 hours) looked at corrosion of casing materials (J55 and N80 steels) exposed to wet and supercritical CO_2 under elevated temperature and pressure.[83] The study confirmed the formation of a protective layer of the corrosion product $FeCO_3$. The corrosion rate decreased dramatically with an increase in test duration, from several mm/year at the initial 100 hours to 0.1 mm/year after 1,000 hours because of the protective effect of the $FeCO_3$ scale formation. The study also evaluated the effect of H_2S (20 ppm) and CO (2,000 ppm) on the corrosion rate of the casing steel. In the presence of these impurities, the weight loss of the casing material was lower than with pure CO_2. The authors concluded that, given the protective effect of $FeCO_3$, there would be little corrosion of the steel casing over a long period of time under stagnant conditions. This means that casing in the reservoir under CO_2 geological storage conditions is likely to remain in place with little structural degradation.

Durability of cement

The cement used in well construction and abandonment is designed to have a long life span. Although no publications were found on the long-term durability of the cement under shale gas well conditions in Australia, studies have investigated cement degradation under simulated CO_2 geological storage conditions.[84] Laboratory experimental studies have focused on the characterisation of cement and of behaviour at the interface of cement and rock, or cement and casing, when exposed to high levels of CO_2. Although CO_2 is a common component of shale gas resources, the conditions in CO_2 storage scenarios are likely to be more challenging for well integrity than would be expected in the Northern Territory's shale gas resources.

Extensive experimental and numerical modelling studies have been conducted to investigate the rate of the interaction between well cement and CO_2 under geologic storage conditions. When pre-cured cement cores are exposed to stationary CO_2 saturated water and supercritical CO_2, the cement alters. This alteration is characterised by a series of concentric fronts of carbonation and dissolution, penetrating from the interface between the fluid and the cement into the unaltered cement core.[85]

Cement integrity is closely associated with the degree of cement carbonation. In general, moderate carbonation of well cement under CO_2 geological storage conditions reduces porosity and permeability, and increases mechanical strength of the cement. However, excessive carbonation has been reported to cause crack formation and loss of compressive strength (although what constitutes the "excessive carbonation" remains a topic for research).[86] For ordinary Portland cement without additives, most experimental studies suggest a carbonate layer thickness of 1-133 mm after 30 years of exposure to CO_2 saturated **brine** or supercritical CO_2. The rate of carbonation is expected to decrease with the increase of exposure time, because the carbonate layer formed in the early stage of exposure has lower porosity than that of the neat cement, hindering penetration of CO_2 and advancement of the

[82] Elsener 2005; Kreis 1991.
[83] Azuma et al. 2013.
[84] Azuma et al. 2013; Satoh et al. 2013.
[85] Zhang et al 2015.
[86] Zhang et al 2015.

carbonate layer towards the interior of the cement.[87] The rate of cement carbonation is affected by temperature, pressure, salinity and mineral compositions of the host rock.

The long-term degradation behaviour of cement in abandoned wells under CO_2 geological storage conditions was evaluated by numerically simulating the **geochemical** reactions between the cement seals and CO_2.[88] The model was validated based on the laboratory experimental results by Satoh et al. before being applied to abandoned wells.[89] It was assumed that supercritical CO_2 or CO_2 saturated water was in contact with the cement. The geochemical simulation of the reactions yielded the extent (length) of the alteration of the cement seals after long periods. For example, the alteration length of cement seals after 1,000 year exposure was about 1 m, leading to the conclusion that cement would be able to isolate CO_2 in the reservoir over the long term.

Several studies have investigated the effect of well cement exposed to a mixture of the acid gases CO_2 and H_2S.[90] The studies have shown that, given a moderate concentration of H_2S in the acid gas (that is, less than 66 mol% H_2S), porosity and permeability changes of the cement are mainly determined by how much of the carbonate species is formed. Formation of sulphur-bearing minerals as a result of interaction between cement and H_2S does not result in significant porosity and permeability changes to the cement, or loss of mechanical strength.

The literature on corrosion and cement degradation considers CO_2 stored at high pressure to be more aggressive than methane.[91] Therefore, it can be concluded that the risk of long-term leakage from shale gas wells (from both casing and cement) would be minimal, provided that shale gas wells are properly designed, installed and maintained. However, there is scope for additional research to specifically assess the impact of abandoned shale gas wells over an extended timeframe.[92]

Durability of cement bonds

As discussed in Section 5.1.2, cement debonding is one of the mechanisms that could compromise well integrity. Permeability evolution along the interfaces (between cement and casing, and cement and host rock) due to flow of CO_2 saturated brine was evaluated in several injection experiments. Microannuli were created artificially between the cement and the casing or host rock, or within the cement core. However, the results from such experiments are not consistent. For example, Carey et al. and Newell and Carey observed an overall decrease in permeability of a cement-steel casing system and a cement-caprock system.[93] This decrease in permeability (or self-healing of defects) was mainly attributed to the migration of re-precipitation of alteration products; that is, $FeCO_3$ for a cement-steel casing system and $CaCO_3$ for a cement-caprock system within the microannulus (interfaces). In contrast, Cao et al. observed that the defects in cement were significantly enlarged, and the overall permeability of the cement-caprock system increased by a factor of eight after 10 days of CO_2 saturated brine flooding.[94] Different flow rates and interface apertures applied during the studies may have contributed to the different results; for example, Cao et al. used a higher flow rate than was used in some of the other studies.

[87] Zhang et al 2015.
[88] Yamaguchi et al. 2013.
[89] Satoh et al. 2013.
[90] Jacquemet et al. 2012; Kutchko et al. 2011; Zhang et al 2015.
[91] Popoola et al. 2013.
[92] NSW Chief Scientist and Engineer, 2014.
[93] Carey et al. 2010; Newell and Carey 2013.
[94] Cao et al. 2013.

Several hypothetical scenarios were simulated in a study by Connell et al.[95] In one scenario, it was found that, for a flow channel 0.01 cm wide, the erosion front took 8 years to travel 50 m for a high deficit in calcium solubility (~400 mg/l) and a pressure gradient (above the hydrostatic gradient) of 0.5 MPa/100 m. The erosion front migration rate dropped significantly with decreased initial channel width; for an initial width of 0.005 cm, the erosion front had migrated 25 m after 12 years. Since the rate of migration drops with distance up the flow channel, the remaining 25 m for the 0.005 cm case would have taken considerably longer than the first 25 m. After the erosion front had broken through the cemented zone of the seal, there was an initial rapid increase in the volumetric flow rate, representing a loss of containment of stored CO_2. These hypothetical scenarios highlight the importance of microannuli in connectivity between different geological formations.

5.2 Well barrier and integrity failure mechanisms summary

Commonly considered well barrier integrity failure mechanisms can be broadly summarised into three categories:

- well integrity failure before installation of casing;
- integrity failure of cement; and
- integrity failure of casing.

Historically, the highest instance of well barrier integrity failures appears to be related to insufficient or poor-quality cementing coverage to seal aquifers or non-reservoir hydrocarbon-bearing formations. In older wells, this was probably due to a lack of information on non-reservoir hydrocarbon-bearing geological layers and the regulatory regime under which the wells were constructed.

The other common well barrier failure mechanism is associated with degradation of the cement sheath and cement bonds to the casing and rock formation. This failure mechanism can be exacerbated if the well is subjected to cyclic pressures, stresses and temperatures. There is a growing body of research on cement durability in the context of CO_2 storage, which is considered to be a more corrosive environment (that is, corrosive formation and reservoir fluids) than methane gas. This research suggests that the degradation length of cement seals after a theoretical 1,000 year exposure would be about 1 m. In a corrosive environment, failure of the metal casing can also occur through corrosion of the metal components of the well.

If a well barrier failure is observed or suspected to have developed, technologies, tools and mitigation measures are available to confirm the failure mechanisms, identify their extent and conduct mitigation operations.

5.2.1 Well integrity failure before casing installation

Before the casing and cement are installed into the borehole, there is the possibility of unintended fluid flow out of or into the borehole. These failures of well control could be caused by:

- drilling fluid pressure that is significantly less than the formation pore fluid pressure;
- overpressured formations or reservoirs;
- drilling fluid pressure that is greater than formation pressure in fractured or permeable formations; or

[95] Connell et al. 2015.

- drilling fluid pressure inducing hydraulic fractures.

Factors that mitigate these failures or the consequences of these failures include:

- identification of geological **hazards** before drilling;
- monitoring of drilling fluid pressure and volume; and
- well control equipment.

5.2.2 Well barrier integrity failure of cement

Failure of the casing cement though degradation, debonding, or insufficient or poor placement of cement could create a conductive pathway and allow movement of fluid or gas up the cement annulus outside the casing. This conductive pathway between formation pore fluids in different geological layers could provide a mechanism for fluid flow if there was a pressure differential or for gas flow driven by buoyancy. Causes of this type of well failure could include:

- unidentified hydrocarbon-bearing formation;
- poor wellbore condition due to excessive borehole breakout or washout;
- poor hole cleaning and mud conditioning, resulting in mud channelling in the cement sheath;
- cement slurry loss into fractured formations;
- uncentralised casing pipe, resulting in a partial cement sheath;
- cement shrinkage;
- cyclic wellbore pressures and temperatures; or
- cement degradation in a corrosive environment.

Factors that mitigate these failures or the consequences of these failures include:

- good quality geological information, including fractured formations or zones, and identification of hydrocarbon-bearing formations in the overburden and aquifers;
- good drilling practices to provide high-quality intact borehole for cementing;
- cement bond logging to investigate the integrity of the cement sheath; and
- remedial cement repairs applied to identified problem zones.

5.2.3 Well barrier integrity failure of casing

Failure of the wellbore casing though corrosion, burst or collapse could allow loss of wellbore fluid to the surrounding rock. Causes of these failures could include:

- corrosive formation or reservoir fluids;
- poorly cemented casing;
- internal damage or wear to casing; or
- a large pressure difference between the internal and external fluids.

Factors that mitigate these failures or the consequences of these failures include:

- casing pressure monitoring;
- Inspection of casing using multifinger caliper logs, magnetic thickness tool and borehole cameras; and
- casing patching or repair.

5.3 Well failure rates

Compromised well integrity or barrier failure can be an issue in oil and gas production operations. Several studies have identified single-barrier integrity issues in a significant percentage of oil and gas wells; however, the available data indicate that rates of complete well integrity failure (multibarrier failure) affecting groundwater are low. This section reviews barrier and well failure rates reported in open-source international literature for oil and gas wells, with data primarily from North America. The literature presented primarily covers conventional oil and gas resources. Well integrity risks and potential consequences are influenced by the resource characteristics, as outlined in Section 2, and this situation also applies to shale gas wells. There are enough similarities in the well construction methods and the geology (given that shale gas wells are often drilled in the same sedimentary basins as conventional oil and gas wells) for studies of well integrity in other settings to provide an indicator of potential well integrity issues in shale gas development. Data on the integrity of shale gas wells are included in several studies of oil and gas well integrity, and in two studies on unconventional wells. The data presented allow a comparison of shale gas wells with other types of oil and gas wells.

5.3.1 Oil and gas well failure rates in Ohio and Texas, United States

A comprehensive study on groundwater contamination incidents related to conventional oil and gas activities in Ohio and Texas, United States by Kell covered a large well population at different phases of the well life (**Table 1**).[96] It included incidents related to well integrity and those resulting from other activities, including leakage from surface pits, transport and storage of **produced water** and oil, and waste disposal. The data are predominately for conventional oil and gas wells, although the data from Texas include 16,818 wells drilled for shale gas and oil, primarily in the Barnett Shale.

Table 1: Summary of well numbers in the study of wells in Ohio and Texas, United States. [97]

Operation stage	Number	
	Ohio (1983-2007)	Texas (1993-2008)
Wells drilled	34,000	187,788
Hydraulic fractured wells	27,969	> 13,000
Producing wells	50,342-64,830	237,136-253,090
Wells plugged	28,000	140,818

The average depth of wells drilled in Ohio was 1,140-1,446 m (3,745-4,745 feet) during the study period (1983-2007). In Texas in 2007, the average depth was 2,517 m (8,258 feet). The groundwater contamination incidents and related contamination causes are summarised in **Table 2**; in relation to well-related groundwater contamination incidents, contamination from the orphaned wells had the highest number of reported incidents. For non-well-related incidents, contamination from surface pits or storage tanks had the highest number of reported incidents.

[96] Kell 2011.
[97] Kell 2011.

Table 2: Summary of groundwater contamination incidents at different stages of the well life cycle. Numbers of well integrity incidents related to groundwater contamination are shown in parentheses.[98]

Operation stage	Number	
	Ohio (1983-2007)	Texas (1993-2008)
Site preparation	0	0
Drilling and completion	74 (11)	10 (6)
Hydraulic fracturing	0	0
Production	39 (12)	56 (6)
Orphaned wells	41(41)	30 (28)
Waste management and disposal	26 (16)	75 (6)
Plugging and site reclamation	5 (4)	1 (1)
Unknown	0	39
Total number of incidents	185 (84)	211 (47)

King and King estimated barrier and well failure rates using the data from Kell's study (**Table 3**).[99] The barrier failure rate was 0.1-0.035% and the well failure rate was one order of magnitude lower than that. King and King defined a well barrier as "*a means of containing wellbore pressure and fluids*", and well failure as *"all well barriers failing in sequence and a leakage pathway being created across all the well barriers"*.[100]

The study by Kell relied on reported contamination incidents,[101] and there may have been integrity issues in other wells that did not result in contamination of a drinking water well or were not noticed and reported. Therefore, the barrier failure rate and well failure rate in the study should be considered a low-end estimate of the number of well integrity issues.

Table 3: Estimates of well barrier failure and well failure rates. Modified from King and King, primary data from Kell.[102]

State	Number of wells	Barrier failure frequency range (containment)	Well integrity failure range (containment lost)	Leaks to groundwater by sampling
Ohio	64,830	0.035% in 34,000 wells (0.1% in older wells – worst case)	0.06% for all wells	Details not available
Texas	253,090	0.02% all wells	0.02% for older era wells; 0.004% for newer wells	0.005-0.01% for producers; 0.03-0.07% for injectors
Texas	16,000 horizontal, multifractured	No failure reported	No failure data or pollution reported	No well-associated pollution

In Texas, no groundwater contamination incidents related to hydraulic fracturing were identified over the study period, during which large-volume, multistaged hydraulic fracturing operations for shale gas well stimulation were carried out in over 16,000 Barnett Shale wells. This may be because the wells were characterised while they were still young, so the failure mechanisms described earlier may have

[98] Kell 2011.
[99] King and King 2013.
[100] King and King 2013.
[101] Kell 2011.
[102] Kell 2011; King and King 2013.

not yet had a chance to develop. Intensive, long-term monitoring of stimulated wells would be required to establish whether groundwater contamination occurs over longer timeframes. Only one shale wells was drilled in Ohio during the study period.

5.3.2 Oil and gas well failure rates in Alberta, Canada

In the context of assessing site suitability for CO_2 storage in geological media, Watson and Bachu evaluated the potential for gas and CO_2 leakage along existing oil and gas wells by analysing a large dataset collected by the Alberta Energy Resources Conservation Board (**ERCB).**[103] The database contains information for more than 315,000 conventional oil, gas, and injection wells in the province of Alberta, Canada. No shale gas or oil wells were included in this study because the development of these resources in Alberta is at the exploratory stage. The ERCB records well leakage at the surface as either surface-casing-vent flow (referred to in the industry as **SCVF**) through wellbore annuli or gas migration (referred to in the industry as **GM**) along the outside of the casing. Surface-casing-vent flow occurs when gas enters the exterior production casing annulus from a source formation below the surface **casing shoe**, and flows to surface through the annulus when the casing vent is open, or builds gas pressure in the annulus when the casing vent is closed. Gas migration occurs when gas migrates along the outside of the cemented surface casing (**Figure 13**). The ERCB requires that all wells drilled and cased be tested for surface-casing-vent flow within 60 days of drilling rig release and before final abandonment. Wells must be repaired immediately if they have:

- positive surface-casing-vent flow and exhibit gas flow rates greater than 300 m^3/day;
- a stabilised surface-casing build-up pressure that is greater than the water hydrostatic pressure gradient to the depth of the surface-casing shoe; or
- liquid hydrocarbon flow or saline water flow.

Wells with positive surface-casing-vent flow that fall below these criteria must be checked regularly, with results reported to the ERCB and with repairs carried out at the time of abandonment.

Insufficient cement height in the annulus or poor-quality cement is the cause of surface-casing-vent flow and gas migration. However, producing reservoirs are often not the source for the surface-casing-vent flow and gas migration.[104] As illustrated in **Figure 13,** the gas for the surface-casing-vent flow and gas migration commonly originates from a thin intermediate depth gas zone. The wellbore interval in the reservoir and adjacent formations is often sealed with high-quality cement due to a significant water loss of the cement slurry in the reservoir section during cementing.[105] Conversely, intermediate and shallow depth intervals are often sealed with lower quality cement with a number of filler additives, which do not always generate good primary cement seals. [106]

Figure 14 shows historic drilling activity and occurrence of surface-casing-vent flow and gas migration in Alberta over the past 100 years, both as a percentage of wells drilled in a given year and as a cumulative figure over time. As shown in **Figure 14**, the percentage of cumulative wells with surface-casing-vent flow and gas migration is about 4.6%. The ratio of wells with surface-casing-vent flow and gas migration to the wells drilled decreased from over 4% in 1995 to below 2% in 2005 (**Figure 14**), probably as a result of important regulatory changes, which require that any leaking wells be repaired before well abandonment. An alternative explanation for this reduction is the age of wells. Since about

[103] Watson and Bachu 2009.
[104] Watson and Bachu 2009.
[105] Dusseault and Jackson 2014.
[106] Watson and Bachu 2009.

1995, there has been a significant increase in the number of wells drilled. These relatively new wells had a maximum age of about 10 years when the study was carried out; consequently, the well failure mechanisms (for example, corrosion) leading to the surface-casing-vent flow and gas migration may have not developed sufficiently to cause an evident problem.

Figure 13: Schematic of gas migration (left side of wellbore) and surface-casing-vent flow (right side of wellbore), originating from a thin, intermediate-source depth zone. Modified from Dusseault et al. 2014.[107]

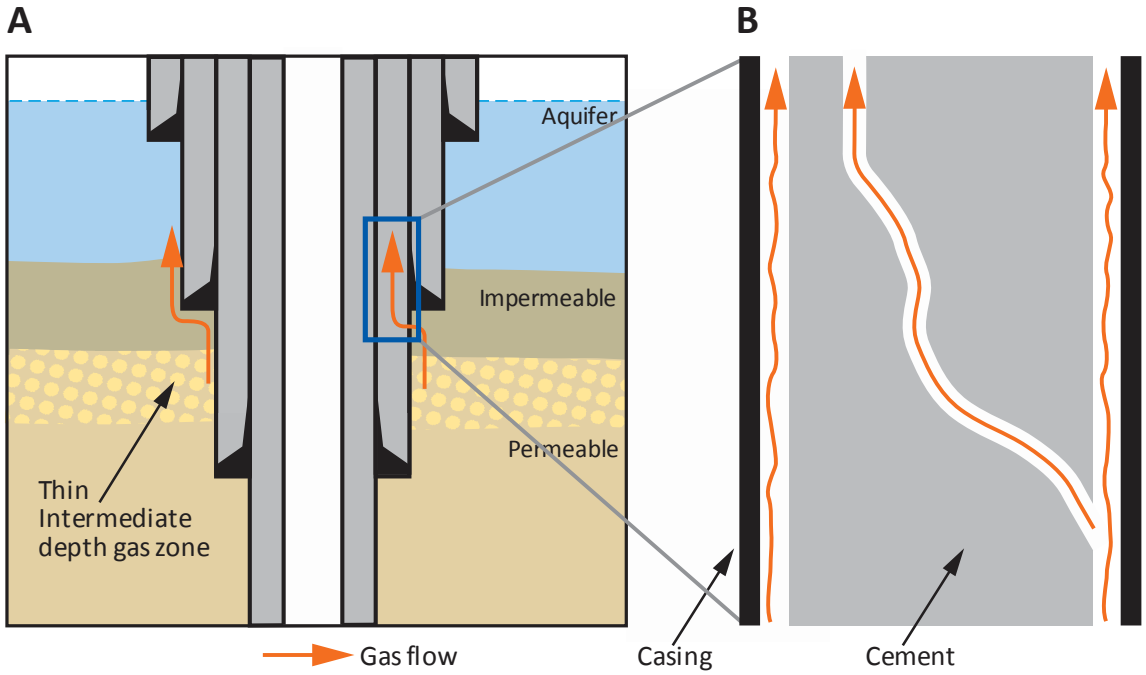
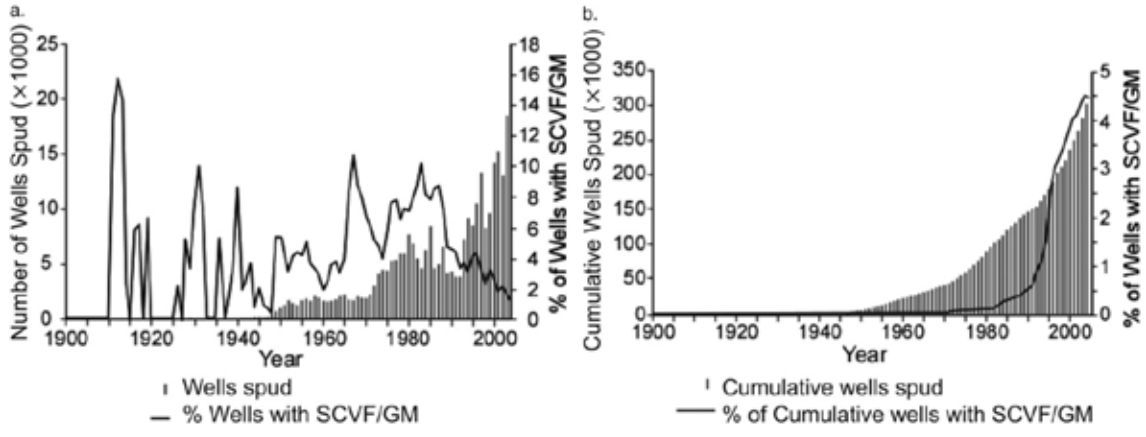


Figure 14: Historical levels of drilling activity and surface-casing-vent flow and gas migration occurrence in Alberta: (a) by year of well drilling commencement and (b) by cumulative wells drilled.[108] Used with permission Society of Petroleum Engineers.

GM, gas migration; SCVF, surface-casing-vent flow



[107] Dusseault et al. 2014.
[108] Watson and Bachu 2009.

Watson and Bachu identified six factors that have a major impact on the occurrence of surface-casing-vent flow and gas migration: geographic area; **well deviation**; well type; abandonment method; oil price, regulatory changes; and un-cemented casing and hole annulus. These factors are discussed below.

Geographic area

The occurrence of surface-casing-vent flow and gas migration is more likely in a test area designated by ERCB for special testing requirements for leakage. **Table 4** compares surface-casing-vent flow and gas migration occurrence in Alberta and within the test area. The percentage of wells with surface-casing-vent flow and gas migration is significantly higher in the test area than the average value in Alberta. The greater percentage of reported leakage may be a reflection of the testing requirements in the test area. However, the more stringent testing requirements could have arisen because of historical well integrity problems in the test area. Saponja discussed typical geological formations that made obtaining and maintaining an adequate cement seal much more difficult in the test area.[109] Furthermore, enhanced oil recovery and other stress-inducing operations that are performed in the area can significantly increase the potential for surface-casing-vent flow and gas migration to occur.[110]

Well deviation

Deviated wells have paths that 'deviate' from the vertical. As shown in **Table 4**, well deviation has a major impact on the occurrence of surface-casing-vent flow and gas migration in the test area. Poor casing centralisation was suspected to be the main reason for the poor cement seals and the resulting increase in well leakage. Casing that is not properly centred in the well may have caused insufficient mud displacement and non-uniform placement of the cement slurry, resulting in mud channels in the cement sheath or partial coverage of the casing.

Table 4: Occurrence of surface-casing-vent flow and gas migration in a test area compared with Alberta province. Data from Watson and Bachu[111]

GM, gas migration; SCVF, surface-casing-vent flow

	Alberta	Test area	% of deviated wells in the test area	Deviated well in the test area
Total number of wells	316,439	20,725	6.5%	4,560
Wells with SCVF	12,458	1,902	15.3%	1,472
Wells with GM	1,843	1,187	64.4%	1,550
Wells with GM/SCVF	176	116	65%	-
SCVF percentage	3.9%	9.2%	-	32.3%
GM percentage	0.6%	5.7%	-	34%
Combined percentage	4.6%	15.5%	-	66%

Well type

The study by Watson and Bachu showed that the drilled and abandoned wells (for example, exploration wells not developed as production wells) reported a surface-casing-vent flow and gas migration occurrence rate of about 0.5%, whereas the overall occurrence rate for all wells was about

[109] Saponja 1999.
[110] Dusseault and Jackson 2014.
[111] Watson and Bachu 2009.

4.6%.[112] The cased and abandoned wells had an overall occurrence rate of about 14%. The cased wells accounted for more than 98% of all well leakage cases reported. The authors attributed their results to historical changes in abandonment requirements for drilled and abandoned wells. The findings may also be due to the fact that the cased and abandoned wells had a long producing life, and the stimulation and production operations created a gas pathway behind the casing, whereas a well that is drilled and immediately abandoned and plugged with a number of long cement plugs does not have such a potential for fluid pathway development. [113]

Abandonment method

The predominant method for well abandonment in Alberta was bridge plugs capped with cement, placed using the dump-bailer method. It was found that this method may not be adequate in providing a sufficient cement seal in the long term.[114] Other abandonment methods – such as placing a cement plug across completed intervals using a balanced-plug method or setting a cement retainer and squeezing cement through **perforations** – are expected to have lower failure rates in the long term.

Oil price, regulatory changes and surface-casing-vent flow and gas migration testing

Watson and Bachu found that the occurrence of surface-casing-vent flow and gas migration correlated strongly with oil price in the period between 1973 and 1999 (**Figure 15**).[115] This correlation may be explained by the level of activity and equipment availability impacting wellbore construction practices in the field. Furthermore, higher prices were accompanied by economic incentives to develop the heavy oil area in Alberta that broadly correspond to the test area. Heavy oil wells require thermal stimulation; high well density; and deviated, directional and horizontal well technology. The correlation between oil price and occurrence of surface-casing-vent flow and gas migration started to diverge in 2000. This may be a reflection on the effect of the regulatory change that began in the mid-1990s.

Un-cemented casing and hole annulus

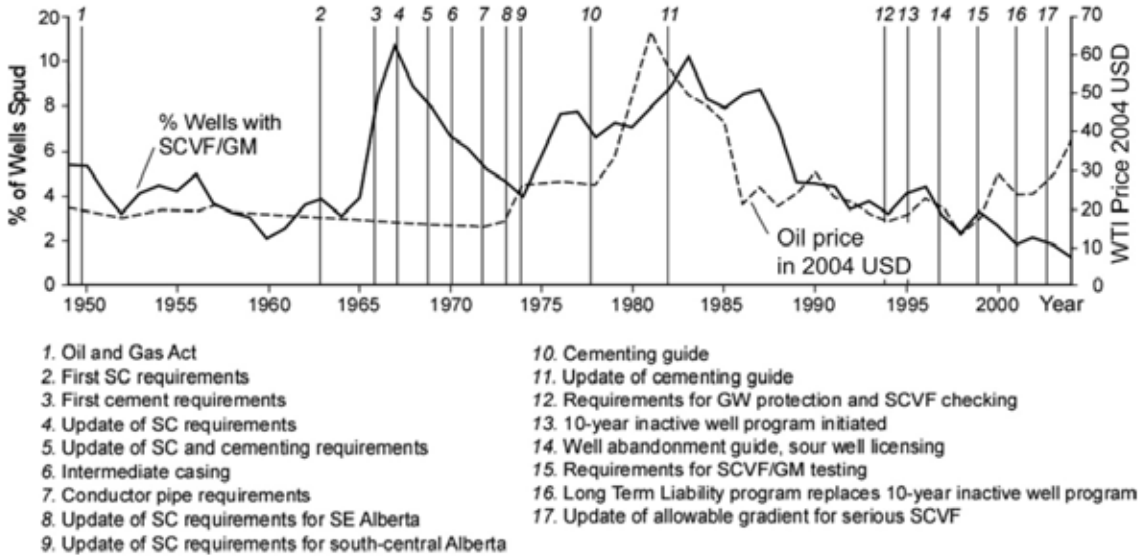
Watson and Bachu found that insufficient cement height and an **openhole** annulus are the most important indicators for occurrence of surface-casing-vent flow and gas migration.[116] These factors have a significant impact on external casing corrosion, which can create potential leaks through the casing wall. The authors analysed the logs of 142 wells to assess the casing and the cement bond quality, and observed that:

- most of the significant corrosion occurs on the external wall of the casing;
- a significant portion of wellbore length is un-cemented;
- external casing corrosion is most likely to occur in areas where there is no or poor cement; and
- some wells showed that external casing corrosion was located in the area with good cement quality; in most of these cases, channelling within the cement sheath accounted for the external casing corrosion.

[112] Watson and Bachu 2009.
[113] Dusseault and Jackson 2014.
[114] Watson and Bachu 2009.
[115] Watson and Bachu 2009.
[116] Watson and Bachu 2009.

Figure 15: Occurrence of surface-casing-vent flow and gas migration in Alberta in relation to oil price and regulatory changes.[117] Used with permission Society of Petroleum Engineers.

GM, gas migration; GW, groundwater; SC, surface casing; SCVF, surface-casing-vent flow



5.3.3 Oil and gas well failure rates in Colorado, United States

Wattenberg Field, Denver-Julesburg Basin

Stone et al. conducted a risk assessment of fresh water aquifer contamination due to hydrocarbon or hydraulic fracturing fluid migration from oil and gas wells in Wattenberg field, the largest field in the Denver-Julesburg Basin in Colorado, United States.[118] The Wattenberg Field is predominately a conventional oil and gas field that has been actively developed since the 1970s, with tight gas development involving hydraulic fracturing in later years. Development of shale gas resources has been the focus since 2010, with 973 horizontal wells drilled by 2013. Water aquifer contamination was determined based on detection of **thermogenic** gas or other identified hydrocarbons or fracturing fluids in water wells that are within a radial distance of 0.5 miles from the oil and gas well. The study analysed data from 17,948 wells drilled between 1970 and 2013. It identified possible well barrier failures by remedial cementing operations below the surface casing shoe. The study assumed that remedial cement operations at shallow depths are generally characterised by faulty barriers and the possible presence of sustained casing pressure. Well integrity failures (or catastrophic barrier failures) resulting in migration of hydrocarbons to aquifers were identified by detection of thermogenic gas in **offset** water wells, combined with evidence of catastrophic barrier failure in the adjacent oil and gas wells.

Surface casings of wells drilled in the field in the 1970s were set at a shallow depth, insufficient to fully protect the aquifers. Later, cement remediation was performed below the surface casing shoe to rectify the problem. Since 1994, the surface casing has been set deeper to protect the aquifer. Furthermore, in the 1970s, the top of the production casing cement was designed to cover 'known' hydrocarbon-bearing formations. However, shallow hydrocarbon-bearing formations were not

[117] Watson and Bachu 2009.
[118] Stone et al. 2016b.

discovered until the early 1980s. These overpressured shallow formations have low permeability, and the production cement was not designed to isolate them in the annulus; only since the 1990s have the production cement tops been designed to cover the shallow hydrocarbon-bearing zones.

The wells in the field were categorised based on the well barriers; specifically, the shoe depth of the surface casing, the top of the cement in the production annulus and the number of intermediate casings (**Table 5**). A well in a higher category has a higher number of well barriers and a lower risk of well failure.

Table 5: Wellbore barrier categories, ranked from highest risk to lowest risk. Modified from Stone et al.[119]

Barrier	Category	Surface casing	Intermediate casing strings	Level of top of production casing cement	Risk level
1	**1**	Shallow		Below overpressured hydrocarbon reservoir	**High**
1	**2**	Shallow		Below under pressured hydrocarbon reservoir	
2	**3**	Shallow		Above top of gas	
2	**4**	Shallow		Above surface casing shoe	
3	**5**	Deep		Below under pressured hydrocarbon reservoir	
3	**6**	Deep		Above top of gas	
4	**7**	Deep		Above surface casing shoe	
5	**8**	Deep	1	Below top of gas	
4	**9**	Shallow	1	Above casing shoe	
6	**10**	Deep	1	Above top of gas	
6	**11**	Deep	1	Above casing shoe	
8	**12**	Deep	2	Above casing shoe	**Low**

The rates of barrier and well failures for the wells in the field were analysed based on well category, and are summarised in **Table 6** for vertical and horizontal wells. No wells of Category 8-12 exist in this field (all the wells have no intermediate casing).

Of the 17,948 wells studied, 10 wells (or 0.05% of original wells) were identified as having well failure (catastrophic barrier failure). Nine wells had a shallow surface casing set above the base of the aquifer, and the other well in Category 5 had deep surface casing and no evidence of water aquifer contamination. However, this latter well had elevated benzene levels at the surface near the well, which could have been due to surface leaks in the flowline or production tank; therefore, it was also included in the count for well failure.

A total of 418 vertical or deviated wells (2.48% of the original wells) were identified as having potential barrier failures that required cement remediation below the surface casing shoe. The shallow surface casing, coupled with the age of the wells, led to sustained casing pressure and subsequent cement remediation. However, no evidence of thermogenic gas migration to the aquifer was found associated with the potential barrier failures from the water testing in adjacent water wells. The most common barrier failure is insufficient surface-casing depth and inadequate production cement design. For wells that had been designed and constructed correctly, no well failures were observed.

[119] Stone et al. 2016a.

Table 6: Potential barrier and well failures in the Wattenberg field. Modified from Stone et al. 2016. [120]

Cat., category; D & A, drilled and abandoned; P & A, plugged and abandoned

	Vertical deviated wells					Horizontal wells				
Well category	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)
Cat. 1	166	100	60.24	3	1.81	0	0	0	0	0
Cat. 2	621	219	35.27	5	0.81	0	0	0	0	0
Cat. 3	46	16	34.78	1	2.17	0	0	0	0	0
Cat. 4	7	0	0	0	0	0	0	0	0	0
Cat. 5	8,789	77	0.88	1	0.01	0	0	0	0	0
Cat. 6	5,433	6	0.11	0	0	269	0	0	0	0
Cat. 7	1,766	0	0	0	0	704	0	0	0	0
Cat. 8 To Cat. 12	0	0	0	0	0	0	0	0	0	0
Total	**16,828**	**418**	**2.48**	**10**	**0.06**	**973**	**0**	**0**	**0**	**0**
D & A	147					0				
Total wells	16,975					973				
P & A	1105					3				

For horizontal wells that had been constructed since 2010, no barrier and well failures were identified. The study also found no evidence of hydraulic fracturing operations directly contaminating water aquifers in the field. All the well failures were related to hydrocarbon migration through the wellbore to the aquifer or surface.

No corrosion-related barrier and well failures were identified in these wells, because the produced water has lower total dissolved solids and lower salinity compositions than many gas fields in the United States.

Piceance, Raton and San Juan Basins, Colorado, United States

A risk assessment study similar to that for the Wattenberg field in the Denver-Julesburg basin was conducted for the oil and gas wells in three basins in Colorado: Piceance, Raton and San Juan.[121] The assessment confirmed that natural gas migration from poorly constructed wellbores can happen, but occurs infrequently. It also confirmed that there has been no occurrence of hydraulic fracturing fluid contamination in the three basins.

Piceance Basin

Drilling in the Piceance Basin is for conventional oil and gas resources, using vertical and deviated wells. There have been some horizontal exploration wells testing shale resources since 2008. The assessment analysed data from 10,998 wells completed between 1935 and mid-2014, of which 156 wells were drilled and then abandoned without completing for production. All the wells were

[120] Stone et al. 2016b.
[121] Stone et al. 2016a.

categorised based on their original casing and cement design (**Table 5**). Potential barrier failures were identified by any cement remediation of any casing string (not just below the surface casing shoe) or evidence of sustained casing pressure. Sustained casing pressure is common in the basin due to shallow gas shows above the top of the production cement in the annulus. In addition, effective cement isolation of the shallow gas-bearing formation is challenging because of **lost circulation** in these shallow formations. Well failures (catastrophic barrier failures) were identified as wells that had barrier failures inducing a conduit for hydrocarbon migration to water aquifers, which was confirmed by isotopic and compositional analysis from offset water wells.

The assessment found that potential barrier failures occurred in 377 of 10,842 wells (3.5% of original producing wells) in the basin (**Table 7**). Category 8 wells had the highest potential barrier failure rate (30%; 18 of the 60 wells). Even though this category had deep surface casing and an intermediate casing string, the top of the production cement was below the top of the gas-bearing formation. Furthermore, casing corrosion contributed to the higher potential barrier failure rates experienced for lower risk well barrier designs in the field. This is because the produced water had high salinity and the gas stream had an average elevated concentration of CO_2. Most of the cement remediation needed was because of holes and pitting developing in the carbon steel casing. The lower risk wells in Categories 6 and 7 had lower potential barrier failure rates (2.33-3.01%). Although the top of the production cement is designed to be above the top of gas-bearing formations for wells in these categories, the potential barrier failure rates being above zero demonstrated the challenging geological conditions that are present in the shallow formation. These conditions prevent effective isolation of production cement and sustained casing pressure from shallow hydrocarbon deposits. Nine of the 10,842 originally producing wells were identified as having well failure (catastrophic barrier failures) related to hydrocarbon migration to fresh water aquifers. All of these nine wells had high sustained casing pressure before thermogenic gas detection in offset water wells. No evidence was found of hydraulic fracturing fluid migration to fresh water aquifers or surface soil.

Raton Basin

Drilling in the Raton Basin has targeted coal bed methane (or **coal seam gas**, **CSG**) resources, with some hydraulic fracturing. There has also been some exploration for conventional and unconventional gas resources. The assessment analysed data from 3,547 wells drilled and completed between 1920 and December 2013 in the Raton Basin, with only 173 wells drilled before 1995. Some 188 of the wells were drilled and subsequently plugged and abandoned without completing for production. All the wells were categorised based on their original casing and cement design (**Table 5**). Potential barrier failures were identified by any sign of cement remediation of any casing string. Well failure (catastrophic barrier failure) was identified using the method similar to that for wells in Piceance Basin; that is, detection of thermogenic gas in offset water wells or surface soil, and evidence of well barrier failures contributing to migration of the thermogenic gas to the aquifer.

The assessment showed that the highest potential barrier failure rate occurred in wells of Category 5 or 6 (80.7% for Category 5 and 59.38% for Category 6, **Table 7**). However, cement remediation was mainly needed because of a change in regulations (which required the production cement tops to be above the previous casing shoes), rather than because of well barrier failure or development of sustained casing pressure. Most wells designed in the Raton Basin are in Category 7, which had the lowest potential barrier failure rate because of its redundant barrier designs and the top of production cement being above the surface casing shoe. Some 0.43% of wells in Category 7 received cement remediation due to cement contamination, presence of microannulus or cement cracking.

Table 7: Barrier and well failure in the Piceance, Raton and San Juan Basins.

Cat., category, D & A, drilled and abandoned; P & A, plugged and abandoned

	Piceance Basin					Raton Basin					San Juan Basin				
Well category	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)	Original well count	Potential barrier failures	Potential barrier failure rate (%)	Well failures	Well failure rate (%)
Cat. 1	0	0	0	0	0	0	0	0.00	0	0	0	0	0	0	0
Cat. 2	48	4	8.33	0	0	23	2	8.70	1	4.35	12	0	0	1	8.33
Cat. 3	145	10	6.90	2	1.38	4	1	25.00	0	0	13	0	0	0	0
Cat. 4	5.9	10	1.96	0	0	45	1	2.22	0	0	71	0	0	0	0
Cat. 5	1,789	125	6.99	2	0.11	399	322	80.70	0	0	54	30	55.56	1	1.85
Cat. 6	6,233	145	2.33	4	0.06	32	19	59.38	0	0	348	84	24.14	0	0
Cat. 7	1,862	56	3.01	1	0.06	2,800	12	0.43	2	0.07	2,677	4	0.15	0	0
Cat. 8	60	18	30.00	0	0	7	3	42.86	0	0	64	5	7.81	0	0
Cat. 9	90	2	2.22	0	0	0	0	0	0	0	17	0	0	0	0
Cat. 10	0	0	0	0	0	20	2	10.00	0	0	148	4	2.70	0	0
Cat. 11	105	7	6.67	0	0	20	1	3.45	0	0	427	0	0	0	0
Cat. 12	1	0	0	0	0	0	0	0.00	0	0	0	0	0	0	0
Total	**10,842**	**377**	**3.48**	**9**	**0.08**	**3,359**		**10.81**	**3**	**0.09**	**3,831**	**127**	**3.32**	**2**	**0.05**
D & A	156					188					358				
Total wells	10,998					3,547					4189				
P & A	335					352					387				

Of the 3,359 original producing or shut-in wells, three (or 0.09%) were identified to have well failures, with one Category 2 well and two Category 7 wells. In one Category 2 well and one Category 7 well, the failure was due to ineffective plugging and abandonment of the wellbores rather than the initial wellbore design. The reason for the failure in the second Category 7 well was unclear because of uncertainty about the origin of the gas detected in the water well. The study also found no direct evidence that any of the hydraulic fracturing operations contaminated the fresh water aquifers in the basin.

San Juan Basin

Drilling in the San Juan Basin targeted coal bed methane (or coal seam gas) resources, with some hydraulic fracturing. There has been some exploration for conventional and unconventional gas resources, and some conventional oil production. The assessment analysed data from 4,189 wells drilled between 1901 and 2014 in the San Juan Basin, of which 358 wells were drilled and subsequently plugged and abandoned without being completed. All the wells were categorised based on their original casing and cement design (**Table 5**). Potential barrier failures were identified by any cement remediation of any casing string, based on the assumption that the remediation was needed because the oil and gas wells experienced sustained casing pressure. Well failure was identified using a method similar to that for wells in Piceance Basin; that is, detection of thermogenic gas in offset water wells or surface soil, and evidence of well barrier failures contributing to the migration of thermogenic gas to the aquifer. The potential barrier and well failures in the basin are summarised in **Table 7.**

Of 3,831 originally producing wells, 127 (3.32%) were found to have potential barrier failure. This relatively low overall potential failure rate resulted from the predominantly robust barrier designs implemented in the basin. Category 5 wells had a high potential barrier failure rate of 55.56%, due to the top of production cement being lower than the top of the gas-bearing formation, whereas the design of the Category 6 wells corrected this defect. However, the relatively high potential barrier failure rate of 24.14% in the Category 6 wells showed that the shallow geological conditions made it difficult to effectively create a cement seal in the production casing annulus. Most of the wells with a Category 7 well design had a relatively low potential barrier failure rate (0.15%). Some 54% of the wells with potential barrier failure were originally completed between 1999 and 2004.

As shown in **Table 7**, two of the 3,831 originally producing oil and gas wells (0.05%) in the basin were identified as having well failures. This relatively low failure rate was due to the implementation of a low-risk nested barrier design with deep surface casing (Category 7). This design was adopted because of the geology of the basin, shallow coal deposits and structurally shallow depth of hydrocarbon-bearing formations. The two wells with catastrophic well failure were drilled before 1961. The Category 2 well was found to have been improperly plugged and abandoned in the 1960s, and the Category 5 well had improper cement coverage in the intermediate casing annulus.

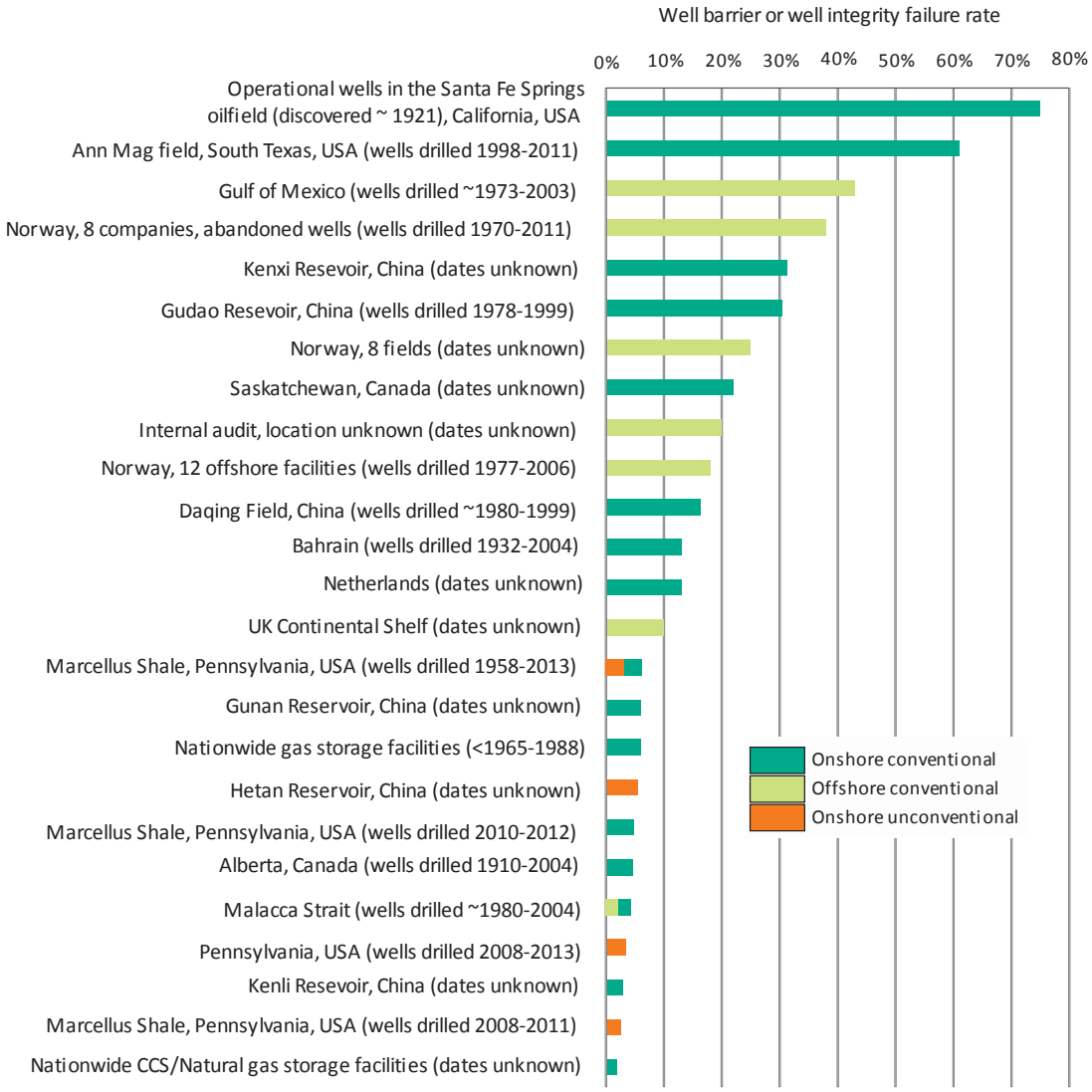
5.3.4 Global oil and gas well failure rates

Davies et al. reviewed studies of well barrier and well integrity failures, based on datasets collected from the public domain, including published literature and online resources.[122] The wells contained in the datasets included production, injection, idle and abandoned wells drilled globally, both onshore and offshore, for exploiting conventional and unconventional reservoirs, and CO_2 and natural gas storage. The datasets vary considerably in terms of the number of wells examined, well age and well design. The study did not attempt to distinguish barrier failures from well integrity failures that led to environment contamination. Also, the study compared data from a range of resource types, jurisdictions and well ages, and its significance and conclusions has been criticised on this basis.[123] As expected, the well barrier and integrity failure rates derived from this study vary widely, ranging from 1.9% to 75% (**Figure 16**). The weighted average rate across all studies is at the lower end of this range, at 6.8%.

The high variation in rates of well integrity issues reported in the literature studied by Davies et al. demonstrates the difficulty in comparing studies on wells that are drilled for different purposes, and that have different criteria for well integrity or well barrier failure. Other confounding factors include geological conditions, regulatory requirements on well construction and abandonment standards, well age, well type and well purpose. Davies et al. also analysed shale well data from Pennsylvania, and this is discussed in Section 5.3.6.

[122] Davies et al. 2014.
[123] Davies et al. 2015; Thorogood and Younger 2015.

Figure 16: Well barrier and integrity failure rates for wells from 25 different studies. Modified from Davies et al.[124]



5.3.5 Well integrity data from Australia

There are only two studies of well integrity data from Australian jurisdictions. One is on coal seam gas well failure rates in Queensland,[125] and the other is on oil and gas failure rates in Western Australia.[126] No other published data are available.

Coal seam gas well failure rates in Queensland, Australia

To date, few estimates have been made of failure rates for coal seam gas wells in Australia. The GasFields Commission Queensland reports statistics from well integrity compliance auditing undertaken from 2010 to March 2015.[127] During this period, 6,734 coal seam gas wells (for exploration,

[124] Davies et al. 2014.
[125] GasFields Commission Queensland 2015.
[126] Patel et al. 2015.
[127] GasFields Commission Queensland 2015.

appraisal or production) were drilled in Queensland, and about 3,500 wells were actively producing by the end of 2014. The non-producing wells do not have gas flow at the well head. The auditing involved testing for both subsurface gas well compliance and surface well head compliance. For the subsurface equipment, no leaks were reported, whereas there have been 21 statutory notifications (a rate of 0.3%) concerning suspect downhole cement quality during construction. After remediation, the cement failure rate was determined to be zero. For subsurface equipment, the conclusion is that the risk of a subsurface breach of well integrity is very low to near zero. A total of 199 surface well head leaks have been reported, all of which have subsequently been fixed.

Oil and gas well failure rate in Western Australia

Patel et al. reported a study on well integrity issues for all the oil and gas wells drilled onshore in Western Australia and in state waters that have not yet been decommissioned.[128] The study found that, of 1,035 non-decommissioned wells, 122 (less than 12%) had compromised well integrity or well barrier failure, but none of these failures resulted in leakage to the external environment.

Production **tubing** (see **Figure 3**) failure was the main cause of well barrier failure. Of the 1,035 wells studied, 86 wells (8.3%) had tubing failure. Tubing leaks can occur through holes being corroded or eroded by production and injected fluid inside the tubing, or from twisting of the tubing.

Casing failure in production casing is mainly due to corrosion, pressure differential and thermal effects, causing the pressure behind the production casing to exceed the collapse resistance of the casing. Of the 1,035 non-decommissioned wells, 22 (2%) had production casing failure.

The other barrier failure identified related to surface production equipment, such as the well head or Christmas tree (the assemblage of valves, spools and fittings used in developing wells, named for its resemblance to a decorated Christmas tree). Surface integrity failure is far less frequent than subsurface failure, because the surface is easier to access and maintain.

The study found that well barrier failure correlated with the age of the well, as shown in **Table 8**.

Table 8: Well integrity data for Western Australia showing a correlation between the age of the well and the type of barrier element failure. Data from Patel et al.[129]

Well age (years)	Tubing failure (%)	Well head or Christmas tree failure (%)	Casing failure (%)
0-10	0.2	0.1	0.4
11-20	0.8	0.0	0.2
21-30	0.9	0.2	0.6
31-40	0.7	0.3	0.3
41-60	5.5	0.8	0.5

5.3.6 Shale gas well integrity

Seven studies have analysed data specific to shale gas wells:

- Five studies – Considine et al., Davies et al. Ingraffea, Ingraffea et al. and Vidic et al. – present data for shale gas wells drilled in the Marcellus Shale in Pennsyvania, United States. The

[128] Patel et al. 2015.
[129] Patel et al. 2015.

Ingraffea et al. study is discussed in Section 5.3.5 and includes conventional oil and gas wells, whereas the other studies only consider unconventional wells;[130]

- Stone et al. present data on shale gas wells drilled in the Wattenberg field, Colorado, United States, as part of a broader study of well integrity in this field discussed in Section 5.3.3;[131] and
- Kell presents data on shale gas wells drilled in Texas, United States, as part of a broader study of oil and gas well integrity in Texas and Ohio, discussed in Section 5.3.1.[132]

All of these studies follow similar methodologies. They rely on reports of violations or incidents in publicly available databases of well data. The five studies conducted in Pennsylvania all relied on publicly available data from the Pennsylvania Department of Environmental Protection Office of Oil and Gas Management website and examination of notices of violations (**NOV**). As outlined in Section 5.3.5, Ingraffea, Ingraffea et al. and Davies et al. also reviewed inspectors' comments for additional evidence of well integrity issues.

The Considine et al. study analysed all well-related NOVs, including those related to surface operations. Their data showed that 2.58% of wells drilled in the study period had an NOV related to well integrity. They characterised these as blowouts (0.11%, 4 events), gas migration (0.06%, 2 events) and cementing and casing issues (2.41%, 85 events). The authors classified blowout and gas migration events as major events based on the level of severity of potential pollution, and these can be considered to be well integrity failures. For all but one of these major events, there is documentary evidence that the impacts had been remediated or that remediation was underway at the time of the study. Vidic et al. found that only 16 out of 6,466 wells (0.25%) were issued with an NOV indicating that the operator failed to prevent a gas or fluid release to an aquifer (interpreted as well integrity failures).

The Texas and Colorado datasets were part of larger studies described in Sections 5.3.1 and 5.3.3, which found no reported incidents of well integrity or hydraulic fracturing related issues for shale gas wells.

Table 9 summarises the findings of these studies. The percentages of wells with potential well integrity issues in the studies from Pennsylvania are similar to those found for oil and gas wells elsewhere. However, most of these studies do not distinguish between single-well barrier failures and total failure of well integrity that can lead to impacts on the environment. None of these studies looked at the scale or consequences of failures in well integrity.

Table 9: Summary of published well integrity data specific to shale gas resource development.

Location and study	Time period	Number of wells	Well barrier issue rate	Well integrity failure rate
Pennsylvania, Ingraffea	2010 - Feb 2012	4,934	7.6%	Not reported
Pennsylvania, Considine et al.	2008 - August 2011	3,533	2.58%	0.17% blowouts and gas migration
Pennsylvania, Vidic et al.	2005-2012	6,466	3.4%	0.25% release to groundwater
Pennsylvania, Ingraffea et al.	2002-2012	6,007	6.2%	Not reported
Pennsylvania, Davies et al.	2005-2013	8,030	6.26%	1.27% leak gas to surface
Colorado, Stone et al.	2010-2014	973	0	0
Texas, Kell	1993-2008	16,818	0	0

[130] Considine et al. 2013; Davies et al. 2014; Ingraffea 2012; Ingraffea et al. 2014; Vidic et al. 2013.
[131] Stone et al. 2016b.
[132] Kell 2011.

5.4 Well failure rates summary

This section reviews the well barrier and well integrity failure rates reported in the open literature. Well barrier failure was identified in several ways, including by sustained casing pressure, surface-casing-vent flow or requirements for remediation of barriers. Well integrity failure was identified by the detection of hydrocarbons in nearby water wells, gas migration outside the surface casing or NOVs issued from regulatory bodies. Many studies do not distinguish between well barrier failures and well integrity failures. This distinction is important because a full integrity failure is required to allow a pathway for contamination of the environment.

The data that have been reviewed indicate that the rate of total well integrity failures that have the potential to cause environment contamination is about one in 1000, and several studies reported no well integrity failures. The rate for single-well barrier issues or failures is about 1-10 in 100, and is consistently in this range for onshore unconventional resources. Well barrier failures do not indicate that a well integrity failure will occur. In most cases, well barrier issues can be remediated. The data specific to shale gas wells indicate that well integrity issues occur at a rate at the lower end of the rates observed for oil and gas wells in general.

An important observation from the available data on well integrity for oil and gas wells is the importance of resource characteristics, well construction methods and regulatory settings. Few studies have investigated the correlation between well construction methods, geological conditions and failure rates. Notable exceptions are the studies by Stone et al. and Watson and Bachu.[133] This is demonstrated in **Figure 17**, which aggregates the data based on well category from the studies by Stone et al. The categories take into account the well construction (that is, the number of barriers) protecting shallow aquifers. There is a strong correlation between well construction category and well barrier failure rates, and between well barrier failure rates and well integrity failure rates. The only exception to this correlation is the barrier failure rates for Category 8 wells in the Raton and Picean Basins (**Figure 17, Table 5** and **Table 7**). Stone et al. described Category 8 wells as those having deep surface casing and intermediate casing strings, and with the top of the production casing cement below the top of the gas zone. The barrier failures were interpreted to be related to inadequate cementing of the production casing. There were no well integrity failures, indicating that the remaining barriers provided protection of shallow aquifers.

Watson and Bachu demonstrated that well barrier failure rates reflect the geological conditions of the wells, regulatory requirements in place during well construction and abandonment, era in which a well was constructed, well type, well purpose and well history, as well as factors such as oil price, availability of equipment and materials, and operator's technical competence in the well construction or abandonment.[134] The authors also found that failure rates of well barriers and well integrity were lower for newer wells.

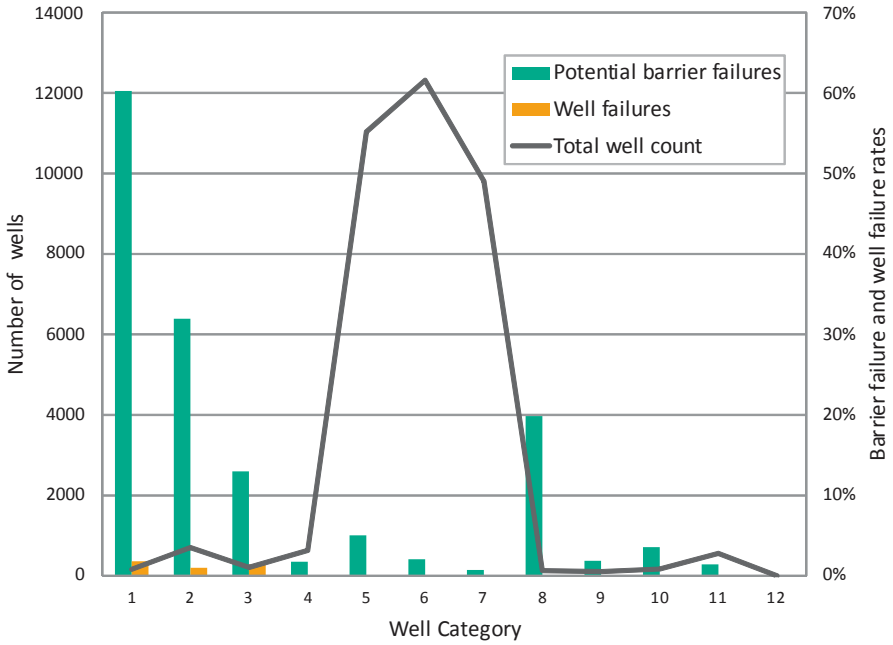
For shale gas wells, Stone et al. showed no well barrier or well integrity failures when wells were constructed according to modern construction standards; similarly low rates were found for conventional wells drilled in the same basin and constructed to the same standards.[135] Ingraffea et al. showed variations in well integrity issues for shale gas wells at different locations in Pennsylvania,

[133] Stone et al. 2016a; Stone et al. 2016b; Watson and Bachu 2009.
[134] Watson and Bachu 2009.
[135] Stone et al. 2016b.

again highlighting the importance of local resource characteristics.[136] Where well integrity issues occur, they can generally be remediated, as demonstrated by Considine et al.[137]

The risk of well integrity issues appears to be reduced by constructing wells with deep surface casing to protect aquifers, and using intermediate casing or production casing with adequate cementing. Local conditions (including geology, aquifer depth, presence of pressured zones, presence of shallow gas-bearing zones and presence of corrosive fluids) should be taken into account when determining casing and cementing depths.

Figure 17: Aggregated data from well integrity studies in several basins in Colorado (well categories are defined in **Table 5**). Stone et al.[138]



[136] Ingraffea et al. 2014.
[137] Considine et al. 2013.
[138] Stone et al. 2016a; Stone et al. 2016b.

6 Potential for hydraulic fractures to act as contaminant transport pathways

Contamination of surface and groundwater assets may occur if deep formation fluids or introduced chemicals from drilling and hydraulic fracturing activities reach water-bearing formations, overlying aquifers or nearby water bores. Conceptually, these migration pathways could be a hydraulic fracture lateral intersection with a water bore; a direct hydraulic fracture connection from the reservoir into the overlying aquifer; a hydraulic fracture intersection with a natural fracture or fault, which then connects to an aquifer; or cracks in the annular region between the casing and the well.[139] These pathways are illustrated in **Figure 18**.

Typically, shale resources are found 1,500-4,000 m below the earth's surface. Given that most groundwater resources are only a few hundred metres deep, it is unlikely that hydraulic fractures will grow into a nearby water bore, which are much shallower.[140] Dusseault and Jackson conclude that the migration of hydraulic fracturing or formation fluids (including natural gas) to the surface as a result of hydraulic fracturing of typical shale gas reservoirs is unlikely, except when abandoned or suspended wells are intersected by the hydraulic fracturing fluids during the high-pressure stage of fluid injection.[141]

Recent studies have looked into the possibility of shallow groundwater contamination due to hydraulic fracturing fluid migration along conductive faults. Birdsell et al. reviewed the recent literature on this topic and used transport simulations to quantify the amount of fracturing that could potentially reach an overlying aquifer.[142] Based on modelling studies, the authors concluded that the likelihood of hydraulic fracturing reaching a water resource is low when the vertical separation between the reservoir and the overlying aquifer is large and other natural pathways (such as faults or leaky wells) are absent. Even in the absence of a permeable pathway, their results show a potential upward migration of hydraulic fracture fluids of about 100 m through a relatively low-permeability overburden. Birdsell et al. also reported instances of fluid migration that have occurred in the past, and the need for detailed modelling approaches that can explain these occurrences. [143] The finding of this study have been cited in a report from the US EPA.[144] In the case of deep shale formations, it is unlikely that hydraulic fractures would grow in a way that stimulated a conductive pathway between a shale reservoir and an overlying aquifer, when the vertical separation distance is in the order of thousands of metres. [145]

Using a numerical groundwater flow model that considers advective transport through bulk media and preferential flow through fractures, Myers concluded that the interaction between fractured shale and fault zones can reduce the time for the contaminants to reach near-surface aquifers from thousands of years to tens or hundreds of years.[146] However, Saiers et al. identified significant shortcomings in that transport model; the authors concluded that the assumptions and the prediction do not faithfully

[139] Reagan et al. 2015.
[140] Davies et al. 2012; Flewelling et al. 2013.
[141] Dusseault et al. 2014.
[142] Birdsell et al. 2015.
[143] Birdsell et al. 2015.
[144] US EPA Report.
[145] US EPA Report.
[146] Myers 2012.

represent the reality, and they suggested ways in which the model could be improved.[147] Cohen et al. identified additional issues in the model assumptions and boundary conditions, and also pointed out critical errors in the calculations.[148] Gassiat et al. used a finite element-based numerical groundwater flow model and publicly available data for shale gas basins to simulate hydraulic fracturing in the vicinity of a permeable fault zone. The authors found that, under certain conditions (such as the presence of a highly permeable fault, high overpressure in the shale unit and fracturing in the upper portion of the shale near the fault), contaminants can reach shallow aquifers in less than 1000 years after fracturing.[149] They suggested that fracturing operations be avoided near potentially conductive faults, and that fluid migration via faults be monitored over longer timespans. Flewelling and Sharma argued that these predictions are unreliable because the analysis contains significant gaps, the modelled scenarios are unreasonable, and the model has not been validated against physically plausible conditions; they concluded that there is not enough evidence to conclude that this type of migration could occur over the specified timeframe.[150] Kissinger et al. simulated long-term methane migration through a fault zone for the Lower-Saxony region in Germany, and found that migration of methane to shallow layers can occur in the presence of a fully penetrating fault zone and low gas saturation of the overburden (1 %).[151] However, the authors noted that these results contain significant parameter and scenario uncertainties, and therefore need to be treated with caution. Further studies with better numerical models are required to fully understand subsurface flows, and to investigate fluid migration over long time scales and its impact on aquifers.

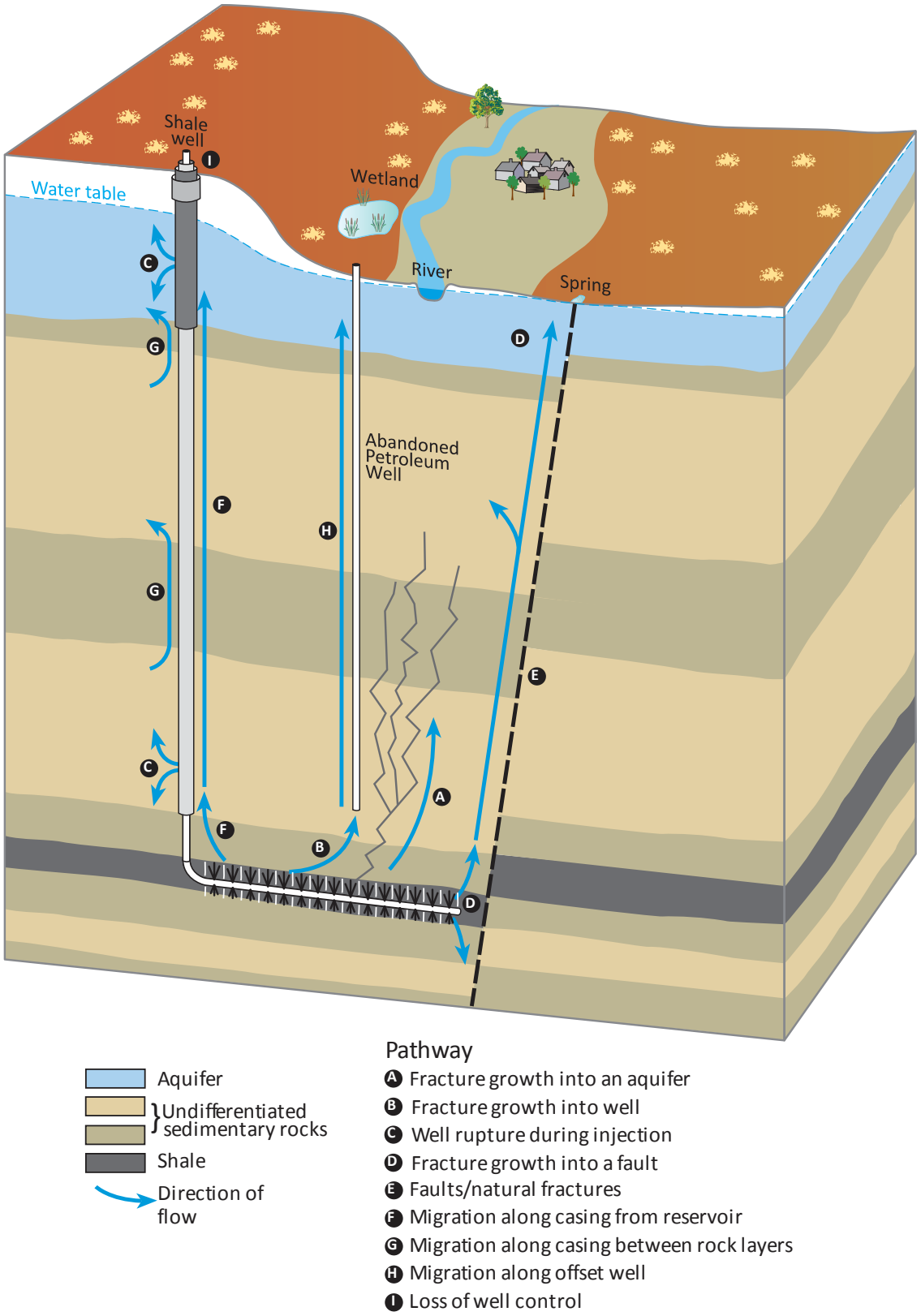
Laboratory studies suggest that aquifer contamination via a subsurface pathway is unlikely. Engelder et al. conducted a series of imbibition experiments on cuttings recovered from the Union Springs Member of the Marcellus gas shale in Pennsylvania, and on core plugs of the Haynesville gas shale from northwest Louisiana, and demonstrated that aquifer contamination due to fracture propagation through a subsurface pathway is unlikely.[152] The authors attribute this finding to reasons such as low water saturation of gas shale, sequestration of injected water into dry gas shale by imbibition, the presence of capillary seals that prevented gas leakage, and large osmotic pressures that will drive the treatment fluids into gas shale. A study by Flewelling and Sharma discusses the main barriers to upward fluid migration of fracturing fluids, concluding that the timescales for migration would be long (more than a million years), given that the permeability and flow rates are low.[153] Even in overpressured basins, they suggest that the permeability required to maintain elevated subsurface pressure over geologic time will result in negligible vertical flow rates.

In the context of shale gas development, microannulus delamination of the wellbore (as discussed in Section 5.1.2) is considered to be the most plausible contamination pathway by which introduced chemicals from drilling and hydraulic fracturing, and hydrocarbons in the formation, could leak into an overlying aquifer or the atmosphere. For fluid to move, there would need to be a driving force: buoyancy for oil and gas, and pressure gradients for water. Pressures within the shales will decrease during production, and any recovery in pressure would only occur over geological timescales. The volume of water in resource shales, including any residual fracturing fluid, is small in the context of the overall groundwater system, and it is mostly immobile.

[147] Saiers and Barth 2012.
[148] Cohen et al. 2013.
[149] Gassiat et al. 2013.
[150] Flewelling and Sharma 2014.
[151] Kissinger et al. 2013.
[152] Engelder et al. 2014.
[153] Flewelling and Sharma 2014.

In situations such as the Northern Territory where there is a large vertical separation between aquifers and the shale gas layer, and the layered geology includes large stress barriers, there is a low possibility for hydraulic fracturing fluids to reach an overlying aquifer.

Figure 18: Potential contamination pathways from drilling and hydraulic fracturing activities.



7 Well integrity management

Well integrity management across the life cycle of a well has become a focus for industry over recent years, in recognition of the value of proactive well integrity management in reducing risks.[154] Well design needs to consider hazards that might arise throughout the life cycle, and the design will have ramifications for how wells can be operated later in their life. The operating life of a well can cover several decades, and responsibility for a well is often passed between different teams within the operator. Third parties are often involved in well drilling and operations, and in the supply of materials such as casing and cement. The level of complexity in the design and operating parameters for wells means that there are risks associated with the transfer of responsibility between different teams and throughout the life of the well. Life cycle well integrity management aims to minimise these risks by establishing processes around well integrity management.

The focus on well integrity management has led to the development of ISO 16530-1:2017, which states that *"The well operator should have a well integrity management system (**WIMS**) to ensure that well integrity is maintained throughout the well life cycle by the application of a combination of technical, operational and organizational processes"*.[155] The NORSOK D-010 standard also requires management of well integrity throughout the life cycle of a well.[156]

A WIMS provides a framework for managing the risk due to loss of well integrity over the life cycle of a well, and identifies the responsibilities of the organisation as a whole in safeguarding environmental assets and public health. The key elements of a WIMS framework are:

- **risk assessment**, which includes techniques to:
  - identify the well integrity hazards and associated risks over the life cycle of the well;
  - determine acceptance levels for risks;
  - define control measures and mitigation plans for managing and reducing risks that exceed acceptance levels;
- an **organisational structure** with clearly defined roles and responsibilities for all personnel involved in well integrity management;
- **well barrier documents** that clearly identify and define:
  - well barriers (that is, a combination of components or practices that prevent or stop uncontrolled movement of well fluids);
  - methods to combine multiple barriers and redundancies to ensure reliability;
  - administrative controls that provide information on controlling activities related to well integrity (such as design and material handling standards, procedures and policy manuals);
- **performance standards** for people, equipment and the management system;
- **defined standards for well barrier verification**, such as functional, leak and axial load tests, and well load case modelling verification, to ensure that well barriers meet the acceptance criteria;

[154] Connon and Corneliussen 2016; Smith et al. 2016; Sparke et al. 2011; Wilson 2015.
[155] ISO 16530-1:2017.
[156] NORSOK D-010.

- **a continuous improvement process** that defines how knowledge and information should be communicated to personnel responsible for well integrity during the life of the well, and how improvements can be implemented;
- **a management of change process** to record changes to well integrity requirements for an individual well or the WIMS itself; and
- **an audit process** that demonstrates conformance with the WIMS.

A summary of how different organisations have used WIMSs to manage their assets, the observed benefits, the technical challenges that were involved in their implementation, and the key lessons that were learned can be found in recent literature.[157] Wilson et al. provide recommendations and guidance for building an effective WIMS after taking into account the industry standards, local regulatory requirements and the organisation's needs.[158]

[157] Connon and Corneliussen 2016; Gell et al. 2015; Haga et al. 2009; Kumar et al. 2014; Smith et al. 2016.
[158] Wilson 2015.

8 Well integrity summary

Wells provide access to the shale gas resource to allow the controlled flow of the gas to the surface. Shale gas wells are drilled through the geological layers that overlie the shale resource. These layers will include permeable layers that contain aquifers or saline groundwater, as well as low-permeability layers that form natural barriers to vertical movement of fluid. However, wells may inadvertently provide potential pathways for the contamination of subsurface water and the release of fluids to the surface that include:

- unintended release of drilling muds, hydraulic fracturing fluids or gas from the well into aquifers or other groundwater bodies during well operations;
- unintended releases of fluids from the well at the surface; and
- migration of fluids along the well to other rock layers or to the surface.

Well integrity refers to how the well is constructed and operated to maintain safety, and to prevent these unintended releases of fluids to the environment or migration of fluid along the well. The concept of well barriers is fundamental to well integrity. Barriers prevent or stop uncontrolled fluid flow into, out of, or along the well. Physical barriers include casing and cement, drilling fluids, impermeable formations, well heads and BOPs. In addition to physical barriers, well integrity makes use of operational barriers (monitoring, work instructions and procedures), human barriers (competent personnel) and administrative barriers (standards and policies, and quality assurance).

Current industry practice for shale gas well design is to have at least two independent and verified physical barriers to maintain well integrity. A well integrity failure will therefore only occur if both physical barriers fail. If there is a multibarrier system, degradation or failure of one barrier will not lead to the release of fluids from the well. Such well barrier issues are often included in studies of well integrity in oil and gas wells, with rates of wells with a barrier issue of 1-10% reported. By contrast, studies that report on well integrity failure (all barriers failed), which is required for an actual release of fluids to the environment, show low rates of failure, typically less than one in 1,000.

The most commonly reported mechanism for well integrity failure is the migration of gas (predominately methane) along the outside of the casing, which shows that there is a pathway for flow. The buoyancy of gas provides the driving force for it to travel up these pathways. The gas may be sourced from any gas-bearing geological layer that the well passes through, and may originate from outside the shale reservoir. The presence of this pathway does not necessarily mean that other fluids (saline water, for example) will move between horizons, because this would also require sufficient pore pressure differentials between different rock layers to drive fluid flow. During production, pressures within a shale gas reservoir will be lowered, and any fluid flow is likely to be *towards* the reservoir rather than *away* from it. If there are saline groundwater layers in the overburden above the shale resource with pore pressures over the hydrostatic gradient, then some upward movement of this water may be possible. The rates of flow along the outside of the wellbore are likely to be low, even for gas, because of the limited size of the flow pathways.

The risk of fluid or gas migration along the outside of a well continues after the well has been plugged and abandoned, while other well integrity failure risks will no longer exist or will be significantly reduced. Although there are few studies of the long-term integrity of oil and gas wells, it is a topic of recent research for CO_2 geosequestration. The design and construction methods for wells for CO_2 geosequestration will be similar to those used in the oil and gas industry. Studies suggest that the

cements used in well construction are likely to resist chemical and mechanical degradation, and maintain integrity for thousands of years, so long as the cement was appropriately designed and placed.

A well integrity failure may be catastrophic when there is a complete loss of control of the well that allows an inrush of formation fluids or gases, which then travel to the surface, resulting in a blowout. Blowouts are most likely to occur during drilling operations; they are potentially life-threatening for personnel working on the drill rig, and may also lead to release of fluids to the surface environment. The low permeability of shale gas resources reduces the inherent risk of blowouts in comparison with conventional oil and gas resources. Few blowouts have been reported in shale gas wells globally.

The risks associated with well integrity failure depend on how the well is constructed. For example, the risks of natural gas migration and contamination of shallow aquifers are increased when the surface casing does not extend below the base of these aquifers, or the production casing is inadequately cemented. Geological conditions are also important; for example, if there are shallow gas-bearing formations that may provide a source for gas migration along the well and overpressured layers that may drive fluid flow.

Current industry practice is to consider well integrity across the entire life cycle of the well. This approach recognises the fact that wells are often in operation for decades, and that actions at each phase have implications for well integrity in subsequent phases. The responsibilities for management of a well are often handed over to different teams within an organisation; therefore, a system that tracks well integrity is important for continuity. The implementation of WIMS is a fundamental component of this life cycle management, and allows well integrity to be tracked for each well in an operator's well inventory. The elements of a WIMS include risk assessment criteria; organisational structure (roles, responsibilities and competencies); well barrier design, verification and monitoring requirements; performance standards; and reporting requirements.

Shale gas wells are highly engineered, and well integrity is an important driver in their design, construction and operation. Each well must be designed to take into account its specific characteristics related to risk of integrity failure: characteristics such as the geology and the purpose of the well. Therefore, a WIMS outlines a process and objectives rather than prescribing particular design elements. Examples of leading operational practice in well integrity management can be found in ISO 16530-1:2017 on well integrity life cycle governance, NORSOK D-010 on well integrity in drilling and well operations, and the Norwegian Oil and Gas Association recommended guidelines.[159]

Hydraulic fracturing operations are conducted through wells, and place certain demands on well integrity due to the fluid pressures involved. These pressures may increase the likelihood of delamination of wellbore in the vicinity of the reservoir. However, engineering to withstand these pressures is a routine component of well design, and there are only a few examples globally of well integrity failure during hydraulic fracturing resulting in the release of fluids to the environment.

Other hydraulic fracture fluid pathways that could be created or dilated by the hydraulic fracturing operation include upward growth of hydraulic fractures and interaction of hydraulic fractures with natural faults. The literature suggests that the contamination of shallow aquifers via migration of hydraulic fracturing fluids from deep reservoirs in this way is highly unlikely where the vertical separation distance is large, as is likely to be the case in the Northern Territory.

The consequences of well integrity failures from shale gas development are likely to be less severe than those for conventional oil and gas resources. Shale gas resources have low reservoir deliverability,

[159] ISO 16530-1:2017; Norwegian Oil and Gas 2016; NORSOK D-010.

which means that they cannot produce large volumes of fluids at a high rate. Conventional resources tend to have higher deliverability because each well accesses a larger reservoir volume of oil or gas and has a higher likelihood of overpressures. There have been several high-profile well integrity incidents on conventional oil and gas wells (the Montara and Macondo wells, for example) that have led to improvements to WIMSs in industry and regulation in many jurisdictions, including the Northern Territory. This increased focus on well integrity is also applicable to shale gas wells, and is likely to reduce the risks of well integrity incidents during the development of these resources.

The low rates of complete well integrity failure for shale gas developments reported in the literature have been achieved with current industry practices and regulatory frameworks, suggesting that well integrity risks are being addressed to a large extent during drilling and production. Longer term (post abandonment) well integrity and the potential for migration of gas along the outside of casing is not as well understood, and although the impacts of an individual well are likely to be small, this aspect warrants further investigation.

9 Regulatory frameworks for drilling and hydraulic fracturing operations

9.1 Well integrity regulatory frameworks in the Northern Territory

At the time the Inquiry was called in December 2016, the regulatory framework for petroleum activities in the Northern Territory was going through a process of reform in response to:

- the 2010 Montara Commission of Inquiry (**Montara Inquiry**);
- Dr Tina Hunter's review of the capacity of the Northern Territory's legal framework to regulate the development of an onshore petroleum industry (**2012 Hunter Report**); and
- the inquiries conducted by Dr Allan Hawke AC into the potential environmental impacts of hydraulic fracturing in the Northern Territory (**2014 Hawke Report**) and the environmental assessment and approval process (**2015 Hawke Report**).[160]

The regulatory framework was moving from a prescriptive approach to objectives-based regulation. This process started with the implementation of the Petroleum (Environment) Regulations (**PER**) to regulate environmental risks and impacts associated with petroleum activities. In its submission to the Inquiry, the Northern Territory Department of Primary Industries and Resources (**DPIR**), as the lead regulator, noted that two additional regulations were intended as part of the reform process to regulate exploration and production activities.[161] These regulations were also intended to be objective based and to follow the "as low as reasonably practicable" (**ALARP**) principle to manage risks, as adopted in the PER.

The current regulatory framework for petroleum activities consists of the *Petroleum Act* as the primary legislative instrument, supported by the PER, the Petroleum Regulations (which cover minor administrative aspects of resource management) and the Schedule of Onshore Petroleum Exploration and Production Requirements (**Petroleum Schedule**). The Petroleum Schedule is enforced by ministerial directive to licence holders; it regulates certain petroleum activities, drilling and hydraulic fracturing. The schedule is highly prescriptive and lacks flexibility. Hunter has recommended phasing out the Petroleum Schedule because it does not have the same legal force as regulation and does not align well with objective-based regulation.[162]

under the current regulatory framework, an operator must first obtain an exploration permit by application through a competitive process. Once a permit has been obtained, before any drilling or hydraulic fracturing activity can commence on a tenure, the tenure holder must obtain a petroleum project approval for those activities. To obtain such approval, the tenure holder must submit a project application for well drilling, workover or stimulation activities. The application is assessed by the DPIR Energy Division. In the DPIR's submission, they state that "T*he integrity of wells is a particular focus of*

[160] Borthwick 2010; 2014 Hawke Report; 2015 Hawke Report; Hunter 2012. DPIR submission 226 p37.
[161] DPIR submission 226 p39
[162] Hunter 2016.

the Energy Division's assessment".[163] The assessment process has requirements that directly relate to well integrity, including:[164]

- **BOP** systems, BOP drills and a well control manual;
- minimum depths for the setting of surface casing, a requirement for the cementing of all casing strings to surface, and mandatory validation of casing and cement using cement bond logs;
- mandatory validation of all barriers by pressure testing, and mandatory formation integrity testing or leak-off tests;
- installation and testing of a completion tubing string (additional barrier); and
- all reasonable steps being taken to prevent communication between, leakage from, or the pollution of aquifers.

There are similar requirements for hydraulic fracturing activities, including:

- mandatory water quality testing, before, during and after the hydraulic fracturing;
- safe separation, through impermeable formations, between shallow aquifers and the hydrocarbon target zone (the section that is to be fractured);
- submission of fracture modelling confirming maximum **fracture height** and length (confirming safe separation);
- chemicals list for public disclosure on DPIR's website;
- use of pressure safety trip-out systems during fracture stimulation activities; such systems prevent exceedance of allowable pressure limits of surface pipework and downhole casing; and
- pressure monitoring confirming that well integrity has not been affected by fracture stimulation activities.

The tenure holder must also submit an environment management plan (**EMP**) for the activities that complies with the **PER** for assessment. One of the EMP requirements is a risk assessment of potential environmental impacts on aquifers from hydraulic fracturing, including baseline assessment of known aquifers, monitoring, modelling of fracture propagation and well completion schematics. There is overlap between the EMP requirements and the Petroleum Schedule.

If the tenure holder already has approval for project activities, the holder cannot vary from the approved program and must operate in accordance with any conditions of the approval. Approval for revised or additional activities requires an operational application.

The DPIR has implemented a process for the regulator to continually assess the integrity status of wells during drilling operations.[165] The *Well integrity verification form* and process was developed following the Montara Inquiry; it requires the assessor to evaluate the integrity of the well, confirming that the well has been constructed to levels exceeding API standards. This assessment is based on information provided by the tenure holder in daily drilling and other reports, and the well planning information submitted in the application for the drilling activity.

The Petroleum Schedule also has requirements for well abandonment. Wells cannot be abandoned in the Northern Territory without prior approval. The tenure holder is required to describe the plugging and abandonment program, and the procedures that will be used to validate the integrity of the barriers.

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[163] DPIR submission p29
[164] DPIR submission Attachment C
[165] DPIR submission p34

The DPIR has implemented a range of other measures related to well drilling and hydraulic fracturing in response to the Montara Inquiry and the Hawke reports of 2014 and 2015.[166] These measures include:

- increasing capability through recruitment of more petroleum engineers, training in well integrity and a mandatory CERT IV in Government Investigations;
- more robust approval assessment processes, with guidelines and checklists to increase the rigour of assessments, and a triple signatory and assessment approval system;
- introduction of additional prescriptive mandatory requirements that tenure holders must follow, including the requirement to cement all casing strings to surface; submission of fracture propagation models to illustrate separation between the stimulated zone and aquifers; and water monitoring before, during and after any hydraulic fracturing activities;
- improvement of transparency by requiring EMPs to be publicly available via DPIR's website;
- improvement of audit processes, with checklists for well drilling operations, hydraulic fracturing operations and well testing operations; and enabling of independent third-party inspectors, in addition to DPIR officers, to carry out operational and environmental inspections and audits through the Petroleum Schedule;
- implementation of the PER and associated processes; and
- a full review and update of the Petroleum Schedule in 2016.

A well operations management plan could operate in conjunction with an EMP, as recommended by Dr Tina Hunter.[167]

9.2 Well integrity regulatory frameworks in other jurisdictions

The regulatory framework for petroleum activities is objective based in Western Australia , the Commonwealth (offshore operations administered by the National Offshore Petroleum Safety and Environmental Management Authority, **NOPSEMA**) and South Australia. These jurisdictions do not have codes of practice for drilling or hydraulic fracturing operations; instead, they rely on the operator to identify hazards and manage risks according to the ALARP principle. The Commonwealth and Western Australian regulations are those that have most recently been updated, in 2016 and 2015, respectively. Both require the submission of a well operations management plan (**WOMP**, referred to as a well management plan in South Australia) for drilling. Relevant regulation in these two jurisdictions requires well integrity to be addressed in the WOMP. NOPSEMA provides guidance on the information required in the WOMP, and guidelines for applying the ALARP process to well integrity.[168] Neither jurisdiction has any prescriptive requirements about well design or well integrity. The Commonwealth regulations do, however, define reportable incidents for well integrity. Commonwealth and Western Australian regulations also provide for multiwell WOMPs to be created. Such WOMPs may be used for a group of wells in close proximity and with similar characteristics; for example, multiple directional wells drilled from a single location.

In South Australia, the long history of industry operation and regulation is worth noting. There are several operators with a long track record of operations, providing a track record of environmental and safety performance. The South Australia regulatory framework requires a statement of environmental objectives (**SEO**) to be developed on the basis of an environmental impact report that must be

[166] DPIR submission p37-45
[167] Hunter 2016.
[168] NOPSEMA 2016; NOPSEMA 2017.

conducted for all petroleum activities. The SEO describes how potential threats and risks of the specific activity on the environment will be managed. Approved SEOs effectively become project-specific regulations that are gazetted and made publicly available. SEOs are reviewed every five years, allowing for adaption to changing requirements and operational practices. The South Australia regulations also allow the classification of operators as requiring either high-level or low-level official surveillance. The classification is based on a rigorous audit and assessment process, and allows the regulator to place more emphasis on operators with less experience or those conducting novel activities. Before commencing activities, operators must submit an activity notification, and approval is granted based on an assessment of the operator's demonstrated capabilities and how the activities will be conducted to comply with relevant SEOs. This is largely similar to the WOMPs used by the Commonwealth and Western Australia. South Australia has no prescriptive requirements for well operations.

The Commonwealth, South Australia and Western Australia all have requirements for inspection or surveillance of field activities. All jurisdictions have a team of technical staff with expertise in petroleum operations to undertake assessment and inspection activities.

The New South Wales and Queensland regulatory frameworks are also largely objective based; however, both have codes of practice for coal seam gas drilling that are mandated in regulations.[169] Queensland also has a code of practice for other petroleum drilling, although this has not been made mandatory.[170] These codes were developed in close consultation with stakeholders, and are specific to the context of each jurisdiction. The codes are mandatory and include prescriptive requirements around process (requirements for matters to be considered during design of a well, for example) and some specific requirements for well construction and abandonment (surface casing setting depths and pressure testing of casing, for example). Santos supported the use of codes of practice in their submission to the Inquiry.[171] The Queensland codes of practice mandate the use of WIMSs.

[169] NSW Department of Trade and Investment 2012; QLD Department of Natural Resources and Mines 2017.
[170] QLD Department of Natural Resources and Mines 2016.
[171] Santos submission 168, p72.

10 Policy options for regulation related to well integrity

The following policy options address well integrity in the context of shale gas development in the Northern Territory, and need to be considered in the context of the overall regulatory framework for petroleum development. Local conditions are important in determining well integrity risks, and policy options must take into account the uncertainty that arises from the current limited amount of activity in shale gas resources in the Northern Territory to date.

10.1 Collection of baseline data

Baseline studies of **environmental receptors** are critical for assessing the performance of the industry. In the context of well integrity, appropriate baseline information should include measurements of shallow aquifer characteristics and surface hydrocarbon gas fluxes. The parameters that should be measured in shallow aquifers include water chemistry, water levels and hydrocarbon content (including isotopic composition, to provide indication of source). Similarly, baseline measurements of surface hydrocarbon gas flux should include characterisation of the chemical and isotopic compositions. The baseline characterisation of hydrocarbon gases will be important for understanding the occurrence of gas migration along the outside of casing (the most commonly reported well integrity failure mechanism). Harkness et al. provide a recent example of the techniques that can be used in integrated geochemical investigation of potential sources of natural gas and water contamination in a region with shale gas drilling activities, and demonstrate the value of baseline data.[172] Regional variability and the scale of proposed development will dictate the spatial density of the baseline measurements required.

10.2 Developing an understanding of well integrity risks in the Northern Territory

Onshore petroleum activity in the Northern Territory has been limited, with only 236 wells drilled as at October 2017. These wells have been drilled over a period of more than 50 years, and have primarily targeted conventional petroleum resources. The amount of data available from offset wells in the Northern Territory's prospective shale gas basins is limited. Similarly, the experience of the operators and regulators working with this resource is limited, although they bring experience from working in similar resources elsewhere. Although a great deal of knowledge of well integrity risk and its management is available from other jurisdictions, information on the characteristics of the Northern Territory's resources are an important input into the hazard identification process for well integrity management.

No shale gas projects in the Northern Territory have advanced past the exploration phase. If the moratorium is lifted, there will be a period of time as operators progress from exploration to appraisal. This increase in activities provides an opportunity for adaptive regulation through an objective-based

[172] Harkness et al. 2017.

regulatory regime. Setting prescriptive regulatory requirements based on limited data and experience may not allow risks to be managed effectively as additional information on local hazards is discovered. Therefore, an objective-based regulatory regime that recognises the uncertainty may be a more appropriate way of managing the risks.

During the early stages of shale gas developments, there may be an opportunity for collaboration between operators, to share relevant data on well integrity. Although the regulator receives data from operators soon after wells or geophysical surveys are completed, these data are not made public for a period of time. Basic information in well completion reports is kept confidential for 2 years and 28 days from the date of rig release (that is, when the drill rig is demobilised at the completion of drilling activities), and geophysical data is kept confidential for a period of 3 years. Interpreted data are not released for a period of 6 years from when they are collected. There may be a role for the regulator to facilitate the early sharing of data relevant to well integrity hazard identification and risk assessment between operators and with other stakeholders. This could be through a simple data exchange, or the regulator could coordinate the development of a basin-wide well integrity management approach.

Development of a basin-wide approach to well integrity management that involves the regulator, all operators in the basin, independent advisers and other stakeholders may provide a means of reducing risks and accelerating the development of leading practices for the region. This process could facilitate the sharing of baseline environmental survey methods and data, information on well integrity hazards and operational practices for well integrity management.

10.3 Requirement for well integrity management throughout the well life cycle

The prevention of well integrity failures throughout the life cycle of a well requires active management, and many jurisdictions require operators to demonstrate that they have a WIMS that takes into account well integrity throughout the well life cycle. The management of integrity for individual wells should be conducted within a system for managing well integrity for all of the operator's well stock. There are several international standards that set out well integrity management processes, and well integrity management methods are continually improving. Policies should allow or require operators to continually update their processes, to keep up to date with evolving industry practices and standards. Independent certification against these international standards by recognised classification societies could also be part of demonstrating the standing of an operator's well integrity management processes. There are multiple points at which compliance with this requirement could be evaluated, including the assessment of the technical capacity of applicants during permit application, renewal or amendment processes; during the approval process for well drilling and associated activities (such as hydraulic fracturing or abandonment); or during periodic review of an operator's performance.

A comprehensive policy on well integrity management will also set out the regulator's responsibilities for review and assessment of an operator's well integrity management approach, and for an inspection regime to ensure compliance. The policy should also state the operator's reporting requirements for well integrity incidents, and should set out penalties for non-compliance.

In addition to a WIMS, assessment of well integrity management on a well-by-well basis is necessary to address well-specific risks. Well integrity hazard identification and risk assessment is an important component of well integrity management. Commonwealth and Western Australian regulations require well management plans that outline the risk assessment approach used, the risks identified and the well integrity management practices that will be put in place to be submitted to the regulator for

assessment. The current project application process for drilling activities in the Northern Territory requires the operator to describe components of well integrity management, but does not explicitly require an overall well integrity management plan for the full life cycle of a well.

10.4 Considerations for codes of practice, guidelines and minimum standards

The intention of the regulator in the Northern Territory is to adopt an objective-based regulatory regime, with regulations for petroleum exploration and production alongside the PER. These regulations would be supported by guidelines (which already exist for the PER), and codes of practice that would assist in the interpretation and implementation of the regulations by operators and regulators. The content of a code of practice around well integrity or well construction and abandonment for the Northern Territory will depend on the structure of relevant regulations. The Commonwealth (NOPSEMA) and Western Australian regulatory frameworks provide examples of recently implemented objective-based regulation. In regard to well integrity, the guidelines in these jurisdictions set out what a well management plan must contain, but do not prescribe minimum technical requirements. The operator must demonstrate that they are managing risks in accordance with the ALARP concept. In contrast, the codes of practice developed in New South Wales and Queensland contain many prescriptive elements.

Consideration must be given to the interaction between prescriptive components of a code of practice and the ALARP concept that is integral to objective-based regulation. Based on the well integrity risks identified in this report, the following items could be prescribed through regulation or associated guidelines and codes of practice to be included in a well management plan for the Northern Territory:

- requirement for a well integrity management plan that includes consideration of:
  - well integrity management across the well life cycle;
  - the operator's process for managing well integrity risks;
  - how well integrity hazards are identified, and risks assessed and managed;
  - well barrier plans throughout the life cycle, performance standards and a verification approach;
  - reporting and documentation;
  - change management;
- requirements to characterise aquifers, saline water zones and gas-bearing zones in the overburden during drilling;
- how the well design and operation will provide protection of aquifers;
- requirements to monitor for methane migration along the outside of casing; and
- requirements to verify the integrity of the bond between casing, cement and the formation, periodically and before abandonment.

The New South Wales and Queensland codes of practice were developed in consultation with industry and other stakeholders. A similar consultative approach that draws from the basin-wide well integrity management approach outlined in Section 10.2 is recommended for the Northern Territory. This approach can be used to identify whether any minimum standards should be put in place.

10.5 Developing leading well abandonment practices for the Northern Territory

Although the objectives of abandonment are clear, the long-term integrity of shale gas wells post abandonment is uncertain. There has been little monitoring of well integrity post abandonment and, where integrity issues have been found, it has been difficult to investigate the causes. Effective well abandonment requires wells to have integrity at the end of their operating life. It is important to consider the post-abandonment integrity requirements as part of the design of the well and management of its integrity, and this is part of the reasoning for the policy option set out in Section 10.3. The impacts of well integrity failure post abandonment are likely to be small on a well-by-well basis, with the main risk being migration of gases along the outside of the casing.

Given the current state of shale gas development in the Northern Territory, it is unlikely that a large number of wells will be abandoned in the near future. This provides an opportunity to determine appropriate practices for abandonment of shale gas wells in the Northern Territory, by establishing a long-term abandonment assessment program. This program could assess well abandonment options in the context of the Northern Territory's shale resources, and could be conducted in conjunction with the basin-wide well integrity management approach outlined in Section 10.2. The difficulty of remediating integrity issues in abandoned wells means there must be an emphasis on abandonment practices that will reduce the risk. A long-term abandonment assessment program could consider:

- geological zones along the well that need to be isolated in the long term;
- reviews and testing of durability of cements and casing;
- partial abandonment of some wells to allow for long-term monitoring;
- evaluation of post-abandonment monitoring approaches;
- trials of novel abandonment methods and materials; and
- calculation of costs of abandonment, to assist in the calculation of security bonds.

Well abandonment is a global issue, with estimates that about 30,000 wells will need to be plugged and abandoned globally over the next 15 years.[173] DNV GL (an international accredited registrar and classification society) has recently developed guidelines for risk-based abandonment of offshore wells.[174] Well abandonment practices are likely to see a good deal of innovation as the scale of abandonment activity increases globally and there is increased scrutiny of environmental performance.

The Northern Territory currently does not allow wells to be abandoned without prior approval (according to the Petroleum Schedule, Clause 328 (1)). The requirement for approval for abandonment of a well and for the operator to outline the approach to well abandonment and the maintenance of well integrity post abandonment will reduce risk associated with abandoned wells.

10.6 Providing transparency to address community concerns

Well integrity is often raised as an issue by the broader community, and this was reflected in many of the submissions to the Inquiry from both advocacy groups and private individuals.[175] Greater

[173] Ouyang and Allen 2017.
[174] DNVGL-RP-E103.
[175] Arid Lands Environment Centre, Submission 411, (Arid Lands Environment Centre submission), p3; Lock the Gate Alliance, Submission 171, (Lock the Gate Alliance submission), p21; Carol Randall and Andrew Smith, Submission 395, (C Randall and A Smith submission), p7; Rod Dunbar, Submission 297, (Dunbar submission), p3

confidence in regulatory processes can often by developed through inclusive participation of stakeholders, the implementation of transparent processes and open communication.[176] Transparency requires open publicly available communication about the well integrity process, including details of the process, roles and responsibilities of regulators and operators, and the information used within the process to make decisions.[177] The basin-wide well integrity management approach outlined in Section 10.2 provides a mechanism through which the community can participate in well integrity management. This approach would allow stakeholders to have input into the identification of the well integrity issues that must be managed; it would also make publicly available information on well integrity hazards and risk assessments for basins prospective for shale gas in the Northern Territory.

The requirement for EMPs to be published provides a level of transparency around the management of environmental risks. Should WOMPs be used in the Northern Territory, consideration should be given to making at least the well integrity management component of these plans publicly available. Also, consideration should be given to making a well integrity summary for all wells in the Northern Territory publicly available. These summaries could contain the current well barrier schematic (similar to the one shown in Appendix 2) along with a statement of the status of the barriers in the well, and could be accessible through the Spatial Territory Resource Information Kit for Exploration (STRIKE) web-mapping tool. Interested stakeholders could then easily see the current well integrity status for wells in a region.

A simple mechanism for public complaints should also be available. This system could be for complaints about any aspects of shale gas development, not just well integrity issues. There are several examples of such systems in other jurisdictions around the world.[178]

10.7 Avoiding legacy issues

Wells that are suspended (that is, not in production and yet to be abandoned) may present an unnecessary well integrity risk. When there are legitimate reasons for a well to be suspended, it is crucial that well integrity continues to be actively managed. The Northern Territory currently only allows wells to be suspended for two years at a time (According to the Schedule, Clause 328 (5)(e)). This is a similar approach to the 'idle iron' policy adopted for offshore wells in the Gulf of Mexico, according to which wells must be abandoned within five years of production ceasing.[179] The requirement for approval for suspension of a well, along with the time limit, and requirements for the operator to outline the well integrity management and monitoring of the suspended well, will reduce risk by ensuring that wells are only suspended with good reason and that their integrity is maintained while they are suspended.

[176] Dietz and Stern 2007.
[177] Dietz and Stern 2007.
[178] For example Queensland's CSG Compliance Unit https://www.business.qld.gov.au/industries/mining-energy-water/resources/land-environment/landholders/monitoring-complaints; Colorado's Oil and Gas Conservation Commission http://cogcc.state.co.us/complaints.html#/complaints.
[179] US Bureau of Ocean Energy Management 2010.

11 Conclusions

Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface. Well integrity is established via the use of barriers that prevent these unintended fluid flows. For shale gas wells, a two-barrier principle is applied, whereby at least two independent and verified barriers are in place. Unintended or uncontrolled fluid flow will only occur if both barriers fail, resulting in failure of the integrity of the well.

Well integrity and its management throughout the life cycle of the well is important for the safe, efficient and environmentally sustainable development of shale gas resources. Potential hazards to the integrity of a well can relate to the purpose of the well, the way it has been constructed, and the characteristics of the resource and the overlying geology.

The characteristics of shale gas resources mean that there is a low likelihood of catastrophic well integrity failures (such as blowouts) that result in a release of drilling or formation fluids to the surface environment and a potentially hazardous release of gas. Specifically, the low permeability of shale resources limits the rate at which fluids can enter the well, decreasing but not eliminating the risk of catastrophic well integrity failures.

The most plausible environmental risk related to shale gas well integrity is from the migration of gas up the outside of the well. This gas may originate from the shale gas resource or from gas-bearing layers in the rock layers that overlie it. The rates of gas leakage for individual wells are likely to be small because of the small cross-sectional area and long length of leakage pathways; however, the cumulative effects from a large number of wells may be significant. This risk is also present after wells have been abandoned, and there is limited data on the long-term integrity of shale gas wells.

Subsurface risks associated with hydraulic fracturing relate primarily to the impacts of hydraulic fracturing on the potential for gas migration up the outside of the well. The potential for hydraulic fracturing fluid to reach shallow aquifers via other mechanisms – such as excessive vertical growth of hydraulic fractures or hydraulic fracture intersection with existing structures – is considered to be low.

There is limited published data on rates of well integrity failure in shale gas developments globally. The data available indicate that failure rates are at the lower end of those for other oil and gas wells.

The risks posed by well integrity issues require proactive management of well integrity. The industry and regulators have increasingly focused on well integrity over the past decade, to improve safety and environmental performance. In particular, the focus has been on managing well integrity across the life cycle of the well, with operators now routinely deploying WIMSs. These systems allow the integrity of wells to be managed across their entire life cycle so that the risks can be managed. WIMSs involve:

- identification of hazards and assessment of risks;
- clear identification of well barriers at every phase of the well's life cycle;
- performance standards for well barriers and their components;
- verification procedures for well barriers against the performance standards; and
- an organisational approach to well integrity management that includes identification of roles and responsibilities, and processes for continuous improvement, change management and audit.

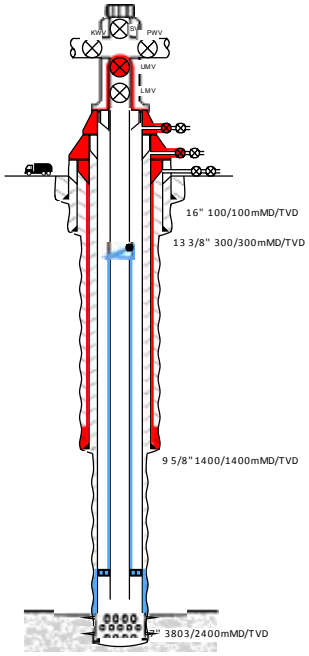
Although global experience in shale gas development provides useful evidence of well integrity risks and their management, there is limited experience in the Northern Territory's onshore gas resources because of the nascent stage of the industry. A basin-wide well integrity management approach that facilitates the sharing of data and well integrity management approaches between operators, regulators and other stakeholders may prove useful in reducing well integrity risks, should an onshore gas industry develop. This approach would allow industry to develop leading practices appropriate for the risks identified in the Northern Territory's shale gas resources. Methods for ensuring the long-term integrity of wells post abandonment could also be explored, helping to reduce the uncertainty around this phase of the well life cycle. Baseline studies to characterise environmental receptors before shale gas activities start will be important to assist in any future evaluation of the environmental impact of the industry.

A regulatory framework that addresses well integrity risks and other subsurface risks during drilling and hydraulic fracturing activities will need to provide a balance between providing guidance on the identification and minimisation of risks while allowing operators to adopt better practices as they are developed.

Appendix A Example well barrier schematic

WELLBARRIER

Field : Csiro
Well : 01
Schematic : WB.D 4.1-a1 rev. 1
Date : 23.Oct.2017
Prepared by : Tore Fjågesund (u)
Verified by :



Depth reference: Landrig, unspecified depth reference

Graphics by Wellbarrier

Producer

Gas producer

Draft

Primary barrier elements

Element	Qualification	Monitoring
Downhole safety valve	Inflow test to xxx Bar	Periodic inflow testing
Tubing	Pressure test to xxx Bar	A-annulus pressure
Production packer	Pressure test to xxx Bar	A-annulus pressure
Production casing	Pressure test to xxx Bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure

Secondary barrier elements

Element	Qualification	Monitoring
Surface x-mas tree	Pressure test to xxx Bar	Periodic testing
Spool wellhead B with access valve	Pressure test to xxx Bar	External observation and periodic testing ov valves
Spool wellhead A with access valve	Pressure test to xxx Bar	External observation and periodic testing of valves
Casing hanger	Pressure test to xxx Bar	C-annulus pressure
Intermediate casing	Pressure test to xxx Bar	C-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	C-annulus pressure

Healthy well, no or minor issue

Note :

Glossary

Term	Description
Abandonment	Ceasing efforts to produce fluids (oil or gas) from a well and plugging the well without adversely affecting the environment.
Annulus	The gap between any of the following: tubing and casing, two casing strings, or casing and wellbore. The annulus between the tubing and casing is the primary path for producing gas from coal seam gas wells.
Aquifer	An identifiable stratigraphic formation that has the potential to produce useful flows of water and may include formations where, due to hydraulic fracturing activity, a changed hydraulic conductivity allows such water flows.
Blowout	A sudden and uncontrolled escape of fluids to the surface from the wellbore.
Blowout preventer	A large valve or mechanical device placed at the top of a well that can be used to seal and regain control of the well in the case of a blowout.
Borehole	Generally refers to a narrow, artificially constructed hole drilled for purposes other than production of oil, gas or water (for example, to intercept, collect or store water from an aquifer; to passively observe or collect groundwater information; or to undertake mineral exploration). Also known as a bore, drill hole or piezometer hole.
Borehole breakouts	Enlargement and elongation of a borehole cross-section in a preferential direction. Formed by the break up of the wall of the wellbore in a direction parallel to the minimum horizontal stress.
Brine	Saline water with a total dissolved solid concentration greater than about 40,000 ppm. Sea water has total dissolved solids of around 30,000 ppm.
Casing	Steel pipe used to line a well and support the rock. Casing extends to the surface and is sealed by a cement sheath between the casing and the rock.
Casing shoe	A short adaptor that fits on the downhole end of the casing string, to facilitate insertion of the casing into the well.
Casing string	Steel pipe used to line a well and support the rock. The casing extends to the surface and is sealed by a cement sheath between the casing and the rock. Often, multiple casings are used to provide additional barriers between the formation and well.
Catastrophic barrier failure	A complete loss of control of the well that allows an inrush of formation fluids or gases, which then travel to the surface, where they are released to the environment.
Cement sheath	A cement ring in the annulus between the casing and the wellbore, or between two casing strings.
Coal seam gas (CSG)	A form of natural gas (generally 95-97% pure methane, CH_4) that is typically extracted from permeable coal seams at depths of 300-1000 m. Also called coal seam methane or coalbed methane.

Decommissioning	The process used to remove a well or other infrastructure from service.
Drilling mud	Also known as drilling fluid, provides cooling and lubrication to the drill bit and drill string, lifts drill cuttings from the well and is a component of well control.
Environmental receptors	Living organisms, habitats or natural resources that may be adversely affected by environmental contamination.
Exploration well	A well that is drilled to test for: • the presence of oil or gas; • natural underground reservoirs suitable for storing oil or gas; or • obtaining stratigraphic information for exploring for oil or gas.
Flowback	Allowing fluids to flow from the well following a hydraulic fracturing treatment. Flowback fluid is composed of a mixture of hydraulic fracturing fluid and formation fluid.
Formation fluid	Any fluid within the pores of the rock. May be water, oil, gas or a mixture. Formation water in shallow aquifers can be fresh. Formation water in deeper layers of rock is typically saline.
Formation pore pressure	The pressure in the porous rock around the well.
Fracture gradient	The pressure required to induce fractures in rock at a given depth.
Fracture height	The distance between the top and bottom of the fracture.
Fracture width	Fracture width is the separation between the two faces of the fracture. Its value is largest at the wellbore and tapers towards the tip of the fracture.
Gas migration (GM)	Flow of gas along the annulus between casing strings, cement and the formation.
Geochemical	Relating to the chemistry of geological material (rocks, the Earth).
Groundwater	Water occurring naturally below ground level (whether in an aquifer or other low-permeability material), or water occurring at a place below ground that has been pumped, diverted or released to that place for storage. Does not include water held in underground tanks, pipes or other works.
Hazard	Inherent property of an agent or situation having the potential to cause adverse effects when an organism, system or population (or subpopulation) is exposed to that agent.
Horizontal drilling	Drilling of a well in a horizontal or near-horizontal plane, usually within the target formation. Requires the use of directional drilling techniques that allow the deviation of the well on to a desired trajectory. Horizontal wells typically penetrate a greater length of the reservoir than a vertical well, significantly improving production while minimising the surface footprint of drilling activities.
Hydraulic conductivity	A coefficient of proportionality describing the rate at which a fluid can move through a permeable medium.

Hydraulic fracturing	Also known as 'fracking', 'fraccing' or 'fracture simulation', this is a process by which geological formations bearing hydrocarbons (oil and gas) are 'stimulated' to increase the flow of hydrocarbons and other fluids towards the well. In most cases, hydraulic fracturing is undertaken where the permeability of the formation is initially insufficient to support sustained flow of gas. The process involves the injection of fluids, proppant and additives under high pressure into a geological formation to create a conductive fracture. The fracture extends from the well into the production interval, creating a pathway through which oil or gas is transported to the well.
Hydraulic fracturing fluid	The fluid injected into a well for hydraulic fracturing. Consists of a primary carrier fluid (usually water or a gel), a proppant such as sand and one or more additional chemicals to modify the fluid properties.
Impact	The difference between what would happen as a result of activities and processes, and what would happen without them. Impacts can be changes that occur to the natural environment, community or economy. They can be a direct or indirect result of activities, or a cumulative result of multiple activities or processes.
Injection well	A well used to inject fluid into the subsurface. This may be for waste water disposal, enhanced oil recovery, gas storage, or CO_2 sequestration.
Lost circulation	The reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string.
Microannulus	See 'Annulus' above.
Offset well	An existing well in close proximity to a proposed well. An offset well may provide information for the planning of a new well, or may be imacted by the drilling of a new well.
Openhole	An uncased section of a well.
Overburden	Material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials such as ores or coal, especially those deposits that are mined from the surface by open-cut methods.
Overpressure	Occurs when the pore is higher than the hydrostatic pressure, caused by an increase in the amount of fluid or gas in the rock, or changes to the rock that reduce the amount of pore space. If the fluid cannot escape, the result is an increase in pore pressure. Overpressure can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure
Packer	A device that can be run into a well; the device has a small initial outside diameter and is expanded inside the well to seal the wellbore. Used to isolate zones within a well in applications such as multistage hydraulic fracturing.
Perforation	A channel created through the casing and cement in a well to allow fluid to flow between the well and the reservoir (hydraulic fracturing fluids into the reservoir, or gas and oil into the well). The most common method uses perforating guns equipped with shaped explosive charges that produce a jet.

Permeability	The measure of the ability of a rock, soil or sediment to yield or transmit a fluid. The magnitude of permeability depends largely on the porosity and the interconnectivity of pores and spaces in the ground.
Plug	A mechanical device or material (such as cement) placed within a well to prevent vertical movement of fluids.
Plugged and abandoned	A well that has been permanently closed, with plugs inserted to isolate sensitive formations and aquifers, and surface infrastructure removed.
Pore pressure	The pressure of formation fluids in pores within rock in the subsurface.
Porosity	The proportion of the volume of rock consisting of pores, usually expressed as a percentage of the total rock or soil mass.
Preferential flow	The uneven and often rapid and short-circuiting movement of water and solutes through porous media (typically soil), characterised by small regions of enhanced flux (such as faults, fractures or other high permeability pathways), which contributes most of the flow, allowing much faster transport of a range of contaminants through that pathway.
Pressure test	A method of testing well integrity by raising the internal pressure of the well up to maximum expected design parameters.
Principal stress	The stress component perpendicular to a given plane, which may be compressional or tensional (that is, there is no shear stress component). Also known as normal stress.
Produced water	Water brought to the surface via a well; in the case of coal seams, water that is pumped out of the seams to release the natural gas during the production phase. Some of this water is returned fracturing fluid and some is natural 'formation water' (often salty water that is naturally present in the coal seam). This produced water moves back through the coal formation to the well along with the gas, and is pumped out via the well head.
Production zone	The section of a well from which fluids or gas are produced.
Proppant	A component of the hydraulic fracturing fluid system comprised of sand, ceramics or other granular material that 'prop' open fractures to prevent them from closing when the injection is stopped.
Reservoir	A geological formation with adequate porosity, fractures or joints that can store hydrocarbons.
Risk	The probability of an adverse effect in an organism, system or population (or subpopulation) caused under specified circumstances by exposure to an agent.
Seismic survey	A method for imaging the subsurface using controlled seismic energy sources and receivers at the surface. Measures the reflection and refraction of seismic energy as it travels through rock.
Shale gas	Natural gas that is generally extracted from a fine grained sedimentary rock that has naturally low permeability. The gas has usually formed in place (source rock is the reservoir).

Stress	Force applied to a body with units of force per area. Rocks within the earth are subjected to stresses caused by the weight of overlying rocks and tectonics (movement within the earth).
Surface casing vent flow (SCVF)	Flow of gas from a vent in the annulus between surface casing and other casing strings in a well.
Sustained casing pressure (SCP)	Sustained pressure in the annulus between casing strings.
Tight gas	A gas resource in very low permeability reservoir rock. The reservoir usually requires stimulation (hydraulic fracturing) to enable economic production. Shale resources are differentiated from tight gas resources based on their rock type.
Tubing	Steel pipe that is hung inside the casing. The tubing string may have a pump installed at its lower end and, for pumped wells, is a primary path for producing fluids from coal seam gas wells.
Thermogenic	Produced by a thermal process. Shale gas and oil are typically thermogenic and are produced by thermal maturation of organic matter.
Unconventional resource	Petroleum (oil and gas) resources that cannot be developed using conventional oil and gas technologies. Includes coal seam gas, shale gas and oil, tight gas and basin centred gas.
Washout	An enlarged region of a wellbore. A number of factors can cause this, such as excessive bit jet velocity, soft or unconsolidated formations, and in situ rock stresses.
Well	A hole drilled in to the earth from which petroleum or other fluids can be produced.
Wellbore	The hole produced by drilling, with the final intended purpose being for production of oil, gas or water.
Well barrier	Envelope of one or several dependent barrier elements (including casing, cement, and any other downhole or surface sealing components) that prevent fluids from flowing unintentionally between a bore or a well and geological formations, between geological formations or to the surface.
Well breach	Failure in cement, casing, downhole or surface sealing components.
Well deviation	The angle at which a wellbore diverges from vertical.
Well head	The surface infrastructure that controls pressure and access at the top of a well.
Well integrity	Well integrity is the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface.
Well integrity failure	May result from a well breach (or a number of well breaches), and can take the form of a hydrological breach (fluid moves between different geological units) or an environmental breach (fluid leaks from the well at the surface or contaminates water resources).
Well logging	The process of recording a signal from a geophysical tool run into a well.

Well pad	The area of land on which the surface infrastructure for drilling and hydraulic fracturing operations are placed. The size of a well pad depends on the type of operation (e.g. well pads are larger at exploration than at production).
Workover	The restoration or stimulation of a production well to restore, prolong or increase the production of oil or gas.
Zonal isolation	Exclusion of fluids such as water or gas in one zone from mixing with fluids in another zone.

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Scope of Services

3.1 Background to the Inquiry

On 14 September 2016 the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory. At the same time, the Chief Minister announced that a *Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory* (the **Inquiry**) would be established and released draft Terms of Reference, which were open for public comment for four weeks.

On 3 December 2016 the Northern Territory Government announced the final Terms of Reference for the Inquiry and the composition of the panel that will be undertaking the Inquiry (the **Panel**).

The Inquiry was established under section 4 of the *Inquiries Act 1945* (NT) and is comprised of a judicial chair, the Hon Justice Rachel Pepper, and ten scientists with expertise in areas ranging from hydrogeology to social science.

The Inquiry's final Terms of Reference can be read in full on the Inquiry's website (www.frackinginquiry.nt.gov.au).

On 20 February 2017 the Inquiry released a Background and Issues Paper, also available on the Inquiry's website, which was followed by hearings and community meetings in March 2017 in various town centres and remote communities across the Northern Territory. The Issues Paper includes a timeline for the Inquiry, which indicates that an interim report will be released in mid-2017, a draft final report will be released during the last quarter of the year, and a final report will be released in December 2017.

The Hydraulic Fracturing Taskforce (the **Taskforce**) has been established in the Department of the Chief Minister to support the Panel.

3.2 Terms of Reference for the Inquiry and the social impact theme

The Panel has divided the work of the Inquiry into the following themes: water, land, air, social impacts, economic conditions, cultural conditions, human health, land access, and the regulatory framework. This request for tender relates to the social impacts theme only, however, there are overlaps with the economic, cultural and regulatory framework themes.

The Terms of Reference for the Inquiry require the Panel to do the following:

a. determine and assess the impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the associated activities;
b. determine whether additional work or research is required to make that determination;
c. for each risk that is identified, advise the level of impact or risk that is acceptable in the Northern Territory context;
d. describe methods, standards or strategies that can be used to reduce the impact and risk to acceptable levels; and
e. identify what government can do, including implementing any policy, regulatory or legislative changes, to ensure that the impacts and risks are reduced to the required levels.

The Background and Issues Paper includes a non-exhaustive list of the potential risks and benefits associated with the social impact theme at page 21.

The Terms of Reference make it clear that the Panel must not only look at the impacts of hydraulic fracturing and the associated activities on social conditions in the Northern Territory – the Panel must also consider the social impacts of the onshore unconventional gas industry as a whole on the Northern Territory. This is made clear in the following extract from the Terms of Reference, which has been amended to include the relevant language only:

"When the inquiry makes a determination… about whether or not there has been an impact or risk on … social conditions, the inquiry will … consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry. This may be undertaken through a social impact assessment or similar activity."

In accordance with the definitions in the Terms of Reference, a reference to an "unconventional reservoir" in this document is a reference to a reservoir where the rock formation is shale. There is currently no gas being produced from shale reservoirs in the Northern Territory. The Amadeus Basin is currently producing gas from conventional reservoirs.

3.3 Steering Committee

A Steering Committee has been established to oversee the work of the supplier. The Steering Committee is comprised of the Hon Justice Rachel Pepper, Dr David Ritchie, Prof Peta Ashworth and the Executive Director of the Hydraulic Fracturing Taskforce. The point of contact for all matters will be the Executive Director of the Hydraulic Fracturing Taskforce.

3.4 Probity Advisor

The Territory has appointed a Probity Advisor to oversee the Territory's processes in relation to the stages of this process. The Probity Advisor's role is to ensure that fairness and impartiality are observed throughout, and that the evaluation criteria stated in any related documentation are consistently applied to all submissions.

Part A – Social Impact Assessment

3.5 Development and implementation of a social impact assessment framework

The supplier must develop a leading practice framework for the identification, assessment and management of the social impacts[1] associated with the development of onshore unconventional gas in the Northern Territory. The framework:

a) must include a requirement for public participation;

b) may include components of both strategic and project-level social impact assessment; and

c) must operate in conjunction with the Northern Territory and Commonwealth environmental assessment frameworks in a way that minimises unnecessary duplication and inconsistency.

The supplier must explain why the proposed framework is leading practice and in doing so must refer to the literature and leading practice social impact assessment frameworks used in other jurisdictions, including overseas jurisdictions.

The supplier must describe the current policy and regulatory regime in the Northern Territory for the identification, assessment and management of social impacts associated with onshore unconventional gas development.

The supplier must identify the structural, policy, regulatory and legislative reforms that must be made to the current regime in the Northern Territory to implement the social impact assessment framework described above.

The supplier must describe how the framework will operate in conjunction with the Northern Territory and Commonwealth environmental assessment frameworks in a way that minimises unnecessary duplication and inconsistency.

3.6 Beetaloo Sub-basin

The supplier must identify the people or groups of people that are most likely to be impacted by the development of unconventional gas resources in and around the Beetaloo sub-basin, shown in Attachment B, which may include, without limitation, community members, pastoralists, Aboriginal organisations and local businesses (the Affected Communities).

1 A 'social impact' is defined as a change to any of the values or conditions set out at **Attachment A** and must include cumulative social impacts.

The supplier must describe the methodology used to identify the Affected Communities.

The supplier must describe the Affected Communities (that is, describe the community profile or baseline conditions), which must include a description of the values listed at Attachment A and how such information was collected.

The supplier must describe the type of potential social impacts, issues, concerns, risks and benefits that may arise from the development of the unconventional gas industry in the Beetaloo sub-basin on the Affected Communities. In identifying the potential impacts the supplier must consider:

a. the list of social impacts, risks and benefits described in sections 7.5, 7.6, 7.7, and 7.8 of the *Background and Issues Paper*;
b. submissions made to the Panel in connection with the *Background and Issues Paper*;
c. social impacts, issues, benefits and risks typically associated with the development of onshore unconventional gas resources that have been identified in the literature and in other jurisdictions; and
d. issues that have been identified in other social impact assessments and related studies that have been completed in or around the Beetaloo sub-basin, including those listed at **Attachment C**.

For each potential impact identified, the supplier must, to the extent possible:

a. assess the potential impact (or risk) in terms of likelihood and consequence (high, medium, low);
b. identify a potential measurable indicator, which can be qualitative or quantitative, and develop a methodology for the collection of appropriate baseline data in the Affected Communities so that changes in social values or conditions as a result of any unconventional gas development can be measured over time;
c. collect such baseline data;
d. identify ways to avoid, mitigate and/or manage the risk over time (including the entity that should be responsible for the management and monitoring of such risk) and predict what the level of risk will be following mitigation; and
e. indicate whether or not the level of risk following mitigation would be deemed acceptable, and why.

For every potential social benefit that is identified, the supplier must recommend strategies to realise and maximise such benefit.

The supplier must identify any issues that must be addressed in subsequent project-based social impact assessments associated with the development of unconventional gas in the Beetaloo sub-basin.

The supplier must develop and implement a leading practice community consultation program to support its responses to section 3.6. The supplier must consult, without limitation and where practicable, the Aboriginal Areas Protection Authority; the Northern Land Council; the Departments of Primary Industry, Resources and Trade, Business and Innovation, and Tourism Northern Territory; local and regional councils; the Northern Territory Cattleman's Association; Northern Territory Farmers, and petroleum operators and titleholders in the Beetaloo sub-basin. The Steering Committee must approve the program prior to implementation.

Part B - Social Licence to Operate

3.7 The supplier must describe, with reference to the literature and examples from other jurisdictions:

a. the concept of a "social licence to operate" as it applies to the onshore unconventional gas industry in the Northern Territory;

b. the nature and extent of any potential risks to affected stakeholders, including the Northern Territory Government, petroleum titleholders and operators in the Northern Territory, the Northern Territory community, and the communities affected by development, where industry has not obtained and/or maintained a social licence to operate;
c. the measures that onshore unconventional gas industry and government can take to enable industry to earn and maintain a social licence to operate in the Northern Territory; and
d. how industry's social licence to operate can be measured in the Northern Territory, including a part of the Northern Territory.

3.8

The supplier must identify, to the extent practicable, the measures that the petroleum titleholders and operators in the Beetaloo sub-basin have taken in the past, and can take in the future, to earn and maintain a social licence to operate in the Affected Communities.

3.9 Timelines and Reporting

The work must be in the form of a written report.

The report must include a literature review that includes all references used in section 3.5 and 3.6.

At the end of each calendar month following the award of the tender the supplier must provide the Steering Committee with a written progress report and a verbal presentation within five working days of receipt of the report.

The supplier must provide the Steering Committee with a draft final report and a verbal presentation to the Steering Committee on or prior to 1 September 2017.

A final report must be provided to the Steering Committee by 15 September 2017 and the supplier must present the final report to the Panel on a date to be determined.

The Inquiry will publish the final report on the Inquiry's website on a date to be determined.

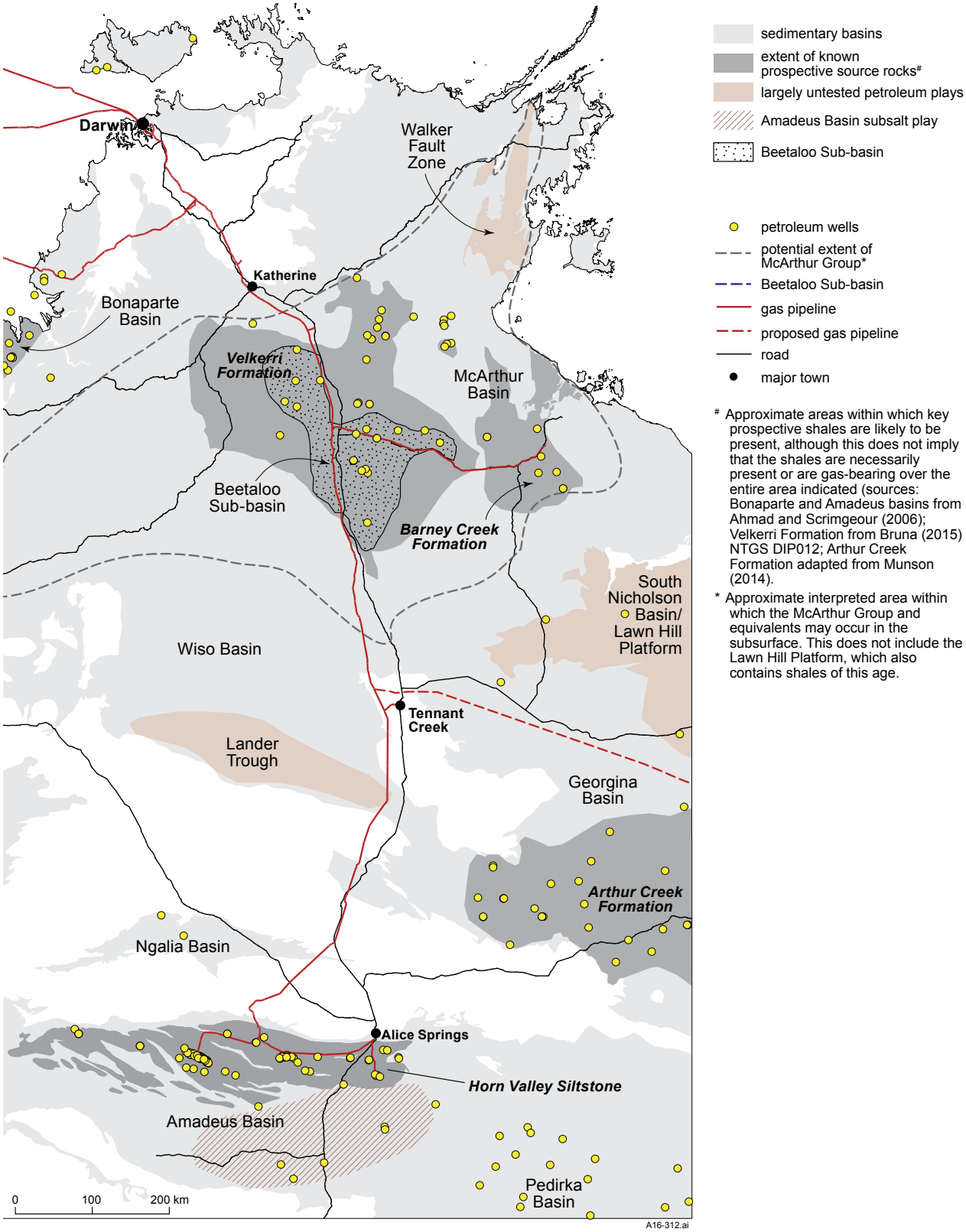
Attachment A

The *International Association for Impact Assessment* defines "social impacts" as changes to one or more of the following:[2]

a. people's way of life – that is, how they live, work, play and interact with one another on a day-to-day basis;
b. their culture – that is, their shared beliefs, customs, values and language or dialect;
c. their community – its cohesion, stability, character, services and facilities;
d. their political systems – the extent to which people are able to participate in decisions that affect their lives, the level of democratisation that is taking place, and the resources provided for this purpose;
e. their relationship with their environment – the quality of the air and water people use; the availability and quality of the food they eat; the level of hazard or risk, dust and noise they are exposed to; the adequacy of sanitation, their physical safety, and their access to and control over resources;
f. their health and wellbeing – health is a state of complete physical, mental, social and spiritual wellbeing and not merely the absence of disease or infirmity;
g. their personal and property rights – particularly whether people are economically affected, or experience personal disadvantage which may include a violation of their civil liberties; and
h. their fears and aspirations – their perceptions about their safety, their fears about the future of their community, and their aspirations for their future and the future of their children, in each case, to the extent such impact would not otherwise be assessed as part of an environmental impact assessment under Northern Territory or Commonwealth legislation.

2 Adapted from Vanclay, F. 2003 International Principles for Social Impact Assessment. Impact Assessment and Project Appraisal 21(1), 5-11 (available at http://dx.doi.org/10.3152/147154603781766491 last accessed 21 April 2017).

Attachment B(1)



Approximate areas within which key prospective shales are likely to be present, although this does not imply that the shales are necessarily present or are gas-bearing over the entire area indicated (sources: Bonaparte and Amadeus basins from Ahmad and Scrimgeour (2006); Velkerri Formation from Bruna (2015) NTGS DIP012; Arthur Creek Formation adapted from Munson (2014).

* Approximate interpreted area within which the McArthur Group and equivalents may occur in the subsurface. This does not include the Lawn Hill Platform, which also contains shales of this age.

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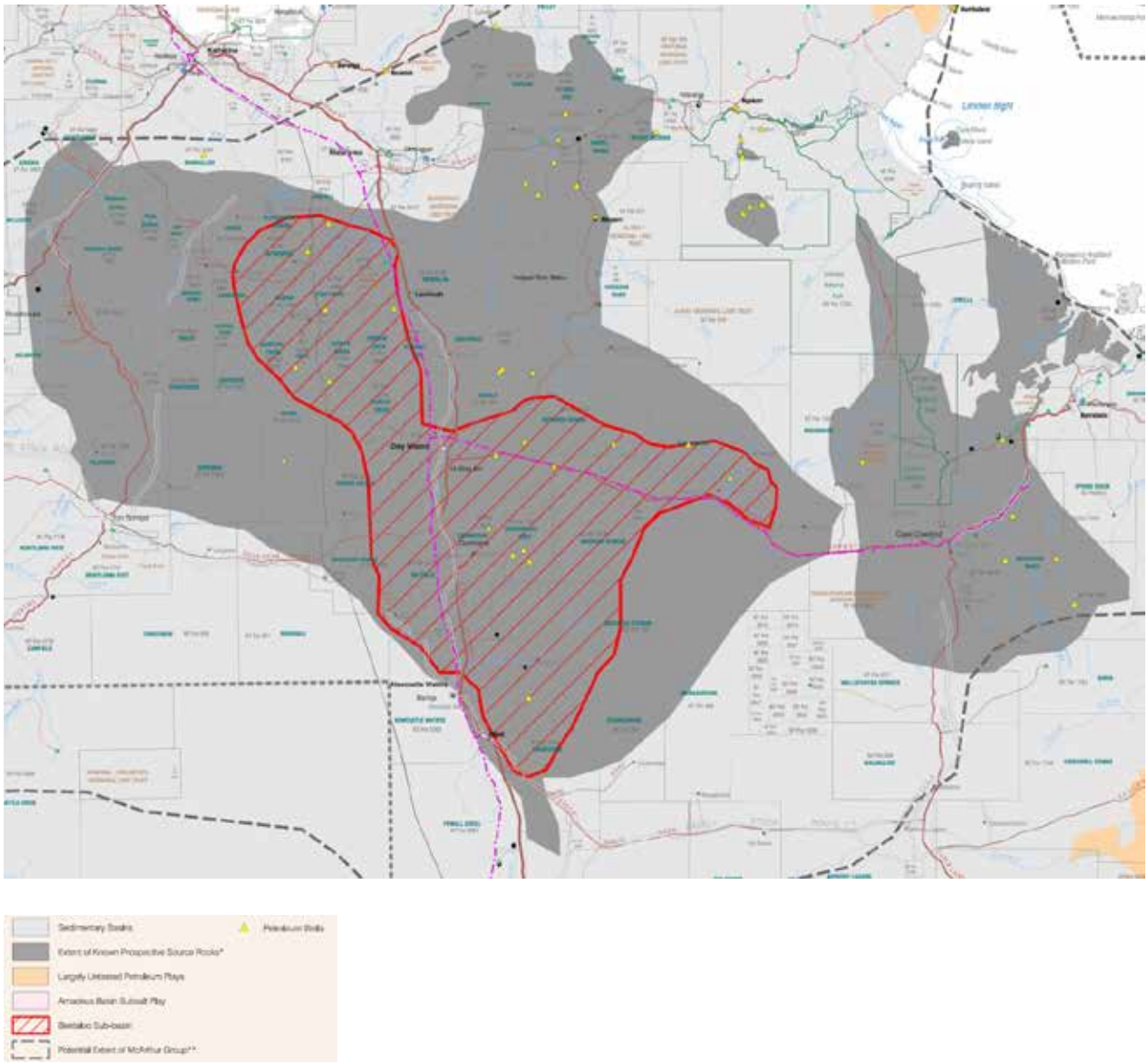
NORTHERN TERRITORY GOVERNMENT

Attachment B(2)



Attachment C

- The research monograph entitled Ngukurr at the Millenium:" A Baseline Profile for Social Impact Planning in South East Arnhem Land, by J. Taylor, J. Bern, and K.
- Social Impact Assessment undertaken by EcOz in connection with the Western Desert Resources Roper Bar Iron Ore Project.
- The Economic and Social Impact Assessment undertaken by EcOz in connection with the Sherwin Creek Iron Ore Project.
- The Social Impact Assessment Scoping Study and the Economic and Social Impact Assessment undertaken by Circle Advisory in connection with the Northern Gas Pipeline.

ACIL ALLEN CONSULTING

FINAL REPORT TO
SCIENTIFIC INQUIRY INTO HYDRAULIC FRACTURING IN THE NORTHERN TERRITORY
OCTOBER 2017

THE ECONOMIC IMPACTS OF A POTENTIAL SHALE GAS DEVELOPMENT IN THE NORTHERN TERRITORY

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Interpreting this report

ACIL Allen Consulting ('ACIL Allen') was engaged by the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory ('the Inquiry') to conduct an economic study into the impacts and risk of an unconventional shale gas industry in the Northern Territory. As one part of its scope of works, ACIL Allen has conducted a series of modelling tasks, including the development of a commercial financial model.

All economic modelling is subject to uncertainty, and should be treated with caution. ACIL Allen Consulting ('ACIL Allen') considers the modelling presented in this report is subject to higher than usual uncertainty. This is because of the unusual nature of the task ACIL Allen has undertaken.

The development of a shale gas industry in the Northern Territory is at the very earliest possible stages. To date, there has been one fracture stimulated horizontal well that has been tested in a near-production setting – Origin Energy's Amungee NW-1H well, in the Beetaloo Sub-Basin of the McArthur Basin. While the well delivered a positive production test result, significant further testing is required to determine the precise scale, scope and qualities of shale gas production potential in this sub-basin alone, let alone the remainder of the Northern Territory.

However, in order to conduct economic impact assessment modelling, it has been necessary for ACIL Allen to develop a commercial financial model of an industry in the Northern Territory. This model has been built using a range of assumptions, and does not represent an assessment of the commercial viability of a shale gas industry development in the Northern Territory. It is not possible to conduct such modelling at this point in the industry's life cycle, as even the most basic information regarding the quantity and quality of gas in situ is unknown.

Ultimately, ACIL Allen was engaged by the Inquiry to articulate the potential **economic** benefits, impacts and risks of a shale gas industry in the Northern Territory. We have done this using our best estimates of what a successful development may look like, based on:

- the views of the Northern Territory Government, potential industry operators, non-gas industry stakeholders, Traditional Owners and native title holders, non-government organisations, and representative bodies;
- our own expertise in gas market and economic impact modelling;
- the experience of shale gas industry development in analogous regions across the world; and
- the latest research, data and insights of shale gas industry economics.

ACIL Allen has developed a framework that has allowed it to deal with the uncertain nature of our task, which is presented in Chapter II of this report. However, as a result of the significant information limitations, ACIL Allen advises those who read this report to treat the results with higher than usual caution. The modelling prepared and results presented in this report should be treated as what they are – **an estimate of the economic impacts of a shale gas industry development** – and not for what they are not – an assessment of the commercial viability of a shale gas industry development in the Northern Territory.

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EXECUTIVE SUMMARY

The Inquiry

Hydraulic fracturing for onshore unconventional gas has been subject to significant debate in the Northern Territory in recent years. Following a change of government in 2016, the Northern Territory Government announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs including the use of hydraulic fracturing for exploration, extraction, production and including Diagnostic Fracture Injection Testing (DFITs).

On 3 December 2016 the Northern Territory Government announced an independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory. The Inquiry is investigating the environmental, social and economic risks and impacts of hydraulic fracturing ('fracking') of onshore unconventional gas reservoirs and associated activities in the Northern Territory.

ACIL Allen Consulting ('ACIL Allen') was appointed on 24 May 2017 to assist the Inquiry understand the potential economic benefits, impacts and risks of the development of an onshore unconventional gas industry in the Northern Territory. An abbreviated version of the scope of works is presented below, and the full terms of reference included in Appendix A.

ACIL Allen has been engaged by the Inquiry and this, our Final Report, has been released for public consumption.

Our scope of works

ACIL Allen Consulting has been appointed by the Inquiry to assess the actual and potential direct and indirect economic benefits, risks and impacts of fracking on the Northern Territory under the current regulatory regime.

To facilitate this, ACIL Allen's scope of works gives regard to three distinct scenarios:

1. Scenario 1, or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place (the 'base case')
2. Scenario 2, which involves the development of the onshore unconventional shale gas industry in the Northern Territory (the 'unconstrained case')
3. Scenario 3, which involves the development of unconventional shale gas reservoirs in the Beetaloo sub-basin only.

In order to do this, ACIL Allen will complete two main tasks:

— **Conduct economic impact assessment modelling, using ACIL Allen's suite of in-house economic models**, including models of the national gas and electricity markets. To complete this task, ACIL Allen will develop credible, evidenced-based scenarios for the development of shale gas projects in the

Northern Territory under a set of assumptions which are agreed by the Inquiry. The outcome of this task will be quantitative economic impact assessment results under each of the three scenarios listed above.

— **Research, analyse, articulate and discuss the potential impacts on the Northern Territory economy's other industries**, including but not limited to tourism, agriculture, horticulture and pastoral. This will centre on findings of stakeholder consultation and a review of relevant international literature and case studies. The outcome of this task will be a chapter or chapters in the final report of this engagement that outlines the economic risks and provides suggestions on policy initiatives the Inquiry may recommend to the Northern Territory Government in the Inquiry report.

Scope variation – 18 July

Following the completion of its initial research and round of stakeholder consultation in the Northern Territory, ACIL Allen presented the Inquiry with a proposal to vary its scope of works.

The key finding of our initial research and consultation was that it was not possible to conduct economic modelling giving regard to the three scenarios as requested by the Inquiry in its scope of works. This was primarily due to lack of information about the size or scope of commercial shale gas reserves in the Northern Territory (both in the Beetaloo sub-basin and in the Northern Territory more broadly), and the embryonic stage of the industry's life cycle. The scenarios as described by the Inquiry implied a precision which ACIL Allen was not comfortable providing.

ACIL Allen proposed to conduct modelling on the basis of **five** scenarios, briefly outlined below and explained further in this report.

1. **"Baseline":** The moratorium remains in place
2. **"Shale CALM":** The moratorium is lifted, and exploration and appraisal activity occurs. However, the results of testing indicate the resource is not commercial, and no further activity takes place.
3. **"Shale BREEZE":** The moratorium is lifted, and exploration and appraisal activity occurs. A relatively small scale development occurs, targeting production of 100 terajoules (TJ) per day.
4. **"Shale WIND":** The moratorium is lifted, and exploration and appraisal activity occurs. A moderate scale development occurs, targeting production of 400 TJ/day.
5. **"Shale GALE":** The moratorium is lifted, and exploration and appraisal activity occurs. A relatively large scale development occurs, targeting production of 1000 TJ/day.

Complementing these scenarios is a qualitative probability matrix, which is intended to articulate the subjective likelihood that a given scenario would come to fruition under a series of moratorium lifting scenarios. This is presented at the end of this summary.

ACIL Allen considered that the scenarios as described above would achieve the objectives of the scope of works while also dealing with the lack of information and articulating the significant uncertainty which currently exists regarding the prospects of a shale gas industry in the Northern Territory.

No other aspects of the engagement were proposed to change. The Inquiry agreed to the scope variation post this meeting, and these are the scenarios ACIL Allen has adopted for its economic modelling and policy analysis tasks.

Our methodology

ACIL Allen has completed two discrete but related tasks to meet the objectives of this scope of works.

Economic impact assessment modelling

We have completed **an economic impact assessment** on the five scenarios above, where the four "Shale" scenarios are compared to a baseline assessment of the modelled growth of the Northern Territory economy absent the development of a shale gas industry. In order to complete the economic impact assessment, ACIL Allen conducted an iterative process of modelling across four models:

1. **Gas Market Modelling:** Understanding the supply and demand for gas from a Northern Territory shale gas industry under each scenario, to determine the volume of gas that could be placed in the market at

market prices each year of the study. This task was completed using ACIL Allen's *GasMark* model of the east coast gas market.

2. **Project Development Modelling:** Understand the production and infrastructure requirements to meet the volume of gas to be placed in the market, using a bespoke shale well production schedule model. This model required two major inputs: an assumed single average type curve of a hypothetical shale well (different for each scenario) and a series of assumptions regarding the infrastructure required to enable production to occur (wells, pads, gathering pipes, roads, water, camps, labour). This occurred in two streams:
   a) "ProjectCo": the hypothetical development company responsible for exploring, appraising and developing the shale gas industry in the Northern Territory.
   b) "PipelineCo": the hypothetical builder, owner and operator of new pipeline infrastructure required to facilitate the sale of ProjectCo shale gas to market.

   ProjectCo and PipelineCo are separate entities, but interact via tariffs paid by ProjectCo to PipelineCo for the provision of pipelines to transport gas to market.
3. **Project Cash Flow Modelling:** Understanding the financial implications of the development using assumptions regarding the cost of development of ProjectCo and PipelineCo, and volume and price data derived from *GasMark*. ACIL Allen has built a bespoke discounted cash flow model that takes into account all features of ProjectCo's finances, including estimates of taxation. PipelineCo is built as a simple discounted cash flow model with capital investment, ProjectCo tariffs revenue and operating expenditure.
4. **Economic Impact Assessment Modelling:** The summary inputs and outputs of the ProjectCo and PipelineCo cash flow modelling are converted to a national accounting framework and processed through ACIL Allen's *TasmanGlobal* computable general equilibrium (CGE) model. The four development scenarios are compared to the baseline assessment of the future growth of the Northern Territory economy to produce estimates of the potential economic impacts of each development scenario as a discrete set of outputs.

   Outputs are presented at the Northern Territory and Australia level, under the Australian Bureau of Statistics National Accounting framework for income, expenditure and output – including at ANZSIC major industry level. This ensures a comprehensive understanding of both positive and negative impacts of an industry. This process is described at length in Sections II and III of this report.

Perspectives on economic policy issues

We have also completed a qualitative research exercise centred on understanding the potential economic policy implications of a shale gas industry in the Northern Territory. This is informed somewhat by the outputs of the economic impact assessment modelling, as these articulate the potential "pressure points" that may emerge at an industry level.

ACIL Allen has completed this in two chapters of this report.

1. A **literature review** centred on current academic research and practical insights of sustainable resources industry development, with an Australian bent.
2. A **discussion of six key policy issues** that were raised during stakeholder consultation. We have included examples of onshore gas industry development and other resources industry development in other jurisdictions, as our literature review indicates resources-related developments have similar benefits and costs.

   ACIL Allen has not sought to develop a policy reform program to help capture benefits and mitigate risks, as this is beyond the scope of works we have been asked to complete.

Economic impact assessment summary

ACIL Allen has conducted this economic impact assessment under five scenarios; a base case, and four scenarios which are independent deviations from this base case.

The base case is ACIL Allen's assessment of the future growth of the Northern Territory and Australian economies under current policy settings, which is effectively an assessment of the economy if the

moratorium on fracking was to remain in place. The four scenarios are in line with the cash flow modelling results presented in this report.

In line with ACIL Allen's scope of works, the modelling outputs have been presented for three regions: Northern Territory, Rest of Australia, and Australia (which is the sum of the first two regions), and under the following macroeconomic variables:

- Real income (Gross Real Income)
- Real output (Gross State Product and Gross Domestic Product, and change in industry output from the base case)
- Real final demand (State Final Demand and Domestic Final Demand)
- Real investment (Business Investment)
- Real exports (for the Northern Territory, international and interstate; for Australia, international only)
- Real employment (FTE employment and employment by industry)
- Real wages
- Population
- Taxation (by major heads of taxation)

Base case

In order to assess the economic impact of a potential shale gas industry, it has been necessary to define what the Northern Territory economy will look like without a shale gas industry in the future. This is known as the "base case" scenario, which projects the long term growth of the Northern Territory economy.

The Northern Territory's recent economic performance has been driven by the impact of INPEX's Ichthys offshore gas and LNG facility development. To this point, the impact has been mostly centred on the initial surge and subsequent fall in construction activity, with the lift in production and export still on the horizon. ACIL Allen has included a projection of the impact of Ichthys' production phase on the Northern Territory economy in its base case.

Other foreseen events for the Northern Territory included in the base case include:

- The impact of the Northern Territory Government's **10 Year Infrastructure Plan**
- **Project Seadragon**, and the significant impact on the Northern Territory Government's aquaculture industry
- The highly likely development of an offshore gas project to support the **backfill of DLNG** as existing supplies deplete
- An **expanded horticulture sector**, in line with research presented by NT Farmers and the perspective of Northern Territory Government stakeholders

In Gross Territory Product (GTP) terms, ACIL Allen's base case projects the Northern Territory economy will grow by an average of 2.9 per cent over the forecast period (2018-2043) (Figure ES1, Panel 1). This is lower than the average GTP growth of four per cent recorded over the past decade, which was mostly influenced by the impact of first the DLNG project and then the Ichthys LNG project.

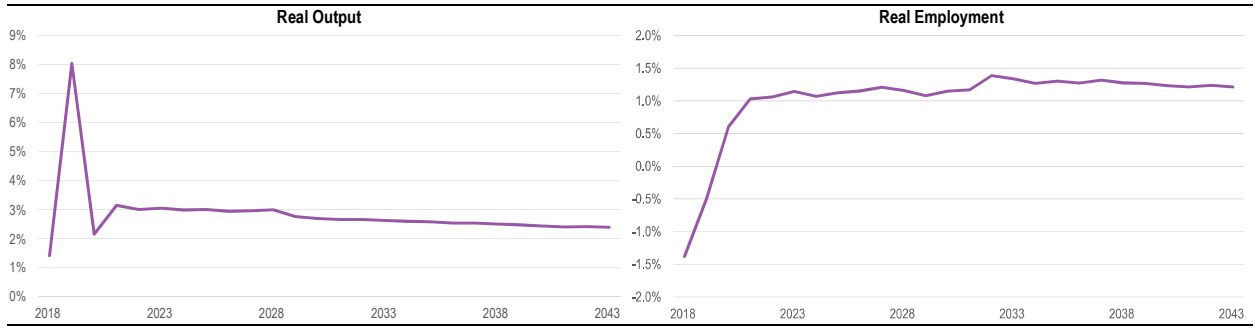
Growth is forecast to spike in the short term, with GTP growth of eight per cent forecast in 2019 on account of the ramp up in Ichthys LNG production. This manifests as an increase in the Petroleum sector's output, and a lift in the real export base of the Northern Territory economy. As LNG production ramps up and then reaches a steady-state level of production, this is only anticipated to have a one year impact on the Territory's growth rate.

Following the ramp up of Ichthys LNG Project, ACIL Allen forecasts there will be a period of slightly above average growth through the 2020s, as the Territory's aquaculture and horticulture industries grow faster than the rest of the economy, and the Northern Territory Government's 10 Year Infrastructure Plan plays out. The impact of the new offshore gas development to back fill DLNG is somewhat limited, as much of the supplies and services for an offshore development are by necessity imported. This manifests in a strong increase in Business Investment (and therefore State Final Demand), but a commensurate increase in imports, therefore a near-zero impact on overall GTP.

Beyond the 2020s, ACIL Allen projects the Northern Territory economy will grow in line with population growth, labour force participation and productivity growth. All up, the Northern Territory economy is projected to grow from a $23.4 billion economy (2018 dollars) in 2018 to a $47.9 billion economy by the end of the forecast period.

ACIL Allen's base case assumes total employment in the Northern Territory economy will grow by an average of one per cent per annum over the forecast period (Figure ES1, Panel 2). Short term employment growth follows the trajectory of the unwinding of the remainder of the Ichthys LNG project, with employment forecast to fall by 1.4 per cent in 2018 and 0.5 per cent in 2019. Thereafter, total employment is forecast to grow by an average of 1.2 per cent per annum.

FIGURE ES 1 BASE CASE HEADLINE RESULTS, REAL OUTPUT AND REAL EMPLOYMENT, ANNUAL PERCENTAGE CHANGE, FORECAST



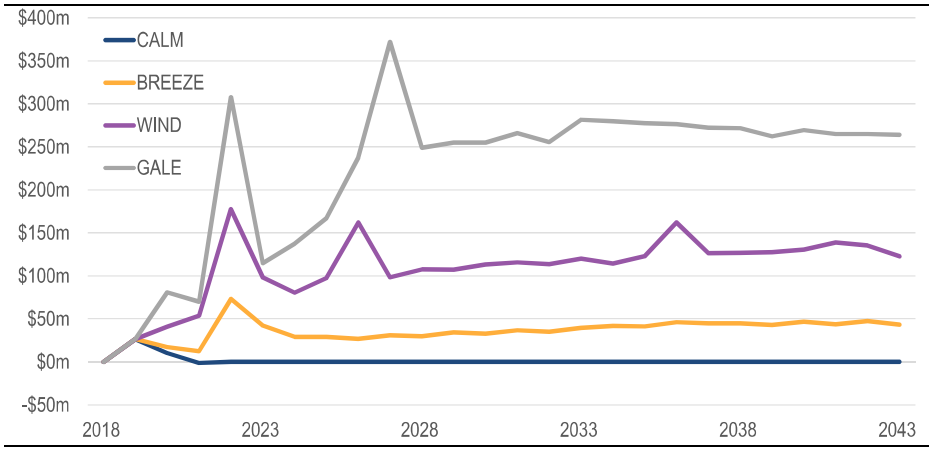
SOURCE: ACIL ALLEN CONSULTING

Economic impact assessment results

ACIL Allen's economic impact assessment illustrates the potential economic upsides and downsides in the event of small, medium and large scale shale gas industry developments in the Northern Territory, and the flow on effects to the rest of the Australian economy. While the base case and CALM scenarios, where no shale gas industry development occurs, show the Northern Territory economy is set to grow in the years ahead, the development scenario modelling shows the shale gas industry could have an overall net positive impact on the future growth of the Northern Territory economy.

ACIL Allen projects a shale gas industry development could result in a net real income (a measure of the overall wealth impact of the industry's development) increase of between $937.2 million (BREEZE), $2.8 billion (WIND) and $5.8 billion (GALE) for the Northern Territory over the modelling period, or between $36 million, $108.4 million and $222.2 million per annum. This equates to a net real income per capita increase of $146, $439 to $903 per capita (based on the Northern Territory's 2018 population) over the modelling period, which is mostly caused by increased Northern Territory Government revenue. The rest of Australia also sees a lift in real income, of between $3.4 billion (BREEZE), $9.1 billion (WIND) and $12.5 billion (GALE) over the modelling period, on account of the flow on impact of lower gas prices across the economy and the increase in Commonwealth taxes associated with the development (refer to Figure ES 2).

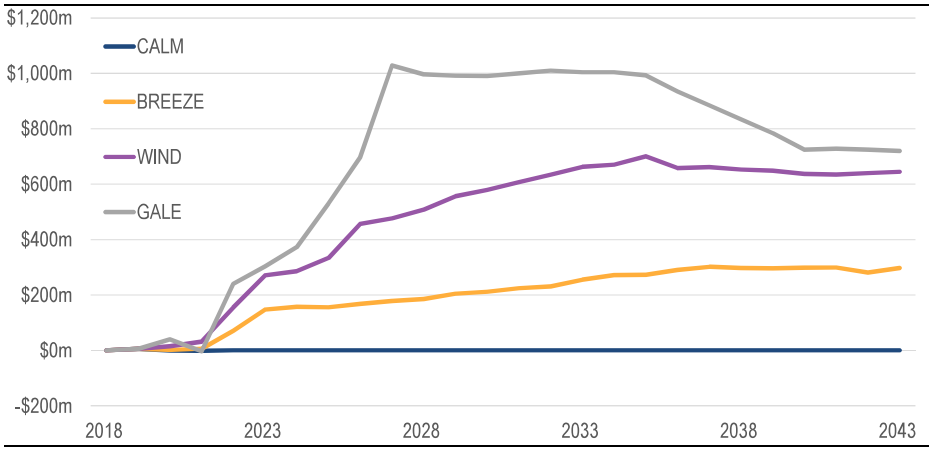
FIGURE ES 2 REAL INCOME, ANNUAL DEVIATION FROM BASE CASE, A$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

The net economic benefit (in terms of increase to the Northern Territory's Real Gross Territory Product) to the Northern Territory ranges from $5.1 billion in the BREEZE scenario ($196.5m per annum), to $12.1 billion ($466.4m per annum) in the WIND scenario, to $17.5 billion ($674.4m per annum) in the GALE scenario, in real 2018 dollar terms. In annual average terms, this is the equivalent of an additional 0.8 per cent, 1.9 per cent to 2.9 per cent of the Northern Territory's forecast Gross Territory Product in 2018 (Figure ES 3).

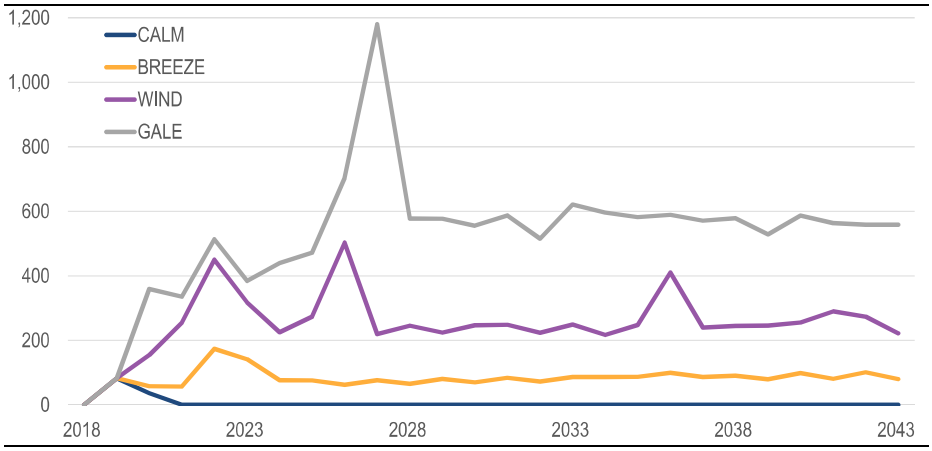
FIGURE ES 3 REAL OUTPUT, ANNUAL DEVIATION FROM BASE CASE, A$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

This additional economic activity will generate employment opportunities for Territorians, with an estimated 2,154 FTE jobs (BREEZE), to 6,559 FTE jobs (WIND) to 13,611 FTE jobs (GALE) generated by the various development scenarios over the forecast period – over and above the existing employment growth ACIL Allen has forecast in its base case (Figure ES 4). This equates to between 82 FTEs, 252 FTEs, and 524 FTEs of net employment growth in each year on average. This includes indirect employment generated by the local spending of the industry. While modest in the context of the overall Northern Territory labour market, this represents the capital intensive nature of the shale gas industry and modelling assumptions (see Section 6).

FIGURE ES 4 REAL EMPLOYMENT, FTE JOB YEARS, REAL TERMS, BY SCENARIO

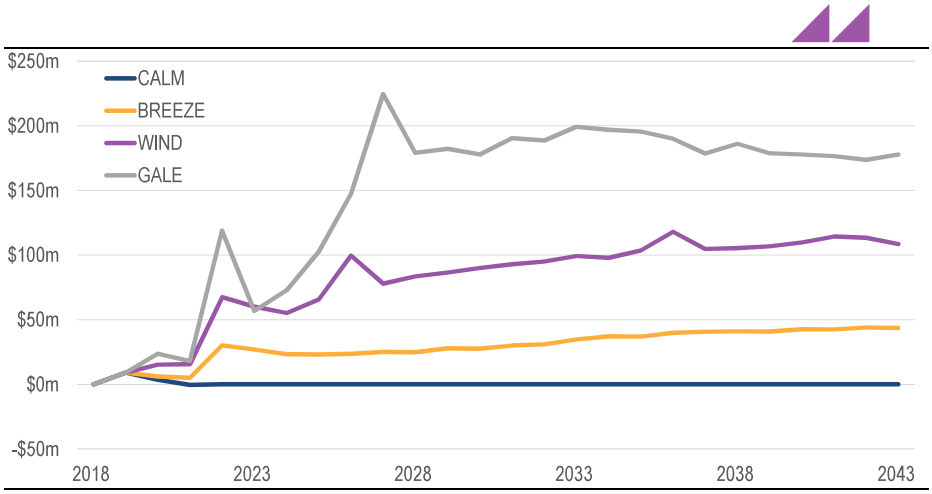


SOURCE: ACIL ALLEN CONSULTING

For Territorians, the most visible channel of economic impact likely to be seen is an increase to Territory Government revenue. ACIL Allen estimates a successful shale gas industry development could generate between $757 million (BREEZE), $2.1 billion (WIND) and $3.7 billion (GALE) in additional revenue for the Northern Territory Government over the 25 year modelling period, or between $29.1 million, $80.6 million, and $143.2 million per annum (Figure ES 5). In the larger case, this represents a sizeable increase to the Northern Territory's recurrent revenue base of 2.2 per cent, or more than eight per cent if Commonwealth Government grants are excluded. ACIL Allen has modelled royalty revenue, payroll tax and implied GST raised in the Northern Territory.

ACIL Allen's analysis shows a shale gas industry could also deliver windfall growth in Commonwealth revenue, even as the cascading impact of reduced gas prices from the development reduces the income earned by the gas sector outside of the Northern Territory. ACIL Allen has modelled company income tax, personal income tax and PRRT revenue.

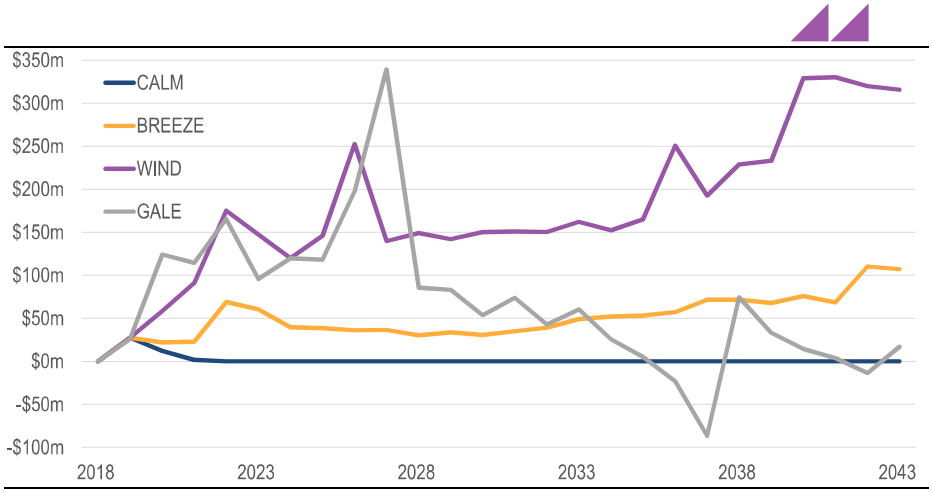
FIGURE ES 5 REAL TAXATION, NORTHERN TERRITORY GOVERNMENT, A$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

ACIL Allen estimates the Commonwealth Government could expect to raise between $1.3 billion (BREEZE), $4.6 billion (WIND), and $5.5 billion (GALE) in income and profits based taxation over the forecast period, or $50.2 million, $176.2 million and $210.4 million per annum (Figure ES 6).

FIGURE ES 6 REAL TAXATION, COMMONWEALTH GOVERNMENT, A$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

Project development probability matrix, and key development assumptions

As discussed in Section 4, the shale gas industry in the Northern Territory is at such an early stage that the modelling conducted in this engagement is subject to more than the usual uncertainty. Below, ACIL Allen has presented a subjective probability matrix to represent the qualitative likelihood of each scale of development occurring (Figure ES 7).

On the basis of the financial modelling undertaken on the each development scenario, ACIL Allen has assessed the probability of a shale gas industry developing in the Northern Territory in each case. This is based on the outcomes of the financial modelling, the uncertainty regarding the size of the Northern Territory's commercial reserves, and the challenges associated with producing gas at a price which the market will accept. As the development scales up, these challenges will become greater, leading to a reduced likelihood that any given scale of development can be realised.

ACIL Allen has also formed a view that the probability of a shale gas industry developing in the Northern Territory will improve the greater the potential area for exploration and appraisal. This is in line with international experience, which shows that it is often developments which occur following an initial discovery and development that prove to be the most commercial.

For example, under the GALE scenario, ACIL Allen has assessed, on current information, the likelihood of a shale gas industry that will begin to scale to 1000 terajoules per day (TJ/day) of gas production at an average price of $4.01 per gigajoule (GJ) within the next five years as low, assuming the moratorium is lifted in full across the Northern Territory. If there is only a partial lift in the moratorium, this becomes a very low probability, because there is less of an ability for a potential shale gas industry to find the most commercial shale gas deposits.

In the context of the probability matrix, ACIL Allen notes that it has made a critical assumption that the shale gas developments modelled in this report are a "dry gas play". That is, the hydrocarbons produced in a development do not include higher value liquid hydrocarbons such as ethane, propane, butane or crude oil. A "liquids rich" shale gas play results in a very small increase in operating costs (associated with increased processing to separate the higher value hydrocarbons from the lower value hydrocarbons), and a very large increase in potential production revenue. This improves the commercial viability of a shale

gas development, to the point where a larger development may have a higher probability of occurring versus a dry gas play.

For further information on the development scenarios, refer to Section 4.

To be clear, this matrix is not an assessment of the commercial prospects of a shale gas industry in the Northern Territory, as ACIL Allen has not been engaged to assess this, and it is too early in the industry's development to make such a determination.

FIGURE ES 7 ACIL ALLEN DEVELOPMENT SCENARIO PROBABILITY MATRIX

			POLICY SCENARIO PROBABILITY MATRIX		
INDUSTRY DEVELOPMENT SCENARIO	**Production Profile**	**Production Cost Regime**	**PERMANENT MORATORIUM**	**PARTIAL LIFT**	**FULL LIFT**
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	**Scenario 1** Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	**Scenario 2** Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	**Scenario 3** Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

SOURCE: ACIL ALLEN CONSULTING

1 REPORT STRUCTURE AND KEY TERMS

Structure of this report

As this is a complex engagement, ACIL Allen has structured its report in a logical fashion, with overarching Chapters and a series of Sections underneath. The contents of each remaining Chapter and Section is briefly outlined below (excluding this introductory chapter).

Chapter I: Preliminary Information

Section 2: Economic context. This section provides relevant contextual information regarding the structure and recent performance of the Northern Territory economy, the Australian economy, Australia's gas and electricity markets (including a brief discussion of recent policy initiatives) and the Northern Territory's energy markets.

Section 3: Unconventional gas and hydraulic fracturing. This section provides relevant contextual information regarding unconventional gas and hydraulic fracturing techniques, a brief overview of unconventional gas extraction in Australia, and the recent experience of hydraulic fracturing for shale gas in the Northern Territory prior to the moratorium.

Chapter II: Shale Gas Industry Development Scenarios

Section 4: Project Assumptions and Development Scenarios. This section outlines the process used to derive the industry development scenarios discussed above, including a full explanation of the target and realised gas sales and prices, single average type curve assumptions and production and supporting infrastructure requirements. This includes the timing of development under each scenario.

Section 5: Project Cash Flow Modelling. This section outlines the ProjectCo and PipelineCo financial models, including all assumptions relating to the cost of development and overall financial position of ProjectCo under each set of assumptions outlined in Section 4.

Chapter III: Economic Impact Assessment

Section 6 through 11: Economic Impact Assessment Results. This section outlines the economic forecasting results of the baseline scenario, before articulating the economic impact assessment results of the four scenarios under the criteria established.

Section 12: Economic Impact Assessment Summary. This section briefly outlines the results of the economic impact assessment chapter of the report in a brief, easy to understand format centred on the highest level economic outputs and a narrative style description of the exercise.

Chapter IV: Economic Policy Considerations

Section 13: Shale Gas Economics Literature Review. This section contains a thorough review of contemporary academic literature regarding the benefits and costs of shale gas industry development, and measures that can be taken to ensure sustainable economic development.

Section 14: Perspectives on Policy. This section uses domestic and international case studies and feedback from stakeholder consultation to articulate some of the key policy issues likely to emerge should a shale gas industry successfully develop in the Northern Territory. This section does not include ACIL Allen's perspective on measures the Northern Territory Government should adopt, as this is outside of our scope of works.

Appendices

Appendices Part One: Information relevant to the engagement that has not been included in the body of the report but which ACIL Allen believes is important to ensure transparency.

Appendices Part Two: Information regarding the structure and processes of ACIL Allen's economic and gas market models.

Glossary of terms and abbreviations

Throughout this report, ACIL Allen has used a number of technical terms related to both the economic and energy market modelling tasks it has completed. These terms are outlined below.

Term	Definition
"Fracking"	In this report, ACIL Allen will specifically define "fracking" as the process of hydraulically fracturing shale formations for the purposes of targeting hydrocarbons.
Employment	The number of full time equivalent job years created as a result of a project or expenditure in the economy, which includes direct and indirect (flow-on) employment.
Exchange rate	The exchange rate is expressed as the AUD/USD exchange rate unless otherwise stated and is denoted as A$ throughout the document.
Exports	The value of goods exported and amounts receivable from non-residents for the provision of services by residents.
Gross product or real economic output	*A measure of the size of an economy* Gross product is a measure of the output generated by an economy over a period of time (typically a year). It represents the total dollar value of all finalised goods and services produced over a specific time period and is considered as a measure of the size of the economy. At a national level, it is referred to as Gross Domestic Product (GDP); at the state level, Gross State Product (GSP); while at a regional level, Gross Regional Product (GRP).
Gross value added	*A measure of the value of goods and services produced in an industry or sector of an economy.* Gross Value Added (GVA) is the output of an industry or sector minus intermediate consumption. GVA therefore represents the value of all goods and services produced, minus the cost of all inputs and raw materials used to produce that good or service. Unlike Gross Product, GVA does not include the value of taxes minus subsidies.
Imports	The value of goods imported to a region and amounts payable to non-residents for the provision of services to residents.

Term	Definition
Job years	Real employment is measured in job years. A job year is employment of one full time equivalent (FTE) person for one year. Alternatively in can be expressed as one 0.5 FTE person for two years.
Millions, billions and trillions of standard cubic feet	In this report, ACIL Allen Consulting will make use of units of measurement for hydrocarbons in millions, billions and trillions of cubic feet (mmscf, BCF and TCF). These units of measurement are an order of magnitude apart: 1,000mmscf = 1 BCF 1,000BCF = 1 TCF These units of measurement are the industry standard for measurement of gas produced at the wellhead of a development. ACIL Allen Consulting will refer to "BCF" produced per well.
Net Real Income, Net Gross Territory Product and other "Net" Prefixes	The economic modelling outputs in this report are presented in "net" terms, unless otherwise stated. This is a representation of the aggregated economic impact on the particular variable, being the gross benefit of an investment less the crowding out effect on other sectors.
Net present value (NPV)	The value of a future stream of income (or expenses) converted into current terms by an assumed annual discount rate. The underlying premise is that receiving, say, $100 in 10 years is not 'worth' the same (i.e. is less desirable) than receiving $100 today. For the purposes of this study, NPV calculations have been made based on a discount rate of 10 per cent. The discount rate has been selected as a balance between a typical commercial financial discount rate (12-15 per cent) and a typical social discount rate (seven per cent).
Real and nominal dollars	Nominal dollars are dollars that are expressed in the actual dollars that are spent or earned in each year, including inflation effects. Real dollars have been adjusted to exclude any inflationary effects and therefore allow better comparison of economic impacts in different years. Over time, price inflation erodes the purchasing power of a dollar thereby making the comparison of a dollar of income in 2063 with a dollar of income in 2016 invalid. Adjusting nominal dollars into real dollars overcomes this problem. All values are expressed in real dollar terms with a base year of 2016, unless otherwise stated.
Real income	*A measure of the welfare of residents in an economy through their ability to purchase goods and services and to accumulate wealth* Although changes in real economic output are useful measures for estimating how much the output of the economy may change due to the Project, changes in real income are also important as they provide an indication of the change in economic welfare of the residents of a region through their ability to purchase goods and services. Real income measures the income available for final consumption and saving after adjusting for inflation. An increase in real income means that there has been a rise in the capacity for consumption as well as a rise in the ability to accumulate wealth in the form of financial and other assets. The change in real income from a development is a measure of the change in the economic welfare of residents within an economy.
State final demand	*A measure of the value of goods and services in an economy*

Term	Definition
	The aggregate obtained by summing government final consumption expenditure, household final consumption expenditure, private gross fixed capital formation and the gross fixed capital formation of public corporations and general government. It is conceptually equivalent to the Australia level aggregate domestic final demand.
Terajoules and petajoules	Terajoules and petajoules are a standardised unit of energy measurement, used in the energy and pipeline sectors. In this report, ACIL Allen will refer to energy production in terms of terajoules per day (TJ/day) and petajoules per annum (PJ/annum). One terajoule (TJ) = ~0.001 petajoules (PJ)
Working age population	All usual residents of Australia aged 15 years and over except members of the permanent defence forces, certain diplomatic personnel of overseas governments customarily excluded from census and estimated population counts, overseas residents in Australia, and members of non-Australian defence forces (and their dependants) stationed in Australia.

LIST OF ACRONYMS

Abbreviation	Full name
ABS	Australian Bureau of Statistics
AUD/ A$ or $	Australian dollars
BCF	Billions of cubic feet of gas
Billion	Billion measured by $1x10^9$ (or 1,000 million) as per the US convention
CAPEX	Capital expenditure
CGE	Computable general equilibrium (model)
CPI	Consumer Price Index
FIFO	Fly in-fly out work practice
FTE	Full time equivalent
GDP	Gross Domestic Product
GSP	Gross State Product
GST	Goods and services tax
GTP	Gross Territory Product
GVA	Gross Value Added
LNG	Liquefied natural gas
Million	Million measured by $1x10^6$ (or 1,000 thousand) as per the US convention
mmscf	Millions of cubic feet
NPV	Net present value
OPEX	Operational expenditure
PJ	Petajoules
PJ/day	Petajoules per day
PRRT	Petroleum Resources Rent Tax
TCF	Trillion cubic feet
TJ	Terajoules
TJ/day	Terajoules per day

Abbreviation	Full name
USD or US$	United States dollars
WPI	Wage Price Index

Stakeholder consultation

While our own independent research has helped form much of the inputs into our methodology, ACIL Allen also conducted an extensive program of stakeholder consultation in the first month of the engagement. ACIL Allen met with the following groups as part of its structured program of stakeholder consultation, and held follow up meetings with a range of stakeholders to gather additional information as the engagement progressed. Stakeholders were provided with a Consultation Guide prepared by ACIL Allen, and comprehensive verbatim notes of the consultation sessions were taken by ACIL Allen. A copy of the Consultation Guide has been included in Appendix B.

Stakeholders have been presented in alphabetical order.

TABLE 1.1 ACIL ALLEN STAKEHOLDER CONSULTATION

Stakeholder Organisation	Method of Meeting	Stakeholder Group
Australian Petroleum Production & Exploration Association	Face to face	Non-Government Organisation
Central Land Council	Teleconference	Traditional Owner representative
Lock the Gate Alliance & The Australia Institute	Face to face (Lock the Gate) and teleconference (The Australia Institute)	Non-Government Organisation
MS Contracting	Teleconference	Industry operators
Northern Land Council	Face to face	Traditional Owner representative
NT Cattlemen's Association	Face to face	Non-Government Organisation
NT Department of Business, Trade and Innovation	Face to face	Government
NT Department of Primary Industry and Resources	Face to face	Government
NT Department of Primary Industry and Resources (follow up)	Teleconference	Government
NT Farmers	Face to face	Non-Government Organisation
NT Treasury	Face to face	Government
NT Treasury (follow up)	Teleconference	Government
NT Treasury (second follow up)	Teleconference	Government
Origin Energy	Face to face and teleconference	Industry operators
Origin Energy (follow up)	Face to face	Industry operators
Pangaea Pty Ltd	Teleconference	Industry operators
Pangaea Pty Ltd (follow up)	Teleconference	Industry operators
Santos	Face to face	Industry operators
Santos (follow up)	Teleconference	Industry operators

In addition to the consultation sessions above, ACIL Allen received a variety of material from all stakeholders throughout the engagement, and drew on submissions made to the Inquiry by the full range of stakeholders.

I

PRELIMINARY INFORMATION

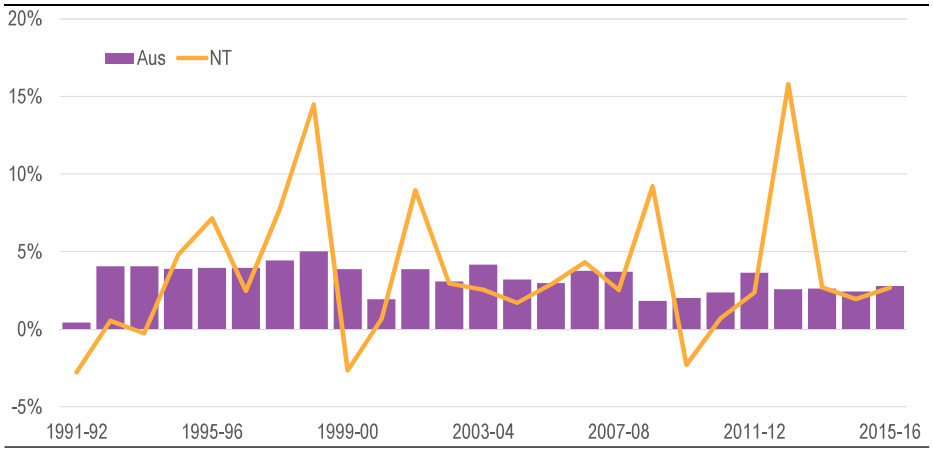
2 ECONOMIC CONTEXT

2.1 Economic trends

The Northern Territory economy is a regional economy, which generated $23 billion in Gross State Product (GSP) in 2015-16, accounting for 1.4 per cent of Australia's Gross Domestic Product (A$1.6 trillion). Northern Territory is an emerging economic centre, with average annual rates of growth in the economy exceeding five per cent per annum over the past five years (around double the rates of growth recorded in the national economy over the same period).

Economic growth in the Northern Territory is fairly volatile due to its small size and narrow economic base. As a result, major investments can have a disproportionately large impact on overall growth. The development of the Ichthys LNG Project has had a substantial impact on the Northern Territory economy, driving growth (as measured by Gross Territory Product) to a high of 15.8 per cent in 2012-13 as investment activity accelerated. While investment activity levels have remained at historically high levels, as the pace of growth in investment has slowed this has had a corresponding impact on the broader measures of growth in the Northern Territory.

FIGURE 2.1 REAL ECONOMIC GROWTH, NORTHERN TERRITORY AND AUSTRALIA, ANNUAL PERCENTAGE CHANGE

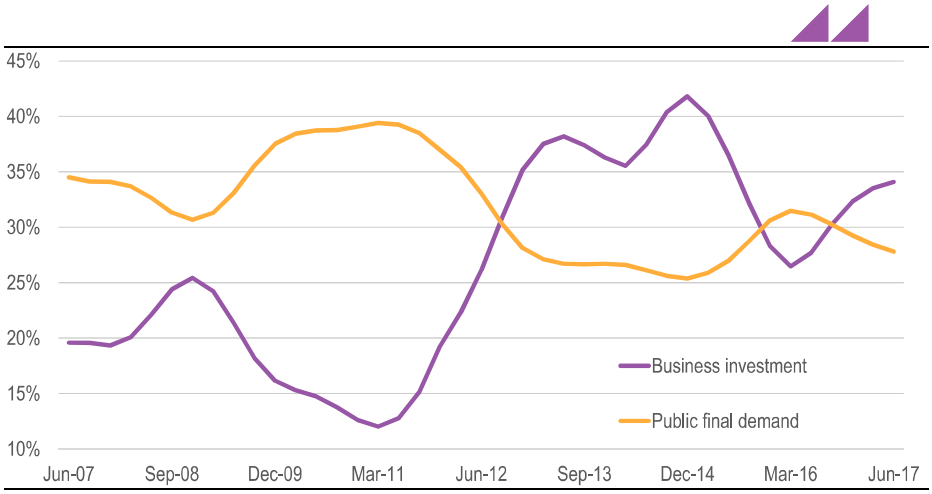


SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 5220.0

Business investment has driven overall levels of growth in the Northern Territory economy in recent years, due to the impact of the development of the Ichthys LNG Project. Business investment has averaged 31

per cent per annum on average since the commencement of the Project, and has accounted for 34 per cent of all domestic economic activity, as measured by State Final Demand. This has seen business investment overtake government spending and investment activity in the Territory (as measured by Public Final Demand) as the key driver of domestic economic growth (see Figure 2.2 below).

FIGURE 2.2 NT BUSINESS INVESTMENT AND PUBLIC FINAL DEMAND AS A SHARE OF TOTAL FINAL DEMAND



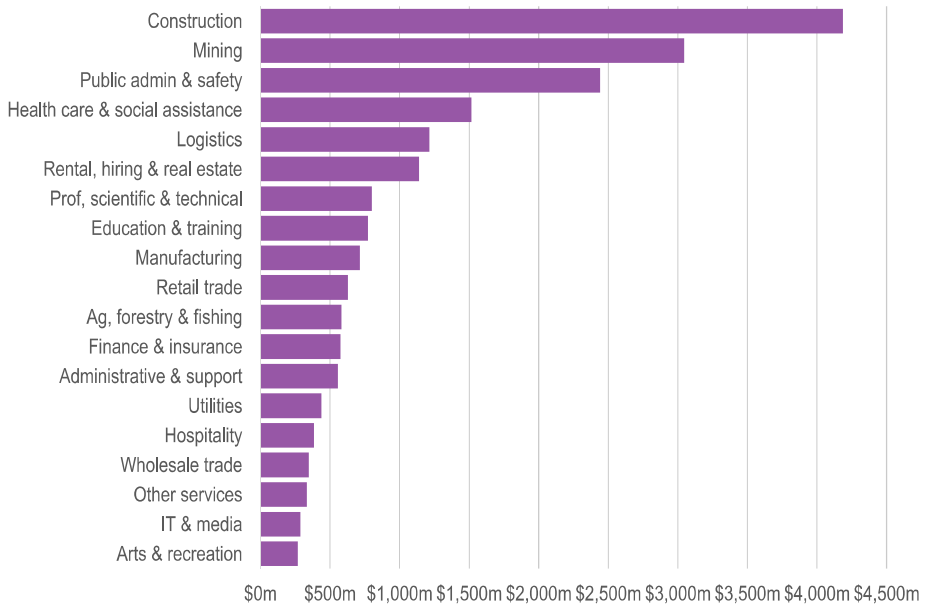
SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 5242.0

Historically, it has been government that has been the dominant sector of the Northern Territory economy, due in large part to the Commonwealth's large defence presence. However, in recent years significant development in the resources sector has seen it overtake the public sector as the driver of the Territory's economy. The substantial developments in the resources sector has in turn stimulated construction activity, which became the largest contributor to the Territory economy in 2015-16.

By value add, the largest industries in the Northern Territory in 2015-16 were Construction ($4.2 billion or 21 per cent of the economy), Mining ($3 billion or 15 per cent of the economy), and Public Administration and Safety ($2.4 billion or 12 per cent of the economy) (refer to Figure 2.3).

However, ACIL Allen estimates that as the Ichthys LNG Project transition from construction to production, this will see the Mining industry overtake the Construction industry to become the largest industry in the Northern Territory.

FIGURE 2.3 NT OUTPUT BY INDUSTRY, 2015-16, A$ MILLION

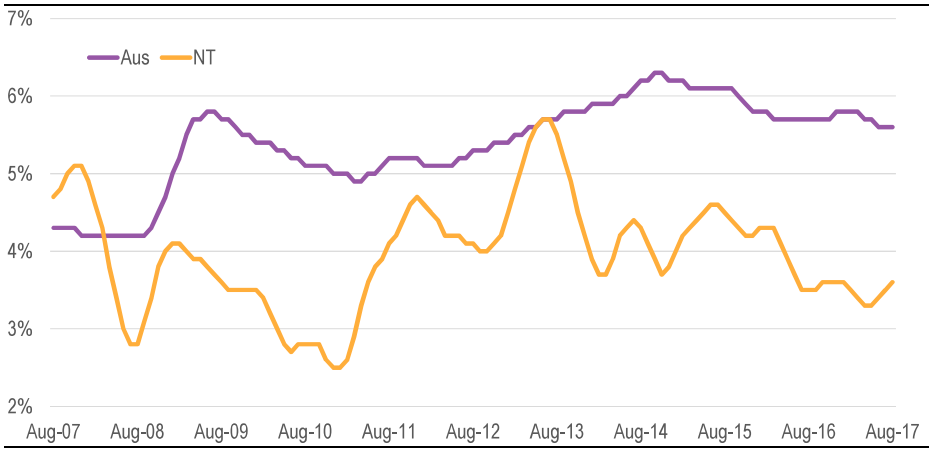


SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 5220.0

2.2 Labour market trends

The Northern Territory historically has had high levels of labour force utilisation. Overall levels of labour force participation have averaged 74 per cent over the past decade, which is well above the national average of 65 per cent. Employment opportunities have in turn meant that the average rates of unemployment are well below those recorded in another other part of Australia (refer to Figure 2.4 below).

FIGURE 2.4 UNEMPLOYMENT RATE, PERCENTAGE OF WORKFORCE UNEMPLOYED

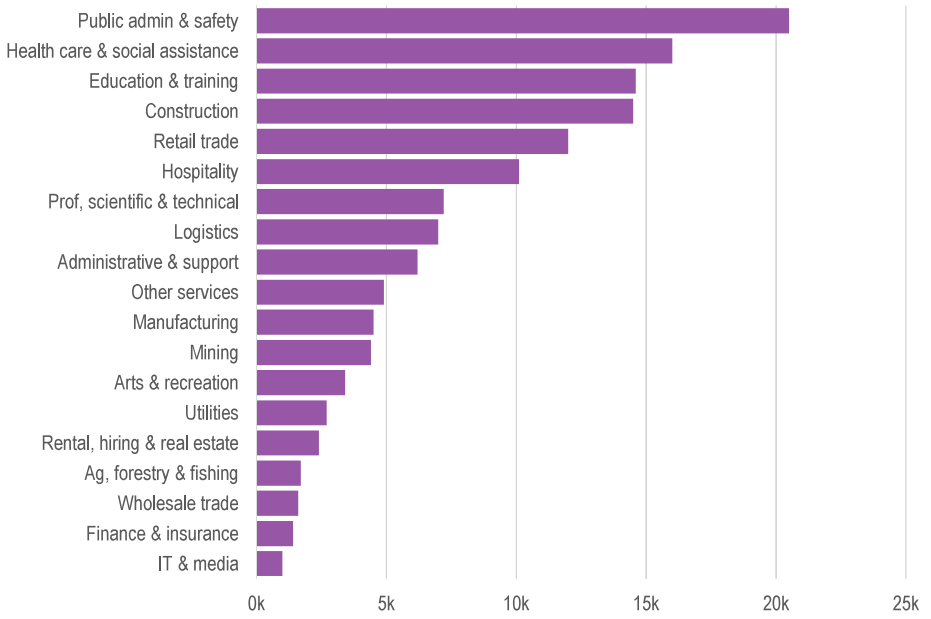


SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6202.0

Total employment in the Northern Territory was 132,200 in August 2017, which was just below the record high of 139,900 in February 2017. Over the five years to August 2017, total employment has increased by 5,600 or 4.4 per cent.

Employment trends in the Northern Territory have been largely driven jobs growth in government and in construction, which has increased its capacity in line with developments in the resources sector. Over the past five years, there has 5,100 new jobs created in government, with a further 2,900 new jobs created in construction. Against these trends, the largest decreases in employment have been seen in agriculture (4,700) and wholesale trade (1,700).

FIGURE 2.5 NT EMPLOYMENT BY INDUSTRY, JUNE 2017, THOUSANDS



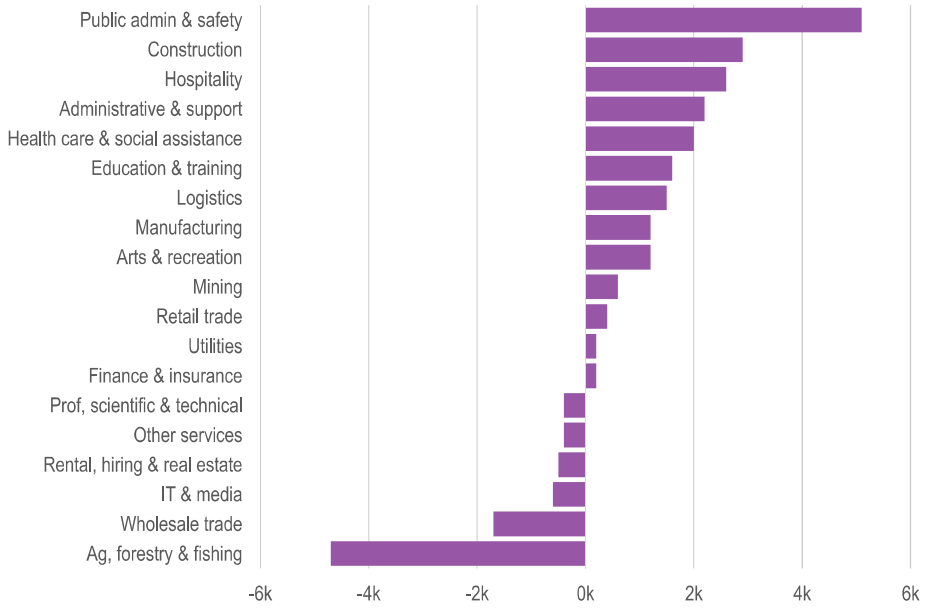
SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6202.0

Wage trends in the Northern Territory have typically followed broader wage trends across the national economy in recent years. Despite robust labour market conditions in the Territory, wages growth (as measured by the Wage Price Index (WPI)) has trended lower in recent years, due to the combination of the unwinding of the resources boom, structural factors such as lower levels of productivity, and the low inflation environment.

Over the year to June 2017, wages growth in the Territory averaged 2.1 per cent, which is well down on the most recent high of 4.2 per cent in December 2011 during the height of the resources boom. Across the public and private sectors, significant variances emerge, with public sector wages growing by three per cent over the year to June 2017, compared to just 1.7 per cent in the private sector.

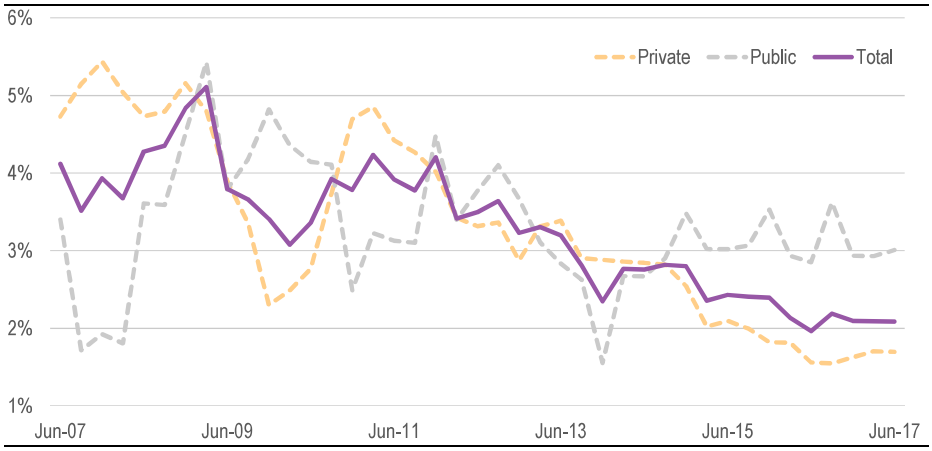
These trends are broadly consistent with the trends across the national economy, where the WPI rose by 1.9 per cent over the year to June 2017.

FIGURE 2.6 NT EMPLOYMENT BY INDUSTRY, CHANGE BETWEEN JUNE 2012 & JUNE 2017, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6202.0

FIGURE 2.7 NT WAGE PRICE INDEX, PUBLIC SECTOR, PRIVATE SECTOR AND TOTAL, ANNUAL PERCENTAGE CHANGE



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6345.0

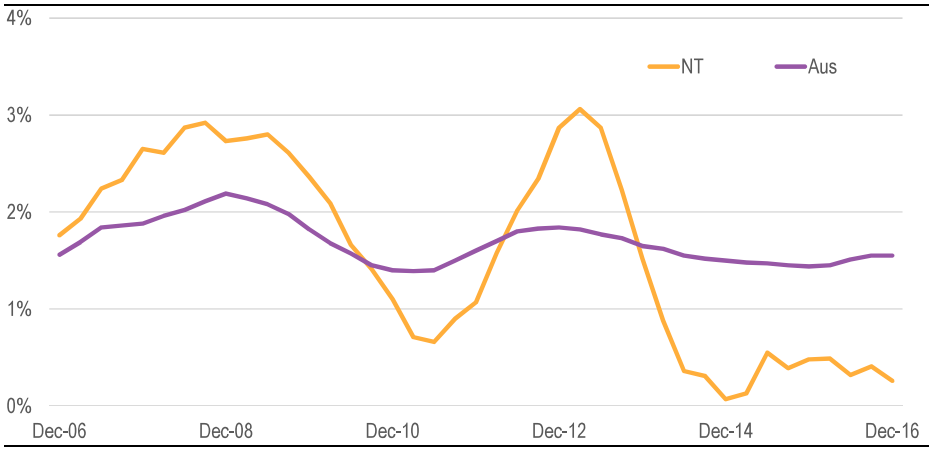
2.3 Population trends

In recent years, population growth in the Northern Territory has slowed significantly relative to the demographic trends in other parts of Australia. Over the 12 months to December 2016, the population of

the Northern Territory grew by just 0.3 per cent, which was the slowest rate of growth of any state or territory in Australia, and well down on the most recent high of 3.1 per cent in March 2013.

By contrast, population trends across Australia have been relatively stable, with the estimated resident population in Australia increasing by an annual rate 1.6 per cent by the end of 2016. The constancy of Australia's population trends reflects the relatively stronger rates of population in the larger states of New South Wales (annual growth 1.5 per cent by the end of 2016) and Victoria (annual growth of 2.4 per cent), offsetting the slowing rates of population growth in the resources states like Western Australia (annual growth of 0.7 per cent by the end of 2016), Queensland (1.5 per cent) and the Northern Territory.

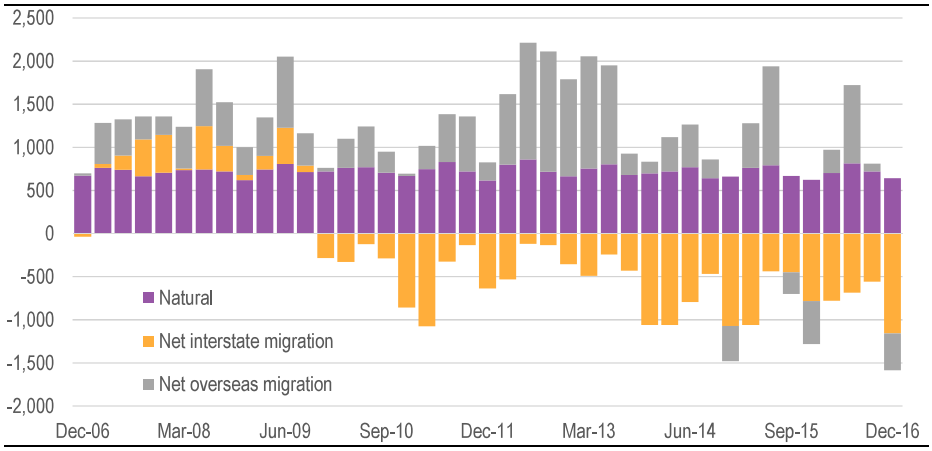
FIGURE 2.8 POPULATION GROWTH, ANNUAL PERCENTAGE CHANGE



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 3101.0

The end of the resources boom has had a pronounced impact on the population trends in the predominately mining states and territories in Australia. For the Northern Territory, this has seen the levels of overseas migration fall significantly (see Figure 2.9), as potential overseas migrants seek to settle in other parts of Australia where their job prospects are stronger.

FIGURE 2.9 COMPOSITION OF NT POPULATION GROWTH



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 3101.0

2.4 Northern Territory Government finances

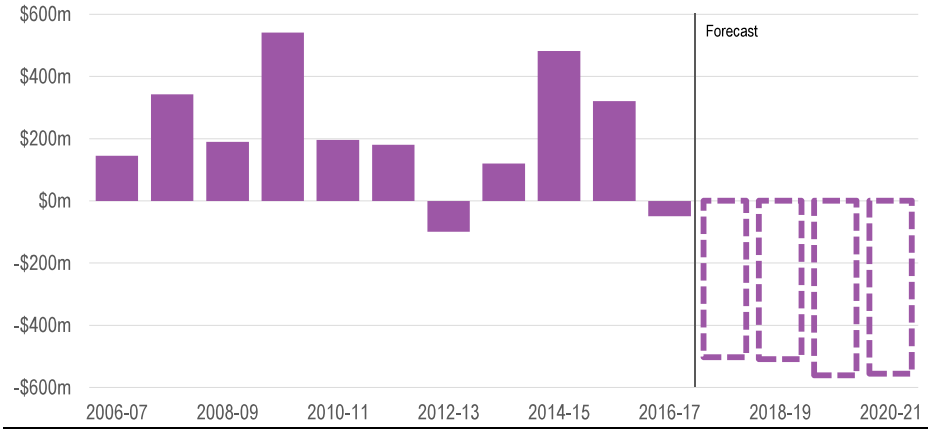
The Northern Territory's 2017-18 Budget, released on in May 2017, projects five consecutive net operating deficits for the Territory's General Government sector (the arm of government that provides most services to the community), with net debt rising from $2.4 billion to $5.5 billion between 2016-17 and 2020-21. The Northern Territory non-financial public sector raised $1.9 billion in revenue from its own sources in 2016-17, and recorded total operating expenditure of $6.5 billion.

The Goods and Services Tax, including redistribution effects, is the Northern Territory Government's largest source of revenue, accounting for 49 per cent of the Territory's revenue in 2016-17 (the last year of actual data). With a large land mass and low population density, the delivery of government services is a challenge in the Northern Territory. The Commonwealth Grants Commission's formula for distributing the GST assessed the Northern Territory Government requires between four and five times the hypothetical equal per capita distribution of GST revenue.[1]

Expenditure challenges are writ large across all elements of Northern Territory public finances. The high share of the Northern Territory's population that is Aboriginal or Torres Strait Islander, remoteness and regional costs, higher wage costs, and lack of administrative scale all result in the Commonwealth Grants Commission assessing the Territory as requiring significant assistance from the GST to help in the provision of services, vis-à-vis the other States and Territories. The Northern Territory has been a significant recipient State in the GST distribution system since its inception.

However, the Northern Territory's broader public finance challenges are a relatively recent phenomenon. This is because as a result of the release of the 2016 Census the Australian Bureau of Statistics believes the population of the Northern Territory is smaller than previously thought, while the Commonwealth Grants Commission believes the Northern Territory requires less GST per capita than previously thought to compensate it for structural spending challenges.[2] NT Treasury considers this is a structural shock to the Territory's finances.

FIGURE 2.10 NT GOVERNMENT NET OPERATING BALANCE, ACTUAL & FORECAST, $M



SOURCE: AUSTRALIAN BUREAU OF STATISTICS, CONSECUTIVE NT BUDGETS

2.5 Recent Australian energy market developments

Over time, the individual energy markets across Australia's eastern states have become joined up through a series of policy changes and asset investments. The system is referred to as the "National Electricity Market", or NEM for short. Broadly speaking, it encompasses the full supply chain from the extraction of

[1] Commonwealth Grants Commission. 2017. *2017-18 Update Report.* Accessed online at http://www.cgc.gov.au
[2] NT Treasury. 2017. *2017-18 State Budget, Northern Territory.* Accessed online at http://www.budget.nt.gov.au

hydrocarbons and other fossil fuels through to the consumption of electricity, gas and other fuels by domestic consumers and processing for export.

A series of significant developments in Australia's energy market have emerged in recent years, driven by rapid technological change, the pressing need for action to address climate change, and the development of new onshore and offshore hydrocarbon industries targeting both domestic and international sales of petroleum products.

Broadly speaking, these issues have manifested in significant uncertainty regarding the future direction of energy policy in Australia; higher wholesale gas prices, which feed through the entire NEM supply chain; and pressures to rapidly adjust to low emissions energy technologies.

The principal short term issue is an elevated level gas market uncertainty in eastern Australia. The long-anticipated transition of the east coast domestic gas market as a result of the development of six large export LNG trains at Gladstone has reached a critical point, with the last three trains having been commissioned between December 2015 and September 2016. The full extent of the dislocation in the domestic gas market caused by the LNG projects is now being felt as production ramps up and the market moves to a new equilibrium state.

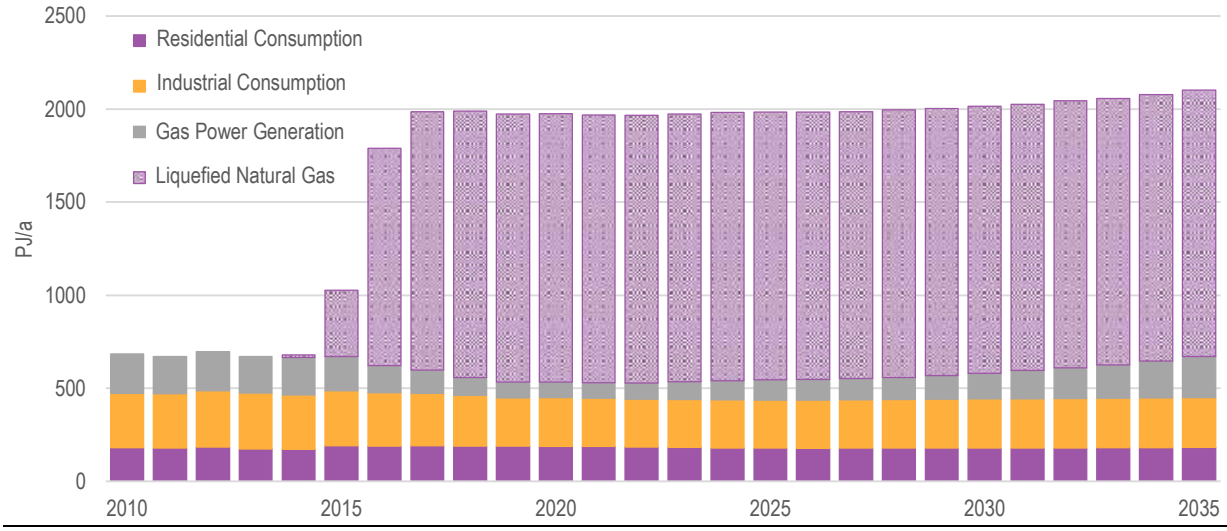
A number of other risk factors have become more prominent in recent times. A relatively severe winter in 2016 combined with constraints on the electricity interconnector between Victoria and South Australia resulted in high electricity and gas prices which caused distress for large industrial users and brought a renewed political focus on the idea of an electricity interconnector between South Australia and New South Wales.

2.5.1 Eastern Australia gas demand and the LNG export transformation

Over the past six years there has been an unprecedented transformation of the eastern Australia gas market, driven by large-scale export LNG developments and associated upstream coal seam gas (CSG) field production facilities in Queensland. Three separate LNG export projects, with a combined production capacity in excess of 25 million tonnes per year of LNG, were commissioned between late 2014 and late 2016. These facilities have a combined gross gas requirement of around 1,500 PJ/a—more than double the amount of gas currently used in the entire eastern Australia domestic gas market.

The Australian Energy Market Operator (AEMO) released its 2016 National Gas Forecasting Report (NGFR) in December 2016. Figure 2.11 shows historical and forecast levels of gas demand in eastern Australia (Queensland, New South Wales, Victoria, Tasmania and South Australia; the NGFR does not include Northern Territory) under AEMO's Neutral scenario. This shows a tripling of total gas demand in eastern Australia, driven by the rapid expansion of LNG production from the six LNG trains now operational at Gladstone in central Queensland.

FIGURE 2.11 HISTORICAL AND FORECAST GAS DEMAND IN EASTERN AUSTRALIA



SOURCE: ACIL ALLEN ANALYSIS OF DATA PRESENTED IN THE AEMO 2016 NATIONAL GAS FORECASTING REPORT, DECEMBER 2016

These LNG projects have had impacted on the domestic gas market by reducing the availability of gas to supply domestic markets; affected the price of domestic gas and the ways in which gas prices are determined; and affected levels of domestic gas consumption, particularly in the power generation sector.

Gas for power generation was, for a number of years, expected to be a driver of strong growth in demand for gas in eastern Australia. Gas-fired power generation was commonly seen as offering a cleaner energy transition pathway to a lower emissions future. However, in practice, the role of gas-fired generation in the eastern Australian market has evolved very differently.

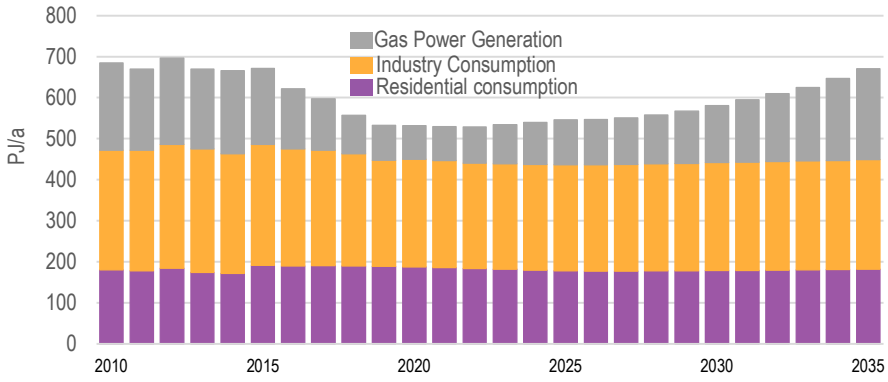
With large amounts of large-scale renewable energy (mostly wind) being added to the system to meet mandated renewable energy targets, and strong uptake of subsidised rooftop solar photovoltaic systems, the demand for centrally-generated electricity in the National Electricity Market has fallen and average wholesale electricity prices have been suppressed. In these circumstances, and with tight gas supply and rising gas prices, a number of large gas-fired generators have been mothballed or de-rated. This has allowed them to profit by using their contractual gas entitlements to sell gas to LNG and/or other domestic gas buyers, rather than using it to generate electricity. The Tamar Valley (Tasmania)[3] and Swanbank E (Queensland) combined cycle gas turbine (CCGT) generators have been mothballed, and the Pelican Point CCGT in Adelaide has cut back its operations and on-sold much of its gas entitlements[4].

The overall result has been to drive a significant reduction in recent and projected gas demand in the eastern Australian domestic market. This is shown in Figure 2.12. Overall domestic demand is expected to decline from 700 PJ per annum in 2012 to around 530 PJ per annum by 2019. Most of the decline will occur in the gas-fired power generation sector, with gas use by large industrial consumers also expected to fall. In the retail residential and commercial sectors consumption is expected to remain relatively flat, with increasing customer numbers (driven by demographic growth) offset by declining average consumption per customer (as a result of improved appliance efficiency, better building standards and increased penetration of electric reverse-cycle air-conditioning).

[3] Tamar Valley was temporarily returned to service in 2016 in response to an extended outage on the Basslink electricity interconnector between Victoria and Tasmania.
[4] In March 2017, the owner of Pelican Point (Engie) announced that it would recommission its second turbine by July 2017, returning the station to full capacity. This decision followed a deal in which Origin Energy agreed to provide gas to Pelican Point and to enter into an offtake agreement covering 240 MW of capacity from the station. The deal follows critical power shortages and blackouts in South Australia in late 2016 and early 2017, and is designed to improve the security of the grid in South Australia following closure of coal-powered generation at Port Augusta.

The steep decline in gas-fired power generation reflects a number of factors: abnormally high levels of gas-fired generation in the recent past (particularly in 2013 and 2014) driven by readily-available and low cost gas from the ramp-up of coal seam gas (CSG) production in Queensland; rising gas prices resulting in lower levels of economic dispatch of gas-fired generators; and increased penetration of renewable generation sources displacing marginal gas-fired generation.

FIGURE 2.12 HISTORICAL AND FORECAST DOMESTIC GAS DEMAND IN EASTERN AUSTRALIA



SOURCE: ACIL ALLEN ANALYSIS OF DATA PRESENTED IN THE AEMO 2016 NATIONAL GAS FORECASTING REPORT, DECEMBER 2016

Implications for eastern Australia gas supply

The structural transformation of the eastern Australia gas market brought about by the establishment of the Queensland LNG industry has seen a large increase in the demand for east coast natural gas with a consequent tightening of supply to domestic gas buyers. At the same time, the LNG developments have seen the rapid expansion of gas production from CSG fields in Queensland. The LNG export developments have been the primary driver for this increased production, although some of this gas has been (and continues to be) supplied to the domestic gas market.

It is nevertheless the case that a large part of the gas production capacity in eastern Australia has been committed, on a long-term basis, to support LNG production activities. The affected production sources include not only the Queensland CSG projects controlled by the LNG proponents who have prioritised delivery to the LNG facilities over domestic market sales. It has also seen the commitment of large volumes of third-party gas supply, under long-term contract arrangements, to supply additional gas to the LNG projects. There is anecdotal evidence that, for at least some of the Queensland CSG fields intended to support LNG production, production performance has been below design expectations and the costs of production higher than anticipated. As a result, LNG project proponents have turned to third-party producers—traditionally suppliers to the domestic market—to seek incremental gas supply.

While the LNG projects have increased demand for gas in eastern Australia, they have also led to development of large tracts of gas, and has increased the number of potential suppliers to the domestic gas market. These newly developed sources of gas could, depending on market conditions, supply the domestic gas market. Indeed, data published by AEMO on the Natural Gas Services Bulletin Board confirms that, during the severe southern winter in July 2016, QCLNG diverted some gas supply from its Gladstone operations into the southern states domestic market.

2.5.2 Northern Gas Pipeline

Jemena is currently constructing the Northern Gas Pipeline (NGP) between Tennant Creek in the Northern Territory and Mount Isa in north-west Queensland. The NGP is designed to allow gas from the Northern Territory to be delivered into the Eastern Australian market from late 2018. To the extent that the project succeeds in allowing substantial quantities of competitively priced gas from the Northern Territory

to enter the East Coast market, the project represents a competitive threat to other sources of gas supply in eastern Australia.

Jemena took delivery of the first batch of pipe for the NGP in October 2016 and has commenced construction. However the size of the project has been scaled back, reflecting a lack of customer commitment. The diameter of the pipeline has been reduced to 12" (from the 14" diameter pipe originally planned), with a corresponding reduction in throughput capacity from 120 TJ/d to 90 TJ/d.

Given the current scarcity of gas available for commitment into new long-term contracts in the east coast market, this lack of customer support strongly suggests that the issue facing the NGP project relates to a lack of proven gas reserves available to support firm gas sales agreements, rather than a lack of demand from end-user customers. Apart from the gas being sold into the project by the Northern Territory government from its Blacktip entitlements, no other gas supply has yet been committed to the project. The Blacktip gas has effectively been committed to the Mount Isa market in Queensland (which has an annual gas requirement comparable to the annualised throughput capacity of the NGP in its current configuration).

Under current policy settings, NGP does not appear likely to deliver large quantities of competitively priced gas into the east coast market.

2.5.3 Australian Domestic Gas Security Mechanism

In response to the current tight gas supply situation, sharply rising prices and forecasts of potential supply shortages, the Australian Government has moved to bolster domestic gas supply by introducing the Australian Domestic Gas Security Mechanism (ADGSM) which will rely on the Australian Government's constitutional powers in relation to export controls. The ADGSM has been described by the government as a 'targeted, temporary measure … to repair markets and allow Australian users to compete on a level playing field'. The objective of the policy is to ensure that there is a secure supply of gas to meet the forecast needs of Australian gas consumers by requiring, if necessary, LNG producers that are drawing gas from the domestic market to limit their exports or to find offsetting sources of new gas.

The ADGSM came into effect on 1 July 2017. Operational details are set out in Guidelines dated 30 June 2017. In summary the ADGSM will operate as follows:

1. Export controls may be triggered on an annual basis if the Minister determines that there is likely to be shortage of domestic gas supply in the next year, and that LNG exports are likely to contribute to that shortfall.
2. If such a trigger occurs, LNG exporters would provide information to determine if they are 'net-deficit' projects that are withdrawing more gas from the domestic market than they are contributing to it. LNG exporters assessed as being 'no effect' or 'net suppliers to the domestic market' will not face any export restrictions.
3. The extent of any export restrictions will depend on the 'Total Market Security Obligation' (TMSO) determined by the Minister and the proportion of the gas shortfall attributable to net-deficit LNG projects.
4. 'Net deficit' exporters will be required to contribute to the achievement of the TMSO on a pro-rata basis according to the extent of their market deficits. This will be done by restricting Export Permissions for these exporters.
5. Each 'net deficit' exporter will be required to meet its individual Exporter Market Security Obligation either by restricting exports, or by increasing domestic production.

The Guidelines restrict the scope of 'domestic suppliers' by excluding suppliers that developed gas for the primary purpose of export. The tests also involve the concept of 'own gas', with a source of gas to the LNG plants being considered 'own gas' rather than gas obtained from domestic suppliers if it is owned by an LNG joint venture, or by one of the joint venture partners who developed and contracted the gas for LNG export sale. These provisions will reduce significantly the amount of gas deemed to be diverted from domestic markets by the LNG project.

Assessment

On the basis of what is set out in the Guidelines it appears that the only party likely to be caught under the ADGSM arrangements is the Santos-operated Gladstone LNG project, which is heavily reliant on third

party gas. However, depending on how the definitions of 'third party gas' and 'own gas' are interpreted, even GLNG's obligations may be relatively limited. We are aware of several 'third party' sales contracts under which GLNG has access to gas supply totalling between 475 and 635 TJ/day. However, a number of these contracts are likely to meet the test for 'own gas' and/or 'export compatible third party gas'.

GLNG is likely to be the only liable party, and its net deficit is likely to be relatively small for the reasons mentioned above. Even if the Minister declares a domestic shortage and imposes an Export Market Security Obligation on GLNG, questions remain regarding the price at which that gas would be offered to the market, how it would be sold, and what would happen to any gas offered for sale but not taken up. The Guidelines are largely silent on the matter of the price or terms upon which any gas withheld from export under the ADGSM would be offered for sale to domestic consumers.

On balance, we think that the ADGSM is unlikely to result in any large quantities of additional gas being supplied into the domestic market, nor is it likely to result in significant downward pressure on domestic gas prices.

2.5.4 Regulatory reform: the Vertigan Inquiry

In June 2017 the Gas Market Reform Group, chaired by Dr Michael Vertigan AC, published a final design recommendation for a 'Gas Pipeline Information Disclosure and Arbitration Framework'.

The overarching objective of the new information disclosure and arbitration framework is to facilitate access on reasonable terms to services provided by 'non-scheme' (that is, currently unregulated) pipelines, including SEA Gas.

The information disclosure requirements and arbitration processes proposed by Vertigan are set out in changes to the *National Gas Law* that recently passing through the South Australian parliament.

The arbitration process covers disputes on any matter (including price or other terms and conditions). It may be triggered by either the prospective shipper or the pipeline operator. While the arbitration mechanism is a key element of the new framework, it is intended that commercial negotiation will continue as the principal means by which access terms and conditions are determined and that the arbitration mechanism will rarely be triggered. That is, it is intended that the threat of arbitration will be sufficient to encourage the parties to reach a commercial agreement.

The arbitration design involves a three stage process:

Stage 1: Shipper considers whether to seek access having regard to basic information published by pipeline operator

Stage 2: Shipper requests access and enters into commercial negotiations with pipeline operator. Negotiations informed by further information exchanges

Stage 3: If negotiations fail, either party may seek arbitration. Arbitrator to make decision having regard to the arbitration principles

Under the new framework, existing and prospective new shippers may be less inclined to agree to commercially negotiated terms for pipeline services and more inclined to have recourse to arbitration. This is because, while the arbitration process is said to be 'binding', the shipper is not in fact bound to enter into a gas transport services agreement on the terms set out in the arbitrator's decision. The shipper can elect (within 30 days) not to proceed in which case it is still able to continue to negotiate for transport. Under this scenario, the only downside from the shipper's perspective is that it foregoes the right to trigger a new arbitration process (for a similar service) for 12 months. In effect, the prospective shipper has a free option to see if it can get a better outcome under arbitration than it would achieve by accepting commercially negotiated terms.

2.5.5 The Finkel Review

The Independent Review into the Future Security of the National Electricity Market (the 'Finkel Review', named after the Review's Chair Dr Alan Finkel) was commissioned by the Council of Australian Governments (COAG), in order to address the security and reliability challenges faced by the National Electricity Market in the context of transitioning policy imperatives and emerging and evolving technologies.

The report primarily addresses key issues in the National Electricity Market – such as the balance of security and reliability, affordability and reduced emissions, as well as new technology integration and rising gas prices rendering stations unviable – and provides guidance on measures to address current and future challenges.

Finkel believed energy policy in Australia should be calibrated to deliver four central objectives:

- increased security
- future reliability
- rewarding consumers, and
- lower emissions

The principal recommendation of the review is that technological change is occurring rapidly in the energy sector, and the way forward is to provide certainty to both the energy sector and Australians more broadly as to how Australia will meet its international emissions reduction commitments. In this respect, security references the National Electricity Market's ability to respond to disturbances, which with the inclusion of variable renewable energy generation will require more attention than with more traditional, fossil fuel methods of electricity generation.

Underpinning these are three pillars promoting an "orderly transition" to the future energy mix, better system planning and stronger governance. An orderly transition is upheld by the recommendation of a Clean Energy Target, and the recommendation for a mandatory three years' notice prior to closure of a generator. Improved system planning seeks a system wide grid plan that informs investment decisions and improved reporting and analysis in regards to reliability and security. Stronger governance is recommended to be delivered through a new energy security board, and strengthened market bodies.

The Finkel Review outlines a blueprint of recommendations for the transition that makes special mention of the increased requirement for flexible, gas-fired generation to support the variable renewable energy generation. Finkel also noted that in the short to medium term tightening gas supply, and therefore rising prices, threaten the economics of such generators.

Despite the clear findings and roadmap provided by the Finkel Review, there remains significant uncertainty regarding the direction of energy policy in Australia.

2.6 The Northern Territory's gas industry and energy markets

The Department of Industry, Science and Innovation suggest the Northern Territory consumed 46.2PJ of natural gas in 2014-15, making it the largest source of energy for the Territory.[5] This gas is used to produce electricity and to fuel industry, as well as being used in the processing of Liquefied Natural Gas (LNG) that is exported through the Darwin LNG Plant (which does not show up in the Department's statistics as it is not consumed in the NT).

The majority of the Territory's gas is provided by three fields: ENI's Blacktip Gas Field, in the Bonaparte Basin off the north west coast of the Northern Territory[6] (predominantly for domestic consumption), ConocoPhillips' Bayu-Undan field in the Australia-Timor-Leste Joint Petroleum Development Area[7] (predominantly for LNG exports) and from fields in the Amadeus Basin to the east of Alice Springs, with the Mereenie Oil and Gas Field the major producing play[8]. The Ichthys LNG project, owned and operated by Japanese energy company INPEX, produces LNG at a facility in the Port of Darwin, but extracts gas from the Browse Basin off the north west coast of Western Australia.

The major players in the Northern Territory energy market are NT Power and Water Corporation ('PowerWater'), the State-owned transmission and network company, and Territory Generation, the wholesale provider of electricity. The two entities were formerly one vertically integrated entity but were structurally separated in 2014 as part of a broader program of electricity market reform.[9] PowerWater and Territory Generation represent a significant share of the residential and small scale commercial/industrial

[5] Department of Industry, Science and Innovation, 2016. *Australian Energy Statistics 2016, Table D*. Accessed online at http://www.industry.gov.au
[6] ENI Australia. 2016. *ENI in Australia*. Accessed online at http://www.eni.com/
[7] ConocoPhillips. 2017. *Our Business Activities – Bayu-Undan*. Accessed online at http://www.conocophilips.com.au/
[8] Central Petroleum. 2017. *Mereenie Oil and Gas Field*. Accessed online at http://www.centralpetroleum.com.au/
[9] Territory Generation. 2017. *Territory Generation: About Us*. Accessed online at http://www.territorygeneration.com.au

energy markets in the Territory. The Territory has a contestable market for residential and small scale commercial users.

3 UNCONVENTIONAL GAS AND HYDRAULIC FRACTURING

3.1 What is Hydraulic Fracturing?

There are two broad types of gas reserves: conventional and unconventional. Conventional gas reserves accumulate in confined areas with well-connected pore spaces in a sedimentary basin. This allows for effective drainage of reserves with well-placed vertical wells. By contrast, unconventional gas reserves accumulate in a larger area amongst more tightly bound and less porous sedimentary basins, which are typically lower in the ground. A visual representation of conventional and unconventional gas accumulations and some of the extraction techniques is provided in Figure 3.1 (overleaf).

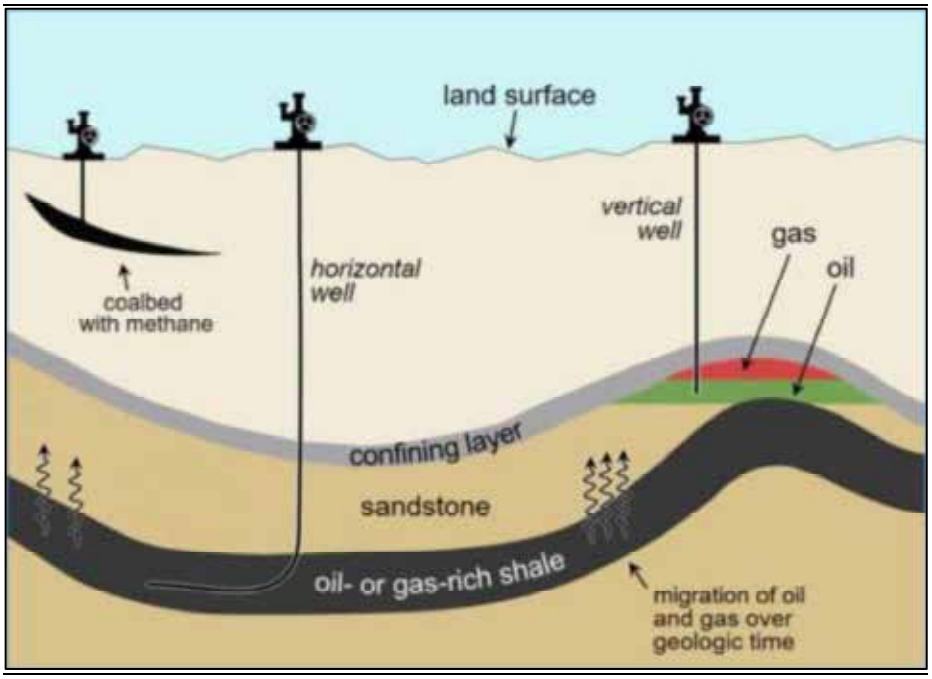
Artificial stimulation is typically required to make the gas in unconventional reservoirs flow through a well. One commonly used technique to achieve this is called hydraulic fracturing, commonly known as 'fracking'. Fracking basically involves pumping a mixture of water, sand and chemical additives ('fracking fluid') into the production well, under pressure, so that the rocks containing the gas resources crack. This allows the gas contained in the tight reservoir to flow more freely.

3.1.1 Shale gas versus coal seam gas (CSG)

Fracking is used to extract both coal seam gas (CSG) and shale gas. The two types of resources differ significantly.

- CSG is typically extracted from wells that are much closer to the land surface (300m – 1,000m) than shale wells (1,500m – 4,000m)
- CSG is typically much closer to the surface, and therefore closer to potable water sources such as aquifers. Shale gas is not typically located near aquifers
- CSG is most often extracted using vertical wells, while shale gas is extracted using a combination of vertical and horizontal drilling techniques
- CSG wells are typically low productivity and require a larger number of wells, where shale gas wells produce more energy per well. However, shale wells use more water per well, and operate across a larger underground footprint.
- The land surface area of CSG wells and shale gas wells is largely the same.

FIGURE 3.1 DIFFERENT TYPES OF PETROLEUM ACCUMULATIONS AND DEVELOPMENT



SOURCE: THE INQUIRY, VIA U.S. ENVIRONMENTAL PROTECTION AGENCY.

3.1.2 The fracking process

Shale gas is mainly methane (often with associated liquid hydrocarbons) that is trapped within clay-rich sedimentary rock at depths greater than 1,500 metres. The low permeability of the rock means that gas, either absorbed or in a free state, in the pores of the rock, is unable to flow easily.

To extract shale gas, wells are drilled anywhere from 1,500 – 4,000 metres deep through various layers of rock to access the shale. The wells are lined with various steel casings, which are cemented using fit-for-purpose cement designed to protect groundwater from contamination.

To maximise shale gas recovery a technique called horizontal drilling is used. This technique typically involves the well changing from a vertical to a horizontal direction deep underground.

Before gas can be extracted from the shale gas reservoir, hydraulic fracturing must occur. Hydraulic fracturing is a technique used to enhance the production of the gas. Hydraulic fracturing refers to the injection of fluid (comprising approximately 99.5% water and proppant (sand) and approximately 0.5% chemical additives) at high pressure into targeted sections of the layers of gas-bearing rocks. This creates localised networks of fractures that unlock gas and allow it to flow into the well and up to the surface. An average of 20 to 30 megalitres (ML) of water is used per fracked horizontal well over the life of the well.

After fracturing, the hydraulic pressure is released and most of the 'frack fluid' is pumped back out of the well. Typically gas production from the well builds up over a period of days or weeks as the frack fluid is recovered (a process known as 'well clean-up'). Much of the sand remains in the well, propping open the cracks so that gas flow is maintained (hence 'proppant').

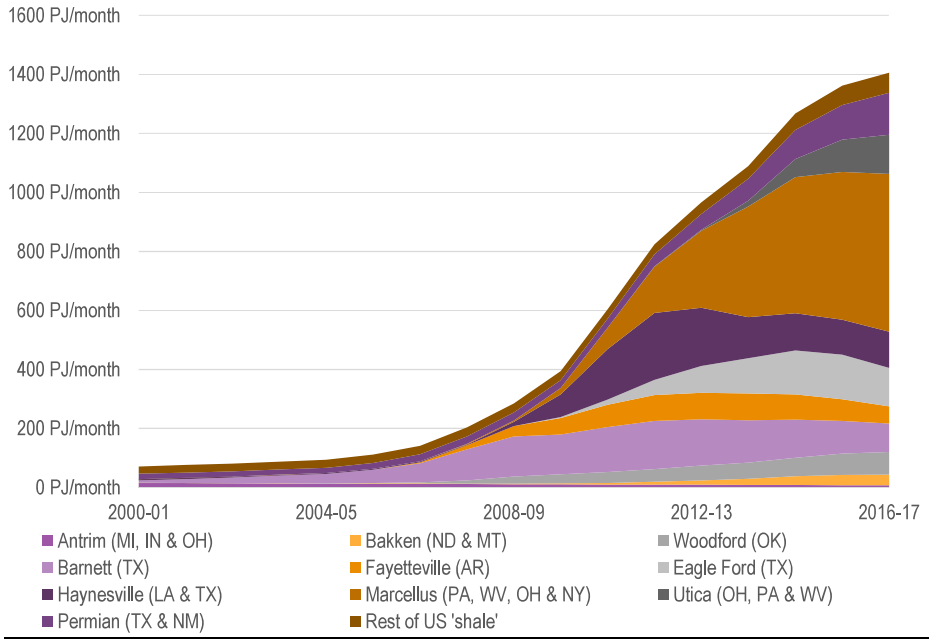
3.2 The "Shale Revolution"

Fracking is not a particularly new or novel technique for accessing petroleum deposits. However, rapid technological improvements and a period of very high natural gas prices in the United States led to a

significant wave of exploration and investment targeting shale gas with horizontal drilling techniques. The result has been a so-called "shale revolution", which has put significant downward pressure on energy prices in the United States and across the world.[10]

Production of petroleum products from US shales has grown exponentially between 2007 and 2017, and the shale gas industry deepens and continues to learn the most economic ways to target and extract oil and gas from shales. According to the US Energy Information Administration, the volume of dry shale gas produced in the United States has increased 15-fold between 2005-06 and 2016-17, from an average of 110.8 PJ per month to 1405.3 PJ per month (Figure 3.2).[11]

FIGURE 3.2 DRY SHALE GAS PRODUCTION, UNITED STATES, BY MAJOR PLAY, PJ/MONTH (12 MONTH AVERAGE)



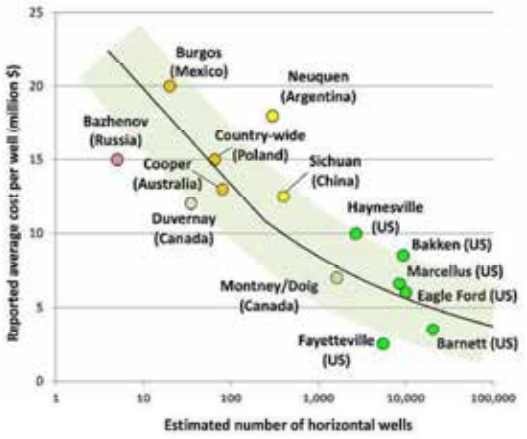
SOURCE: ACIL ALLEN CONSULTING, US EIA

US producers have been able to extract more gas per well each year for the past 10 years, as technology advancements like longer horizontal drilling, improved fracturing techniques, and increased knowledge of the geology of formations have led to surging productivity. These conspire to reduce the average cost of establishing a single petroleum well, which is the single largest influence on the wellhead cost of gas produced.[12] More than anything though, there is a strong negative relationship between the total number of wells drilled in a shale gas play and the overall average cost per well drilled in said play (that is, the more wells drilled the lower the marginal cost of establishing a well).

This "learning effect", where the incremental cost of delivering a unit of gas has been shown to fall substantially over time, has been the catalyst behind the shale revolution, and the ability for the shale industry in the United States to deliver gas at increasingly lower prices (Figure 3.3).

[10] European Commission. 2017. *Shale gas production costs: historical developments and outlook*. Accessed online at http://www.insightenergy.org/
[11] US Energy Information Administration. 2017. *US dry shale gas production, monthly data.* Accessed online at http://www.eia.gov
[12] ACOLA. 2013. *Engineering Energy: Unconventional Gas Production in Australia, A study of shale gas in Australia*. Accessed online at http://www.acola.org.au/

FIGURE 3.3 THE INTERNATIONAL SHALE LEARNING CURVE



SOURCE: US EIA

3.3 Shale gas in the Northern Territory

Given the significant uncertainty regarding the shale gas potential of the Northern Territory, ACIL Allen Consulting has prepared this brief summation based on information presented by the Inquiry in its Interim Report, released in July 2017.

There are a range of estimates available regarding the shale gas potential of the Northern Territory. Geoscience Australia believes there is 257,276 PJ of potential gas resource trapped in shale formations across the Territory – the vast majority of this concentrated in the Beetaloo Sub-Basin of the McArthur Basin, in northern central Northern Territory. The US Energy Information Administration's 2015 *Technically Recoverable Shale Oil and Shale Gas Resources* report for Australia estimated approximately 262 TCF of shale gas was in situ in the Northern Territory's two most explored basins, Beetaloo and Georgina.[13]

Additional resource is thought to exist to the south (the Amadeus Basin, which is currently subject to conventional gas production), north west (an onshore portion of the predominately offshore Bonaparte Basin), south east (the Georgina Basin) and south-south east (the Pedrika Basin). However, the majority of the effort of potential industry operators has been spent better understanding the geology and petroleum potential of the Beetaloo Sub-Basin.

A map of the Northern Territory's known and approximated source rocks for hydrocarbons is presented in Figure 3.4 (page 27).

According to the Department of Primary Industry and Resources,[14] there have been eight hydraulically fractured wells targeting unconventional shale gas in the Northern Territory. Four such wells have been drilled in the Georgina Basin, and four in the Beetaloo Sub-Basin.

The most significant well drilled to date is Origin Energy's ('Origin') Amungee NW-1H well, which completed a 57 day production test prior to the moratorium taking effect.[15] The well was a 1,100m long horizontal fracture stimulated well with 11 fracture stages, targeting the so-called "Velkerri B shale" layer within the basin. Origin reported a positive production test, and in conjunction with additional geological data gathered over its exploration program to date lodged a notice with the Petroleum Resource Management System (PRMS) that identified a "Contingent Resource" of 6.6 TCF of technically

[13] US EIA. 2015. *Technically Recoverable Shale Oil and Shale Gas Resources: Australia*.
[14] Scientific Inquiry. 2017. *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Interim Report, July 2017*. Accessed online at http://www.frackinginquiry.nt.gov.au/
[15] Origin Energy. 2017. *Notice to market: Beetaloo Basin drilling results indicate material gas resource, 15 February 2017.* Accessed online at http://www.asx.com.au/

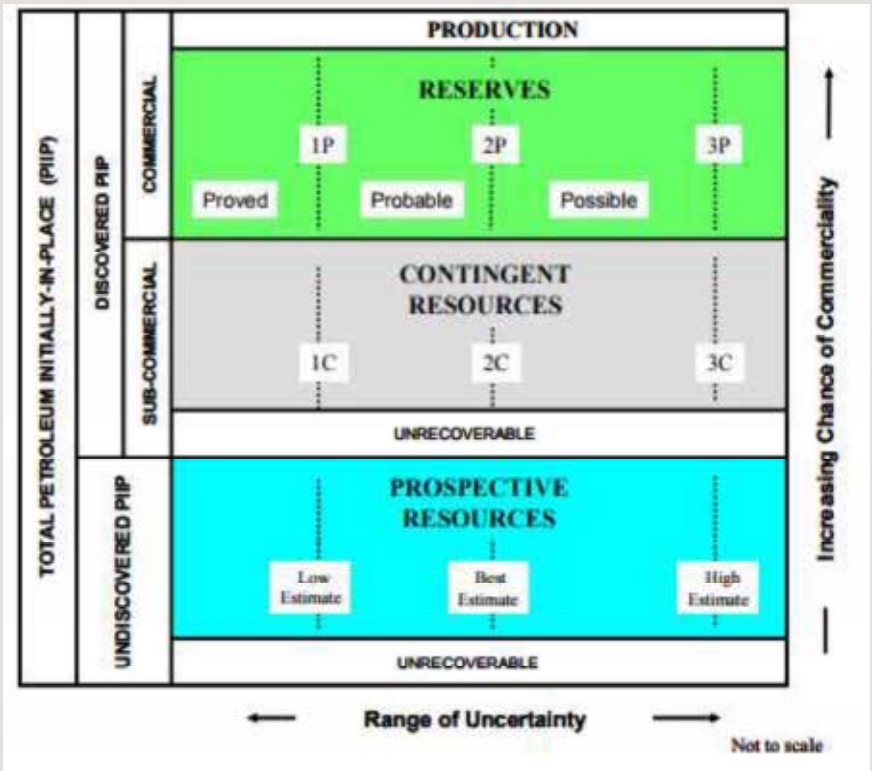
recoverable gas (the PRMS system is outlined briefly in Box 3.1). A 6.6 TCF discovery is significant; it is 50 per cent larger than the "Pluto" onshore LNG project in Western Australia, which cost an estimated $15 billion to develop (including liquefaction facilities).

BOX 3.1 THE PETROLEUM RESOURCE MANAGEMENT SYSTEM

The Petroleum Resource Management System is the system used to classify the commerciality of conventional and unconventional hydrocarbon discoveries in a clear, consistent and transparent manner as it relates to companies listed on the Australian Stock Exchange. All publicly listed Australian companies are required to report on the outcomes of their exploration activities using this framework.

It is a framework that allows companies to determine the quantity of petroleum thought to be in place in a particular area using probabilistic modelling and an assessment of commerciality contingent on the ability to deliver the petroleum to market.

Petroleum deposits effectively move through a codified lifecycle, starting out as prospective resources, progressing to contingent resources – which are deposits with confirmed petroleum in place, but with questions over the commerciality of the deposit – and finally to commercial reserves and eventual production. This framework, prepared by the Society of Petroleum Engineers, is reproduced below.



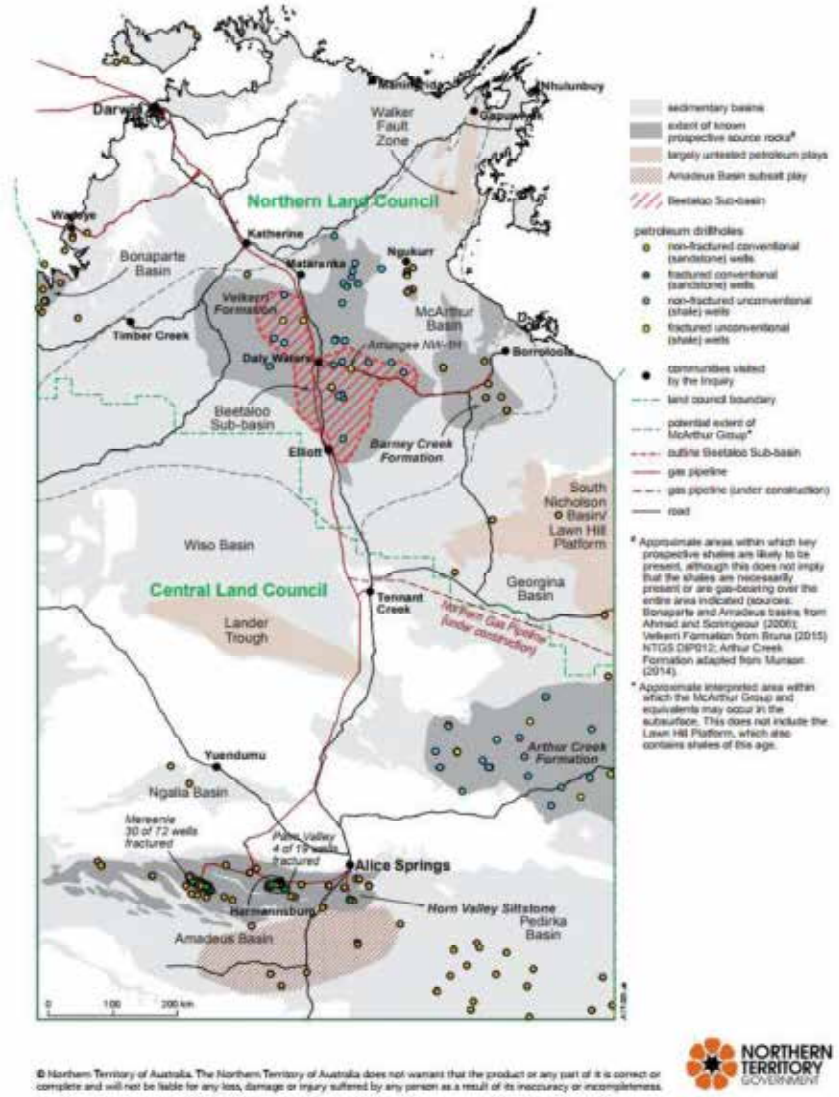
SOURCE:SOCIETY OF PETROLEUM ENGINEERS PETROLEUM RESOURCE MANAGEMENT SYSTEM

Origin Energy's discovery in the Beetaloo Sub-Basin has been assessed by Origin as a 2C grade contingent resource. In lay terms, this means Origin is fairly certain there is commercial scale petroleum in place, but requires further testing to confirm this, and still has significant commercial hurdles to overcome to progress to determination of a commercial reserve.

Origin's contingent resource is the only material discovery made so far. While the Northern Territory is thought to have significant shale gas, it is a mostly unknown proposition and requires significant further exploration, testing and appraisal to ascertain a more defined estimate of its potential. There are three

lead industry proponents seeking to undertake exploration and appraisal of shale gas deposits in the Beetaloo Sub-Basin and beyond. These are Origin Energy Ltd (an ASX-listed energy company), Pangaea Resources Pty Ltd (a privately held exploration company) and Santos Ltd (an ASX-listed energy company). These three companies are the lead operators in the region, with a range of other companies holding shares in exploration and appraisal projects. There are also a raft of companies which hold exploration permits covering mostly unexplored regions of the Northern Territory.

FIGURE 3.4 POSSIBLE SHALE GAS DEPOSITS, NORTHERN TERRITORY



SOURCE: SCIENTIFIC INQUIRY INTO HYDRAULIC FRACTURING

II

SHALE GAS INDUSTRY DEVELOPMENT SCENARIOS

4 PROJECT ASSUMPTIONS AND DEVELOPMENT SCENARIOS

4.1 Introduction

The shale gas industry in the Northern Territory is in a pre-embryonic stage of development. To date, there has been one fracked well which has progressed to a 57 day production test. In the Marcellus Basin in the United States State of Pennsylvania, more than 2,000 wells are drilled every year. Information on the potential of the industry, and how it may develop in Northern Territory, is scant.

The results of our modelling are subject to higher than usual uncertainty and should be treated as what they are – an estimate of the impacts of a hypothetical development – and not for what they are not – a prediction of what will actually happen in the future. As a result of this lack of defined information, ACIL Allen sought approval from the Scientific Inquiry to modify its scope of works slightly.

ACIL Allen's original scope of works was to complete economic modelling under three scenarios:

1. The moratorium on fracking remained in place in perpetuity ('Baseline')
2. The moratorium on fracking is lifted for the entire Northern Territory ('full lift')
3. The moratorium on fracking is lifted in the Beetaloo Sub-Basin only ('Beetaloo only')

This was the premise with which ACIL Allen conducted its program of stakeholder consultation in the Northern Territory. This implication of these scenarios is that it was possible to develop a model of what *would* happen should the moratorium be lifted at some point in the future.

However, as we began to gather more information from government agencies, industry operators, and conducted our own research, it became clear that there was no way of knowing what *would* happen, as was the original intent of our scope of works.

With the endorsement of the Scientific Inquiry, ACIL Allen has modified the initial scope of works to instead complete economic modelling on five scenarios. These scenarios make a broad assumption that the quantity of shale gas in the Northern Territory is not a constraint, but instead the constraint on the size of a potential development is on the demand side and contingent on the development of a quantity of gas that can meet certain price points in the market. These are discussed below.

In addition to the uncertainty regarding the scale of commercial quality shale gas reserves, ACIL Allen was confronted with a significant challenge to develop a set of underlying assumptions that would allow it to "build" a shale gas industry in the Northern Territory. Typically, economic modelling is conducted using a project or industry-level financial model; the development of a shale gas industry in the Northern Territory is so early stage that such information was scant and largely held in commercial confidence by potential industry operators.

ACIL Allen has sought to be as transparent as possible in this process. This section details every assumption made in regards to the development of an industry financial model, including a rationale for the assumption and a source where one is available. We have not been able to independently source

evidence for every assumption required to build the financial model; some assumptions regarding the cost of particular elements of a hypothetical development have by necessity been sourced as "industry operators".

The sum total of this scope variation is ACIL Allen now completing its economic modelling task using information that is our assessment of what a successful shale gas industry *could* look like in the Northern Territory. The Scientific Inquiry agrees that this fulfils the overall objectives of the economic advisory services we have been asked to provide, which is to articulate for Territorians the potential economic impacts, benefits and risks to them should an industry develop in the future.

The chapter of our report outlines:

1. The five industry development scenarios (baseline, exploration only, and three production scenarios)
2. The process of determining the inputs and outputs of the industry development scenarios
3. The overlaying assumptions used to determine gas prices, sales and production volumes in each of the production scenarios
4. The underlying assumptions used to build the financial models of an industry
5. The financial models of gas industry development in the three production scenarios
6. The financial models of gas pipeline development in the three production scenarios

4.2 Modelling process

ACIL Allen has undertaken a comprehensive exercise to build the assumptions set and associated inputs and outputs used to facilitate the cash flow and economic modelling required to complete our scope of works. The modelling occurred in four sequential phases, outlined below.

1. **Gas Market Modelling:** Understanding the supply and demand for gas from a Northern Territory shale gas industry under each scenario, to determine the volume of gas that could be placed in the market at market prices each year of the study. This was completed using ACIL Allen's *GasMark* gas market model. A description of the manner in which ACIL Allen's *GasMark* deals with new sources of supply is provided in Box 4.1, and a full outline of *GasMark's* underlying system and processes is provided in F.

   The task of gas market modelling was different to a normal modelling task, as ACIL Allen typically knows the quantity, target sales price and underlying cost structure of a new gas development prior to attempting to place it into the market in *GasMark*. Due to the early stage of development, there is no information regarding the underlying cost structure of the gas present in the Northern Territory, even a very limited understanding of the quantity and quality of the gas itself. To make up for this information gap, in this engagement, ACIL Allen first had to determine how much gas could be sold to the market, to then understand the infrastructure required to facilitate the extraction of gas, and ultimate cost structure of the gas.

   At first, ACIL Allen developed target levels of gas production under the three scenarios: 100. These target production levels were input into *GasMark* iteratively, with $0.25 incremental price increase (starting at $2.00/GJ) per iteration. *GasMark* then determined how much gas could be placed in the market at each price point in each year of the study (through 2035). ACIL Allen then conducted a simple NPV calculation using a 10 per cent discount rate to determine the price and volume quantities that should be adopted for ProjectCo to maximise its revenue. These price and volume calculations were adopted as the actual values for modelling.

2. **Project Development Modelling:** Understand the production and infrastructure requirements to meet the volume of gas to be placed in the market, using a bespoke shale well production schedule model.

   This model required two major inputs: an assumed single average type curve of a hypothetical shale well (different for each scenario) and a series of assumptions regarding the infrastructure required to enable production to occur (wells, pads, gathering pipes, roads, water, camps, labour). This occurred in two streams:

   a) "ProjectCo": the hypothetical development company responsible for exploring, appraising and developing the shale gas industry in the Northern Territory.

BOX 4.1 ACIL ALLEN'S GASMARK MODEL AND NEW DEVELOPMENTS

ACIL Allen's *GasMark* model is built from the bottom up using both real world supply and demand sources and pipelines which link supply to demand. When considering the right size of new sources of supply and transport, ACIL Allen considers:

- Current and projected future pipeline capacities across the national gas grid, and transport costs based on actual tariffs (for regulated pipelines) or estimated tariffs (for unregulated pipelines)
- Current and projected future supply from currently producing and committed sources of gas, as well as yet-to-be-discovered gas, by taking publicly available information on reserve size, depletion rate and estimated production costs
- Current and projected future demand from households, industry, electricity generation and LNG export facilities, based on publicly available information and internally generated projections, cross-checked against forecasts prepared by the Australian Energy Market Operator (National Gas Forecasting Report).

The model takes this information and attempts to clear the market in the most efficient manner possible, taking into account effective final prices (ex-field, processing and transport inclusive).

When considering a new production project, ACIL Allen will typically incorporate assumptions about the volume of new gas supply that will be made available to the market. ACIL Allen instructs the model to offer the new gas into the market at a particular price point or in accordance with a specified supply cost curve, and the market finds a new equilibrium – which may include reducing the production of existing fields or stopping the development of planned fields if they are made uncompetitive versus the new supply. The model will only dispatch the new gas offered into the market to the extent that it is able to competitively meet demand at the price offered.

As discussed above (Page 22), this engagement requires a somewhat different approach because, given the early stage of shale gas exploration in the Northern Territory, there is a lack of reliable information regarding the size of the gas resource and its costs of production. We assume the existence of a significant shale gas resource in the Northern Territory and to use the gas model to determine the hypothetical cost of production (and consequently, the minimum ex-field selling prices) needed in order to achieve market penetration at the levels implied by the three staged market development scenarios.

SOURCE: ACIL ALLEN CONSULTING

b) "PipelineCo": the hypothetical builder, owner and operator of new pipeline infrastructure required to facilitate the sale of ProjectCo shale gas to market.

ProjectCo and PipelineCo are separate entities, but interact via tariffs paid by ProjectCo to PipelineCo for the provision of pipelines to transport gas to market.

3. **Project Cash Flow Modelling:** Understanding the financial implications of the development using assumptions regarding the cost of development of ProjectCo and PipelineCo, and volume and price data derived from *GasMark*.

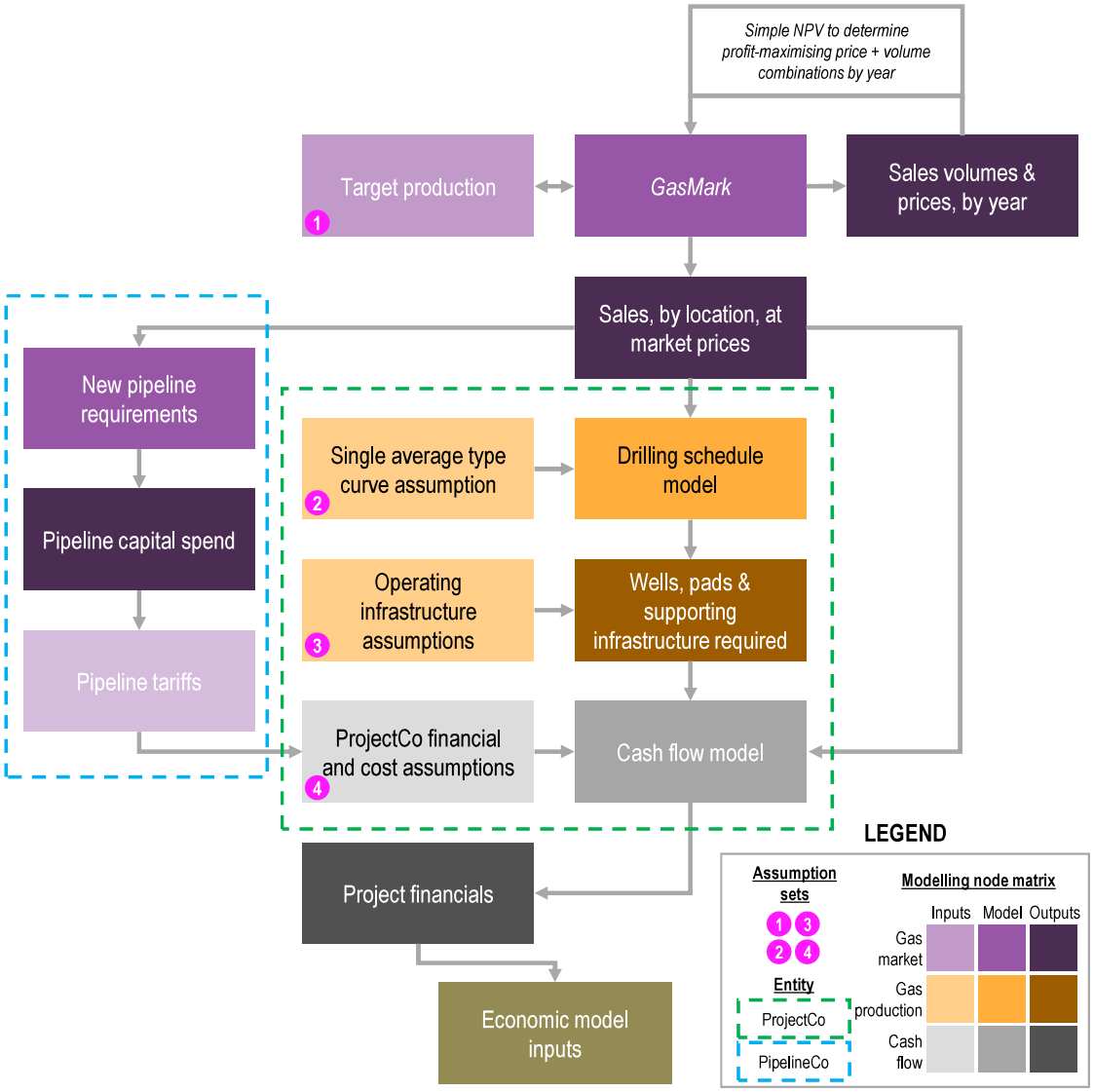
   ACIL Allen has built a bespoke discounted cash flow model that takes into account all features of ProjectCo's finances, including estimates of taxation. PipelineCo is built as a simple discounted cash flow model with capital investment, ProjectCo tariffs revenue and operating expenditure.

4. **Economic Impact Assessment Modelling:** The summary inputs and outputs of the ProjectCo and PipelineCo cash flow modelling are converted to a national accounting framework and processed through ACIL Allen's *TasmanGlobal* computable-general equilibrium (CGE) model. The four development scenarios are compared to the baseline assessment of the future growth of the Northern Territory economy to produce estimates of the potential economic impacts of each development scenario as a discrete set of outputs.

   Outputs are presented at the Northern Territory and Australia level, under the Australian Bureau of Statistics National Accounting framework for income, expenditure and output – including at ANZSIC major industry level. This ensures a comprehensive understanding of both positive and negative impacts of an industry.

This is a complex and iterative process. The process is outlined in the flow chart below (Figure 4.1). Specific details regarding the models and modelling techniques described above can be found the appendix of this report. The remainder of this chapter outlines the process of modelling, the assumptions used, and the outputs of each phase of modelling.

FIGURE 4.1 ACIL ALLEN MODELLING FLOW CHART



SOURCE: ACIL ALLEN CONSULTING

4.3 Shale gas industry development scenarios

ACIL Allen's three onshore gas industry development scenarios

1. **BREEZE Scenario:** Target production of 100 TJ/day of gas into existing pipeline infrastructure, the net effect being an increase in the amount of Northern Territory gas flowing through the Northern Gas Pipeline (NGP) into the East Coast market. This was selected as the "small" scale development following consultation with industry stakeholders and a review of their submissions to the Inquiry.
2. **WIND Scenario:** Target production of 400 TJ/day into newly constructed pipeline infrastructure, to fill short term gap in East Coast industrial and power generation, and penetrate the Northern Territory market (post-Blacktip) thereafter. This was selected as the "medium" scale development following consultation with industry stakeholders and a review of their submissions to the Inquiry.
3. **GALE Scenario:** Target provision of 1000 TJ/day into the existing Darwin LNG facility and additional East Coast supply (for power generation and LNG), replacing the Bayu-Undan feed stock as it depletes in the middle of the next decade. This was selected as the "large" scale development as a development of such scale would allow for scale economies to embed significantly into the project, and allow ProjectCo to provide the scale of gas feed into LNG production.

The rationale and supporting evidence for each scale of development is outlined below. As discussed above, at this stage these volumes of gas production are only "target" rates which have been fed into ACIL Allen's *GasMark* model for the purposes of determining what can be realistically sold into the market at particular price points. A second stage of modelling is conducted to determine how much gas ProjectCo will provide to the market in order to maximise its revenue generating capacity.

Critical assumption: A dry gas development

One critical and overarching assumption in ACIL Allen's development scenarios is the play that is developed is a 100 per cent "dry gas" play. That is, there are no higher value hydrocarbons, such as butane, ethane, propane or crude oil targeted for extraction, nor extracted, by ProjectCo. A "liquids rich" shale gas play results in a very small increase in operating costs (associated with increased processing to separate the higher value hydrocarbons from the lower value hydrocarbons), and a very large increase in potential production revenue. As a result, the net effect of a liquids rich development is to significantly improve total project economics.

ACIL Allen has assumed a dry gas play for two reasons. As discussed in Section 3.2, Origin Energy's Amungee NW-1H well produced dry gas from the Velkerri B shale, the shale which has been the target play of operators that have explored in the Beetaloo Sub-Basin. While operators are of the view there is likely to be a liquids rich shale in the sub-basin, it is too early to estimate the types or quantities of liquids available for extraction. Given this uncertainty, ACIL Allen has not sought to model any liquids.

In addition, ACIL Allen's scope of works requires a conservative assessment of the potential. Given the significant boost to project economics associated with a liquids rich development, ACIL Allen is more comfortable excluding the potential from its modelling. We can confidently state however that should a liquids rich development occur, the overall project economics will be significantly more positive, and the value of the shale gas industry to the Northern Territory would be significantly larger.

4.3.2 BREEZE Scenario: Target 100TJ/day scale

Based on ACIL Allen's assessment of the Northern Territory gas market in Section 2.6, there is currently a surplus of gas in the Northern Territory for the purposes of domestic consumption. This, and the potential for future on and offshore gas developments in the Northern Territory, has spurred the development of a gas pipeline linking Tennant Creek and Mt Isa in Queensland to the East Coast Gas Market – the Northern Gas Pipeline.

In 2006, Northern Territory Power and Water, the Territory's State-owned utility provider, entered into a 25 year off take agreement with ENI to take between 23 PJ/year and 37 PJ/year of gas from an onshore processing facility on the Territory coast.[16] However, it appears the current agreement results in the provision of more gas than is required by the Territory, with NT Power and Water effectively underwriting

[16] Ibid

the initial development of the NGP through the on-sale of Blacktip gas to a major industrial user in Queensland.[17]

The current 12-inch diameter specification of the NGP allows for the provision of up to 90 terajoules per day (TJ/day) of gas to the East Coast market.[18] As it stands, there is likely to be significant unutilised capacity on the pipeline upon commissioning, with the on-sale of Blacktip gas referred to above utilising only about one-third of the available capacity.

The Blacktip gas field has an estimated remaining life of 18 years, based on current reserves and assuming a flat production profile of 87.4 TJ/day (about 32 PJ/year). Under current estimates of NT domestic demand, there is unlikely to be a need for a major new source of gas for NT domestic consumption over the forecasting period of *GasMark* (2017 – 2035). However, the entry of NT Power and Water into the national gas market via the Northern Gas Pipeline affords it an opportunity to become a larger player in the provision of gas to East Coast markets.

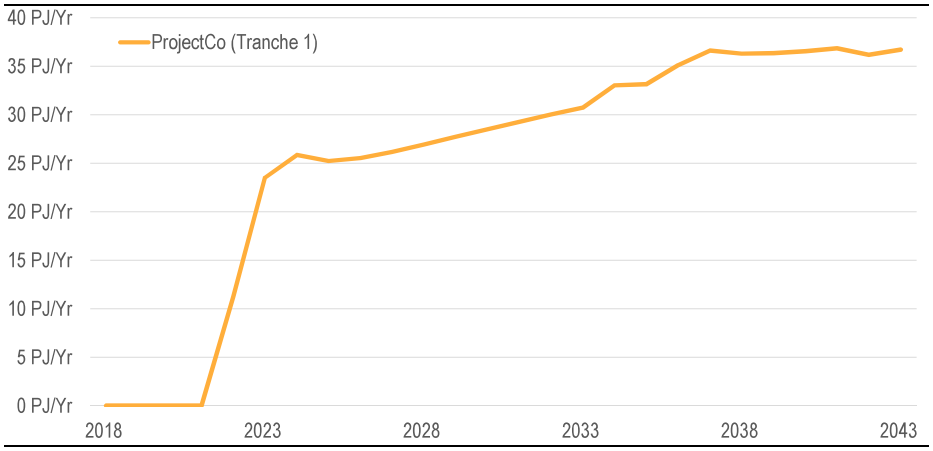
Our preliminary analysis using ACIL Allen's *GasMark* model shows that on the basis of growth in NT demand and potential to supply the East Coast market through the current specification of the NGP, there is room for between 24 and 34 PJ/year of new gas to enter the market at current prices between 2018 and 2035. It is assumed that ProjectCo will meet this demand.

Under the first scenario, it is assumed ProjectCo begins to produce shale gas in FY2022, with the current moratorium on activities lifting at the end of FY2018 and the exploration/appraisal phase of development occurring in FY2019, FY2020 and FY2021. At the tail end of FY2021, ProjectCo begins to build the facilities required to tie into the Amadeus Gas Pipeline, which at that time will be linked to the East Coast market via the NGP. ProjectCo produces gas at an initial rate of 33.4 TJ/day in 2022, ramping up to 90 TJ/day in 2034 as the Blacktip field begins to wind down production.

The model assumes the price of gas from ProjectCo is set at a level that allows for competitive supply into the East Coast market without displacing production of Blacktip gas that is contractually committed to NT Power and Water. Initially, all of the gas produced by ProjectCo flows to the East Coast gas market. After 2030 some ProjectCo gas starts to be delivered to the Northern Territory market, backfilling the decline in production from Blacktip. However, as *GasMark* is only able to produce estimates to 2035, ACIL Allen has assumed production remains constant from 2036 to 2043.

The profile of gas production by ProjectCo in BREEZE is below (Figure 4.2).

FIGURE 4.2 PROJECTCO GAS PRODUCTION, BREEZE SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

[17] NT Power and Water. 2017. *Power and Water positioned to enter the Australian gas market*. Accessed online at http://www.powerandwater.com.au/

[18] Australian Energy Market Operator. 2017. *Gas Statement of Opportunities, March 2017*. Accessed online at http:///www.aemo.com.au/

4.3.3 WIND Scenario: Target 400TJ/day scale

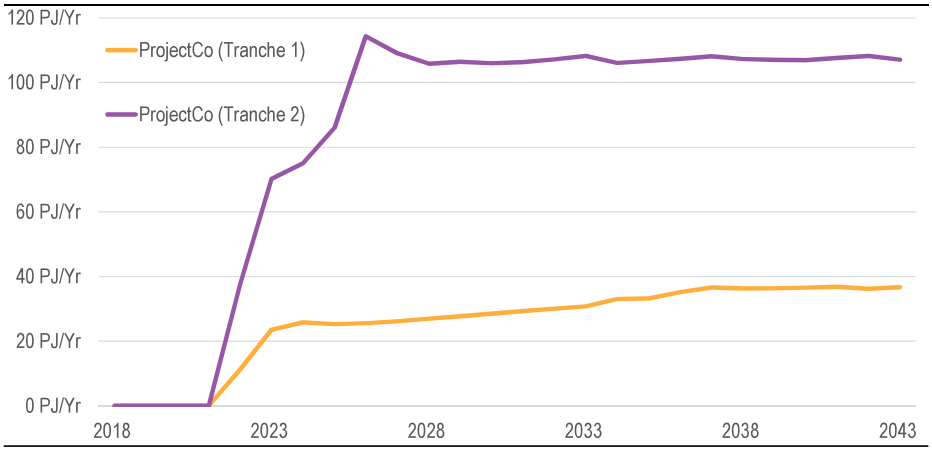
The WIND scenario assumes ProjectCo is further able to deliver commercial gas into the NGP and East Coast market. After a successful initial development, ProjectCo seeks to build its market share on the East Coast via production efficiencies to take advantage of push and pull factors in East Coast gas markets associated with the development of higher cost coal seam gas (CSG) production and the backfill requirements of existing LNG facilities in Queensland.

ProjectCo's target production rate for this scenario is 400TJ/day – or an additional 300TJ/day over the BREEZE scenario. Modelling indicates that under the optimal price/volume strategy adopted, the maximum amount of gas that could flow to the East Coast market under current market assumptions is an incremental 244 TJ/day peak in 2026 (total gas produced 315 TJ/day), with a long term equilibrium of 210 TJ/day by 2035 (total gas produced 300 TJ/day).

The majority of this gas is placed into the East Coast market, requiring additional pipeline infrastructure be developed as the capacity of the existing NGP is 100 per cent subscribed by ProjectCo. Pipeline-related assumptions are outlined in Section 4.5.1.

The production profile of ProjectCo in the WIND scenario is presented in Figure 4.3.

FIGURE 4.3 PROJECTCO GAS PRODUCTION, WIND SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

4.3.4 GALE Scenario: Target 1000TJ/day scale

The Darwin LNG plant (DLNG) is currently supplied feed gas from the Bayu-Undan gas project in off the coast of the Northern Territory in the Australia Timor-Leste Joint Petroleum Development Area. DLNG has a single production train[19], producing up to 3.7 million tonnes of LNG per annum for sales to Japan[20]. To produce 3.7 million tonnes of LNG, the plant requires approximately 225 PJ/year of feed gas.

As it stands, Bayu-Undan provides 100 per cent of the feed in gas to the plant. The field is set to reach maturity in 2022-23, and will progressively reduce its production. Unless replacement gas is found DLNG will cease production some time towards the end of the next decade. Acknowledging this, the owners of the Bayu-Undan joint venture have begun independently investigating new sources of gas for the plant, at this stage focussed on a new large scale offshore development off the coast of the Northern Territory.[21]

ACIL Allen assumes ProjectCo is able to build to a scale that would allow it to progressively replace the Bayu-Undan gas field as the feed in gas for DLNG, allowing the existing train to continue production

[19] ConocoPhillips. 2017. *Our Business Activities – DLNG*. Accessed online at http://www.conocophilips.com.au/
[20] Santos. 2017. *Bayu-Undan/Darwin LNG Joint Venture*. Accessed online at http://www.santos.com/
[21] Energy News Bulletin. 2017. *Barossa development begins*. Accessed online at http://www.energynewsbulletin.net/

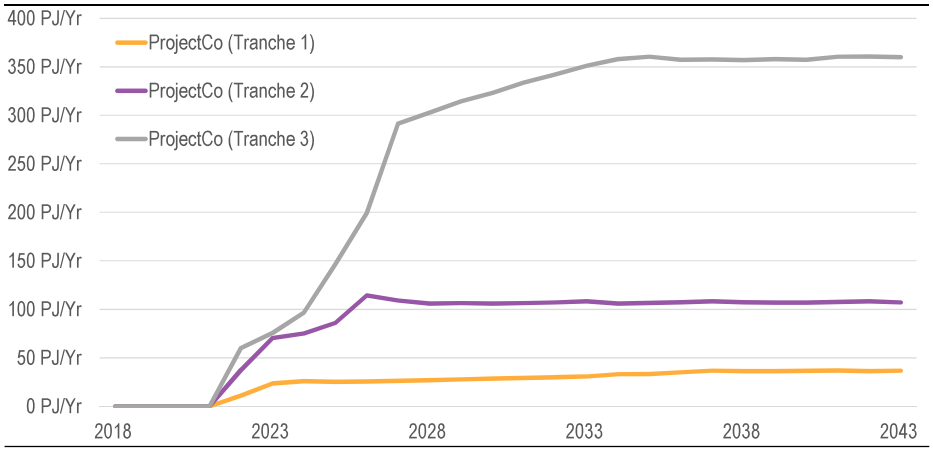
beyond 2022-23 at current rates. This necessitates investment to expand the Amadeus Gas Pipeline to allow more gas to flow north to DLNG.

For the purposes of economic modelling, it is assumed that DLNG will continue to produce LNG at its current rate with or without ProjectCo gas. In the base case, it is assumed one of the new offshore developments discussed above comes to pass and this gas backfills DLNG. This is a critical assumption, as it means there is no incremental value associated with LNG production attributable to ProjectCo gas – the incremental value is any change to the production profile, profitability and local content of gas required to backfill DLNG in an onshore scenario versus an offshore scenario. This is discussed further in Section 6.

It is also assumed that due to ProjectCo's increasing scale economies, its cost of production falls below the rate of the WIND scenario, allowing for further gas sales into the East Coast gas market – potentially including partial backfill of an LNG train at Gladstone. In any event, the cascading effect of ProjectCo's gas results in a reduction in the wholesale price of gas in the East Coast market, with the "ripple" effect of injection of more gas flowing west to east leading to less gas produced in Queensland fields moving south. Similarly to DLNG, there is no incremental value associated with LNG backfill.

As such, this necessitates further investment in the NGP and Carpentaria Gas Pipeline over and above the investment assumed to be required to meet WIND East Coast exports. As a result, ProjectCo is able to fulfil its full target production of 1000 TJ/day by 2035. Economies of scale in production allowing it to increase its penetration of the East Coast market over the WIND scenario. The production profile of ProjectCo under these assumptions is shown below (Figure 4.4).

FIGURE 4.4 PROJECTCO GAS PRODUCTION, PJ/ANNUM, GALE SCENARIO



SOURCE: ACIL ALLEN CONSULTING

4.3.5 Final volumes and prices

The final volumes and selling prices for ProjectCo gas under each scenario are presented below, in real 2017 terms, inclusive of transport costs. Details on the stratified sales of gas by market (domestic NT, East Coast and DLNG) are presented in Appendix C.

TABLE 4.1 PROJECTCO FINAL GAS VOLUMES AND PRICES, BY SCENARIO, $/GJ & PJ/ANNUM

	BREEZE		WIND		GALE	
	Volume	Price	Volume	Price	Volume	Price
Year	PJ/annum	$/GJ	PJ/annum	$/GJ	PJ/annum	$/GJ
2018	-	-	-	-	-	-
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-

	BREEZE		WIND		GALE	
	Volume	Price	Volume	Price	Volume	Price
Year	PJ/annum	$/GJ	PJ/annum	$/GJ	PJ/annum	$/GJ
2021	-	-	-	-	-	-
2022	11.3	7.37	37.7	5.65	60.1	6.12
2023	23.5	7.64	70.2	6.07	75.6	6.12
2024	25.9	7.64	75.0	6.09	96.5	6.12
2025	25.2	7.69	85.9	6.12	146.6	5.96
2026	25.5	8.16	114.3	6.19	199.3	5.88
2027	26.2	8.37	109.1	6.79	291.5	5.88
2028	26.9	8.48	105.9	7.33	302.8	5.82
2029	27.7	8.94	106.5	7.74	314.4	5.77
2030	28.5	9.04	106.0	7.97	323.2	5.73
2031	29.3	9.24	106.3	8.19	333.7	5.70
2032	30.0	9.32	107.2	8.43	342.2	5.67
2033	30.7	9.89	108.2	8.55	351.3	5.65
2034	33.0	9.81	106.1	8.80	357.9	5.63
2035	33.2	9.84	106.6	9.05	360.4	5.61
2036	35.1	9.84	107.3	9.05	357.5	5.55
2037	36.6	9.84	108.1	9.05	357.7	5.48
2038	36.3	9.84	107.3	9.05	357.0	5.42
2039	36.4	9.84	107.0	9.05	358.0	5.35
2040	36.6	9.84	107.0	9.05	357.4	5.28
2041	36.9	9.84	107.6	9.05	360.6	5.28
2042	36.2	9.84	108.3	9.05	360.7	5.28
2043	36.7	9.84	107.1	9.05	360.0	5.28

SOURCE: ACIL ALLEN CONSULTING

4.4 Adopting single average type curves

To progress from the volume of gas to be sold to the cost of production, ACIL Allen has formulated a series of assumptions regarding the quality of the gas reserve available to ProjectCo in each of the scenarios. The manifestation of this is what is known as a "type curve", which shows how much gas is produced from a single well at any one point in time (in this case per annum).

ACIL Allen has developed its own type curves, rather than using estimated type curves for gas fields in the Northern Territory. This is because there has been one successful horizontally drilled shale gas well for production testing in the Northern Territory: Origin Energy's Amungee NW-1H. The results of this test were positive, but cannot be used for our type curve assumption for three reasons:

- The well only involved 11 "frack" stages (number of fracture stimulation points from the well). A typical horizontal well will have at least 20 frack stages, and in most cases many more.
- The well's production profile was atypical, with a very low initial production rate and an almost perfectly flat production curve.[22] A typical shale gas well has a high initial production in the first year or two relative to the average production over the well life, and lower than average production over the well life thereafter.

[22] Origin Energy. 2017. Submission to the Inquiry, #272. *Accessed online at http://www.frackinginquiry.nt.gov.au*

Nonetheless, ACIL Allen has attempted to adopt the "flatter" characteristic of the Amungee NW-1H well in its type curve

— The well underwent production testing for 57 days. This is less than two months, making development of an estimated type curve problematic

ACIL Allen has adopted a "single average type curve" for the purposes of modelling. In reality, every well will produce a different type curve, relating to the location the well is drilled, the specific geology of the formation, and the particular techniques used. However, ACIL Allen considered it impractical to develop multiple type curves, and considers that the ultimate production in a given development can be summarised by a single average type curve regardless.

A typical shale gas type curve is a hyperbolic decline function, where the production of a well in the first period (typically reported in months) is very high relative to the average monthly production over the life of the well. A well's production declines rapidly from this initial production rate, and continues to produce for a long period of time at very low levels.

There are four key pieces of information required to develop a type curve:

— Initial production rate (IP): the volume of gas produced in the first month of the well's life
— Decline rate (in two parts: exponent and rate): the speed in which the well's production declines per month
— Estimated Ultimate Recovery (EUR): the ultimate volume of gas that will be extracted from the well over its useful life, measured in petajoules (PJ)
— Well life (an exogenous figure): the useful production life of each well

ACIL Allen has developed a single average type curve for each of the three shale gas development scenarios in the Northern Territory. We have built our type curves using a variety of sources – on the advice of potential shale gas operators and the Northern Territory Government – and used the operators' collective assumption that a shale gas well in the Northern Territory would have a useful life of 20 years.

Much of the information used is related to the Marcellus Basin shale gas play, in the United States of America State of Pennsylvania. The rationale for the Marcellus analogue is that both Marcellus and Beetaloo basin plays are thought exhibit similar geological characteristics: assumed to be a mostly dry gas play, similar shale formation, similar depths and similar geology.[23]

The parameters of ACIL Allen's development type curve assumptions are below Table 4.2.

TABLE 4.2 ACIL ALLEN TYPE CURVE ASSUMPTIONS

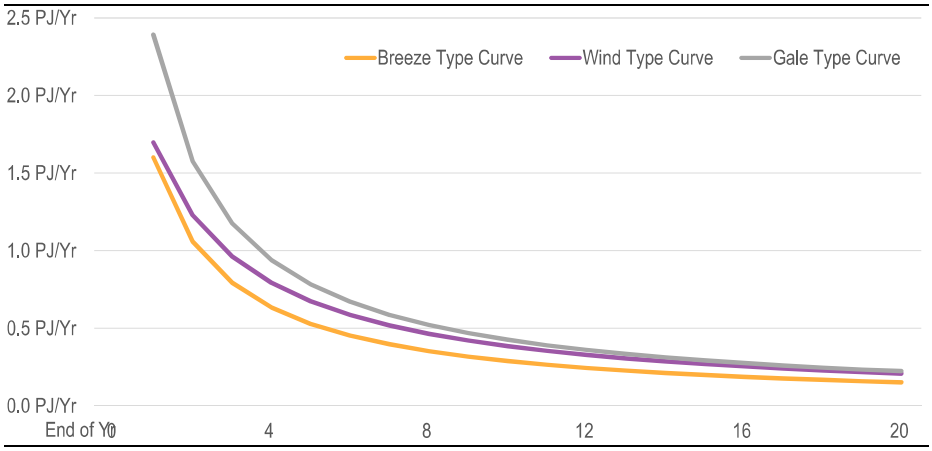
Scenario	Initial Production (mmscf/month)	Decline exponent	Decline rate (% per month)	EUR (Petajoules per well)	Well life (years)
BREEZE	160	1.0	5.3%	8.4	20
WIND	160	1.0	3.8%	10.6	20
GALE	240	1.0	5.4%	12.7	20

SOURCE: ACIL ALLEN CONSULTING, DERIVED USING VARIOUS SOURCES BELOW

ACIL Allen's type curves are presented below, in annual production terms. The type curves essentially "graduate" in each scenario (each curve produces more gas at every point in time), as a proxy measure for the fact that better project economics are required for ProjectCo to progress from one scenario to the next.

[23] Consensus view sourced from Origin Energy, Santos and Department of Primary Industry and Resources submissions to the Scientific Inquiry into Hydraulic Fracturing Issues Paper.

FIGURE 4.5 PROJECTCO SINGLE AVERAGE TYPE CURVES, BY SCENARIO, ANNUAL PRODUCTION (PJ)



SOURCE: ACIL ALLEN CONSULTING

The type curve is a critical assumption, as it governs the number of wells required to meet target production rates, which flows through to capital and operating costs as well as the economic impact (as this is fundamentally driven by total expenditure). The rationale for ACIL Allen's type curve assumptions are below.

4.4.1 Initial Production Rate (IP)

ACIL Allen initially developed its type curve assumption from a report prepared by petroleum engineer Gary Swindell, titled *Marcellus Shale in Pennsylvania: A 3,800 Well Study of Estimated Ultimate Recovery (EUR)*. The table in this report has been reproduced below (Figure 4.6).

FIGURE 4.6 SWINDELL REPORT DATA

The increase in initial production rate during the early years of the Marcellus development may be related to an increase in the horizontal length during the same period. For a subset of 2,168 wells where an estimate of the horizontal length was able to be made, the average horizontal section increased from 2,280 ft in 2008; 2,890 ft. in 2009; 3,800 ft in 2010; 4,100 ft. in 2011; 4,500 ft. in 2012 and 4,751 in the 2013 vintage wells.

Average decline profiles for the whole state, vintaged by the year of first production are summarized in **Table 1**.

Vintage	Average initial production Mcf/month	Average initial decline rate - %	Hyp b factor	Average EUR Statewide - Bcfe
2008	43,263	43.87	0.65	2,032.69
2009	71,768	43.21	0.55	3,327.25
2010	121,248	48.52	0.65	4,873.21
2011	121,339	49.02	0.66	4,531.52
2012	129,302	48.38	0.51	4,201.77
2013	172,787	46.22	0.39	5,397.40

Table 1. Average decline profiles for the Pennsylvania Marcellus.

SOURCE: SWINDELL, G. 2016. MARCELLUS SHALE IN PENNSYLVANIA: A 3,800 WELL STUDY OF ESTIMATED ULTIMATE RECOVERY (EUR)

As the target of the Swindell study is estimating average EUR, his study does not include contemporary information regarding initial production rates. The study used data from the Pennsylvania Department of Environmental Protection, which mandates that producers in the State must report monthly production figures for all shale wells drilled in the Marcellus shale.

This is a regulatory requirement to assist the Department manage the industry and its impact on the environment. However, the Department also publishes all of this data on the internet, allowing for precise analysis of shale gas production from wells drilled in the Marcellus Basin. ACIL Allen initially sought out this data to verify the findings of this report, but after understanding the depth of data available instead used the data to determine an appropriate initial production rate for its type curves.

ACIL Allen extracted well level production data from 2012 to 2016. Data for 2012 to 2014 was reported on a six-monthly basis, while 2015 and 2016 was monthly data. Initially, ACIL Allen converted production data to monthly mmscf by dividing total production in the period by the number of days in the period, multiplying this by 365.25 days (a standard year) and divided this by 12.

ACIL Allen then filtered out well data that was not dry gas and was not a horizontally drilled well. This resulted in 171,611 individual data points over 7,925 wells for analysis.

ACIL Allen then determined the time which each well initially came online by applying a formula that looked up the first time a Well ID Number appeared in the database. If this was in the first six months of 2012, this data was ignored as it was the first time Well ID Numbers appears for many wells which may have been producing for some time. Applying this filter allowed ACIL Allen to determine the average IP rate for wells drilled in particular years. These are presented in a table below.

TABLE 4.3 INITIAL PRODUCTION RATES OF SHALE GAS WELLS DRILLED IN MARCELLUS BASIN BY YEAR

Period	Initial Production (TJ/month)	# of Wells in Sample
2012 (2H2012 only)	134.7	746
2013	177.3	1402
2014	209.6	1217
2015	184.6	1004
2016	233.3	672

SOURCE: ACIL ALLEN CONSULTING, PA DEPARTMENT OF ENVIRONMENTAL REGULATION

This data suggests the IP rate of horizontal dry shale gas wells drilled in the Marcellus Basin has increased over time, from 127.7 mmscf/month (134.7 TJ/month) in the second half of 2012 to 221.1 mmscf/month (233.3 TJ/month) in 2016. The increase has not been linear, with a decline in 2015.

ACIL Allen adopted an IP rate of 160 mmscf/month (168.8 TJ/month) for its BREEZE and WIND scenarios, and an IP rate of 240 mmscf/month (253.2 TJ/month) in its GALE scenario. ACIL Allen has adopted these as conservative estimates, noting:

- technological progress in the shale gas industry is rapid, so adopting IP rates that are two to five years behind the analogue shale is conservative
- the anticipated geology of the most prospective areas of the Northern Territory is conducive to the development of long horizontal wells, which tend to have higher IP rates.

It is noted that this IP rate is higher than the Amungee NW-1H well (33.5 mmscf/month or 35.3TJ/month), and higher than the most comprehensive previous study of the economics of shale gas developments in Australia, the Australian Council of Learned Academics report *Unconventional Gas Production: A study of shale gas in Australia* (the 'ACOLA report'), of 446Mscf per day (13.6 mmscf/month or 14.3TJ/month). ACIL Allen has not adopted the well profile of NW-1H for the reasons identified above. ACIL Allen has not adopted the well profile of the hypothetical shale gas development presented in the ACOLA report as we are of the view it is now out of date, given it is based on the findings of a 2012 US Energy Information Agency report, which itself was based on data that is two years older again, and is not certain that it represents the experience of the Marcellus shale given the significant discrepancy between it and data prepared by the Government of Pennsylvania.

4.4.2 EUR and Well Life

Determining the EUR of a well is a difficult exercise, even when information is fully available. It can only be known once a well has reached the end of its useful life, which in the case of the current shale gas

industry in the United States is not possible. It is possible to determine probabilistic measurements of well EUR, but ACIL Allen does not have access to the requisite information to do so.

The EUR is a central assumption, as it is the variable in the type curve that provides the most sensitivity to the number of wells required to facilitate the volume of production under each scenario, and the expenditure on supporting infrastructure. ACIL Allen was unable to source adequate analogue data to adopt like for like for a modelling assumption, and so was left to piece together evidence for credible EUR assumptions from a range of sources. These are discussed below.

EUR is a function of the quality of the geology of the shale, the length of the horizontal section of the well being drilled, the precision of the drilling activity taking place, and the number of fracking stages per unit of lateral length. Research presented to the Inquiry and ACIL Allen by industry operators shows that shale gas operators in the United States are drilling increasingly long horizontal wells with the aim of increasing the EUR per well and thus lowering their development costs.[24]

There is some conjecture regarding the relationship between lateral drilling length and the volume of gas extracted per well, to the extent that EUR per 1,000 feet of lateral drilling (the industry definition of well productivity) increases as the horizontal well length increases. A recent paper by Yuan et al, published in the Society of Petroleum Engineers, found there was no additive effect of gas recovery per 1,000 foot of horizontal drilling in the Barnett Basin (in Texas), but that there was a clear relationship between the length of drilling and early production.[25] In addition to the above factors, EUR is thought to be partially a function of initial production rates per well, to the extent it reflects the quality of the shale targeted and the ultimate productivity of the well drilled. Therefore, EUR per well is likely to exhibit a positive relationship with the length of the horizontal section of a well.

This is reinforced by academic literature, such as in the Swindell report referenced in Section 4.4.1. The Swindell report found the mean EUR per well across the study period (wells spudded between 2008 and 2013) was 5.0PJ per well, with approximately 80 per cent of wells exhibiting an EUR per well of 6.3 PJ or less.[26] The Swindell data suggests the average lateral length of wells drilled in the Marcellus Basin has increased from 2,280 feet (694 metres) in 2008 to 4,751 feet (1,448 metres) in 2013 – more than doubling over this time.[27] The Swindell report does show average EUR per well by year of well spudding has increased over time, from 2.1 PJ in 2008 to 4.7 PJ in 2011, and to 5.7 PJ in 2013. Assuming a steady compound annual growth rate from 2011 to 2013 (9.5 per cent per annum), the PJ per well in the Marcellus Basin could have increased to 8.2 PJ per well on average in 2017.

The latest report on US shale gas industry performance prepared by the US Energy Information Administration, which ACIL Allen has relied upon for other assumptions in this report, found EUR in the Marcellus Basin had increased from 4.6PJ per well in 2010 to 6.8 PJ per well in 2014.[28] Assuming a steady compound annual growth rate (11.9 per cent per annum), the PJ per well in the Marcellus Basin could have increased to 9.5 PJ per well on average in 2017.

A second piece of research prepared by the US EIA suggested the average EUR of wells spudded in the Marcellus Basin has increased from 0.4 PJ in 2008 to 5.4 PJ in 2010, and 6.8 PJ in 2013.[29] Assuming a steady compound annual growth rate from 2010 to 2013 (7.5 per cent), the PJ per well in the Marcellus Basin could have increased to 9.0 PJ per well on average in 2017.

While useful, these estimates are based wholly on the continuation of historic growth rates in PJ per well, without assuming any technological progress which has occurred in the United States in recent years. This also illustrates the inherent difficulty in assessing EUR, as even in one of the most widely studied basins there is significant uncertainty.

Outside of these two papers, ACIL Allen was unable to source academic literature that was able to strike a balance between rigorous academic analysis and the contemporary experience of the shale gas industry in the United States. The published data produced above contained data for wells that was at least three

[24] See Origin (2017), Santos (2017) and Pangaea (2017).
[25] Yuan, G. et al. 2017.
[26] Swindell, G. 2016. *Marcellus Shale in Pennsylvania: A 3,800 well study of estimated Ultimate Recovery (EUR).* Accessed online at http://www.gswindell.com/
[27] Contemporary industry information suggests the average horizontal drilling length in the Marcellus Basin has increased to 7,000 feet (2,133 metres) in 2016.
[28] US EIA. 2016. *Trends in US Oil and Natural Gas Upstream Costs*. Accessed online at http://www.eia.gov/
[29] Staub, J. 2015. *The growth of US natural gas: An uncertain outlook for US and world supply*. Accessed online at http://www.eia.gov/

years old, and given the rapid productivity increases of the industry (see Section 3.2), is considered the best available conservative estimate of contemporary shale gas industry practices.

To compensate for this, ACIL Allen accessed a series of reports prepared by US shale gas industry operators for the Securities and Exchange Commission.[30] These reports indicated a strong trend of increasing EUR in the Marcellus Basin over time, and projections of further increases into the future. These reports were supportive of EURs in excess of 21.1 PJ per well at the leading edge of developments in the Marcellus Basin.

Operators provided a very large range of EUR per well that could be expected in the Northern Territory, of 4.2 - 21.1 PJ per well. For instance, Santos, in a submission to the Inquiry, indicated it was expecting an EUR of 12.2 PJ to 21.5 PJ of raw gas per well (raw gas suggesting it includes components which would be stripped out following extraction such as carbon dioxide).[31] Origin provided a range of between 5.2 PJ and 15.8 PJ per well in one of its submissions to the Inquiry.[32] Pangaea did not provide a range of expected EUR in its exploration areas, but it did cite evidence of 21.1+ PJ per well EUR outcomes in the United States.[33]

As a conservative assumption, ACIL Allen has adopted a graduated EUR for each scenario, starting with an 8.4 PJ per well in the BREEZE scenario in line with ACIL Allen's simple extrapolation analysis presented above. EUR rates of 10.6 PJ per well and 12.7 PJ per well are adopted for WIND and GALE scenarios, reflecting that to progress to increasingly large development ProjectCo would be required embed technological improvements or the quality of the shale would have to improve. This strikes the balance between ACIL Allen's requirement to take conservative assumptions, consider the most relevant contextual information of contemporary practice in the shale gas industry, and deliver economic modelling results on the economic impact of the industry (as opposed to delivering an assessment of the economics of the shale itself). This assumption also reflects the relationship between longer lateral lengths and PJ per well observed in the literature.

Operators suggested an average well life of 20 years, which ACIL Allen understands is in line with international experience. ACIL Allen has adopted this across the three scenarios.

4.4.3 Decline rates

ACIL Allen has assumed a decline rate and decline exponent that allows for the delivery of the target EUR of gas in each scenario over a 20 year well life, assuming the IP rate of either 160 mmscf/month (168.8 TJ/month) or 240 mmscf/month (253.2 TJ/month). ACIL Allen has adopted a decline exponent of 1.0, given there is no compelling reason to adopt a decline exponent of greater than or less than 1.0 – the exponent varies significantly across plays. Therefore in effect, the decline rates adopted are a residual calculation based on assumed IP, EUR and well life.

As discussed in Section 4.4, ACIL Allen has sought to qualitatively reflect the relatively low decline rate experienced in the NW-1H well drilled and spudded by Origin. This can be seen below, with the BREEZE type curve versus a hypothetical average decline curve developed from the data presented in Swindell report and the ACOLA report.

The assumed single average type curves for each scenario are applied to the production volumes modelled in Section 0 to determine the scale of the development required. The process of combining these two outputs, and the assumptions used to determine the scale of the development, are discussed in the next section.

[30] ACIL Allen accessed material prepared by US shale companies Cabot, Antero, Eclipse Resources, EQT, Gulfport Resources, Rice Energy, Southwestern Energy, and Tourmaline Corp, which were mostly in the form of SEC-compliant investor presentations. These reports contain the historic and projected future productivity of wells drilled in the Marcellus Basin. While these reports are not prepared according to the scientific method of academic research, they represent a body of evidence that is contemporary and based on the current experience of independent operators in the United States.

[31] Santos. 2017. *Submission to the Scientific Inquiry into Hydraulic Fracturing, Submission #232*. Accessed online at http://www.frackinginquiry.nt.gov.au

[32] Origin. 2017. *Submission to the Scientific Inquiry into Hydraulic Fracturing, Submission #272*. Accessed online at http://www.frackinginquiry.nt.gov.au

[33] Pangaea. 2017. *Submission to the Scientific Inquiry into Hydraulic Fracturing, Submission #427*. Accessed online at http://www.frackinginquiry.nt.gov.au

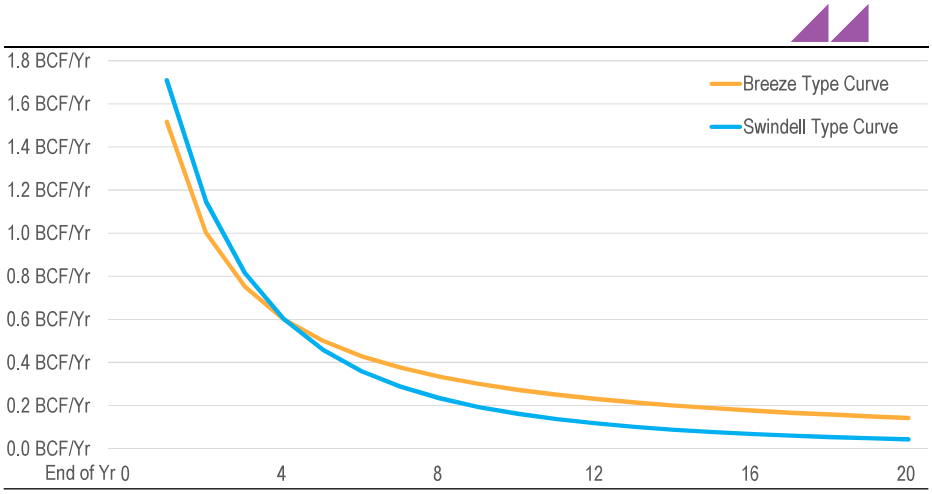
4.5 ProjectCo drilling schedule and supporting infrastructure

This section details how ACIL Allen estimated the number of wells required to meet the production profile of each production scenario presented in Section 0. The estimation of the number of wells under each production scenario enabled ACIL Allen to estimate the supporting infrastructure requirements, including:

- number of pads;
- required length of connecting roads; and
- required length of gathering pipes.

The process used by ACIL Allen to estimate the required number of wells and these infrastructure requirements is detailed below.

FIGURE 4.7 HYPOTHETICAL DECLINE RATE, OBSERVED IN MARCELLUS BASIN VS ACIL ALLEN TYPE CURVE ASSUMPTION



SOURCE: PA DEPARTMENT OF ENVIRONMENTAL REGULATION, ACIL ALLEN CONSULTING

4.5.1 Number of wells required

To estimate the required number of wells to meet each development scenario's production profile, ACIL Allen required estimates of:

- sales volumes (as estimated by *GasMark* and presented in Section 0); and
- single average type curve assumptions (presented in Section 4.4).

Combining these two inputs allowed ACIL Allen to estimate the number of new wells required over time to meet the production profile estimated by *GasMark*. This is a two-step process, involving new wells and existing wells.

Existing wells are wells which have been constructed in previous periods, and which are still producing gas. Each year, there are a number of new wells commissioned, which decline in production on an annual basis in line with ACIL Allen's assumed single average type curve. New wells are wells which are required to be built in a given year to make up for a gap between required production and existing well production. The number of new wells required is calculated by subtracting required production from existing production, and dividing by the annual initial production rate of a new well. This excludes Year One of production, as there is no existing production, and 100 per cent of required production must be met by new wells.

Figure 4.8 highlights the number of new wells required to be drilled per annum to meet the production profile in each development scenario.

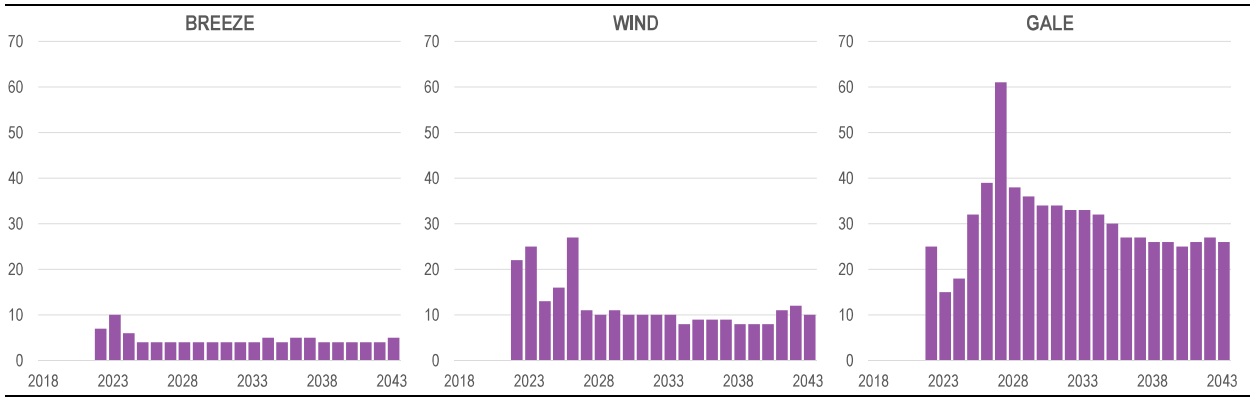
Over the study period, ACIL Allen has estimated that a total of; 103 wells will be drilled (at an average of four wells drilled per annum) under the BREEZE development scenario, 167 new wells under the WIND

development scenario (at an average of 10.3 wells drilled per annum) and 670 new wells under the GALE development scenario (at an average of 25.8 wells drilled per annum); to meet each scenario's production profile.

Figure 4.9 presents the total number of wells that are operating per annum by development scenario. Towards the end of the study period, the number of wells that are operating under each development scenario begins to level off as production profile of each development scenario hits its target level of production.

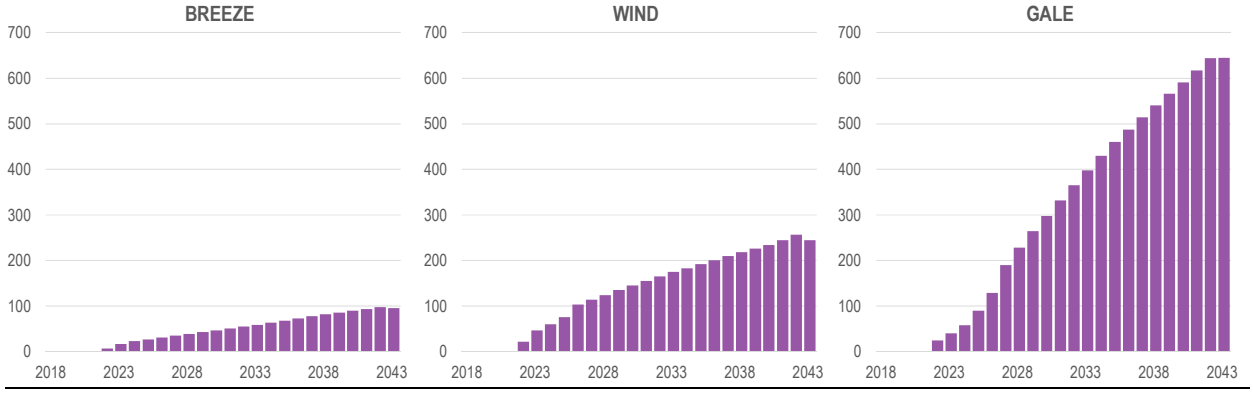
Through the study period, the number of wells in operation peaks at 98 in 2042 under the BREEZE development scenario, and 257 in the WIND development scenario. The number of wells in operation peaks one year later at 645 for the GALE development scenario.

FIGURE 4.8 DRILLING SCHEDULE, NUMBER OF WELLS DRILLED PER ANNUM, BY DEVELOPMENT SCENARIO



SOURCE: ACIL ALLEN CONSULTING

FIGURE 4.9 NUMBER OF OPERATING WELLS PER ANNUM, BY DEVELOPMENT SCENARIO



SOURCE: ACIL ALLEN CONSULTING

4.5.2 Supporting infrastructure

In addition to the number of wells, there is a range of supporting infrastructure required to enable gas to be extracted, processed, and sent to market. ACIL Allen has developed a simplified supporting infrastructure regime using a series of ratios, presented in Table 4.4. Supporting infrastructure requirements are a function of the number of wells built in a given year.

TABLE 4.4 SUPPORTING INFRASTRUCTURE REQUIREMENTS

Supporting Infrastructure	Assumption	Source
Pads	Every eight wells drilled requires one new pad. If nine wells are drilled, two pads are required, and a new pad is not required until the number of new wells drilled exceeds 16.	ACIL Allen estimate based on industry consultation
Roads	For every one pad, 1.7km of roads are required for connection purposes.	ACIL Allen estimate based on industry consultation
Gathering pipes	For every one pad, 1km of 5 inch piping is required for gathering purposes.	ACIL Allen estimate based on industry consultation

These values for supporting infrastructure are fed into ProjectCo's financial model, and are costed in line with assumptions presented in Section 5.1.

4.6 Development prospect matrix

The above development scenarios are hypothetical, based on what a development could look like should ProjectCo discover a commercial quality shale gas reserve in the Northern Territory. This is subject to significant uncertainty, because there has been such little exploration activity that it is not possible to determine the extent to which a development is likely to occur.

With this in mind, ACIL Allen has developed a qualitative matrix to represent the prospect of each development occurring (Figure 4.10). On the basis of the financial modelling undertaken on the each development scenario, ACIL Allen has assessed the probability of a shale gas industry developing in the Northern Territory in each case. This is based on the outcomes of the financial modelling, the uncertainty regarding the size of the Northern Territory's commercial reserves, and the challenges associated with producing gas at a price which the market will accept. As the development scales up, these challenges will become greater, leading to a reduced likelihood that any given scale of development can be realised.

ACIL Allen has also formed a view that the probability of a shale gas industry developing in the Northern Territory will improves the greater the potential area for exploration and appraisal. As discussed in Section 3.2, international experience suggests that the ability to deliver large scale commercial quantities of petroleum products from prospective shale gas resources is a function of the volume of exploration and activity which has occurred, and the area available for exploration and activity to occur. This is driven by institutional learning, the ability to find better quality reserves over time, and economies of scale and scope.

For example, under the GALE scenario, ACIL Allen has assessed, on current information, the likelihood of a shale gas industry that will begin to scale to 1000 terajoules per day (TJ/day) of gas production at an average price of $4.01 per gigajoule (GJ) within the next five years as low, assuming the moratorium is lifted in full across the Northern Territory. If there is only a partial lift in the moratorium, this becomes a very low probability, because there is less of an ability for a potential shale gas industry to find the most commercial shale gas deposits.

In the context of the probability matrix, ACIL Allen notes that it has made a critical assumption that the shale gas developments modelled in this report are a "dry gas play". That is, the hydrocarbons produced in a development do not include higher value liquid hydrocarbons such as ethane, propane, butane or crude oil. A "liquids rich" shale gas play results in a very small increase in operating costs (associated with increased processing to separate the higher value hydrocarbons from the lower value hydrocarbons), and a very large increase in potential production revenue. This improves the commercial viability of a shale gas development, to the point where a larger development may have a higher probability of occurring versus a dry gas play.

FIGURE 4.10 ACIL ALLEN POLICY SCENARIO PROBABILITY MATRIX

			POLICY SCENARIO PROBABILITY MATRIX		
INDUSTRY DEVELOPMENT SCENARIO	Production Profile	Production Cost Regime	PERMANENT MORATORIUM	PARTIAL LIFT	FULL LIFT
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	**Scenario 1** Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	**Scenario 2** Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	**Scenario 3** Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

SOURCE: ACIL ALLEN CONSULTING

4.7 PipelineCo development assumptions

To get ProjectCo's gas to market, it will need to be transmitted on a series of major gas transmission pipelines. As discussed in Section 0, there is limited capacity available on existing gas transmission pipelines. As a result, new pipelines must be developed.

PipelineCo is the builder, owner and operator of new major transmission pipeline infrastructure required to facilitate the development of ProjectCo's gas fields in each of the three scenarios. The development of PipelineCo is significantly simpler than ProjectCo, as PipelineCo simply builds pipelines of the requisite size to convey ProjectCo's gas to market over the life of the modelling period. PipelineCo is modelled as a typical pipeline owner-operator, with a relatively low required rate of return on its investments reflecting the relative safety of investment in pipeline infrastructure.

The key assumptions used to develop PipelineCo are presented below.

- PipelineCo builds all of its pipelines in the two years prior to the first flow of ProjectCo gas, to a specification that will allow it to carry the peak load of ProjectCo gas in the modelling period.
- PipelineCo has a 40 year investment horizon, and sets tariffs at a level that allow it to generate a six per cent pre-tax internal rate of return in a simple DCF model.
- PipelineCo's operating costs are set at 1.25 per cent of its total up front capital costs, and begin accruing from one year post the commencement of construction.
- Finally, part of PipelineCo's capital investment is stratified into initial investment in pipelines, which can carry a certain volume of uncompressed gas, and ongoing smaller capital investments required to build compression stations on the pipeline network as transmission requirements increase.

There are five distinct pipelines that are required to be built or duplicated over the three development scenarios, with the diameter of the pipe changing in each scenario depending on the volume of gas requiring transmission. The below matrix outlines the diameter of each pipe on PipelineCo's network in each scenario.

TABLE 4.5 PIPELINECO PIPELINE SPECIFICATIONS

Pipeline (length)	Breeze diameter	Wind diameter	Gale diameter
Tie into Amadeus pipeline (50km)	12 inch	19 inch	22 inch
Amadeus duplication (300km)	10 inch	18 inch	22 inch

Pipeline (length)	Breeze diameter	Wind diameter	Gale diameter
Northern Gas Pipeline (NGP) duplication (622km)	N/A	16 inch	21 inch
Carpentaria Gas Pipeline (CGP) duplication (841 km)	N/A	15 inch	21 inch
DLNG Feed Pipeline (new pipeline) (550km)	N/A	N/A	20 inch

Note: For simplicity, ACIL Allen assumed the processing facility built by ProjectCo is approximately 50 kilometres away from the Amadeus pipeline, and 550km away from the DLNG facility. Outside of this, ACIL Allen has not assumed a location for the development

SOURCE: ACIL ALLEN CONSULTING

ACIL Allen has not considered the mooted Moomba-Alice Springs gas pipeline in this analysis for two reasons. First, it is simpler to assume that existing pipeline routes are expanded or duplicated rather than developing an entirely new pipeline from scratch, as existing pipeline lengths, routes and cost estimates are available. Second, the Moomba-Alice Springs pipeline has been discussed for some time, and is yet to progress beyond the pre-feasibility study stage, albeit the Federal Government committed to fund a more detailed feasibility study earlier this year.[34] At face value, the Moomba-Alice Springs gas pipeline would represent a viable route to market for gas produced by a Northern Territory shale gas development.

[34] NT News. 2017. *Federal Government to investigate feasibility of north-south gas pipeline, 2 April 2017*. Accessed online at http://www.ntnews.com.au/

5 PROJECT DEVELOPMENT FINANCIAL MODEL

After shaping the development, using a series of modelling tasks, ACIL Allen has converted ProjectCo and PipelineCo's development plans in each scenario into three separate financial models. The financial models for ProjectCo are prepared as discounted cash flow ('DCF') model as if ProjectCo was a standalone corporate entity with a relatively simple financial structure. This requires a series of assumptions, which are outlined in Section 5.1. The outcome of the DCF modelling for ProjectCo is presented in Section 5.2. Recognising the role that assumptions can play in the results of DCF modelling, ACIL Allen has presented a series of sensitivity analysis on key inputs under each scenario. The results of this are presented in Section 5.3. Finally, the simple financial model for PipelineCo is outlined in Section 5.4.

5.1 ProjectCo financial inputs and assumptions

This section details the remaining key inputs and assumptions used to populate the cash flow model for each development scenario.

5.1.1 Overall inputs and assumptions

The inputs and assumptions used to populate the framework of the cash flow model are presented in the table below.

Input or Assumption	Value	Source
Reporting year	Financial year	ACIL Allen
Cash flow model start date	2018	ACIL Allen
Discount rate start date	2018	ACIL Allen
Discount rate	10 per cent	ACIL Allen

5.1.2 Financial inputs and assumptions

The inputs and assumptions used to estimate ProjectCo's non capital, operating and taxation expenses are presented in the table below.

Input or Assumption	Value	Source
Share of capital funded by debt	66.7 per cent	ACIL Allen estimate based on industry standards
Share of capital funded by equity	33.3 per cent	ACIL Allen estimate based on industry standards

Input or Assumption	Value	Source
Term length of debt	20 years	ACIL Allen estimate based on industry standards
Amortisation of debt	Yes	ACIL Allen based on industry standards
Native Title payments, exploration	3 per cent of proponent exploration cost	Stakeholder consultation
Native Title payments, operations	10 per cent of royalty payments	Stakeholder consultation
Pastoralist payments, operations	$250,000 per pad	Stakeholder consultation
Exploration permit	$4,927 per permit	NT Government[35]
Exploration permit renewal	$1,642 per permit	NT Government*
Production permit	$18,000 per block	NT Government*
Production permit renewal	$1,642 per permit	NT Government*
Environmental bond	Estimated cost of abandonment	Stakeholder consultation

5.1.3 Capital inputs and assumptions

The inputs and assumptions used to estimate ProjectCo's capital expenditure are presented in the table below.

Input or Assumption	Value	Source
Cost, drilling construction *(well-related civil work, surface hole preparation, drilling, fracture stimulation, completion, connection. This includes implicit costs of water extraction and sand acquisition for proppant)* *(also include implicit capital cost of a processing facility as a cost per 8.4-10.6-12.7PJ of gas. ACIL Allen could not determine the cost of a standalone processing facility)*	$18 million per well	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; – ACOLA, *Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report*, June 2013; and – industry consultation.
Costs, pad construction	$3.7 million per pad	ACIL Allen estimate based on industry consultation
Number of wells drilled per pad	8 wells per pad	ACIL Allen estimate based on industry expectations
Costs, gathering pipes construction	$350,000 per km	ACIL Allen estimate based on industry consultation assuming a 5 inch diameter pipe at $70,000 per inch kilometre
Costs, road construction	$450,000 per 1.7km	Cummings Economics, *Submission to Infrastructure Australia*, 2012
Costs, camp construction	$8 million per camp	ACIL Allen, based on: – Estimated cost per bed of INPEX Icthys camp, when applied to 150 bed camp structure = $11.1m.[36] – Stakeholder consultation

[35] https://nt.gov.au/industry/mining-and-petroleum/petroleum-titles/petroleum-titles-fees-and-rents
[36] INPEX. 2013. *ICHTHYS LNG PROJECT'S MANIGURR-MA VILLAGE OPEN FOR BUSINESS*. Accessed online at http://www.inpex.com/

Input or Assumption	Value	Source
Useful life, drilling	20 years	ACIL Allen based on standard ATO practice
Useful life, pad	20 years	ACIL Allen based on standard ATO practice
Useful life, gathering pipes	20 years	ACIL Allen based on standard ATO practice
Useful life, road	20 years	ACIL Allen based on standard ATO practice
Useful life, camp	20 years	ACIL Allen based on standard ATO practice
Abandonment, well	$250,000 per well	ACIL Allen based on industry consultation
Abandonment, pad	$100,000 per pad	ACIL Allen based on industry consultation

5.1.4 Operating inputs and assumptions

The inputs and assumptions used to estimate the operating cost of ProjectCo are presented in the table below.

Input or Assumption	Value	Source
All-in costs *(downhole maintenance and monitoring, extraction processing, labour, overheads, compliance, insurance)*	$1.50 per GJ	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; and – industry consultation.
Gathering and compression costs *(operations and maintenance for gathering pipelines, processing for sale)*	$0.75 per GJ	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; and – industry consultation.
Avoided cost of fuel *(included in 'all-in' costs and gathering and compression costs which reduces operating cost per GJ. Cost saving is mostly associated with diesel fuel hauling and storage costs)*	$0.90 per GJ	Industry consultation
Camp operating cost	$10 million per camp per annum	Industry consultation

5.1.5 Learnings inputs and assumptions

The inputs and assumptions used to estimate the learnings the ProjectCo will achieve over its economic life are presented in the table below.

Input or Assumption	Value	Source
Drilling construction costs	15 per cent, cap at 40 per cent per annum	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; – ACOLA, *Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report*, June 2013; and – industry consultation.
Pad construction costs	15 per cent, cap at 40 per cent per annum	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; – ACOLA, *Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report*, June 2013; and – industry consultation.
All-in operating costs	7.5 per cent, cap at 20 per cent per annum	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; – ACOLA, *Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report*, June 2013; and – industry consultation.
Gathering and compression operating costs	7.5 per cent, cap at 20 per cent per annum	ACIL Allen estimate based on: – US Department of Energy, *Trends in US Oil and Natural Gas Upstream Costs*, March 2016; – ACOLA, *Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report*, June 2013; and – industry consultation.

5.1.6 Labour inputs and assumptions

The inputs and assumptions used to estimate the labour component of ProjectCo are presented in the table below.

Input or Assumption	Value	Source
Average construction salary	$150,000 per FTE	ACIL Allen
Average operations salary	$150,000 per FTE	ACIL Allen
Field construction	35 FTEs per pad	Industry consultation
Camp construction	15 FTEs per camp	Industry consultation
Field operations	8 FTEs per pad	Industry consultation
Field abandonment	10 FTEs per pad	Industry consultation
Camp operations	20 FTEs per camp	Industry consultation

5.1.7 Pipeline tariffs

ACIL Allen anticipates ProjectCo will be able to utilise some latent capacity on existing gas transmission pipelines. The assumed tariffs for these are below. ACIL Allen has taken a conservative assumption and bought capacity at the quoted spot rate by pipeline owners, noting that realised tariffs are likely to be lower. Tariffs for new pipelines developed by PipelineCo are presented in Section 0.

Input or Assumption	Value	Source
Amadeus Gas Pipeline	$0.58 per GJ	APA Group
Northern Gas Pipeline (NGP)	$1.45 per GJ	Jemena Group
Carpentaria Gas Pipeline (CGP)	$1.56 per GJ	APA Group

5.1.8 Water inputs and assumptions

The inputs and assumptions used to estimate ProjectCo's total water requirements are presented in the table below.

Input or Assumption	Value	Source
Water requirements	41ML per frack	ACIL Allen estimate based on: – ACOLA, *Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report*, June 2013; and – industry consultation. As a conservative estimate, ACIL Allen has doubled its expected water use projection.
Water recycle rate	0 per cent recycled	ACIL Allen estimate
Number of fracking stages	20 fracks and 1 hydraulic fracture stimulation program per well	ACIL Allen estimate based on industry consultation
Water charges	$0/ML	NT Government, there is currently no policy to charge users of groundwater for the use of groundwater resources. The cost of extracting ground water is implicit in ACIL Allen's well cost assumption

5.1.9 Macroeconomic inputs and assumptions

The macroeconomic inputs and assumptions that impact on ProjectCo's net cash flows are presented in the table below.

Input or Assumption	Value	Source
Long-term bond rate	3.5 per cent	ACIL Allen
Interest rate	6 per cent	ACIL Allen
Inflation	Real terms	ACIL Allen

5.1.10 Taxation inputs and assumptions

The taxation inputs and assumptions used in this cash flow assessment of ProjectCo are presented in the table below.

Input or Assumption	Value	Source
Payroll tax rate, Northern Territory	5.5 per cent	NT Department of Treasury and Finance http://www.treasury.nt.gov.au/TaxesRoyaltiesAndGrants/PayrollTax/Pages/Payroll-Tax-Rates-and-Thresholds.aspx
Payroll tax threshold, Northern Territory	$1.5 million	NT Department of Treasury and Finance http://www.treasury.nt.gov.au/TaxesRoyaltiesAndGrants/PayrollTax/Pages/Payroll-Tax-Rates-and-Thresholds.aspx
Company tax rate	30 per cent	ATO
Quarantine losses	Yes	ACIL Allen based on standard ATO practice
PRRT rate	40 per cent	ATO
PRRT general expenditure growth rate	4 per cent	ACIL Allen
Oil and gas royalty rate, Northern Territory	10 per cent of well head value	NT Department of Treasury and Finance

5.2 ProjectCo cash flow modelling results

Based on the set of inputs and assumptions detailed in the previous sections, the estimated net cash flows of ProjectCo for each development stage is presented below.

ACIL Allen estimated the net cash flows of each development scenario using a bottom-up approach. This involved estimating costs for capital, operations, other operating costs and direct taxation payments made by ProjectCo and the resulting margin under each development scenario (refer to Table 5.1 and Figure 5.1 overleaf).

TABLE 5.1 AVERAGE COST BETWEEN 2022 AND 2043 OF EACH PROJECTCO DEVELOPMENT SCENARIO, FINANCIAL YEAR, REAL TERMS, A$ PER GJ

Cost	BREEZE	WIND	GALE
CAPEX	$2.20/GJ	$1.74/GJ	$1.45/GJ
Interest	$1.20/GJ	$0.86/GJ	$0.55/GJ
OPEX	$1.77/GJ	$1.59/GJ	$1.46/GJ
Taxation	$0.75/GJ	$0.71/GJ	$0.45/GJ
Other costs	$0.16/GJ	$0.13/GJ	$0.09/GJ
Total costs (ex-field)	**$6.07/GJ**	**$5.03/GJ**	**$4.01/GJ**
Market price (ex-transport tariff)	**$6.84/GJ**	**$5.11/GJ**	**$3.75/GJ**
Margin	**$0.77/GJ**	**$0.09/GJ**	**-$0.26/GJ**

Note: Market prices presented are ex-transport tariff.

SOURCE: ACIL ALLEN CONSULTING

The largest components of ProjectCo's cost structure are the costs associated with capital expenditure. For example, under the BREEZE development scenario, the cost of capital averages $2.20 per GJ, with the resulting average interest costs associated with financing capital expenditure of $1.20 per GJ. The costs of capital and interest reduce in the subsequent WIND and GALE development scenarios due to improved learnings and the economies of scale achieved under a larger production scenario.

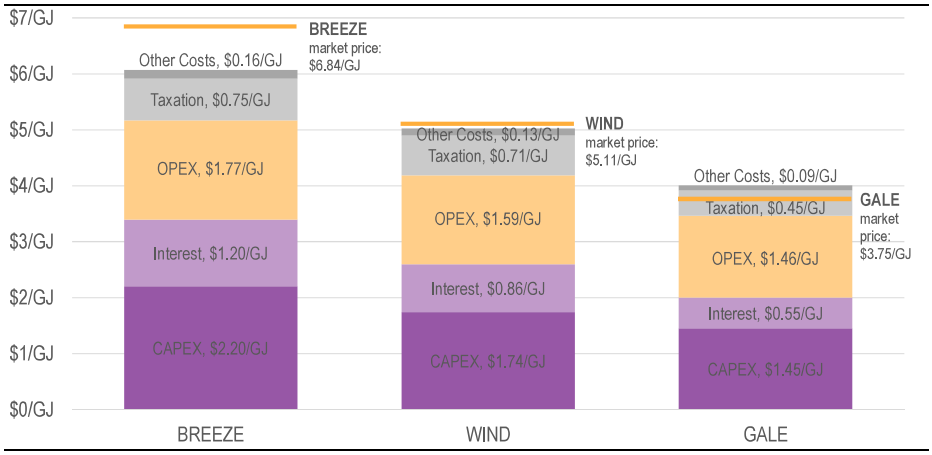
Ex-field costs associated with ProjectCo's production phase are the next biggest share of its total cost structure. For example, under the BREEZE development stage, operating costs average $1.78 per GJ, reducing to an average of $0.55 per GJ under the GALE development scenario as a result of the improved learnings and economies of scale benefits.

Taxation payments made by ProjectCo are dependent on the economics of each development stage. Based on the margins generated under each development scenario, the tax payments are expected to range from $0.74 per GJ under the BREEZE development scenario to $0.45 per GJ under the GALE development scenario.

Based on the 20 year study period, this does not allow enough time for ProjectCo to return a substantial dividend on its capital expenditure. However, beyond the study period and over the economic life of the Project, the dividends increase and the Project's taxation payment increase.

Ex-field all other costs include costs for abandonment, payments to native title owners and pastoralists, and licensing. On average, other costs make up a very small proportion of ProjectCo's cost structure under each development scenario.

FIGURE 5.1 AVERAGE COST BETWEEN 2022 AND 2043 OF EACH PROJECTCO DEVELOPMENT STAGE, FINANCIAL YEAR, REAL TERMS, A$ PER GJ



Note: Market prices presented are ex-transport tariff.

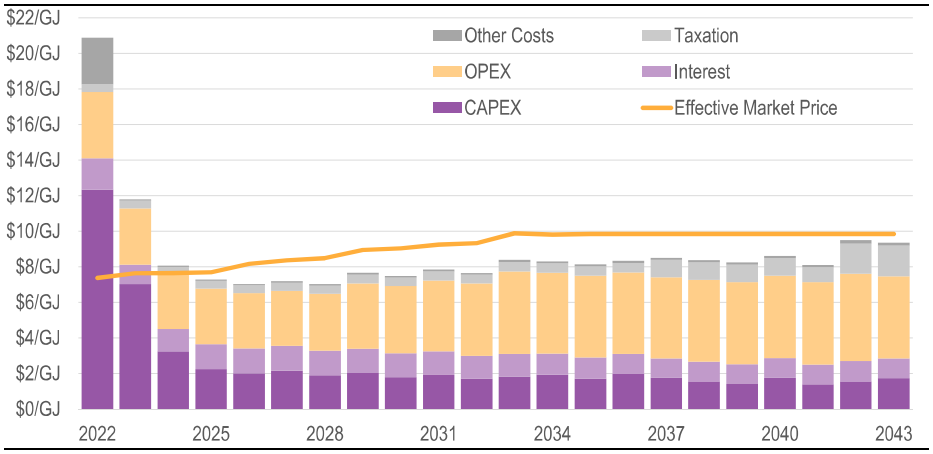
SOURCE: ACIL ALLEN CONSULTING

The figures presented in Figure 5.1 represent averages over the period between 2022 and 2043, and therefore do not necessarily represent the operating position of each development scenario at any one time. It is for this reason in Figure 5.1 that the GALE development scenario shows an operating loss over the study period.

Figure 5.3 below presents the operating position of the BREEZE development scenario each year over the study period. At the start of the development, the capital requirements of ProjectCo are significant, but as ProjectCo reaches a steady state of production, the level capital required to maintain steady state production significantly falls. This results in ProjectCo operating at a loss in the early years of the development (when capital costs are high), with a positive margin being generated once steady state production is reached (due to lower capital requirements).

This is consistent across all development scenarios.

FIGURE 5.2 AVERAGE COST BETWEEN 2022 AND 2043 OF BREEZE DEVELOPMENT SCENARIO, FINANCIAL YEAR, REAL TERMS, A$ PER GJ



Note: Market prices presented are ex-transport tariff.

SOURCE: ACIL ALLEN CONSULTING

5.2.1 CALM

The CALM scenario is the scenario that sees ProjectCo undertake a three year program of exploration and appraisal, but fail to progress beyond this due to an inability to find a commercial quality shale gas reserve. The CALM scenario is also the basis for the first four years (in Year 0, nothing occurs as the moratorium is lifted) of the production scenarios discussed below, but instead of an assumption that no commercial quality shale gas is discovered, the assumption is a requisite scale commercial shale gas reserve is discovered.

ACIL Allen has assumed in the first year of the exploration and appraisal program, ProjectCo builds eight production wells, and the associated infrastructure to support the program. This is valued at $315.9 million. In Year two of the exploration and appraisal program, testing, commercial analysis and other services are purchased to allow ProjectCo to understand the shale it is testing. This is valued at $166.9 million. In Year three, residual exploration expenditure occurs, as ProjectCo decommissions its exploration and appraisal program due to a failure to find a commercial shale gas reserve. This is valued at $4.2 million.

In the CALM scenario, this is the extent of ProjectCo's financial model. The total cost of the exploration and appraisal program is $500 million. It is assumed ProjectCo does not earn any revenue from its operations, meaning the discounted net cash flows of ProjectCo are estimated to total -$440 million over the study period (refer to Figure 5.3 overleaf).

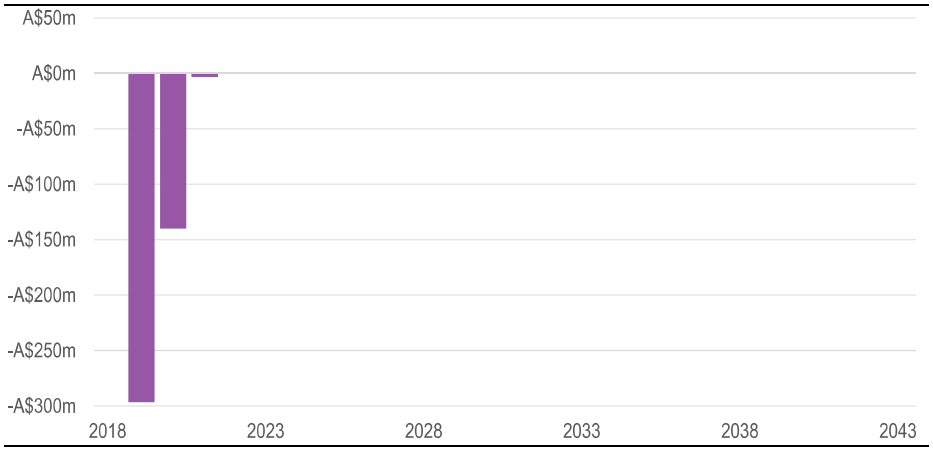
In the BREEZE, WIND and GALE scenarios, the expenditure associated with CALM is the starting point of the cash flow model, and is recovered progressively over the modelling period as ProjectCo moves into production and begins to generate positive cash flows.

5.2.2 BREEZE

Based on the production profile and the associated drilling schedule developed by ACIL Allen, it is estimated the capital requirements of ProjectCo under the BREEZE development scenario over the study period would total $2 billion, at an average of $76 million per annum.

The cost of drilling and associated pad costs are estimated to total $1.5 billion over the study period, making them the largest component of total capital expenditure. The remainder of the capital expenditure consists of supporting infrastructure, such as gathering pipes, roads and camp construction costs.

FIGURE 5.3 CALM NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



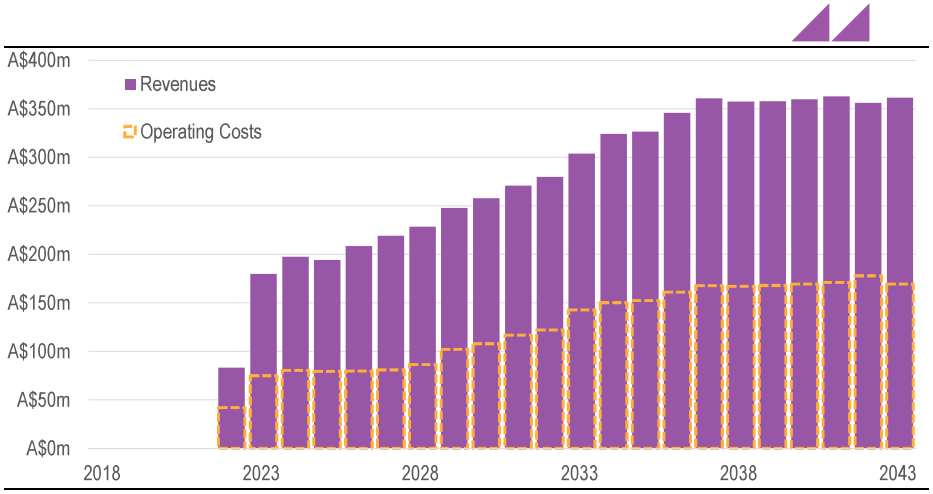
SOURCE: ACIL ALLEN CONSULTING

The operating costs of ProjectCo reach a steady state of around $170 million per annum in 2037 (refer to Figure 5.4 overleaf). Over the study period, operating costs total $2.8 billion at an average of $107 million per annum. Transport costs total $1.6 billion over the study period, and are the largest component of ProjectCo's total operating cost structure.

The capital expenditure and operating costs generate a steady state of revenue of around $350 million per annum by 2037. Over the study period, the revenues are estimated to total $6.2 billion at an average of $238 million per annum.

Once ProjectCo becomes liable for PRRT payments, PRRT payments overtake company taxation payments as the major profits based tax.

FIGURE 5.4 BREEZE OPERATING POSITION, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

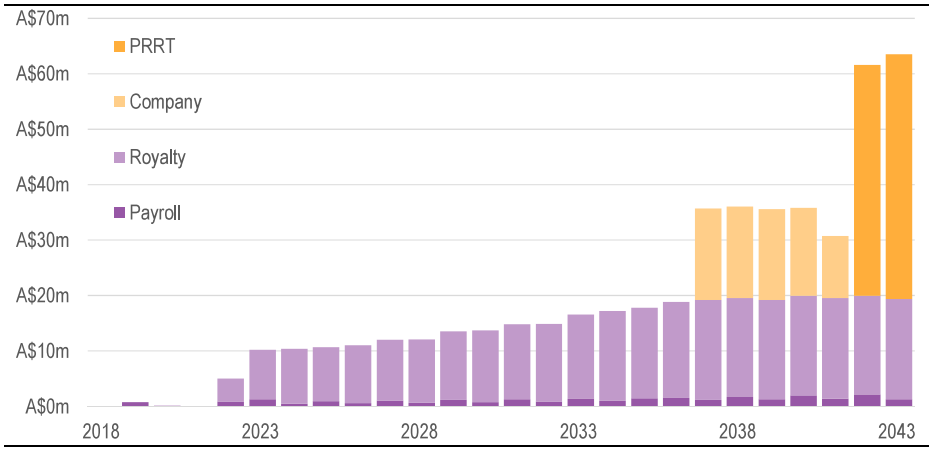
Figure 5.4 presents the major heads of taxation ProjectCo is liable to pay over the study period. Under the BREEZE development scenario, it is estimated that ProjectCo becomes liable for profit based taxation payments from 2037.

Company taxation payments to the Commonwealth are estimated to be first payable in 2037 and total $76.5 million at an average of $2.9 million per annum over the study period. As the taxable income of ProjectCo increases over time and the Project's PRRT credits are fully consumed, ProjectCo becomes liable for PRRT payments in 2042, and total $85.8 million over the study period.

Over the study period, the Northern Territory Government will be the primary beneficiary of taxation payments made by ProjectCo. This will largely occur through the form of royalty payments, which are estimated to total $309 million over the study period or $11.9 million per annum.

The Northern Territory Government will also receive payroll taxation payments from ProjectCo, which are estimated to total $27.2 million over the study period, or on average $1.1 million per annum.

FIGURE 5.5 BREEZE DIRECT TAXATION PAYMENTS, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

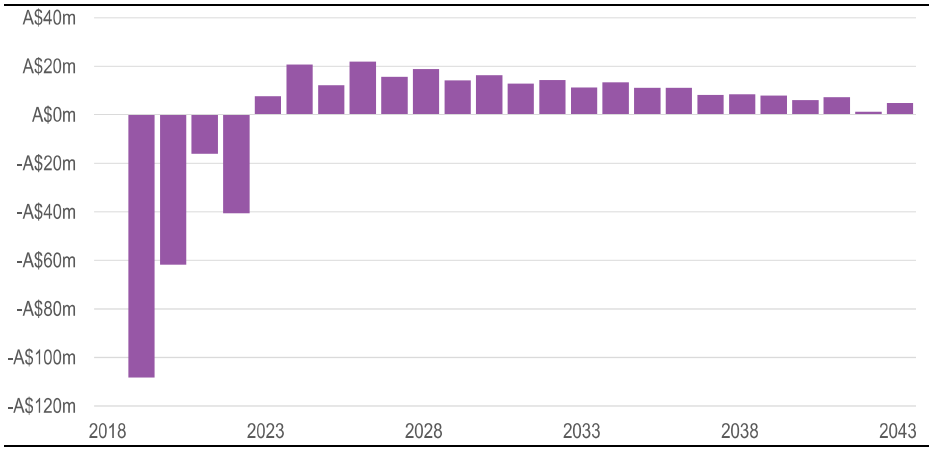
The level of taxation receipts collected by both Commonwealth and Territory governments are dependent on the magnitude of net cash flows generated by ProjectCo, which are of course highly sensitive to the inputs and assumptions that underpin the cash flow model.

Over the study period, the discounted net cash flows of ProjectCo are estimated to total $19.4 million, at an average of $0.8 million per annum. Under the set of inputs and assumptions presented above, interest payments on the debt required to fund ProjectCo's capital expenditure, and the cost of PRRT payments first being realised in 2042, are major determinants of the Project's overall economic viability from a discounted cash flow prospective.

This is because the cash flow model has been developed to fund capital expenditure via debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo in the early years reduce the level of debt the Project is required to take on, which reduces interest payments and further increases the Project's net cash flows.

However, as taxation expenses increase when ProjectCo's taxable income increases towards the end of the study period, positive net cash flows are reduced, resulting in ProjectCo's financing more of its capital expenditure by debt, which increases interest payments and further reduces net cash flows.

FIGURE 5.6 BREEZE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



Note: Discount rate of 10 per cent per annum.

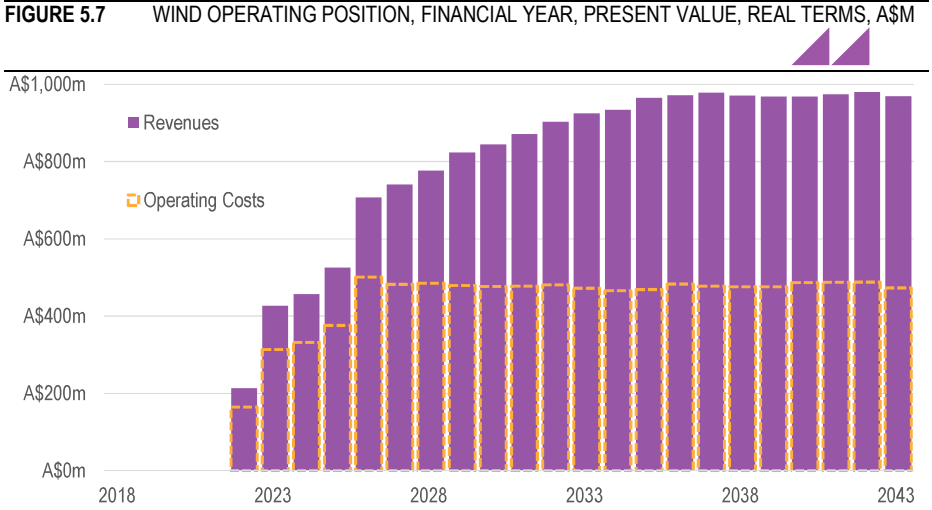
SOURCE: ACIL ALLEN CONSULTING

5.2.3 WIND

Based on the production profile and the associated drilling schedule developed by ACIL Allen, it is estimated the capital requirements of ProjectCo under the WIND development scenario over the study period would total $4.3 billion, at an average of $167 million per annum. The cost of drilling and associated pad costs are estimated to total $3.5 billion over the study period, making them the largest component of total capital expenditure. The remainder of the capital expenditure consists of supporting infrastructure, such as gathering pipes, roads and camp construction costs.

The operating costs of ProjectCo reach a steady state of around $480 million per annum in 2027 (refer to Figure 5.7). Over the study period, operating costs total $9.8 billion at an average of $379 million per annum. Transport costs total $6.3 billion over the study period, and are the largest component of ProjectCo's total operating cost structure.

FIGURE 5.7 WIND OPERATING POSITION, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A$M



SOURCE: ACIL ALLEN CONSULTING

The capital expenditure and operating costs generate a steady state of revenue of around $970 million per annum by 2035. Over the study period, the revenues are estimated to total $17.9 billion at an average of $688 million per annum.

Figure 5.8 presents the major heads of taxation ProjectCo is liable to pay over the study period. Under the WIND development scenario, it is estimated that ProjectCo becomes liable for profit based taxation payments from 2037.

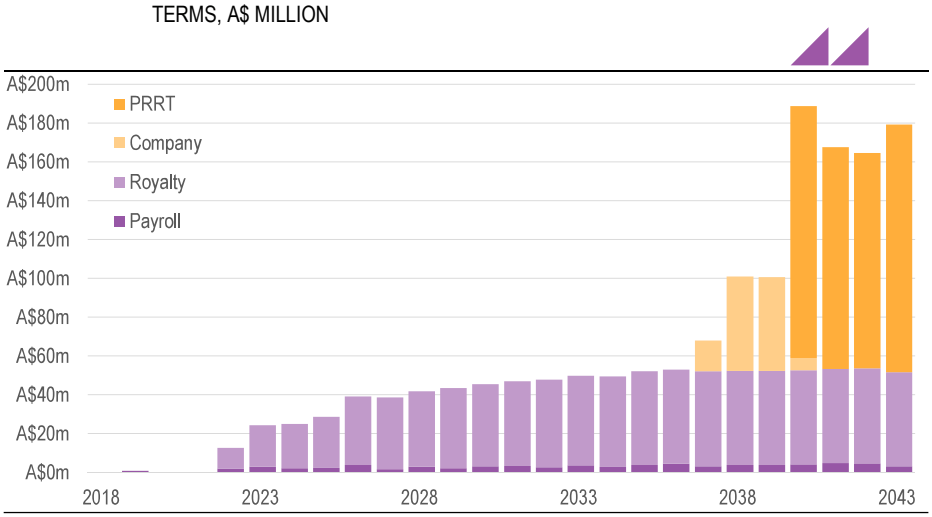
Company taxation payments to the Commonwealth are estimated to be first payable in 2037 and total $119 million at an average of $4.6 million per annum over the study period. As the taxable income of ProjectCo increases over time and the Project's PRRT credits are fully consumed, ProjectCo becomes liable for PRRT payments in 2040, and total $483 million over the study period.

Once ProjectCo becomes liable for PRRT payments, PRRT payments overtake company taxation payments as the major profits based tax.

Over the study period, the Northern Territory Government will be the primary beneficiary of taxation payments made by ProjectCo. This will largely occur through the form of royalty payments, which are estimated to total $875 million over the study period or $34.4 million per annum.

The Northern Territory Government will also receive payroll taxation payments from ProjectCo, which are estimated to total $71.1 million over the study period, or on average $2.7 million per annum.

FIGURE 5.8 WIND DIRECT TAXATION PAYMENTS, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A$ MILLION



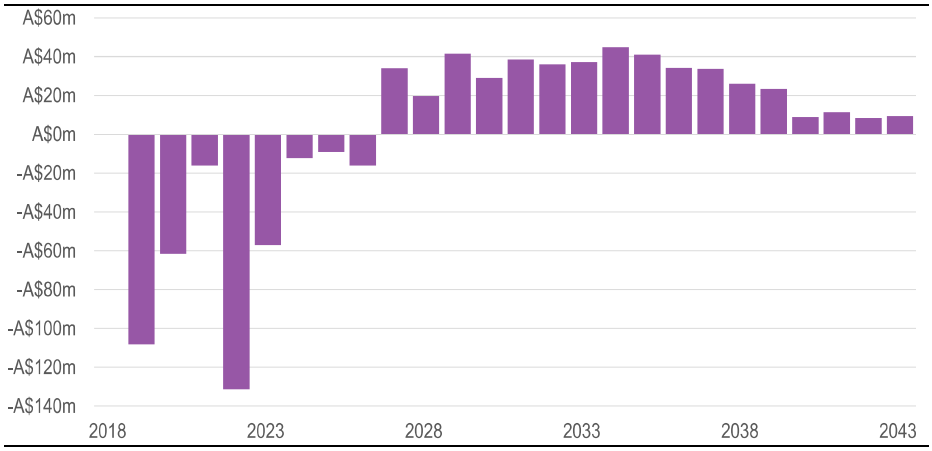
SOURCE: ACIL ALLEN CONSULTING

The level of taxation receipts collected by both Commonwealth and Territory governments are dependent on the magnitude of net cash flows generated by ProjectCo, which are of course highly sensitive to the inputs and assumptions that underpin the cash flow model.

Over the study period, the discounted net cash flows of ProjectCo are estimated to total $65.9 million, at an average of $2.5 million per annum. Under the set of inputs and assumptions presented above, interest payments on the debt required to fund ProjectCo's capital expenditure, and the cost of PRRT payments first being realised in 2040, are major determinants of the Project's overall economic viability from a discounted cash flow prospective.

This is because the cash flow model has been developed to fund capital expenditure via debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo in the early years reduce the level of debt the Project is required to take on, which reduces interest payments and further increases the Project's net cash flows.

FIGURE 5.9 WIND NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



Note: Discount rate of 10 per cent per annum.

SOURCE: ACIL ALLEN CONSULTING

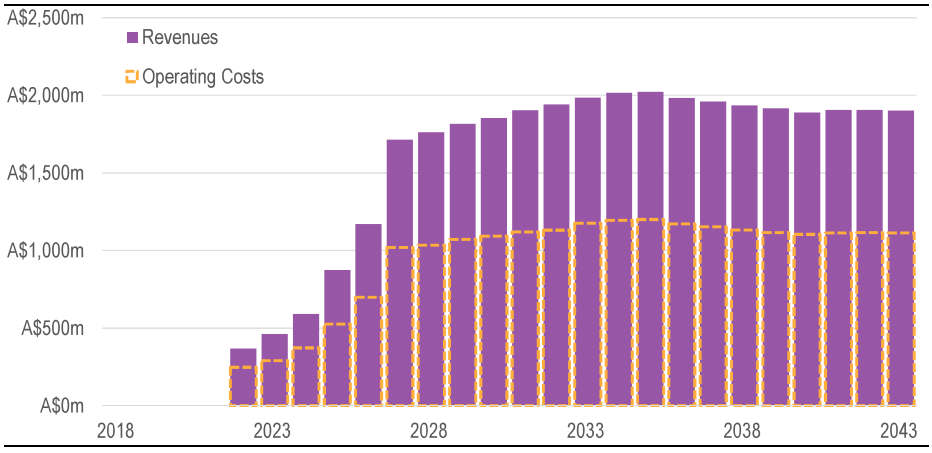
However, as taxation expenses increase when ProjectCo's taxable income increases towards the end of the study period, positive net cash flows are reduced, resulting in ProjectCo's financing more of its capital expenditure by debt, which increases interest payments and further reduces net cash flows.

5.2.4 GALE

Based on the production profile and the associated drilling schedule developed by ACIL Allen, it is estimated the capital requirements of ProjectCo under the GALE development scenario over the study period would total $9.8 billion, at an average of $378 million per annum. The cost of drilling and associated pad costs are estimated to total $8.5 billion over the study period, making them the largest component of total capital expenditure. The remainder of the capital expenditure consists of supporting infrastructure, such as gathering pipes, roads and camp construction costs.

The operating costs of ProjectCo reach a steady state of around $1.1 billion per annum in 2027 (refer to Figure 5.10).

FIGURE 5.10 GALE OPERATING POSITION, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A$M



SOURCE: ACIL ALLEN CONSULTING

Over the study period, operating costs total $21 billion at an average of $816 million per annum. Transport costs total $11.8 billion over the study period, and are the largest component of ProjectCo's total operating cost structure. The capital expenditure and operating costs generate a steady state of revenue of around $1.9 billion per annum by 2030. Over the study period, the revenues are estimated to total $35.9 billion at an average of $1.4 billion per annum.

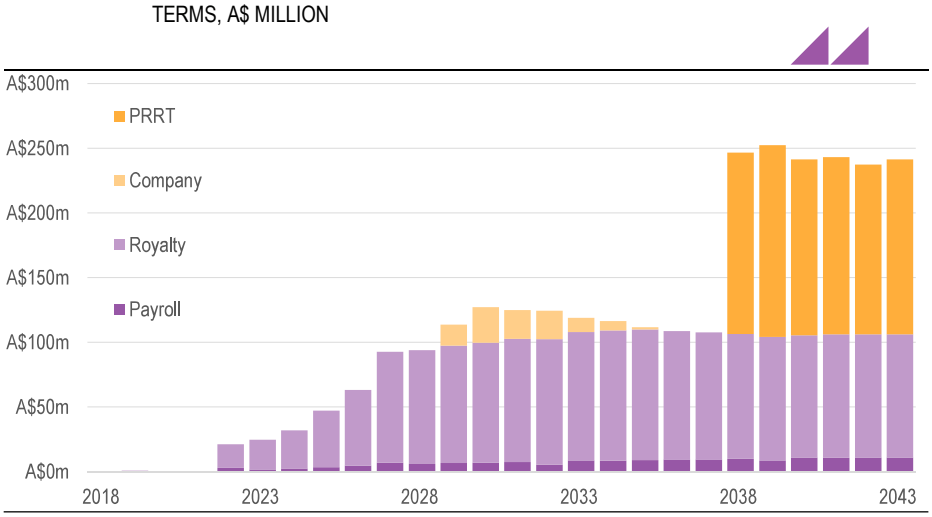
Figure 5.11 presents the major heads of taxation ProjectCo is liable to pay over the study period. Under the GALE development scenario, it is estimated that ProjectCo becomes liable for profit based taxation payments from 2029.

Company taxation payments to the Commonwealth are estimated to be first payable in 2029 and total $108 million at an average of $4.2 million per annum over the study period. As interest payments increase over time, the taxable income of ProjectCo decreases, as results in no company taxation payments in 2036 and 2037. However, as ProjectCo's taxable income for PRRT calculations increases, and over time and the Project's PRRT credits are fully consumed, ProjectCo will become liable for PRRT payments in 2038, totalling $828 million over the study period.

Over the study period, the Northern Territory Government will be the primary beneficiary of taxation payments made by ProjectCo. This will largely occur through the form of royalty payments, which are estimated to average $1.8 billion over the study period or $69 million per annum.

The Northern Territory Government will also receive payroll taxation payments from ProjectCo, which are estimated to total $163 million over the study period, or on average $6.3 million per annum.

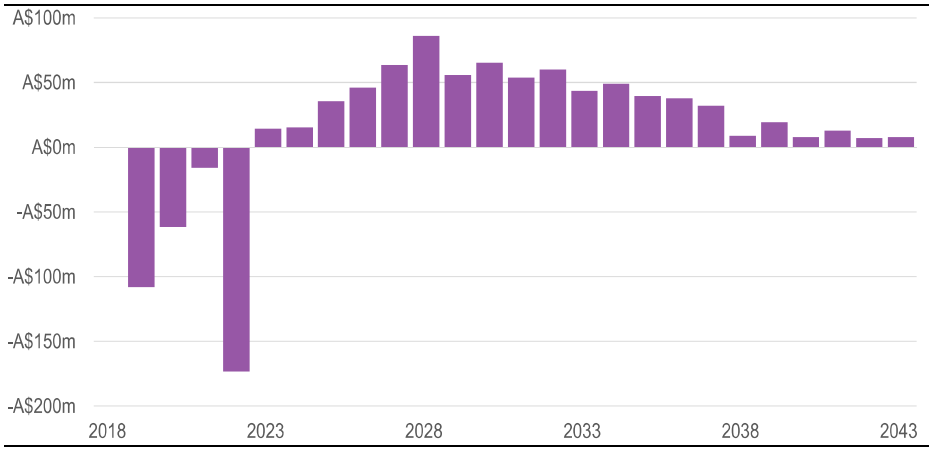
FIGURE 5.11 GALE DIRECT TAXATION PAYMENTS, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

The level of taxation receipts collected by both Commonwealth and Territory governments are dependent on the magnitude of net cash flows generated by ProjectCo, which are of course highly sensitive to the inputs and assumptions that underpin the cash flow model.

FIGURE 5.12 GALE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



Note: Discount rate of 10 per cent per annum.

SOURCE: ACIL ALLEN CONSULTING

Over the study period, the discounted net cash flows of ProjectCo are estimated to total $403 million, at an average of $15.5 million per annum. Under the set of inputs and assumptions presented above, interest payments on the debt required to fund ProjectCo's capital expenditure, and the cost of PRRT payments first being realised in 2038, are major determinants of the Project's overall economic viability from a discounted cash flow prospective.

This is because the cash flow model has been developed to fund capital expenditure via debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo in the early years reduce the level of debt the Project is required to take on, which reduces interest payments and further increases the Project's net cash flows. However, as taxation expenses increase when ProjectCo's taxable income increases towards the end of the study period, positive net cash flows are reduced, resulting in ProjectCo financing more of its capital expenditure by debt, which increases interest payments and further reduces net cash flows.

5.3 Sensitivity analysis – ProjectCo cash flow modelling results

The overall economics of ProjectCo are highly sensitive to a number of key assumptions presented in the above sections. In order to highlight the degree of sensitivity of ProjectCo to the inputs and assumptions used in this study, ACIL Allen has undertaken sensitivity analysis for four key inputs and assumptions, and have presented the results as the discounted net cash flows of each development scenario.

The key variables ACIL Allen has presented sensitivity analysis on are:

- EUR: +/- 3.8 PJ from the base case;
- interest rate: +/- 1 percentage point from the base case;
- market price: +/- 20 per cent from the base case; and
- learnings: +/- 20 per cent from the base case.

5.3.1 BREEZE

A summary of the change in total and average annual discounted net cash flows of ProjectCo are presented in Table 5.2 and Figure 5.13.

TABLE 5.2 SUMMARY OF SENSITIVITY ANALYSIS, BREEZE NET CASH FLOWS, DISCOUNTED, REAL TERMS, A$ MILLION

Sensitivity	Total	Average
EUR		
Base case, 8.4 PJ	$19.4 million	$0.8 million
High case, 12.7 PJ	$135 million	$5.2 million
Low case, 4.2 PJ	-$83.6 million	-$3.2 million
Interest Rate		
Base case, 6 per cent	$19.4 million	$0.8 million
High case, 7 per cent	-$11 million	-$0.4 million
Low case, 5 per cent	$45.4 million	$1.8 million
Market Price		
Base case	$19.4 million	$0.8 million
High case, +20 per cent	$154 million	$5.9 million
Low case, -20 per cent	-$154 million	-$5.9 million
Learnings		
Base case	$19.4 million	$0.8 million
High case, +20 per cent	$30.3 million	$1.2 million
Low case, -20 per cent	-$8.6 million	-$0.3 million

SOURCE: ACIL ALLEN CONSULTING

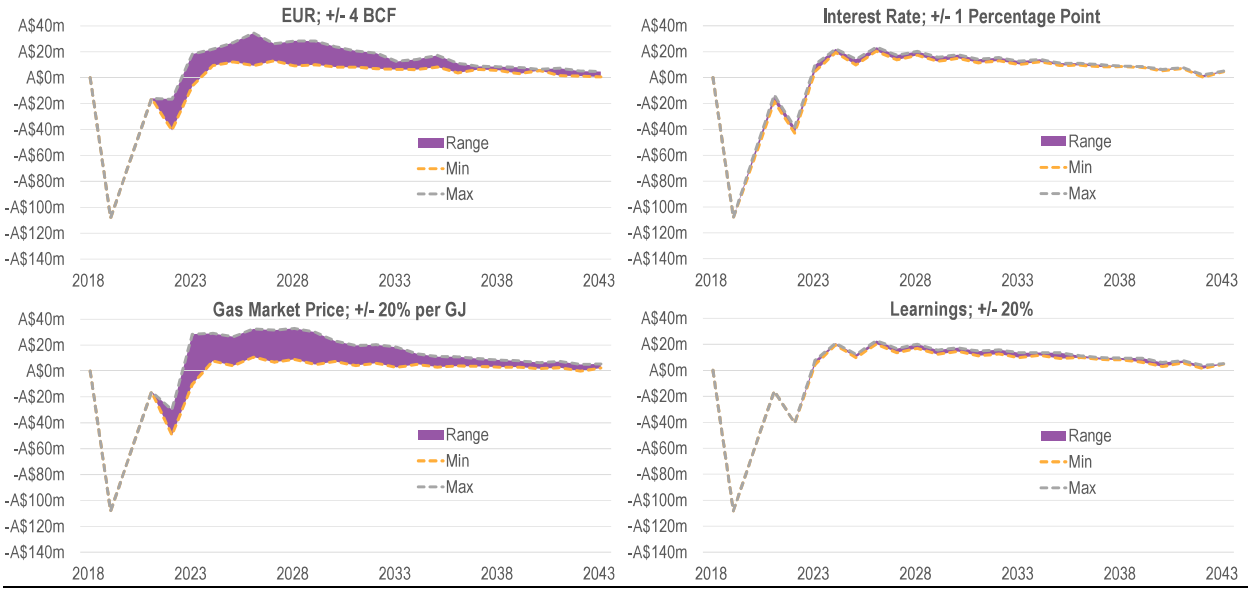
Table 5.2 and Figure 5.13 demonstrate that a change to the market price has the greatest variability on the discounted net cash flows of ProjectCo, while a change in the EUR also has a significant impact on the variability of ProjectCo's cash flows.

When the market price is increased by 20 per cent, the discounted net cash flows of ProjectCo increase from $19.4 million to $154 million. Similarly, when the EUR is increased to 12.7 PJ, the discounted net cash flows increase to $135 million.

The variability of the cash flows to changes in the interest rate or learnings are less pronounced, but still significant. For example, when the interest rate increases by one percentage point, total discounted net cash flows decrease from $19.4 million to -$11 million, and if the rate of learnings are decreased by 20 per cent, the discounted net cash flows fall to -$8.6 million.

Similar to the base case discount net cash flow results presented in Section 5.2, this variance is due to how the cash flow model has been developed, where capital expenditure is financed by debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo reduce the level of debt the Project is required to take on to finance its capital requirements, which reduces interest payments and further increases the Project's net cash flows. However, as net cash flows are reduced, the Project is required to finance more of its capital expenditure by debt, which increases interest payments and further reduces the Project's net cash flows.

FIGURE 5.13 SENSITIVITY ANALYSIS, BREEZE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

5.3.2 WIND

A summary of the change in total and average annual discounted net cash flows of ProjectCo are presented in Table 5.3 and Figure 5.14.

TABLE 5.3 SUMMARY OF SENSITIVITY ANALYSIS, WIND NET CASH FLOWS, DISCOUNTED, REAL TERMS, A$ MILLION

Sensitivity	Total	Average
EUR		
Base case, 10.6 PJ	$65.9 million	$2.5 million
High case, 14.8 PJ	$352 million	$13.5 million
Low case, 6.3 PJ	-$82.4 million	-$3.2 million
Interest Rate		
Base case, 6 per cent	$65.9 million	$2.5 million
High case, 7 per cent	$2.1 million	-$0.1 million
Low case, 5 per cent	$129 million	$5 million
Market Price		
Base case	$65.9 million	$2.5 million
High case, +20 per cent	$484 million	$18.6 million
Low case, -20 per cent	-$492 million	-$18.9 million
Learnings		
Base case	$65.9 million	$2.5 million
High case, +20 per cent	$117 million	$4.5 million
Low case, -20 per cent	-$31.5 million	-$1.2 million

Sensitivity	Total	Average

SOURCE: ACIL ALLEN CONSULTING

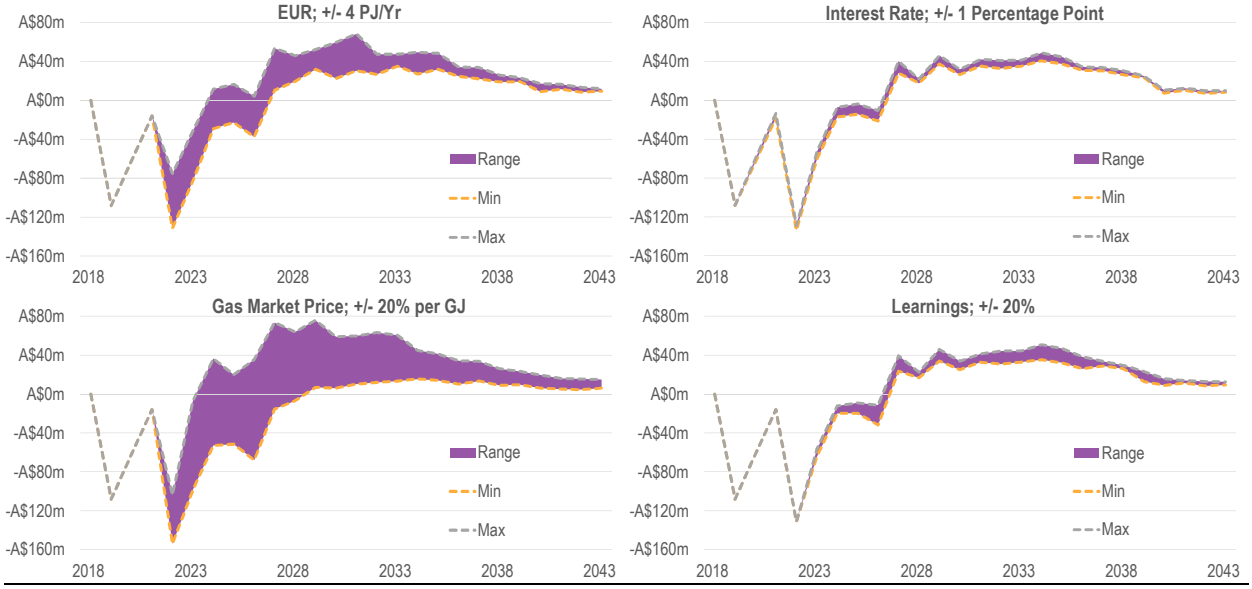
Table 5.3 and Figure 5.14 demonstrate that a change to the market price has the greatest variability on the discounted net cash flows of ProjectCo, while a change in the PJ also has a significant impact on the variability of ProjectCo's cash flows.

When the market price is increased by 20 per cent, the discounted net cash flows of ProjectCo increase from $65.9 million to $484 million. Similarly, when the BFC is increased to 14.8 PJ, the discounted net cash flows increase to $352 million.

The variability of the cash flows to changes in the interest rate or learnings are less pronounced, but still significant. For example, when the interest rate increases by one percentage point, total discounted net cash flows decrease from $65.9 million to $2.1 million, and if the rate of learnings are decreased by 20 per cent, the discounted net cash flows fall to -$31.5 million.

Similar to the base case discount net cash flow results presented in Section 5.2, this variance is due to how the cash flow model has been developed, where capital expenditure is financed by debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo reduce the level of debt the Project is required to take on to finance its capital requirements, which reduces interest payments and further increases the Project's net cash flows. However, as net cash flows are reduced, the Project is required to finance more of its capital expenditure by debt, which increases interest payments and further reduces the Project's net cash flows.

FIGURE 5.14 SENSITIVITY ANALYSIS, WIND NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

5.3.3 GALE

A summary of the change in total and average annual discounted net cash flows of ProjectCo are presented in Table 5.4 and Figure 5.15.

TABLE 5.4 SUMMARY OF SENSITIVITY ANALYSIS, GALE NET CASH FLOWS, DISCOUNTED, REAL TERMS, A$ MILLION

Sensitivity	Total	Average
EUR		
Base case, 12.7 PJ	$403 million	$15.5 million
High case, 16.9 PJ	$777 million	$29.9 million
Low case, 8.4 PJ	$420 million	$16.2 million
Interest Rate		
Base case, 6 per cent	$403 million	$15.5 million
High case, 7 per cent	$322 million	$12.4 million
Low case, 5 per cent	$483 million	$18.5 million
Market Price		
Base case	$403 million	$15.5 million
High case, +20 per cent	$1,041 million	$40 million
Low case, -20 per cent	-$593 million	-$22.8 million
Learnings		
Base case	$403 million	$15.5 million
High case, +20 per cent	$474 million	$18.3 million
Low case, -20 per cent	$224 million	$8.6 million

SOURCE: ACIL ALLEN CONSULTING

Table 5.4 and Figure 5.15 demonstrate that a change to the market price has the greatest variability on the discounted net cash flows of ProjectCo, while a change in the PJ also has a significant impact on the variability of ProjectCo's cash flows.

When the market price is increased by 20 per cent, the discounted net cash flows of ProjectCo increase from $403 million to $1 billion. Similarly, when the PJ is increased to 16.9 PJ, the discounted net cash flows increase to $777 million.

Over the study period, the variability of the cash flows to changes in the interest rate or learnings are less pronounced, and less pronounced than the BREEZE and WIND development scenarios. However, over the economic life of ProjectCo under the GALE development scenario, changes to the base case interest rate and learnings are significant.

Over the study period, when the interest rate increases by one percentage point, total discounted net cash flows decrease from $403 million to $322 million, and if the rate of learnings are decreased by 20 per cent, the discounted net cash flows falls to $224 million.

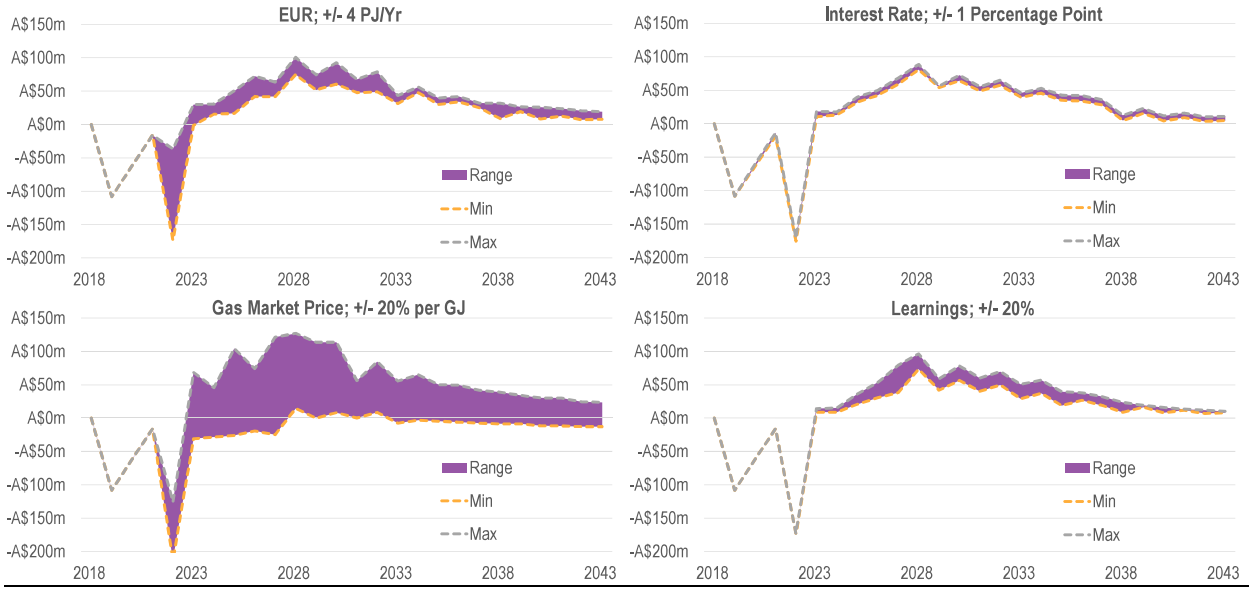
It should be noted, however, under the low case EUR sensitivity, when the PJ is lowered to 8.4, the discounted net cash flows of ProjectCo are higher than the base case. This is due to the impact that payments for PRRT have on the economics of ProjectCo. Under a lower EUR, ProjectCo's taxable income is less, resulting PRRT payments being payable in later years. Over the economic life of ProjectCo, the base case total discounted net cash flows are greater than total discounted net cash flows of the lower EUR sensitivity.

The total discounted net cash flows under the lower sensitivities for the GALE development scenario are also positive, compared to the BREEZE and WIND development scenarios over the study period. However, over the economic life of ProjectCo under the GALE development scenario, total discounted net cash flows are negative, as is the case in the other development scenarios.

Similar to the base case discount net cash flow results presented in Section 5.2, this variance is due to how the cash flow model has been developed, where capital expenditure is financed by debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo reduce the level of debt the Project is required to take on to finance its capital requirements,

which reduces interest payments and further increases the Project's net cash flows. However, as net cash flows are reduced, the Project is required to finance more of its capital expenditure by debt, which increases interest payments and further reduces the Project's net cash flows.

FIGURE 5.15 SENSITIVITY ANALYSIS, GALE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

5.4 PipelineCo financial model

PipelineCo is modelled using a simple DCF model with a series of assumptions regarding the cost of development and operation, required pre-tax internal rate of return. Using the assumed pipeline diameters developed in Section 4.6, and the gas sales volumes of ProjectCo in each scenario developed in Section 0, PipelineCo aims to deliver its pipeline project in each scenario to an NPV = $0 after 40 years (the useful life of the pipeline infrastructure), using a six per cent discount rate (the pre-tax internal rate of return).

To do this, it sets a flat real tariff equal to the amount that will allow it to deliver on its financial target. These tariffs are presented below. The tariffs are charged to ProjectCo, where they accrue as an operating cost. This requires a special treatment in the economic impact assessment modelling, which is discussed in the next Chapter.

TABLE 5.5 PIPELINECO PIPELINE TARIFFS

Pipeline	Breeze tariff ($/GJ)	Wind tariff ($/GJ)	Gale tariff ($/GJ)
Tie into Amadeus pipeline (50km)	0.2479	0.1651	0.1884
Amadeus duplication	2.0060	0.4471	0.3719
Northern Gas Pipeline (NGP) duplication	N/A	0.9350	0.6458
Carpentaria Gas Pipeline (CGP) duplication	N/A	1.3563	0.8601
DLNG Feed Pipeline (new pipeline)	N/A	N/A	0.6882

SOURCE: ACIL ALLEN CONSULTING

III

ECONOMIC IMPACT ASSESSMENT

6 ECONOMIC IMPACT ASSESSMENT INTRODUCTION

This section of the reports explores the economic impacts of the development of a shale gas industry in the Northern Territory, through the lens of ProjectCo as it has been defined in Chapter II of this report. The tool for this exploration is ACIL Allen's in-house Computable General Equilibrium (CGE) model, *TasmanGlobal*. The model and critical underlying assumptions are outlined in Appendix E.

The modelling period lines up with cash flow modelling period outlined in previous sections: 2018 to 2043. The 25 year modelling period allows for an articulation of the initial capital intensive phase of a development, and a period of operation where capital intensity is lower, and means any economic impacts articulated are conservative relative to presenting a 50 or 100 year modelling period – which is subject to additional uncertainty.

In line with ACIL Allen's scope of works, the modelling outputs have been presented for three regions: Northern Territory, Rest of Australia, and Australia (which is the sum of the first two regions), and under the following macroeconomic variables:

- Real income (Gross Real Income)
- Real output (Gross State Product and Gross Domestic Product, and change in industry output from the base case)
- Real final demand (State Final Demand and Domestic Final Demand)
- Real investment (Business Investment)
- Real exports (for the Northern Territory, international and interstate; for Australia, international only)
- Real employment (FTE employment and employment by industry)
- Real wages
- Population
- Taxation (by major heads of taxation)

ACIL Allen has conducted this economic impact assessment under five scenarios; a base case, and four scenarios which are independent deviations from this base case.

The base case is ACIL Allen's assessment of the future growth of the Northern Territory and Australian economies under current policy settings, which is effectively an assessment of the economy if the moratorium on fracking was to remain in place. The four scenarios are in line with the cash flow modelling results presented in this report.

The results of the base case are presented in annual percentage change terms, where the scenarios are presented as a deviation in the base case, in millions of real dollars or FTE job years as relevant.

In order to complete this task, ACIL Allen has made a series of assumptions regarding the base case and the channel of economic impacts in the four scenarios. These are outlined below. The remainder of this chapter presents the results of the economic impact assessment in the base case and under each of the four scenarios.

6.1 Base case assumptions

Typically, ACIL Allen would model the base case of an economic impact assessment as a function of the continuation of recent economic trends in the particular regions being studied. During its research and stakeholder consultation, ACIL Allen discovered a series of additional assumptions to include in its base case assessment of the Northern Territory economy, which mostly centred on adding realism and nuance to the short and medium term outlook.

6.1.1 NT Government 10 year infrastructure plan

In June 2017, the Northern Territory Government released its 10 Year Infrastructure Plan, a document intended to guide the public and private sector's expectations regarding planned infrastructure investments to be made by the Northern Territory Government.[37] The Plan discusses a number of matters, but critically provides some quantitative guidance regarding the future infrastructure spending plans of the Northern Territory Government. ACIL Allen has attempted to give regard to the direction of infrastructure spending presented in this report in its base case, but has stopped short of including all planned investments as there is significant uncertainty regarding which projects will be funded, when they will commence, and who will fund them.

6.1.2 INPEX Ichthys LNG project

INPEX's LNG project is assumed to begin production in the fourth quarter of 2017-18, ramping up to 8.6 million tonnes 2018-19 before plateauing at 8.9 million tonnes a year from 2019-20 onwards. The start of operations results in a significant increase in the Northern Territory's Gross Territory Product (GTP) over this period, which can be seen in the significant growth in the Northern Territory's real exports in 2018-19.

6.1.3 Darwin LNG

As discussed in Section 4.3.4, the Darwin LNG facility is currently supplied feed gas from the Bayu Undan field. Although gas from the Bayu Undan field is anticipated to decline as the field reaches its end of life, Darwin LNG is assumed to continue LNG production of 3.7 million tonnes a year over the forecast period using gas sourced from the development of an alternative gas field or fields. As outlined previously, there is already significant exploration activity underway off the coast of the Northern Territory.

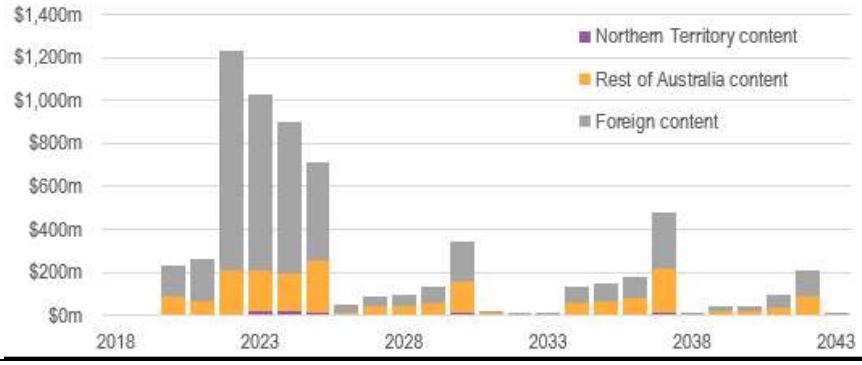
To model this, the base case includes explicit capital ($6.8 billion) and operating costs to construct and operate the necessary offshore infrastructure and a new subsea pipeline to facilitate this development. In the Gale production scenario, it is assumed that the onshore gas production replaces production from the offshore development, thereby eliminating the need to undertake much of the capital and operations expenditure, particularly from 2023 onwards. The capital and operating expenditure component of this assumed offshore development is provided in Figure 6.1.

ACIL Allen has produced these estimates based on previous confidential work associated with large scale offshore gas developments, and has right-sized the facility to provide enough feed gas to supply DLNG only. As the figure indicates, there is a high degree of imported content in this development, in line with the experience of recent major developments in Australia.

The critical implication of this assumption is there is **no incremental increase in LNG production** facilitated by the shale gas industry development.

[37] Department of Infrastructure, Planning and Logistics. 2017. *10 Year Infrastructure Plan*. Accessed online at http://www.dipl.nt.gov.au/

FIGURE 6.1 NEW OFFSHORE DEVELOPMENT TO FEED DLNG, CAPITAL AND OPERATING EXPENDITURE, BY JURISDICTION OF SPENDING, $M



SOURCE: ACIL ALLEN CONSULTING

6.1.4 Project Sea Dragon

Project Sea Dragon is a large-scale, integrated, land-based prawn aquaculture project in northern Australia designed to produce high-quality, year-round reliable volumes for export markets. At the time of the modelling, environmental approvals for Stage 1 of the project had progressed with approval of the project being recommended by the Northern Territory Environment Protection Authority (NT EPA).[38] In the reference case it has been assumed that production from Stage 1 begins in 2019-20 with further approvals and ramp-up to the full planned project by the early 2030's. Stage 1 will comprise approximately 1,080 ha of prawn farming capacity plus associated infrastructure onsite with the full scale Project reaching 10,000 ha of prawn farming capacity with production of 165,000 tonnes a year and revenues of over $3 billion a year.

6.1.5 Horticulture industry

During stakeholder consultation in the Northern Territory, ACIL Allen was presented with a report prepared for NT Farmers which articulated the value of the horticulture industry in the Northern Territory. NT Farmers provided a view to ACIL Allen that the Australian Bureau of Statistics significantly understated the value of the horticulture industry. This view was supported by other stakeholders, including NT Treasury.

ACIL Allen modified the base level of horticulture industry output, land use and employment using this report, which resulted in an increase to the size of agriculture industry relative to the standard definition used.

6.2 Scenario assumptions

ACIL Allen has made a series of assumptions regarding the transmission of economic benefits and costs in the policy scenarios, which are outlined below. These are in addition to the more standard assumptions like the CPI, currency and industry interactions, which are outlined throughout this document.

6.2.1 Local content

It is necessary to assume a level of local content provision in the delivery of the development scenarios, as there is no information regarding the actual or planned volume of local purchasing that ACIL Allen is able to rely upon. Broadly speaking, ACIL Allen assumed two dimensions to local content penetration: there would be an increasing share of supplies and services provided by Northern Territory firms over time, and there would a step change increase under each scenario.

[38] Seafarms. 2017. *Project Seadragon: Project Status*. Accessed online at http://seafarms.com.au/project-status/

In the case of an increased share over time, this is to reflect the plans of industry to engage local suppliers to assist in the industry's development, but also to reflect it is not as simple as suppliers being able to supply products and services from day one of the development. In the case of a step change increase under each scenario, this reflects ACIL Allen's view that the larger an industry gets, the more opportunities there are to deliver local providers opportunities as scale economies can develop. This manifests in a slightly lower share of local content in the GALE scenario compared to the WIND scenario, but the larger size of the GALE scenario means the value of local content in the project in dollar terms is larger.

ACIL Allen's assumed local content shares in the provision of capital and operating goods (excluding labour) is outlined in the tables below.

FIGURE 6.2 LOCAL CONTENT SHARES, PER CENT OF TOTAL SPENDING, EX LABOUR

SOURCE: ACIL ALLEN CONSULTING

6.2.2 Gas producers – price impact

Due to the complex nature of the gas market modelling undertaken for this task, ACIL Allen has made a simplifying assumption that there is no net change to the supply of or demand for gas in the national gas market resulting from the development of ProjectCo. Instead, the channel of impact is through a reduction in the prices paid by consumers, and a commensurate reduction in margins across the supply chain. The value of these quantum of these reductions is presented in Appendix C.

ACIL Allen adopted this assumption as there is significant uncertainty regarding national energy policy, and it was difficult to determine a credible way to treat which suppliers may choose to turn off their supply in the case of ProjectCo's development. To do this would have required a second round of gas market modelling, which could have then resulted in additional gas sales opportunities for ProjectCo, which would have then required a third round of gas market modelling and so on. Instead, by channelling the impact through prices, the modelling results articulate how a shale gas industry in the Northern Territory may impact on real incomes, real consumption and Commonwealth taxation revenue.

In reality, if a shale gas industry was able to penetrate the market to the degree assumed in this modelling task, it is possible some producers would exit the market. However it is difficult to determine who, when and where, and what the flow on effects may be given the uncertainty regarding both the industry development scenarios ACIL Allen has developed and the current state of the national market.

6.2.3 Employment – no net growth in Australia

As a conservative assumption, ACIL Allen assumed there would be no net employment growth in the Australian economy as whole resulting from the shale gas industry's development in the Northern Territory. This is because the Inquiry is mostly concerned with the potential impacts on the Northern Territory rather than the Australian economy as a whole, and the approach ACIL Allen has adopted with regards to the gas industry (ie no incremental increase in LNG production, and restricting gas industry impacts to price only) means adopting this assumption generates more conservative results.

In reality, it is likely there would be some net increase in employment outside of the Northern Territory, particularly in the development of pipeline infrastructure, the impact on Commonwealth finances, and the second round impacts of lower gas prices on consumer and business spending.

6.2.4 Agriculture – area of disturbance approach

ACIL Allen has made a broad assumption that no shale gas industry development will be allowed to occur:

- on or near sacred Aboriginal sites,
- on or near prime horticultural land,
- in proximate distance to major towns or cities
- on or near any major tourist attractions or locations
- on or near nature reserves, national parks and other land-based natural resources

Given this, ACIL Allen considers it highly unlikely there will be any impact on industries or stakeholders associated with these land uses in the event the industry develops, insofar as a reduced availability of land or conflicting land use goes.

However, it is possible, and indeed highly likely, that a shale gas industry will develop on pastoral properties, which cover approximately 45 per cent of the Northern Territory's land mass.[39] For example, Origin's exploration permit areas encompass 18,512km^2 of pastoral lease property.[40]

In order to model this, ACIL Allen has developed area of disturbance calculations under each scenario, centred on calculations of the land use associated with each element of a shale gas industry's development. We have calculated a gross square meterage of disturbance under each scenario using the table below and applying it to the volume of infrastructure developed, and then doubling it as a conservative assumption. The total area of disturbance under each scenario is presented in Table 6.1.

[39] Pastoral Land Board. 2016. *Pastoral Land Board Annual Report: 2015-16*. Accessed online at http://www.denr.nt.gov.au/
[40] Origin. 2017. *Environmental Plan Summary, Beetaloo Sub-Basin*. Accessed online at http://www.dpir.nt.gov.au/

ACIL Allen then assumed this land would become unavailable for the pastoral industry to raise cattle. To determine the impact, ACIL Allen calculated the average value per hectare of the cattle industry in the Northern Territory, multiplied this by the loss in land available for pastoral industry activities, and subtracted this from the future growth of the industry.

TABLE 6.1 TOTAL AREA OF LAND DISTURBANCE, BY SCENARIO

Scenario	Disturbance (km^2)
BREEZE	67.7
WIND	231.7
GALE	475.9

7 BASELINE SCENARIO

This section provides the results of ACIL Allen's base case economic modelling for the Northern Territory over the period from 2018 to 2043. This includes outputs for key macroeconomic variables only, and does not include real income and real taxation, which are calculated as levels in the scenarios only.

7.1 Scenario description

As discussed in Section 2, the Northern Territory's recent economic performance has been driven by the impact of INPEX's Ichthys offshore gas and LNG facility development. To this point, the impact has been mostly centred on the initial surge and subsequent fall in construction activity, with the lift in production and export still on the horizon. As discussed in Section 6, ACIL Allen has included a projection of the impact of Ichthys' production phase on the Northern Territory economy in its base case.

Other foreseen events for the Northern Territory included in the base case include:

- The impact of the Northern Territory Government's 10 Year Infrastructure Plan
- Project Seadragon, and the significant impact on the Northern Territory Government's aquaculture industry
- The highly likely development of an offshore gas project to support the backfill of DLNG as existing supplies deplete
- An expanded horticulture sector, in line with research presented by NT Farmers and the perspective of Northern Territory Government stakeholders

Other than the above modifications, the base case assumes that as a starting point the structure of the Northern Territory economy is as it is today. For instance, the largest employing sector is Government Services, with 47,390 employees in 2018.

7.2 Real output – total

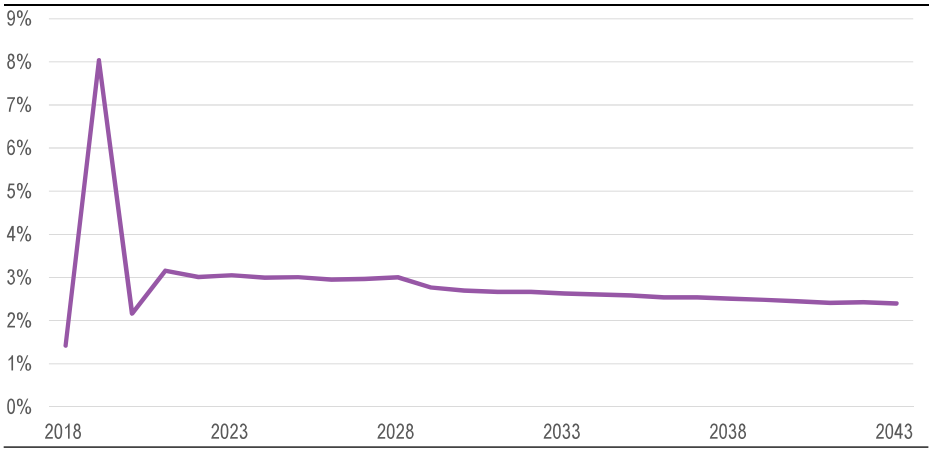
In Gross Territory Product (GTP) terms, ACIL Allen's base case projects the Northern Territory economy will grow by an average of 2.9 per cent over the forecast period (2018-2043) (Figure 7.1). This is lower than the average GTP growth of four per cent recorded over the past decade, which was mostly influenced by the impact of first the DLNG project and then the Ichthys LNG project.

Growth is forecast to spike in the short term, with GTP growth of eight per cent forecast in 2019 on account of the ramp up in Ichthys LNG production. This manifests as an increase in the Petroleum sector's output, and a lift in the real export base of the Northern Territory economy. As LNG production ramps up and then reaches a steady-state level of production, this is only anticipated to have a one year impact on the Territory's growth rate.

Following the ramp up of Ichthys LNG Project, ACIL Allen forecasts there will be a period of slightly above average growth through the 2020s, as the Territory's aquaculture and horticulture industries growth faster than the rest of the economy, and the Northern Territory Government's 10 Year Infrastructure Plan plays out. The impact of the new offshore gas development to back fill DLNG is somewhat limited, as much of the supplies and services for an offshore development are by necessity imported. This manifests in a strong increase in Business Investment (and therefore State Final Demand), but a commensurate increase in imports, therefore a near-zero impact on overall GTP.

Beyond the 2020s, ACIL Allen projects the Northern Territory economy will grow in line with population growth, labour force participation and productivity growth. All up, the Northern Territory economy is projected to grow from a $23.4 billion economy (2018 dollars) in 2018 to a $47.9 billion economy by the end of the forecast period.

FIGURE 7.1 GROSS TERRITORY PRODUCT, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



SOURCE: ACIL ALLEN CONSULTING

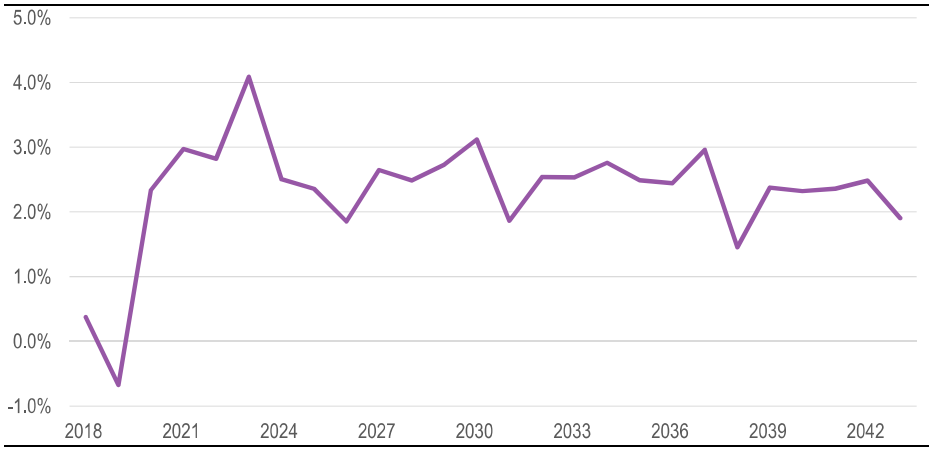
7.2.1 State Final Demand

ACIL Allen's base case projects the Northern Territory's State Final Demand will grow by an average of 2.3 per cent over the forecast period. This compares to growth of 4.4 per cent over the previous decade, where State Final Demand both grew and declined in excess of 10 per cent per annum on three separate occasions as a result of investments in LNG processing facilities.

ACIL Allen has not assumed the development of new onshore LNG processing facilities in its base case, and so the Northern Territory's State Final Demand is projected to be less volatile in the years ahead. Notwithstanding, State Final Demand is projected to be relatively flat over the next two years as the remainder of the uplift associated with the Ichthys LNG project comes out of the economy.

State Final Demand growth is projected to be strongest in the years leading up to 2023, as a result of the impact of the development of the new offshore gas extraction facility to backfill the DLNG facility. State Final Demand growth is forecast to hit 4.1 per cent in 2023, before easing to 1.9 per cent in 2026 (Figure 7.2).

FIGURE 7.2 STATE FINAL DEMAND, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



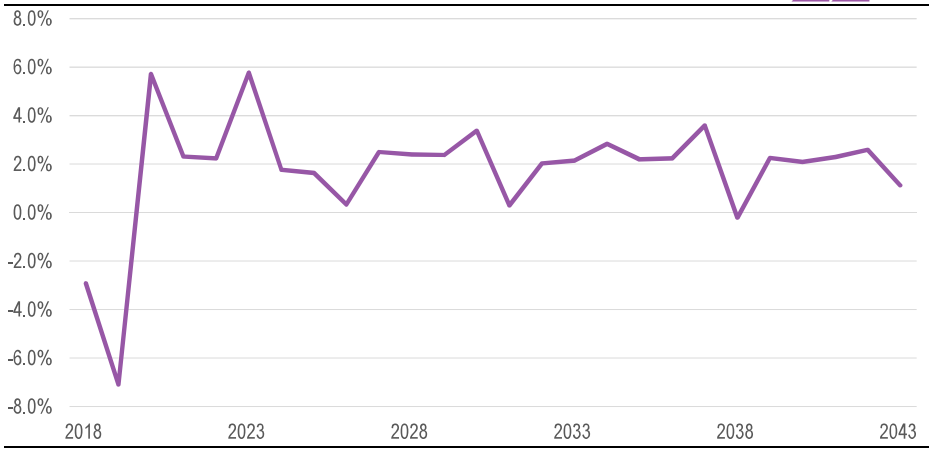
SOURCE: ACIL ALLEN CONSULTING

Business investment

The biggest driver of changes in State Final Demand on an annual basis is business investment, which is often subject to large, lumpy periods of spending by the private sector. This has been the experience of the Northern Territory economy in recent years, as discussed in Section 2.

ACIL Allen's base case forecasts two more years of declining business investment in the Northern Territory associated with the final stages of the Ichthys LNG project. Thereafter, business investment is forecast to grow by an average of four per cent per annum between 2020 and 2023, as the new offshore gas industry development progresses and other investments in aquaculture and horticulture progress. Over the full forecast period (2018 to 2043), business investment is forecast to grow by 1.8 per cent per annum (Figure 7.3). This is slower than the average growth of eight per cent per annum over the past decade, which was characterised by two years of 35 per cent and 65 per cent growth in investment in 2012 and 2013, respectively.

FIGURE 7.3 BUSINESS INVESTMENT, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE

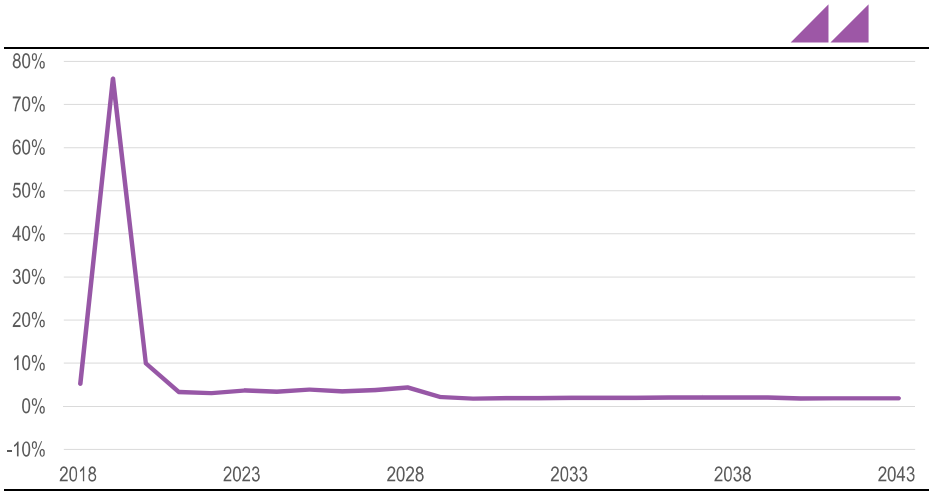


SOURCE: ACIL ALLEN CONSULTING

7.2.2 Real Exports

In ACIL Allen's base case, the Northern Territory's export outlook is dominated by the impact of the progression of the Ichthys LNG project to full production in 2019. In this year alone, the base case forecasts the Northern Territory's real exports will increase by 76 per cent (Figure 7.4).

FIGURE 7.4 REAL EXPORTS, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



SOURCE: ACIL ALLEN CONSULTING

This is effectively a structural increase in the Northern Territory's real exports base, as the Ichthys LNG project is projected to produce at its steady state level 8.9 million tonnes of LNG per annum. Excluding this one off increase, ACIL Allen's base case forecasts real exports from the Northern Territory will increase by 2.8 per cent per annum, largely on account of the increased activity associated with the Territory's horticulture and aquaculture industries.

7.3 Real output – industry

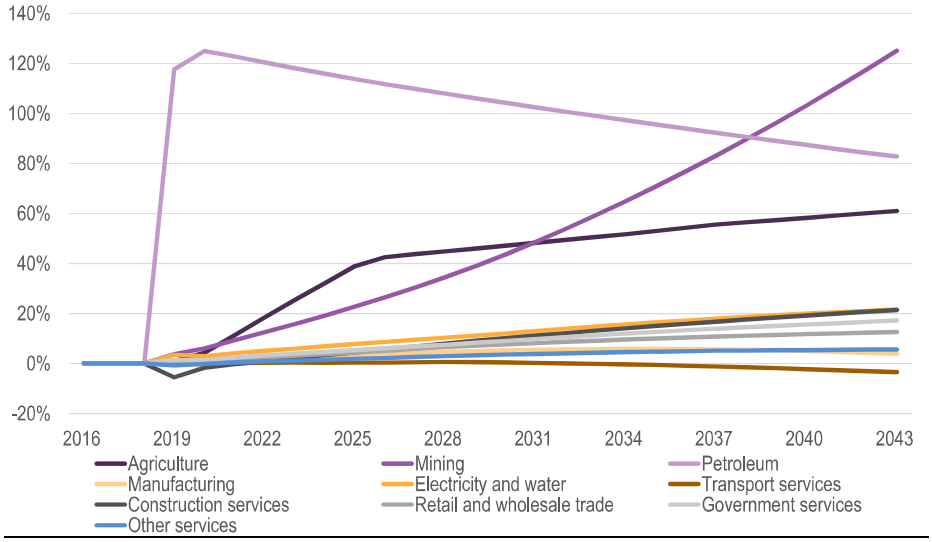
ACIL Allen produced estimates of future industry output growth on the basis of growth or decline from a starting level observed in actual Australian Bureau of Statistics data (2016). To progress these estimates to the modelling period, ACIL Allen has rebased its industry growth projections to the 2018 year and presented the results as a cumulative change in output from the 2018 year.

The fastest growing industry in the base case is Agriculture, which is forecast to grow by 9.1 per cent over the modelling period. This is on account of the impact of Project Seadragon, the rebased estimates of the size and growth potential of the Northern Territory's horticulture industry, and the Northern Territory Government's policies to improve the prospects of the whole agriculture industry (including pastoral industries).

The petroleum industry is also projected to grow faster than average, albeit all of the growth occurs in the first three years of the study period of account of the lift in production from the Ichthys LNG project. Direct industry output from the petroleum industry does not show the same characteristics as export growth for the Northern Territory as a whole as most of the industry output component of the petroleum industry occurs in the extraction of hydrocarbons, which in this case occurs off the coast of Western Australia rather than the Northern Territory. In a similar vein, the addition of a new offshore gas development assumed in the base case simply replaces otherwise lost industry output rather than adding new industry output.

Most other sectors are projected to grow around the same pace as the Northern Territory economy more broadly (Figure 7.5).

FIGURE 7.5 REAL OUTPUT, INDUSTRY LEVEL, NORTHERN TERRITORY, CUMULATIVE PERCENTAGE CHANGE FROM BASE YEAR (2018), BASE CASE



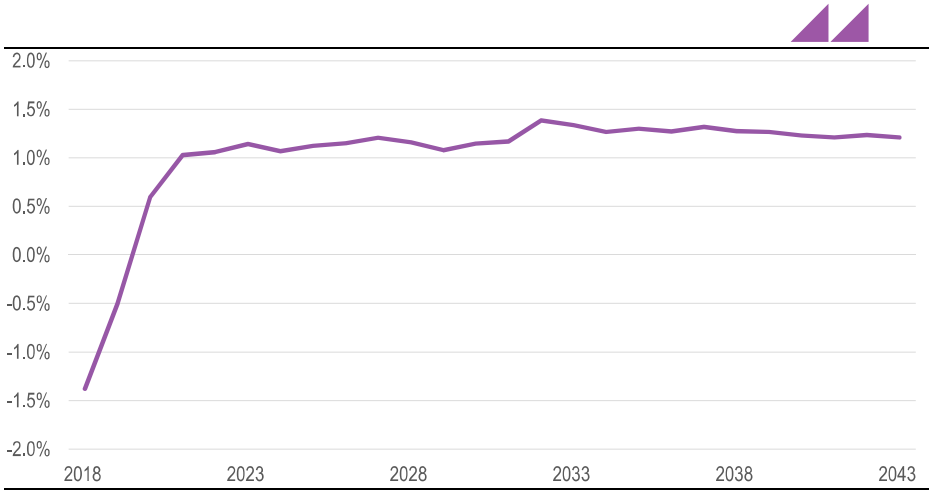
SOURCE: ACIL ALLEN CONSULTING

7.4 Labour market

7.4.1 Total employment

ACIL Allen's base case assumes total employment in the Northern Territory economy will grow by an average of one per cent per annum over the forecast period (Figure 7.6). Similar to the State Final Demand and Business Investment variables, short term employment growth follows the trajectory of the unwinding of the remainder of the Ichthys LNG project, with employment forecast to fall by 1.4 per cent in 2018 and 0.5 per cent in 2019. Thereafter, total employment is forecast to grow by an average of 1.2 per cent per annum.

FIGURE 7.6 REAL EMPLOYMENT, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



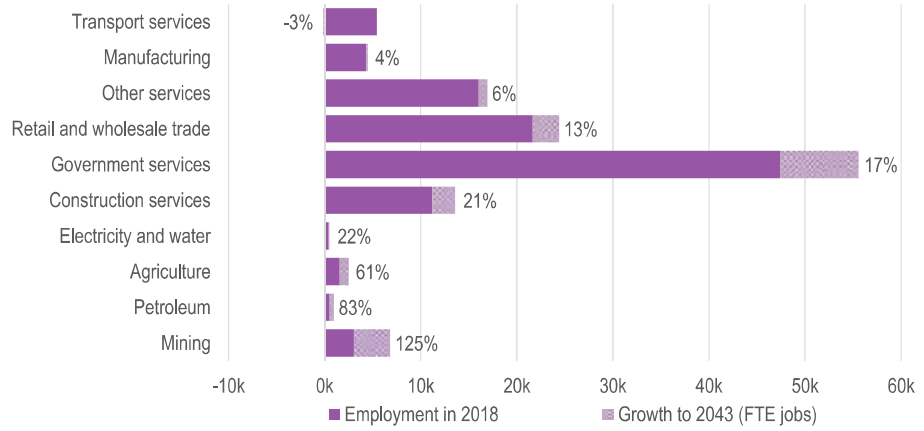
SOURCE:ACIL ALLEN CONSULTING

7.4.2 Industry employment

While total employment growth is forecast to remain relatively stable, ACIL Allen's base case forecasts a shift in the composition of employment in the Northern Territory. Employment growth is forecast to be largest in the Government Services sector, with an additional 8,181 FTE jobs created over the study period. This sector accounts for almost half of total FTE employment growth in the Northern Territory over the period. The other two sectors recording large growth in FTE numbers are similarly already large: retail and wholesale trade (2,729 FTE jobs) and construction (2,397 FTE jobs). However, in percentage change terms these sectors produce relatively modest results (between 13 per cent and 21 per cent, respectively).

The three sectors forecast to see large percentage increases in employment growth are mining (125 per cent), petroleum (83 per cent) and agriculture (61 per cent). In total FTE job terms however, these three sectors are forecast to deliver just over one third of the total employment growth of the three largest employing sectors in the Northern Territory (Figure 7.7).

FIGURE 7.7 REAL EMPLOYMENT, INDUSTRY CHANGES, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE

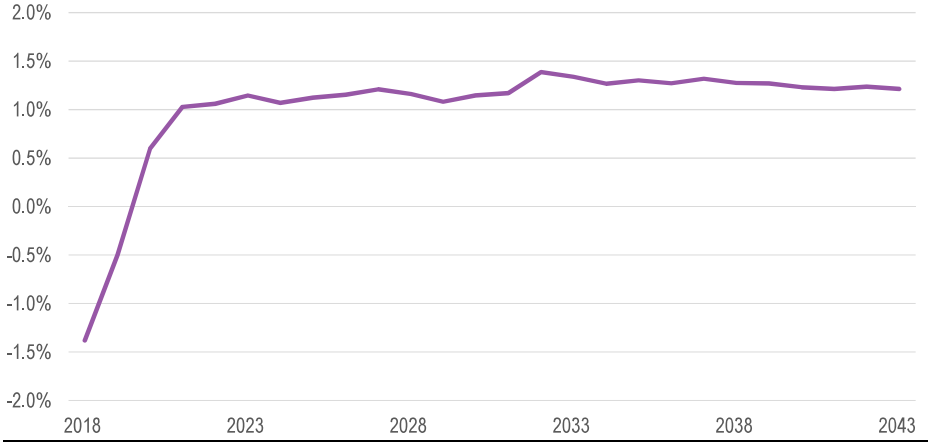


SOURCE: ACIL ALLEN CONSULTING

7.5 Population

ACIL Allen forecasts the Northern Territory's population will shrink modestly in the first two years of the forecast period, on account of the impact of the wind down of the construction phase of the Ichthys LNG project on the Northern Territory economy. Thereafter, ACIL Allen forecasts the Northern Territory's population will grow by an average of 1.2 per cent per annum, reaching 334,037 in 2043 (Figure 7.8)

FIGURE 7.8 POPULATION GROWTH, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



SOURCE: ACIL ALLEN CONSULTING

7.6 Summary

Table 7.1 presents a summary of the base case economic forecasts presented in this section.

TABLE 7.1 ACIL ALLEN BASE CASE, SUMMARY OF ECONOMIC MODELLING RESULTS

	2018 level	2043 level	Annual Average Percentage Change
Real output			
Northern Territory	$23,402m	$47,852m	2.9%
Real Final Demand			
Northern Territory	$28,457m	$51,318m	2.3%
Real investment			
Northern Territory	$10,027m	$16,149m	1.8%
Northern Territory real exports			
Northern Territory	$6,299m	$21,575m	5.7%
Real Output, Industry Growth (Index; 2018 = 100)			
Agriculture	100	109.1	
Mining	100	102.9	
Petroleum	100	103.0	
Manufacturing	100	102.0	
Electricity and water	100	102.0	
Transport services	100	102.1	
Construction services	100	101.9	
Retail and wholesale trade	100	102.0	
Government services	100	101.6	
Other services	100	102.0	
Real employment (total)			
Northern Territory	131,310	173,018	1.0%
Real employment by industry (FTE)			
Agriculture	1,546	2,489	1.9%
Mining	3,017	6,789	3.3%
Petroleum	518	947	4.0%
Manufacturing	4,325	4,497	0.2%
Electricity and water	400	487	0.8%
Transport services	5,425	5,237	-0.1%
Construction services	11,189	13,586	0.8%
Retail and wholesale trade	21,664	24,393	0.5%
Government services	47,390	55,571	0.6%
Other services	16,024	16,924	0.2%

	2018 level	2043 level	Annual Average Percentage Change
Real population			
Northern Territory	245,872	334,037	1.2%

SOURCE: ACIL ALLEN CONSULTING

8 CALM SCENARIO

This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the "Onshore Unconventional Gas Industry" or "the Industry".

The economic impact of the development of the Industry under the CALM development scenario, as detailed in Section 6, was assessed using ACIL Allen's *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

8.1 Scenario description

As discussed in Section 4.3, The CALM scenario is the scenario that sees ProjectCo undertake a three year program of exploration and appraisal, but fail to progress beyond this due to an inability to find a commercial quality shale gas reserve. The CALM scenario is also the basis for the first four years (in Year 0, nothing occurs as the moratorium is lifted) of the production scenarios discussed below, but instead of an assumption that no commercial quality shale gas is discovered, the assumption is a requisite scale commercial shale gas reserve is discovered.

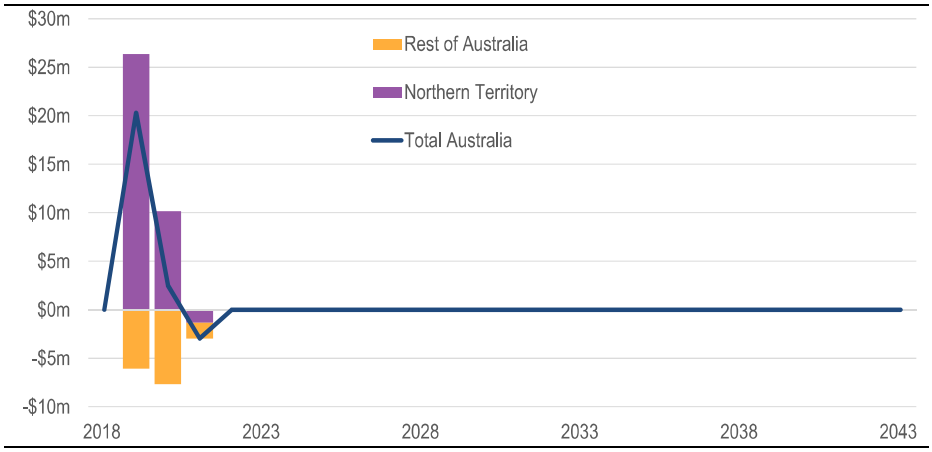
8.2 Real income

Real income impacts are realised in the Territory through increased employment, payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners.

In total, the real income impact of the Industry is estimated to total $19.8 million at over the study period (refer to Figure 8.1). In the Northern Territory, real income is estimated to total $35.2 million, while in the

Rest of Australia real income will fall by $15.4 million, as a result of a reallocation of labour to the Territory for the Industry's appraisal phase.

FIGURE 8.1 CALM REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



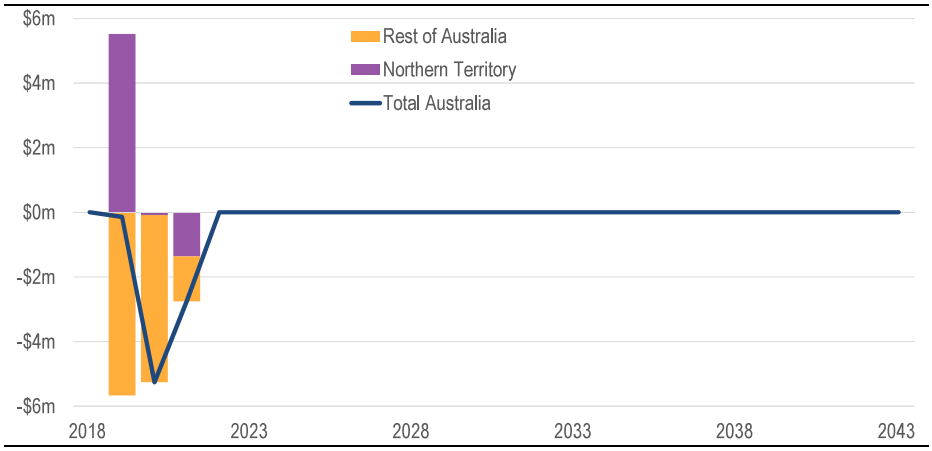
SOURCE: ACIL ALLEN CONSULTING

8.3 Real output

The real output impact of the Industry is different to the real income impact because output does not include increases to welfare that is generated through additional employment and wages growth.

Under the CALM development scenario, real output is estimated to fall by a total of $8.2 million (refer to Figure 8.2). In the Northern Territory, it is estimated real output will increase by $4.1 million and fall by $12.2 million across the Rest of Australia (the result of a reallocation of labour to the Territory for the Industry's appraisal phase) over the study period.

FIGURE 8.2 CALM REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION

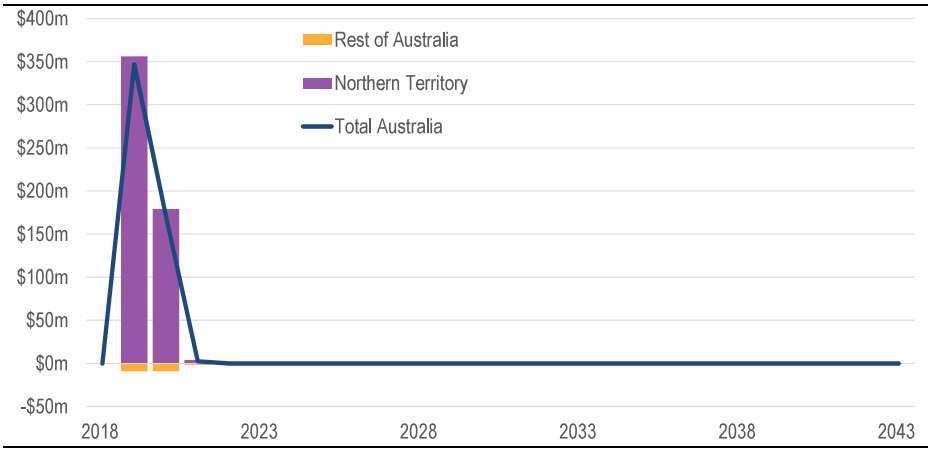


SOURCE: ACIL ALLEN CONSULTING

8.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output. In total, the real Final Demand impact of development under the CALM scenario is estimated to total $519 million over the study period (refer to Figure 8.3). In the Northern Territory it is estimated real Final Demand will increase by $539 million and fall by $19.7 million across the Rest of Australia (the result of a reallocation of labour to the Territory for the Industry's appraisal phase) over the study period.

FIGURE 8.3 CALM REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION

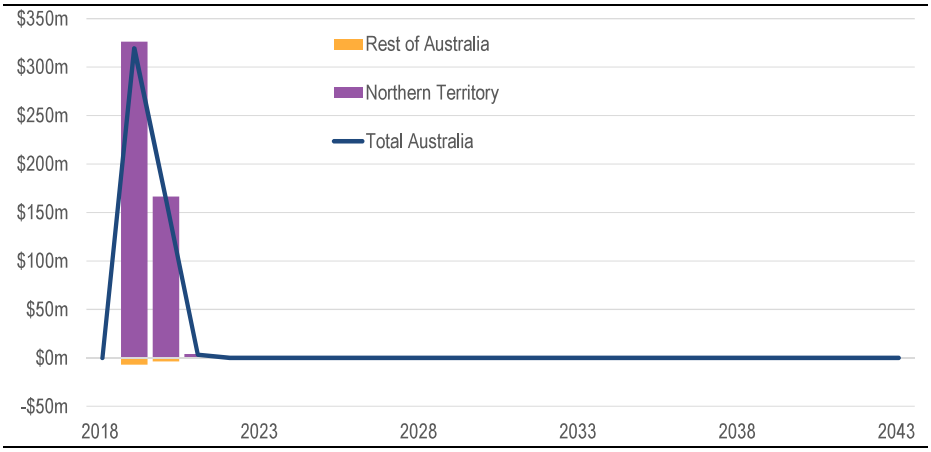


SOURCE: ACIL ALLEN CONSULTING

Real investment

In the Northern Territory, the major component of the Industry's real Final Demand impact is in relation to investment. The real investment impact of the Industry is estimated to total $486 million over the study period (refer to Figure 8.4). In the Northern Territory it is estimated real investment will increase by $497 million and fall by $11.4 million across the Rest of Australia (the result of a reallocation of labour to the Territory for the Industry's appraisal phase) over the study period.

FIGURE 8.4 CALM REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



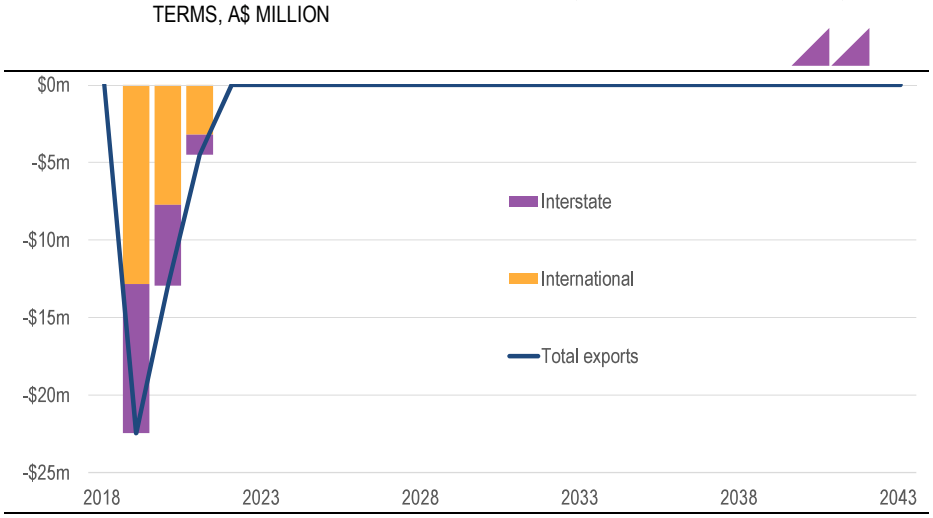
SOURCE: ACIL ALLEN CONSULTING

8.3.2 Real exports

The reallocation of labour resources to the Northern Territory under the CALM development scenario for the appraisal of the Industry results in labour not generating export revenue in other industries in the economy, which results in a net loss to exports in the Territory (refer to Figure 8.5).

In total, the *Tasman Global* CGE model estimates that real exports in the Territory will contract by $39.9 million. The majority of this will be lost from international exports ($23.8 million), with $16.1 million from interstate exports.

FIGURE 8.5 CALM NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



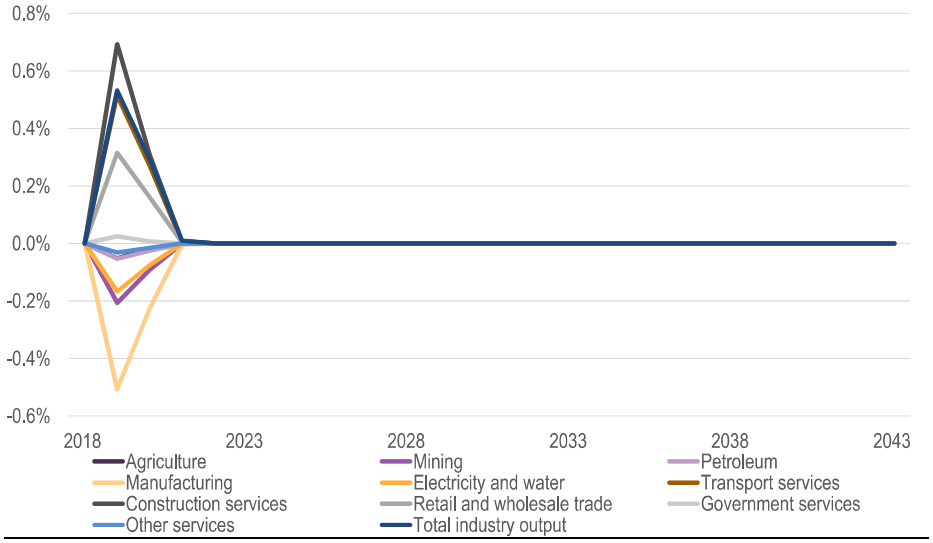
SOURCE: ACIL ALLEN CONSULTING

8.4 Real output – industry

Figure 9.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the CALM development scenario, the largest impact will be realised in the Construction Services industry, which between 2019 and 2021 will generate average growth over and above the base case by 0.34 per cent per annum. The Transport Services industry also will generate additional growth of 0.26 per cent per annum between 2019 and 2021 over and above the base case.

The largest negative impact of the Industry under the CALM development scenario is estimated to occur in the Manufacturing industry, which is estimated to contract by 0.25 per cent per annum between 2019 and 2021 relative to the base case. For the remaining Northern Territory industries, the impact of the Industry under the CALM development scenario is negligible.

FIGURE 8.6 CALM NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

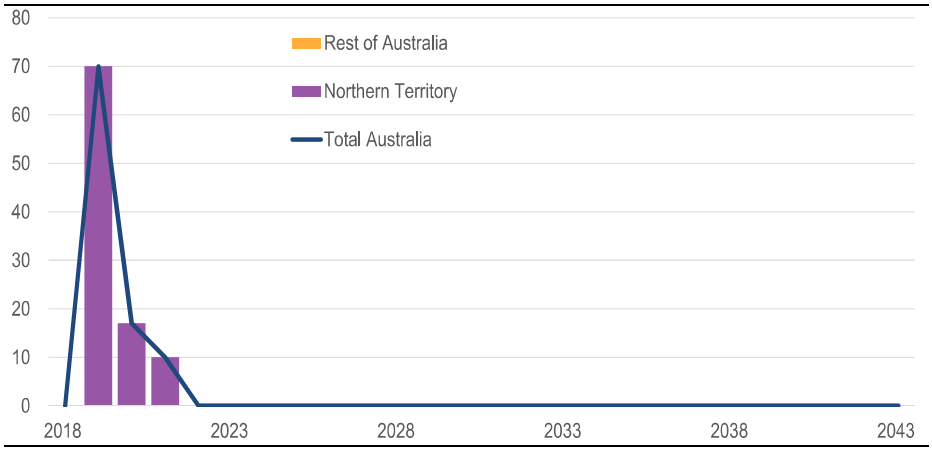
8.5 Labour market

8.5.1 Employment

Under the CALM development scenario, the Industry is expected to require some short term employment opportunities.

Over the study period, it is estimated the development of the Industry will require direct employment of 97 FTE jobs, there is no labour requirements after 2021 (refer to Figure 8.7). Overall, it is estimated that the Industry under the CALM scenario will generate total direct and indirect jobs of 119 FTE jobs over the study period.

FIGURE 8.7 CALM DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

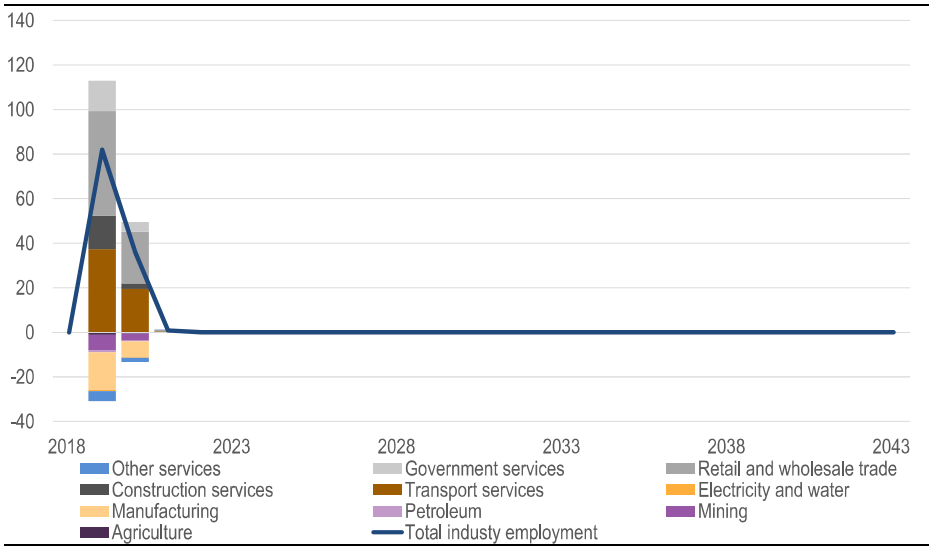
8.5.2 Industry real employment

While the development of the Industry under the CALM development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory. Figure 9.9 displays the impact the Industry has on direct and indirect employment by industry in the Northern Territory. Under the CALM development scenario, the largest impact will be realised in the Retail and Wholesale Trade industry, which between 2019 and 2021 will generate total additional jobs over and above the base case of 71 FTE jobs, and is a result of the consumption impacts arising from the boost to real incomes in the Territory.

The Transport Services (57 FTE jobs), Government Services (18 FTE jobs) and Construction Services Industry (17 FTE jobs) will also receive a boost to employment over and above the base case over the study period.

The largest negative impact of the Industry under the CALM development scenario is estimated to occur in the Manufacturing industry, which is estimated to contract by 24 FTE jobs over the study period relative to the base case. For the remaining Northern Territory industries, the impact of the Industry under the CALM development scenario is negligible.

FIGURE 8.8 CALM NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS

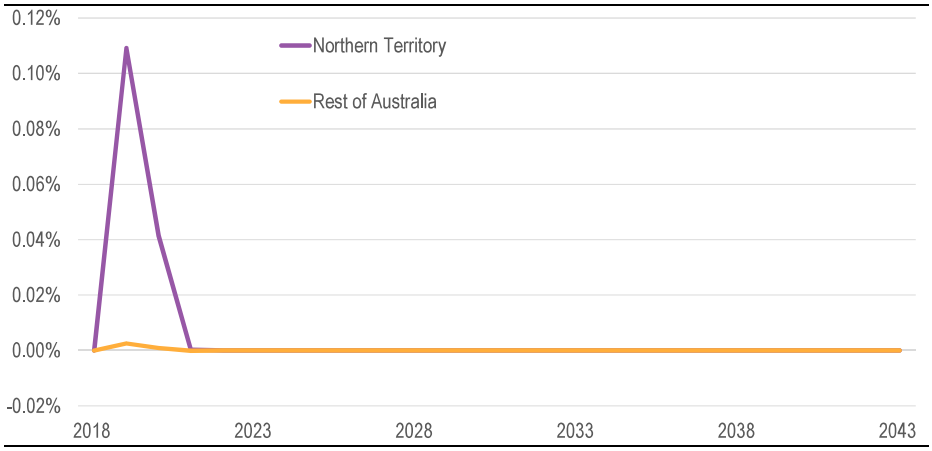


SOURCE: ACIL ALLEN CONSULTING

8.5.3 Real wages

The development of the Industry is estimated to provide a temporary boost to real wages in the Northern Territory between 2019 and 2021 of 0.05 per cent per annum. The impact across the Rest of Australia is negligible, given that there is no job creation under the CALM scenario (refer to Figure 8.9).

FIGURE 8.9 CALM REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE

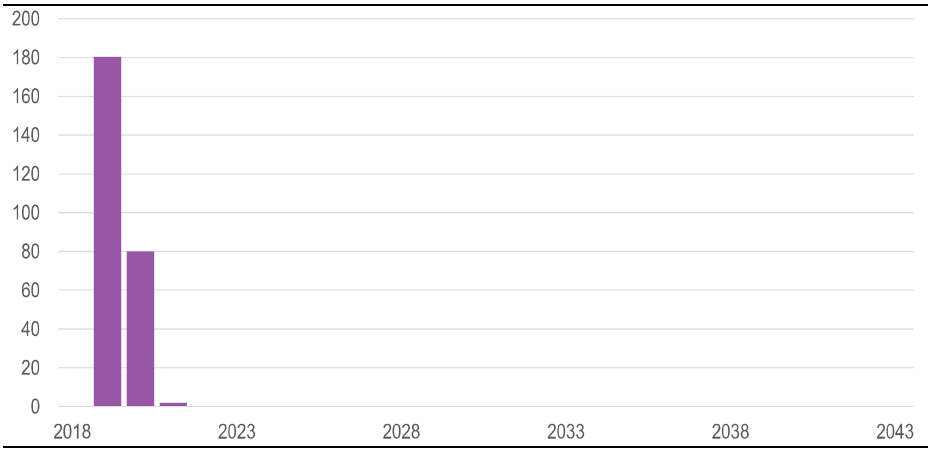


SOURCE: ACIL ALLEN CONSULTING

8.6 Population

The development of the Industry is estimated to provide a temporary boost to population in the Northern Territory of 180 persons in 2019, 80 persons in 2020 and two persons in 2021. After 2021 there is no impact on the Territory's population.

FIGURE 8.10 CALM NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER

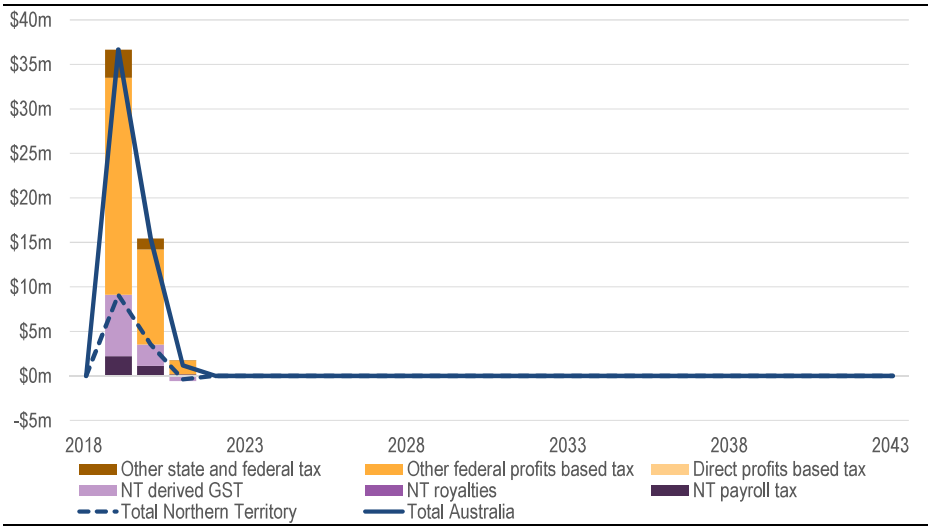


SOURCE: ACIL ALLEN CONSULTING

8.7 Real taxation

The development of the Industry under the CALM scenario will generate a short term taxation benefits to the Northern Territory and the Commonwealth Governments, primarily in the form of indirect profits based taxes and GST (refer to Figure 8.11).

FIGURE 8.11 CALM REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Between 2019 and 2021, it is estimated the Commonwealth Government will be in receipt of $36.6 million of indirect company taxation payments, and a further $8.7 million is estimated to be generated in GST collections.

The Industry under the CALM development scenario will also generate $3.5 million in payroll taxation payments to the Northern Territory Government, while $4.5 million is expected to be generated in other state and federal taxes (such as personal income, excises, fringe benefits and capital gains tax receipts).

8.8 Summary

Table 8.1 presents a summary of the economic modelling results presented in the section.

TABLE 8.1 CALM DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	$35.2m	$1.4m	$30.3m
Rest of Australia	-$15.4m	-$0.6m	-$12.8m
Total Australia	**$19.8m**	**$0.8m**	**$17.5m**
Real output			
Northern Territory	$4.1m	$0.2m	$3.7m
Rest of Australia	-$12.2m	-$0.5m	-$10.2m
Total Australia	**-$8.2m**	**-$0.3m**	**-$6.5m**
Real Final Demand			
Northern Territory	$539.1m	$20.7m	$460.2m
Rest of Australia	-$19.7m	-$0.8m	-$16.5m
Total Australia	**$519.4m**	**$20.0m**	**$443.7m**
Real investment			
Northern Territory	$496.9m	$19.1m	$424.0m
Rest of Australia	-$11.4m	-$0.4m	-$9.6m
Total Australia	**$485.5m**	**$18.7m**	**$414.4m**
Northern Territory real exports			
International	-$23.8m	-$0.9m	-$20.0m
Interstate	-$16.1m	-$0.6m	-$13.6m
Total	**-$39.9m**	**-$1.5m**	**-$33.6m**
Real employment			
Northern Territory	119 FTEs	5 FTEs	
Rest of Australia	-119 FTEs	-5 FTEs	
Total Australia	**0 FTEs**	**0 FTEs**	
Real employment by industry			
Agriculture	-2 FTEs	0 FTEs	
Mining	-10 FTEs	0 FTEs	
Petroleum	-1 FTEs	0 FTEs	

	Total	Average	NPV (7 per cent)
Manufacturing	-24 FTEs	-1 FTEs	
Electricity and water	-1 FTEs	0 FTEs	
Transport services	57 FTEs	2 FTEs	
Construction services	17 FTEs	1 FTEs	
Retail and wholesale trade	71 FTEs	3 FTEs	
Government services	18 FTEs	1 FTEs	
Other services	-6 FTEs	0 FTEs	
Total industry employment	**119 FTEs**	**5 FTEs**	
Real population			
Northern Territory	262 persons	10 persons	
Real taxation			
Northern Territory			
Payroll tax	$3.5m	$0.1m	$3.0m
Royalties	$0.0m	$0.0m	$0.0m
Derived GST	$8.7m	$0.3m	$7.5m
Total Northern Territory	**$12.2m**	**$0.5m**	**$10.5m**
Commonwealth			
Direct profits based tax	$0.0m	$0.0m	$0.0m
Other federal profits based tax	$36.6m	$1.4m	$31.2m
Other state and federal tax	$4.5m	$0.2m	$3.8m
Total Commonwealth	**$41.1m**	**$1.6m**	**$35.0m**
Total Australia	**$53.3m**	**$2.0m**	**$45.5m**

SOURCE: ACIL ALLEN CONSULTING

9 BREEZE SCENARIO

This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the "Onshore Unconventional Gas Industry" or "the Industry".

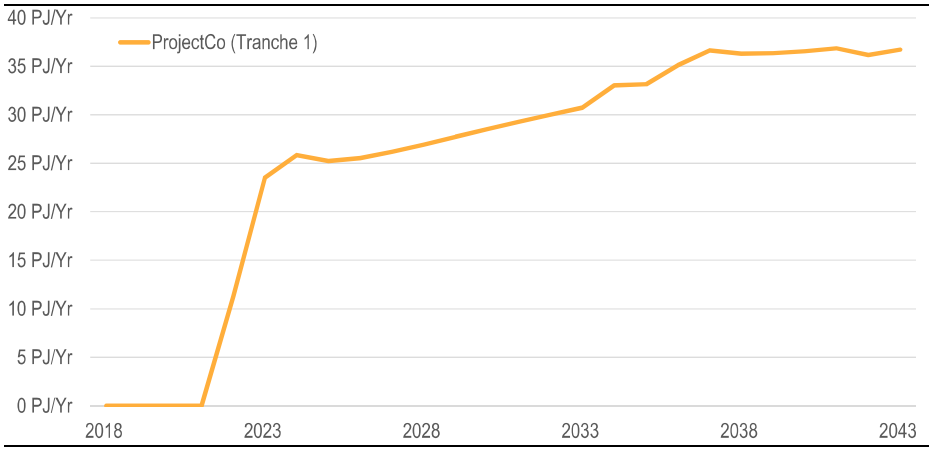
The economic impact of the development of the Industry under the BREEZE development scenario, as detailed in Section 4.3.2, was assessed using ACIL Allen's *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

9.1 Scenario description

As discussed in Section 4.3.2, under the BREEZE development scenario it is assumed shale gas production commences in FY2022, with the current moratorium on activities lifting at the end of FY2018 and the exploration/appraisal phase of development occurring in FY2019, FY2020 and FY2021. At the tail end of FY2021, facilities required to tie into the Amadeus Gas Pipeline are built and then linked to the East Coast market via the NGP. Gas is produced at an initial rate of 33.4 TJ/day in 2022, ramping up to 90 TJ/day in 2034.

The profile of gas production by ProjectCo in BREEZE is below in Figure 9.1.

FIGURE 9.1 GAS PRODUCTION, BREEZE SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

9.2 Real income

The development of the Industry has a significant impact on the real income of Australia. Real income is a measure of the economic welfare (or standard of living) improvement as a result of the developments. The change in real income captures the effect of net foreign income transfers associated with ownership of the capital along with changes in the purchasing power of Australian residents.

The real income impact of the Industry is largely accrued through the profits generated by the Industry once it is operational, which also determines the level of profits based taxation paid by the Industry. Overall, the majority of the real income impact of the development under the BREEZE scenario is transferred from the Northern Territory to the Rest of Australia, in the form of Commonwealth Government taxes and because the equity ownership of the Industry is assumed to be largely on the east coast of Australia.

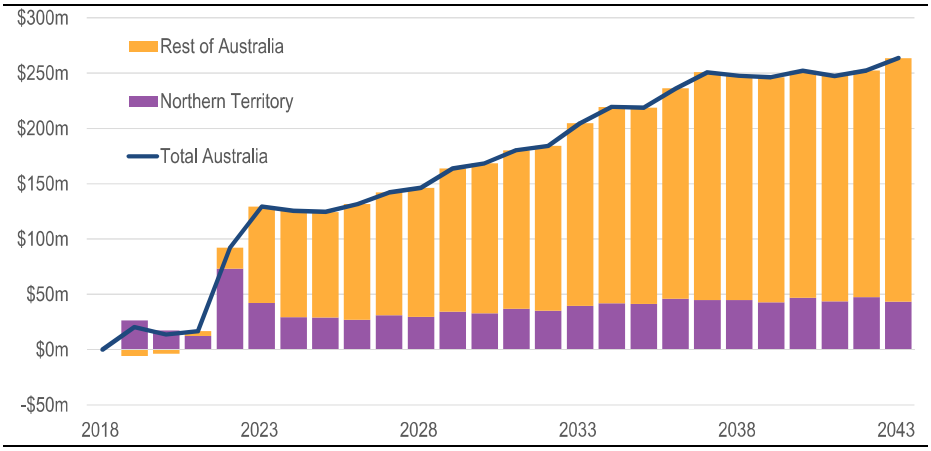
Real income impacts are still realised in the Territory, through increased employment and a redistribution of the profits based taxation payments from the Commonwealth back to the Territory. Royalty and payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners also contribute to the real income impact in the Territory.

In total, the real income impact of the Industry is estimated to total $4.3 billion at an average of $165 million per annum over the study period (refer to Figure 9.2). The real income impact reaches a steady state of around $250 million per annum in 2037, once the Industry reaches its steady state of production.

Over the study period, the real income impact in the Northern Territory is estimated to total $937 million, at an average of $36.1 million per annum. Real incomes are expected to peak at $73.2 million in 2022, which coincides with peak employment and peak wages growth in the Territory. Once the Industry reaches its steady state level of production, the real income impact in the Territory averages around $44.7 million per annum.

The real income impact is largely felt on the east coast of Australia, which is estimated to total $3.3 billion at an average of $128 million per annum over the study period. Real incomes are expected to peak in 2043 at $220 million, as the Industry reaches peak production.

FIGURE 9.2 BREEZE REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

9.3 Real output

The real output impact is largely accrued through the impact the Industry has on investment in the Northern Territory and the value of the gas exported from the Territory to the Rest of Australia. The real output impact of the Industry is different to the real income impact because, in an output sense, the value of the gas exported is realised in the Territory, whereas in an income sense, the value of the gas exported is realised through profits generated and taxation payments, which largely accrue on the east coast of Australia.

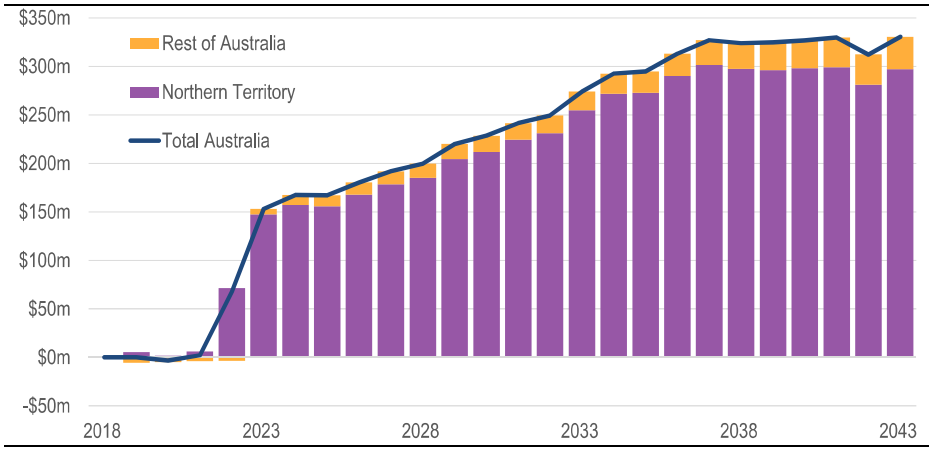
Under the BREEZE development scenario, real output is estimated to total $5.5 billion at an average of $205 million per annum over the study period (refer to Figure 9.3). The real output impact reaches a steady state of around $325 million per annum in 2037, as a steady state of production is reached.

Over the study period, the real output impact in the Northern Territory is estimated to total $5.1 billion, at an average of $196 million per annum. Real output is expected to increase over the study period in line with the increase in the level of production. At steady state production in 2037, output in the Territory is estimated to average $295 million per annum.

Relative to the size of the Northern Territory's economy, the increase in real output from the development of the Industry represents a boost to Gross Territory Product of 0.11 per cent in 2037, once the level of real output reaches a steady state.

Across the Rest of Australia, the real output impact is largely driven by an increase to consumption by the household sector, as a result of the rising real incomes from the development on the Rest of Australia. Over the study period, it is estimated the real output impact on the Rest of Australia will total $406 million at an average of $15.6 million per annum.

FIGURE 9.3 BREEZE REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

9.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output.

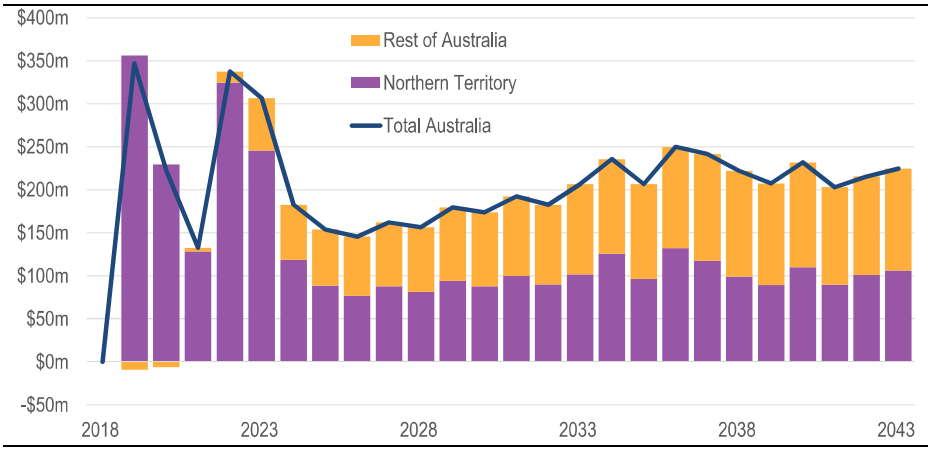
The real Final Demand impact of development under the BREEZE scenario in the Northern Territory is largely accrued through the investment needed to fund the Industry's capital requirements. For the Rest of Australia the impact largely results from the household consumption impacts that are accrued from rising real incomes resulting from the development.

In total, the real Final Demand impact of development under the BREEZE scenario is estimated to total $5.3 billion at an average of $205 million per annum over the study period (refer to Figure 9.4).

Real Final Demand in the Territory is expected to peak at $356 million in 2019, during the Industry's exploration phase, and be maintained at high level during the capital intensive development phase, where real Final Demand is estimated to increase by $325 million by 2020. Over the study period, the Final Demand impact is estimated to total $3.3 billion at an average of $196 million per annum.

Throughout the Rest of Australia, the real Final Demand impact of the Industry does not have a material impact until the Industry becomes profitable in 2023, and when the real income impact begins to impact on household consumption. Over the study period, the Final Demand impact is estimated to total $2 billion at an average of $79 million per annum.

FIGURE 9.4 BREEZE REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Real investment

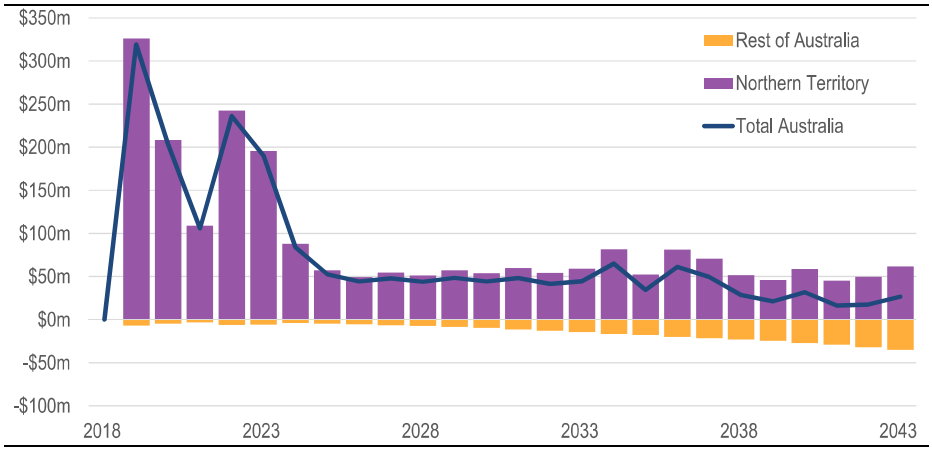
In the Northern Territory, the major component of the Industry's real Final Demand impact is in relation to investment, and is the result of the ongoing capital intensive nature of unconventional shale gas developments.

In total, the real investment impact of the Industry is estimated to total $1.9 billion at an average of $73.4 million per annum over the study period (refer to Figure 9.5). The exploration phase of the Industry is when the real investment impact of the Industry peaks ($326 million in 2019) and again during the development and the duplication of the Amadeus pipeline ($243 million in 2023).

Following the capital intensive initial production phase of the Industry, the real investment reduces as less capital is required to reach the target production level. Over the study period, real investment in the Territory is estimated to total $2.3 billion at an average of $87 million per annum.

Across the Rest of Australia, ACIL Allen estimates that as a result of a reallocation of labour resources to the Northern Territory, the impact on real investment throughout the Rest of Australia falls by of $359 million at an average of $13.8 million per annum over the study period.

FIGURE 9.5 BREEZE REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



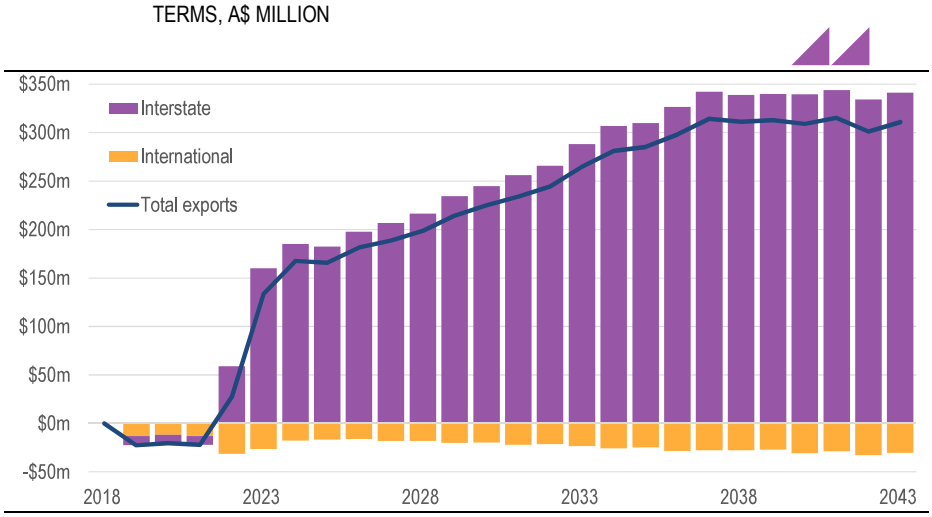
SOURCE: ACIL ALLEN CONSULTING

9.3.2 Real exports

The impact the Industry has on the Northern Territory's real exports is the other main driver of the impact on the Territory's real output. While gas is not exported to international markets under the BREEZE development scenario, it is exported from the Territory to the Rest of Australia (specifically the east coast of Australia).

Over the study period, the development is estimated to increase real exports by $5.2 billion at an average of $201 million per annum (refer to Figure 9.6). The increase in real exports is driven by the boost to interstate exports ($5.8 billion over the study period or $223 million per annum), which offsets the small decrease in international exports resulting from the impact of an expected appreciation in the Australian Dollar ($573 million over the study period or $22 million per annum).

FIGURE 9.6 BREEZE NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Once a steady state of real exports is reached in 2037, it is estimated that the exports generated by the Industry under the BREEZE development scenario would account for 1.6 per cent of the Territory's total exports.

9.4 Real output – industry

Figure 9.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the BREEZE development scenario, the largest impact will be realised in the Petroleum industry, given that the Industry would be captured under this industry classification. It is estimated that the Petroleum industry will generate growth over and above the base case of 1.9 per cent per annum on average over the study period.

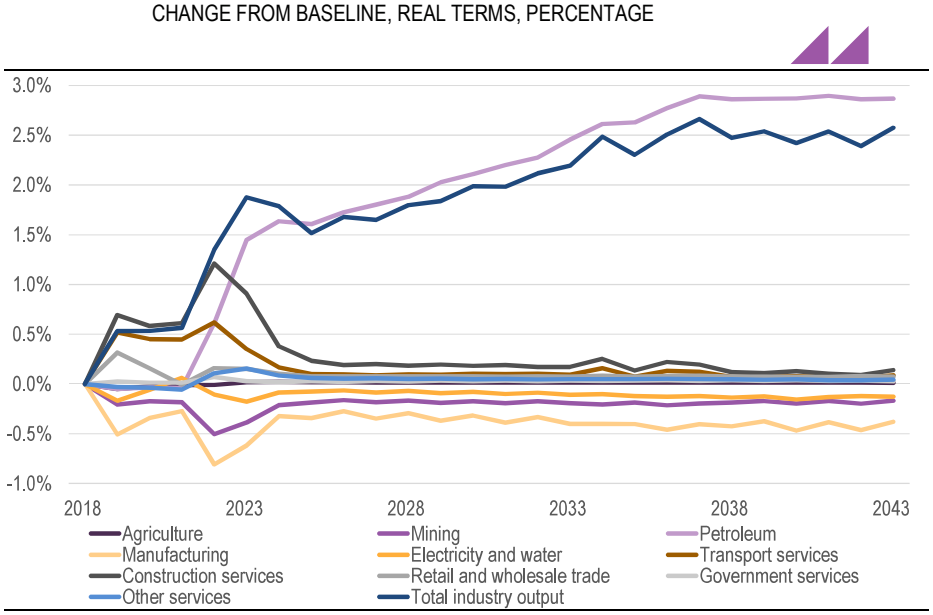
The Construction Services industry is also expected to increase over the study period, averaging growth of 0.3 per cent per annum. The majority of this growth will be realised in the early stages of the Industry's development, with growth expected to peak at 1.2 per cent in 2022.

The Transport Services industry is also estimated to follow a similar trend, growing on average by 0.2 per cent per annum and peaking at 0.6 per cent in 2022, relative to the base case.

The Manufacturing industry is estimated to contract on average by 0.4 per cent per annum over the study period. This reflects the impact of an appreciation in the Australian Dollar on the global competitiveness of export competing businesses in the Territory. In addition, a reallocation of labour away from the Manufacturing industry to the Petroleum industry results in lower output from that industry. A similar impact occurs in the Mining and Electricity and Water industries, which are estimated to contract on average by 0.2 per cent and 0.1 per cent per annum over the study period.

Across all industries, the development of the Industry in the Territory will have a marginal impact on the growth across most industries. Overall, industry growth is estimated to be 1.9 per cent per annum higher than what would otherwise have occurred if the Industry did not exist.

FIGURE 9.7 BREEZE NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

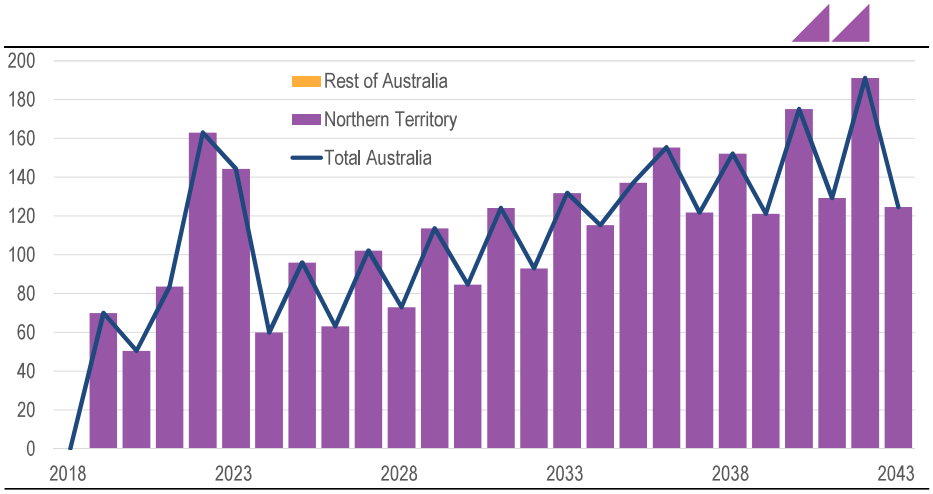
9.5 Labour market

9.5.1 Employment

The development of a new industry in the Territory under the BREEZE development scenario has significant workforce implications. The largest component of the Industry's direct workforce is the staff required to operate the wells and pads. The 'peaking' nature of the FTE requirements presented in Figure 9.8 is a result of the timing of the construction workforce requirements. Labour required for the construction of gas transmission pipelines in the Territory in 2021 and 2022 also contributes to this 'peaking' nature, but on a smaller scale.

Over the study period, it is estimated the development of the Industry will require direct employment of 2,874 FTE jobs at an average of 111 FTE jobs per annum in the Territory. The majority of these FTE jobs are in relation to the construction and operations of the Industry (total of 2,361 FTE jobs at an average of 91 FTE jobs per annum), while a total of 514 FTE jobs (average of 20 FTE jobs per annum) are in relation to the construction of transmission pipes.

FIGURE 9.8 BREEZE DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

However, the total employment impact of the Industry development under the BREEZE scenario is minimal, due to the resulting draw on labour from other industries in the Territory and other parts of Australia.

Over the study period, the Industry is estimated to create 2,145 FTE direct and indirect FTE jobs at an average of 82.5 FTE jobs per annum in the Northern Territory. However, ACIL Allen modelling assumes that these positive impacts will be completely offset by the reallocation of employment from the Rest of Australia to the Territory.

9.5.2 Industry real employment

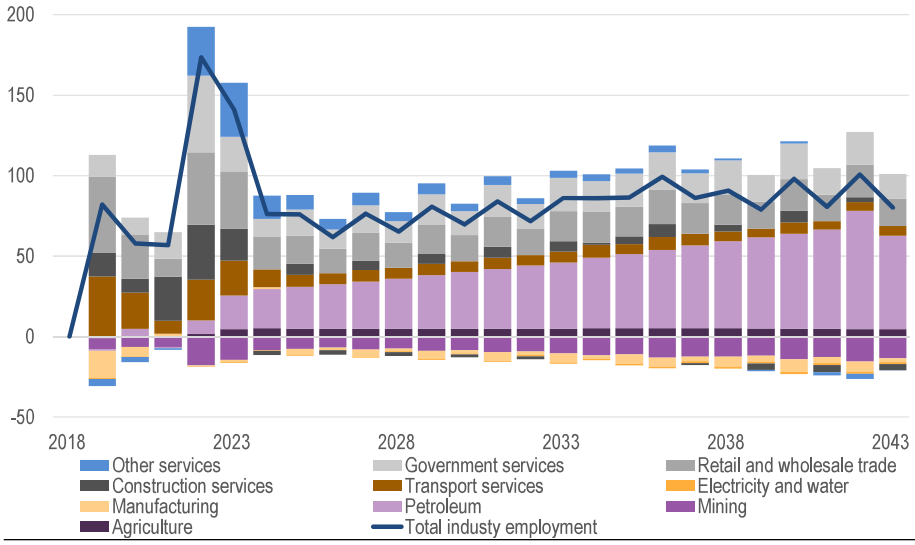
While the development of the Industry under the BREEZE development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory (refer to Figure 9.9).

Over the study period, the Petroleum industry is estimated to see the largest real employment impact, with the creation of 910 FTE jobs at an average of 35 FTE jobs per annum. Significant gains are also estimated in the Retail and Wholesale Trade industry, with a total of 526 FTE jobs at an average of 20.3 FTE jobs per annum to be created, as a result of increased household consumption in the Territory.

The Government Service industry (462 FTE jobs at an average of 17.8 FTE jobs per annum), Transport Services industry (253 FTE jobs at an average of 9.7 FTE jobs per annum) and Construction Services industry (141 FTE jobs at an average of 5.4 FTE jobs per annum) are also estimated to see solid employment gains over the study period under the BREEZE development scenario.

The majority of the labour reallocation, as a result of the development of the Industry, is estimated to occur in Mining (loss of 265 FTE jobs at an average of 10.2 FTE jobs per annum), Manufacturing (loss of 100 FTE jobs at an average of 3.9 FTE jobs per annum) and Electricity and Water (loss of 18.5 FTE jobs at an average of 0.7 FTE jobs per annum).

FIGURE 9.9 BREEZE NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



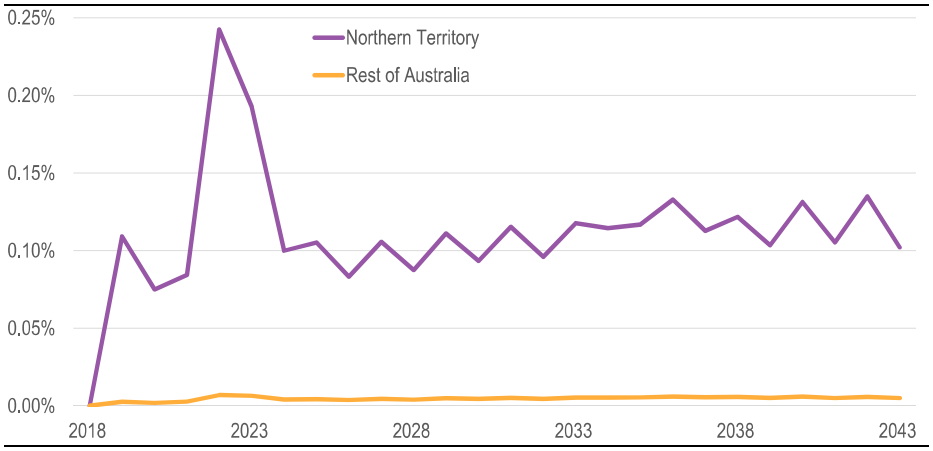
SOURCE: ACIL ALLEN CONSULTING

9.5.3 Real wages

The development of the Industry is estimated to boost real wages in the Northern Territory relative to the Rest of Australia (refer to Figure 9.10).

Over the study period, the increase in real wages is estimated to be on average 0.11 per cent per annum higher than the base case, peaking at 0.24 per cent in 2022 when the demand for labour in the Territory is at its highest. The impact across the Rest of Australia is negligible over the study period, given that there is no job creation under the BREEZE scenario.

FIGURE 9.10 BREEZE REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE



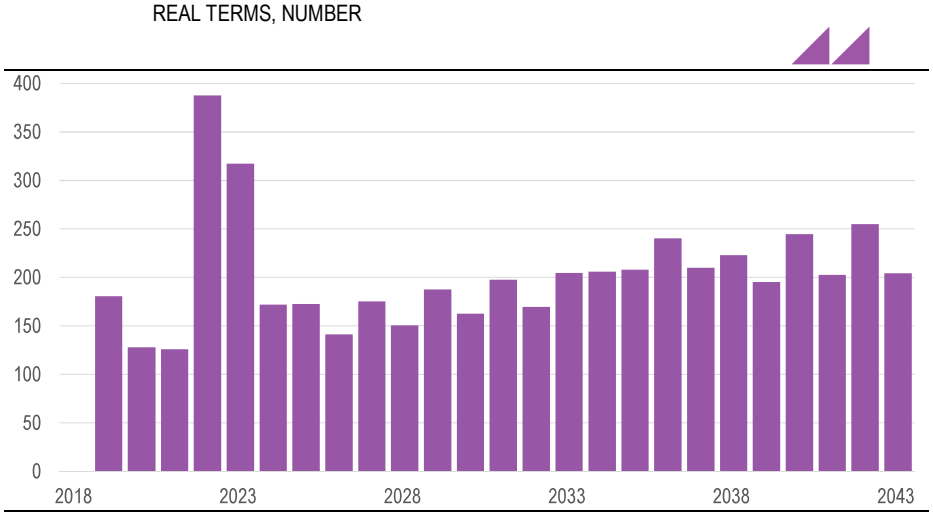
SOURCE: ACIL ALLEN CONSULTING

9.6 Population

The population of the Northern Territory, resulting from the development of the Industry under the BREEZE scenario, is largely driven by interstate migration as workers and their families relocate to the Territory to take up employment opportunities created by the development of the Industry.

Over the study period, it is estimated the population in the Northern Territory will increase by an average of 195 persons per annum. The population impact peaks during the capital intensive construction phase of the development of the Industry at 388 persons in 2022.

FIGURE 9.11 BREEZE NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER



SOURCE: ACIL ALLEN CONSULTING

9.7 Real taxation

The development of the Industry under the BREEZE scenario will generate significant taxation benefits to the Northern Territory and the Commonwealth Government, primarily in the form of profits based taxes, royalty revenues, payroll tax and a range of other taxes.

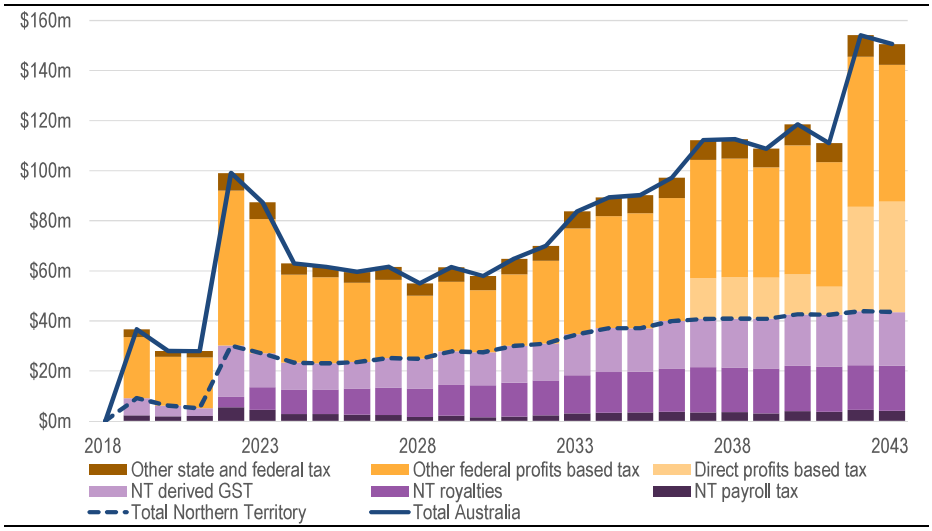
Over the study period, payments to the Commonwealth are projected to be substantial (refer to Figure 9.12). ACIL Allen estimates that the direct profits based taxation payments from the Industry would total $162 million at an average of $6.2 million per annum over the study period. There will also be significant indirect taxation payments collected by the Commonwealth, with payments totalling $989 million at an average of $38 million per annum.

The development of the Industry is estimated to generate other indirect taxation payments to the Commonwealth (such as personal income, excises, fringe benefits and capital gains tax receipts), totalling $154 million at an average of $5.9 million per annum.

Payments made to the Territory Government are expected to be largely accrued through royalty payments, which are estimated to total $309 million at an average of $11.9 million per annum over the study period. Direct and indirect payroll taxation payments to the Territory Government due to the development of the Industry are estimated to total $74.8 million at an average of $5.9 million per annum over the study period.

Increased commercial activity in the Territory is also estimated to result in GST revenues increasing by $373 million at an average of $14.3 million per annum over the study period.

FIGURE 9.12 BREEZE REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

9.8 Summary

Table 9.1 presents a summary of the economic modelling results presented in the section.

TABLE 9.1 BREEZE DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	$937.2m	$36.0m	$380.1m
Rest of Australia	$3,339.9m	$128.5m	$1,099.0m
Total Australia	**$4,277.2m**	**$164.5m**	**$1,479.1m**
Real output			
Northern Territory	$5,107.9m	$196.5m	$1,742.3m
Rest of Australia	$406.5m	$15.6m	$118.7m
Total Australia	**$5,514.4m**	**$212.1m**	**$1,861.0m**
Real Final Demand			
Northern Territory	$3,277.7m	$126.1m	$1,683.0m
Rest of Australia	$2,042.2m	$78.5m	$684.8m
Total Australia	**$5,319.9m**	**$204.6m**	**$2,367.8m**
Real investment			
Northern Territory	$2,264.8m	$87.1m	$1,265.0m
Rest of Australia	-$359.3m	-$13.8m	-$113.7m
Total Australia	**$1,905.4m**	**$73.3m**	**$1,151.2m**
Northern Territory real exports			
International	-$572.5m	-$22.0m	-$225.9m
Interstate	$5,791.6m	$222.8m	$1,948.0m
Total	**$5,219.1m**	**$200.7m**	**$1,722.1m**
Real employment			
Northern Territory	2,145 FTEs	82 FTEs	
Rest of Australia	-2,145 FTEs	-82 FTEs	
Total Australia	**0 FTEs**	**0 FTEs**	
Real employment by industry			
Agriculture	103 FTEs	4 FTEs	
Mining	-265 FTEs	-10 FTEs	
Petroleum	910 FTEs	35 FTEs	
Manufacturing	-100 FTEs	-4 FTEs	
Electricity and water	-19 FTEs	-1 FTEs	
Transport services	253 FTEs	10 FTEs	
Construction services	141 FTEs	5 FTEs	

	Total	Average	NPV (7 per cent)
Retail and wholesale trade	526 FTEs	20 FTEs	
Government services	462 FTEs	18 FTEs	
Other services	133 FTEs	5 FTEs	
Total industry employment	**2,145 FTEs**	**82 FTEs**	
Real population			
Northern Territory	5,061 persons	195 persons	
Real taxation			
Northern Territory			
Payroll tax	$74.8m	$2.9m	$31.0m
Royalties	$309.2m	$11.9m	$105.3m
Derived GST	$372.9m	$14.3m	$139.9m
Total Northern Territory	**$757.0m**	**$29.1m**	**$276.1m**
Commonwealth			
Direct profits based tax	$162.3m	$6.2m	$32.8m
Other federal profits based tax	$988.8m	$38.0m	$395.9m
Other state and federal tax	$154.4m	$5.9m	$59.1m
Total Commonwealth	**$1,305.4m**	**$50.2m**	**$487.8m**
Total Australia	**$2,062.4m**	**$79.3m**	**$764.0m**

SOURCE: ACIL ALLEN CONSULTING

10 WIND SCENARIO

This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the "Onshore Unconventional Gas Industry" or "the Industry".

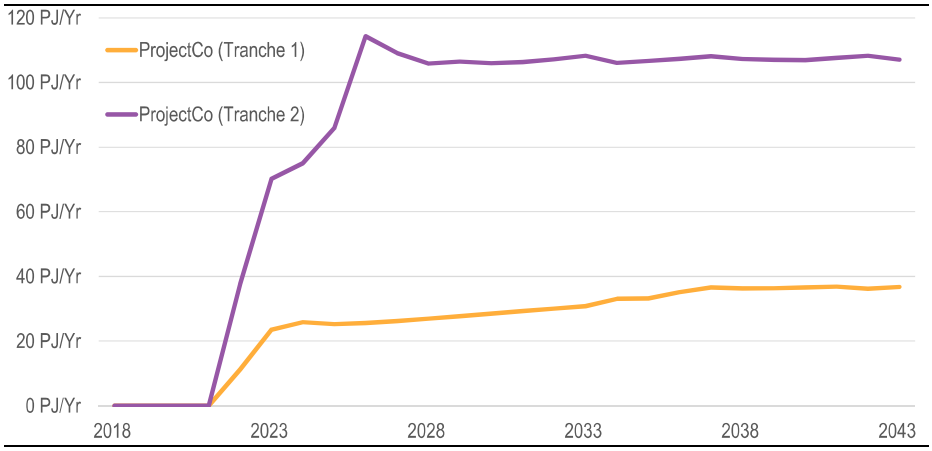
The economic impact of the development of the Industry under the WIND development scenario, as detailed in Section 4.3.3, was assessed using ACIL Allen's *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

10.1 Scenario description

As discussed in Section 4.3.3, under the WIND development scenario, the target production rate increases to 400TJ/day. The majority of gas under this scenario is placed into the East Coast market, requiring additional pipeline infrastructure to be developed as the capacity of the existing NGP is reached. Pipeline-related assumptions are outlined in Section 3.5.1.

The production profile of Industry in the WIND scenario, relative to the BREEZE scenario, is presented in Figure 10.1.

FIGURE 10.1 GAS PRODUCTION, WIND SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

Under the WIND development scenario, the following investment into transmission gas pipelines is also assumed to occur:

- tie into Amadeus pipeline;
- Amadeus duplication;
- National Gas Pipeline duplication; and
- Carpentaria Gas Pipeline duplication.

These assumption are discussed in Section 4.7.

10.2 Real income

The development of the Industry has a significant impact on the real income of Australia. Real income is a measure of the economic welfare (or standard of living) improvement as a result of the developments. The change in real income captures the effect of net foreign income transfers associated with ownership of the capital along with changes in the purchasing power of Australian residents.

The real income impact of the Industry is largely accrued through the profits generated by the Industry once it is operational, which also determines the level of profits based taxation paid by the Industry. Overall, the majority of the real income impact of the development under the WIND scenario is transferred from the Northern Territory to the Rest of Australia, in the form of Commonwealth Government taxes and because the equity ownership of the Industry is assumed to be largely on the east coast of Australia.

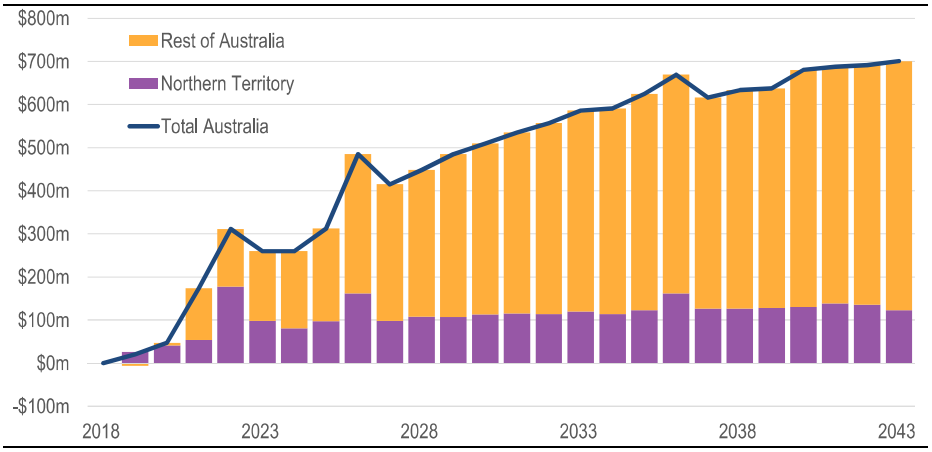
Real income impacts are still realised in the Territory, through increased employment and a redistribution of the profits based taxation payments from the Commonwealth back to the Territory. Royalty and payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners also contribute to the real income impact in the Territory.

In total, the real income impact of the Industry is estimated to total $11.9 billion at an average of $459 million per annum over the study period (refer to Figure 10.2). The real income impact reaches a steady state of around $690 million per annum in 2040.

Over the study period, the real income impact in the Northern Territory is estimated to total $2.8 billion, at an average of $108 million per annum. Real incomes are expected to peak at $177 million in 2022, which coincides with peak employment and peak wages growth in the Territory. Once the Industry reaches its steady state level of production, the real income impact in the Territory averages around $130 million per annum, with further boosts in 2026 and 2036 as a result of investment in to transmission gas pipelines.

The real income impact is largely felt on the east coast of Australia, which is estimated to total $9.1 billion at an average of $351 million per annum over the study period. Real incomes are expected to peak in 2043 at $578 million, when the Industry is at a steady state of production.

FIGURE 10.2 WIND REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

10.3 Real output

The real output impact is largely accrued through the impact the Industry has on investment in the Northern Territory and the value of the gas exported from the Territory to the Rest of Australia. The real output impact of the Industry is different to the real income impact because, in an output sense, the value of the gas exported is realised in the Territory, whereas in an income sense, the value of the gas exported is realised through profits generated and taxation payments, which largely accrue on the east coast of Australia.

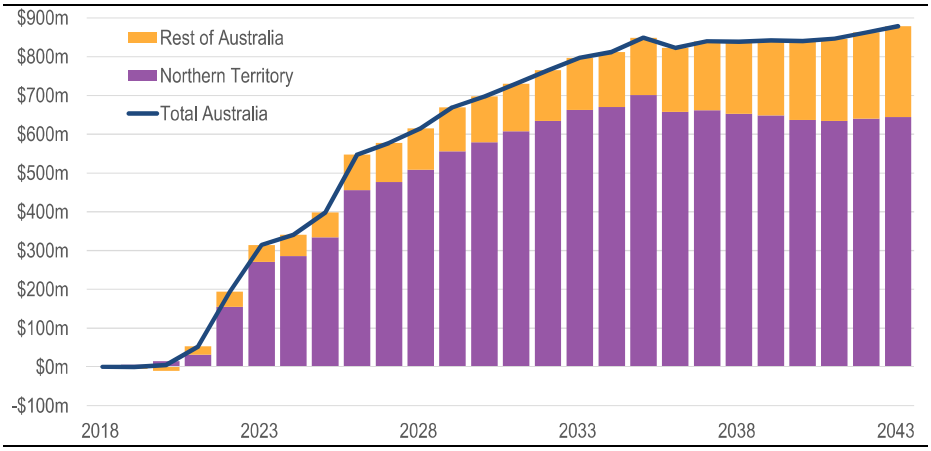
Under the WIND development scenario, real output is estimated to total $15.1 billion at an average of $582 million per annum over the study period (refer to Figure 10.3). The real output impact reaches a steady state of around $846 million per annum in 2036.

Over the study period, the real output impact in the Northern Territory is estimated to total $12.1 billion, at an average of $466 million per annum. Real output is expected to increase over the study period in line with the increase in the level of production. At steady state production in 2037, output in the Territory is estimated to average $646 million per annum.

Relative to the size of the Northern Territory's economy, the increase in real output from the development of the Industry represents a boost to Gross Territory Product of 0.31 per cent in 2037, once the level of real output reaches a steady state.

Across the Rest of Australia, the real output impact is largely driven by an increase to consumption by the household sector, as a result of the rising real incomes from the development on the Rest of Australia. Over the study period, it is estimated the real output impact on the Rest of Australia will total $406 million at an average of $15.6 million per annum.

FIGURE 10.3 WIND REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

10.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output.

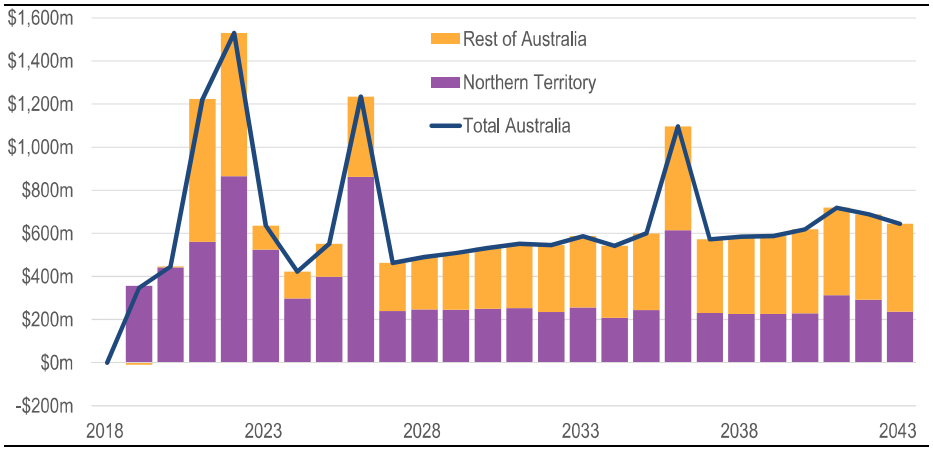
The real Final Demand impact of development under the WIND scenario in the Northern Territory is largely accrued through the investment needed to fund the Industry's capital requirements and the additional investment needed for transmission gas pipelines. For the Rest of Australia the impact largely results from the household consumption impacts that are accrued from rising real incomes resulting from the development, as well as further investment in transmission gas pipelines in Eastern Australia.

In total, the real Final Demand impact of development under the WIND scenario is estimated to total $16.7 billion at an average of $643 million per annum over the study period (refer to Figure 10.4).

Real Final Demand in the Territory is expected to peak at $865 million in 2022, during the Industry's capital intensive development phase and transmission pipeline construction. Over the study period, the Final Demand impact is estimated to total $8.9 billion at an average of $340 million per annum.

Throughout the Rest of Australia, the real Final Demand impact of the Industry is more significant than the impact under the BREEZE development scenario, due to the estimated increase in household consumption and also the construction of transmission gas pipelines on the east coast of Australia. Over the study period, the Final Demand impact is estimated to total $7.9 billion at an average of $303 million per annum.

FIGURE 10.4 WIND REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

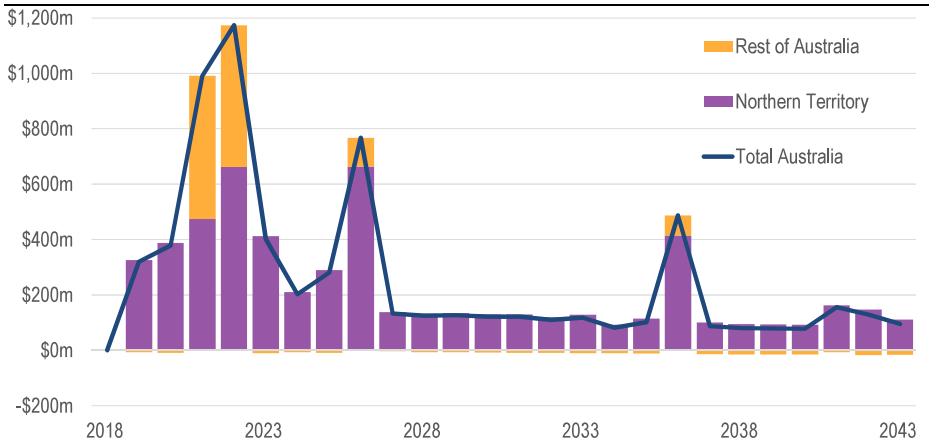
Real investment

In the Northern Territory, the major component of the Industry's real Final Demand impact is in relation to investment, and is the result of the ongoing capital intensive nature of unconventional shale gas developments.

In total, the real investment impact of the Industry is estimated to total $6.7 billion at an average of $259 million per annum over the study period (refer to Figure 10.5). Real investment peaks in 2022 during the development of the Industry and construction of the transmission gas pipelines at $1.5 billion.

Following the capital intensive initial production phase of the Industry, the real investment reduces as less capital is required to reach the target production level. Over the study period, real investment in the Territory is estimated to total $5.8 billion at an average of $222 million per annum.

FIGURE 10.5 WIND REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Across the Rest of Australia, a small boost to real investment is realised through the construction of gas transmission pipelines. However, ACIL Allen also estimates that as a result of a reallocation of labour resources to the Northern Territory, real investment falls in most years through the study period across the

Rest of Australia. The impact on real investment throughout the Rest of Australia increases by $983 million at an average of $37.8 million per annum over the study period.

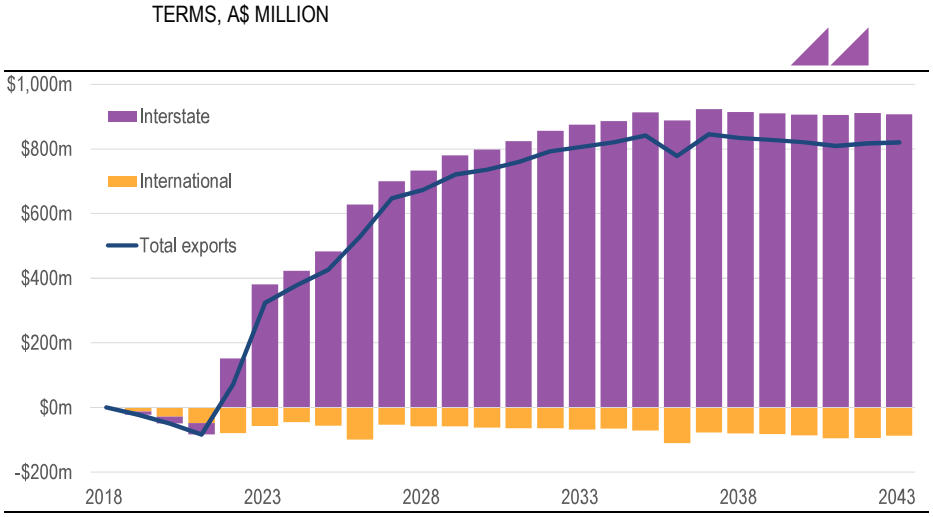
10.3.2 Real exports

The impact the Industry has on the Northern Territory's real exports is the other main driver of the impact on the Territory's real output. While gas is not exported to international markets under the WIND development scenario, it is exported from the Territory to the Rest of Australia (specifically the east coast of Australia).

Over the study period, the development is estimated to increase real exports by $14.9 billion at an average of $574 million per annum (refer to Figure 10.6). The increase in real exports is driven by the boost to interstate exports ($16.6 billion over the study period or $640 million per annum), which offsets the small decrease in international exports resulting from the impact of an expected appreciation in the Australian Dollar ($1.7 billion over the study period or $65.7 million per annum).

Once a steady state of real exports is reached in 2037, it is estimated that the exports generated by the Industry under the WIND development scenario would account for 4.4 per cent of the Territory's total exports.

FIGURE 10.6 WIND NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

10.4 Real output – industry

Figure 10.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the WIND development scenario, the largest impact will be realised in the Petroleum industry, given that the Industry would be captured under this industry classification. It is estimated that the Petroleum industry will generate growth over and above the base case of 5.7 per cent per annum on average over the study period.

The Construction Services industry is also expected to increase over the study period, averaging growth of 0.9 per cent per annum. The majority of this growth will be realised in the early stages of the Industry's development, with growth expected to peak at 3.3 per cent in 2022.

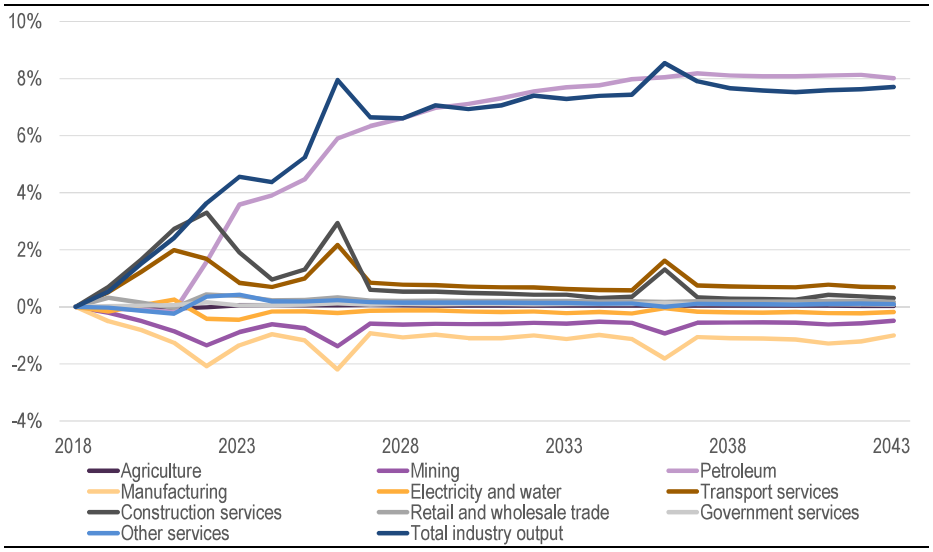
The Transport Services industry is also estimated to follow a similar trend, growing on average by 0.9 per cent per annum and peaking at two per cent in 2021, relative to the base case.

The Manufacturing industry is estimated to contract on average by 1.1 per cent per annum over the study period. This reflects the impact of an appreciation in the Australian Dollar on the global competitiveness of export competing businesses in the Territory. In addition, a reallocation of labour away from the

Manufacturing industry to the Petroleum industry results in lower output from the industry. A similar impact occurs in the Mining and Electricity and Water industries, which are estimated to contract on average by 0.6 per cent and 0.2 per cent per annum over the study period.

Across all industries, the development of the Industry in the Territory will have a marginal impact on the growth across most industries. Overall, industry growth is estimated to be six per cent per annum higher than what would otherwise have occurred, if the development of the Industry did not occur.

FIGURE 10.7 WIND NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

10.5 Labour market

10.5.1 Employment

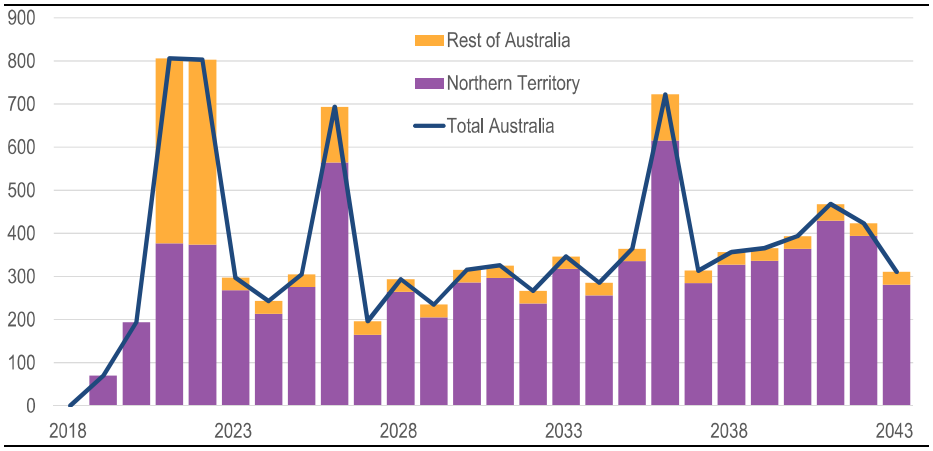
The development of a new industry in the Territory under the WIND development scenario has significant workforce implications. The largest component of the Industry's direct workforce is the staff required to operate the wells and pads. Staff required to operate additional transmission gas pipelines also has a significant impact of direct employment in the Rest of Australia.

The 'peaking' nature of the FTE requirements presented in Figure 10.8 is a result of the timing of the construction workforce requirements. Labour required for the construction of gas transmission pipelines in the Territory in 2021, 2022, 2026 and 2036 also contributes to this 'peaking' nature, but on a smaller scale.

Over the study period, it is estimated the development of the Industry will require direct employment of 7,730 FTE jobs at an average of 297 FTE jobs per annum in the Territory. The majority of these FTE jobs are in relation to the construction and operations of the Industry (total of 5,905 FTE jobs at an average of 227 FTE jobs per annum), while a total of 1,824 FTE jobs (average of 70 FTE jobs per annum) are in relation to the construction and operations of transmission pipes.

Throughout the Rest of Australia, the construction and operations of transmission gas pipelines will require direct employment of 1,663 FTE jobs at an average of 63.9 FTE jobs per annum.

FIGURE 10.8 WIND DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

However, the total employment impact of the Industry development under the WIND scenario is minimal, due to the resulting draw on labour from other industries in the Territory and other parts of Australia.

Over the study period, the Industry is estimated to create 6,559 FTE direct and indirect FTE jobs at an average of 252 FTE jobs per annum in the Northern Territory. However, ACIL Allen estimates that these positive impacts will be completely offset by the reallocation of employment from the Rest of Australia to the Territory.

10.5.2 Industry real employment

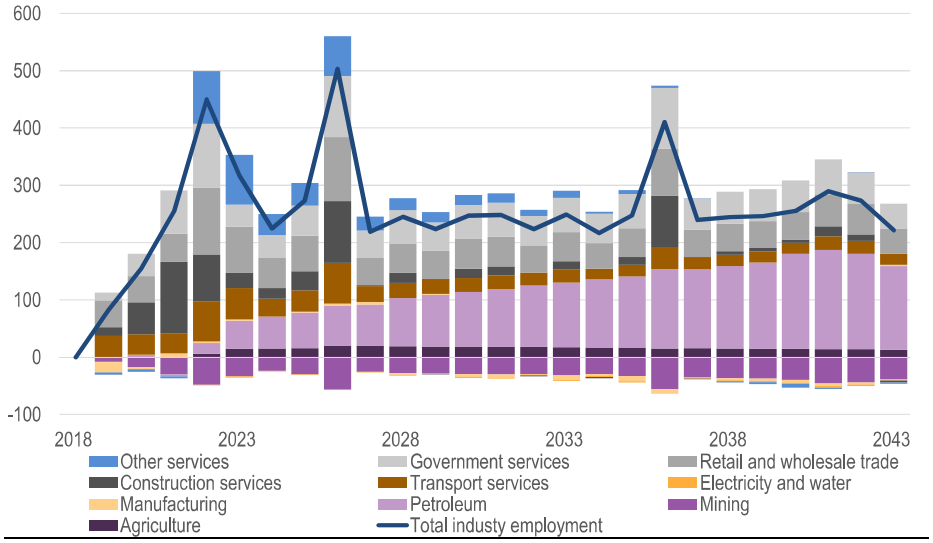
While the development of the Industry under the WIND development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory (refer to Figure 10.9).

Over the study period, the Petroleum industry is estimated to see the largest real employment impact, with the creation of 2,384 FTE jobs at an average of 92 FTE jobs per annum. Significant gains are also estimated in the Retail and Wholesale Trade industry, with a total of 1,437 FTE jobs at an average of 55 FTE jobs per annum to be created, as a result of increased household consumption in the Territory.

The Government Service industry (1,461 FTE jobs at an average of 56 FTE jobs per annum), Transport Services industry (765 FTE jobs at an average of 29 FTE jobs per annum) and Construction Services industry (671 FTE jobs at an average of 26 FTE jobs per annum) are also estimated to see solid employment gains over the study period under the WIND development scenario.

The majority of the labour reallocation, as a result of the development of the Industry, is estimated to occur in Mining (loss of 843 FTE jobs at an average of 32 FTE jobs per annum), Manufacturing (loss of 56 FTE jobs at an average of two FTE jobs per annum) and Electricity and Water (loss of 34 FTE jobs at an average of one FTE jobs per annum).

FIGURE 10.9 WIND NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



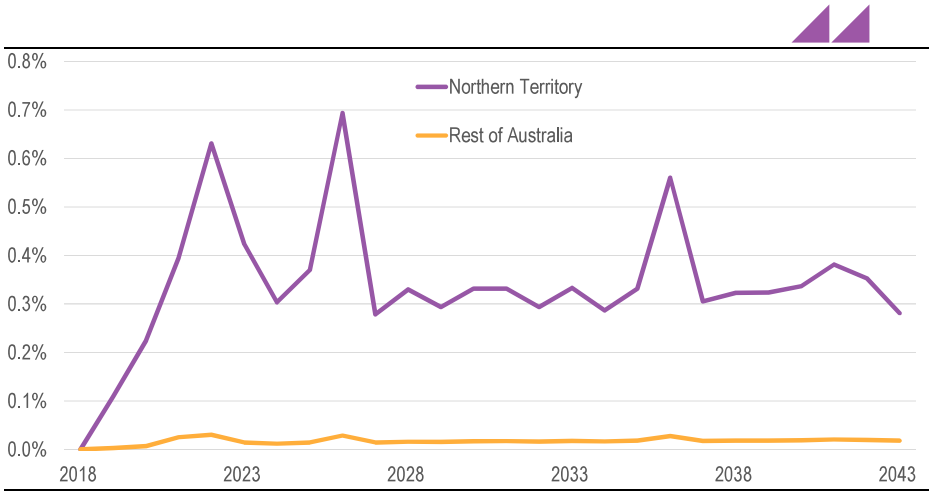
SOURCE: ACIL ALLEN CONSULTING

10.5.3 Real wages

The development of the Industry is estimated to boost real wages in the Northern Territory relative to the Rest of Australia (refer to Figure 10.10).

Over the study period, the increase in real wages is estimated to be on average 0.34 per cent per annum higher than the base case, peaking at 0.69 per cent in 2026 when the demand for labour in the Territory is at its highest. The impact across the Rest of Australia is negligible over the study period, given that there is no net job creation under the WIND scenario.

FIGURE 10.10 WIND REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE



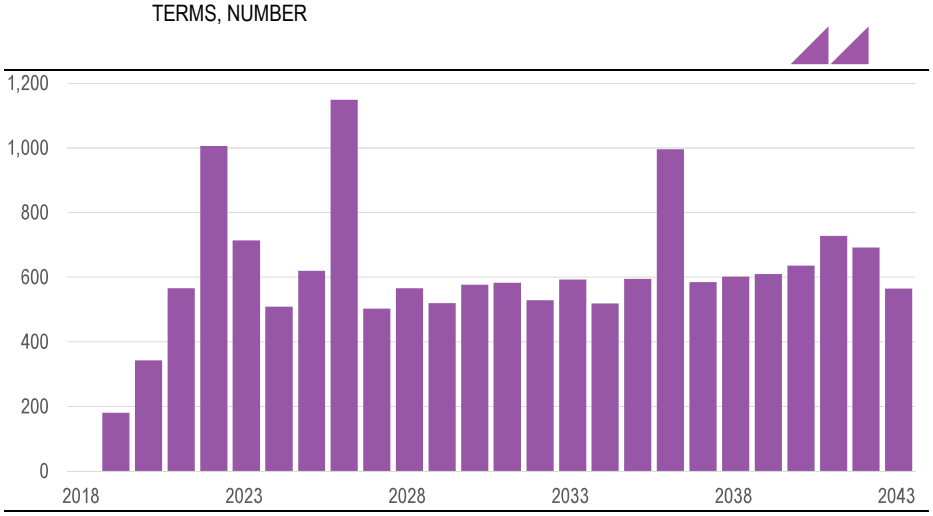
SOURCE: ACIL ALLEN CONSULTING

10.6 Population

The population of the Northern Territory, resulting from the development of the Industry under the WIND scenario, is largely driven by interstate migration as workers and their families relocate to the Territory to take up employment opportunities created by the development of the Industry.

Over the study period, it is estimated the population in the Northern Territory will increase by an average of 595 persons per annum. The population impact peaks during the capital intensive construction phase of the development of the Industry at 1,005 persons in 2022.

FIGURE 10.11 WIND NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER



SOURCE: ACIL ALLEN CONSULTING

10.7 Real taxation

The development of the Industry under the WIND scenario will generate significant taxation benefits to the Northern Territory and the Commonwealth Government, primarily in the form of profits based taxes, royalty revenues, payroll tax and a range of other taxes.

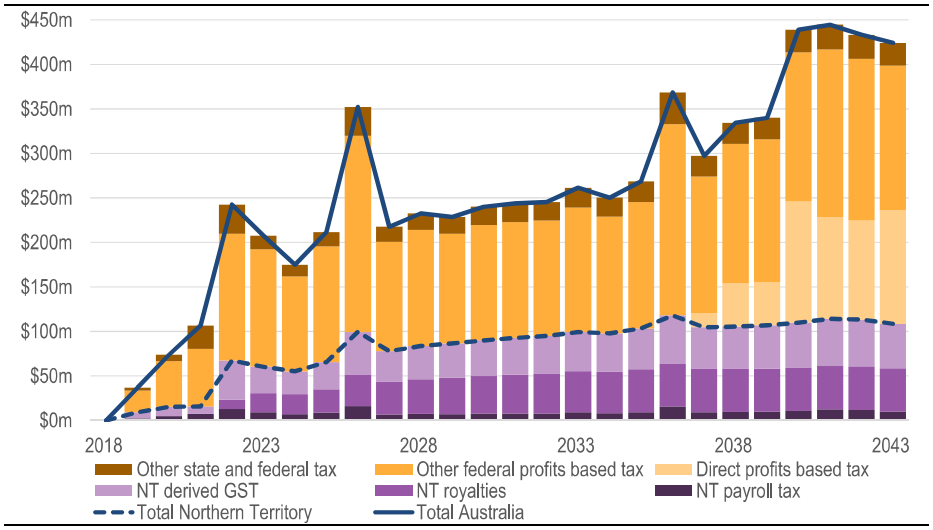
Over the study period, payments to the Commonwealth are projected to be substantial (refer to Figure 10.12). ACIL Allen estimates that the direct profits based taxation payments from the Industry would total $602 million at an average of $23.2 million per annum over the study period. There will also be significant indirect taxation payments collected by the Commonwealth, with payments totalling $3.4 billion at an average of $132 million per annum.

The development of the Industry is estimated to generate other indirect taxation payments to the Commonwealth (such as personal income, excises, fringe benefits and capital gains tax receipts), totalling $542 million at an average of $20.8 million per annum.

Payments made to the Territory Government are expected to be largely accrued through royalty payments, which are estimated to total $895 million at an average of $34.4 million per annum over the study period. Direct and indirect payroll taxation payments to the Territory Government due to the development of the Industry are estimated to total $227 million at an average of $8.7 million per annum over the study period.

Increased commercial activity in the Territory is also estimated to result in GST revenues increasing by $973 million at an average of $37.4 million per annum over the study period.

FIGURE 10.12 WIND REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

10.8 Summary

Table 10.1 presents a summary of the economic modelling results presented in the section.

TABLE 10.1 WIND DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	$2,818.1m	$108.4m	$1,116.2m
Rest of Australia	$9,120.0m	$350.8m	$3,074.0m
Total Australia	**$11,938.1m**	**$459.2m**	**$4,190.2m**
Real output			
Northern Territory	$12,126.1m	$466.4m	$4,178.0m
Rest of Australia	$3,011.7m	$115.8m	$958.6m
Total Australia	**$15,137.8m**	**$582.2m**	**$5,136.6m**
Real Final Demand			
Northern Territory	$8,851.0m	$340.4m	$4,351.2m
Rest of Australia	$7,869.6m	$302.7m	$3,127.5m
Total Australia	**$16,720.6m**	**$643.1m**	**$7,478.7m**
Real investment			
Northern Territory	$5,759.1m	$221.5m	$3,098.7m
Rest of Australia	$983.0m	$37.8m	$754.0m
Total Australia	**$6,742.0m**	**$259.3m**	**$3,852.7m**
Northern Territory real exports			

	Total	Average	NPV (7 per cent)
International	-$1,707.8m	-$65.7m	-$658.8m
Interstate	$16,632.2m	$639.7m	$5,657.9m
Total	**$14,924.3m**	**$574.0m**	**$4,999.1m**
Real employment			
Northern Territory	6,559 FTEs	252 FTEs	
Rest of Australia	-6,559 FTEs	-252 FTEs	
Total Australia	**0 FTEs**	**0 FTEs**	
Real employment by industry			
Agriculture	345 FTEs	13 FTEs	
Mining	-843 FTEs	-32 FTEs	
Petroleum	2,384 FTEs	92 FTEs	
Manufacturing	-56 FTEs	-2 FTEs	
Electricity and water	-34 FTEs	-1 FTEs	
Transport services	765 FTEs	29 FTEs	
Construction services	671 FTEs	26 FTEs	
Retail and wholesale trade	1,437 FTEs	55 FTEs	
Government services	1,461 FTEs	56 FTEs	
Other services	429 FTEs	17 FTEs	
Total industry employment	**6,559 FTEs**	**252 FTEs**	
Real population			
Northern Territory	15,480 persons	595 persons	
Real taxation			
Northern Territory			
Payroll tax	$227.2m	$8.7m	$91.8m
Royalties	$894.6m	$34.4m	$307.5m
Derived GST	$972.7m	$37.4m	$362.7m
Total Northern Territory	**$2,094.4m**	**$80.6m**	**$762.1m**
Commonwealth			
Direct profits based tax	$602.1m	$23.2m	$120.5m
Other federal profits based tax	$3,437.5m	$132.2m	$1,332.6m
Other state and federal tax	$541.7m	$20.8m	$215.8m
Total Commonwealth	**$4,581.3m**	**$176.2m**	**$1,668.8m**
Total Australia	**$6,675.7m**	**$256.8m**	**$2,430.9m**

SOURCE: ACIL ALLEN CONSULTING

11 GALE SCENARIO

This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the "Onshore Unconventional Gas Industry" or "the Industry".

The economic impact of the development of the Industry under the GALE development scenario, as detailed in Section 4.3.4, was assessed using ACIL Allen's *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

11.1 Scenario description

The Darwin LNG plant (DLNG) is currently supplied feed gas from the Bayu-Undan gas project off the coast of the Northern Territory in the Australia Timor-Leste Joint Petroleum Development Area. DLNG has a single production train[41], producing up to 3.7 million tonnes of LNG per annum for sales to Japan[42]. To produce 3.7 million tonnes of LNG, the plant requires approximately 225 PJ/year of feed gas.

As it stands, Bayu-Undan provides 100 per cent of the feed in gas to the plant. The field is set to reach maturity in 2022-23, and will progressively reduce its production. Unless replacement gas is found, DLNG will cease production some time towards the end of the next decade. Acknowledging this, the owners of the Bayu-Undan joint venture have begun independently investigating new sources of gas for the plant, at this stage focussed on a new large scale offshore development off the coast of the Northern Territory.[43]

Under the GALE scenario, ACIL Allen assumes the development of an onshore unconventional gas industry is able to build to a scale that would allow it to progressively replace the Bayu-Undan gas field as the feed in gas for DLNG, allowing the existing train to continue production beyond 2022-23 at current

[41] ConocoPhillips. 2017. *Our Business Activities – DLNG*. Accessed online at http://www.conocophilips.com.au/
[42] Santos. 2017. *Bayu-Undan/Darwin LNG Joint Venture*. Accessed online at http://www.santos.com/
[43] Energy News Bulletin. 2017. *Barossa development begins.* Accessed online at http://www.energynewsbulletin.net/

rates. This necessitates investment to expand the Amadeus Gas Pipeline to allow more gas to flow north to DLNG.

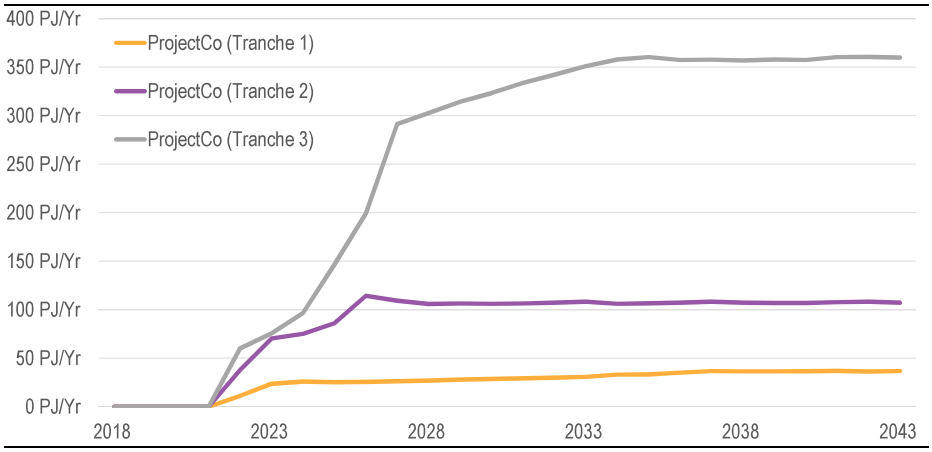
For the purposes of economic modelling, it is assumed that DLNG will continue to produce LNG at its current rate with or without gas from the onshore unconventional gas industry. In the base case, it is assumed one of the new offshore developments discussed above comes to pass and this gas backfills DLNG. This is a critical assumption, as it means there is no incremental value associated with LNG production attributable to onshore unconventional gas industry – the incremental value is any change to the production profile, profitability and local content of gas required to backfill DLNG in an onshore scenario versus an offshore scenario. This is discussed further in Section 6.

It is also assumed that due to increasing scale economies, the cost of production falls below the rate of the WIND scenario, allowing for increased gas sales into the East Coast gas market – potentially including partial backfill of an LNG train at Gladstone – versus the WIND scenario. In any event, the cascading effect of the onshore unconventional gas production results in a reduction in the wholesale price of gas in the East Coast market, with the "ripple" effect of injection of more gas flowing west to east leading to less gas produced in Queensland fields moving south. Similarly to DLNG, there is no incremental value associated with LNG backfill.

As such, this necessitates further investment in the NGP and Carpentaria Gas Pipeline over and above the investment assumed to be required to meet WIND East Coast exports. As a result, the Industry is able to fulfil its full target production of 1000 TJ/day by 2035. Economies of scale in production allowing it to increase its penetration of the East Coast market over the WIND scenario.

The production profile in the GALE scenario is presented in Figure 11.1.

FIGURE 11.1 GAS PRODUCTION, GALE SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

Under the GALE development scenario, the following investment into transmission gas pipelines are also assumed to occur:

- tie into Amadeus pipeline;
- Amadeus duplication;
- National Gas Pipeline duplication;
- Carpentaria Gas Pipeline duplication; and
- construction of DLNG feed pipeline.

These assumption are discussed in Section 4.7.

11.2 Real income

The development of the Industry has a significant impact on the real income of Australia. Real income is a measure of the economic welfare (or standard of living) improvement as a result of the developments. The change in real income captures the effect of net foreign income transfers associated with ownership of the capital along with changes in the purchasing power of Australian residents.

The real income impact of the Industry is largely accrued through the profits generated by the Industry once it is operational, which also determines the level of profits based taxation paid by the Industry. Overall, the majority of the real income impact of the development under the GALE scenario is transferred from the Northern Territory to the Rest of Australia, in the form of Commonwealth Government taxes and given the assumption that the equity ownership of ProjectCo is assumed to be largely on the east coast of Australia.

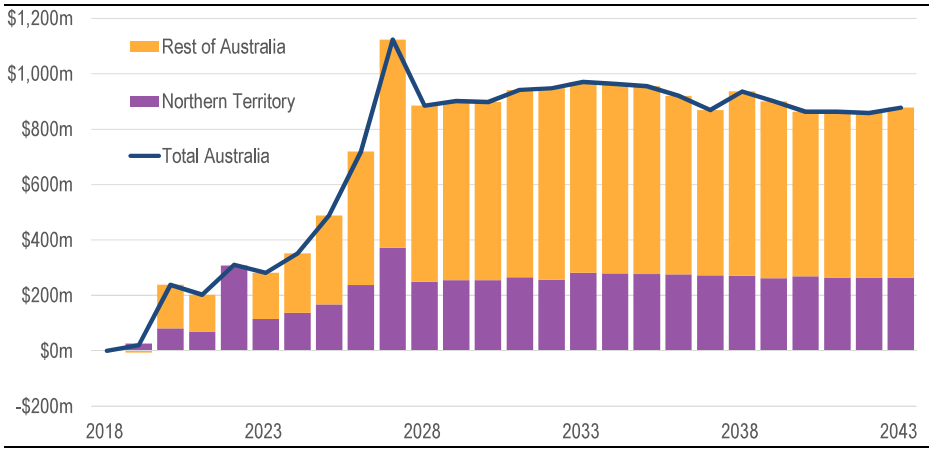
Real income impacts are still realised in the Territory, through increased employment and a redistribution of the profits based taxation payments from the Commonwealth back to the Territory. Royalty and payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners also contribute to the real income impact in the Territory.

In total, the real income impact of the Industry is estimated to total $18.3 billion at an average of $703 million per annum over the study period (refer to Figure 11.2). The real income impact reaches a steady state of around $909 million per annum in 2028. Importantly, the real income impact under the GALE development scenario does not continue to increase like under the BREEZE and WIND development scenarios, because of the reallocation of feed-in gas to DLNG.

Over the study period, the real income impact in the Northern Territory is estimated to total $5.8 billion, at an average of $222 million per annum. Real incomes are expected to peak at $372 million in 2027, which coincides with peak employment and peak wages growth in the Territory. Once the Industry reaches its steady state level of production in 2037, the real income impact in the Territory averages around $267 million per annum.

The real income impact is largely felt on the east coast of Australia, which is estimated to total $12.5 billion at an average of $481 million per annum over the study period. Real incomes are also expected to peak in 2027 at $751 million.

FIGURE 11.2 GALE REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

11.3 Real output

The real output impact is largely accrued through the impact the Industry has on investment in the Northern Territory and the value of the gas exported from the Territory to the Rest of Australia. The real output impact of the Industry is different to the real income impact because, in an output sense, the value of the gas exported is realised in the Territory, whereas in an income sense, the value of the gas exported is realised through profits generated and taxation payments, which largely accrue on the east coast of Australia.

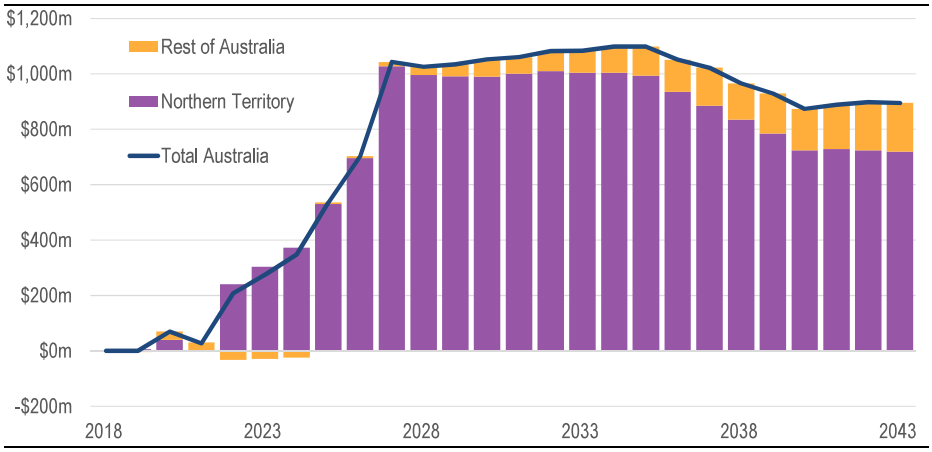
Under the GALE development scenario, real output is estimated to total $19.3 billion at an average of $741 million per annum over the study period (refer to Figure 11.3). Between 2027 and 2035 the real output impact average $1.1 billion per annum, and between 2036 and 2043 the average falls to $940 million per annum. This is due to a transfer between onshore and offshore gas for feed in stock for DLNG that occurs in 2036, which has no significant net real output impact. The majority of this impact is realised in the Territory.

Over the study period, the real output impact in the Northern Territory is estimated to total $17.5 billion, at an average of $674 million per annum. Real output is expected to increase over the study period in line with the increase in the level of production, until 2036 when the transfer between onshore and offshore gas occurs. Between 2027 and 2035 the real output impact average $1 billion per annum, and between 2036 and 2043 the average falls to $792 million per annum.

Relative to the size of the Northern Territory's economy, the increase in real output from the development of the Industry represents a boost to Gross Territory Product of 0.66 per cent in 2037. However, the boost to Gross Territory Product peaks at 1.2 per cent in 2027, and at the end of the study period falls to 0.55 per cent.

Across the Rest of Australia, the real output impact is largely driven by an increase to consumption by the household sector, as a result of the rising real incomes from the development on the Rest of Australia. Over the study period, it is estimated the real output impact on the Rest of Australia will total $1.7 billion at an average of $66.6 million per annum.

FIGURE 11.3 GALE REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

11.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output.

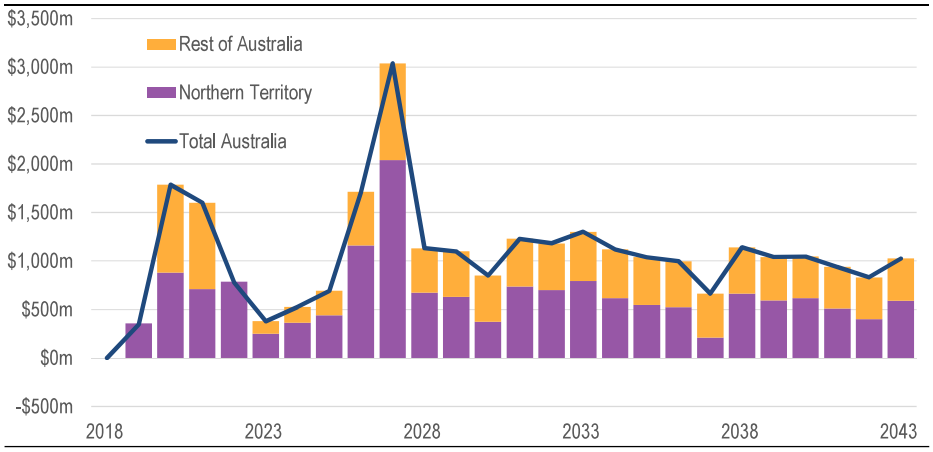
The real Final Demand impact of development under the GALE scenario in the Northern Territory is largely accrued through the investment needed to fund the Industry's capital requirements and investment needed for transmission gas pipelines. For the Rest of Australia the impact largely results from the household consumption impacts that are accrued from rising real incomes resulting from the development, and the additional investment into east coast transmission gas pipelines that is required.

In total, the real Final Demand impact of development under the GALE scenario is estimated to total $27.5 billion at an average of $1.1 billion per annum over the study period (refer to Figure 11.4).

Real Final Demand in the Territory is expected to peak at $2 million in 2022, during the Industry's capital intensive development phase and transmission pipeline construction. Over the study period, the Final Demand impact is estimated to total $16.2 billion at an average of $622 million per annum.

Throughout the Rest of Australia, the real Final Demand impact of the Industry is more significant than the impact under the BREEZE or WIND development scenarios, which is driven by an increase impact to household consumption and also the construction of transmission gas pipelines on the east coast of Australia. Over the study period, the Final Demand impact is estimated to total $11.3 billion at an average of $435 million per annum.

FIGURE 11.4 GALE REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Real investment

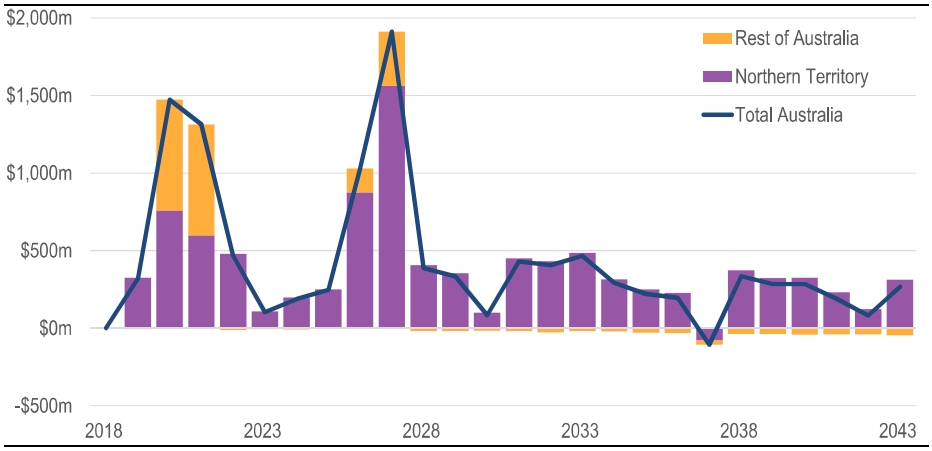
In the Northern Territory, the major component of the Industry's real Final Demand impact is in relation to investment, and is the result of the ongoing capital intensive nature of unconventional shale gas developments.

In total, the real investment impact of the Industry is estimated to total $11.2 billion at an average of $376 million per annum over the study period (refer to Figure 11.5). Real investment peaks in 2027 during the development of the Industry and construction of the transmission gas pipelines at $1.9 billion.

Following the capital intensive initial production phase of the Industry, the real investment reduces as less capital is required to reach the target production level. Over the study period, real investment in the Territory is estimated to total $9.8 billion at an average of $376 million per annum.

Across the Rest of Australia, a small boost to real investment is realised through the construction of gas transmission pipelines. However, ACIL Allen also estimates that as a result of a reallocation of labour resources to the Northern Territory, real investment falls in most years through the study period across the Rest of Australia. The impact on real investment throughout the Rest of Australia increases by $1.4 billion at an average of $54.6 million per annum over the study period.

FIGURE 11.5 GALE REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



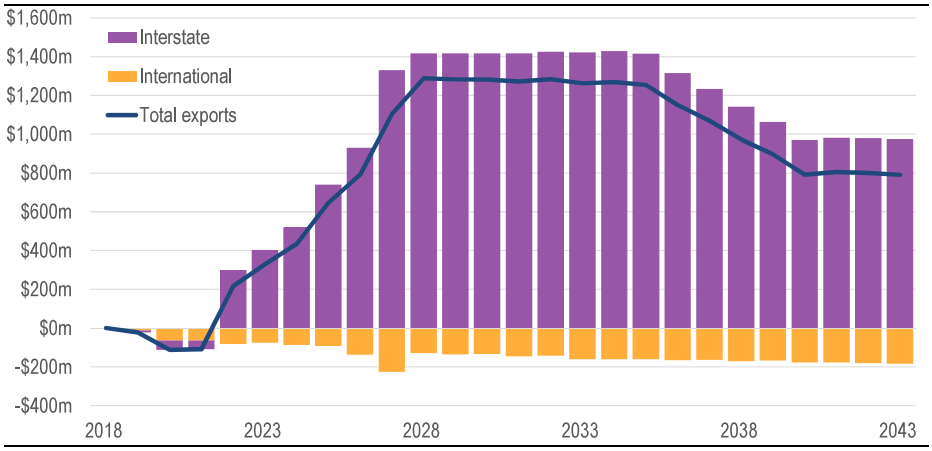
SOURCE: ACIL ALLEN CONSULTING

11.3.2 Real exports

The impact the Industry has on the Northern Territory's real exports is the other main driver of the impact on the Territory's real output. The majority of the gas is not exported to international markets under the GALE development scenario, but is exported from the Territory to the Rest of Australia (specifically the east coast of Australia). While some of the onshore stock from the development of the Industry replaces offshore feed-in stock to DLNG for international exports, because onshore gas is replacing offshore gas, the net impact on the value of the Territory's international exports is zero.

Over the study period, the development is estimated to increase real exports by $20.7 billion at an average of $798 million per annum (refer to Figure 11.6). The increase in real exports is driven by the boost to interstate exports ($24.1 billion over the study period or $929 million per annum), which offsets the small decrease in international exports resulting from the impact of an expected appreciation in the Australian Dollar ($3.4 billion over the study period or $131 million per annum).

FIGURE 11.6 GALE NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Between 2027 and 2035, the value of interstate exports from the Territory average $1.4 billion per annum, and by 2035 the Industry is estimated will account for 5.6 per cent of the Territory's exports. As the value of interstate exports falls to an average of $1.1 billion per annum thereafter, the Industry's contribution to the Territory's exports eases slightly to 3.7 per cent of total exports by 2043.

11.4 Real output – industry

Figure 11.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the GALE development scenario, the largest impact will be realised in the Petroleum industry, given that the Industry would be captured under this industry classification. It is estimated that the Petroleum industry will generate growth over and above the base case of 10.6 per cent per annum on average over the study period. In 2036 when the offshore feed-in stock for DNLG is replaced by onshore feed-in stock, the growth of the industry is estimated to fall to growth of 8.8 per cent per annum.

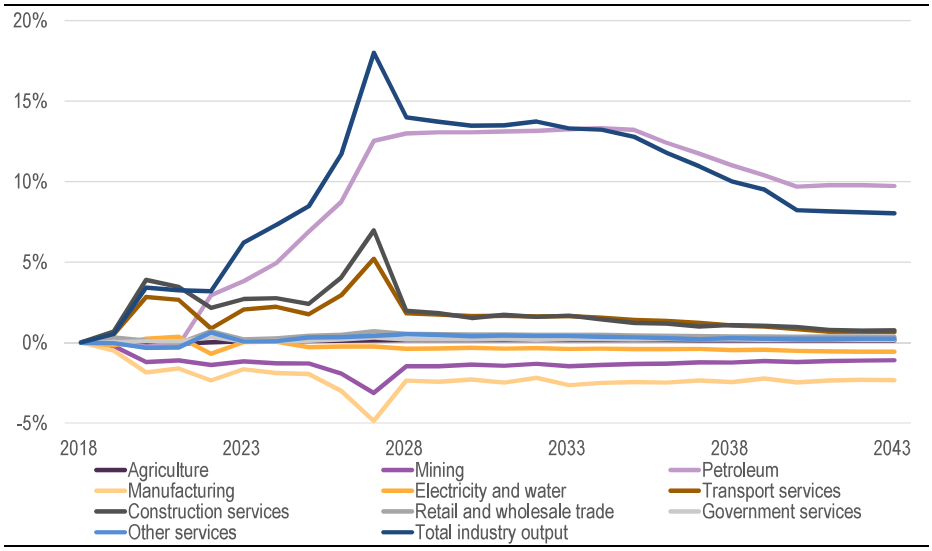
The Construction Services industry is also expected to increase over the study period, averaging growth of 1.9 per cent per annum. The majority of this growth will be realised in the early stages of the Industry's development, with growth expected to peak at seven per cent in 2027.

The Transport Services industry is also estimated to follow a similar trend, growing on average by 1.6 per cent per annum and peaking at 5.2 per cent in 2027, relative to the base case.

The Manufacturing industry is estimated to contract on average by 2.2 per cent per annum over the study period. This reflects the impact an appreciation in the Australian Dollar has on the global competitiveness of export competing businesses in the Territory. In addition, a reallocation of labour away from the Manufacturing industry to the Petroleum industry results in lower output from the industry. A similar impact occurs in the Mining and Electricity and Water industries, which are estimated to contract on average by 1.3 per cent and 0.3 per cent per annum over the study period.

Across all industries, the development of the Industry in the Territory will have a large impact on the growth across most industries. Overall, industry growth is estimated to be 9.4 per cent per annum higher than what would otherwise have occurred, if the development of the Industry did not occur.

FIGURE 11.7 GALE NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

11.5 Labour market

11.5.1 Employment

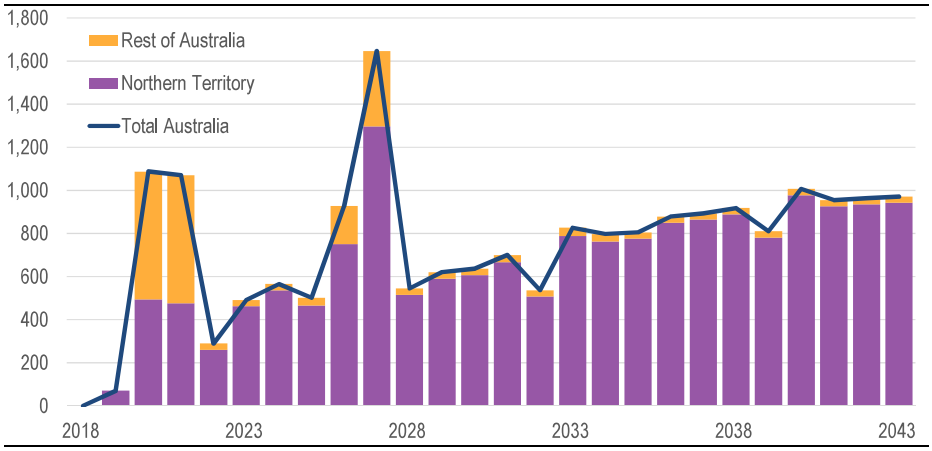
The development of a new industry in the Territory under the GALE development scenario has significant workforce implications. The largest component of the Industry's direct workforce is the staff required to operate the wells and pads. Staff required to operate additional transmission gas pipelines also has a significant impact on direct employment across the Rest of Australia.

The 'peaking' nature of the FTE requirements presented in Figure 11.8 is a result of the timing of the construction workforce requirements. Labour required for the construction of gas transmission pipelines in the Territory in 2021, 2022, 2026 also contributes to this 'peaking' nature, but on a smaller scale.

Over the study period, it is estimated the development of the Industry will require direct employment of 17,187 FTE jobs at an average of 661 FTE jobs per annum in the Territory. The majority of these FTE jobs are in relation to the construction and operations of the Industry (total of 13,300 FTE jobs at an average of 512 FTE jobs per annum), while a total of 3,887 FTE jobs (average of 149 FTE jobs per annum) are in relation to the construction and operations of transmission pipes.

Throughout the Rest of Australia, the construction and operations of transmission gas pipelines will require direct employment of 2,330 FTE jobs at an average of 90 FTE jobs per annum.

FIGURE 11.8 GALE DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

However, the total employment impact of the Industry development under the GALE scenario is minimal, due to the resulting draw on labour from other industries in the Territory and other parts of Australia.

Over the study period, the Industry is estimated to create 13,611 FTE direct and indirect FTE jobs at an average of 524 FTE jobs per annum in the Territory. However, ACIL Allen estimates that these positive impacts will be completely offset by the reallocation of employment from the Rest of Australia to the Territory.

11.5.2 Industry real employment

While the development of the Industry under the GALE development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory (refer to Figure 11.9).

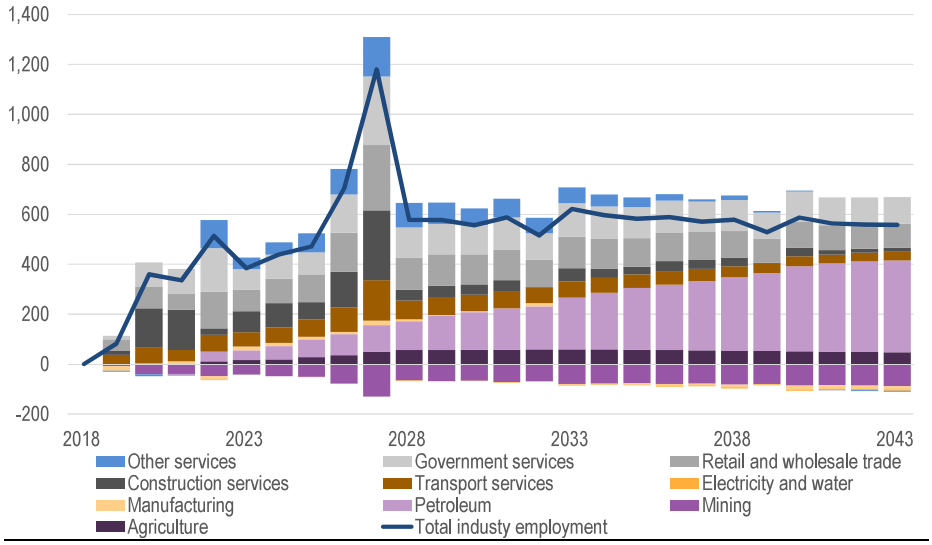
Over the study period, the Petroleum industry is estimated to see the largest real employment impact, with the creation of 4,384 FTE jobs at an average of 169 FTE jobs per annum. Significant gains are also

estimated in the Retail and Wholesale Trade industry, with a total of 2,850 FTE jobs at an average of 110 FTE jobs per annum to be created, as a result of increased household consumption in the Territory.

The Government Service industry (2,985 FTE jobs at an average of 115 FTE jobs per annum), Transport Services industry (1,511 FTE jobs at an average of 58 FTE jobs per annum) and Construction Services industry (1,538 FTE jobs at an average of 59 FTE jobs per annum) are also estimated to see solid employment gains over the study period under the GALE development scenario.

The majority of the labour reallocation, as a result of the development of the Industry, is estimated to occur in Mining (loss of 1,722FTE jobs at an average of 66 FTE jobs per annum), Manufacturing (loss of 18 FTE jobs at an average of one FTE jobs per annum) and Electricity and Water (loss of 62 FTE jobs at an average of two FTE jobs per annum).

FIGURE 11.9 GALE NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



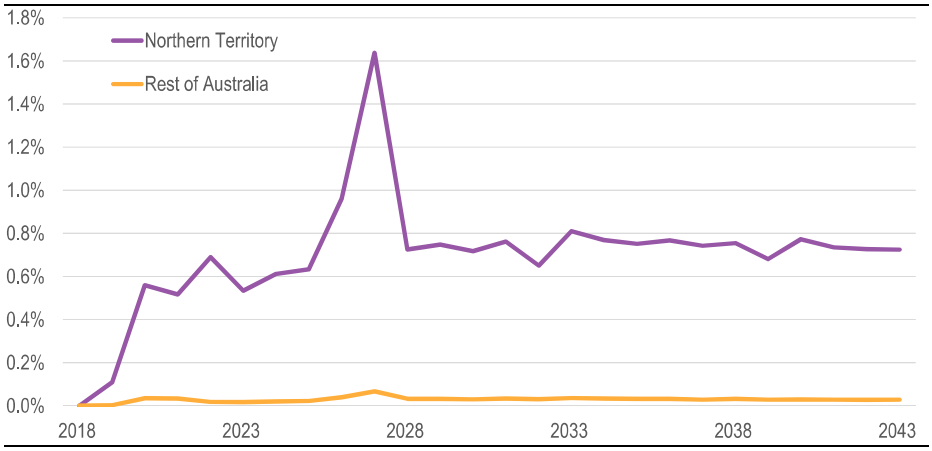
SOURCE: ACIL ALLEN CONSULTING

11.5.3 Real wages

The development of the Industry is estimated to boost real wages in the Northern Territory relative to the Rest of Australia (refer to Figure 11.10).

Over the study period, the increase in real wages is estimated to be on average 0.7 per cent per annum higher than the base case, peaking at 1.6 per cent in 2027 when the demand for labour in the Territory is at its highest. The impact across the Rest of Australia is negligible over the study period, increasing on average by 0.03 per cent per annum over the study period when compared to the base case.

FIGURE 11.10 GALE REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE



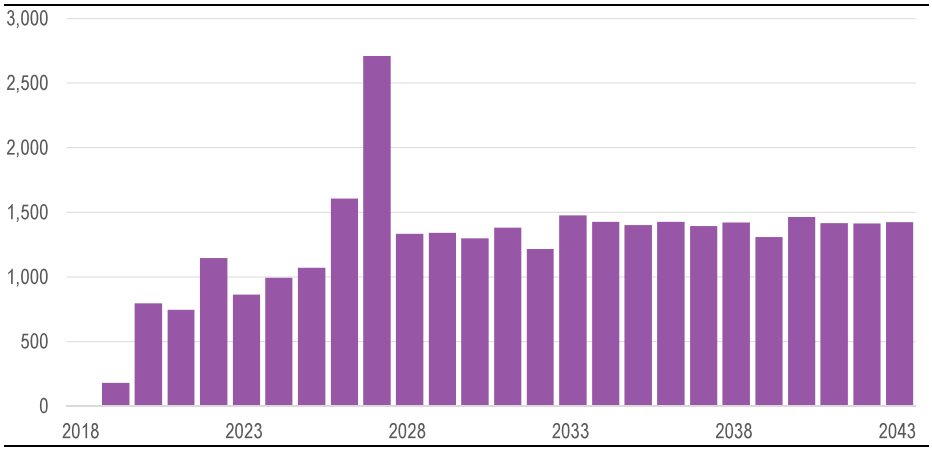
SOURCE: ACIL ALLEN CONSULTING

11.6 Population

The population of the Northern Territory, resulting from the development of the Industry under the GALE scenario, is largely driven by interstate migration as workers and their families relocate to the Territory to take up employment opportunities created by the development of the Industry.

Over the study period, it is estimated the population in the Northern Territory will increase by an average of 1,240 persons per annum. The population impact peaks during the capital intensive construction phase of the development of the Industry at 2,710 persons in 2027.

FIGURE 11.11 GALE NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER



SOURCE: ACIL ALLEN CONSULTING

11.7 Real taxation

The development of the Industry under the GALE scenario will generate significant taxation benefits to the Northern Territory and the Commonwealth Government, primarily in the form of profits based taxes, royalty revenues, payroll tax and a range of other taxes.

Over the study period, payments to the Commonwealth are projected to be substantial (refer to Figure 11.12). ACIL Allen estimates that the direct profits based taxation payments from the Industry would total $936 million at an average of $36 million per annum over the study period.

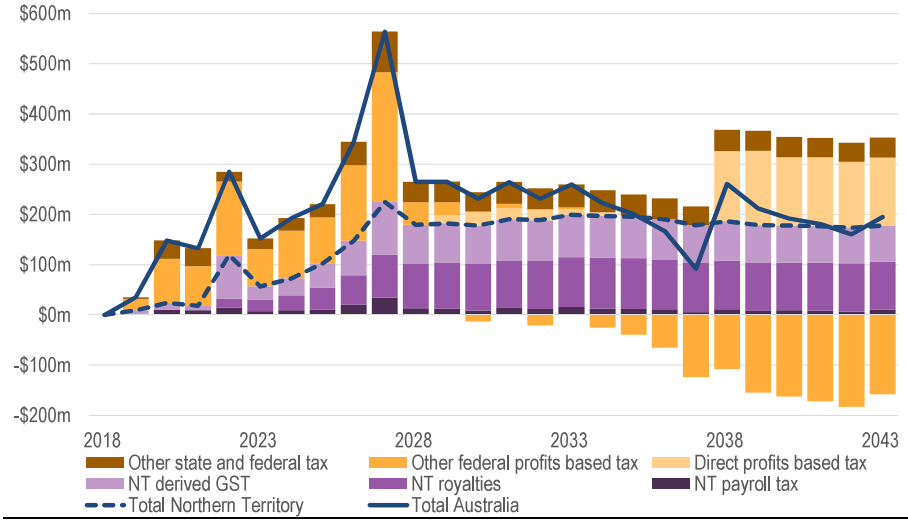
Under the GALE development scenario, when the offshore feed in stock for DNLG in replaced by onshore feed in stock in 2036, indirect profits based taxation payments are reduced because the offshore industry is no longer paying company tax and PRRT. As such, indirect taxation payments collected by the Commonwealth reduce by $136 million at an average of $5.3 million per annum over the study period.

The development of the Industry is estimated to generate other indirect taxation payments to the Commonwealth (such as personal income, excises, fringe benefits and capital gains tax receipts), totalling $950 million at an average of $36.5 million per annum.

Payments made to the Territory Government are expected to be largely accrued through royalty payments, which are estimated to total $1.8 billion at an average of $69 million per annum over the study period. Direct and indirect payroll taxation payments to the Territory Government due to the development of the Industry are estimated to total $288 million at an average of $11 million per annum over the study period.

Increased commercial activity in the Territory is also estimated to result in GST revenues increasing by $1.6 billion at an average of $63.1 million per annum over the study period.

FIGURE 11.12 GALE REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A$ MILLION



SOURCE: ACIL ALLEN CONSULTING

11.8 Summary

Table 11.1 presents a summary of the economic modelling results presented in the section.

TABLE 11.1 GALE DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			

	Total	Average	NPV (7 per cent)
Northern Territory	$5,777.5m	$222.2m	$2,212.9m
Rest of Australia	$12,508.8m	$481.1m	$4,416.6m
Total Australia	**$18,286.3m**	**$703.3m**	**$6,629.5m**
Real output			
Northern Territory	$17,534.7m	$674.4m	$6,298.8m
Rest of Australia	$1,732.1m	$66.6m	$453.6m
Total Australia	**$19,266.9m**	**$741.0m**	**$6,752.4m**
Real Final Demand			
Northern Territory	$16,173.7m	$622.1m	$7,272.4m
Rest of Australia	$11,320.7m	$435.4m	$4,802.4m
Total Australia	**$27,494.4m**	**$1,057.5m**	**$12,074.8m**
Real investment			
Northern Territory	$9,778.6m	$376.1m	$4,768.6m
Rest of Australia	$1,419.3m	$54.6m	$1,233.3m
Total Australia	**$11,198.0m**	**$430.7m**	**$6,001.9m**
Northern Territory real exports			
International	-$3,395.5m	-$130.6m	-$1,261.0m
Interstate	$24,141.4m	$928.5m	$8,590.5m
Total	**$20,745.9m**	**$797.9m**	**$7,329.6m**
Real employment			
Northern Territory	13,611 FTEs	524 FTEs	
Rest of Australia	-13,611 FTEs	-524 FTEs	
Total Australia	**0 FTEs**	**0 FTEs**	
Real employment by industry			
Agriculture	1,023 FTEs	39 FTEs	
Mining	-1,722 FTEs	-66 FTEs	
Petroleum	4,384 FTEs	169 FTEs	
Manufacturing	-18 FTEs	-1 FTEs	
Electricity and water	-62 FTEs	-2 FTEs	
Transport services	1,511 FTEs	58 FTEs	
Construction services	1,538 FTEs	59 FTEs	
Retail and wholesale trade	2,850 FTEs	110 FTEs	
Government services	2,985 FTEs	115 FTEs	
Other services	1,124 FTEs	43 FTEs	
Total industry employment	**13,611 FTEs**	**524 FTEs**	

	Total	Average	NPV (7 per cent)
Real population			
Northern Territory	32,252 persons	1,240 persons	
Real taxation			
Northern Territory			
Payroll tax	$288.2m	$11.1m	$126.1m
Royalties	$1,793.8m	$69.0m	$606.3m
Derived GST	$1,640.2m	$63.1m	$618.8m
Total Northern Territory	**$3,722.2m**	**$143.2m**	**$1,351.3m**
Commonwealth			
Direct profits based tax	$935.8m	$36.0m	$212.2m
Other federal profits based tax	-$136.5m	-$5.3m	$396.4m
Other state and federal tax	$950.2m	$36.5m	$382.7m
Total Commonwealth	**$1,749.5m**	**$67.3m**	**$991.3m**
Total Australia	**$5,471.6m**	**$210.4m**	**$2,342.5m**

SOURCE: ACIL ALLEN CONSULTING

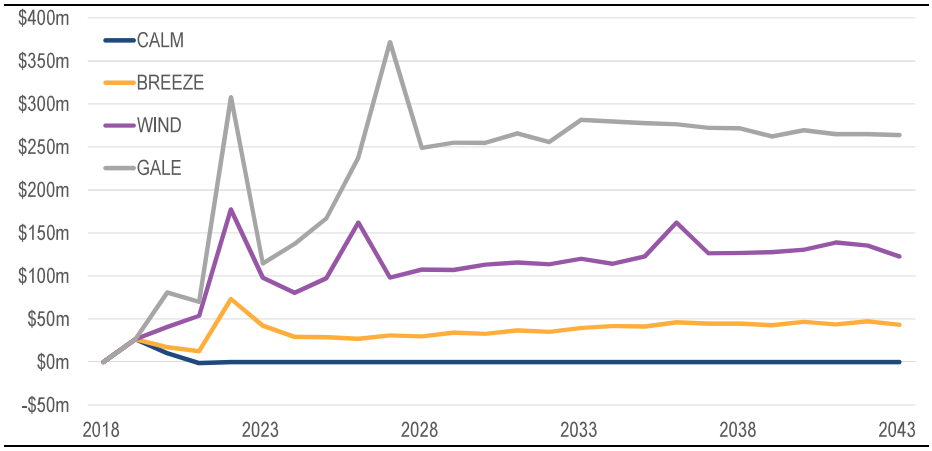
12 CONCLUSIONS AND SUMMARY

12.1 Economic impact assessment summary

ACIL Allen's economic impact assessment illustrates the potential economic upsides and downsides in the event of small, medium and large scale shale gas industry developments in the Northern Territory, and the flow on effects to the rest of the Australian economy. While the base case and CALM scenarios, where no shale gas industry development occurs, show the Northern Territory economy is set to grow in the years ahead, the development scenario modelling shows the shale gas industry could have an overall net positive impact on the future growth of the Northern Territory economy.

ACIL Allen projects a shale gas industry development could result in a net real income increase of between $937.2 million (BREEZE), $2.8 billion (WIND) and $5.8 billion (GALE) for the Northern Territory over the modelling period, or between $36 million, $108.4 million and $222.2 million per annum. This equates to a net real income per capita increase of $146, $439 to $903 per capita (based on the Northern Territory's 2018 population) over the modelling period. The rest of Australia also sees a lift in real income, of between $3.4 billion (BREEZE), $9.1 billion (WIND) and $12.5 billion (GALE) over the modelling period, on account of the flow on impact of lower gas prices across the economy and the increase in Commonwealth taxes associated with the development (refer to Figure 12.1).

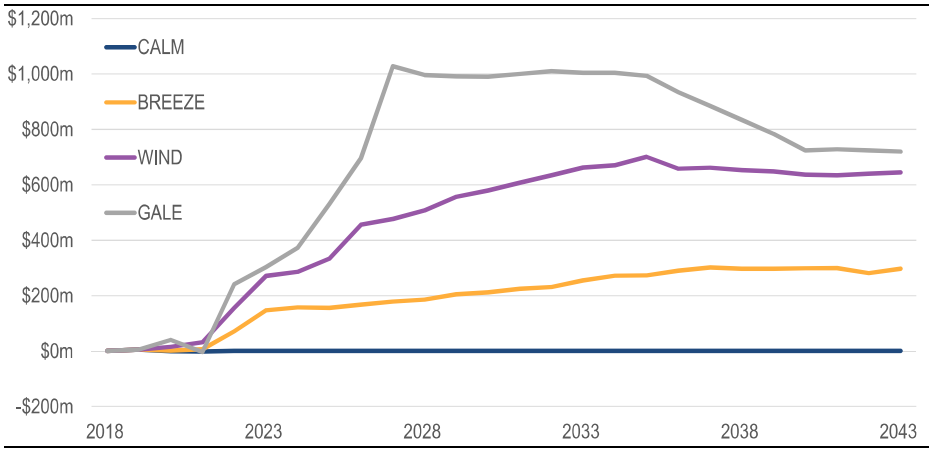
FIGURE 12.1 REAL INCOME, ANNUAL DEVIATION FROM BASE CASE, A$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

The net economic benefit to the Northern Territory ranges from $5.1 billion in the BREEZE scenario ($196.5m per annum), to $12.1 billion ($466.4m per annum) in the WIND scenario, to $17.5 billion ($674.4m per annum) in the GALE scenario, in real 2018 dollar terms. In annual average terms, this is the equivalent of an additional 0.8 per cent, 1.9 per cent to 2.9 per cent of the Northern Territory's forecast Gross Territory Product in 2018 (Figure 12.2).

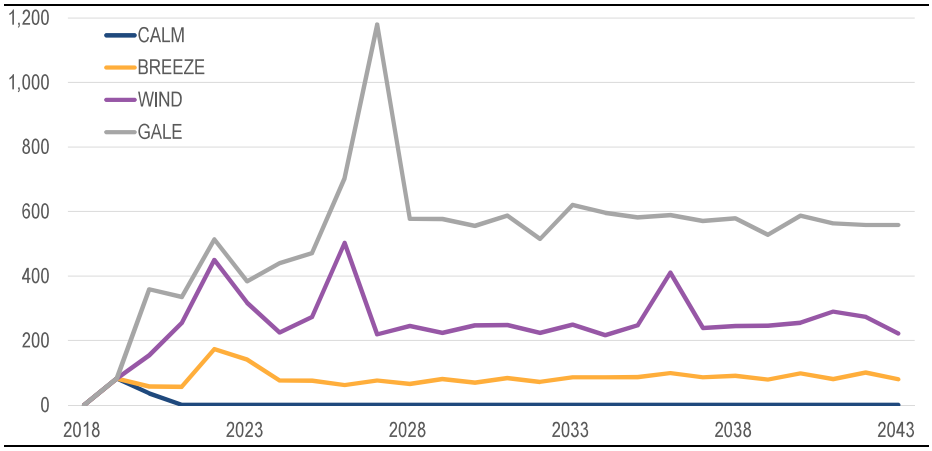
FIGURE 12.2 REAL OUTPUT, ANNUAL DEVIATION FROM BASE CASE, A$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

This additional economic activity will generate employment opportunities for Territorians, with an estimated 2,154 FTE job years (BREEZE), to 6,559 FTE job years (WIND) to 13,611 FTE job years (GALE) generated by the various development scenarios over the forecast period – over and above the existing employment growth ACIL Allen has forecast in its base case (Figure 12.3). This equates to between 82 FTEs, 252 FTEs, and 524 FTEs of net employment growth in each year on average. While modest overall, this represents the capital intensive nature of the shale gas industry, and is also a function of ACIL Allen's conservative treatment of employment growth in its modelling activities (see Section 6).

FIGURE 12.3 REAL EMPLOYMENT, FTE JOB YEARS, REAL TERMS, BY SCENARIO



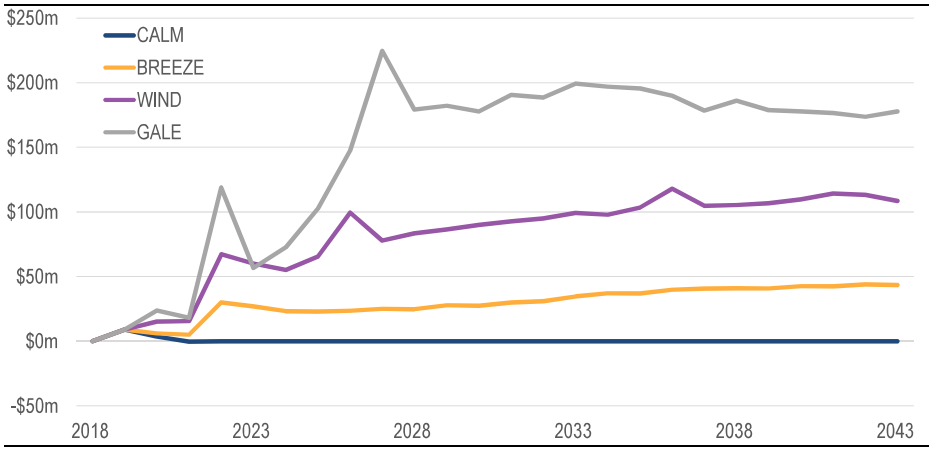
SOURCE: ACIL ALLEN CONSULTING

For Territorians, the primary channel of economic impact that is likely to be felt is the increase to Territory Government revenue. ACIL Allen estimates a successful shale gas industry development could generate

between $757 million (BREEZE), $2.1 billion (WIND) and $3.7 billion (GALE) in additional revenue for the Northern Territory Government over the 25 year modelling period, or between $29.1 million, $80.6 million, and $143.2 million per annum (Figure 12.4). In the larger case, this represents a sizeable increase to the Northern Territory's recurrent revenue base of 2.2 per cent, or more than eight per cent if Commonwealth Government grants are excluded.

ACIL Allen's analysis shows a shale gas industry could also deliver windfall growth in Commonwealth revenue, even as the cascading impact of reduced gas prices from the development reduces the income earned by the gas sector outside of the Northern Territory.

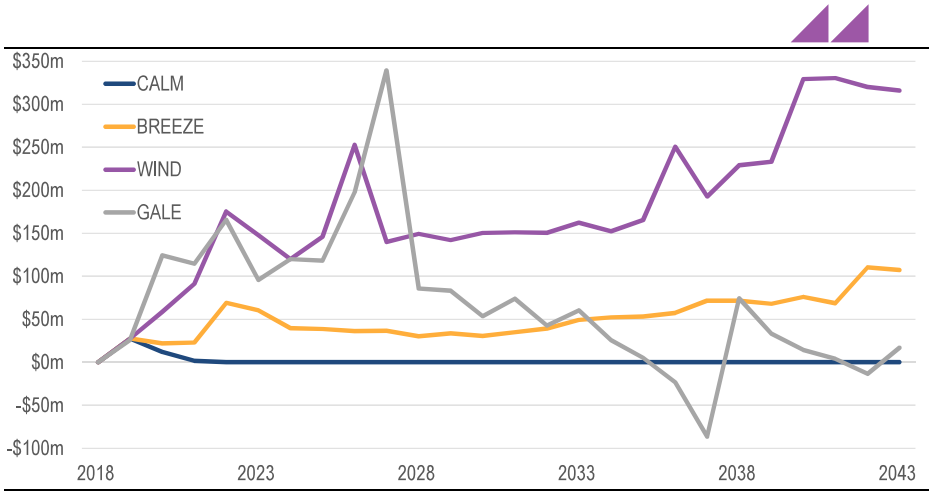
FIGURE 12.4 REAL TAXATION, NORTHERN TERRITORY GOVERNMENT, A$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

ACIL Allen estimates the Commonwealth Government could expect to raise between $1.3 billion (BREEZE), $4.6 billion (WIND), and $5.5 billion (GALE) in income and profits based taxation over the forecast period, or $50.2 million, $176.2 million and $210.4 million per annum (refer to Figure 12.5).

FIGURE 12.5 REAL TAXATION, COMMONWEALTH GOVERNMENT, A$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

As discussed in Section 4, the shale gas industry in the Northern Territory is at such an early stage that the modelling conducted in this engagement is subject to more than usual uncertainty. Below, ACIL Allen has presented the subjective probability matrix prepared to represent the qualitative likelihood of each scale of development occurring (Figure 12.6). This is not an assessment of the commercial prospects of a shale gas industry in the Northern Territory, as ACIL Allen has not been engaged to assess this, and it is too early in the industry's development to make a determination.

FIGURE 12.6 ACIL ALLEN POLICY SCENARIO PROBABILITY MATRIX

			POLICY SCENARIO PROBABILITY MATRIX		
INDUSTRY DEVELOPMENT SCENARIO	**Production Profile**	**Production Cost Regime**	**PERMANENT MORATORIUM**	**PARTIAL LIFT**	**FULL LIFT**
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	**Scenario 1** Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	**Scenario 2** Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	**Scenario 3** Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

SOURCE: ACIL ALLEN CONSULTING

Summary

ACIL Allen's economic impact assessment modelling suggests there will be limited impact on sectors outside of the shale gas industry and its supply chain. This is for a few reasons, some of which centre on the evidence-based assumptions ACIL Allen has made (and which have been endorsed by the Inquiry) related to the treatment of land and water resources. But more significantly is the relatively modest labour requirement of the sector, which means there is limited crowding out activity in the labour market in the Northern Territory. In addition, the shale gas industry is likely to disturb a small surface area relative to the size of the Northern Territory (as stated in Section 6.2.4, 67.2km^2 for BREEZE, 231.7km^2 for WIND, and 475.9km^2 for GALE, compared to the Northern Territory's total land area of 1,421,000km^2).

That is not to say there are no downside risks to a potential shale gas industry development in the Northern Territory. ACIL Allen's economic modelling simply demonstrates that there are quantified net economic benefits available to the Northern Territory economy. There are additional considerations – many of which are outside of the scope of ACIL Allen's work but are being dealt with by others involved in the Inquiry – which must be given due consideration in the process of determining whether the industry should be given a license to operate. ACIL Allen has provided a perspective on these issues in the next Chapter of this report.

12.2 Comparison of ACIL Allen economic impact assessment to APPEA/Deloitte economic impact assessment

As part of its scope of works, ACIL Allen is required to compare the inputs and outputs of its economic impact assessment with the inputs and outputs of the 2015 APPEA/Deloitte study, *Economic impact of shale and tight gas development in the NT*. This is presented in the table below.

Item	APPEA/Deloitte		ACIL Allen		
Case name	"Success"	"Aspirational"	"BREEZE"	"WIND"	"GALE"
Development modelling approach	Deloitte took the price of LNG, subtracted cost of processing and transmission pipeline, and used that to determine its target gas price. From there, it scaled CAPEX & OPEX estimates from a starting position that would allow all gas to be sold assuming a their market price, and had a different breakeven price for three market demand tranches (NT, East Coast and LNG). Deloitte assumed no market constraints.		ACIL Allen began by sizing its developments based on market tolerance, using *GasMark*. From there, ACIL Allen build its developments from the ground up using data to build a single average type curve, a well scheduling model, development cost assumptions by key components, and pipeline assumptions combining current pipeline capacity and new pipelines. ACIL Allen did not assume gas would be used to facilitate any new LNG development, and instead assumed in its base case that an offshore development would be required to backfill the DLNG facility.		
Economic impact assessment modelling approach	In-house CGE model		In-house CGE model		
Volume of gas (peak PJ/annum)	586 PJ/annum in 2040	910 PJ/annum in 2040	36.9 PJ/annum (2041)	108.3 PJ/annum (2042)	365 PJ/annum in 2043
Incremental LNG?	Yes, 100% incremental LNG. Two additional LNG trains to be built, with capital costs included in the economic impact assessment.	Yes, 100% incremental LNG. Three additional LNG trains to be built, with capital costs included in the economic impact assessment.	No LNG in this scenario.	No LNG in this scenario.	No incremental LNG in this scenario. It is assumed the onshore development displaces an offshore development.
CAPEX per well	$6.2m - $9.75m		$19.1m on average (including learnings)	$16.3m on average (including learnings)	$12.7m on average (including learnings)
OPEX per GJ	$0.53 - $0.89/GJ		$1.77/GJ on average (including learnings)	$1.59/GJ on average (including learnings)	$1.46/GJ on average (including learnings)
Wellhead cost per GJ (maximum case)	$1.90 - $2.67/GJ		$6.07/GJ on average	$5.03/GJ on average	$4.01/GJ on average
GTP impact (deviation from baseline in final year of study)	+$5.1bn (2040)	+$7.5bn (2040)	+$0.30bn (2043)	+$0.64bn (2043)	+$0.72bn (2043)
FTE impact (deviation from baseline in final year of study)	+4,195 FTE (2040)	+6,321 FTE (2040)	+80.1 FTE (2043)	+221.5 FTE (2043)	+558.1 FTE (2043)

IV

ECONOMIC POLICY CONSIDERATIONS

13 SHALE GAS ECONOMICS LITERATURE REVIEW

The Northern Territory Hydraulic Fracturing Inquiry has sought information on options for "leading practice" fiscal and regulatory policy reform that would allow exploitation of shale gas resources in a way that would generate sustainable development from an economic perspective in the Northern Territory of Australia. More specifically, the Inquiry is seeking information on a policy regime that would:

- maximise benefits from the industry
- mitigate and manage costs (including risks of adverse impacts)
- capture net benefits for Territorians in general and those in regions affected by development, without impeding investment
- sustain net benefits over time.

The Inquiry stipulated that this advice should include coverage of measures or instruments to mitigate and manage any adverse effects on other Northern Territory industries, and "boom and bust" economic cycles arising from development of a shale gas industry. This requirement indicates that the Inquiry wants advice on policy instruments that would address potential "Resource Curse" consequences, including "Dutch Disease" effects, of development of a shale gas industry in the Northern Territory.

13.1 The efficiency/equity trade off

Economic assessments of policy regimes or changes typically are undertaken by reference to two widely accepted principles relating to comparison of benefits and costs. An economic efficiency criterion focuses on the aggregate of benefits (positive impacts) and costs (negative impacts). A fairness criterion focuses on the distribution of benefits and costs. Sometimes, these criteria have been teased-out to highlight specific aspects of economic efficiency and fairness.

Criteria along these lines have been proposed in public finance/economics texts over the past 90 years or more.[44] They can be traced back to Adam Smith's (1776) pioneering economic work. In Australia, similar criteria have been applied in several reviews of the tax system, over the past 40 years, including the Henry Tax Review in 2010.[45] Also, they have been applied in reviews of royalty policy undertaken for state and territory governments over the same period, including the *Green Paper on Mining Royalty Policy in the Northern Territory* in 1981.[46] In addition, economic efficiency and equity were used as guiding principles in various papers prepared for the previous Commonwealth Governments on climate change policy.

[44] See Dalton (1923), Pigou (1929), Musgrave (1959), Musgrave and Musgrave (1973), Atkinson and Stiglitz (1980), Stiglitz (2000), Rosen and Gayer (2008).
[45] For example, Asprey, others (1975), Commonwealth of Australia, Treasurer (1985), Ralph, others (1998), Commonwealth of Australia, Treasurer (1998), Henry, others (2010), Commonwealth of Australia, the Treasury (2015).
[46] For example, Northern Territory of Australia (1981), Bradley (1986), Australian and New Zealand Minerals and Energy Council, Royalty Working Party (1991) and Australian Ministerial Council on Mineral and Petroleum Resources (2006).

13.1.1 Efficiency principles

The concept of economic efficiency refers to an efficient allocation of resources (human, capital, and natural resources, including land, extractable resources and the environment) at any time and over time. It includes efficient use of resources and efficient distribution of products.

An efficient allocation of resources may be impeded by market failures or policy failures. Market failures – situations in which markets fail to allocate resources efficiently – may arise because of external costs, external benefits, public good characteristics of some goods and services, asymmetric distribution of information, and existence of market power or lack of competition. Policy failure results from government intervention that worsens the allocation of resources because the method of intervention has been poorly designed to correct a perceived market failure or inequity. Policy failure might also result from intervention designed to achieve a political objective regardless of the effects of the policy measure on the efficiency of resource allocation.

Because there are numerous impediments to efficient resource allocation, achievement of the ideal of an efficient allocation of resources or economic efficiency would require multiple, consistent policy adjustments across the economy, not just a policy change to address a particular source of inefficiency. Therefore, the appropriate assessment criterion for formulation of, or a change in policy instruments is usually considered to be an improvement in the efficiency of resource allocation. This means improved capability to provide people with more of what they want (including better health and environmental outcomes) with available resources. Ideally, it involves selection of investments and policy settings that not only produce benefits in excess of costs, but also generate the largest surplus of benefits over costs.

In the case of extraction of exhaustible resources, such as a shale gas, the criterion of improving the efficiency of resource allocation is relevant not only to how and when exploration and extraction take place and how the policy regime affects those activities, but also to how the net *in situ* value of the resource (resource rent) is deployed during and after it is captured. Policy instruments need to be carefully designed to ensure that resource rent is not dissipated or destroyed during exploration and extraction, and is not wasted after it is captured.

The avoidance of unnecessarily large policy administration (compliance, monitoring and enforcement) costs is an aspect of economic efficiency. This sub-criterion has sometimes been referred to as administrative efficiency. It has also been labelled simplicity, because complexity can lead to high administration costs. Often, administrative efficiency or simplicity has been specified as a separate criterion.

13.1.2 Equity principles

Fairness or equity is an important consideration for governments in formulation of policy. The issue relates to treatment of individuals fairly relative to others. It involves highly subjective issues that have to be resolved by value judgements.

Two concepts of equity have been discussed extensively in the economics literature: the ability to pay principle and the benefit principle. These principles pre-date the foundational economic work of Adam Smith (1776), in which they were conflated. Over the past 30 years, a third principle has attained prominence: the concept of intergenerational equity.

The ability to pay principle is that costs of government interventions should be borne differently by people in accordance with differences in economic circumstances, with more being borne by better-off people (vertical equity), and similar burdens for people in similar economic circumstances (horizontal equity). The ability to pay principle has often been a dominant consideration in political discussion of policy issues.

Key issues in considering ability-to-pay in the context of health and environmental risks associated with activities and products are the distribution of the burden of hazards and the distribution of costs and benefits of policy measures designed to address them. A common concern is that low-income households often bear a disproportionate share of health and other environmental risks, and that policies to address these risks may not be progressive in distributing benefits and costs (Parry, others, 2005; Bento, 2013).

The benefit principle of equity states that entities should contribute to government in accordance with benefits received from governments or from society more generally. It is particularly relevant to consideration of fairness issues in respect of extraction natural resources and use of the environment.

The benefit principle indicates that enterprises that are allowed to extract natural resources owned by a government should be required to pay according to the net *in situ* value of the natural resource. Also, it implies that enterprises should be required to pay compensation if, through their use (or abuse) of the natural environment, they impose non-market costs, such as health and environmental costs (external costs), on others. This implication is consistent and closely associated with the *polluter-pays* principle, which states that those who impose environmental and health costs on others should be required to pay.

Intergenerational equity is an important consideration in formulation and assessment of policy regarding exploitation of natural resources. It is relevant because extraction of mineable resources and damage to the natural environment, particularly elements essential to sustain human life, reduce the stock of natural capital available to future generations, denying them opportunities to benefit from natural resources.

The concept of intergenerational equity has risen to prominence over the past 30 years in the context of concomitant emergence and growth of interest in the concept of sustainable development. The concept of sustainable development incorporates economic efficiency and equity principles discussed above. Like efficient allocation of resources at a particular time and over time, sustainable development is concerned with using natural resources efficiently – extracting them efficiently, and taking into account (risk of) damage (particularly irreparable damage) to the natural environment. Both economic efficiency and sustainable development also involve wisely using the proceeds of exploitation of natural resources. Like intergenerational equity, sustainable development is concerned with ensuring that exploitation of extractable resources and the natural environment in the short to medium term does not leave future generations worse off. Both intra-generational equity and sustainable development concepts recognise that reduction of inequality is conducive to improving and sustaining economic growth.

A recurring theme in the economic literature on policy assessment is that criteria such as those discussed above are meant to apply to policy regimes as a whole (comprising policy instruments at all levels of government), rather than to each policy instrument in isolation. A perceived inequity associated with one policy instrument may be offset by a feature of another policy instrument. An inefficiency associated with one part of the policy mix may be reduced by the settings of another part of the policy regime. It is unrealistic to expect that every policy instrument will perform perfectly with respect to all criteria. It is the performance of the whole policy package that matters, not the performance of individual policy mechanisms.[47] Nevertheless, it may be useful to assess how each policy instrument performs with respect to the criteria to ascertain how it might contribute to a package of instruments comprising a good policy regime.

The performance of a policy package can be improved by allocating different policy instruments primarily to different policy objectives or sub-objectives, by carefully selecting/designing instruments that are suited to particular targets, and by deploying at least as many instruments as targets. The process of selecting/designing instruments must allow for the effects of each instrument on all targets, not just the primary one to which it has been assigned. The policy packaging process should also include consideration of the attributes of each instrument and how they might complement features of other instruments (Tinbergen, 1952). Such an approach to policy regime design minimises trade-offs or compromises between degrees of achievement of multiple objectives.

13.2 The "Resource Curse" phenomenon

Substantial natural resource development does not lead automatically to better economic performance and greater well-being of constituents in regions and jurisdictions hosting such activity. Indeed, there is a burgeoning literature on how exploitation of natural resource wealth has too often led to underperformance of the host economy relative to its potential, and relative to economies that are not well endowed with natural resources. This phenomenon has become known as the "Resource Curse".

The concept originated with Gelb (1988) and Auty and Warhurst (1993).[48] It attracted considerable interest from economists following pioneering quantitative work by Sachs and Warner (1995) indicating that economic dependence on mineable resources was correlated with slow economic growth after allowing for structural attributes of countries. Helpful surveys of the literature have been provided in work by

[47] Geoffrey Brennan (1977) discussed these issues specifically with reference to selection/design and assessment of state and local government taxes.
[48] See also Auty (1990).

Humphreys, Sachs and Stiglitz (2007), Arezki and Gylfason (2011), van der Ploeg (2011), Frankel (2012a,b), Shaffer and Ziyadov (2012), and Venables (2016).

Most discussions of the Resource Curse have associated this affliction with developing economies. However, advanced countries with considerable mineable resources wealth are not immune. Indeed, *The Economist* magazine suggested in 1995 that Australia was affected by a "Resource Curse" (Anonymous, 1995). There is considerable circumstantial evidence that Australia has suffered "Resource Curse" symptoms as a result of mismanagement of the mining boom of 2004 to 2011.

A related phenomenon is the "Dutch Disease", which refers to effects of economic restructuring in response to development of a major mineable resources sector. Pre-existing sectors are disadvantaged because of lower export and import prices associated with nominal exchange rate appreciation, and higher costs of domestic inputs as a result of demand from the mining sector and spending of revenue derived from that sector. The higher cost structure and higher nominal exchange rate together represent a real exchange rate appreciation.

The name "Dutch Disease" was applied by *The Economist* magazine (Anonymous, 1977) following the adverse effects of discovery and exploitation of substantial gas resources in the Netherlands a few decades ago. Pioneering analysis of the phenomenon in an Australian context was undertaken by Cairnes (1859, 1873) in respect of the gold rush, and by Gregory (1976). Subsequent important early contributions to the "Dutch Disease" literature were provided by Corden and Neary (1982), Corden (1984) and Van Wijnbergen (1984). A recent useful discussion of "Dutch Disease" in Australia as a result of the 2004-2011 mining boom was presented by Corden (2012).

Mismanagement of structural adjustment in response to a mining boom or interaction of structural adjustment with external benefits of industrial activity can contribute to a "Resource Curse" problem. Indeed, these occurrences are the potential sources of economic disease, not structural adjustment *per se*. They are typically listed as "Resource Curse" mechanisms.

13.2.1 Regional resource curse issues

Until recently, the rapidly growing "Resource Curse" literature had been focussed almost entirely on effects of major mineable resource developments on national economies. Little consideration was given to the potential for "Resource Curse" issues in state and regional economies. This situation changed because of the shale gas and oil boom in the United States.

Over the last six years, economics literature has been accumulating on investigations into the existence or otherwise of "Resource Curse" effects in "local economies" in the United States.[49] Important contributions have been made by Resources for the Future (RFF), a highly regarded United States organisation that has been conducting economic research in relation to environmental and other natural resource issues since 1952. RFF has established research groups focussed on community impacts of shale gas and oil development, and shale public finance.[50]

Investigations of economic impacts of shale gas and oil development in the United States have found strong evidence of local employment gains during the development phase, and increases in incomes through wage/salary increases and private royalty arrangements. However, evidence on long-term growth and development effects is mixed and inconsistent. Several studies provided evidence of negative long-term effects or "Resource Curse" effects. Several other studies found no clear evidence of such effects. Analysis of the mixed and inconsistent results suggests that effects vary across time and locations.

An important insight of the literature relating to the presence or otherwise of regional "Resource Curse" effects is that transmission channels are similar to those for national "Resource Curse" effects. Moreover, policy settings are critical to enabling or avoiding "Resource Curse" problems in sub-national areas, just as they are nationally (Kelsey, Partridge, White, 2016).

[49] For example, see Freeman (2009), James and Aadland (2011), Brown (2014), Jacobsen and Parker (2014), Hausman and Kellogg (2015), Cust and Poelhekke (2015), Mason, Muehlenbachs and Olmstead (2015), James (2015), Kelsey, Partridge and White (2016), Weinstein, Partridge and Tsvetkova (2017), Feyrer, Mansur and Sacerdote (2017), and Allcott and Keniston (2017). A useful review has been provided by Krupnick and Echarte (2017).

[50] For example, see Raimi and Newell (2016a,b), Krupnick and Echarte (2017), Krupnick, Echarte and Meuhlenbachs (2017), and Krupnick, Echarte, Zachary and Raimi (2017).

13.2.2 Resource curse mechanisms

"Resource Curse" effects typically result from poor policies and institutions, not from resource wealth *per se*. Resource wealth that is properly managed should provide important net economic benefits. Their magnitude is dependent on relevant policy settings, as well as the quantity, quality and location of extractable resources.

There are various "Resource Curse" mechanisms that are relevant in the context of the Northern Territory and Australia. These mechanisms are discussed below.

Loss of growth-inducing external benefits

Economic restructuring in response to development of a major mineable resources sector or a prolonged surge in prices of mined commodities could have "Dutch Disease" and "Resource Curse" effects if trade-exposed sectors that are disadvantaged by real exchange rate appreciation would otherwise be sources of significant growth-inducing external benefits (van Wijnbergen, 1984; Sachs, Warner, 1995). However, this would be a matter of concern only if there are more important growth-inducing benefits associated with disadvantaged sectors than with booming sectors (Frankel, 2012a, b).

The notion that external benefits are more substantial in the case of manufacturing, than for mining and agriculture has been suggested in the economics literature from time to time. It can be traced back to Alfred Marshall (1880-1920), David Ricardo (1817) and Adam Smith (1776).

In the economics literature on "Dutch Disease", two forms of external benefits (sources of market failure) have been discussed: spillovers of information about demonstration of technology (often called learning-by-doing effects), and linkages between industries. For example, Sweder van Wijnbergen (1984) focussed on technology demonstration effects, and Jeffrey Sachs and Andrew Warner (1995) discussed linkage effects, as well as demonstration effects. Both works have been widely cited.

Technology demonstration effects external to enterprises and internal to industries were originally assumed to characterise manufacturing. However, it has been widely acknowledged that government attempts in Australia and many natural resource-rich developing countries to promote diversification into import competing manufacturing industry by erecting import tariff and quota barriers were dismal failures. More recently, some have assumed that export-orientated manufacturing is characterised by technology demonstration externalities not matched in other sectors, and on that basis they have advocated diversification from mining into such activity. It must be emphasised that these assumptions have not yet been proven empirically.

If external benefits in the form of technology-demonstration and industry-linkage effects are much greater in lagging or declining sectors, one of which is manufacturing, than in expanding sectors – mining and non-tradeable goods – there would be an economically inefficient decline in growth (Venables, 2016). However, it certainly has not been demonstrated that the external benefits generated by manufacturing are greater than those generated by expanding sectors, which include non-tradeable sectors, as well as mining and processing activities.

Anthony Scott and Peter Pearse (1992) criticised suggestions that governments in natural resource-rich countries, including developed economies like Australia and Canada, should intervene to encourage diversification into so called "high-tech" or "sophisticated" industries to overcome excessive dependence on "old economy" natural resource-based industries. Scott and Pearse pointed out that these arguments have ignored the history of technological advances in the natural resource-based industries.

Jeffrey Frankel (2012a, p. 31) reiterated criticism of the view that external benefits generated by manufacturing would be greater than external benefits from sectors engaged in mining, agricultural, and non-tradeable production:

"…….it must be pointed out that there is no reason why 'learning by (seeing others) doing' should be the exclusive preserve of manufacturing tradeables. Nontradeables can enjoy learning by (seeing others) doing. Mineral and agricultural sectors can as well. Some countries have experienced tremendous productivity growth in the oil, mineral and agricultural sectors."

It is clear that technological progress has inexorably driven down real costs of mining (including oil and gas extraction) and processing of mineable commodities over the long-term. A few examples relevant to

gas include technological advances allowing extraction of petroleum from beneath deeper and deeper water, liquefaction of natural gas and transport of that product, extraction of coal seam gas, and extraction of shale gas and oil.

In addition, there has been a rapid rate of development and introduction of new technology applicable to other tradable sectors including agriculture and some service sectors. For example, backward linkages and "learning by seeing others doing" have facilitated development of a substantial mining services sector in Australia that includes provision of technologically sophisticated solutions to Australian and overseas mining activities.

There have also been important linkage and "learning by seeing others doing" effects in non-tradable sectors of the economy, including some service and construction activities. These sectors have expanded as part of the process of economic adjustment in response to a booming mining (including extraction of oil and gas) sector.

Public discussion regarding development of mineable-resource-rich economies has often produced proposals that governments should intervene to encourage diversification away from extraction activities (as observed by Frankel, 2012a,b, and Venables, 2016). Some proponents of diversification have advocated government incentives for enterprises to take advantage of backward and forward linkages with mining activities. Others have advocated incentives to establish enterprises focussed on manufacturing activities unrelated to mining, presumably because of perceived superior growth-inducing effects of those separate activities.

Venables (2016) pointed out that very few resource-rich countries had been successful in diversifying their economies through policies such as allocation of government revenue from mining to support other sectors, and domestic content requirements. A notable, but rare example was development of the Norwegian marine engineering sector.

In summary, a convincing case for government intervention to offset the economic adjustment process triggered by substantial growth in mined commodity prices and/or major new mining developments has not be found.

13.2.3 Neglect of local supply opportunities

Managers of investment and operational phases of mineable resource projects may neglect local supply opportunities. This may occur because managers have preferred suppliers as a result of previous experience in other jurisdictions. It also may occur because managers lack information on capacities of local suppliers, people, and training facilities, including capacities to adapt to the requirements of investment and operational phases of projects. In addition, local suppliers may lack information regarding the requirements of construction project managers and mine managers. Preferences for previous suppliers and lack of relevant information about locals and projects indicate the existence of information market failure.

A common policy response is specification of local content requirements. Typically they are set on an arbitrary uniform basis for all projects. This regulatory mechanism places responsibility on managers to collect information about local suppliers. It could be expected that this would be pursued just enough to meet local content requirements. That result might mean some economic local supply opportunities are missed or it might raise costs and thereby reduce realised resource rents and the amount captured by government.

An alternative approach is that government could act as an information intermediary. It could communicate with potential purchasers and suppliers about requirements and capabilities, and ensure that relevant information flows in both directions.

Local content requirements address information market failure only indirectly and in an arbitrary way, while the information intermediary option would address the information market failure directly. The former approach would impose costs on purchasers, reducing realised resource rents and potentially returns to government, depending on royalty and tax regimes. The latter approach would be funded by government, logically from resource rent captured by government in an efficient way. The former would cause deadweight losses (inefficiencies). The latter would not. In both cases, benefits should be weighed against costs.

13.3 Managing a "temporary boom"

Economic adjustments to a booming mining sector could have economic "disease" or "curse" elements if the boom is expected to be only a short- to medium-term phenomenon (Corden, 1984; Frankel, 2011, 2012a,b). Commodity-price booms typically fall into this category. Usually, they are much shorter than the post-2004-2011 boom in prices of mined commodities. Also, investment and exploration booms can be brought to an end by the collapse of commodity-price booms or by exploration failures. In addition, mining-related employment typically falls as projects transition from construction to extraction.

A temporary boom could result in a painful adjustment process that has to be reversed when commodity prices inevitably decline. Adjustment costs are then incurred to an unnecessary extent twice. This is economically inefficient, as it wastes resources. Pertinent observations by Jeffrey Frankel (2012a) are re-produced in the following box.

In addition, the macroeconomic instability associated with temporary price booms followed by busts or prolonged price declines is also likely to be detrimental to long-term economic performance (Arezki, 2011; Collier, Venables, 2011; Barnet, Ossowski, 2003; Davis, Ossowski, Daniel, Barnet, 2003).

There is a case for intervention to smooth and moderate real exchange rate changes through fiscal and monetary policy to improve the efficiency of resource allocation in the short-term and over time if losers as well as winners, although gains could be expected to outweigh losses. Gains to consumers from a high nominal exchange rate (cheaper goods and services), and gains to participants in non-trade exposed sectors would be reduced. Meanwhile, participants in all trade-exposed sectors, including the mining sector, would gain from the intervention. Also, benefits from improved economic growth would become widely available.

On the other hand, if it appeared likely that historically high mined-commodity prices and high exploration and investment activity would persist in the long-term, a policy of moderating the high exchange rate caused by a commodity-price and investment mining boom would not be economically sensible. Then, it would be appropriate to facilitate economic adjustments, not moderate them. Therefore, keeping policy options open with a flexible policy approach is important.

BOX 13.1 ECONOMIC WASTE FROM MEDIUM TERM VOLATILITY OF COMMODITY PRICES

"Cyclical shifts of factors of production (labour, capital and land) back and forth across sectors – mineral, agricultural and manufacturing, and services – may incur needless transactions costs. Frictional unemployment of labour, incomplete utilisation of the capital stock, and incomplete occupancy of housing are true deadweight costs (inefficiencies), even if they are temporary. Government policy-makers may not be better than individual economic agents at discerning whether a boom in the price for an export is temporary or permanent. But the government cannot completely ignore the issue of volatility with the logic that the private market can deal with it. When it comes to exchange rate policy or fiscal policy, governments must necessarily make judgements about the likely permanence of shocks."

SOURCE: FRANKEL (2012A), P. 27.

13.3.1 Neglect of external costs

The wellbeing of some parties in the Northern Territory could be adversely affected as a result of neglect of environmental, health and dis-amenity costs of exploration for, and exploitation of mineable resources (Davis, 2015; Krupnick, Gordon, 2015; Bartik, et al, 2017). These costs should include risks or hazards that might result in damage (Gruenspecht, Lave, 1989; Viscusi, 2007).

Such costs could contribute to a "Resource Curse" (Mason, Muehlenbachs, Olmstead, 2015). However, they have not been discussed further in this report as they are outside the scope set out in terms of reference for the assignment.

13.4 Mineral and petroleum commodities and public finances

Resources in the ground are depletable and ultimately exhaustible assets. In Australia, they are owned by state/territory governments onshore and the federal government offshore on behalf of constituents of relevant jurisdictions. These scarce resources have value in excess of the full costs of exploring for and extracting them. This net value *in situ* is often termed resource rent.

The benefit principle of equity indicates that government should capture as much of the resource rent as possible. That is what a private owner of mineable resources would seek to do. It would price the right to extract resources to capture resource rent. The economic efficiency principle indicates that policy instruments deployed to capture resource rent should be carefully designed to avoid destroying part of it by impeding incentives to realise resource rent through exploration, investment and extraction activities.

Realisation of resource rents and government revenue from capture of a substantial proportion of resource rents are not sustainable, because resource rents are derived by depleting exhaustible natural capital. Government revenue deriving from resource rent is really revenue from sale of assets. It is not sustainable like revenue from taxation linked to ongoing activities.

The unsustainability of realisation of resource rents and government revenue therefrom could be addressed by saving resource rents accruing to Australian entities, rather than consuming them.[51] Subsequently, they could be invested astutely in productivity-enhancing built and human capital. Saving and investing resource rents would be consistent with principles of inter-generational equity and efficient inter-temporal allocation of resources. In other words, it would be conducive to sustainable development from an economic perspective. This insight was originated by Solow (1973). It was subsequently developed by Hartwick (1977) and Solow (1986, 1993). The principle is widely accepted in the economics literature as indicated in a review by Barbier (2016).

13.4.1 Raising revenue

Governments that own mineable resources price the right to extract them via royalty regimes. In the Northern Territory, the Government does so via a 10 per cent ad valorem royalty based on wellhead value for oil and gas, and an 18 per cent accounting profits royalty for other mineable resources.

Resource rent that escapes capture by the Northern Territory royalty regimes becomes subject to Commonwealth Government taxes. The petroleum resource rent tax applies at a rate of 40 per cent to a base that crudely represents resource rent less royalty payments to the Territory. The Commonwealth Government's company income tax regime applies at a rate of 30 per cent to an accounting profits base that excludes royalty and petroleum resource rent tax payments. The Commonwealth Government also collects an additional portion of the resource rent through taxation of providers of capital, skilled labour, and other inputs, who have been able to capture part of the resource rent.

Ad valorem royalty regimes cannot capture a substantial amount of rent without causing substantial economic damage. Such regimes make extraction of marginal resources unprofitable and may have the same effect on resources that are not much better than marginal. If royalty rates are not kept low, they can knock out parts of resources or entire resources. They damage incentives to explore, invest and extract at the margin, thereby destroying some resource rent. However, if royalty rates are kept low to avoid such economic damage, they capture only a small proportion of resource rents realisable from exploitation of superior resources. Resource rent is then allowed to escape to other jurisdictions. There is a substantial literature on this matter, and on effects of alternative regimes, including work by Gaffney (1967), Northern Territory (1982), Willett (1985, 2002), Industry Commission (1991), Smith (1997), Lund (2009), ACIL Allen (2010), Henry, others (2010), and Boadway and Keen (2010, 2015).

An accounting profits regime, such as the Northern Territory royalty regime for mineable resources other than oil and gas, and the Commonwealth Government's company income tax regime, are superior to an ad valorem system. However, these systems still tax the cost of equity capital and they do not treat gains and losses symmetrically. Therefore, they discourage exploration and investment.

[51] Resource rents that accrue to overseas entities would not be available to replace depletable assets. To put this in perspective, about 80 per cent of the Australian mining sector is overseas owned (Connolly, Orsmond, 2011).

13.4.2 Spending revenue

Government misspending of revenue derived from a mining boom ignited by high commodity prices or major discovery may cause a genuine economic "disease" or "curse". This may result from the composition or types of spending undertaken, not just the pro-cyclicality problem discussed above.

It appears that the true "disease" experienced by the Netherlands following major discoveries and substantial exports of natural gas resulted from consumption (not saving and investment) of resulting government revenue. This took the form of high levels of social service or welfare payments that amplified economic adjustment issues, were not sustainable, and proved to be politically difficult to remove (Corden, 1984; Hart, 2010).

Determining how much should be saved and invested is not straight forward. One complication is that mineable resources can be at least partly replenished by exploration and technological advances in exploration and extraction. Additional complications working in the opposite direction are that investments in human and built capital and research are imperfect substitutes for mineable resources, and the marginal productivity of reproducible capital would tend to fall as substitution proceeds. Another issue is that only some of the resource rents remaining in private Australian hands after royalty and tax will be saved and invested in Australia, and resource rents captured by overseas entities would probably be lost to the Australian economy. There is an economic case for saving and investment of all government revenue from resource rents in capital-scarce developed countries like Australia, and particularly in relatively undeveloped locations with considerable potential, such as the Northern Territory.[52] This approach was recommended by the Productivity Commission (1998) and its predecessor, the Industry Commission (1991).

Selection of specific investments also matters. Investments that have been poorly conceived, directed towards political objectives, and/or do not pass or are not subjected to comparative social benefit-cost analyses should not been made. Government should not provide infrastructure or concessionary funding for infrastructure or other investments to developers of mining or diversification activities that are the main beneficiaries of the expenditure, without a claw-back mechanism to recover the full economic cost (including an appropriate risk-adjusted rate of capital in alternative uses). Investments should not be made by government for the purpose of impeding desirable structural adjustments.

A logical government investment in a jurisdiction that is relatively unexplored, despite favourable geology, would be expansion of funding of very early stage exploration and prompt release of the resulting information provision. There is a strong economic case for government to engage in such activity to correct two market failures: under-provision of basic geological information by the private sector because of its public good character, and asymmetric distribution of exploration information that tends to lead to wasteful pre-emptive exploration by some parties, and tends to shut out other parties and impede competition for tenements. This case has been understood for 50 years (see Gaffney, 1967; Herfindahl, 1969).

This case for government investment in exploration activity can be extended to justify a tapered subsidy scheme (from 100 per cent down to zero) for some subsequent exploration, followed by prompt release of information, because the transition of exploration information from public to private good as exploration becomes more focussed as it proceeds to later stages of assessment is not a clear-cut step. Moreover, there is a case for government investment in infrastructure and personnel to assemble, analyse, package and release information generated by government and private sector exploration activities. The nominated resource-rent capture regime would claw-back much of the value added by this government expenditure on exploration and information dissemination.

Logically, other government investment would take the form of investment in education, health, and infrastructure designed to complement and boost productivity in tradeable and non-tradeable goods and services sectors, reducing costs in those sectors. Investment could be focussed to support productivity improvements in stressed, lagging tradeable goods sectors. It could also be directed towards helping those lagging sectors indirectly by increasing productivity and constraining price rises in expanding non-

[52] In developing countries, where poverty is a major problem, it would be appropriate to allocate some of the revenues derived from resource rents to consumption spending to alleviate poverty. Particularly high rates of return on investment in education, health and infrastructure in such countries could allow release of some revenues to alleviate poverty directly, in addition to alleviating it indirectly through investments (Sachs, 2007; Collier, van der Ploeg, Spence, Venables, 2010).

tradeable sectors providing inputs to, and competing for resources with lagging sectors (Sachs, 2007; Freebairn, 2012).

The timing of government investment is as important as careful selection of specific investments. As discussed above, pro-cyclical government spending could have economic "disease" or "curse" effects. While these would be moderated as productivity-improving effects of targeted government investment come into play, "disease" or "curse" problems could occur in the interim. This suggests it would be economically appropriate to spread government investments over time in a counter-cyclical fashion.

John Freebairn (2012) suggested that revenues derived from resource rents could be invested in tax reform in a manner designed to reduce inefficiencies of the Australian tax regime as a whole. This could be undertaken along lines suggested by the Henry Tax Review (Henry, others, 2009). It should yield large productivity gains.

A common suggestion for investment of government revenue derived from resource rent is to accumulate foreign assets. This is a way of providing a stream of sustainable future revenue, while reducing economic "disease" problems, because it moderates the real exchange rate appreciation resulting from a booming mining sector. However, in the context of apparent under-investment in human capital and infrastructure in the capital-scarce Australian economy, investment solely in foreign assets seems inappropriate. Higher economic returns could be earned by investing domestically. Moreover, Australia's tax regime interferes with efficient allocation of resources. Therefore, a compromise would appear sensible, including "parking" of a high proportion of revenue derived from resource rents in liquid foreign assets during periods of booming mined-commodity prices, re-investment of some of those funds and new revenue in human capital and infrastructure on a counter-cyclical basis at other times, and investment of government revenue from resource rents in tax reform.[53]

13.5 Optimal regulation of exploration and production

Resource rent may also be misspent through poorly designed exploration tenement policies. Typical tenement regimes in Australia induce dissipation of ex ante resource rent through misallocation of resources. These regimes fall into two categories: conditional first-come-first-served systems and work programme bidding for highly conditional tenure. The mineral exploration tenement regime in the Northern Territory falls into the former category. The Northern Territory petroleum exploration regime is of the latter type.

Both systems tend to dissipate ex ante resource rent and misallocate resources because of distortion of the timing, amount and composition of exploration activity, through the effective allocation of resource rent by government to subsidise exploration that is marginal because of timing, location and technique. The existence of this policy failure in the Northern Territory context was recognised 36 years ago in the *Green Paper on Mining Royalty Policy for the Northern Territory.*

Policy failure associated with regimes with some common features was discussed in a United States context by Gaffney (1967) and Herfindahl and Kneese (1974). Similar issues with conditional first-come-first-served systems in Australia were noted by Fitzgibbons (1977). Inefficiencies associated with both systems in Australian jurisdictions have been analysed in some depth by ACIL Allen (2012), Henry and others (2010), Willett (2002, 1985), Smith (1997), and the Industry Commission (1991). The analysis has been endorsed by the Productivity Commission (2015).

Work program bidding is a mechanism for allocation of exploration tenements. It involves a formal bidding process for areas released for offers of exploration work. Each tenement is allocated to the bidder offering the exploration programme that is judged to be the best. Typically, more and earlier activity are judged to be better.

The location and timing of release of tenements for allocation by work program bidding is determined by government. Explorers are not able to apply for tenements on an *ad hoc* basis under a work program bidding system, in contrast to a conditional-first-come-first-served system.

Typically, the tenements are highly conditional, being subject to relatively short tenure (5 years), periodic relinquishment requirements (50 per cent after the initial 5 years before renewal), and performance of the

[53] A detailed discussion of saving and investment options has been presented by van der Ploeg (2014).

work programme that was bid. Capture of resources and retention of ground on a long-term basis depend on performance of the work programme and discovery of resources.

Following release of an area for work program bidding, a potential explorer seeking to capture tenure would offer no more than a work programme of size and timing that would extinguish *ex ante* resource rent. This would involve increasing and bringing forward exploration relative to the exploration programme a rational explorer would choose with secure, prolonged tenure. The earlier that an area is released for work program bidding, the more important will be the effect of bringing forward exploration, which dissipates *ex ante* resource rent through interest on premature outlays, and higher real costs of exploring earlier, rather than later. The closer that release of an area for bidding approaches the ideal time to commence exploration, the greater will be the relative importance of the tendency to increase the amount of the exploration programme offered above what is reasonably expected to be required for discovery. Then, *ex ante* resource rent is dissipated through economically excessive outlays.

Another adverse effect of work program bidding is that it would also tend to dissipate value added by government funding of very early stage exploration. This work would reduce uncertainty and consequent waste of exploration resources experienced by private sector explorers, raising ex ante resource rent from the perspective of those explorers. Subsequent work program bids would be adjusted to reflect the value added.

14 PERSPECTIVES ON POLICY ISSUES

The literature highlights the range of issues that Governments would need to consider, should the development of a shale gas industry in the Northern Territory proceed. Through the stakeholder consultation process, ACIL Allen gained further insights on the key issues that need to be considered in designing an effective policy and regulatory regime in the Northern Territory, should the development of a shale gas industry proceed. A copy of ACIL Allen's Consultation Guide in presented in Appendix B.

Through the literature review and stakeholder consultation, ACIL Allen has identified six key policy areas considered relevant to the development of a shale gas industry in the Northern Territory. In discussing each of these issues, the de-identified remarks of stakeholders have been included where they provide further context as to the issues and challenges that may arise during a development.

ACIL Allen Consulting has considered the six policy areas as they relate to three key outcomes for the Northern Territory in the event of shale gas industry development.

- Measures to **capture** the benefits
- Measures to **distribute** the benefits
- Measures to **manage** downside risks

As per its scope of works, ACIL Allen Consulting is focussing strictly on the identification of economic policy issues and initiatives that are available to the Northern Territory Government.

14.1 Managing an increase in NT Government revenue

ACIL Allen's modelling suggest the Northern Territory Government would receive between $18 million (BREEZE scenario), $34.4 million (WIND scenario) and $95 million (GALE scenario) in royalty income per annum at full scale production should a shale gas development proceed. This would represent between a 0.3 per cent and 1.4 per cent increase in the revenue base of the Northern Territory Government. In addition, the Territory will raise an estimated $2.9 million (BREEZE), $8.7 million (WIND) and $11.1 million (GALE) in payroll tax, and additional revenue associated with transfer duty, insurance duty and other State taxes which ACIL Allen has not modelled.

Within this policy area, the issues are mostly available to the Northern Territory to capture the benefits and distribute the benefits of a shale development.

In terms of capturing benefits, the Northern Territory Government already levies a 10 per cent ad valorem royalty at the well head (point of production) for all onshore petroleum production. According to NT Treasury, the royalty is calculated using a netback method, which allows operators to deduct upstream costs (principally transport) from the final sales price of gas in order to capture 10 per cent of the well head. This is in line with other Australian States and Territories, which tend to target a 10 per cent return to the community from the sale of mineral and petroleum resources.

The practice of charging the private sector a **royalty** for the sale of a non-renewable resource for extraction is well founded. Broadly, stakeholders were of the view that levying a royalty was a critical way for the Northern Territory to capture the benefits of a shale gas industry development. There was also a view presented to ACIL Allen that the royalty rate could be used as a negotiating tactic for the Government to incentivise non-production elements of the industry to move to the Northern Territory – such as a corporate head office or support function.[54]

It is also important to consider the need for a stable, certain operating environment for potential industry operators. During consultation, industry operators raised the need for a well-defined and stable taxation regime as an important consideration in their decision making as to whether a development would proceed beyond the initial exploration and appraisal phase. [55]

One particular feature of the potential for additional onshore petroleum royalties is how this may interact with Australia's system of **horizontal fiscal equalisation** (colloquially known as "GST distribution"). The Northern Territory is currently a significant beneficiary of the system, mostly on account of its identified additional expenditure needs (see Section 2.4) determined by the Commonwealth Grants Commission.

Each State's onshore petroleum royalty revenue is assessed as part of the Commonwealth Grants Commission's mining revenue assessment; onshore petroleum royalties are considered substantial enough to be assessed as an individual line of revenue. For confidentiality reasons, the Commonwealth Grants Commission does not publish the details of the onshore petroleum royalty assessment, but it does include them in the "other" mineral component. The Northern Territory has an assessed per capita revenue raising capacity in this "onshore oil and gas and other minerals" component of 9.287. This is a similar relativity as the Commission assesses the Western Australian Government in the iron ore royalty assessment (8.831), suggesting a high proportion of the Northern Territory's onshore petroleum royalties could be "equalised away" to other State and Territories in the GST distribution process.

There has also been some discussion that the Commonwealth Government may treat onshore gas revenue as "equal per capita" revenue, which would provide all States with a financial incentive to raise additional revenue from this source as it would not be subject to the GST distribution process. This is an issue worthy of further detailed examination and advice from NT Treasury[56] and the Commonwealth Grants Commission.

After raising the revenue associated with the shale gas industry, the Northern Territory Government has decisions to make regarding the way it will be treated or spent. This is primarily a distribution issue – with both geographic and intergenerational dimensions. While the pressure to spend any uplift in royalty and other revenue is likely to be strong, there are also options for the NT Government to manage the new revenue streams with an eye to intergenerational equity. There are two ways to do this: a wealth fund or a stabilisation fund.

The literature says there is a strong case for windfall royalty revenue to be treated differently. The Government is selling the right to mine a non-renewable resource, which is a one-off transaction. In this respect, mining royalties are different to taxes on income or consumption, which are perennial tax bases. Revenue raised from royalties should therefore be used to compensate society for the realisation of the value. This can be done by investing in the physical or human capital of the economy – to improve its productivity – or by warehousing the revenue in a special fund.

Traditionally, a **wealth fund** is used to accumulate revenue associated with windfall gains or with the extraction of non-renewable resources such as mineral commodities or petroleum products. The most famous example is the Government Pension Fund of Norway, which has an estimated value of just under US$1 trillion. The fund was established in 1990 as a warehouse for government revenue earned from oil company profits.[57] Most major petroleum producing nations have some sort of wealth fund for the purposes of accumulating profits or other revenue (such as royalties).

The Western Australian Government developed its own sovereign wealth fund – the *WA Future Fund* – in its 2012-13 budget as a way of warehousing some of the proceeds of the iron ore royalty boom. The WA Future Fund received an initial capital injection of $1 billion dollars between 2012-13 and 2015-16, and

[54] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.
[55] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.
[56] NT Treasury were cognisant of this risk when ACIL Allen met with personnel during its stakeholder consultation
[57] Sovereign Wealth Fund Institute. 2017. *Norway Government Pension Fund Global – Summary*. Accessed online at http://www.swfinstitute.org/

receives ongoing injections equal to one per cent of the State's royalty revenue per annum, and reinvests all of its earnings in additional capital accumulation.

The WA Future Fund is governed by an Act of Parliament, which forbids any future government to access the funds it is receiving and generation until 2031-32 (unless a Bill can pass with the concurrence of an absolute majority, of both houses of the State Parliament), at which time the State Government projects it will have a nominal value of $4.7 billion.[58] The Act states the annual interest earnings on the WA Future Fund can be used to finance the economic and social infrastructure needs of the State.

While well-intentioned, the broader settings of the State's finances are not ideal to host a wealth fund, given the State has significant public debt and high operating and cash deficits.[59] This means the State Government is effectively borrowing money to store in the fund. It is important to consider the state of public finances when making such significant, long-range decisions.

There are also a number of examples of countries which use a **sovereign wealth fund for the purposes of stabilising government finances**. These kinds of funds tend to be more short to medium term in focus than the long term nature of a wealth fund, and are used as a "banking" mechanism for countries with volatile, uncertain revenue bases. These funds tend to have strict rules around when money is to be deposited and can be withdrawn. The objective of smoothing out fluctuations in government revenue is to avoid large deficits or increased spending of short term increases in revenue.

The central government of Chile has operated a stabilisation fund under various guises since 1985, and has drawn on money stored in it during global economic crises in order to avoid large deficits or recessions in their domestic economy.[60] The rules regarding Chile's current stabilisation fund, the *Economic and Social Stabilization Fund*, are presented in Box 14.1.

BOX 14.1 CHILE COPPER STABILISATION FUND

Chile's Economic and Social Stabilization Fund (the 'ESSF') is often held up as a prime example of best practise stabilisation fund management. The ESSF received an initial seed investment of US$2.5 billion in 2007, following a decision to consolidate two sovereign wealth funds into one with simplified objective of smoothing out revenue fluctuations associated with Chile's copper industry.

The ESSF receives additional capital on an annual basis when Chile's central government budget is in a surplus position equal to or greater than one per cent of GDP – with the capital injection equal to the surplus less the amount equal to one per cent of Chile's GDP. The ESSF mostly invests in low risk government and corporate bonds, allowing it to earn a return above holding cash but also affording flexibility to allow for a quick sale if the fund needs to be accessed.

Chile's central government has an overall "balanced budget" rule, meaning the ESSF can be called upon if there is a projected central government deficit in a given year to avoid the accumulation of debt to finance the operations of government. The ESSF can also be drawn down to fund any unmet pension or social welfare liabilities at the discretion of Chile's Minister for Finance. The ESSF is consistently one of the highest rated funds by the Sovereign Wealth Fund Institute.

SOURCE: GOVERNMENT OF CHILE, NATIONAL RESOURCE GOVERNANCE INSTITUTE, ACIIL ALLEN CONSULTING

The Inquiry is keenly interested in examining the notion of a "royalties for regions" fund, which could quarantine a proportion of royalties associated with the development for spending in the area where resources are extracted. Such a policy was implemented in Western Australia just as its iron ore and gas boom gathered pace in 2008-09, as a result of the negotiations associated with the formation of a new government in a hung parliament. An overview of the structure of the program is in Box 14.2.

[58] Parliament of Western Australia. 2012. *Western Australian Future Fund Act 2012*. Accessed online at http://www.parliament.wa.gov.au/
[59] CCIWA. 2012. *Examining the Issues of Sovereign Wealth Funds*. Accessed online at http://www.cciwa.com/
[60] International Monetary Fund. 2007. *Assessing Chile's Reserve Management*. Accessed online at http://www.imf.org/

BOX 14.2 WESTERN AUSTRALIA'S ROYALTIES FOR REGIONS FUND

The Royalties for Regions Fund Program is administered by the *Royalties for Regions Fund Act 2009*. The Act directs 25 per cent of annual resources royalties raised by the Western Australian Government to a special purpose account that can only be spent in areas outside of the Perth Metropolitan Area. The Act specifies the Fund is to be "over and above" the usual expenditure of government in regional areas, and it can be expended for three purposes:

1. To provide infrastructure and services in regional Western Australia
2. To develop and broaden the economic base of regional Western Australia
3. To maximise job creation and improve career opportunities in regional Western Australia

The remainder of the Program is established by administrative provisions within the Department of Primary Industries and Regional Development (formerly the Department of Regional Development). These provisions set out the strategic framework guiding spending, including the project approvals process which sees Fund applicants skip the usual WA Treasury review process.

There is a $1 billion limit placed on the end of financial year balance of the Fund, meaning in times where royalty revenue is booming, the Fund must expend close to $1 billion per annum. Prior to 2014-15, the Fund received an appropriation equal to 25 per cent of royalty revenue without a cap on the appropriation. This was changed in the 2014-15 State Budget – independent $1 billion appropriation and expenditure caps were put in place – to maintain the integrity of the program and ensure it did not become an undue drag on the State's finances.

SOURCE: ACIL ALLEN CONSULTING

The policy has been in place in Western Australia since 2008-09, quarantining 25 per cent of total royalty revenue (up to an annual amount of $1 billion) for spending on regional development projects, town beautification and social programs. There are a series of changes the Western Australian Government has made to the program in recent years (both past and current Governments) to improve the transparency, decision-making and accountability associated with it, and to shift its focus to job-creating projects rather than the provision of amenity enhancements.

Numerous reviews have also called into question the governance arrangements of the Program, noting it was not subject to the usual scrutiny of government expenditure review.[61] This was particularly true in the early years of the Program, when money was distributed to regional local government authorities with very loose accountability and little guidance on how it should be spent. The Program is now subject to a Special Inquiry.[62]

While these are important considerations, based on the development scenarios modelled by ACIL Allen Consulting it is unlikely that the revenue streams associated with the development of a shale gas industry would be of a requisite scale to warrant development of a specialist fund for the purposes of fiscal stabilisation or intergenerational equity. However, it is worth considering the benefits and costs of such an idea given it is an issue front of mind for many of the stakeholders ACIL Allen consulted.[63]

14.2 Managing an increased demand for labour

The development of the shale gas industry in the Northern Territory has the potential for substantial labour benefits in the form of job creation, skills development and workforce diversification. An increase in the demand for labour from the development of the industry can be measured by the direct labour that is hired to work on the construction and operation phases of the development, as well as the indirect employment impact from the jobs that are generated by the spending in the economy as a result of the development.

[61] WA Office of the Auditor General. 2014. *Royalties for Regions: Are the benefits being realised?* Accessed online at http://www.audit.wa.gov.au/
[62] WA Government. 2017. *Media Statement: Commission of Inquiry to Investigate financial mismanagement, 15 May 2017*. Accessed online at http://www.mediastatements.wa.gov.au/
[63] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

It is estimated the employment impact of a development will average 82 FTE (BREEZE), 252 FTE (WIND) and 524 FTE (GALE), with much of this employment likely to occur in regional areas where the activities of an industry would occur.

Given the remote locations of the development sites, it is expected that a there will be a need for some of the workforce to be employed on a fly-in, fly-out employment roster as the availability of sufficient skilled labour in these areas is unlikely to be able to be sourced locally. However, depending on the location of the development sites, there could be opportunities for nearby regional job seekers to be employed on a drive-in, drive-out basis. The use of regional employment will depend on the skills sets of local job seekers and the availability of training to gain the skills required of the developments. There was a preference in consultation from local communities to maximise the use of local job seekers in order to assist in keeping the benefits of the development of the industry on country.[64]

The more remote locations of the development areas means there is often limited employment and career opportunities. With high levels of unemployment in many regional areas of the Territory, the labour opportunities presented by the development of the shale gas industry are potentially important to improving economic and social outcomes in regional and remote areas.[65]

The types of skills required to develop shale gas deposits differ between the construction and operation phases. In construction the skills set generally favour engineers, drillers, logistics personnel and labourers while engineers, geoscientists and technicians comprise the bulk of the workforce one a project is operational. This range of skill set requirements provides opportunities for job seekers in the Northern Territory, particularly for those job seekers with low skills and those wishing to develop their skills set. It also provides opportunities for trainees and apprentices.

Given the skills set and experience of the Northern Territory workforce, it has been assumed that some specialist skills may need to be sourced from elsewhere in Australia or overseas. However the majority of the workforce is expected to be sourced from within the Territory. During consultation, it was advised that local job seekers would be trained to meet the requirements of the developments. Over time, it is expected that the local employment content of the developments will increase as the skills and experience of the local workforce employed on the developments grow. [66]

There are opportunities for government to maximise the workforce benefits of shale gas development and ensure that benefits are able to be accessed by all job seekers in the Northern Territory. There is **a role for government in co-ordinating the requirements of the shale gas industry with employment and training providers**. This includes identifying the timing of developments and the skills sets required for the construction and operation phases of the developments. There is further opportunity to work with employment agencies and training providers to ensure that they match their services to the needs of the shale gas industry. This will assist in maximising local employment benefits and promoting the distribution of labour benefits to job seekers throughout the Territory.

According to potential suppliers to a shale gas industry, there is an important role for "localised" on the job training opportunities. MS Contracting, one of the major suppliers of supplies and services to the shale gas industry during its brief exploration activities in the Northern Territory, made a submission to the Inquiry and reinforced this submission during stakeholder consultation that referenced the positive outcomes of their localised training program for Indigenous persons in the regions they operate in.[67]

The Northern Territory captures the employment benefits of projects through local labour content policies such as the Indigenous participation in construction projects policy which requires contractors to develop an Indigenous Development Plan aimed at maximising the employment of Indigenous labour and businesses on construction projects. There are benefits in setting local employment targets and Indigenous employment targets as long as they do not result in a misallocation of resources. These types of targets assist in ensuring employment benefits are targeted at local job seekers.

Other programs aimed at maximising local employment and skills development through matching information flows include the NT Apprenticeships and Traineeships Database which is co-ordinated by the Northern Territory Government. The database contains details of all approved apprenticeship / traineeship

[64] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017.*
[65] ACIL Allen notes this is an issue to be covered by the Inquiry's Social Impact consultancy.
[66] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017.*
[67] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 17 October 2017.*

qualifications in the Northern Territory and provides information on all apprenticeship/traineeship qualifications. Programs aimed at facilitating the flow of information will be important tools in ensuring positive outcomes for the workforce in the Northern Territory.

14.3 Maximising local expenditure and opportunities

Local content policy is founded on the principle of full, fair and reasonable opportunity for local businesses to secure work on large public and private sector projects. An important enabling aspect of local content policy is providing the platform for suppliers and project owners to connect, and to understand the demand for and supply of goods and services which may be required in a project.

The development of shale gas in the Northern Territory offers opportunities for local businesses through the expected high local spend.

The location of the development sites in remote areas provides a range of supply opportunities for regional businesses that provide goods and services. Opportunities are varied but examples of the types of local businesses that could be involved in the construction stage include earthmoving and civil engineering companies; trades such as electricians, plumbers and gas fitters; caterers; suppliers of fresh food and household consumables; and training providers.

In operation, there will be ongoing opportunities for local businesses to enter into long term agreements to provide goods and services to the developments. These will include those businesses that provide cleaning, maintenance, catering, grading, electrical, plumbing and other goods and services.

As discussed earlier in this report, there can be a mismatch between the expectations of developers and the capabilities and services of local suppliers which results in local businesses missing out on opportunities. **There is a role for government to ensure that there is an information flow from developers regarding available opportunities**. There is also a role to work with local businesses to ensure they properly communicate their capabilities and availability to service developments.

The Northern Territory already has a number of key initiatives in place to capture the benefits from spending by developments. These include the Building Northern Territory Industry Participation Policy, a Government procurement program requiring local content, and a partnership with the Industry Capability Network Northern Territory (ICN NT), to ensure to the Government's commitment to local participation is met.

There is benefit in setting local content targets for developers and contractors in order to maximise the capture of direct and indirect spending in the Northern Territory as long as they do not result in a misallocation of resources. There is further benefit in working with developers to promote the services of local businesses, particularly those in regional and remote areas. This would assist in distributing the benefits of the developments to businesses located throughout the Territory. **Addressing information asymmetries**, by identifying the timing of developments, and the goods and services required for the construction and operation phases of the developments is an important role for government. This would further assist local industry to access full, fair and reasonable opportunities to capture business opportunities from a new project.

There are opportunities for government to work with local businesses, particularly those in regional areas, to identify business opportunities and to match the services of regional businesses to those opportunities. The remote location of the developments offer important business opportunities for Aboriginal communities such as in the area of cleaning, catering, maintenance services, fire services and other parks and ranger services, the hire of heavy equipment such as graders, and the provision of general labour.

BOX 14.3 BUILDING NORTHERN TERRITORY INDUSTRY PARTICIPATION POLICY

Under the Building Northern Territory Industry Participation Policy, an Industry Participation Plan will be a requirement for all Northern Territory Government assisted private sector projects that have an expected value in excess of $5 million. It will also be a requirement for all Northern Territory Government tendered projects that have an expected value in excess of $5 million and for Territory Public Private Partnerships (Territory Partnerships) which will provide opportunities for all sectors in the economy to contribute to the efficient delivery of infrastructure and services.

Industry Participation Plans are intended to:

- assist project proponents and developers to maximise opportunities to utilise local suppliers, services and labour;
- improve the capacity of businesses to compete globally; and
- assist decision making in relation to Government purchasing and investment where value will be the primary consideration.

SOURCE: NT GOVERNMENT, ACIIL ALLEN CONSULTING

Many regional and remote areas in the Northern Territory are experienced with working with resources companies in the exploration, construction and operation phases of developments. By way of example, the Central Land Council **makes agreements with resources companies on behalf of traditional Aboriginal landowners** that define the outcomes for companies and Aboriginal people before activity commences. These agreements ensure that the benefits of developments flow to Aboriginal people through a commitment to employment, training, sacred site protection, environmental protection and opportunities for Aboriginal people. [68]

These types of agreements, along with a transparent and timely flow of information regarding the timing of developments and their purchase requirements will be essential to maximise the opportunities for businesses in the Northern Territory.

14.4 Industry co-existence

The issue of industry co-existence – the ability for a shale gas industry to "fit in" with the existing industry structures of the Northern Territory – was raised by most stakeholders consulted by ACIL Allen. This issue has a multitude of applications to the work of the Inquiry. The economic dimension is the extent to which a shale gas industry **may impede or distort the allocation of the factors of production**[69], particularly natural resources like land and water.

ACIL Allen's development scenarios anticipate a potential shale gas industry could disturb between 67.7 square kilometres (km^2) in the BREEZE scenario, 231.7km^2 (WIND), and 475.9km^2 in the GALE scenario.[70] This represents some 0.03 per cent of total land in the Northern Territory in the GALE scenario. ACIL Allen has accounted for the opportunity cost of this land by assuming it is made unavailable for cattle pastures. This is the primary channel of negative economic impact on the agriculture industry in the event of a shale gas development (see Section 6.2.4).

Under ACIL Allen's adopted assumptions regarding water use, the development may use between 4.2 GL (BREEZE), 11.2 GL (WIND), and 28.2 GL (GALE) of water, respectively. In annual average terms, over the 25 year project life ACIL Allen has modelled, this represents between a 0.17 GL,

[68] Central Land Council, Making agreements on Aboriginal land: Mining and development, http://www.clc.org.au/articles/cat/mining/, accessed September 2017.
[69] Classical economic theory divides the factors of production – the means of producing goods and services – into four categories: land, labour, capital and enterprise. In this instance, the capital and enterprise are to be provided by the private sector and so this has not been discussed. Labour resources are discussed in Section 14.2.
[70] These values are adopted as conservative assumptions – ie ACIL Allen has overestimated the area of disturbance so as to ensure it cannot be underestimated. It is noted producers expected approximately 100km^2 of land disturbance over the life of their "full scale" developments (400TJ/day), the majority of which is associated with transmission pipelines rather than the number of pads.

0.45 GL and 1.13 GL draw on water supplies. This is significantly less than the Australian Bureau of Statistics estimates is used by the agriculture industry in the Northern Territory (47 GL in 2015-16).[71]

Through the Inquiry, ACIL Allen has received information that suggests there are a range of options available to a shale gas development to source water – both potable and non-potable – in a manner which minimises tensions with existing users. For example, the Department of Primary Industry and Resources has identified underground aquifers with a sustainable groundwater yield of 100GL per annum or more across the four prospective shale gas basins.[72] All things being equal, this would suggest **water is unlikely to be a constraint on the development of a shale gas industry** within the current industry structure of the Northern Territory, and the prospect of a reduction in water availability for non-shale gas industry users in the aggregate is limited. In an economic sense, this means there is unlikely to be an opportunity cost borne by society flowing from the use of water by a shale gas development.

Given the above, **it is unlikely that a shale gas industry will impede on the existing allocation of natural factors of production in the Northern Territory**, in an economic sense. However, it is important for the Northern Territory Government to remain fully aware of the activities of potential shale gas operators to monitor the draw on the Territory's natural resources. This would primarily occur through regulation.

There are regulatory measures in place to manage potential land use tensions between industry and Traditional Owners, through a formalised negotiation process involving the various Aboriginal Land Councils established to govern native title in the Northern Territory. Pastoralists also have access to a process to ensure engagement with potential industry proponents, albeit it is not a formalised regulatory instrument. This issue was raised by representatives of the pastoralist industry during ACIL Allen's stakeholder consultation, noting they had advocated for a legislated right of negotiation, access and veto similar to that available to Traditional Owners. Meanwhile, the **Northern Territory Government controls the allocation of permits** for the purposes of exploration or production of petroleum products through its petroleum title system.

The somewhat complex approach to land access is driven in part by the fact that all mineral and petroleum resources are owned by the Crown, and reflects the view that minerals and petroleum are "a gift of nature" and that benefits should accrue to the community as a whole rather than to those who happen to own the surface rights to the land.[73]

In the United States, petroleum resources are owned by the person or entity which owns the land. This can be the State, but it can also be a home owner whose land sits atop a prospective shale. This has its own benefits – access to land can be a relatively simple process, with direct engagement between a prospective shale gas producer and the private land holder allowing a project to progress rapidly.[74] However, it also has costs – the State does not always realise the value of the resource, but bears some of the cost in terms of infrastructure and regulatory oversight.

ACIL Allen has commented on appropriate regulatory design in Section 14.6.

Water has been a consistent theme throughout the Inquiry. There are many dimensions, most of which are covered by elements outside of the scope of ACIL Allen's engagement. The economic dimension to water use is the opportunity cost attached to the use of water for shale gas, primarily for the purposes of creating "frack fluid" to conduct a fracture stimulation down well.

While technology is rapidly advancing, ACIL Allen has assumed there is no water recycling in its industry development scenarios. Industry operators have assumed a recycling factor of between 30 and 50 per cent of water used for fracture stimulation,[75] while industry has proposed the use of lined water "ponds" to store used fracking fluid as a means of disposing of it through evaporation.[76]

As it stands, the **Northern Territory Government does not put a price on the use of groundwater** for mining or petroleum producers. This is in contrast to other Australian jurisdictions, which charge industrial

[71] Australian Bureau of Statistics. 2017. *ABS Cat. 4618.0: Water Use on Australian Farms*. Accessed online at http://www.abs.gov.au/
[72] Department of Primary Industry and Resources NT. 2017. *Submission to Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: #226*. Accessed online at http://www.frackinginquiry.nt.gov.au/
[73] Productivity Commission. 1991. *Mining and petroleum in Australia: Volume 3*. Accessed online at http://www.pc.gov.au/
[74] Resources for the Future. 2013. *US Shale Gas Development: What led to the boom? Issue brief 13-04*. Accessed online at http://www.rff.org/
[75] Santos. 2017. *Submission to Scientific Inquiry into Hydraulic Fracturing: #168*. Accessed online at http://www.frackinginquiry.nt.gov.au/
[76] Origin Energy. 2017. *Submission to Scientific Inquiry into Hydraulic Fracturing: #153*. Accessed online at http://www.frackinginquiry.nt.gov.au/

users accessing groundwater resources for industrial purposes. For example, the New South Wales Government licenses access to its surface and groundwater resources, and applies a series of tariffs based on the entitlements allocated and actual water drawn from the allocation.[77]

Implementing a water licensing and charging regime would allow the Northern Territory Government to adequately deal with any opportunity cost which may arise as a result of the use of groundwater resources by the shale gas industry. However, this would need to be balanced against the potential costs that would be incurred by industry, and whether the costs impact on the prospects of the shale gas industry's development in the Northern Territory.

Throughout its stakeholder consultation, representatives from industry, government and non-government organisations provided ACIL Allen with a **range of potential co-existence issues** that were not able to be included in the economic modelling activities in our scope of works. These are presented in the table below (Table 14.1), with the channel of impact discussed in a second column.

TABLE 14.1 INDUSTRY CO-EXISTENCE ISSUES IDENTIFIED DURING STAKEHOLDER CONSULTATION

Issue	Discussion
Increased use of major arterial roads through central Northern Territory	Stakeholders from the private sector and government raised the concerns about the potential use of major arterial roads in the Northern Territory flowing from the development of a shale gas industry. They were concerned that this may lead to an increased incidence of traffic accidents, increased congestion, and reduced usability for tourists travelling through central Australia. This may have an impact across the Northern Territory economy, although it is impossible to determine the scale without conducting substantive work to understand the current state of major arterial roads and their use. It could be ameliorated by requesting a shale gas development includes plans to upgrade the road network should traffic volumes grow large, or commitments to manage traffic flows in such a way that it does not impede other road users.
Reduced land use available for cattle farming	ACIL Allen has addressed this in its economic modelling. The transmission mechanism is a reduction in the capital of the Northern Territory's cattle industry, which reduces the ability for it to earn income by an amount equal to the share of cattle pastures disturbed by the shale gas industry.
Reduced water draw available for agricultural and other uses	ACIL Allen has addressed this in the above discussion of natural resource management. There is no price on ground water, and there are no foreseen constraints on the ability for the industry nor current users to draw.
Reputational impact of shale gas on the tourism industry	Stakeholders were concerned that the Northern Territory's "clean and green" reputation could be tarnished by the connotations of a shale gas industry development occurring in the Northern Territory. This may reduce tourism visitor spend, although it would be difficult to measure the impact, likely very small.
The Aboriginal Carbon Fund Savannah Burning Program	Aboriginal rangers in the Northern Territory conduct annual programs of savannah burning, where portions of the Territory's landscape are burned in a controlled manner to reduce fire risk. One component of this program is carbon credit farming, which occurs when burning takes place during periods of the year where the volume of greenhouse gases (methane and carbon monoxide) which escapes into the atmosphere is reduced – leading to reduced environmental impact. A stakeholder was concerned that a shale gas industry may result in a reduced availability of land for burning, which would impact on the rangers who conduct the savannah burning. This may have an impact on the employment of those involved in the savannah burning program. However as discussed, the total area of disturbance of the shale gas industry in the Northern Territory is likely to be very small.

SOURCE: ACIL ALLEN CONSULTING

[77] NSW Government Independent Pricing and Regulatory Tribunal. 2017. *Setting fees and charges*. Accessed online at http://www.water.nsw.gov.au/

14.5 Addressing potential infrastructure constraints

The development of shale gas in the Northern Territory will place additional pressure on existing and planned infrastructure in the Northern Territory including economic infrastructure, social services, social infrastructure, and civic infrastructure. It is expected that the focus will be an increase demand for road, rail and port infrastructure to transport goods and personnel to and from the development sites, in the form of constraints. There could also be additional pressure placed on social infrastructure such as health, education and civic services, particularly in regional areas where infrastructure often has limited capacity to cater for an increase in demand.

Development of infrastructure by the shale gas industry has social and economic benefits for the Northern Territory and particularly for regional areas where much of the infrastructure development is likely to occur. Well planned economic infrastructure is a key enabler for economic and social growth. The development of infrastructure in the Northern Territory is guided by the Northern Territory Infrastructure Strategy that sets out the vision and objectives for infrastructure development along with policy drivers and a framework for the development of infrastructure projects. [78] The Strategy is supported by the Northern Territory 10 Year Infrastructure Plan which details planned projects for the first two years (2017–18 and 2018–19) with proposed infrastructure projects identified in the medium (2019–20 to 2021–22) and longer (2022–23 to 2026–27) term.[79] It is important that the government is made aware of developments in the shale gas industry in order to ensure the infrastructure planning and policy framework in the Territory reflects that development.

Supporting infrastructure is a critical component of any resource venture. Given the remote locations of some resource projects, infrastructure is often provided as part of an integrated self-contained development. However, there are often significant benefits from improvements in infrastructure to other users. The development of the shale gas industry could result in upgrades to infrastructure such as roads, thereby creating efficiencies for other road users. The construction of roads in regional and remote areas can assist in providing better access to communities in these areas providing social benefits such as improved safety outcomes, and economic benefits from a more efficient logistics network, and allowing tourists and other visitors to access these areas. The development of infrastructure also allows better access to developments providing greater opportunities for all residents of the Northern Territory to share in the wealth generated by them.

Consultation found that there were perceived issues with some infrastructure that would support the development of the shale gas industry. Examples include the capacity of the Stuart Highway given the current and potential activity of the resources sector along this Highway.[80] The Northern Territory 10 Year Infrastructure Plan has identified the upgrade of the Highway as a strategic priority to assist freight and economic development. The plan also identifies multiple required road upgrades in the Territory that primarily involve the sealing of regional roads.

An often overlooked feature of the public sector's role in the provision of infrastructure is process surrounding **project selection, prioritisation and long term planning**. Infrastructure investments are often made without due regard given to the basic economic principle of opportunity cost, in that Governments have a limited ability to fund projects. In recent times, both the Australian Government and a number of State Governments have developed independent infrastructure advisory bodies, to assist in the selection, prioritisation and planning for major infrastructure in their respective jurisdictions. The Northern Territory is likely not of the requisite scale to require such a body, but it can learn – and indeed appears to have learned, given its 10 Year Infrastructure Plan – from the principles used to underpin these bodies (Box 14.4).

The Government has a key role in the development of infrastructure in the Northern Territory however with limited resources, **there is a need for private investment**. The Northern Territory 10 Year Infrastructure Plan identifies the private sector as potentially contributing funds to the development of a number of infrastructure projects relevant to the development of shale gas including roads, railways, marine/barge landings, airports, and water supply.

[78] Northern Territory Government (2017), Infrastructure Strategy, Darwin
[79] Northern Territory Government (2017), 10 Year Infrastructure Plan 2017 to 2026, Darwin
[80] ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

BOX 14.4 THE FUNCTIONS OF INFRASTRUCTURE NSW

Infrastructure NSW (INSW) is established by the *Infrastructure NSW Act 2011*, which among other things sets out the general and specific functions of the body. These include:

- prepare and submit to the Premier a 20-year State infrastructure strategy;
- prepare and submit to the Premier 5-year infrastructure plans and other plans requested by the Premier;
- prepare and submit to the Premier sectoral State infrastructure strategy statements;
- prepare project implementation plans for major infrastructure projects;
- review and evaluate proposed major infrastructure projects by government agencies or the private sector and other proposed infrastructure projects (including recommendations for the role of Infrastructure NSW in the delivery of those projects);
- oversee and monitor the delivery of major infrastructure projects and other infrastructure projects identified in plans adopted by the Premier;
- carry out or be responsible for the delivery of a specified major infrastructure project in accordance with an order of the Premier;
- assess the risks involved in planning, funding, delivering and maintaining infrastructure, and the management of those risks;
- provide advice to the Premier on economic or regulatory impediments to the efficient delivery of specific infrastructure projects or infrastructure projects in specific sectors;
- provide advice to the Premier on appropriate funding models for infrastructure;
- co-ordinate the infrastructure funding submissions of the State and its agencies to the Commonwealth Government and to other bodies;
- carry out reviews of completed infrastructure projects at the request of the Premier; and
- provide advice on any matter relating to infrastructure that the Premier requests.

One of the critical features of INSW is any project that receives approval must have undertaken a rigorous, transparent cost-benefit analysis.

SOURCE: INFRASTRUCTURE NEW SOUTH WALES

There are also opportunities to **leverage Australian Government infrastructure funding** to assist in funding any new infrastructure that may be required.

- **The Northern Australia Infrastructure Facility** (NAIF) is a concessional loan facility established by the Australian Government to encourage and complement private sector investment in infrastructure in northern Australia. The Australian Government has made $5 billion available to approve loans between 1 July 2016 and 30 June 2021, with terms determined on a case by case basis.
- **The Building Better Regions Fund** (BBRF) is a grant-based program available to provide infrastructure or community investments in areas outside of Adelaide, Brisbane, Canberra, Melbourne, Perth and Sydney. The application for funding can be made by a Local Government Authority or not for profit organisation, but can be supported by State/Territory Governments and private sector organisations. There is just under $500 million in funding available in the program.
- **The National Water Infrastructure Fund** is available to assist public and private sector entities improve water infrastructure across Australia. Projects can build new or augment existing water infrastructure, including dams, pipelines or aquifer related projects. Projects must be sponsored by a State Government, who must be involved in the project.

These are in addition to regular programs such as national partnerships for roads and rail, local roads investments, and discretionary infrastructure investment funds made available by the Australian Government from time to time.

14.6 Approaches to industry regulation

The Productivity Commission's 2009 review into upstream petroleum regulation in Australia found the system was overly complex, contained numerous overlapping areas of compliance and statutes, and was likely harming the international competitiveness of Australia's energy sector.[81] In 2017, little appears to have change, particularly when it comes to onshore regulation (the Commonwealth Government has implemented some of the Productivity Commission's recommendations regarding consolidation of offshore petroleum regulations).

Petroleum extraction is subject to significant regulatory impost relative to other sectors, in line with the heightened safety risks and potential environmental impacts should something go wrong. During stakeholder consultation, potential industry proponents did not express a strong dissatisfaction with the current regulatory regime for petroleum extraction in the Northern Territory.[82]

The Fraser Institute's Global Petroleum Survey (2015) found **the Northern Territory was rated as the third most development-favourable jurisdiction in Australia** from a regulatory perspective, and the 34th most favourable of 126 jurisdictions surveyed by the Institute.[83] Comment on specific regulatory matters is not within ACIL Allen's scope of works, but at face value it appears the Northern Territory's existing petroleum regime serves the needs of industry well ensuring Territorians are protected.

The most substantive issue regarding industry regulation was a **perception that the Northern Territory Government may not be fully equipped to regulate a shale gas industry**. This was an issue raised by stakeholders from the private sector, government and non-government organisations.[84] Regulatory enforcement is a critical part of the way the Northern Territory Government can help provide the public with certainty industry is meeting its social license to operate. The significant land mass of the Northern Territory, and the remote location of prospective developments, make physical regulation of the industry difficult.

The functions of petroleum regulation are vested in the Department of Primary Industry and Resources' "Energy Services" group.[85] In its 2017-18 Budget, the Northern Territory Government has reduced the appropriation granted to the group from $3.9 million to $3.4 million, on account of the cessation of a one-off research funding grant. There are additional regulations which apply to the petroleum sector, such as occupational health and safety and environmental protection. Broadly speaking, the Northern Territory Government spends $37.2 million on mining and petroleum industry information services and regulation.

While the direct expenditure on petroleum-specific regulation in the Northern Territory is an increase on recent years (the Energy Services group, formerly a part of the Department of Mines and Energy, received an appropriation of $2.6 million in 2014-15 and 2015-16), **the level of funding is low compared to the cost of services of mining and petroleum regulators in other States** (Table 14.2).

The level of expenditure on services is not prima facie a measure of the level of service delivery. However the stark difference between the Northern Territory and other State and Territories suggests stakeholder concerns require this issue to be examined further. In any event, the capacity of regulators to enforce the regulation of a shale gas industry is a significant consideration for the Northern Territory Government. Given the Northern Territory's current financial challenges, there may be a need for the Northern Territory Government to examine innovative approaches to industry regulation.

Best practice principles suggest **industry should "pay its way" when it comes to industry regulation**. This is because appropriate regulations, and regulatory enforcement, is critical to industry earning a social license to operate; operators themselves are also the major beneficiary of a regulatory regime which enables the safe development of an industry. The Northern Territory Government levies a fees and charges regime for onshore petroleum exploration and production licenses, but these are relatively small in the scheme of the life of a development (for example, ACIL Allen estimates ProjectCo will spend just $3.6 million in licensing fees in the GALE scenario – 0.003 per cent of forecast revenue). There may be

[81] Productivity Commission. 2009. *Review of the regulatory burden on the upstream petroleum (oil and gas) sector, April 2009*. Accessed online at http://www.pc.gov.au/
[82] ACIL Allen Consulting. 2017. *Stakeholder Consultation: 27-29 June 2017*.
[83] Fraser Institute. 2016. *Fraser Institute Global Petroleum Survey, 2015*. Accessed online at http://www.fraserinstitute.org/
[84] ACIL Allen Consulting. 2017. *Stakeholder Consultation: 27-29 June 2017*.
[85] NT Treasury. *NT Budget 2017-18, Agency Statements*. Accessed online at http://www.budget.nt.gov.au/

scope to increase these fees and charges in order to fund any uplift in expenditure required to more adequately resource government regulators.

TABLE 14.2 COST OF ADMINISTERING AND REGULATING THE MINERAL AND PETROLEUM SECTORS, BY STATE, 2016-17, $M

State	Mining and/or petroleum information and regulation expenditure	Department/s applying regulation
Queensland	Mining and petroleum $258.5m	Department of Natural Resources and Mines Department of Energy and Water Supplies
South Australia	Mining and petroleum. Also includes some electricity regulatory services related to consumer safety $132.8m	Department of Premier and Cabinet
Western Australia	Mining and petroleum $154.6m	Department of Mines, Industry Regulation and Safety

SOURCE: ACIL ALLEN CONSULTING, BASED ON ANALYSIS OF STATE BUDGET PAPERS

APPENDICES PART ONE: ENGAGEMENT INFORMATION

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A ACIL ALLEN'S TERMS OF REFERENCE

A.1 Background to the Inquiry

On 14 September 2016 the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory. At the same time, the Chief Minister announced that a *Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory* (the **Inquiry**) would be established and released draft Terms of Reference, which were open for public comment for four weeks.

On 3 December 2016 the Northern Territory Government announced the final Terms of Reference for the Inquiry and the composition of the panel that will be undertaking the Inquiry (the **Panel**).

The Inquiry was established under section 4 of the *Inquiries Act 1945* (NT) and is comprised of a judicial chair, the Hon Justice Rachel Pepper, and ten highly regarded scientists with expertise in areas ranging from hydrogeology to social science.

The Inquiry's final Terms of Reference can be read in full on the Inquiry's website (www.frackinginquiry.nt.gov.au).

On 20 February 2017 the Inquiry released a *Background and Issues Paper*, also available on the Inquiry's website, which was followed by hearings and community meetings held in March 2017 in various town centres and remote communities across the Northern Territory. The Issues Paper includes a timeline for the Inquiry, which indicates that an interim report will be released in mid-2017, a draft final report will be released during the last quarter of the year, and a final report will be released in December 2017.

The Hydraulic Fracturing Taskforce (the **Taskforce**) has been established in the Department of the Chief Minister to support the Inquiry.

A.2 Terms of Reference for the Inquiry and the economic impact theme

The Panel has divided the work of the Inquiry into the following themes: water, land, air, social impacts, economic conditions, cultural conditions, human health, land access, and the regulatory framework. This request relates to the economic theme only, however, there are overlaps with the social impact and regulatory framework themes. A sub-group of Inquiry Panel members has been allocated responsibility for each theme.

The Terms of Reference for the Inquiry require the Panel to do the following in respect of each theme:

1. determine and assess the impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the associated activities;
2. determine whether additional work or research is required to make that determination;
3. advise the level of impact or risk that is acceptable in the Northern Territory context;

4. describe methods, standards or strategies that can be used to reduce the impact and risk to acceptable levels; and
5. identify what government can do, including implementing any policy or regulatory changes, to ensure that the impacts and risks are reduced to the required levels.

The *Background and Issues Paper* includes a non-exhaustive list of the potential risks and benefits associated with the economic theme at page 22.

In accordance with the definitions in the Terms of Reference, a reference to an "unconventional reservoir" in this document is a reference to a reservoir where the rock formation is *shale*. There is currently no gas being produced from unconventional, or shale, reservoirs in the Northern Territory. The Amadeus Basin is currently producing gas from conventional reservoirs.

With regard to the third Term of Reference stated above, the level of impact or risk that is acceptable will ultimately be a matter for the decision maker under the relevant legislation (typically the Minister), however, at this stage the meaning of acceptability or acceptable levels of risk is a matter for the Panel, taking into account principles of ecological sustainable development, including the precautionary principle and intergenerational equity.

The Terms of Reference make it clear that the Panel must not only look at the impacts of hydraulic fracturing and the associated activities on economic conditions in the Northern Territory – the Panel must also consider the economic impacts of the onshore unconventional gas industry *as a whole* on the Northern Territory. This is made clear in the following extract from the Terms of Reference, which has been amended to include the relevant language only:

"*When the inquiry makes a determination… about whether or not there has been an impact or risk on … economic conditions, the inquiry will … consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry.*"

A.3 Steering Committee

A Steering Committee has been established to oversee the work. The Steering Committee is comprised of the Hon Justice Rachel Pepper, Dr Vaughan Beck and the Executive Director of the Hydraulic Fracturing Taskforce. The point of contact for all matters will be the Executive Director of the Hydraulic Fracturing Taskforce.

A.4 Probity Advisor

The Territory has appointed a Probity Advisor to oversee the Territory's processes in relation to the stages of this process. The Probity Advisor's role is to ensure that fairness and impartiality are observed throughout, and that the evaluation criteria stated in any related documentation are consistently applied to all submissions.

A.5 Scope of Work

The supplier must consider the following scenarios:

- **Scenario 1** or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place;
- **Scenario 2**, which involves the development of the onshore unconventional shale gas industry in the Northern Territory; and
- **Scenario 3**, which involves the development of unconventional shale gas reservoirs in the Beetaloo Sub-Basin only.

A.6 Benefits

The supplier must describe, in both quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with each of Scenarios 1, 2 and 3 on the Northern Territory economy under the current regulatory regime.[86]

The supplier must describe, in quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with Scenario 2 on the national economy under current regulatory, fiscal and economic settings.

For each of Scenarios 1, 2 and 3 the supplier must estimate the following:

- Gross State Product (**GSP**);
- State Final Demand (**SFD**);
- employment;
- business investment and output;
- CPI;
- population;
- wages; and
- the quantum of royalties that might be received by the Northern Territory Government under the *Petroleum Act 1984* (NT) (to avoid doubt this will include any royalties received in connection with both unconventional and conventional reservoirs).

The supplier must provide the Steering Committee with:

- in accordance with Part C, any assumptions made and an explanation of the methodology used to develop such assumptions, both of which must be approved by the Steering Committee prior to undertaking any economic modelling. The supplier must explain how reasonable and reliable the assumptions are, as well as how any potential bias has been managed, and
- a description of the similarities or differences between the assumptions made under item 7(a) above and the assumptions made in the report entitled *Economic Impact of Shale and Tight Gas Development in the NT* dated 14 July 2017 by Deloitte Access Economics.

The supplier must describe the options available to the Northern Territory Government, whether through policy or regulatory reforms or otherwise, to maximise and sustain the benefits captured by Territorians and others.[87] In this regard the supplier must:

- conduct a literature review to advise on leading practice methods for the sustainable development of onshore unconventional shale gas projects from an economic perspective, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and what lessons can be learned from these experiences in the Northern Territory context.

The supplier must describe the options available to the Northern Territory Government, including regulatory or policy reforms, for how revenue from the development of onshore unconventional shale industry can be retained both jointly and separately in the regions affected by the development and the Northern Territory, in each case, without impeding investment. Consideration must be given to:

- local procurement requirements, local training programs and other mechanisms to improve local capacity as well as any 'Royalty for Regions' or similar type programs, and
- case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and the lessons that can be learned for the Northern Territory context.

[86] Indirect benefits might include the opening up of supply chains for local businesses, innovation spin offs, opportunities to develop or support supply and maintenance industries and any other flow-on opportunities the supplier identifies.

[87] It is noted that onshore unconventional gas industry, local communities, local governments, Aboriginal stakeholders (including Aboriginal land councils and prescribed bodies corporate under the *Native Title Act 1993* (Cth)) have a significant role to play in the maximisation of economic benefits, however, the scope of the work is limited to actions that government can take.

A.7 Risks

The supplier must describe, in qualitative terms, any actual and potential adverse impacts and risks associated with Scenario 1, Scenario 2, and Scenario 3 on the Northern Territory economy under the current regulatory regime.

The supplier must consider the impacts of development on other industries in the Northern Territory, including, but without limitation, the tourism, agricultural, horticultural and pastoral, industries.

The supplier must describe the options available to the Northern Territory Government, including policy or regulatory reforms, to mitigate and manage any actual and potential impacts and risks identified above. For example, the supplier must advise what the Northern Territory Government can do to mitigate any "boom and bust" economic cycle associated with the development of any unconventional shale gas industry.

The supplier must:

- conduct a literature review to advise on leading practice methods that could be used to manage and mitigate any risks identified, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful, and what lessons can be learned from these experiences in the Northern Territory context.

A.8 Assumptions

No production licences have been granted under the Petroleum Act for the purpose of producing unconventional shale gas in the Northern Territory. Further exploration work, including the drilling of appraisal wells, is required to fully understand the scope of the Northern Territory's shale gas reservoirs and whether or not they are commercially recoverable.

The most prospective area for shale gas development, should the moratorium be lifted by the Government, is the Beetaloo Sub-Basin (see Attachment A). Origin Energy announced a significant discovery of unconventional shale gas in the Beetaloo Sub-Basin in February 2017, which significantly increased prior estimates of the resource.

In developing any assumptions required to undertake Part A and B, the supplier must consult with relevant stakeholders, including, but without limitation, the Departments of Treasury and Finance; Primary Industry and Resources; Trade, Business and Innovation; Chief Minister; NT Farmers; the Northern Territory Cattleman's Association; petroleum operators and titleholders in the Beetaloo Sub-Basin, Aboriginal Land Councils, and the Australian Petroleum Production and Exploration Association.

The supplier must notify the Steering Committee prior to any consultation and members of the Steering Committee may attend the consultation.

A.9 Timelines and Reporting

The work must be in the form of a written report. The report must be written in plain English. All technical terms (including economic metrics such as Gross State Product, State Final Demand, and employment multipliers) must be explained.

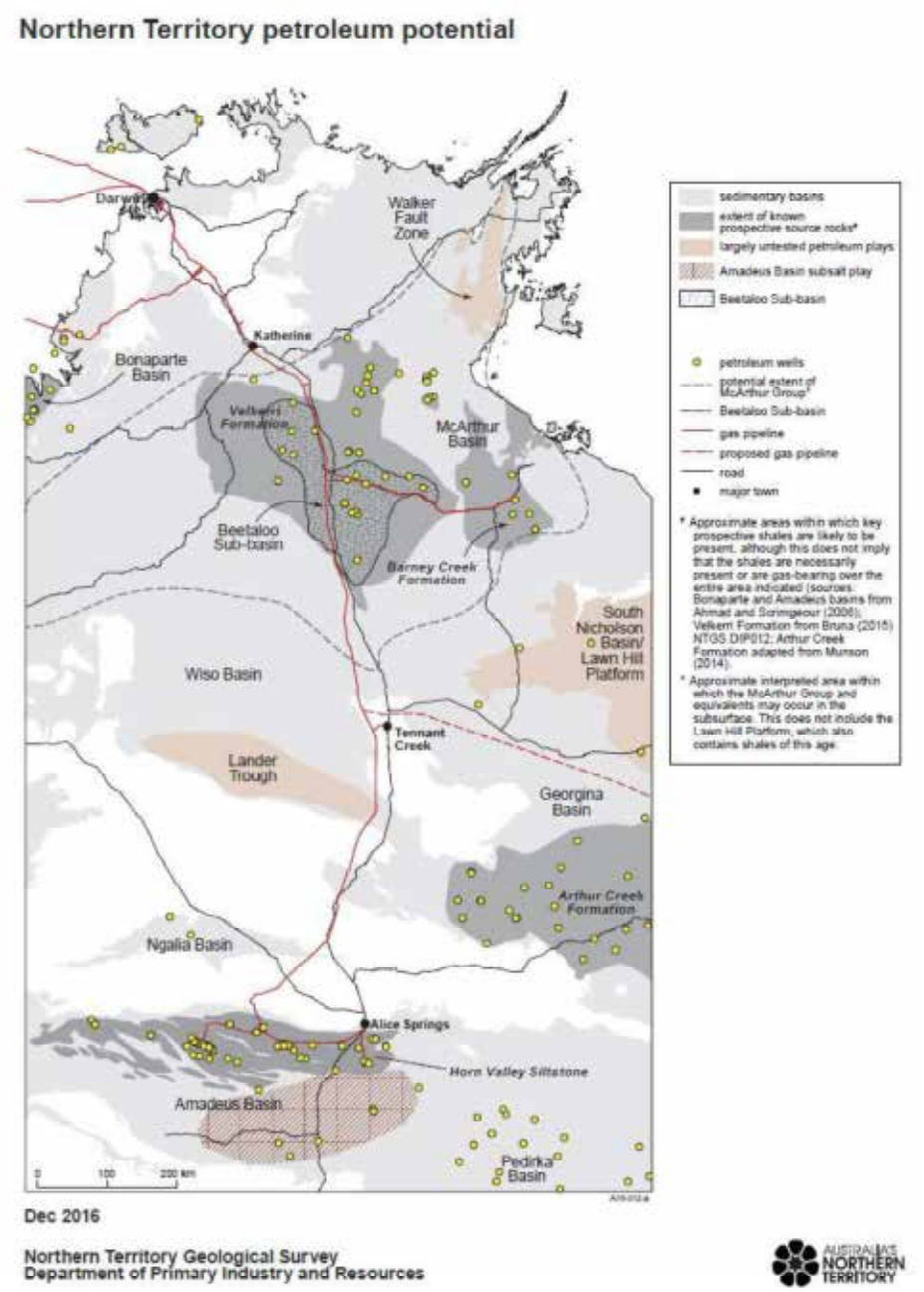
At the end of each calendar month following the award of the tender the supplier must provide the Steering Committee with a written progress report and a verbal presentation within five working days of receipt of the report.

The supplier must provide the Steering Committee with a draft final report and a verbal presentation to the Steering Committee on or prior to 18 August 2017.

A final report must be provided to the Steering Committee by 1 September 2017 and the supplier must present the final report to the Panel on a date to be determined.

The Inquiry will publish the final report on the Inquiry's website on a date to be determined.

The supplier must keep all correspondence, reports and presentations to the Steering Committee confidential, except that the supplier may make the final report publicly available after it has been published on the Inquiry's website.



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B

ACIL ALLEN CONSULTATION GUIDE

The below Consultation Guide was issued to all stakeholders consulted during ACIL Allen's initial round of stakeholder consultation in the Northern Territory in June 2017. It was used to guide conversations, and assist stakeholders to provide the most relevant information for ACIL Allen's scope of works.

Background

On 3 December 2016 the Northern Territory Government announced an independent Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (the 'Inquiry'). The Inquiry is investigating the environmental, social and economic risks and impacts of hydraulic fracturing ('fracking') of onshore unconventional gas reservoirs and associated activities in the Northern Territory.

This was the result of an election commitment made by the current Northern Territory Government while in opposition. On 14 September 2016, the Northern Territory Government announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs, including the use of hydraulic fracturing for exploration, testing, and extraction. The moratorium will remain in place during the Inquiry. The Northern Territory Government's terms of reference guide the conduct of the Inquiry. These are included in Box 14.5.

BOX 14.5 TERMS OF REFERENCE: SCIENTIFIC INQUIRY INTO HYDRAULIC FRACTURING IN THE NORTHERN TERRITORY

The terms of the Inquiry are to:

4. assess the scientific evidence to determine the nature and extent of the environmental impacts and risks, including the cumulative impacts and risks, associated with hydraulic fracturing of unconventional reservoirs and the Associated Activities in the Northern Territory;
5. advise on the nature of any knowledge gaps and additional work or research that is required to make the determination in Item 1, including a program for how such work or research should be prioritised and implemented, that includes (but is not limited to);
   a) baseline surface water and groundwater studies,
   b) baseline fugitive emissions data,
   c) geological and fault line mapping, and
   d) focus areas for baseline health impact assessment,

6. for every environmental risk and impact that is identified in Item 1, advise the level of environmental impact and risk that would be considered acceptable in the Northern Territory context;
7. for every environmental risk and impact that is identified in Item 1,
   a) describe methods, standards or strategies that can be used to reduce the impact or risk; and
   b) advise whether such methods, standards or strategies can effectively and efficiently reduce the impact or risk to the levels described in Item 3;
8. identify any scientific, technical, policy or regulatory requirements or resources that are in addition to the reforms being implemented through the existing environmental reform process that are necessary to reduce environmental risks and impacts associated with the hydraulic fracturing of unconventional reservoirs to acceptable levels; and
9. identify priority areas for no go zones.

SOURCE: HYDRAULIC FRACTURING TASKFORCE

Role of ACIL Allen

ACIL Allen Consulting has been appointed by the Inquiry to assess the actual and potential direct and indirect economic benefits, risks and impacts of fracking on the Northern Territory under the current regulatory regime.

To facilitate this, ACIL Allen's scope of works gives regard to three distinct scenarios:

6. Scenario 1, or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place (the 'base case')
7. Scenario 2, which involves the development of the onshore unconventional shale gas industry in the Northern Territory (the 'unconstrained case')
8. Scenario 3, which involves the development of unconventional shale gas reservoirs in the Beetaloo Sub-Basin only.

In order to do this, ACIL Allen will complete two main tasks:

— **Conduct economic impact assessment modelling, using ACIL Allen's suite of in-house economic models**, including models of the national gas and electricity markets. To complete this task, ACIL Allen will develop credible, evidenced-based scenarios for the development of shale gas projects in the Northern Territory under a set of assumptions which are agreed by the Inquiry. The outcome of this task will be quantitative economic impact assessment results under each of the three scenarios listed above.

— **Research, analyse, articulate and discuss the potential impacts on the Northern Territory economy's other industries**, including but not limited to tourism, agriculture, horticulture and pastoral. This will centre on findings of stakeholder consultation and a review of relevant international literature and case studies. The outcome of this task will be a chapter or chapters in the final report of this engagement that outlines the economic risks and provides suggestions on policy initiatives the Inquiry may recommend to the Northern Territory Government in the Inquiry report.

ACIL Allen is undertaking consultation with key stakeholders in order to inform these two main tasks.

Stakeholder consultation process

The Inquiry has identified your organisation as an interested stakeholder that may be able to assist ACIL Allen in delivering on our scope of works.

This consultation guide provides some basic background information on the Inquiry, and the issues that ACIL Allen is seeking input from participating stakeholders. In order to guide the meeting, ACIL Allen has developed a series of questions that the project team will be asking stakeholders at their scheduled meeting.

Following the initial contact, ACIL Allen may issue additional questions via email to request data or evidence to assist in completing the above tasks.

Please note: all stakeholder consultation will be recorded (via written notes) as evidence for the Inquiry. A member of ACIL Allen's project team will take notes during consultation, and these notes will be delivered to the Inquiry to assist in the formulation of project assumptions and other elements of the engagement as required. ACIL Allen has in place a confidentiality agreement as it relates to the Inquiry and any commercial-in-confidence material provided will be treated as such.

The Northern Territory economy

The Northern Territory economy is a regional economy, which generated $23 billion in Gross State Product (GSP) in 2015-16, accounting for 1.4 per cent of Australia's Gross Domestic Product (A$1.6 trillion). Northern Territory is an emerging economic centre, with average annual rates of growth in the economy exceeding five per cent per annum over the past five years (around double the rates of growth recorded in the national economy over the same period).

Economic growth in the Northern Territory is fairly volatile due to its small size and narrow economic base. As a result, major investments can have a disproportionately large impact on overall growth. The development of the Ichthys LNG Project is already having a substantial impact on the Northern Territory economy, which most recently recorded economic growth of 15.8 per cent in 2012-13 as investment activity accelerated. However, economic growth in the Northern Territory been more measured since, with the economy growing by 2.7 per cent in 2015-16.

The largest industries in the Northern Territory are construction (17.7 per cent of GSP), mining (12.9 per cent) and public administration and safety (10.3 per cent).

The working age population in the Northern Territory is 187,000, with 134,500 person employed as at June 2016. Employment growth in the Northern Territory has been strong for a number of years, with the jobs market only recently contracting in line with a downturn in the resources sector.

Jobs growth in the Northern Territory is heavily influenced by major resource projects, with employment growth at its strongest during the construction of key projects in the Territory, with the falling levels of employment coming as the construction phase is completed.

The estimated residential population in the Northern Territory (as at June 2015) was just under 245,000, with 58 per cent of the population concentrated around the greater Darwin area. Since 2010, the estimated residential population of the Northern Territory has increased by 6 per cent, with greater Darwin growing by 11 per cent and all areas outside of greater Darwin remaining relatively unchanged (less than a 1 per cent increase).

The Northern Territory's 2017-18 Budget, released on in May 2017, projects five consecutive net operating deficits for the Territory Government, with net debt rising from $2.4 billion to $5.5 billion between 2016-17 and 2020-21. The Northern Territory non-financial public sector raised $1.9 billion in revenue from its own sources in 2016-17, and recorded total operating expenditure of $6.5 billion. The Government relies on Commonwealth Government grants to fund a large proportion of its operations.

Fracking

For the purposes of this engagement, ACIL Allen has relied upon background materials produced by the Inquiry and published on its website (www.frackinginquiry.nt.gov.au/information). A brief introduction to fracking, adapted from this information, is included below.

What is fracking?

There are two broad types of gas reserves: conventional and unconventional. Conventional gas reserves accumulate in confined areas with well-connected pore spaces in a sedimentary basin. This allows for effective drainage of reserves with well-placed vertical wells. By contrast, unconventional gas reserves accumulate in a larger area amongst more tightly bound and less porous sedimentary basins, which are typically lower in the ground. A visual representation of conventional and unconventional gas accumulations and some of the extraction techniques is provided in Figure 3.1 (overleaf).

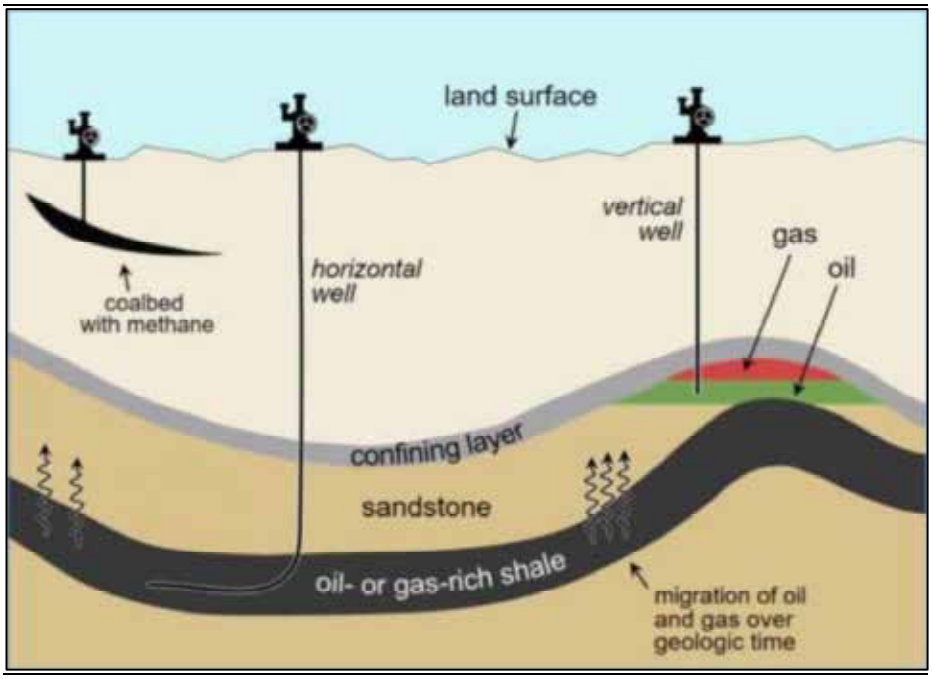
Artificial stimulation is typically required to make the gas in unconventional reservoirs flow through a well. One commonly used technique to achieve this is called hydraulic fracturing, commonly known as 'fracking'. Fracking basically involves pumping a mixture of water, sand and chemical additives ('fracking fluid') into the production well, under pressure, so that the rocks containing the gas resources crack. This allows the gas contained in the tight reservoir to flow more freely.

Shale gas versus coal seam gas (CSG)

Fracking is used to extract both coal seam gas (CSG) and shale gas. The two types of resources differ significantly.

- CSG is typically extracted from wells that are much closer to the land surface (300m – 1,000m) than shale wells (1,500m – 4,000m)
- CSG is typically much closer to the surface, and therefore closer to potable water sources such as aquifers. Shale gas is not typically located near aquifers
- CSG is most often extracted using vertical wells, while shale gas is extracted using a combination of vertical and horizontal drilling techniques
- CSG wells are typically low productivity and require a larger number of wells, where shale gas wells produce more energy per well. However, shale wells use more water per well, and operate across a larger underground footprint.
- The land surface area of CSG wells and shale gas wells is largely the same.

FIGURE 14.1 DIFFERENT TYPES OF PETROLEUM ACCUMULATIONS AND DEVELOPMENT



SOURCE: THE INQUIRY, VIA U.S. ENVIRONMENTAL PROTECTION AGENCY.

The fracking process

Shale gas is mainly methane (often with associated liquid hydrocarbons) that is trapped within clay-rich sedimentary rock at depths greater than 1,500 metres. The low permeability of the rock means that gas, either absorbed or in a free state, in the pores of the rock, is unable to flow easily.

To extract shale gas, wells are drilled anywhere from 1,500 – 4,000 metres deep through various layers of rock to access the shale. The wells are lined with various steel casings, which are cemented using fit-for-purpose cement designed to protect groundwater from contamination.

To maximise shale gas recovery a technique called horizontal drilling is used. This technique typically involves the well changing from a vertical to a horizontal direction deep underground.

Before gas can be extracted from the shale gas reservoir, hydraulic fracturing must occur. Hydraulic fracturing is a technique used to enhance the production of the gas. Hydraulic fracturing refers to the injection of fluid (comprising approximately 99.5% water and proppant (sand) and approximately 0.5% chemical additives) at high pressure into targeted sections of the layers of gas-bearing rocks. This creates localised networks of fractures that unlock gas and allow it to flow into the well and up to the surface. An average of 20 to 30 megalitres (ML) of water is used per fracked horizontal well over the life of the well.

After fracturing, the hydraulic pressure is released and most of the 'frack fluid' is pumped back out of the well. Typically gas production from the well builds up over a period of days or weeks as the frack fluid is recovered (a process known as 'well clean-up'). Much of the sand remains in the well, propping open the cracks so that gas flow is maintained (hence 'proppant').

Basically similar processes can be used to enhance gas production rates in vertical or horizontal wells in other tight reservoirs (both unconventional and conventional).

** Is there any additional information relevant to an economic impact assessment that ACIL Allen Consulting should consider regarding the process of drilling, fracking, and related activities required to produce shale gas?*

The investment and operating expenditure profile of a shale gas project differs significantly from a more conventional gas project, which the Northern Territory has had recent experience with in the form of the INPEX's Ichthys LNG project. A typical fracking project has a smaller upfront capital component than a conventional gas project, but may have larger ongoing capital costs associated with management and maintenance of a given level of production through development of additional wells.

** To your knowledge, is this assumption regarding the capital and operating expenditure profile of a fracking operation versus a conventional gas project correct?*

** Do you have any information or evidence you can provide ACIL Allen regarding the capital and operating expenditure profile of a hypothetical or actual fracking operation in Australia?*

Fracking in the Northern Territory

ACIL Allen is required to develop realistic, evidence-based scenarios for shale gas developments in the Northern Territory over a defined period of time. There are two development scenarios: the moratorium on activities is lifted in the Beetaloo Basin only, and the moratorium on activities in lifted across the entirety of the Northern Territory. In order to develop these scenarios, we require information on shale gas reserves and resources in the Northern Territory.

We understand from information provided to us by the Inquiry and from our initial research that the Beetaloo Basin hosts a highly prospective and large scale (one company has raised the spectre of 6.6 trillion cubic feet of resource in its license area alone) contingent gas resource. By way of contrast, the Pluto LNG project was approved on the basis of a 4.4 trillion cubic feet contingent resource. One of the scenarios ACIL Allen is required to model is the development of the Beetaloo Basin.

** Do you have any information regarding the Beetaloo Basin and its prospectivity that you can share with us to assist us in developing our modelling assumptions?*

ACIL Allen is also required to develop an estimate of the economic impact of the removal of a moratorium on activities across the whole land area of the Northern Territory. The information on the impact of this is largely unknown, as we understand there has been limited shale gas exploration activity outside of the Beetaloo Basin

** Do you consider there is potential for the discovery and development of shale gas reserves outside of the Beetaloo Basin in the Northern Territory? Why or why not?*

Is there any information about the prospectivity of shale gas outside of the Beetaloo Basin that you are able to share with ACIL Allen Consulting?

If the moratorium was lifted across the Northern Territory, are there any areas that should remain "off limits"? If so, which areas and why? If not, why not?

There are significant land holdings in the Northern Territory which are subject to long term pastoral leases, are held under native title, or both.

How would you expect a lift of the moratorium to interact with land ownership in the Northern Territory? Is it reasonable to assume as a starting point that persons or groups which hold land under pastoral lease or native title will not allow development on their land holdings, a view ACIL Allen has formed in a preliminary review of submissions made to the Inquiry?

Any potential shale gas produced from wells in the Northern Territory will require additional processing and transport to reach its end destination – be that consumption in the Northern Territory, consumption in other States, or export. This requires infrastructure over and above the development of fracking wells by project proponents.

What current infrastructure does the Northern Territory have in place to support the processing and transport of shale gas produced?

What infrastructure do you believe would be required to support the processing and transport of shale gas produced in the Northern Territory?

ACIL Allen's understanding is that shale gas operations require specialist skills from a labour perspective. It is considered unlikely that those skills exist in the Northern Territory today.

Does the Northern Territory labour market have enough capacity to absorb a potential increase in labour demand from the development of a shale gas industry? Why or why not?

There are many options for the ultimate use of shale gas produced in the Northern Territory. ACIL Allen's scope of works requires it to consider benefits, impacts and risks to the Northern Territory economy, however this will also involve consideration and analysis of the potential end use of production outside of the Northern Territory.

What are the options for consumption of shale gas produced in the Northern Territory? Where do you think shale gas produced in the Northern Territory would ultimately be consumed? Why?

Potential economic benefits of fracking to the Northern Territory economy

There are a range of potential economic benefits of shale gas production to the Northern Territory. ACIL Allen's economic model assumes there are flow on benefits to industries that supply an industry which growth disproportionately to others, via the supply of services or a reduction the cost base for those industries.

ACIL Allen wishes to hear from you what you consider to be the five most significant channels of **economic benefits** to the Northern Territory, and why.

In your view, what are the key benefits that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities in the Beetaloo basin only?

In your view, what are the key benefits that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities across the Northern Territory?

Potential economic risks of fracking to the Northern Territory economy

There are a range of potential economic risks/costs of shale gas production to the Northern Territory. ACIL Allen's economic model assumes a degree of "crowding out" occurs when a one industry grows disproportionately to others.

ACIL Allen wishes to hear from you what you consider to be the five most significant channels of **economic risks** (costs) to the Northern Territory, and why.

In your view, what are the risks (costs) that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities in the Beetaloo Basin only?

In your view, what are the risks (costs) that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities across the Northern Territory?

Potential economic policy implications of fracking in the Northern Territory

Development of fracking in the Northern Territory is likely to entail some policy challenges for the Northern Territory government. The Inquiry has requested ACIL Allen examine these, using international case studies, best practice, stakeholder views, and our firm's internal expertise in policy development, to provide some initial guidance on the policy issues and challenges that are likely to arise in the case that the moratorium on activities is lifted.

ACIL Allen is required to consider this within the context of the current regulatory regime – that is, we must discuss policy challenges within the constraints of current policies and regulations, and make suggestions to address these.

The Inquiry is cognisant of the potential for "boom-bust" cycles given the Northern Territory's recent experience with the Ichthys LNG Project, and extensive literature associated with resources industry development.

These policy issues and challenges are wide-ranging, and include:

- Human capital (labour supply, education and training, apprenticeships)
- Infrastructure (specific to fracking like pipelines, but also supporting infrastructure like roads)
- Government finances (royalties, expenditure demands)
- Local content ("Buy Local" policy)
- Land access regimes and environmental approvals

Do you have any insights on the potential policy issues which may arise in the Northern Territory in the case that the moratorium on activities is lifted?

Which policy issue(s) do you believe have the potential to create the most risk to the Northern Territory economy? Why?

Other issues

Are there any other issues you wish to raise with us related to our scope of works?

Are there any other costs, benefits or risks associated with each scenario that you would you like to raise?

About ACIL Allen

ACIL Allen Consulting is the largest independent economics and public policy consulting firm in Australia, with a specialisation in economics, policy and strategy advice. With over 60 consultants across five

offices, we have an established reputation for providing sound and independent advice on economic, public policy and organisational issues for all levels of government and business. We have experience in conducting projects that involve policy, program and funding evaluations, analysis of data, development of policy options, extensive stakeholder consultations, and the preparation of clear and concise reports.

Further Enquiries

If you have any questions in relation to the Inquiry, the role of ACIL Allen, and the consultation process that is being undertaken, please contact:

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C GASMARK MODELLING RESULTS

In this Appendix we set out the results of the modelling of the market effects of different Northern Territory shale gas development scenarios using ACIL Allen's GasMark® model of the eastern Australian and Northern Territory gas market. First, we summarise the gas production capacity and ex-field pricing assumptions under the three Northern Territory shale gas development scenarios (BREEZE: 100 TJ/d target market; WIND: 400 TJ/d target market; GALE: 1,000 TJ/d target market), and explain how the 'optimal' ex-field pricing assumptions were determined. We then present key modelling results for each of the three shale gas development scenarios in turn. For each scenario we present the modelling results for:

- modelled production performance of the Northern Territory, including total market penetration over time relative to the assumed level of shale gas production capacity and levels of gas exports from NT to eastern Australia
- levels of gas consumption in the eastern Australian and NT domestic markets, and incremental effects on domestic consumption compared to the Reference Case (no Northern Territory shale gas)
- levels of LNG production in the Northern Territory and Queensland, and incremental LNG production compared to the Reference Case
- wholesale delivered gas prices in Queensland, New South Wales, Victoria and South Australia, and the incremental effects on gas prices compared to the Reference Case.

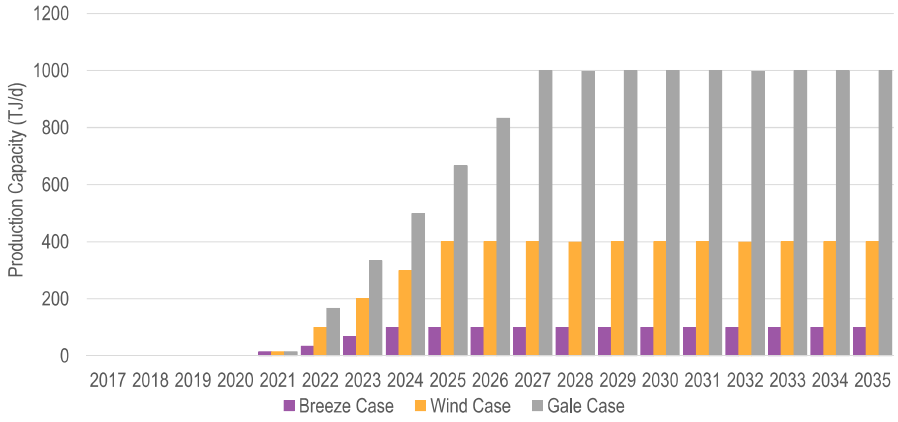
C.1 Northern Territory shale gas production and pricing assumptions

The three Northern Territory shale gas development scenarios each adopt different assumptions about the levels of shale gas production capacity that are offered into the market. The production capacity ramp-up profiles for the three cases are summarised in Figure C.1.

However, the fact that production capacity is made available or 'offered to the market' does not guarantee that all of that capacity will be taken up. If the price at which the shale gas can be offered to the market is too high, then some or all of the production capacity will remain idle. Gas users will either obtain supply from another, more competitively-prices supply source, or if this is not possible, will forego consumption because they cannot afford to buy gas at the price offered. All else being equal, it would be reasonable to expect that as the shale gas prices required to justify commercial production from the Northern Territory increase, the quantity of gas actually taken up in the market will decrease.

For the purposes of this analysis, 'optimal' ex-field pricing assumptions for each scenario were determined by using the *GasMark* model to test the volumes of gas sold across a range of ex-field pricing assumptions. Generally speaking, the volumes of gas sold fall as prices rise. Multiplying the volumes of gas sold by the price at which the gas is offered into the market allows calculation of annual gas sales revenue. The 'optimal' price path for each scenario is then the price path that

FIGURE C.1 AVAILABLE SHALE GAS PRODUCTION CAPACITY FOR THE THREE NORTHERN TERRITORY SHALE GAS DEVELOPMENT SCENARIOS



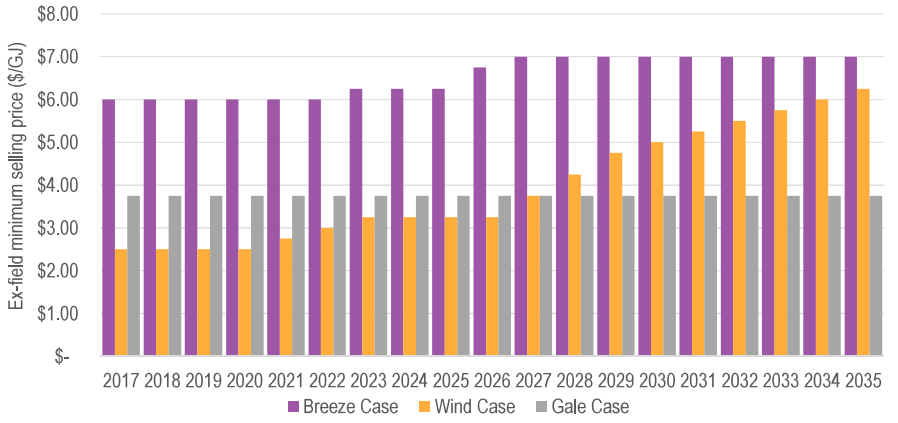
SOURCE: ACIL ALLEN GASMARK MODELLING

maximises the net present value (NPV) of modelled revenues over time. We have used a discount rate of 15 per cent (pre-tax) to calculate the NPV of revenues.

The 'optimal' prices effectively represent the maximum (capital inclusive) average cost of shale gas production that will need to be achieved if the Northern Territory producers are to earn a commercial rate of return on the targeted volumes of gas sales. If the producers are able to produce gas at a cost lower than the 'optimal' prices, they will be able to achieve rates of return above the minimum commercial threshold.

In these circumstances, producers would have no incentive to offer gas for sale at lower prices reflecting their long-run marginal costs of production because the modelling shows that they would not achieve a large enough increase in sales volumes to offset the reduction in revenue per unit of gas sold. The 'optimised ex-plant gas price assumptions for the three scenarios are shown in Figure C.2.

FIGURE C.2 'OPTIMAL' EX-PLANT PRICE ASSUMPTIONS FOR THE THREE NORTHERN TERRITORY SHALE GAS DEVELOPMENT SCENARIOS



SOURCE: ACIL ALLEN GASMARK MODELLING

C.2 Modelling results: BREEZE Case

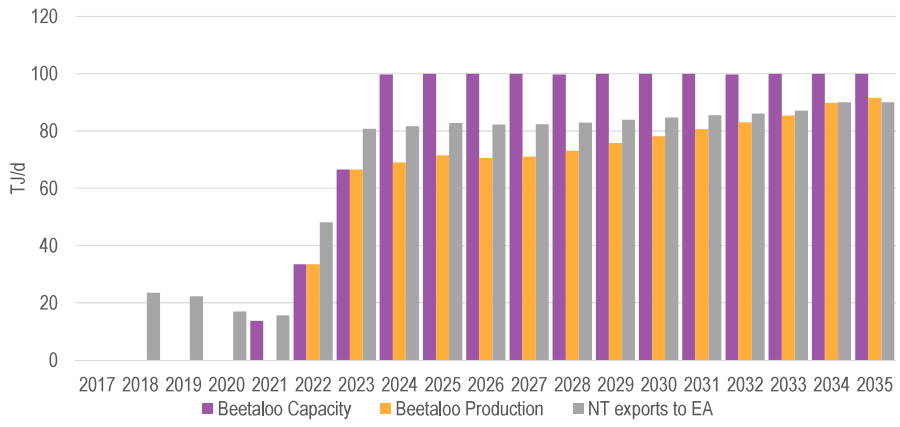
C.2.1 Northern Territory Shale Gas production performance: BREEZE Case

Figure C.3 shows the Northern Territory Shale Gas production performance under the BREEZE Case (100 TJ/d nominal production capacity). Capacity is assumed to ramp up from 2021, reaching the full 100 TJ/d nominal capacity by 2024. Actual levels of shale gas production taken up in the market increase from around 35 TJ/d in 2022 to a maximum of 92 TJ/d by the end of the modelling period.

Under the optimal pricing assumptions, the full 100 TJ/d of production capacity is not utilised during the modelling period to 2035. Higher rates of production could be achieved by discounting ex-field selling prices, but this would result in a reduction in the overall NPV of sales revenues.

Initially the total gas exports to eastern Australia (via the Jemena Northern Gas Pipeline, 'NGP') are significantly higher than the amount of Northern Territory shale gas being produced. This reflects the contribution to EA exports from Blacktip gas under the existing arrangements with PowerWater. However, the proportion of Northern Territory shale gas in exports increases over time, and by 2034 the volume of Northern Territory shale gas production reaches 90 TJ/d, equal to the assumed capacity of the NGP. Once the NGP capacity is reached, incremental production of Northern Territory shale gas is supplied into the NT market.

FIGURE C.3 NORTHERN TERRITORY SHALE GAS PRODUCTION PERFORMANCE: BREEZE CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)

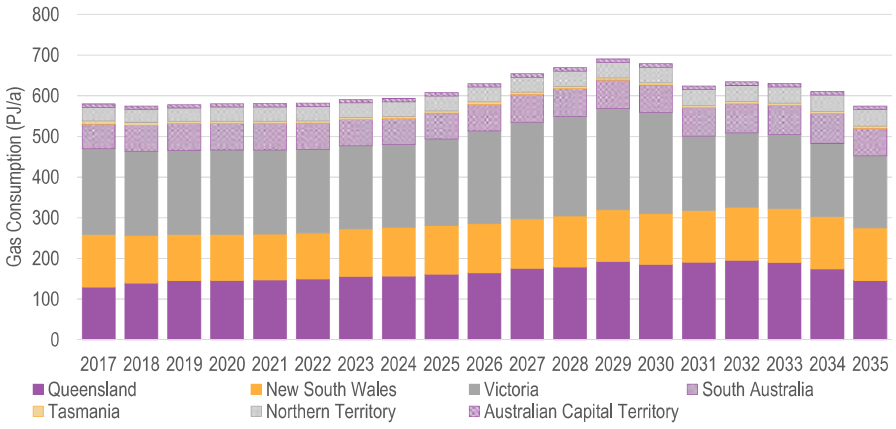


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.2.2 Consumption volume effects: BREEZE Case

Figure C.4 shows the modelled levels of domestic gas consumption, by State/Territory, under the BREEZE Case assumptions. Domestic consumption recovers from current levels to reach almost 700 PJ/a by 2029, but then falls to less than 600 PJ/a by the end of the modelling period as a result of constrained gas supply, with new sources of supply unable to fully replace current production as reserves are depleted.

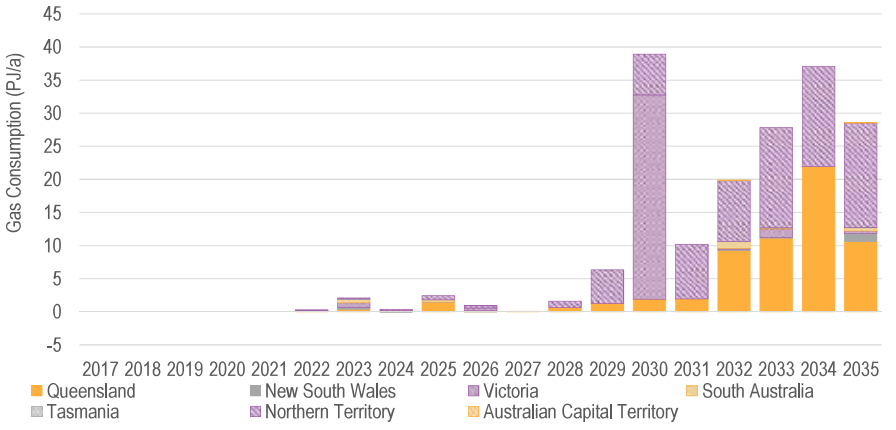
FIGURE C.4 BREEZE CASE: GAS CONSUMPTION



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.5 shows the incremental levels of gas consumption in eastern Australia and the Northern Territory under the BREEZE Case assumptions, when compared to the Reference Case (without Northern Territory shale gas production). As shown, there is little incremental effect on consumption until 2029. Prior to that time, the NT gas exports to eastern Australia (Figure C.3 refers) are effectively substituting for high-cost local supply sources. However, from 2029 on total consumption levels increase relative to the Reference Case as the increased levels of overall gas supply reduce the amount of 'demand destruction' as the supply position from non-shale sources in both the Northern Territory and eastern Australia tightens. In most years, the largest consumption effects are felt in the Northern Territory and Queensland, but there is one year (2029) in which Victorian consumption is also given significant (indirect) support as a result of the introduction of NT shale gas into the eastern Australian market.

FIGURE C.5 BREEZE CASE: GAS CONSUMPTION DIFFERENTIAL FROM REFERENCE CASE

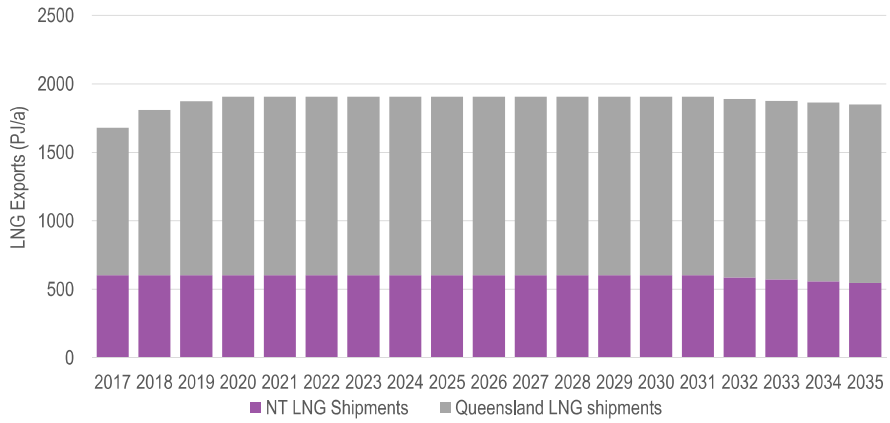


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.6 shows the total levels of LNG exports from eastern Australia (NT shipments: Darwin LNG and INPEX Ichthys LNG; Queensland shipments: Gladstone LNG, Australia Pacific LNG, Queensland Curtis LNG) under the BREEZE Case assumptions. Compared to the Reference Case (no Northern Territory

shale gas production) there is no change in LNG shipments from NT or Queensland under the BREEZE Case.

FIGURE C.6 LNG SHIPMENTS: BREEZE CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)



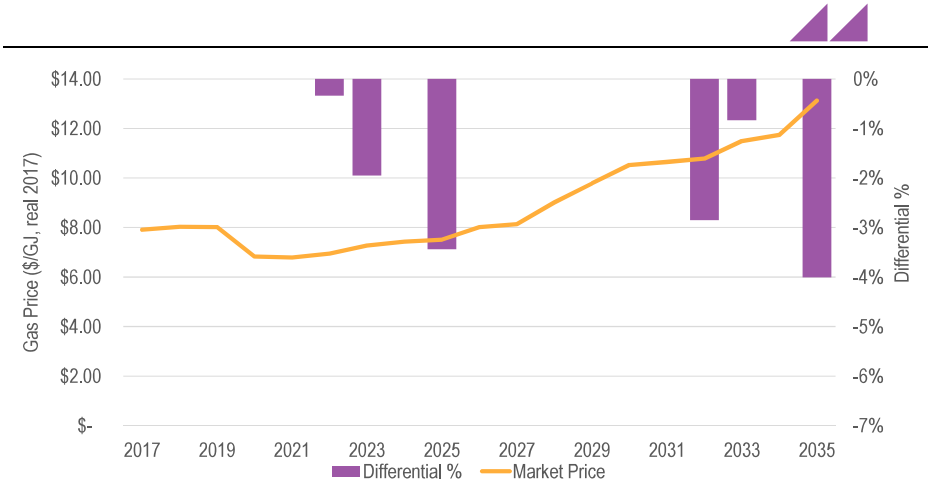
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.2.3 Eastern Australia price effects: BREEZE Case

The increase in gas supply to eastern Australian as a result of imports of Northern Territory shale gas under the BREEZE Case assumptions results in modest, intermittent downward pressure on wholesale delivered gas prices.

Figure C.7 shows the market price at Brisbane, and the per cent price differentials from the Reference Case, under the BREEZE Case assumptions. The price effects tend to occur toward the end of the modelling period although in Queensland there are also some significant effects (up to 4 per cent reduction in price) over the period 2022 to 2025.

FIGURE C.7 BREEZE CASE: DELIVERED WHOLESALE GAS PRICES AT BRISBANE

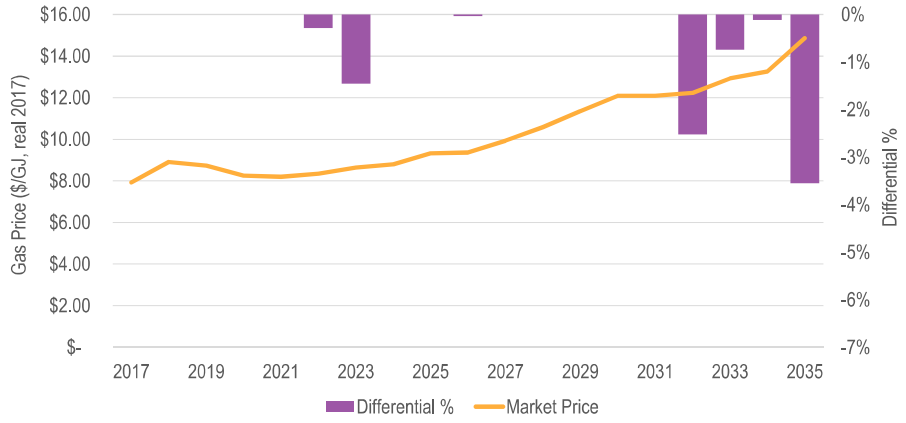


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.8 shows the corresponding price effects in New South Wales (Sydney). Total price levels are higher in Sydney than in Brisbane (because of the added transport costs). When compared to the

Reference Case results, the early differential price impacts (2022 to 2025) are less apparent than in Queensland, but the patterns of price movement toward the end of the modelling period (2032 on) are generally similar. Levels of downward movement in gas price are somewhat lower (in percentage terms) in Sydney than in Brisbane, reflecting the increased distance from the incremental source of supply.

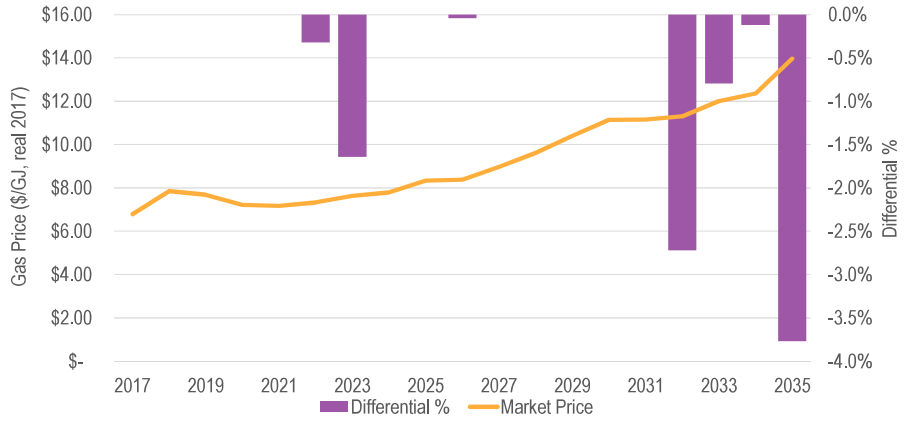
FIGURE C.8 BREEZE CASE: DELIVERED WHOLESALE GAS PRICE AT SYDNEY



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.9 shows the corresponding results for wholesale gas prices at Melbourne. Total price levels are lower than for Sydney, because of Melbourne's proximity to the major production sources in Bass Strait. In terms of differential price effects compared to the Reference Case, the results for Melbourne are very similar to Sydney.

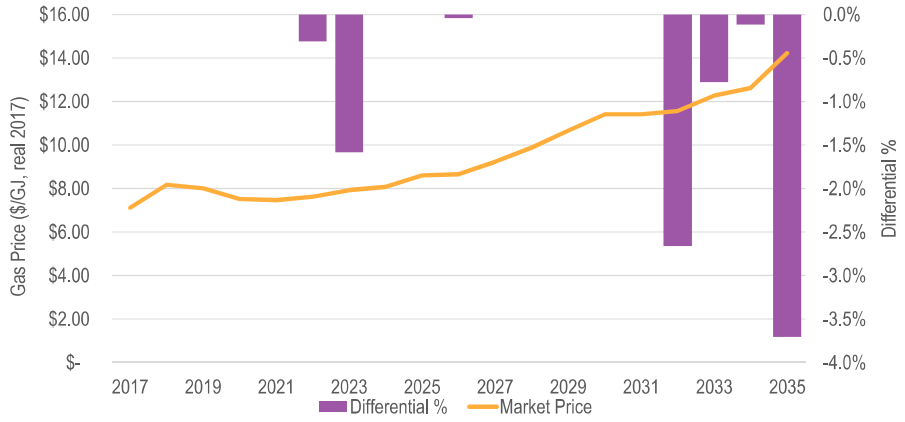
FIGURE C.9 BREEZE CASE: DELIVERED WHOLESALE GAS PRICE AT MELBOURNE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.10 shows the corresponding results for wholesale gas prices at Adelaide. Total price levels are slightly higher than for Melbourne, but show a similar pattern of movement. In terms of differential price effects compared to the Reference Case, the results for Adelaide are very similar to both Melbourne and Sydney.

FIGURE C.10 BREEZE CASE: DELIVERED WHOLESALE GAS PRICE AT ADELAIDE



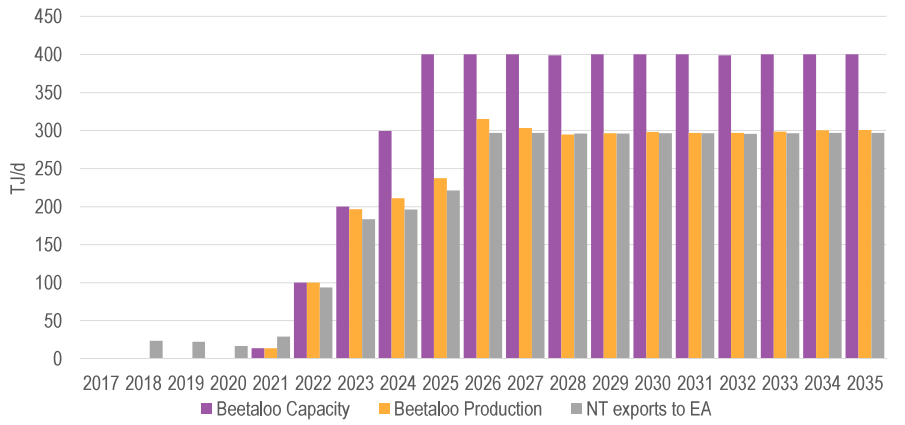
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.3 Modelling results: WIND Case

C.3.1 Northern Territory Shale Gas production performance: WIND Case

Figure C.11 shows the Northern Territory Shale Gas production performance under the WIND Case (400 TJ/d nominal production capacity). Capacity is assumed to ramp up from 2021, reaching the full 400 TJ/d nominal capacity by 2025. Actual levels of shale gas production taken up in the market increase from 100 TJ/d in 2022 to a maximum of 315 TJ/d by 2026, then fall slightly to plateau at around 300 TJ/d through to the end of the modelling period. Under the optimal pricing assumptions, the full 400 TJ/d of production capacity is not utilised during the modelling period to 2035. Higher rates of production could be achieved by discounting ex-field selling prices, but again this would result in a reduction in the overall NPV of sales revenues. Initially the total gas exports to eastern Australia (via the Jemena Northern Gas Pipeline, 'NGP') are significantly below the amount of Northern Territory shale gas being produced, which indicates that some of the Northern Territory gas production is taken up in the Northern Territory. By 2028, the quantities of Northern Territory shale gas closely match the total volume of exports to eastern Australia.

FIGURE C.11 NORTHERN TERRITORY SHALE GAS PRODUCTION PERFORMANCE: WIND CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)

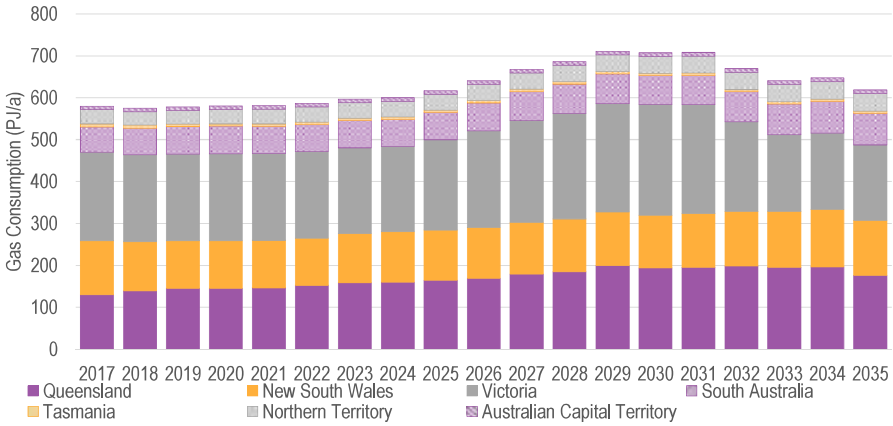


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.3.2 Consumption volume effects: WIND Case

Figure C.12 shows the modelled levels of domestic gas consumption, by State/Territory, under the WIND Case assumptions. Domestic consumption recovers from current levels to peak at a little over 700 PJ/a by 2029, but then falls to around 615 PJ/a by the end of the modelling period as a result of constrained gas supply, with new sources of supply unable to fully replace current production as reserves are depleted.

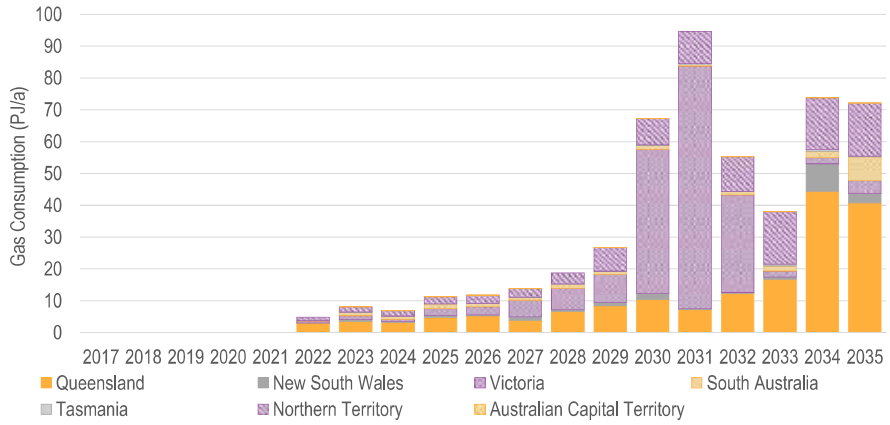
FIGURE C.12 WIND CASE: GAS CONSUMPTION



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.13 shows the incremental levels of gas consumption in eastern Australia and the Northern Territory under the WIND Case assumptions, compared to the Reference Case. The levels of incremental consumption rise slowly over the period 2022 to 2029. During this period, the NT gas exports to eastern Australia (Figure C.11 refers) are largely substituting for high-cost local supply sources. However, from 2030 on total consumption levels increase sharply relative to the Reference Case as the increased levels of overall gas supply reduce the amount of 'demand destruction' as the supply position from non-shale sources in both the Northern Territory and eastern Australia tightens. The largest consumption effects are felt in the Queensland, Victoria and the Northern Territory. Victorian consumption is impacted not as a result of physical supply from the Northern Territory but because NT supply reduces the levels of gas exported from Victoria to interstate markets – particularly New South Wales.

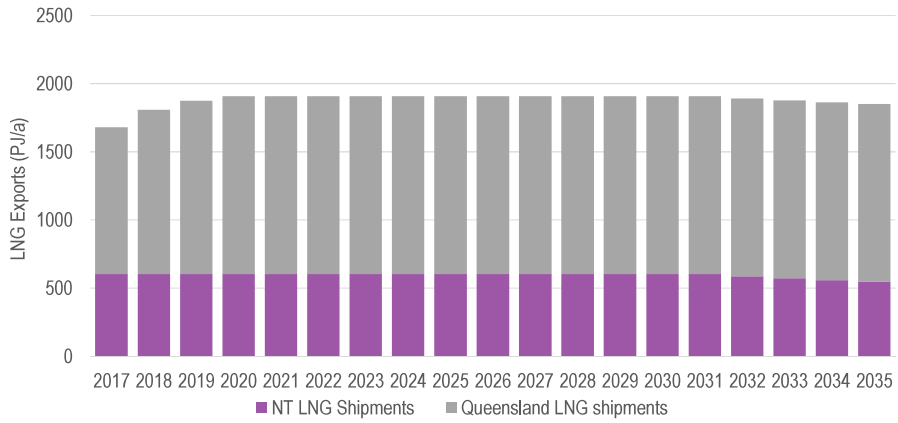
FIGURE C.13 WIND CASE: GAS CONSUMPTION DIFFERENTIAL FROM REFERENCE CASE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.14 shows the total levels of LNG exports from eastern Australia (NT shipments: Darwin LNG and INPEX Ichthys LNG; Queensland shipments: Gladstone LNG, Australia Pacific LNG, Queensland Curtis LNG) under the WIND Case assumptions. Compared to the Reference Case (no Northern Territory shale gas production) there is no change in LNG shipments from NT or Queensland under the WIND Case.

FIGURE C.14 LNG SHIPMENTS: WIND CASE (400 TJ/D NOMINAL PRODUCTION CAPACITY)



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

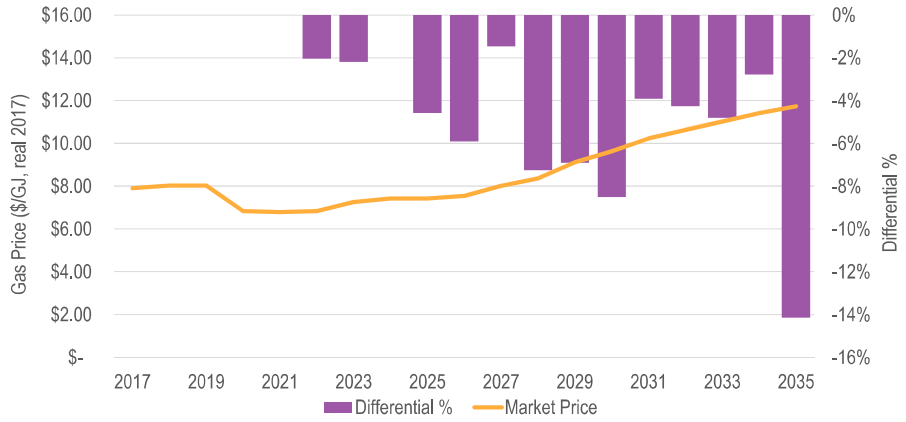
C.3.3 Eastern Australia price effects: WIND Case

The increase in gas supply to eastern Australian as a result of imports of Northern Territory shale gas under the WIND Case assumptions results in significant and sustained downward pressure on wholesale delivered gas prices. The level of price reductions tends to increase over time as more NT gas is taken up in the eastern Australian domestic market.

Figure C.15 shows the market price at Brisbane, and the per cent price differentials from the Reference Case, under the WIND Case assumptions. The price effects tend to increase across the modelling period, averaging 5 per cent over the period 2022 to 2035, and reaching 14 per cent by the end of the modelling

period. The price effects come about principally as a result of the additional supply volumes which reduce the number of periods through the year when supply becomes very tight and prices are bid up to high levels.

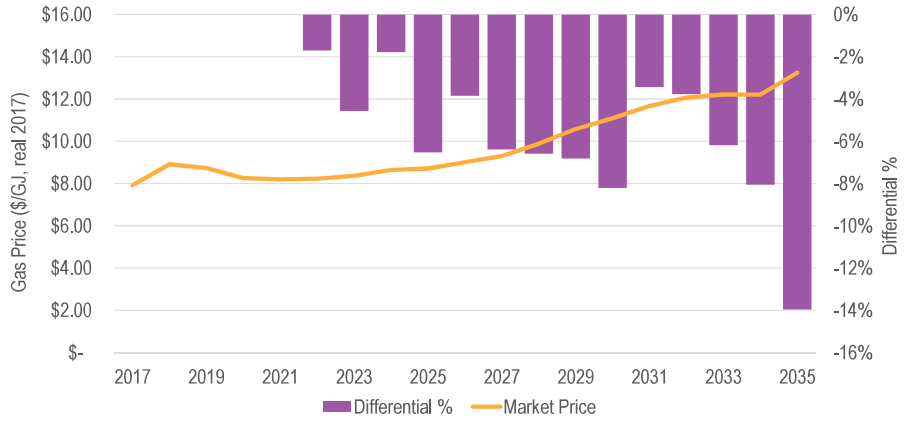
FIGURE C.15 WIND CASE: DELIVERED WHOLESALE GAS PRICES AT BRISBANE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.16 shows the corresponding price effects in New South Wales (Sydney). Total price levels are higher in Sydney than in Brisbane (because of the added transport costs). When compared to the Reference Case results, the patterns of price movement are generally similar to those observed in Queensland. The price effects tend to increase across the modelling period, averaging 6 per cent over the period 2022 to 2035, and reaching 14 per cent by the end of the modelling period.

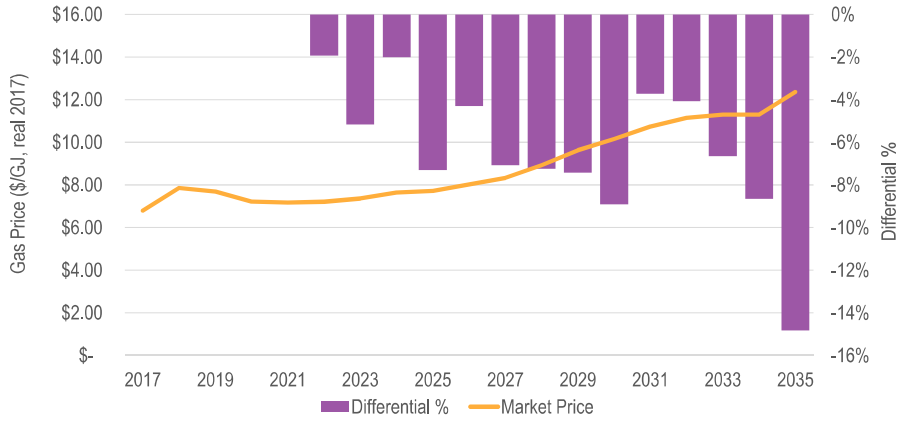
FIGURE C.16 WIND CASE: DELIVERED WHOLESALE GAS PRICE AT SYDNEY



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.17 shows the corresponding results for wholesale gas prices at Melbourne. Total price levels are lower than for Sydney, because of Melbourne's proximity to the major production sources in Bass Strait. In terms of differential price effects compared to the Reference Case, the results for Melbourne are very similar to Sydney.

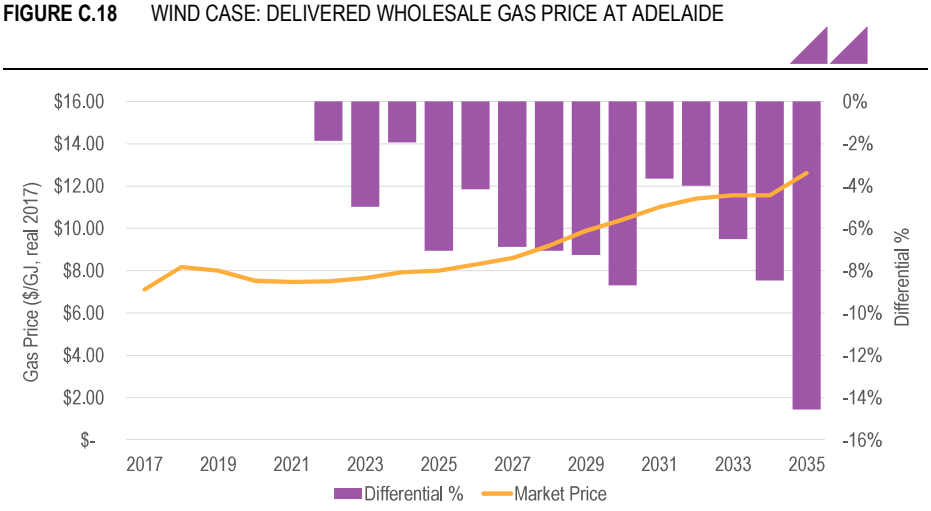
FIGURE C.17 WIND CASE: DELIVERED WHOLESALE GAS PRICE AT MELBOURNE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.18 shows the corresponding results for wholesale gas prices at Adelaide. Total price levels are slightly higher than for Melbourne, but show a similar pattern of movement. In terms of differential price effects compared to the Reference Case, the results for Adelaide are very similar to both Melbourne and Sydney.

FIGURE C.18 WIND CASE: DELIVERED WHOLESALE GAS PRICE AT ADELAIDE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

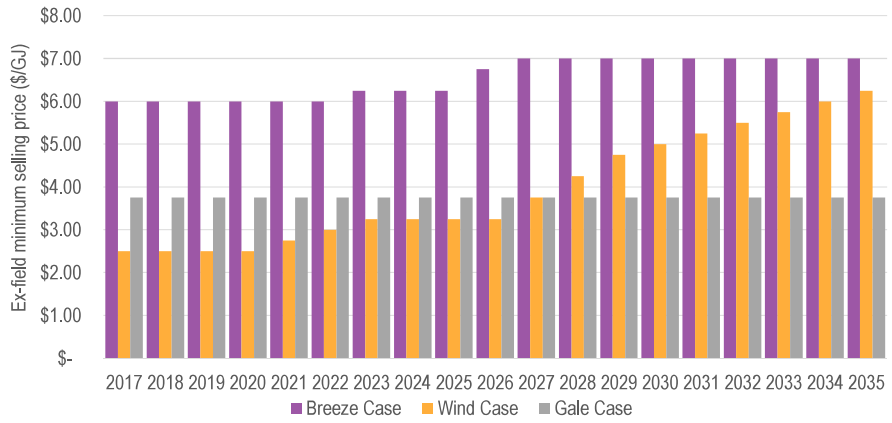
C.4 Modelling results: GALE Case

C.4.1 Northern Territory Shale Gas production performance: GALE Case

Figure C.19 shows the Northern Territory Shale Gas production performance under the GALE Case (1,000 TJ/d nominal production capacity). Capacity is assumed to ramp up from 2021, reaching the full 1,000 TJ/d nominal capacity by 2027. Pipeline capacity augmentation allows delivery of gas to Darwin LNG as well as expanded supply to eastern Australia. Actual levels of shale gas production taken up in the market increase from 400 TJ/d in 2025 to 800 TJ/d by 2027, then continues to climb steadily. Under

the optimal pricing assumptions, the full 1,000 TJ/d of production capacity is not utilised until 2034. Higher rates of production could be achieved earlier by discounting ex-field selling prices, but as for the previous cases this would result in a reduction in the overall NPV of sales revenues. From 2025 on, total gas exports to eastern Australia (via the Jemena Northern Gas Pipeline, 'NGP') are significantly below the amount of Northern Territory shale gas being produced, which indicates that a substantial amount of the Northern Territory gas production is taken up in the Northern Territory. By the end of the modelling period, the quantities of Northern Territory shale gas being produced exceed the total volume of exports to eastern Australia by some 315 TJ/d.

FIGURE C.19 NORTHERN TERRITORY SHALE GAS PRODUCTION PERFORMANCE: GALE CASE (1000 TJ/D NOMINAL PRODUCTION CAPACITY)

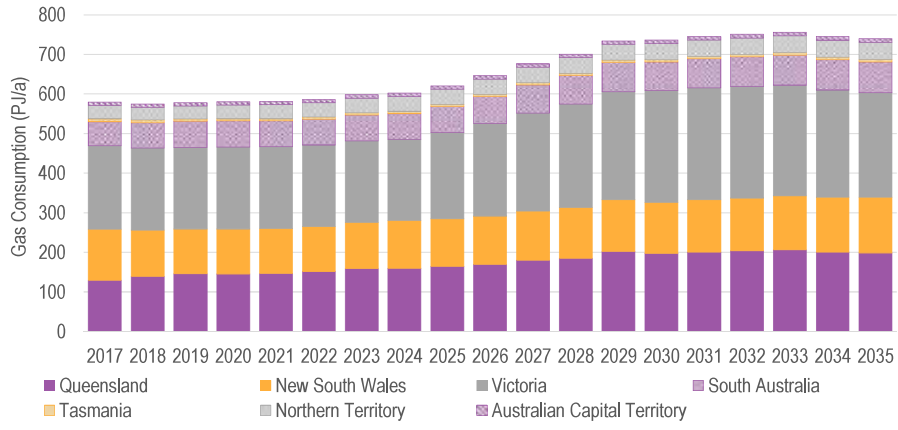


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.4.2 Consumption volume effects: GALE Case

Figure C.20 shows the modelled levels of domestic gas consumption, by State/Territory, under the GALE Case assumptions. Domestic consumption recovers from current levels to peak at a little over 750 PJ/a in 2033, but then falls to 740 PJ/a by the end of the modelling period as gas supply constraints start to be felt, with new sources of supply unable to fully replace current production as reserves are depleted.

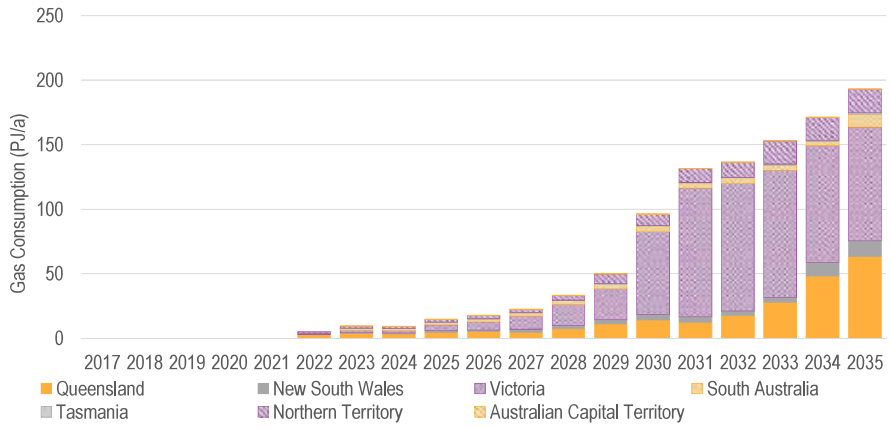
FIGURE C.20 GALE CASE: GAS CONSUMPTION



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.21 shows the incremental levels of gas consumption in eastern Australia and the Northern Territory under the GALE Case assumptions, compared to the Reference Case. The levels of incremental consumption rise slowly over the period 2022 to 2029, reaching a total incremental consumption level of about 50 PJ/a. However, from 2030 on total consumption levels increase sharply relative to the Reference Case as the increased levels of overall gas supply reduce the amount of 'demand destruction' as the supply position from non-shale sources in both the Northern Territory and eastern Australia tightens. By the end of the modelling period in 2035, the total incremental supply stands at almost 200 PJ/a. The largest consumption effects are felt in the Victorian, Queensland, and Northern Territory markets. Victorian consumption is impacted not as a result of physical supply from the Northern Territory but because NT supply reduces the levels of gas exported from Victoria to interstate markets – particularly New South Wales.

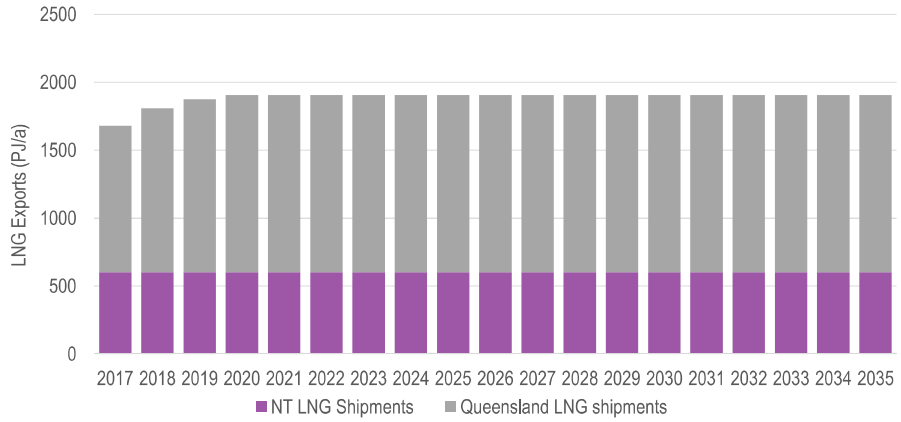
FIGURE C.21 GALE CASE: GAS CONSUMPTION DIFFERENTIAL FROM REFERENCE CASE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.22 shows the total levels of LNG exports from eastern Australia (NT shipments: Darwin LNG and INPEX Ichthys LNG; Queensland shipments: Gladstone LNG, Australia Pacific LNG, Queensland Curtis LNG) under the GALE Case assumptions. Compared to the Reference Case (no Northern Territory shale gas production) there is no change in LNG shipments from NT or Queensland under the WIND Case.

FIGURE C.22 LNG SHIPMENTS: GALE CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)



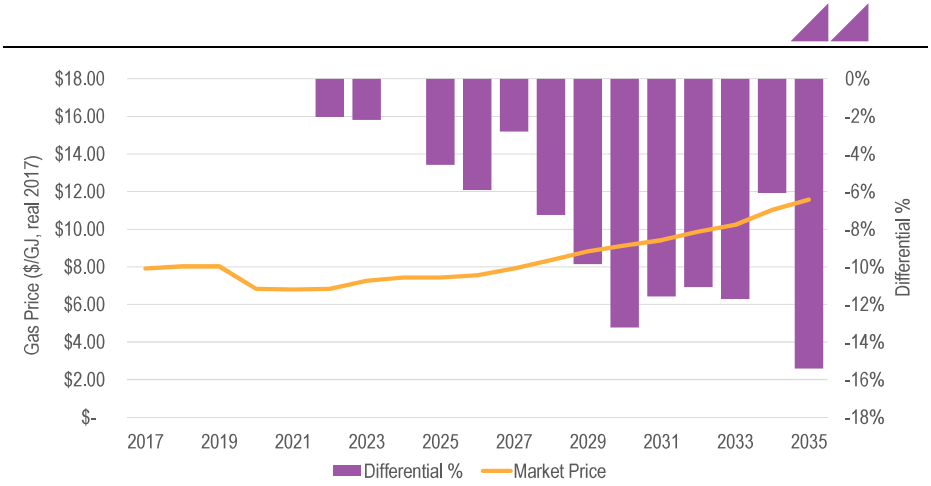
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.4.3 Eastern Australia price effects: GALE Case

The increase in gas supply to eastern Australian as a result of imports of Northern Territory shale gas under the GALE Case assumptions results in significant and sustained downward pressure on wholesale delivered gas prices. The level of price reductions tends to increase over time as more NT gas is taken up in the eastern Australian domestic market.

Figure C.23 shows the market price at Brisbane, and the per cent price differentials from the Reference Case, under the GALE Case assumptions. The price effects tend to increase across the modelling period, averaging 7 per cent over the period 2022 to 2035, and reaching 15 per cent by the end of the modelling period. The price effects come about principally as a result of the additional supply volumes which reduce the number of periods through the year when supply becomes very tight and prices are bid up to high levels.

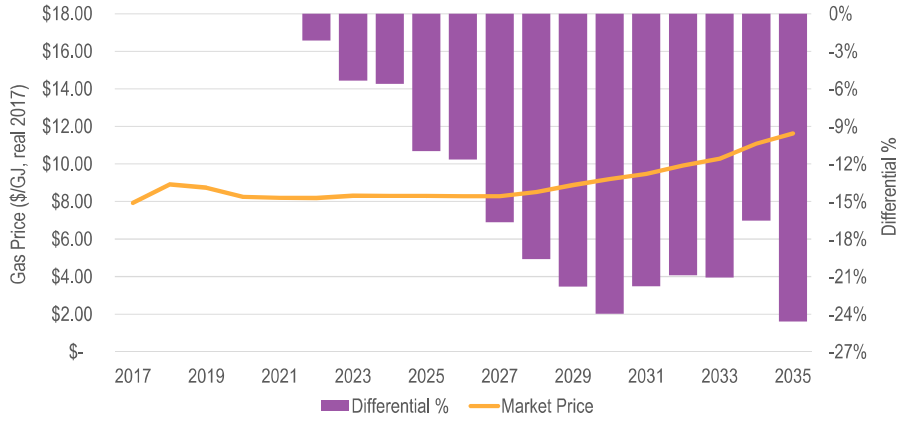
FIGURE C.23 GALE CASE: DELIVERED WHOLESALE GAS PRICES AT BRISBANE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.24 shows the corresponding price effects in New South Wales (Sydney). Total price levels are higher in Sydney than in Brisbane (because of the added transport costs). When compared to the Reference Case results, the patterns of price movement are generally similar to those observed in Queensland, but are considerably stronger. The price effects tend to increase across the modelling period, averaging 16 per cent over the period 2022 to 2035, and reaching 25 per cent by the end of the modelling period.

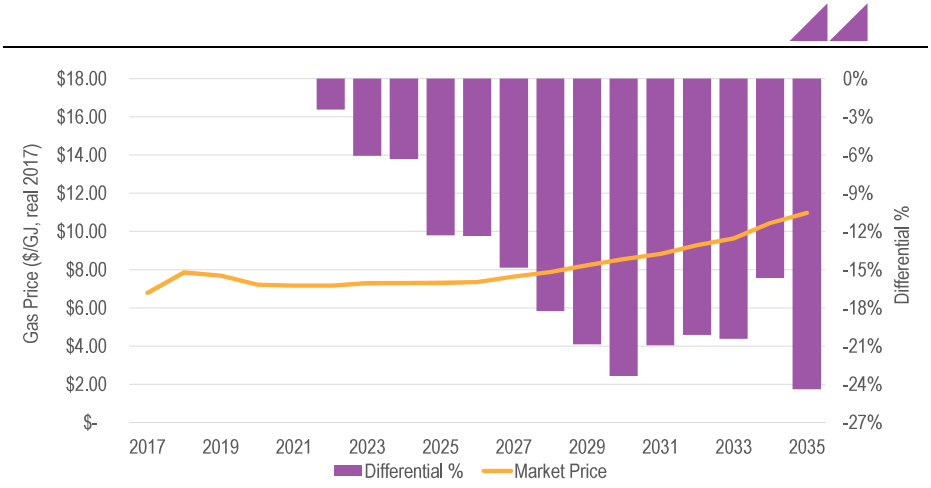
FIGURE C.24 GALE CASE: DELIVERED WHOLESALE GAS PRICE AT SYDNEY



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.25 shows the corresponding results for wholesale gas prices at Melbourne. Total price levels are lower than for Sydney, because of Melbourne's proximity to the major production sources in Bass Strait. In terms of differential price effects compared to the Reference Case, the results for Melbourne are very similar to Sydney.

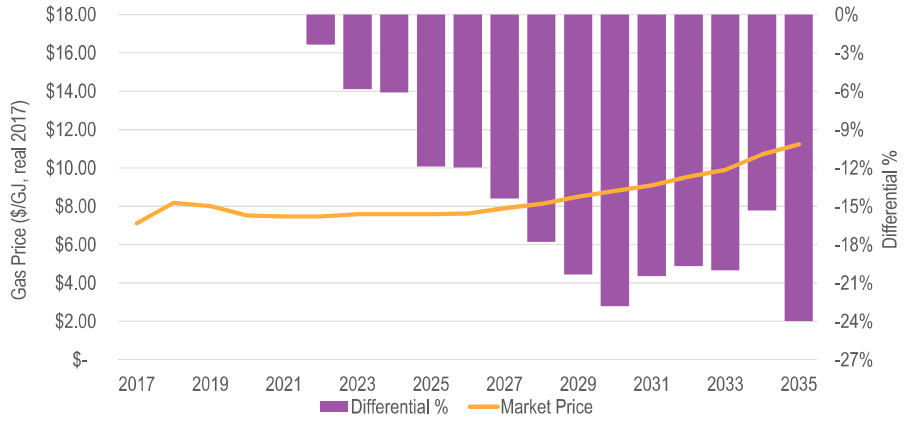
FIGURE C.25 GALE CASE: DELIVERED WHOLESALE GAS PRICE AT MELBOURNE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.26 shows the corresponding results for wholesale gas prices at Adelaide. Total price levels are slightly higher than for Melbourne, but show a similar pattern of movement. In terms of differential price effects compared to the Reference Case, the results for Adelaide are very similar to both Melbourne and Sydney.

FIGURE C.26 GALE CASE: DELIVERED WHOLESALE GAS PRICE AT ADELAIDE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

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APPENDICES PART TWO: ABOUT ACIL ALLEN'S MODELS

E

TASMAN GLOBAL

ACIL Allen's CGE model *Tasman Global* is a powerful tool for undertaking economic impact analysis at the regional, state, national and global level.

There are various types of economic models and modelling techniques. Many of these are based on partial equilibrium analysis that usually considers a single market. However, in economic analysis, linkages between markets and how these linkages develop and change over time can be critical. *Tasman Global* has been developed to meet this need.

Tasman Global is a large-scale CGE model which is designed to account for all sectors within an economy and all economies across the world. ACIL Allen uses this modelling platform to undertake industry, project, scenario and policy analyses. The model is able to analyse issues at the industry, global, national, state and regional levels and to determine the impacts of various economic changes on production, consumption and trade at the macroeconomic and industry levels.

A Dynamic Model

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before a policy change and one following). A dynamic model such as *Tasman Global* is beneficial when analysing issues where both the timing of and the adjustment path that economies follow are relevant in the analysis.

The Database

A key advantage of *Tasman Global* is the level of detail in the database underpinning the model. The database we will use for this project is derived from the Global Trade Analysis Project (GTAP) database (version 8.1). This database is a fully documented, publicly available global data base which contains complete bilateral trade information, transport and protection linkages among regions for all GTAP commodities.

The GTAP model was constructed at the Centre for Global Trade Analysis at Purdue University in the United States. It is the most up-to-date, detailed database of its type in the world.

Tasman Global builds on the GTAP model's equation structure and database by adding the following important features:

- dynamics (including detailed population and labour market dynamics)
- detailed technology representation within key industries (such as electricity generation and iron and steel production)
- disaggregation of a range of major commodities including iron ore, bauxite, alumina, primary aluminium, brown coal, black coal and LNG
- the ability to repatriate labour and capital income
- a detailed emissions accounting abatement framework

- explicit representation of the states and territories of Australia
- the capacity to explicitly represent multiple regions within states and territories of Australia

Nominally the *Tasman Global* database divides the world economy into 141 regions (133 international regions plus the 8 states and territories of Australia) although in reality the regions are frequently disaggregated further. ACIL Allen regularly models Australian projects or policies at the regional level.

The *Tasman Global* database also contains a wealth of sectoral detail currently identifying up to 70 industries (Table 1). The foundation of this information is the input-output tables that underpin the database. The input-output tables account for the distribution of industry production to satisfy industry and final demands. Industry demands, so-called intermediate usage, are the demands from each industry for inputs.

For example, electricity is an input into the production of communications. In other words, the communications industry uses electricity as an intermediate input. Final demands are those made by households, governments, investors and foreigners (export demand). These final demands, as the name suggests, represent the demand for finished goods and services. To continue the example, electricity is used by households – their consumption of electricity is a final demand.

Each sector in the economy is typically assumed to produce one commodity, although in *Tasman Global*, the electricity, transport and iron and steel sectors are modelled using a 'technology bundle' approach. With this approach, different known production methods are used to generate a homogeneous output for the 'technology bundle' industry. For example, electricity can be generated using brown coal, black coal, petroleum, base load gas, peak load gas, nuclear, hydro, geothermal, biomass, wind, solar or other renewable based technologies – each of which have their own cost structure.

The other key feature of the database is that the cost structure of each industry is also represented in detail. Each industry purchases intermediate inputs (from domestic and imported sources) primary factors (labour, capital, land and natural resources) as well as paying taxes or receiving subsidies.

Factors of Production

Capital, land, labour and natural resources are the four primary factors of production. The capital stock in each region (country or group of countries) accumulates through investment (less depreciation) in each period. Land is used only in agriculture industries and is fixed in each region. *Tasman Global* explicitly models natural resource inputs as a sector specific factor of production in resource based sectors (coal mining, oil and gas extraction, other mining, forestry and fishing).

Population Growth and Labour Supply

Population growth is an important determinant of economic growth through the supply of labour and the demand for final goods and services. Population growth for the 112 international regions and for the 8 states and territories of Australia represented in the *Tasman Global* database is projected using ACIL Allen's in-house demographic model. The demographic model projects how the population in each region grows and how age and gender composition changes over time and is an important tool for determining the changes in regional labour supply and total population over the projection period.

For each of the 120 regions in *Tasman Global*, the model projects the changes in age-specific birth, mortality and net migration rates by gender for 101 age cohorts (0-99 and 100+). The demographic model also projects changes in participation rates by gender by age for each region, and, when combined with the age and gender composition of the population, endogenously projects the future supply of labour in each region. Changes in life expectancy are a function of income per person as well as assumed technical progress on lowering mortality rates for a given income (for example, reducing malaria-related mortality through better medicines, education, governance, etc.). Participation rates are a function of life expectancy as well as expected changes in higher education rates, fertility rates and changes in the workforce as a share of the total population.

Labour supply is derived from the combination of the projected regional population by age by gender and the projected regional participation rates by age by gender. Over the projection period labour supply in most developed economies is projected to grow slower than total population as a result of ageing population effects.

For the Australian states and territories, the projected aggregate labour supply from ACIL Allen's demographics module is used as the base level potential workforce for the detailed Australian labour market module, which is described in the next section.

SECTORS IN THE *TASMAN GLOBAL* DATABASE

	Sector		Sector
1	Paddy rice	36	Paper products, publishing
2	Wheat	37	Diesel (incl. nonconventional diesel)
3	Cereal grains nec	38	Other petroleum, coal products
4	Vegetables, fruit, nuts	39	Chemical, rubber, plastic products
5	Oil seeds	40	Iron ore
6	Sugar cane, sugar beef	41	Bauxite
7	Plant- based fibres	42	Mineral products nec
8	Crops nec	43	Ferrous metals
9	Bovine cattle, sheep, goats, horses	44	Alumina
10	Animal products nec	45	Primary aluminium
11	Raw milk	46	Metals nec
12	Wool, silk worm cocoons	47	Metal products
13	Forestry	48	Motor vehicle and parts
14	Fishing	49	Transport equipment nec
15	Brown coal	50	Electronic equipment
16	Black coal	51	Machinery and equipment nec
17	Oil	52	Manufactures nec
18	Liquefied natural gas (LNG)	53	Electricity generation
19	Other natural gas	54	Electricity transmission and distribution
20	Minerals nec	55	Gas manufacture, distribution
21	Bovine meat products	56	Water
22	Meat products nec	57	Construction
23	Vegetables oils and fats	58	Trade
24	Dairy products	59	Road transport
25	Processed rice	60	Rail and pipeline transport
26	Sugar	61	Water transport
27	Food products nec	62	Air transport
28	Wine	63	Transport nec
29	Beer	64	Communication
30	Spirits and RTDs	65	Financial services nec
31	Other beverages and tobacco products	66	Insurance
32	Textiles	67	Business services nec
33	Wearing apparel	68	Recreational and other services
34	Leather products	69	Public Administration, Defence, Education, Health
35	Wood products	70	Dwellings

Note: nec = not elsewhere classified.

The Australian Labour Market

Tasman Global has a detailed representation of the Australian labour market which has been designed to capture:

- different occupations
- changes to participation rates (or average hours worked) due to changes in real wages
- changes to unemployment rates due to changes in labour demand

- limited substitution between occupations by the firms demanding labour and by the individuals supplying labour
- limited labour mobility between states and regions within each state.

Tasman Global recognises 97 different occupations within Australia – although the exact number of occupations depends on the aggregation. The firms who hire labour are provided with some limited scope to change between these 97 labour types as the relative real wage between them changes. Similarly, the individuals supplying labour have a limited ability to change occupations in response to the changing relative real wage between occupations. Finally, as the real wage for a given occupation rises in one state relative to other states, workers are given some ability to respond by shifting their location. The model produces results at the 97 3-digit ANZSCO (Australian New Zealand Standard Classification of Occupations) level.

The labour market structure of *Tasman Global* is thus designed to capture the reality of labour markets in Australia, where supply and demand at the occupational level do adjust, but within limits.

Labour supply in *Tasman Global* is presented as a three stage process:

- labour makes itself available to the workforce based on movements in the real wage and the unemployment rate;
- labour chooses between occupations in a state based on relative real wages within the state; and
- labour of a given occupation chooses in which state to locate based on movements in the relative real wage for that occupation between states.

By default, *Tasman Global*, like all CGE models, assumes that markets clear. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model).

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. *GasMark Global Australia* (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australian and Western Australian modules), but which has the capacity to interface with international LNG markets.

The model can be specified to run at daily, monthly, quarterly or annual resolution over periods up to 30 years.

F.1 Settlement

At its core, GMG Australia is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[88], consists of three terms:

- the integral of the demand price function over demand; minus
- the integral of the supply price function over supply; minus
- the sum of the transportation, conversion and storage costs.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

The figure below seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of the figure below show simple linear demand and supply functions for a particular market. The charts in the middle of the figure below show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clearly evident at a quantity of 900

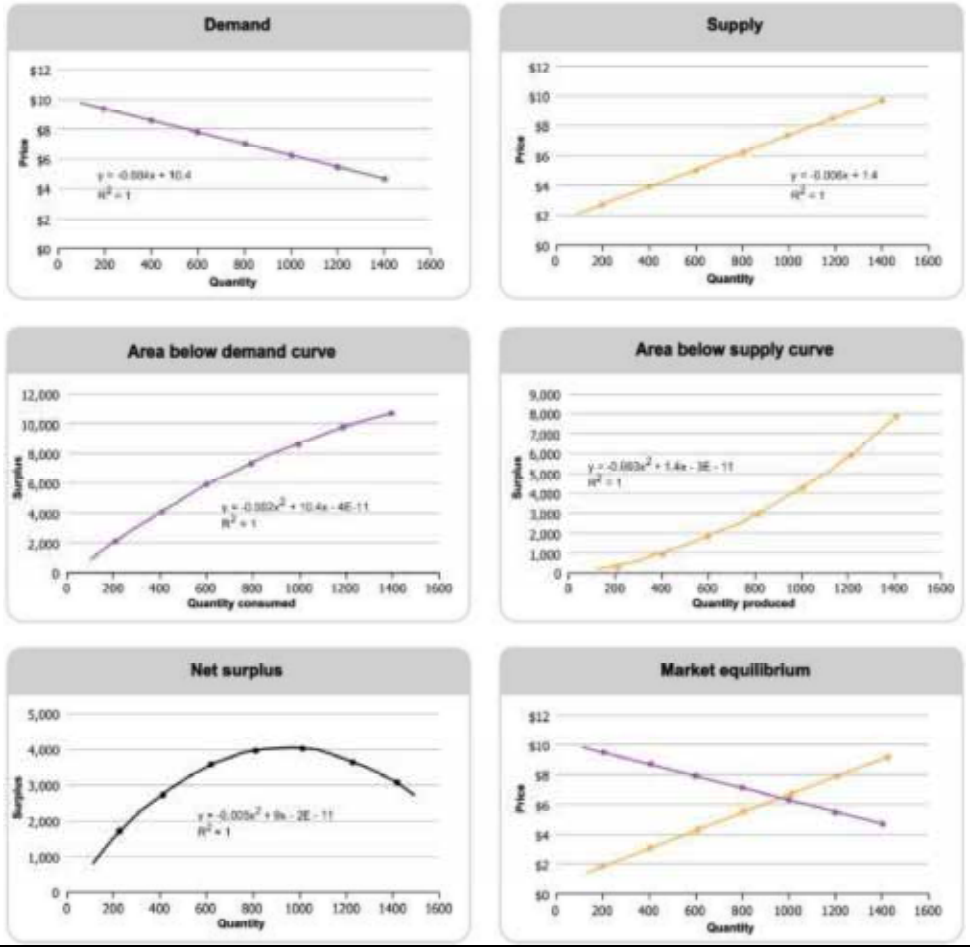
[88] The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

SIMPLIFIED EXAMPLE OF MARKET EQUILIBRIUM AND SETTLEMENT PROCESS



SOURCE: ACIL ALLEN CONSULTING

F.2 Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated

as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields, or could be a specific producer in a smaller region. Similarly a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to GMG Australia can be categorised as follows:

- **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.
- **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual and daily gas demand including daily demand profiles, and price tolerance.
- **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity (which may vary over time), flow characteristics (uni-directional or bi-directional) and tariffs.
- **Existing and potential new LNG facilities**: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

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ABOUT ACIL ALLEN CONSULTING

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WE PROVIDE SENIOR ADVISORY SERVICES THAT BRING UNPARALLELED STRATEGIC THINKING AND REAL WORLD EXPERIENCE TO BEAR ON PROBLEM SOLVING AND STRATEGY FORMULATION.

Appendix 17 Scope of services for economic impact modelling

Scope of Services

Background to the Inquiry

On 14 September 2016 the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory. At the same time, the Chief Minister announced that a *Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory* (the **Inquiry**) would be established and released draft Terms of Reference, which were open for public comment for four weeks.

On 3 December 2016 the Northern Territory Government announced the final Terms of Reference for the Inquiry and the composition of the panel that will be undertaking the Inquiry (the **Panel**).

The Inquiry was established under section 4 of the Inquiries Act 1945 (NT) and is comprised of a judicial chair, the Hon Justice Rachel Pepper, and ten highly regarded scientists with expertise in areas ranging from hydrogeology to social science.

The Inquiry's final Terms of Reference can be read in full on the Inquiry's website (www.frackinginquiry.nt.gov.au).

On 20 February 2017 the Inquiry released a Background and Issues Paper, also available on the Inquiry's website, which was followed by hearings and community meetings held in March 2017 in various town centres and remote communities across the Northern Territory. The Issues Paper includes a timeline for the Inquiry, which indicates that an interim report will be released in mid-2017, a draft final report will be released during the last quarter of the year, and a final report will be released in December 2017.

The Hydraulic Fracturing Taskforce (the **Taskforce**) has been established in the Department of the Chief Minister to support the Inquiry.

Terms of Reference for the Inquiry and the economic impact theme

The Panel has divided the work of the Inquiry into the following themes: water, land, air, social impacts, economic conditions, cultural conditions, human health, land access, and the regulatory framework. This request relates to the economic theme only, however, there are overlaps with the social impact and regulatory framework themes. A sub-group of Inquiry Panel members has been allocated responsibility for each theme.

The Terms of Reference for the Inquiry require the Panel to do the following in respect of each theme:

- determine and assess the impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the associated activities;
- determine whether additional work or research is required to make that determination;
- advise the level of impact or risk that is acceptable in the Northern Territory context;
- describe methods, standards or strategies that can be used to reduce the impact and risk to acceptable levels; and
- identify what government can do, including implementing any policy or regulatory changes, to ensure that the impacts and risks are reduced to the required levels.

The *Background and Issues Paper* includes a non-exhaustive list of the potential risks and benefits associated with the economic theme at page 22.

In accordance with the definitions in the Terms of Reference, a reference to an "unconventional reservoir" in this document is a reference to a reservoir where the rock formation is *shale*. There is currently no gas being produced from unconventional, or shale, reservoirs in the Northern Territory. The Amadeus Basin is currently producing gas from conventional reservoirs.

With regard to the third Term of Reference stated above, the level of impact or risk that is acceptable will ultimately be a matter for the decision maker under the relevant legislation

(typically the Minister), however, at this stage the meaning of acceptability or acceptable levels of risk is a matter for the Panel, taking into account principles of ecological sustainable development, including the precautionary principle and intergenerational equity.

The Terms of Reference make it clear that the Panel must not only look at the impacts of hydraulic fracturing and the associated activities on economic conditions in the Northern Territory – the Panel must also consider the economic impacts of the onshore unconventional gas industry as a whole on the Northern Territory. This is made clear in the following extract from the Terms of Reference, which has been amended to include the relevant language only:

> *"When the inquiry makes a determination… about whether or not there has been an impact or risk on … economic conditions, the inquiry will … consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry."*

Steering Committee

A Steering Committee has been established to oversee the work. The Steering Committee is comprised of the Hon Justice Rachel Pepper, Dr Vaughan Beck and the Executive Director of the Hydraulic Fracturing Taskforce. The point of contact for all matters will be the Executive Director of the Hydraulic Fracturing Taskforce.

Probity Advisor

The Territory has appointed a Probity Advisor to oversee the Territory's processes in relation to the stages of this process. The Probity Advisor's role is to ensure that fairness and impartiality are observed throughout, and that the evaluation criteria stated in any related documentation are consistently applied to all submissions.

Scope of Work

The supplier must consider the following scenarios:

- **Scenario 1** or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place;
- **Scenario 2**, which involves the development of the onshore unconventional shale gas industry in the Northern Territory; and
- **Scenario 3,** which involves the development of unconventional shale gas reservoirs in the Beetaloo sub-basin only.

Benefits

The supplier must describe, in both quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with each of Scenarios 1, 2 and 3 on the Northern Territory economy under the current regulatory regime.[1]

The supplier must describe, in quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with Scenario 2 on the national economy under current regulatory, fiscal and economic settings.

For each of Scenarios 1, 2 and 3 the supplier must estimate the following:

- Gross State Product (**GSP**);
- State Final Demand (**SFD**);
- employment;
- business investment and output;
- CPI;
- population;
- wages; and
- the quantum of royalties that might be received by the Northern Territory Government under the *Petroleum Act 1984* (NT) (to avoid doubt this will include any royalties received in connection with both unconventional and conventional reservoirs).

1 Indirect benefits might include the opening up of supply chains for local businesses, innovation spin offs, opportunities to develop or support supply and maintenance industries and any other flow-on opportunities the supplier identifies.

The supplier must provide the Steering Committee with:

- in accordance with Part C, any assumptions made and an explanation of the methodology used to develop such assumptions, both of which must be approved by the Steering Committee prior to undertaking any economic modelling. The supplier must explain how reasonable and reliable the assumptions are, as well as how any potential bias has been managed, and
- a description of the similarities or differences between the assumptions made under item 7(a) above and the assumptions made in the report entitled Economic Impact of Shale and Tight Gas Development in the Northern Territory dated 14 July 2017 by Deloitte Access Economics.

The supplier must describe the options available to the Northern Territory Government, whether through policy or regulatory reforms or otherwise, to maximise and sustain the benefits captured by Territorians and others.[2] In this regard the supplier must:

- conduct a literature review to advise on leading practice methods for the sustainable development of onshore unconventional shale gas projects from an economic perspective, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and what lessons can be learned from these experiences in the Northern Territory context.

The supplier must describe the options available to the Northern Territory Government, including regulatory or policy reforms, for how revenue from the development of onshore unconventional shale industry can be retained both jointly and separately in the regions affected by the development and the Northern Territory, in each case, without impeding investment. Consideration must be given to:

- local procurement requirements, local training programs and other mechanisms to improve local capacity as well as any 'Royalty for Regions' or similar type programs, and
- case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and the lessons that can be learned for the Northern Territory context.

Risks

The supplier must describe, in qualitative terms, any actual and potential adverse impacts and risks associated with Scenario 1, Scenario 2, and Scenario 3 on the Northern Territory economy under the current regulatory regime.

The supplier must consider the impacts of development on other industries in the Northern Territory, including, but without limitation, the tourism, agricultural, horticultural and pastoral, industries.

The supplier must describe the options available to the Northern Territory Government, including policy or regulatory reforms, to mitigate and manage any actual and potential impacts and risks identified above. For example, the supplier must advise what the Northern Territory Government can do to mitigate any "boom and bust" economic cycle associated with the development of any unconventional shale gas industry.

The supplier must:

- conduct a literature review to advise on leading practice methods that could be used to manage and mitigate any risks identified, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful, and what lessons can be learned from these experiences in the Northern Territory context.

2 It is noted that onshore unconventional gas industry, local communities, local governments, Aboriginal stakeholders (including Aboriginal land councils and prescribed bodies corporate under the *Native Title Act 1993* (Cth)) have a significant role to play in the maximisation of economic benefits, however, the scope of the work is limited to actions that government can take.

Assumptions

No production licences have been granted under the Petroleum Act for the purpose of producing unconventional shale gas in the Northern Territory. Further exploration work, including the drilling of appraisal wells, is required to fully understand the scope of the Northern Territory's shale gas reservoirs and whether or not they are commercially recoverable.

The most prospective area for shale gas development, should the moratorium be lifted by the Government, is the Beetaloo sub-basin (see Attachment A). Origin Energy announced a significant discovery of unconventional shale gas in the Beetaloo sub-basin in February 2017, which significantly increased prior estimates of the resource.

In developing any assumptions required to undertake Part A and B, the supplier must consult with relevant stakeholders, including, but without limitation, the Departments of Treasury and Finance; Primary Industry and Resources; Trade, Business and Innovation; Chief Minister; Northern Territory Farmers; the Northern Territory Cattlemen's Association; petroleum operators and titleholders in the Beetaloo sub-basin, Aboriginal Land Councils, and the Australian Petroleum Production and Exploration Association.

The supplier must notify the Steering Committee prior to any consultation and members of the Steering Committee may attend the consultation.

Timelines and Reporting

The work must be in the form of a written report. The report must be written in plain English. All technical terms (including economic metrics such as Gross State Product, State Final Demand, and employment multipliers) must be explained.

At the end of each calendar month following the award of the tender the supplier must provide the Steering Committee with a written progress report and a verbal presentation within five working days of receipt of the report.

The supplier must provide the Steering Committee with a draft final report and a verbal presentation to the Steering Committee on or prior to 18 August 2017.

A final report must be provided to the Steering Committee by 1 September 2017 and the supplier must present the final report to the Panel on a date to be determined.

The Inquiry will publish the final report on the Inquiry's website on a date to be determined.

The supplier must keep all correspondence, reports and presentations to the Steering Committee confidential, except that the supplier may make the final report publicly available after it has been published on the Inquiry's website.

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