# WATER



7

## 7.1 Introduction

Water-related risks were the central concern raised in the submissions received by the Panel and in the community consultations. The experience of shale gas development overseas, particularly in the US, provides some basis for this concern, noting, however, that the technological, geological, biophysical and regulatory characteristics applying to the shale gas industry in other countries are not necessarily comparable to those in the NT.

Concerns around the impacts of CSG development were also reflected in public anxiety about any onshore shale gas development in the NT. However, it is important to recognise that the process of CSG extraction is very different to that of shale gas extraction because large volumes of water need to be extracted from the coal seam aquifer during CSG operations prior to the start of hydraulic fracturing to ensure the gas flow (see Chapter 5).

Water is an essential part of traditional Aboriginal culture, both in terms of access for survival for groups living in remote areas, and also in terms of its spiritual link to Aboriginal sacred sites and religious customs. The NLC articulated the importance of water to the Aboriginal people, noting that,

> *"Water is both steeped in Aboriginal mythology and history and critical to the present day maintenance of life, culture and livelihoods. Water always has and always will be central to Aboriginal identity and, thus, to the continued maintenance of Aboriginal law and culture in this country."* [1]

The Aboriginal Areas Protection Authority (**AAPA**)[2] noted that the practice of shale gas hydraulic fracturing could have significant impacts on sacred sites arising from interference with either surface water or groundwater (see also Chapter 11).

The sustainable management of surface and groundwater resources will be crucial to the development of any onshore shale gas industry in the NT. Sustainable development involves the protection of three water-related environmental values: water quantity; water quality; and aquatic ecosystems. The protection of these values is realised by achieving the following three objectives: first, to ensure surface and groundwater resources are used sustainably; second, to maintain acceptable quality of surface and groundwaters; and third, to adequately protect ecosystems that are dependent on surface water or groundwater.

The Panel has assessed the water-related risks associated with any shale gas development in the NT using the risk assessment framework detailed in Chapter 4. In total, 20 risks to water supply, water quality, and aquatic ecosystems have been assessed.

The Panel has focussed its attention on the Beetaloo Sub-basin because this is the most prospective onshore shale gas region in the NT (Chapter 6), and, more importantly, it has been comparatively well studied. A number of the conclusions drawn for the Beetaloo Sub-basin have broader relevance across the NT. The paucity of information about regional surface water and groundwater processes in other regions of shale gas prospectivity in the NT has prevented the assessment of some risks more broadly. However, the assessment methodology used by the Panel for the Beetaloo region provides a good model for what must be applied to the other prospective shale basins to evaluate the location-specific risks posed by any shale gas development in those areas.

1 Northern Land Council, submission 647 (**NLC submission 647**), p 5.
2 Aboriginal Areas Protection Authority, submission 1150 (**AAPA submission 1150**).

## 7.2 Water in the NT

The climate in the NT ranges from tropical and monsoonal in the north, to arid or semi-arid in the southern and central regions. The rainfall ranges from around 2,000 mm per year in the north, to approximately 150 mm per year in the Simpson Desert (**Table 7.1; Figure 7.1**).

The wet season (October-April) monsoons totally dominate the rainfall from north of around Tennant Creek (500 mm/y), and there is virtually no rain during the dry season (May-September). During these wet season monsoons, aquifers are recharged, floodplains are inundated, and billabongs and waterholes are refreshed. Further south, the rainfall is also influenced by the monsoons, but there are also increasing relative amounts of winter rain so that the low rainfall of the southern NT becomes essentially a-seasonal.

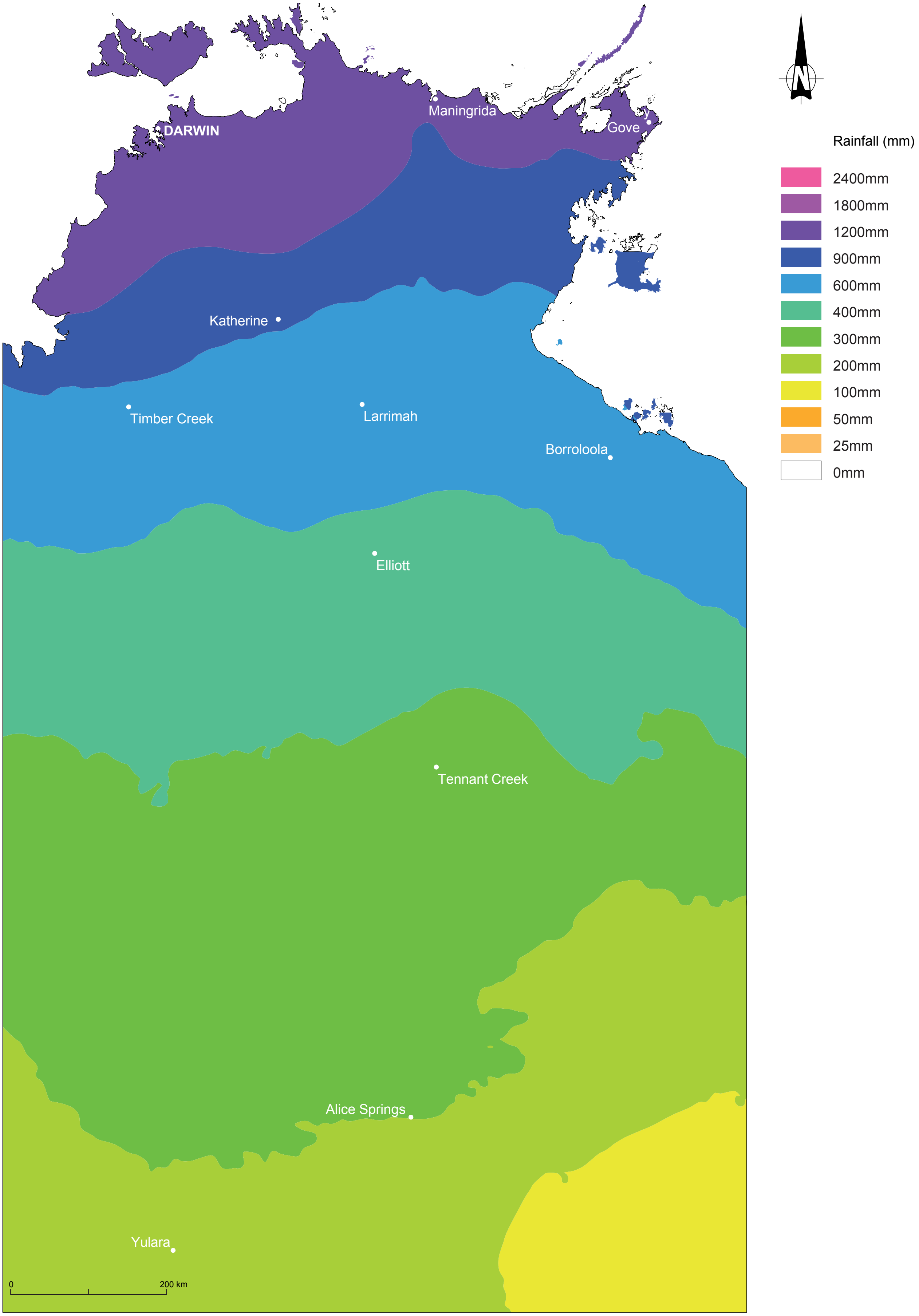
Given the multiple decades lifespan of any onshore shale gas industry, the Panel sought information from the Bureau of Meteorology (**BOM**) on the possible future changes of climate in the NT.[3] In summary, it is predicted that by 2050, there will be little change in the annual rainfall but increased intensity of extreme rainfall events, such as the wettest day of the year. Increased intensity during the wet season will increase runoff during storm events and influence streamflows. There is very high confidence that warming will continue across the NT, with different climate models predicting between 1.0-1.5 °C and 2.0-3.0 °C increases in mean annual surface temperature by 2050.[4] Not surprisingly, given the potential temperature increase, it is also predicted that evapotranspiration (water use by vegetation) will increase, although the magnitude of the change is unclear. The implications of climate change for groundwater processes and recharge rates are also unclear at this stage.

**Table 7.1:** Long-term average rainfall and evaporation levels. Source: BOM.[5]

| Location (station number) | Rainfall (mm/yr)<br>Years data were collected | Evaporation (mm/yr)<br>Years data were collected |
|---|---|---|
| Darwin<br>(14015) | 1722<br>(1941-2017) | 2454<br>(1957-2017) |
| Katherine<br>(14903) | 1088<br>(1943-2017) | 2270<br>(1999-2011) |
| Daly Waters<br>(14626) | 675<br>(1939-2017) | 2960<br>(1954-1970) |
| Elliott<br>(15131) | 589<br>(1949-2017) | 2743<br>(1980-2010) |
| Alice Springs<br>(15590) | 284<br>(1941-2017) | 3142<br>(1959-2017) |

3 Bureau of Meteorology submission 475 (**BOM submission 475**).
4 BOM submission 475, p 3.
5 BOM submission 475, p 5.

**Figure 7.1:** Average annual rainfall in the NT over the period 1960-1990. Source: BOM.



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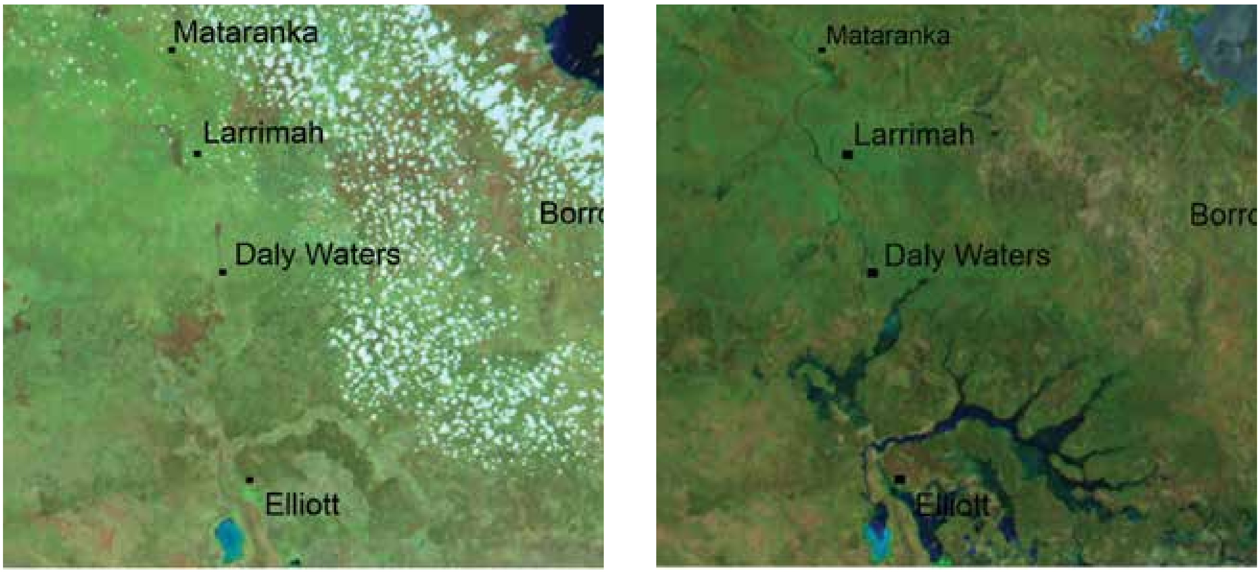
### 7.2.1 Surface water resources

The surface water hydrology of the NT is reasonably well known. The two main sources of information are, first, the Department of Environment and Natural Resources (**DENR**) streamflow records for most major streams in the NT, and second, the extensive information on the surface water resources of northern Australia that was gathered in the Northern Australia Sustainable Yields Project undertaken by CSIRO in 2009.[6]

The northern, central, and southern regions of the NT are distinctly different, reflecting the contrasting patterns of rainfall amount and its seasonality. The northern region (Top End) has extensive river and wetland systems, whereas surface water is largely absent from the southern region, except for short periods during the wet season and isolated spring-fed systems.[7] The two largest perennial river systems in the NT, the Daly and the Roper, have their flow maintained during the dry season by discharges from the CLA groundwater system.[8] In the central semi-arid regions of the NT, stream flow is seasonal (wet season) and often does not occur for years. An insight into the permanence of water in the NT landscape has been developed by Geoscience Australia through collating satellite imagery collected since 1987, shown in **Figure 7.2**. The mainstream networks in the NT are shown in **Figure 7.3**. As noted below in Section 7.2.3, very little is known about the aquatic ecology of the temporary streams and water bodies in the semi-arid and arid regions of the NT.

**Figure 7.2:** Satellite images showing the variation in surface water occurrence between: (a) 1 October 2015 (late dry season) and (b) 3 January 2016 (following extreme monsoonal rains). Source: BOM.[9]




(a): Satellite imagery 1 October 2015.

(b): Satellite imagery 3 January 2016.

6 CSIRO 2009.
7 Department of Environment and Natural Resources, submission 449 (**DENR submission 449**); Gautam 2017.
8 Bruwer and Tickell 2015; Department of Environment and Natural Resources, submission 230 (**DENR submission 230**), Addendum 2.
9 BOM 2017a.

**Figure 7.3 (a):** Map of the rivers of the NT. Source: DENR.

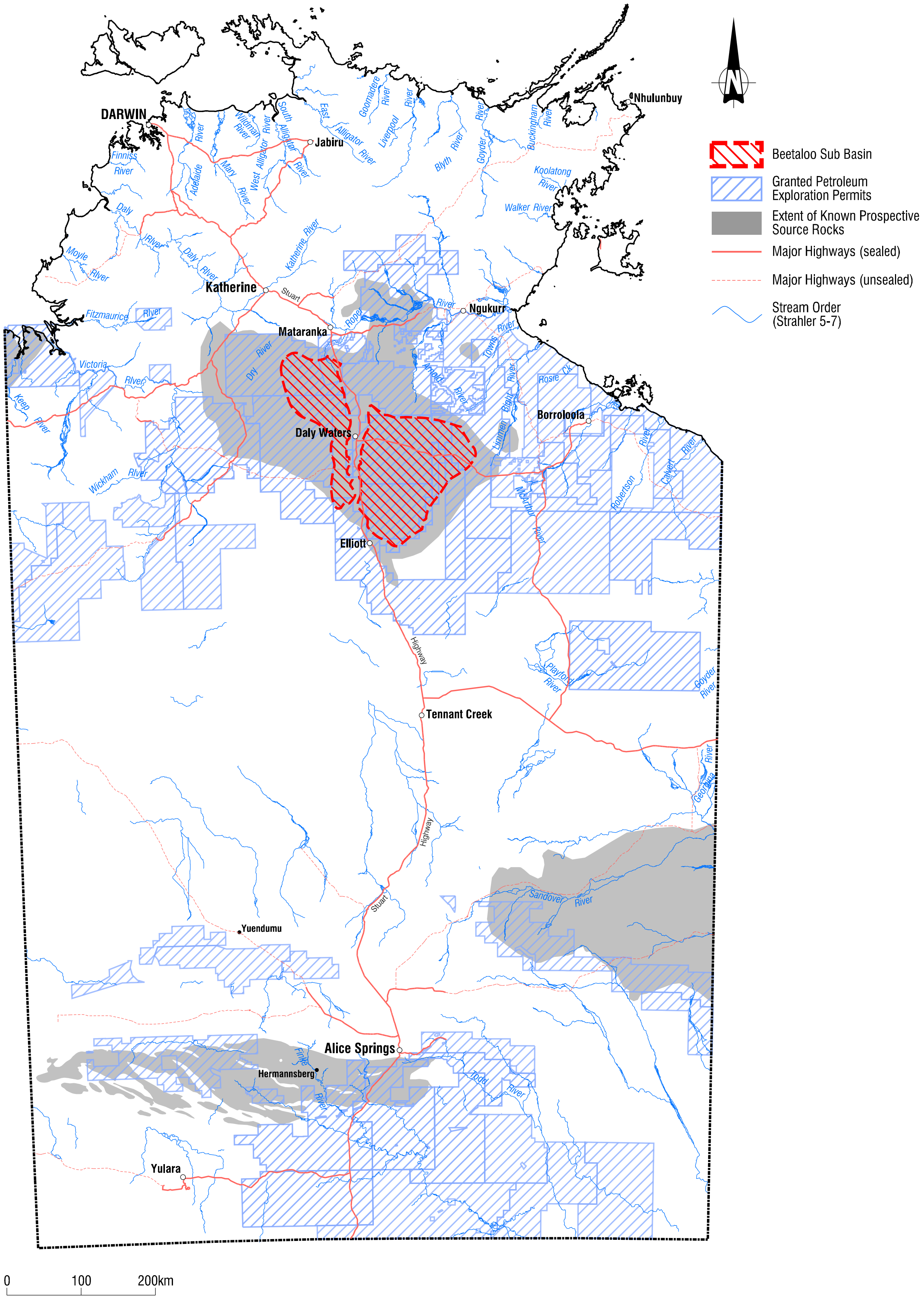
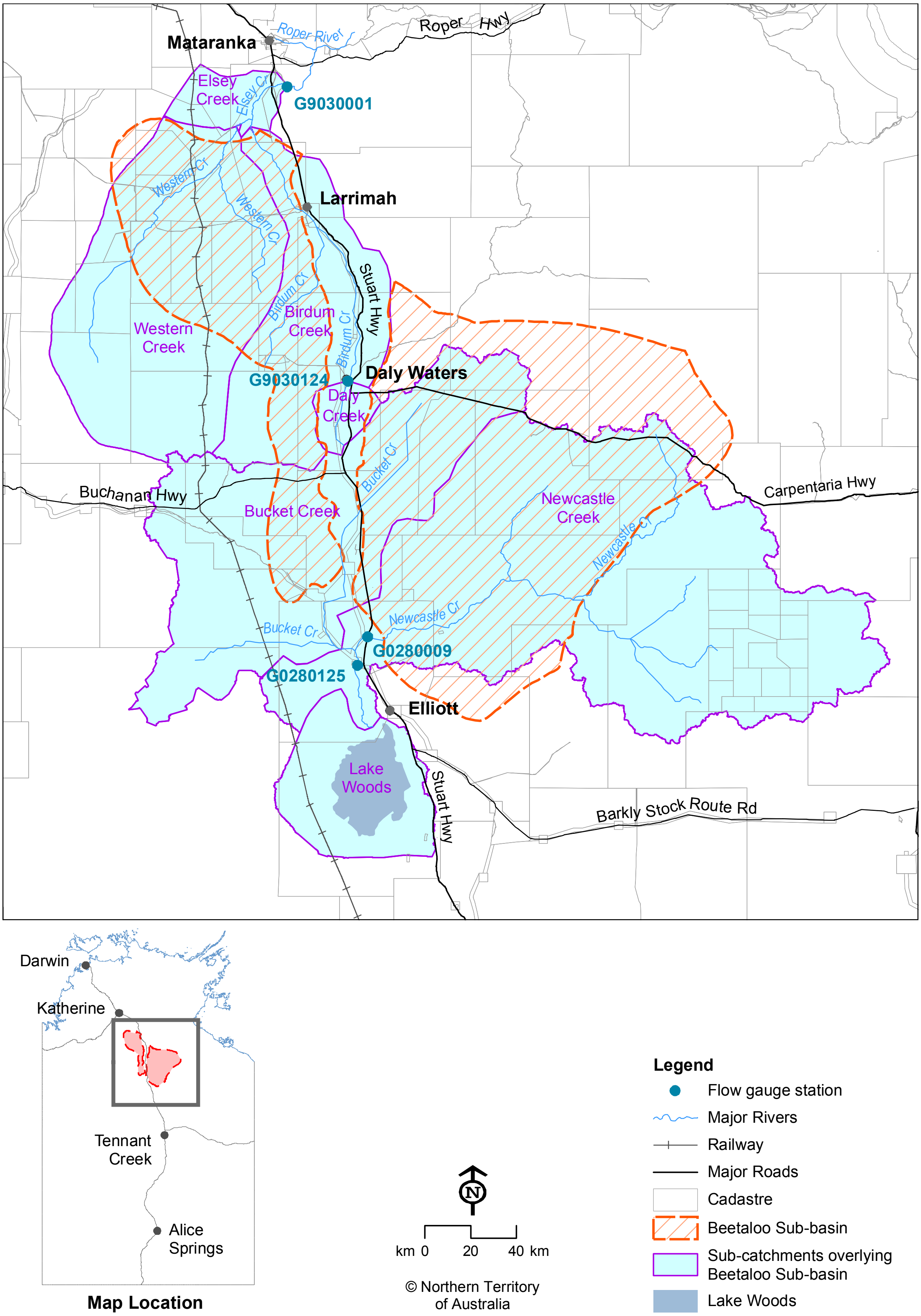


**Figure 7.3 (b):** Temporary rivers in three areas of the Beetaloo Sub-basin: (a) north-west region, (b) southern region, and (c) north-east region. Source: DENR.



## 7.2.2 Groundwater resources

Groundwater accounts for 90% of all of the NT consumptive water supplies,[10] a much higher proportion than for any other Australian jurisdiction.[11] The NT has a number of large groundwater basins, including the Daly, Georgina and Wiso Basins in the central region, the Amadeus Basin to the south and west of Alice Springs, and the Great Artesian Basin in the southeast corner.[12] These basins have large storage capacities. The Daly Basin is seasonally recharged by monsoonal rainfall and the northern part of the Georgina Basin that is known to discharge into the Roper River.[13] For the other (more arid) basins, recharge is episodic and dependent on infrequent large rainfall events or recharge locations a long way from the NT for the Great Artesian Basin.[14] In these basins, groundwater quality decreases with reduced recharge rates, and in the semi-arid and arid zones is commonly brackish to saline, with elevated concentrations of ions such as fluoride and nitrate.[15]

These contrasting groundwater basins vary in their likely sensitivity to water demands of shale gas and other developments. As a general rule, groundwater systems in the Top End are relatively more resilient to extraction and other impacts because they have more rapid through-flow rates, and are replenished more frequently.[16] By contrast, impacts on arid zone groundwater systems are likely to be greater and occur for longer, because these systems are recharged far more slowly, if at all.

Predicting the likely impacts of any onshore shale gas development on groundwater resources in prospective shale basins requires a detailed understanding of their hydrogeological and hydrochemical characteristics under pre-development (baseline) conditions. Current understanding of these groundwater characteristics is reasonable for parts of the Beetaloo Sub-basin, but generally low for other prospective shale gas basins in the NT (for example, the Northern Amadeus Basin, the Arthur Creek Formation, the McArthur Basin and the Bonaparte Basin).[17]

Imperial Oil and Gas has also provided an internal company report on the hydrology of the McArthur Basin Central Trough.[18]

DENR has collated the available information and reports for the Daly, Wiso and Georgina Basins, which overlie the Beetaloo Sub-basin and surrounds, at depths of 100-400 m below the surface (**Figure 7.4**).[19] The various groundwater systems associated with these basins are broadly grouped as the CLA, a significant regional aquifer system comprising fractured and karstic rocks.[20] Karst systems are formed by the dissolution of soluble rocks such as limestone, dolomite and gypsum and are characterised by underground drainage systems with sinkholes and caves.

**Table 7.2** summarises the current knowledge of the shallow aquifers (that is, down to a depth of approximately 200 m) in each of the prospective shale gas basins in the NT. Information is provided on the proximity of the aquifer(s) to the surface, the thickness and nature of the overlying strata, and the possible preferential pathways from surface to the aquifer. This latter information has been used in Section 7.6.3 to assess the possible contamination of surface aquifers from surface spills of wastewater from a hydraulically fractured shale gas operation.

10 Includes water for domestic use, irrigation, stock watering and industry.
11 DENR submission 230, p 3.
12 DENR submission 230, pp 3, 6.
13 Fulton and Knapton 2015, p 37.
14 DENR submission 230, p 3; Bruwer and Tickell 2015; Fulton and Knapton 2015; GHD 2016.
15 Yin Foo and Matthews 2000; Fulton and Knapton 2015; Bruwer and Tickell 2015; GHD 2016.
16 DENR submission 230, Appendix A.
17 Department of Environment and Natural Resources, submission 428 (**DENR submission 428**), pp 1-12.
18 Imperial Oil and Gas Pty Ltd, submission 1163 (**Imperial Oil and Gas submission 1163**).
19 Tickell and Bruwer 2017.
20 Fulton and Knapton 2015, p 32.

**Table 7.2:** Status of knowledge about shallow aquifers in each of the prospective shale gas basins: proximity of aquifers to surface, thickness and nature of overlying strata, possible preferential pathways from surface to aquifer. See **Figure 6.2** for the locations of the shale basins. Source: DENR;[21] Knapton;[22] Bruwer and Tickell.[23]

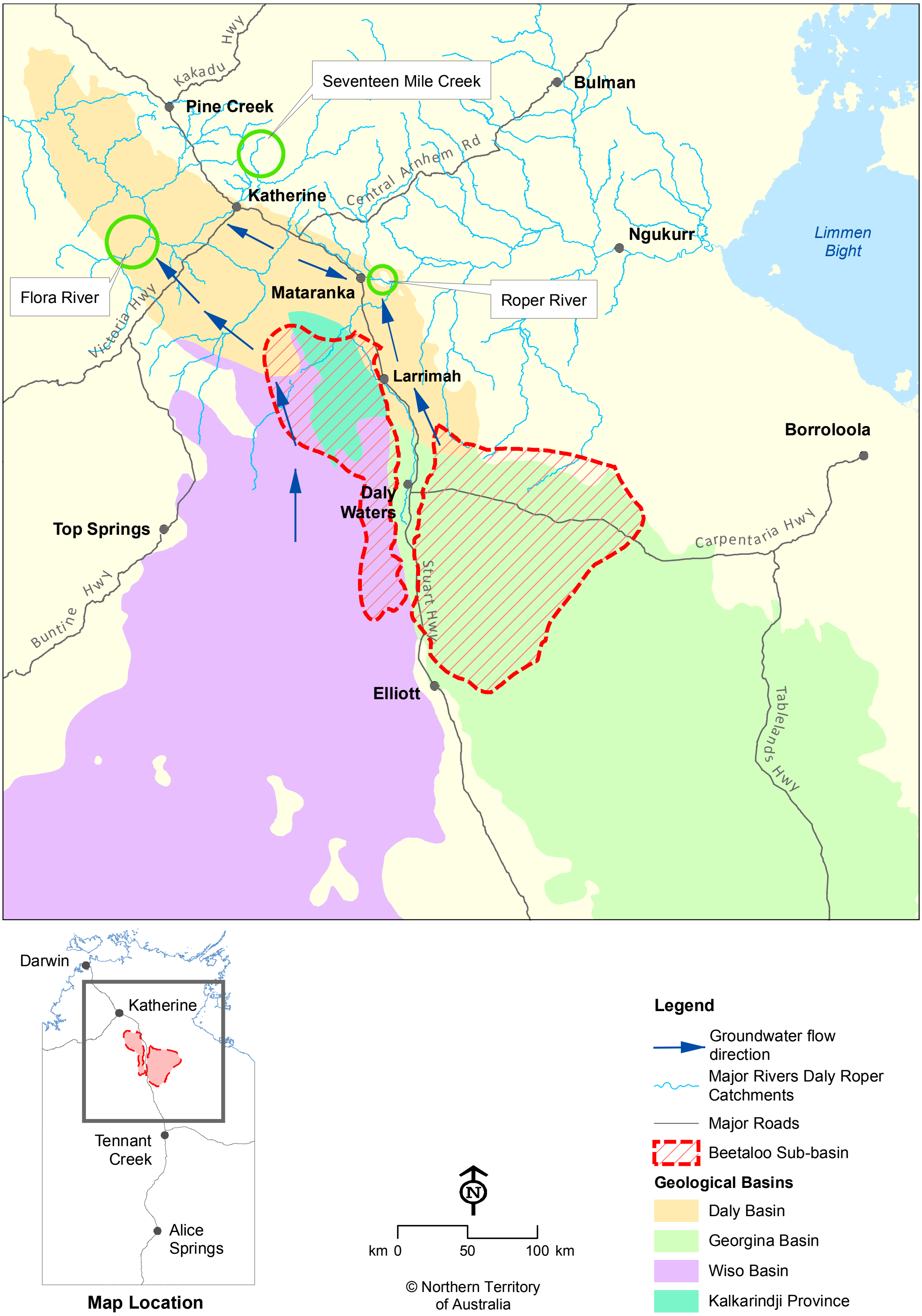
| Shale basin | Aquifer | Summary |
|---|---|---|
| McArthur Basin<br>Northern extremity of Beetaloo Sub-basin (Mataranka to Larrimah) | Tindall Cambrian Limestone Aquifer (CLA) | • Hydrogeology is considerably different in the area around Mataranka (20-40 km south) compared to the central and southern part of the Beetaloo Sub-basin.<br>• Geology dominated by weathered Tindall Limestone with a thin cover of Cretaceous sandstone.<br>• Water table is shallow with a thin unsaturated zone and reduced or no overlying clayey strata.<br>• Evidence for preferential pathways with karstic formations. |
| McArthur Basin<br>Beetaloo Sub-basin<br>East of Stuart Highway (Larrimah to Daly Waters) | Tindall/Gum Ridge (CLA) | • Is the only known aquifer in this region - average depth to the formation is 30 m.<br>• Water table is approximately 45 m deep and aquifer expected to be intersected within 15 m of the top of the water table (that is at 60 m).<br>• Most of the region is covered by low permeability cretaceous sediments.<br>• Surface expression of collapse structures in the underlying limestone exist, but open sinkholes that provide a preferential pathway to the aquifer are rare. |
| McArthur Basin<br>Beetaloo Sub-basin<br>East of Stuart Highway (Daly Waters to Elliott) | Anthony Lagoon Formation (CLA) | • This formation exists either below 50 m of Cretaceous sediment or sub crops at shallow depth at its margins.<br>• Water table is at approximately 60 m and aquifers may be intersected within 60 m below the water table (that is at 120 m).<br>• Low permeability black soils cover a large part of the Barkly Tablelands.<br>• Collapse structures generally do not develop in this formation. |
| | Gum Ridge Formation (CLA) | • Mostly underlies the Anthony Lagoon Formation at depth (approximately 300 m) so at low risk from surface spills, but subcrops at shallow depth on the basin margins.<br>• The two aquifers (Gum Ridge and Anthony Lagoon) are vertically separated by a low permeability layer.<br>• At the centre of the basin, the top of the Gum Ridge Formation is approx. 300 m below the surface, while on the western margin near Elliott, the top of the Formation is at 40 m depth.<br>• An aquifer could be expected to be intersected within 30 m of the top of the Formation (that is at 60 m).<br>• The overlying layer is highly clayey with occasional disaggregated limestone beds - there is unlikely to be preferential flow pathways in this layer. |
| Wiso Basin<br>West of Stuart Highway adjacent to Beetaloo Sub-basin | Montejinni Limestone (CLA) | • Extensive across the Sturt Plateau - overlain by approximately 50 m of Cretaceous sediments and bounded below at approximately 70 m depth by the undulating Antrim Plateau Volcanics. A much shallower aquifer system than the Anthony Lagoon Beds.<br>• Water table is at 50 to 60 m below surface so aquifer is very thin in most places. Only prospective for water supply where it has infilled the troughs of the basement.<br>• Significant number of collapsed structures in the limestone are expressed on the surface as sinkholes. However, open sinkholes that provide a preferential pathway to the aquifer are rare.<br>• At Gorrie Station in the north, where the cretaceous sediments are thinnest (about 30 m) and where groundwater is intersected at 30 m, potential for preferential pathways to the aquifer may exist. |
| McArthur Basin | Barney Creek Formation | • Relatively few bores drilled in this region and only one detailed study for water supply in the vicinity of Borroloola.<br>• Aquifers overlying the Barney Creek Formation generally occur at shallow depth and may be developed in shallow Cretaceous sediments, Proterozoic sandstone or in the karstic terrain of the Karns Dolomite Formation.<br>• Water table may exist at approximately 20 to 30 m depth.<br>• Surface layer is sand and clay soils.<br>• Open sinkholes occur on the areas underlain by Karns Dolomite and these represent preferred flow pathways to the aquifer. |

21 DENR submission 428; Department of Environment and Natural Resources, submission 481 (**DENR submission 481**).
22 Mr Anthony Knapton, submission 426 (**A Knapton submission 426**).
23 Bruwer and Tickell 2015.

**Table 7.2**: *Continued.*

| Shale basin | Aquifer | Summary |
|---|---|---|
| Georgina Basin | Arthur Creek Formation | • No hydrogeological studies have been undertaken in this region.<br>• Hydrogeological knowledge is limited to bores drilled for stock watering purposes.<br>• Aquifers overlying the Arthur Creek Formation mostly exist in limestone or sandstone.<br>• Water table is at approximately 80 to 100 m depth.<br>• The surface of the region is covered by a sandy and clayey weathered horizon to approximately 50 m depth. |
| Bonaparte Basin | | • The only hydrogeological studies conducted in this region are near the Keep River Plains.<br>• A palaeo-channel aquifer exists directly beneath the black soil floodplain and small fractured rock aquifers exist in the Proterozoic rocks surrounding the floodplain - the palaeo-channel aquifer may be intersected between 20 and 30 m below surface, while bores in the Proterozoic fractured rock aquifers typically intersect water below 30 m from surface.<br>• Water table lies at approximately 10 to 20 m depth.<br>• The black soil areas of the plains are low in permeability (recharge rate ~ 0.1 mm/y) and receive no fresh recharge, while the red soils which generally overlie the sandstone bedrock, receive moderate recharge (~ 40 mm/y) through the wet season.<br>• No areas where sinkholes occur that represent preferential pathways to the aquifer. |
| Amadeus Basin | | • Aquifers have developed in sandstones, dolomites and shales and occur in primary (intergranular) and secondary porosity (fractures, karst).<br>• Depending on location, the depth to aquifers will vary from near surface (30 m) to over 100 m - water table may be from close to surface to below 100 m.<br>• One permeability study undertaken in the Amadeus Basin over the Mereenie Sandstone in the Rocky Hill region. This region is outside the area mapped as overlying prospective shale gas source rocks, but results could be indicative of weathered Mereenie Sandstone across the Amadeus Basin.<br>• Drainage rate was between 80 and 130 mm/y.<br>• There are no features such as sinkholes, which could represent a preferential pathway to the underlying aquifer. |
| Pedirka Basin | | • The aquifer overlying the Pedirka Basin comprises mainly sandstones within the sediments of the Great Artesian Basin (GAB).<br>• The permeable of sediments that form the aquifer may be intersected from ground surface around the margin areas of the basin with the water table existing at approximately 60 m.<br>• Beyond the sub cropping margins, the sediments of the GAB are overlain and the aquifer is confined by the impermeable mudstones of the Cretaceous aged Rolling Downs Group of rocks.<br>• In the area underlain by the Pedirka Basin, the top of the GAB sediments may be intersected from surface in the western margin to hundreds of metres beneath mudstone towards the centre of the basin.<br>• The sediments of the GAB are highly permeable where they outcrop. Where they are overlain by the Rolling Downs Group, the aquifer is confined and is not susceptible to surface infiltration. |

**Figure 7.4:** Cambrian Limestone Aquifer overlying the three main Basins (Daly, Wiso, and Georgina) and the Beetaloo Sub-basin. Source: DENR.[24]




24 DENR submission 230.

Two other groundwater studies currently underway will provide additional information on the Beetaloo Sub-basin groundwater systems. Unfortunately, these studies will not be completed in time to be considered by the Panel. They will, however, contribute to the acquisition of baseline information that the Panel has recommended as a prerequisite to the commencement of production of any onshore shale gas industry (see Section 7.4.3).

The first of these studies is being undertaken by Geoscience Australia as part of its *Exploring for the Future* programme.[25] Geoscience Australia is studying the regional groundwaters in two regions: in the South Stuart Corridor (between Alice Springs and Tennant Creek), and the Northern Stuart Corridor (around Daly Waters). Both studies include the collection of targeted new baseline geoscience information, including geophysical surveys, hydrogeological mapping and groundwater chemistry analysis, to provide regional-scale estimates of aquifer volumes and groundwater quality (including salinity). These investigations will help identify potential recharge areas in all of the project areas, while also establishing baseline monitoring sites to better understand groundwater aquifers and processes, including relative rates of recharge. For the Northern Stuart Corridor, Geoscience Australia has advised the Panel that, *"there is reasonable data and understanding of the groundwater system north of Daly Waters, but very sparse data south of Daly Waters".*[26] Both the Northern and Southern Stuart Corridor studies will be completed by June 2020.

The second study is being undertaken by CSIRO, which has been engaged by Origin and Santos to characterise the groundwater environment, assess the flow mechanisms in the CLA, and assess the groundwater recharge rate and age of water in that aquifer.[27] This study is expected to be completed by mid-2018.

With all potential onshore shale gas areas in the NT, there is very little information about the nature of the deeper groundwater systems, and moreover, there is limited understanding (based on deep exploration drilling to date) of the deeper geological systems in these basins. The relatively impermeable nature of gas bearing shales, and their distance beneath potable water aquifers, suggests very limited and extremely slow (likely to be in the order of thousands of years) interchange between shale rocks and overlying aquifers under existing conditions.[28]

### 7.2.3 Aquatic ecosystems and biodiversity

Rivers, wetlands and other water-dependent ecosystems are a dominant feature of the northern (higher rainfall) region of the NT, and are also critical ecosystems in many parts of the central and southern more arid regions.[29] Far northern Australia has one of the world's highest concentrations of free-flowing (undammed) rivers, and these, along with their associated wetlands, are of international significance because of their ecological intactness and high biodiversity values.[30]

**Figure 7.3** illustrates the surface water networks in the NT. Most of the streams shown are temporary. Those in the north generally flow each year during the summer wet season (intermittent), while those in the southern semi-arid regions flow for only short periods of time during larger wet seasons (ephemeral), and those in arid regions may not flow for many years (episodic). Temporary water bodies (for example, waterholes and billabongs) also occur in the semi-arid and arid regions of the NT, but generally only for short periods of time after substantial rains.[31] They are particularly important in supporting biodiversity (aquatic and terrestrial) and provide valuable ecosystem services.[32]

25 Geoscience Australia submission 414.
26 Geoscience Australia submission 414, p 5.
27 Santos submission 420, pp 10-11.
28 US EPA 2016a, Chapters 6.50-6.52.
29 Duguid et al. 2005.
30 Lukacs and Finlayson 2008.
31 Duguid et al. 2005.
32 Acuna et al. 2017, pp 13-14.

While there has been considerable research undertaken over the past decade to improve the knowledge of surface water aquatic ecosystems in northern Australia,[33] there is still a need for this knowledge to be synthesised and collated into a coherent package for use in water resource and environmental management in the NT. There is limited understanding of the aquatic ecology of the temporary streams and waterbodies that dominate the semi-arid and arid regions of Australia,[34] or the environmental flows required to maintain most of Australia's tropical rivers in good ecological health.[35] One exception is the Daly River, where extensive hydrological research has been undertaken to underpin sustainable agricultural development.[36]

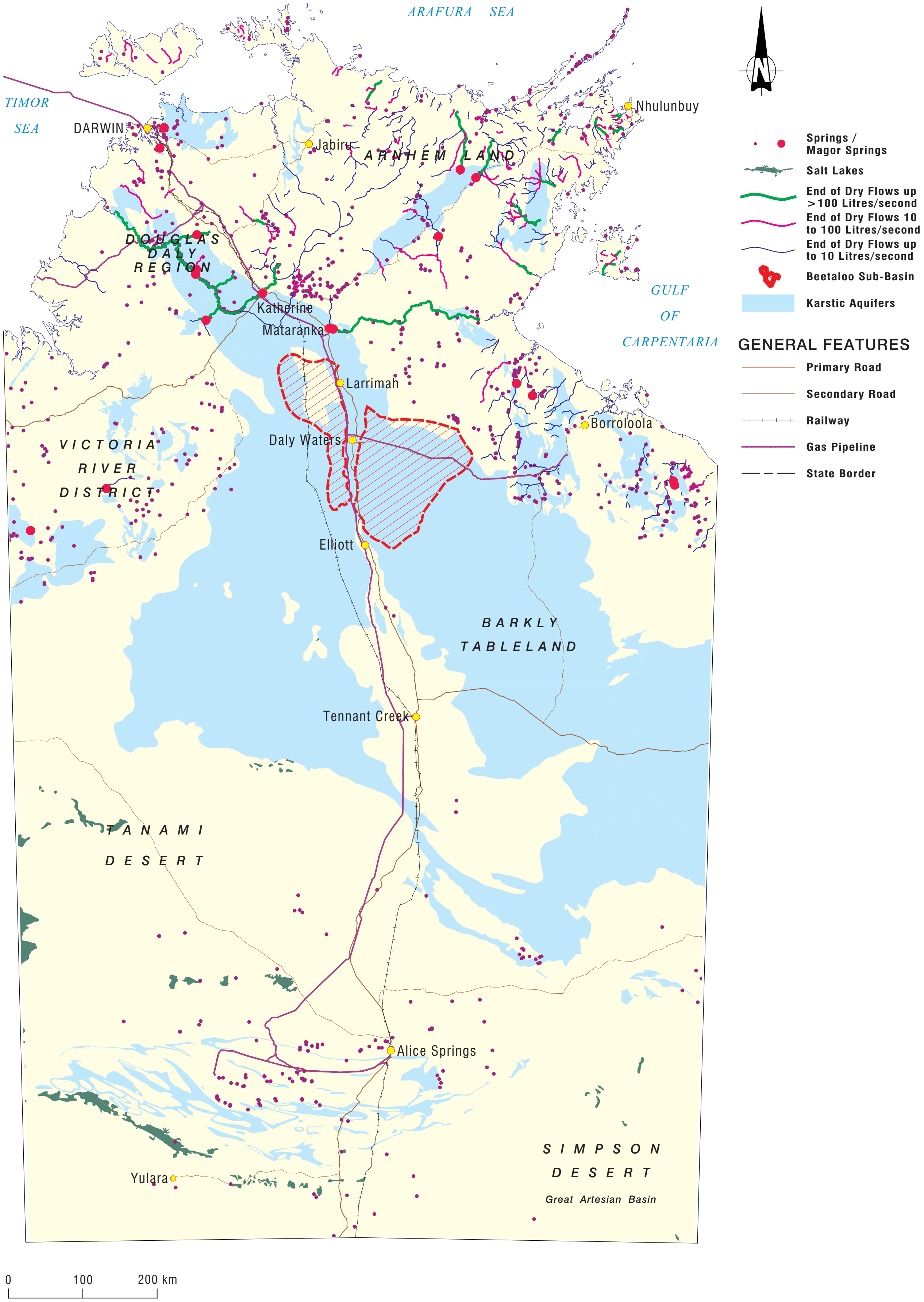
This lack of knowledge is not unique to Australia. Recently, Acuna et al. lamented the lack of effective recognition and management of temporary streams around the world.[37] They argued that temporary streams in arid and semi-arid landscapes are particularly important in supporting biodiversity, provide valuable goods and services, and should be managed as unique ecohydrological types, not as "second-class ecosystems".[38] In addition to acknowledging that they are unique ecosystems, there is a need to develop conservation targets and management action plans to ensure these temporary aquatic systems are not further degraded.[39]

The Panel has recommended that the improved understanding of the flow-ecology relationships of these systems be undertaken as part of the strategic regional environmental and baseline assessment process recommended in Section 7.4.3. (***Recommendation 7.5***) and Chapter 15.

There is limited knowledge about groundwater dependent ecosystems (**GDE**) in the NT (**Figure 7.5**). Many types of GDE exist, including surface water ecosystems that rely on the surface expression of groundwater, such as rivers, waterholes and springs, terrestrial ecosystems that rely on the subsurface presence of groundwater, and subterranean ecosystems, including cave and aquifer ecosystems.[40]

33 Pusey and Kennard 2009; Close et al. 2012; King et al. 2015; Waltham et al. 2013; Pearson et al. 2015.
34 Beesley and Prince 2010; Davis et al. 2017.
35 Warfe et al. 2011; King et al. 2015.
36 Erskine et al. 2003.
37 Acuna et al. 2014; Acuna et al. 2017.
38 Acuna et al. 2017, pp 13-14.
39 Acuna et al. 2017, pp 15-17; Boulton 2014.
40 BOM 2017a.

**Figure 7.5:** Map of the groundwater-dependent ecosystems in the NT. Source: DENR.



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There is increasing awareness around Australia of the importance and need for protection of subterranean ecosystems, including stygofauna (the invertebrates living in aquifers). For example, in Western Australia, stygofauna are recognised as being of global significance due to high levels of endemism and substantial diversity.[41] They are known to occur in aquifers in limestone, sandstone and alluvium in the Kimberley region.[42] Recently, Queensland released guidelines for the assessment of stygofauna,[43] and NSW released risk assessment guidelines for groundwater dependent ecosystems.[44] The Panel is not aware of any studies of stygofauna within aquifers in the NT.

### 7.2.4 Water use and management

The NT supports a diverse range of water-dependent industries, including agriculture, horticulture, pastoralism, tourism and recreational fishing. The two largest perennially flowing rivers, the Daly and the Roper, are particularly important tourist and recreational fishing destinations, and are fed from the Daly, Georgina and Wiso Basins.[45] The pastoral and horticultural industries are also heavily dependent on groundwater.

#### *7.2.4.1 Water Act*

Water resource planning in the NT occurs under the Water Act 1992 (NT) (**Water Act**). The Controller of Water and Minister for Environment and Natural Resources (**Minister for Environment**) have powers and decision-making functions under the Water Act and are supported by DENR.[46] The Water Act provides for statutory-based water licences (entitlements), the declaration of Water Control Districts (**WCDs**), and the development of water allocation plans (**WAPs**) within the WCDs.[47]

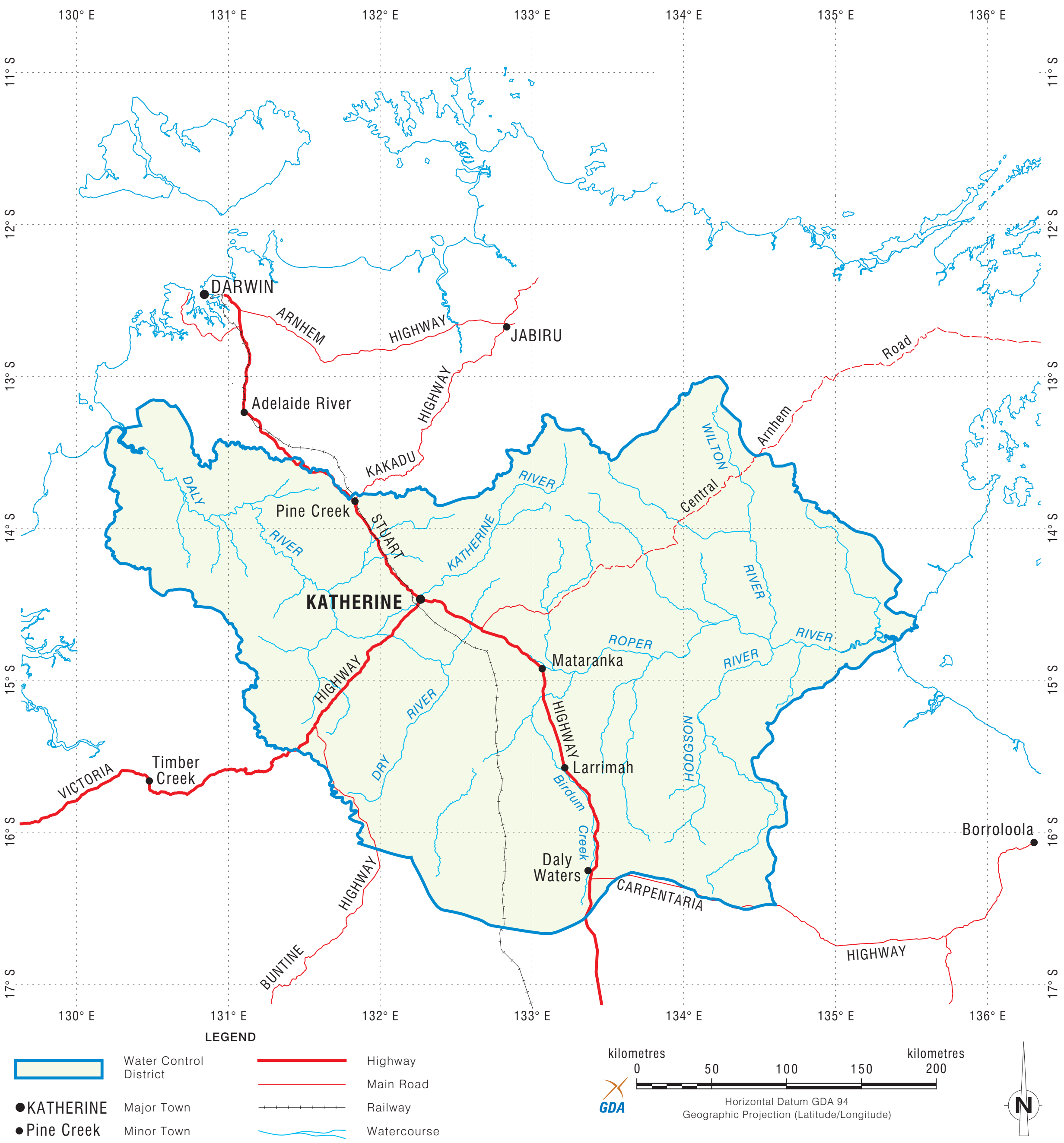
WCDs have been declared in areas of the NT where there is a need for improved management of water resources to avoid overusing groundwater, river flows, or wetlands. Currently, there are eight WCDs in the NT. Of particular relevance to this Inquiry is the Daly-Roper WCD covering the northern part of the Beetaloo Sub-basin (**Figure 7.6**)[48] and the Alice Springs WCD covering the western part of the Amadeus Basin.

WAPs are developed in consultation with community and technical groups and outline how a water resource (for example, a river or an aquifer) is to be managed. They set out the objectives, rules and strategies, and monitoring and performance indicators for managing the water resource to maximise environmental, economic, social and cultural outcomes (a beneficial use).[49] WAPs set limits on the availability of water assigned to each beneficial use, and define rules for managing water licences (entitlements) and water trading.[50]

WAPs have been declared for Alice Springs, Western Davenport, Katherine and Berry Springs.[51] New WAPs are being prepared for Mataranka-Daly Waters, Oolloo, Howard and Ti Tree. Three WAPs will exist within the Daly-Roper Water Control District, Katherine, Oolloo and Mataranka-Daly Waters, with the latter covering the northern part of the Beetaloo Sub-Basin.[52]

41 WA EPA 2016.
42 WA EPA 2007; Humphreys 2006.
43 Queensland DSITI 2015.
44 Serov et al. 2012.
45 DENR submission 230, p 3.
46 DENR submission 230, p 4.
47 Water Act, s 22.
48 https://nt.gov.au/environment/water/water-control-districts.
49 https://denr.nt.gov.au/land-resource-management/water-resources/water-allocation-plans.
50 DENR submission 230, pp 1-7.
51 https://denr.nt.gov.au/land-resource-management/water-resources/water-allocation-plans.
52 DENR submission 230, p 6.

**Figure 7.6:** Daly-Roper water control district. Source: DENR.





**Notes:**

1. **Revocation:**
   *Northern Territory Government Gazette No. G50 dated 17 December 2008 revoked on 8 December 2008 the Katherine Water Control District declared on 26 April 2007 and published in Gazette No. G19 dated 9 May 2007.*
2. **Declaration:**
   *Northern Territory Government Gazette No. G50 dated 17 December 2008 declared on 8 December 2008 the Daly Roper Water Control District.*
3. **Purpose:**
   *Daly Roper Water Control District declared for surface water and groundwater management purposes.*



NORTHERN TERRITORY GOVERNMENT

The NT Water Allocation Planning Framework (**Framework**) provides a framework for how water must be allocated in the NT. The Framework requires that water be allocated first to non-consumptive purposes (that is, environmental and cultural purposes). Allocations for consumptive uses (that is, for agriculture and pastoral uses where the water does not return to the water resource system) are then made in respect of the remaining resource. In determining how much water should be allocated to consumptive and non-consumptive uses, the Framework provides that all available scientific data should be used. Where no scientific research is available, the Framework sets rules for how water is to be allocated. [53] For the Top End of the NT, these rules require that 80% of a river flow at any time, and at least 80% of the annual recharge of an aquifer must be allocated to the environment. For the arid zone (which includes the semi-arid zone), at least 95% of a river's flow at any time must be allocated to the environment, and for aquifers, there should be no deleterious change to groundwater dependent ecosystems, and total extraction over a period of at least 100 years should not exceed 80% of the total aquifer storage at the start of extraction.

The Government recently introduced a Strategic Aboriginal Water Reserve policy to provide Aboriginal people *"with increased opportunity to access water resources for their economic development. Strategic Aboriginal Water Reserves (SWRs) are a reserved percentage of water from the consumptive pool within a Water Allocation Plan area exclusively accessible to eligible Aboriginal people to use, or trade."* [54]

Many high yielding aquifers within the NT are close to full allocation against the prescribed contingent allocations.[55] Groundwater and surface water resources in a number of specific areas such as Alice Springs, Darwin Rural, Douglas Daly, Katherine and Mataranka are recognised as being under pressure from resource development.[56]

#### *7.2.4.2 Application of the Water Act to petroleum activities*

Petroleum activities (which would include the extraction of any onshore shale gas) are currently exempt from the application of certain provisions of the Water Act, including the requirement to have a water extraction licence (entitlement).[57] This also means that shale gas operations are not considered in WAPs. The exemption of shale gas developments has been the case since the introduction of the Water Act in 1992, reflecting Government's longstanding position that activities undertaken on petroleum tenements are appropriately regulated by petroleum legislation administered by DPIR.

On 18 November 2015, the previous Government announced its intention to amend the Water Act to remove this exemption so that the Water Act would also apply to mining and petroleum activities.[58] The current Government has also committed to remove the exemption to ensure that the mining and petroleum industries are subject to the same licence and permit requirements as all other water users.[59] To date, however, this amendment has not occurred.

If the Water Act is amended, the effect will be that gas companies will be required to obtain a water extraction licence for groundwater under s 30 of the Water Act. Gas companies would also require a licence from the Controller of Water Resources to drill or construct a water bore, discharge to a surface or groundwater system, build a dam or similar structure, interfere with a waterway, recharge an aquifer, or dispose of waste underground. The Water Act currently prohibits all these activities unless a person has a licence or exemption.

At this stage, it is unclear to the Panel what conditions the Controller of Water Resources would place on water extraction by gas companies should the relevant exemption under the Water Act be removed.

The Panel notes that under the current water legislation, water licences for consumptive uses are free, a situation that does not exist anywhere else in Australia.[60] The Panel is firmly of the view that the Water Act should be amended to require shale gas companies to acquire and pay for water extraction licences for their activities. For example, assuming that permanent licences for 3,000-5,000 ML /y of water are needed for the Beetaloo Sub-basin shale gas operations (see Section 7.3.1.4), at a possible cost of $1,000 per ML, this would raise $3 to $5 million for the Government.

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53 DENR submission 230, Appendices A and B.
54 NT Government 2017c.
55 DENR submission 230, Appendices A and B.
56 DENR submission 230, p 6.
57 Water Act, s 7; DENR submission 230, p 7.
58 DENR submission 230, p 7.
59 DENR submission 230, p 10.
60 NWC 2015.

The Panel also notes a recent report by the Productivity Commission that the Water Act is still not compliant with the National Water Initiative. It recommended that, *"the Northern Territory should establish statutory-based entitlement and planning arrangements that provide for water access entitlements that are long-term, not tied to land, and tradable"*.[61]

***Recommendation 7.1***

***That the Water Act be amended prior to the grant of any further exploration approvals to require gas companies to obtain water extraction licences under that Act.***

***Recommendation 7.2***

***That the Government introduces a charge on water for all onshore shale gas activities.***

#### *7.2.4.3 Petroleum Act*

Currently, water use and extraction by gas companies is regulated under the Petroleum Act and supporting regulations. In terms of water extraction on a petroleum exploration permit, the Petroleum Act allows interest holders to *"use the water resources of the exploration permit area for his domestic use and for any purpose in connection with his approved technical works program and other exploration"*.[62]

In the event that the water extraction in a petroleum permit area may have an adverse environmental impact, an environment management plan must be approved under the Petroleum Environment Regulations before the activity can proceed (see Chapter 14). It is open to the Minister for Resources to attach conditions to any approval of an environment management plan to ensure that the undertaking of the activity is consistent with the principles of ESD.[63]

At this stage, it is not clear what conditions the Minister would place on water extraction because the Minister has not considered any application under the Petroleum Environment Regulations to undertake hydraulic fracturing.

As noted above, the Panel has recommended that the Water Act be amended immediately, and in so doing, duplication in approvals for the same activity should be avoided.

#### *7.2.4.4 EPBC Act*

The *Environment Protection and Biodiversity Conservation Act 1999* (Cth) (**EPBC Act**) provides the legal framework to protect and manage nationally and internationally important flora, fauna, ecological communities, and heritage places. The Act can trigger a requirement for an environmental impact assessment of activities that are listed as having potential impact on matters of national environmental significance (**MNES**), including nationally threatened species and migratory species. If a MNES might be affected by a development, the project may require assessment under the EPBC Act.

In 2013, the Australian Government introduced a 'water trigger' into the EPBC Act through the *Environment Protection and Biodiversity Conservation Amendment Act 2013* (Cth). Specifically, this amendment provides that water resources are a MNES in relation to CSG and large coal mining development. An action that involves a CSG development or a large coal mine requires approval from the Commonwealth Minister for the Environment if that action has, will have, or is likely to have, a significant impact on a water resource. Currently, the water trigger in the EPBC Act does not apply to shale gas developments despite water resources clearly being of environmental significance to these developments. There is no good reason why that Act should not be amended to apply the water trigger to onshore shale gas.

***Recommendation 7.3***

***That the Australian Government amends the EPBC Act to apply the 'water trigger' to onshore shale gas development.***

61 Productivity Commission 2017, p 24.
62 Petroleum Act, s 29(2)(d).
63 Petroleum Environment Regulations, cl 11(2)(a)(i).

## 7.3 Likely water requirements of any onshore shale gas industry in the NT

The onshore shale gas industry in Australia is still in its relative infancy, and the average volume of water needed to hydraulically fracture Australian shales is not as well known as the average volume required for CSG extraction.[64] The actual volume required for the hydraulic fracturing process in any given basin depends on the local geological conditions (such as depth to shale layers, porosity and existing fractures in the shale), the number and length of the horizontal wells, and the number of fracture stimulations along each horizontal well. It can vary both within, and between, geological basins.

Current estimates indicate that typically 1-2 ML is required for each of the well drilling and hydraulic fracturing stages of a fracture stimulation program,[65] although actual volumes can vary depending upon the particular conditions at a site, the length of the horizontal well, and the number of fracturing stages. For example, the US EPA reported that the median volume of water required to fracture a horizontal gas well in the US in 2014 was 19 ML, noting that the average number of fracturing stages at this time was about 14. This number has now increased to about 30 stages.[66] Origin has suggested that it will require 50-60 ML for drilling and stimulation per well in the Beetaloo Sub-basin, based on a 20-40 stage hydraulic fracturing program per well, while also noting that the industry is utilising longer laterals and an increased number of hydraulic fracturing stages.[67]

The water requirements for Origin's 2016 testing of the Amungee NW-1H well in the Beetaloo Sub-basin were consistent with this estimate, with approximately 11 ML required for the full 11-stage fracture stimulation program, and between 0.7 to 1.4 ML per stage.[68] Section 7.3.1.4 provides further details on the potential water requirements for drilling and hydraulic fracturing for a possible shale gas development in the Beetaloo Sub-basin.

DPIR has identified four major basins in the semi-arid and arid regions of the NT where onshore shale gas development could potentially take place (see Chapter 6).[69] Given that surface water resources typically only occur in these regions for a few months of the year, and even then only during large wet seasons, it is likely that groundwater will be the main water resource available for any onshore shale gas developments, at least in semi-arid and arid regions of the NT.

It is increasingly common practice for proponents to recycle as much of the flowback fluid from the hydraulic fracturing operations as possible.[70] This can comprise up to 30-80% of the water requirements for the operation, depending on the amount that reports as flowback,[71] and therefore, reduce the demand for groundwater. However, the extent to which this flowback water can be reused for hydraulic fracturing depends on its salt content and any residual chemicals. Origin, Santos and Pangaea Resources Pty Ltd (**Pangaea**) all expect to recycle in excess of 30% of the flowback fluid.[72] Origin has indicated that the composition of the flowback water from the Amungee NW-1H well would be compatible with reuse for subsequent hydraulic fracture operations.[73]

The Panel considers the major water use by any onshore shale gas industry would be for drilling and hydraulically fracturing. Although, as the Northern Land Council has indicated in its submission, the industry will need water for other uses including, *"water requirements for infrastructure, construction, dust suppression, maintenance and drinking".* [74]

64 ACOLA Report, p 114.
65 ACOLA Report, pp 113-114; US EPA 2016a, pp 4-10; APPEA submission 215, pp 45-46.
66 US EPA 2016a.
67 Origin submission 153, p 85.
68 Origin submission 153, p 86.
69 DPIR submission 226, p 2.
70 US EPA 2016a, Chapter 8.1.
71 US EPA 2016a, Chapter 8.
72 Origin submission 153; Santos submission 168, p 97; Pangaea submission 220, p18.
73 Origin submission 433, pp 20-26.
74 Northern Land Council, submission 471 (**NLC submission 471**), p 8.

## 7.3.1 Beetaloo Sub-basin case study

### *7.3.1.1 General*

As noted in Chapter 6, the Beetaloo Sub-basin is the most prospective shale gas region in the NT (**Figure 6.2**). It is also a region where groundwater resources have been relatively well studied, albeit with important knowledge gaps. As stated above, it is for this reason that the Panel has used the Beetaloo Sub-basin as a case study to better understand the water-related risks associated with any onshore shale gas industry in the NT.

The Beetaloo Sub-basin is a subsurface basin within the broader McArthur Basin, with no surface expression or local outcropping of the rocks. The Sub-basin has a thickness of greater than 3,000 m below the overlying basins and the Sturt Plain (**Figure 7.7**). It underlies a relatively flat landscape (115-319 m Australian height datum (**AHD**)) and has an area of approximately 27,000 km². The Sub-basin's climate ranges from a dry tropical savannah climate in the north, to a warm desert climate towards the south. The average rainfall ranges from around 800 mm in the north to around 600 mm in the south (**Table 7.1**). This rainfall is closely linked to the northern Australian monsoonal system, and falls largely between December and March each year.

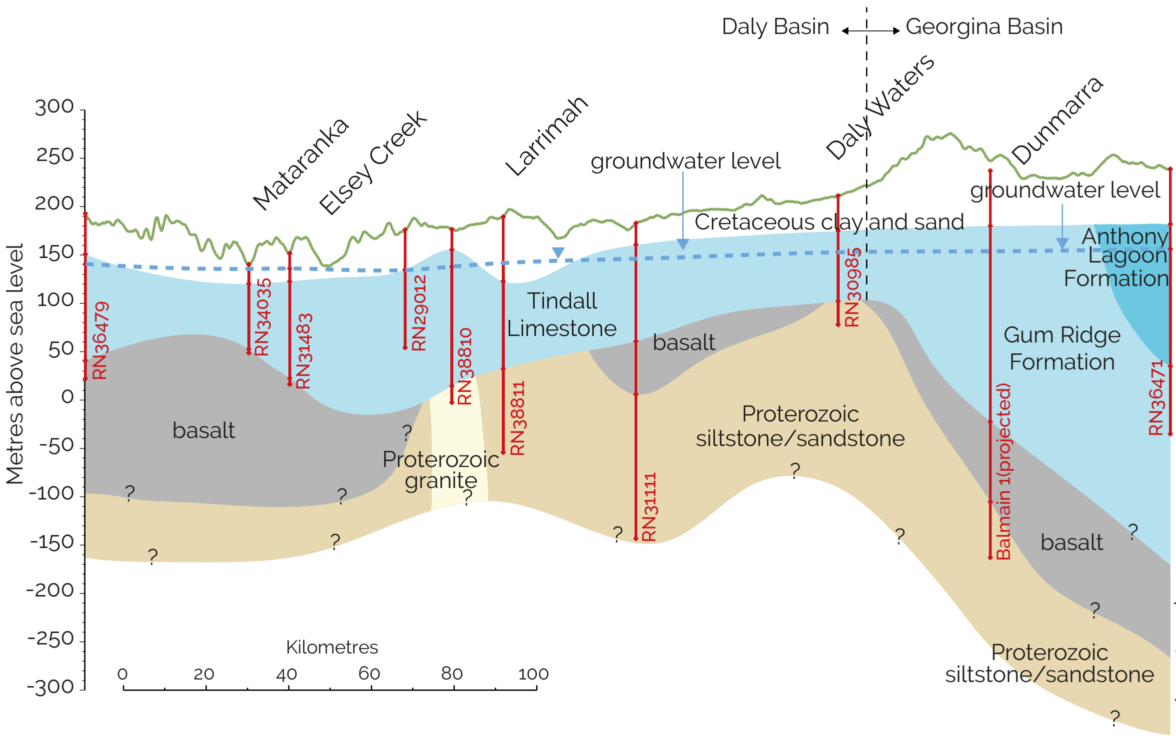
**Figure 7.7 (a):** Stratigraphic section of the Beetaloo Sub-basin region showing the relative positions of the Anthony Lagoon Formation and Gum Ridge Formation aquifers. Source: Origin.[75]

| Thickness (m) | Age | Lithology | Formation | |
|---|---|---|---|---|
| 0-130 | Cretaceous | | | Undifferentiated Cretaceous |
| 0-200 | Cambrian | | 🔵 | Anthony Lagoon Formation |
| 0-300 | | | 🔵 | Gum Ridge Formation |
| 0-440 | | | | Antrim Plateau Volcanics |
| 0-75 | | | 🔵 | Bukalara Sandstone |
| | Proterozoic | | | Chambers River Formation |
| | | | | Bukalorkmi Sandstone |
| | | | 🟠 | Kyalla Formation |
| | | | | Moroak Sandstone |
| | | | 🟠 | Velkerri Formation |
| | | | | Dolerite |
| | | | | Bessie Creek Sandstone |

🔵 Potable Aquifer 🟠 Hydrocarbon Target Zone

75 Origin submission 153, p 54.

**Figure 7.7 (b):** Geological cross section from Mataranka to south of Daly Waters of the Cambrian Limestone Aquifer, showing the Tindall Limestone, the Gum Ridge Formation and the Anthony Lagoon Formation. Source: Tickell 2015.[76]




The Panel has received submissions from Imperial Oil and Gas and Hancock Prospecting Pty Ltd (**Hancock Prospecting**) expressing concern that they may be disadvantaged if only the Beetaloo Sub-basin is considered for the development of any onshore shale gas industry.[77] Imperial Oil and Gas argues that it has viable shale gas reservoirs covered by exploration permits in the McArthur Basin Central Trough.[78] Hancock Prospecting has two exploration permits (EP 153 and EP 154) east of Mataranka and outside the area of Beetaloo Sub-basin (see **Figure 6.6**).

Imperial Oil and Gas and Hancock Prospecting have also argued that the boundary marked on **Figure 6.6** is arbitrary and that additional drilling is likely to show the shale resource extending further to the north.[79] They also note that the Northern Territory Geological Survey is conducting work in this region. Hancock Prospecting EP 154 is close to the Roper River and Elsey National Park, and it is undoubtedly for this reason that Hancock Prospecting has informed the Panel that it will relinquish portions of EP 154 to allow a 25 km buffer from the Mataranka Hot Springs and the Roper River and a 15 km buffer from Elsey National Park.[80] Hancock Prospecting has indicated to the Panel that these buffer zone distances *"were a subjective assessment … of the distance required to provide comfort to the community that these areas were not at risk, rather than any reference to any scientific rationale."*[81] In response to the Panel's questions, Hancock Prospecting provided references to studies suggesting that hydraulic fracturing of shale gas resources was unlikely to cause problems to surface water aquifers.[82] However, these studies are not specific to the area covered by Hancock Prospecting's EP. Additionally, Hancock Prospecting has not provided any evidence that its use of the groundwater resources would not adversely affect groundwater-dependent ecosystems in this region (for example, Mataranka Hot Springs). The Panel also notes that Mataranka business owners, residents and Aboriginal communities have rejected this suggested buffer zone as *"not enough"*.[83]

76 Tickell 2015.
77 Imperial Oil and Gas Pty Ltd, submission 300 (**Imperial Oil and Gas submission 300**), p 5; Hancock Prospecting Pty Ltd, submission 461 (**Hancock Prospecting submission 461**).
78 Imperial Oil and Gas Pty Ltd, submission 408 (**Imperial Oil and Gas submission 408**).
79 Imperial Oil and Gas submission 300, p 5; Hancock Prospecting submission 461.
80 Hancock Prospecting submission 461, pp 1-2.
81 Hancock Prospecting Pty Ltd, submission 645 (**Hancock Prospecting submission 645**), p 3.
82 Hancock Prospecting submission 645, p 3.
83 The Katherine Times, 27 September 2017, p 7.

Mataranka Falls. Source: Max Rawlings.

#### *7.3.1.2 Surface water*

The Beetaloo Sub-basin consists of three surface water drainage basins (**Figure 7.3 (b)**):[84]

- first, the internally draining Newcastle Creek and Bucket Creek system that ends in Lake Woods;
- second, the north-west flowing Western Creek and Birdum Creek system that drains into Elsey Creek and then into the Roper River; and
- third, the largely east flowing creeks that drain towards the Gulf of Carpentaria, including Limmen Bight River, October Creek and Cox River.[85]

Although these creeks flow only for short periods during the wet season, there can be substantial flows and flooding depending upon the wet season, as is shown by the modelled one-in-10-year and one-in-100-year flood flows in Newcastle Creek, Daly Waters Creek and Elsey Creek in **Table 7.3**. Additionally, **Figure 7.8** shows the modelled extent of flooding for a one-in-100-year flood event, primarily for Newcastle Creek.[86] Ms Pauline Cass[87] provided information to the Panel to make the point that the Beetaloo Sub-basin is prone to severe storms and flooding during the wet season, making access to well pads and infrastructure difficult during these times, and also making wastewater ponds at risk of overflowing.

84 DENR submission 449; Gautam 2017, p 9, Fig 3.1.
85 Santos submission 168, pp 50-51. The headwaters of these streams are associated with the Santos EP161, located on the eastern edge of the Beetaloo Sub-basin.
86 DENR submission 449; Gautam, 2017, pp 10-14.
87 Ms Pauline Cass, submission 1152, p 2.

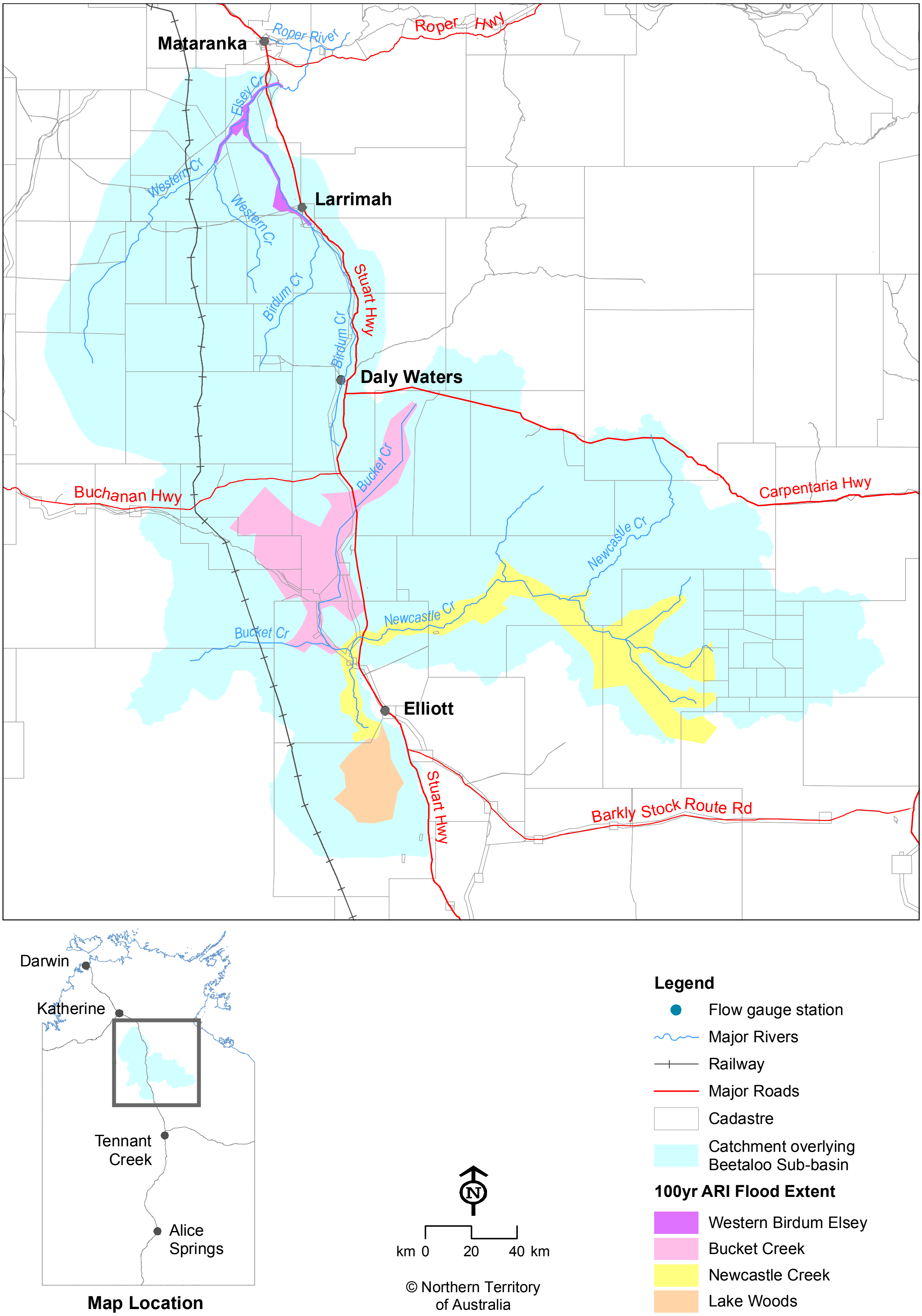
High flow in Newcastle Creek. Source: Dr. Matt Bolam.

**Table 7.3:** Flood frequency analysis for major creeks in the Beetaloo Sub-basin. Flows in ML/d. See **Figure 7.3** for gauging station locations. Source: DENR.[88]

| | Newcastle Cr at Stuart Highway (G0280009) | Daly Water Cr (G9030124) | Elsey Cr at Warlock Ponds (G9030001) |
|---|---|---|---|
| 1:100-year flow | 362,000 | 12,000 | 126,000 |
| 1:10-year flow | 53,000 | 2,200 | 26,000 |

88 DENR submission 449.

**Figure 7.8:** The extent of a 1:100 year flood in Newcastle and Bucket Creeks. Source: DENR.






NORTHERN TERRITORY GOVERNMENT

The CLA is critical for maintaining baseflow in the Roper River system and for sustaining Elsey National Park, Mataranka thermal pools, Red Lily Lagoon, and the riparian vegetation along the Roper River beyond the Beetaloo Sub-basin.[89] The Tindall aquifer extension of this system to the northwest also maintains base flow in the Daly River. However, the Panel has very little information on the location, hydrological characteristics and ecology of temporary water bodies more broadly in the Beetaloo Sub-basin. An exception is the recent report on the biology of Longreach Waterhole[90]. The Panel has recommended that this information be obtained as part of a SREBA (see Section 7.4.3 and ***Recommendation 7.5***).

#### *7.3.1.3 Groundwater*

The limestone formations, including the Tindall Limestone in the Daly Basin, the Montejinni Limestone in the Wiso Basin and the Gum Ridge Formation in the Georgina Basin, host the majority of the groundwater resources in the region (**Figure 7.4**).[91] However, no hydrogeological distinction is made between each of the formations, and they are considered to constitute a single, extensive aquifer system: the CLA.[92]

The Beetaloo Sub-basin groundwater system consists of two parts: east and west of the Stuart Highway (**Table 7.2**).[93] Groundwater systems hosted in the Georgina (east) and Wiso (west) Basins, respectively, overlie these parts. East of the Stuart Highway, the Georgina Basin hosts two groundwater systems: an upper system within the Anthony Lagoon Formation and a lower system within the limestones of the Gum Ridge Formation. To the west of the Stuart Highway, the Wiso Basin in the Sturt Plateau region is mostly shallow and hosts a single thin aquifer in the Montejinni Limestone.[94] In much of the Georgina Basin, the Gum Ridge aquifer occurs below the Anthony Lagoon Beds, approximately 35-220 m (average 105 m) below the surface (**Figure 7.7 (b)**).[95] To the north in the Daly Basin, the hydro-stratigraphically equivalent Tindall Limestone Aquifer forms the main aquifer system.

The regional groundwater flow of the aquifers in the Beetaloo Sub-basin is generally northwards, as shown in **Figure 7.4**. It has been reported that the flow is greater in the north (steeper hydraulic gradient) and that the lower hydraulic gradient in the south is due to the more limited recharge due to lower rainfall. Groundwater flow rates vary considerably from tens of m/y around Katherine to 1 m/y and less in the Beetaloo Sub-basin.[96]

The Panel has been informed by DENR that no monitoring of groundwater levels is currently undertaken in either the Anthony Lagoon Formation or Gum Ridge Formation aquifers and *"hence, there is no knowledge of the behaviour and response to seasonal or event based recharge to the Anthony Lagoon Formation aquifer. Any inference of recharge in the Gum Ridge (Tindall Limestone) Formation basin is made through assessment of groundwater quality data and water isotope analysis which indicate fresher and younger groundwater on the western margin of the basin (approximately parallel to the Stuart Highway)."* [97]

An estimated 800 registered water bores in the Beetaloo Sub-basin[98] extract around 6,000 ML/y of groundwater, presumably from the shallow CLA, with most of this used for stock watering.[99] This aquifer also provides domestic water for several Communities, including Elliott, Newcastle Waters, Daly Waters and Larrimah. Just north of the Beetaloo Sub-basin, the towns of Mataranka and Katherine access water from the same aquifer system. Katherine is the largest user at 8,000 ML/y, although not all of this comes from the Tindall Limestone Aquifer.[100]

There is limited information about the groundwater systems in rocks underlying the CLA and their connectivity with this groundwater system.

89 Bruwer and Tickell 2015; A Knapton submission 426.
90 Dr. Matthew Bolam, submission 523; Eldridge and Schubert 2017.
91 DENR submission 428, pp 7-8.
92 DENR submission 428, p 7.
93 DENR submission 428, p 8.
94 Fulton and Knapton 2015; Bruwer and Tickell 2015; GHD 2016; DENR submission 428, p 8.
95 DENR submission 428, p 8; Fulton and Knapton 2015, pp 38-40.
96 Department of Environment and Natural Resources, Submission 429 (**DENR submission 429**), pp 2-4.
97 DENR submission 230, p 2.
98 Origin submission 153, p 46.
99 Fulton and Knapton 2015.
100 DPIR submission 226, Addendum 2.

Water bore.

## Groundwater processes

Knowledge of the recharge rate of an aquifer is important because it is used by water resource management agencies to estimate the 'sustainable yield' of an aquifer, that is, the volume that can be extracted annually for consumptive uses without causing short- or long-term adverse impacts on the aquifer.

Details of the processes controlling recharge of the majority of the CLA are poorly known,[101] although it is considered that recharge only occurs in the wet season when rainfall intensity and duration are sufficient to overcome evapotranspiration. Infiltration through sinkholes and preferential recharge through soil cavities are thought to be the dominant recharge mechanisms. DENR suggests that recharge through the soil matrix only occurs if the total annual rainfall exceeds around 700 mm/y.[102] Bruwer and Tickell found that the observed groundwater levels around Mataranka (rainfall 1,035 mm/y) were seasonally responsive, while those at Larrimah (rainfall 860 mm/y) showed a muted response to rainfall.[103]

For the most studied northern part of the CLA, between Mataranka and Daly Waters, the recharge rate has been estimated at between 100,000 ML/y and 300,000 ML/y.[104] Jolly et al. derived a recharge rate of around 100,000 to 130,000 ML/y, largely on the basis of the dry season flow in the Roper River, assuming this is entirely groundwater fed.[105] However, Bruwer and Tickell used a number of empirical approaches to estimate a higher recharge rate for the region between Mataranka and Daly Waters of around 330,000 ML/y over the past 30 years.[106]

The area around Mataranka (that is, up to around 20 to 40 km away from the springs and Roper River area) has very different hydrogeology to that in the Beetaloo Sub-basin. The hydrogeological environment of the Beetaloo Sub-basin is characterised by a deep water table, thick unsaturated zone, intervening clay strata and lower rainfall, and therefore, recharge. The environment around Mataranka is dominated by weathered Tindall Limestone with a thin cover of Cretaceous sandstone, a shallower water table, a thinner unsaturated zone, and reduced clayey strata in the unsaturated zone, and a higher rainfall.[107]

101 Fulton and Knapton 2015, p 37.
102 DENR submission 428, p 12.
103 Bruwer and Tickell 2015, pp 32, 35.
104 Jolly et al. 2004; Bruwer and Tickell 2015; Fulton and Knapton 2015, p 38.
105 Jolly et al. 2004.
106 Bruwer and Tickell 2015.
107 Bruwer and Tickell 2015; A Knapton submission 426, p 3.

There is also evidence for preferential pathways from the surface to the groundwater as the geological environment around Mataranka is similar to that around Katherine with karstic formations and sinkholes evident.[108] The thinner and more permeable unsaturated layer, the possible preferential pathways, and the higher rainfall all contribute to the higher recharge of groundwater in this area.[109] Estimating recharge rates for surface aquifers in the southern region of Beetaloo Sub-basin from Daly Waters to Elliott is complicated due to the two-aquifer system in this region (that is, the Anthony Lagoon Formation aquifers overlying the Gum Ridge aquifers (**Figure 7.7 (b)**) and the lower rainfall (**Table 7.1**).[110] Geoscience Australia has noted that. *"there is reasonable data and understanding of the groundwater system north of Daly Waters, but very sparse data south of Daly Waters"*.[111]

Tickell and Bruwer suggest that the Anthony Lagoon Formation aquifers are most likely recharged through two possible mechanisms: direct infiltration of rainfall, or the infiltration of standing surface water accumulated in the shallow chain of lakes on the Barkly Tablelands following large rainfall events.[112]

Direct infiltration recharge to the Gum Ridge aquifers between Daly Waters and Elliott is not likely due to the confining sediments of the Anthony Lagoon Formation. Bruwer and Tickell suggest that the most likely recharge mechanism is through the sediments of the Ashburton Range, which forms the western boundary of this aquifer. Water quality analyses and carbon dating of groundwater in the Gum Ridge Formation support this mechanism, as fresher and younger groundwater occurs in the aquifer parallel to the western contact zone.[113]

The most recent information available to the Panel indicates that because of the very low hydraulic gradient and low recharge, the rate of groundwater flow over the bulk of the Beetaloo Sub-basin is unlikely to exceed 1 m/y.[114] This slow rate of movement has important implications for the design of monitoring systems as well as for assessing the risk likely to be posed by any contamination of the groundwater (see Sections 7.6.1, 7.6.2 and 7.6.3). By contrast, further to the north and closer to the discharge zone into the Roper River, the flow velocity has been estimated to be as high as 1,000 m/y.[115]

As noted earlier, both Geoscience Australia and CSIRO are currently undertaking regional and local-scale studies to improve understanding of recharge mechanisms and total aquifer storage and sustainable yield in the Beetaloo region. Unfortunately, these studies are not scheduled for completion in time for the Inquiry to deliver this Report.

### Water quality

The near surface (that is 100-200 m deep) groundwater quality within the Beetaloo Sub-basin is quite good.[116] In the underlying Gum Ridge Formation, the total dissolved salts (**TDS**) concentration is around 500 mg/L, while the overlying Anthony Lagoon aquifer is saltier (TDS around 1,000 mg/L), but is used by pastoralists for stock watering because of the extra cost of having to drill into the deeper (lower salinity) Gum Ridge aquifer.

Fulton and Knapton and Tickell and Bruwer have summarised water quality data for the major groundwater basins, including the Beetaloo Sub-basin.[117] The major ion concentrations for the Gum Ridge and Anthony Lagoon aquifers in the Beetaloo Sub-basin are shown in **Table 7.4**. Both aquifers display a Na-Ca-Mg cationic signature and a $HCO_3$-$SO_4$ anionic signature. The high proportion of Ca-Mg-$HCO_3$ is expected in these limestone and dolomite aquifer systems.[118]

As discussed further in Section 7.5.2, it is possible that the gas companies could use deeper, poorer quality groundwater for hydraulic fracturing.

108 Karp 2008; A Knapton submission 426, p 3.
109 Bruwer and Tickell 2015; A Knapton submission 426, p 3.
110 DENR submission 428, p 14; Tickell and Bruwer 2017, pp 35-45.
111 Geoscience Australia Submission 414, p 5.
112 Tickell and Bruwer 2017, pp 19-21.
113 DENR submission 428, p 14; Tickell and Bruwer 2017.
114 DENR submission 429, pp 2-3.
115 A Knapton submission 426, p 2; Karp 2005; Karp 2008.
116 Fulton and Knapton 2015, p 38.
117 Fulton and Knapton 2015, p 39; Tickell and Bruwer 2017, pp 23-31.
118 Fulton and Knapton 2015, p 40.

**Table 7.4:** Groundwater quality of Beetaloo Sub-basin aquifers. Source: Fulton and Knapton 2015, Tickell and Bruwer 2017.[119]

| Aquifer | No of samples | Conductivity (uS/cm) | Lab pH (mean) | Major ion concentration (mg/L)* | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Na | Ca | Mg | $HCO_3$ | $SO_4$ | Cl |
| Gum Ridge | 144 | 350-3000 (1390) | 7.5 | 2-440 (130) | 16-200 (86) | 11-116 (53) | 56-680 (440) | 6-650 (150) | 2-620 (160) |
| Anthony Lagoon | 86 | 670-6470 (1590) | 7.6 | 9-380 (150) | 12-300 (88) | 25-134 (57) | 86-530 (330) | 18-980 (230) | 16-570 (210) |

* mean concentration in brackets

## Groundwater dependent ecosystems

There is insufficient information concerning GDEs in the Beetaloo Sub-basin or elsewhere in the NT. The SREBA recommended in Section 7.4.3 seeks to address this knowledge gap.

DENR suggests that groundwater dependent surface ecosystems are unlikely to occur in the Beetaloo Sub-basin because the groundwater table in this region is typically greater than 30 m deep and is not connected to the surface.[120] However, the Panel is not aware of any systematic survey to locate groundwater dependent surface ecosystems in this region and that it is possible that some may be present.

It is also possible that stygofauna are present in these aquifers, but again the Panel has not been able to identify any studies of stygofauna in that region. The potential importance of stygofauna has been highlighted in at least one submission.[121] Given the karstic nature of the landscape, the Panel's view is that there is considerable likelihood of groundwater dependent (including stygofauna) or groundwater influenced ecosystems associated with springs, sinkholes, caves and preferential groundwater flow pathways in the Beetaloo Sub-basin. Such groundwater dependent ecosystems are likely to be susceptible to excessive groundwater use and any contamination from shale gas hydraulic fracturing operations.[122]

As noted above, the Daly and Roper river systems are important groundwater dependent ecosystems. Their flows during the dry season are sustained by groundwater discharges from the CLA.[123] Although the Roper River system is outside the Beetaloo Sub-basin, concern has been expressed that this system could be adversely affected if the quantity or quality of the aquifer discharging into this system was influenced by any shale gas industry in the Beetaloo Sub-basin.[124] The Panel's assessment of the risks to surface and groundwater dependent ecosystems are contained in Section 7.7.

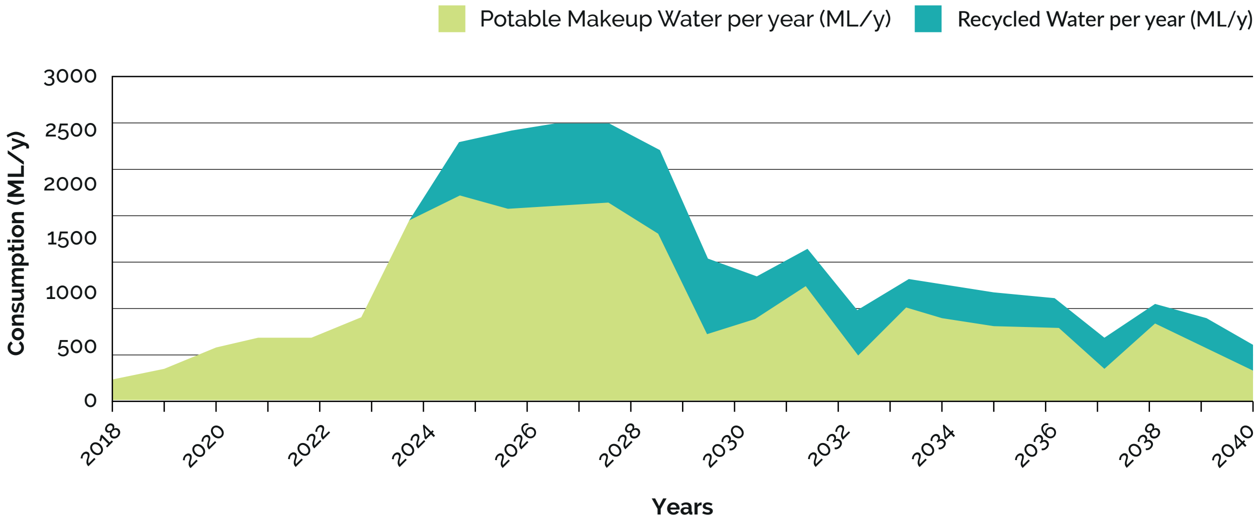
### *7.3.1.4 Possible development scenarios*

The three petroleum companies currently with exploration activity in the Beetaloo Sub-basin, Origin, Santos and Pangaea, have provided the Panel with various possible onshore shale gas development scenarios.[125] Their estimates suggest a combined development over the next 25 years that could result in some 1,000 to 1,200 wells, associated with approximately 150 well pads.[126]

The development scenario proposed by the petroleum industry will require an average of 2,500 ML/y (up to 5,000 ML/y at peak demand) of water for well drilling and hydraulic fracturing,[127] or a total of 20,000-60,000 ML from the aquifer system over the 25 years. Origin provided indicative water requirements for a 450 well shale gas operation over 25 years, which will require an average of around 1,200 ML/y, reaching a maximum of around 2,500 ML per year between years five and nine (**Figure 7.9**).[128]

119 Fulton and Knapton 2015; Tickell and Bruwer 2017.
120 DENR submission 230, Addendum 1.
121 Stygoecologia Australasia, submission 407 (**Stygoecologia submission 407**).
122 A Knapton submission 426, p 2.
123 Bruwer and Tickell 2015.
124 Mr Michael Somers and Mrs Glenys Somers, submission 377 (**Somers submission 377**), p 1; A Knapton submission 426, p 2.
125 Origin submission 153, p 36; Santos submission 168, p 35; Pangaea submission 220, p 21.
126 Assuming eight horizontal wells per pad.
127 This assumes around 1-2 ML would be required for the drilling of each well and 1-2 ML for each hydraulic fracture stage or around 10-20 ML for a 10-stage stimulation of each well.
128 Origin submission 153.

**Figure 7.9:** Indicative water requirements for a 450 well shale gas operation over 25 years. Note this assumes 30% recycling of flowback water. Source: Origin.[129]




DPIR has also provided the Panel with estimates of the size of a potential onshore shale gas industry, and its water use, in the NT.[130] DPIR envisages a larger shale gas industry, possibly around 6,250 wells, for the Beetaloo Sub-basin,[131] although it should be noted that DPIR estimates do not include any assessment of the economic viability of the onshore gas industry, and are based solely on potential supply, rather than demand, scenarios with no cogent evidence supporting this estimate.[132] A development scenario that produces 53,250 PJ of gas over 40 years (around 6,250 wells, about 420 well pads), with each well producing 8 PJ of gas, would require 125,000 ML of water over the 40 years (or around 3,000 ML per year), assuming that each well requires 25 ML of water and that there is a 20% recycle rate.

## 7.4 Assessment of water-related risks

### 7.4.1 General

The Petroleum Environment Regulations[133] require that an environment management plan (**EMP**)[134] must be prepared and approved by the Minister for Resources prior to commencing hydraulic fracturing, because it is *"regulated activity"*.[135] The EMP must include an environmental risk assessment and strategies[136] to ensure that:

- onshore oil and gas activities are carried out in a manner consistent with the ESD principles; and
- environmental impacts and risks associated with onshore oil and gas development activities are reduced to a level that is ALARP and acceptable.

The Panel has used the risk assessment methodology set out in Chapter 4. For the purposes of describing the 'consequence' and 'likelihood' levels that are 'low', 'medium' and 'high', the Panel has developed the descriptions in **Table 7.5**.

129 Origin submission 153, p 86.
130 DPIR submission 226, Addendum 1.
131 DPIR submission 226, Addendum 1, p 4.
132 DPIR submission 424, p 7; DPIR submission 226, Addendum 1.
133 Petroleum Environment Regulations Guide.
134 Petroleum Environment Regulations Guide, p 20.
135 Petroleum Environment Regulations, cl 5.
136 Petroleum Environment Regulations Guide, p 26.

**Table 7.5:** Acceptability criteria adopted for the water-related risks.

| Environmental value | | Environmental objectives | Acceptability criteria |
|---|---|---|---|
| Water quantity | Surface water | To ensure surface water resources are used sustainably. | Low likelihood that water use will exceed 20% of flow at any time.(1) |
| | Groundwater - regional | To ensure ground water resources are used sustainably. | Low likelihood that water use will exceed 20% of the 'sustainable yield' at any time.(1) |
| | Groundwater - local | To ensure ground water resources are used sustainably. | Low likelihood that drawdown of water supply bores within 1 km of shale gas development will be greater than 1 m. |
| Water quality | Surface water | To maintain acceptable quality of surface water resources. | Low likelihood that any toxicant will exceed the NHMRC drinking water guidelines (human health) or ANZECC water quality guidelines (stock drinking, agriculture).(2) |
| | Groundwater | To maintain acceptable quality of groundwater resources. | Low likelihood that any toxicant will exceed the NHMRC drinking water guidelines (human health) or ANZECC water quality guidelines (stock drinking, agriculture) in water supply bores.(2) |
| Aquatic ecosystems | Surface water - use | To protect surface water dependent ecosystems. | Low likelihood that water use will exceed 20% of flow at any time.(1) |
| | Surface water - quality | To protect surface water dependent ecosystems. | Low likelihood that any toxicant will exceed the applicable ANZECC water quality guidelines for protection of aquatic life.(2) |
| | Groundwater - quality | To protect groundwater dependent ecosystems. | Low likelihood that any toxicant will exceed the applicable ANZECC water quality guidelines for protection of aquatic life.(2) |
| Aquatic biodiversity | Surface and groundwater resources | To protect surface water and groundwater aquatic biodiversity. | No significant long-term change in aquatic biodiversity. |

(1) DENR water allocation rules (DENR submission 230, Appendix A and B).
(2) Note: some toxicity of some chemicals in shale gas wastewater to human health, stock or aquatic ecosystems are not yet known.

There are a number of national and international guidelines and standards for human and environmental risk assessment that can be used to guide the development of risk assessments for onshore shale gas developments. These include:

- Standards Australia/Standards New Zealand, Risk management - principles and guidelines;[137]
- Standards Australia/Standards New Zealand, Managing environment-related risk;[138]
- *Environmental Health Risk Assessment: Guidelines for assessing human health risks from environmental hazards;*[139]
- *Environmental risk assessment guidance manual for industrial chemicals;*[140]
- *Environmental risk assessment guidance manual for agricultural and veterinary chemicals;*[141] and
- *Chemical Risk Assessment Guidance Manual: for chemicals associated with coal seam gas extraction.*[142]

137 AS/NZS 2009.
138 AS/NZS 2012.
139 enHealth 2012.
140 EPHC 2009a.
141 EPHC 2009b.
142 Australian Department of the Environment and Energy 2017a-f.

Other useful guidelines and tools include:

- *National Environment Protection (Assessment of Site Contamination) Measure;*[143]
- *Australian and New Zealand Guidelines for Fresh and Marine Water Quality;*[144]
- *Australian Drinking Water Guidelines;*[145]
- The US EPA Risk Tools and Databases;[146]
- *OECD Environmental Risk Assessment Toolkit: Tools for environmental risk assessment and management;* [147]and
- *Inventory Multi-tiered Assessment and Prioritisation* (**IMAP**) *framework* through NICNAS.[148]

Together, these documents provide useful guidance on how to undertake detailed and robust human and environmental risk assessments for any onshore shale gas development in the NT, even if not specifically tailored to that industry.

### 7.4.2 Example environment risk assessments

The Panel has reviewed a number of relevant risk assessments with a view to providing advice on 'world leading practice' environmental risk assessment for any onshore shale gas development. Only one of these assessments was directly relevant to any hydraulically fractured onshore shale gas operations in the NT. The Panel has also reviewed a number of human health risk assessments in Chapter 10 (Section 10.1.1.4), again for the purpose of providing advice on world leading practice in respect of these assessments. Somewhat disturbingly, Lane and Landis report that in the US, only three environmental risk assessments have been published, despite the huge increase in hydraulically fractured wells over the past decade or so.[149]

#### *7.4.2.1 Santos*

Santos provided two human health and environmental risk assessments that the company had conducted for its Gladstone Liquified Natural Gas Queensland CSG project for drilling fluids and hydraulic fracking fluids.[150] A similar chemicals risk assessment for the Santos Narrabri CSG project is also available.[151] While these assessments were not directly relevant to shale gas, and did not fully consider all the potential exposure pathways, the Panel considers them to have used an appropriate approach for assessing the risk of water contamination by any onshore shale gas industry in the NT. The methodology used was consistent with Australian and international (primarily European REACH, WHO and US EPA) guidance documents and protocols,[152] and was an example of the type of formal risk assessment that could be used by the industry to better assess the risks for onshore shale gas in the NT context. That is, the risk assessment considered the compositions of hydraulic fracturing fluid mixtures, and flowback and produced waters in terms of their human and environmental toxicology, and considered in detail the probability of exposure of the various receptor species or groups of people to those waters through those pathways.

#### *7.4.2.2 Origin*

Origin has submitted to the Panel its EMP for the Amungee NW-1H hydraulic fracturing operation undertaken in 2016.[153] As part of this EMP, Origin commissioned AECOM Australia Pty Ltd (**AECOM**) to undertake a risk assessment for the hydraulic fracturing test program at the Amungee NW-1H well in the Beetaloo Sub-basin.[154] This used a similar methodology to the Santos risk assessments described above.

The AECOM risk assessment evaluated the toxicity of the individual chemicals used in the hydraulic fracturing process and estimated the cumulative risks of the total fluid mixture to humans, and terrestrial and aquatic biota. It also assessed the flowback waters using the

143 NEPC 2013.
144 ANZECC 2000.
145 NHMRC 2016.
146 US EPA 2017c.
147 OECD 2015.
148 https://www.nicnas.gov.au/chemical-information/imap-assessments.
149 Lane and Landis 2016.
150 Santos 2016a.
151 Santos 2016b.
152 Santos Ltd, submission 280 (**Santos submission 280**), pp 109-111, 134-135.
153 Origin submission 153.
154 Origin Energy Ltd, submission 466 (**Origin submission 466**).

measured chemical composition, which included the chemicals (geogenics) leached from the deep shale formation. The methodology incorporated an assessment of potential exposure routes to humans and environmental biota, with the following identified as the only potentially complete exposure pathways:

- incidental ingestion and dermal contact of flowback fluid by human trespassers at the flowback fluid storage ponds; and
- potential releases of flowback fluid to aquatic environments.

The Panel is critical of this risk assessment insofar as possible exposure pathways were excluded as not being complete (that is, one or more steps in the exposure pathway were assessed to be missing). But, surprisingly, based on the assumed success of the risk mitigation measures that Origin proposed, AECOM assessed that there were no pathways by which hydraulic fracturing chemicals could have an impact on beneficial groundwater in the project area. AECOM did assess that potential impacts to surface water ecosystems could occur if substantial releases of flowback water from the above ground flexi-ponds, due to integrity or piping failure or overflow due to high rainfall, resulted in overland flow to surface water bodies, but it found likelihood of that occurring as low due to the type of storage units used and the leak detection systems employed. Not surprisingly, given the very limited scope of this risk assessment, AECOM assessed the overall risk to human health and environment associated with the chemicals involved in hydraulic fracturing at the Amungee well as 'low'. It should be noted that this assessment, while designed to be somewhat generic, was developed for an exploration well, and was not a risk assessment for a multi-well production pad for a fully developed operational onshore shale gas production field.

### *7.4.2.3 National Chemical Risk Assessment*

The Panel also received a submission of human health and environmental risk assessments and associated exposure pathway conceptualisations from the Commonwealth Department of the Environment and Energy,[155] the NCRA. The NCRA considers the potential risks to the environment (surface and near surface water environments) and human health of the 113 chemicals identified as being used for CSG extraction in Australia in the period 2010 to 2012.[156] The focus of the assessment is on the impacts of surface discharges (spill or leaks) on surface water and near-surface groundwater extending to potential down gradient effects on surface water through overland flow or discharge of the shallow groundwater into surface waterways. The concentration on surface issues is based on international experience that indicates the surface is the highest risk pathway for activities associated with the extraction of onshore shale gas.

Although scenario-based rather than fully probabilistic, and also for CSG and not shale gas, these risk assessments demonstrate that detailed assessments for any onshore shale gas development in the NT is both feasible and desirable. The package of products from the NCRA includes a national guidance document that provides world leading practice advice on approaches for human and environmental risk assessments for the coal and coal seam gas industries.[157]

In particular, the new risk assessment guidance specifies that naturally occurring geogenic chemicals mobilised by drilling or hydraulic fracturing, and found in drilling fluids and drilling muds, flowback and produced water, brines, and treated water, should be included as an essential component of any risk assessment. Also included are recommendations for direct toxicity assessments of complex mixtures, such as fracking fluids and produced waters, where use of toxicity values for individual chemicals may either overestimate or underestimate the toxicity of the mixture.[158] The approaches outlined in this guidance document could be readily adapted for any development of any onshore shale gas industry in the NT.

***Recommendation 7.4***

***That the Government develops specific guidelines for human health and environmental risk assessments for all onshore shale gas developments consistent with the National Chemicals Risk Assessment framework, including the national guidance manual for human and environmental risk assessment for chemicals associated with CSG extraction.***

155 Australian Department of the Environment and Energy 2017a-f.
156 Australian Department of the Environment and Energy 2017a-f.
157 Australian Department of the Environment and Energy 2017a-f.
158 Australian Department of the Environment and Energy 2017a-f.

### 7.4.3 Strategic regional environmental and baseline assessment (SREBA)

As noted above, the Panel has sought to assess the water-related risks using the risk assessment framework detailed in Chapter 4. However, in attempting to do this, it is apparent that available knowledge and data on the NT's water resources (surface and groundwater) and their associated aquatic ecosystems is presently insufficient to permit the risks associated with the development of any onshore shale gas industry in the NT to be assessed with certainty. Accordingly, the Panel has applied the precautionary principle when developing its recommendations to mitigate risks.

It is therefore the Panel's view that there is a need for a SREBA so that the environmental impacts and risks associated with the development of any prospective onshore shale gas basin in the NT are fully understood and can be appropriately managed. The Beetaloo Sub-basin should be the first priority for a SREBA because this is the most likely area for an approval production licence to be granted for the purpose of producing onshore shale gas if the Government lifts the moratorium (see Chapter 6).

The need for baseline information has been referred to in many submissions, noting that without such information it is not possible to know whether future changes, for example, in groundwater quality or methane levels, are due to any onshore shale gas industry. The Environmental Defenders Offices of Australia (**EDOA**) in a submission to a Senate Inquiry into water use by extractive industries noted the need for

> *"improved standards for upfront environmental impact assessment should be developed, including: minimum standards for groundwater and surface water modelling; improved consideration of the capacity of a water resource to support mining operations, and ultimately rehabilitation activities, over time; a requirement that decision makers must not approve a project until the proponent has provided adequate baseline data and has adequately addressed any concerns raised by the regulator or independent assessors advising the regulator; and application of the precautionary principle."* [159]

The SREBA should focus on providing a baseline understanding of the surface and groundwater resources, hydrogeology, aquatic ecosystems and terrestrial ecosystems using data that is representative of the geographic, climatic, and hydrogeological characteristics of any prospective basin, and an assessment of the vulnerability of these systems to any hydrological changes associated with any onshore shale gas development. This vulnerability assessment will require the development of regional groundwater and surface water models of sufficient complexity to be able to predict the effects of water abstraction by the industry on availability of water for human, agricultural and pastoral, and environmental needs (see Chapter 15 for details on the objectives and scope of a SREBA).

In this regard, the Panel notes that in the May 2017 budget, the Commonwealth has extended the bioregional assessment program for CSG and coal mining to include shale gas development. Additionally, $30.4 million has been allocated for new combined geological and bioregional resource assessments in three (unspecified) onshore regions.[160] It is currently unclear how these initiatives will progress the understanding necessary to inform management of any onshore shale gas industry in the NT, although the Panel notes that the understanding of deeper groundwater systems is unlikely to be able to be sufficiently progressed without primary data acquired from the drilling of the deeper sequences containing shale gas.

The Panel received many submissions[161] and comments during the community forums suggesting that a SREBA should be undertaken before any exploration drilling and hydraulic fracturing occurs. Having said this, the Panel also received submissions from the gas industry arguing that current regulations are sufficient to allow exploration to occur during the conduct of the SREBA.[162] Having carefully considered all submissions and comments, the Panel has nevertheless retained its earlier finding that a SREBA can occur concurrently with exploration (see Chapters 15 and 16) (with respect to the Panel's recommendation to overcome 'exploration creep'

159 EDOA 2017, p 3.
160 Australian Government 2017b.
161 Lock the Gate Alliance Northern Territory, submission 1250 (**Lock the Gate submission 1250**).
162 Australian Petroleum Production and Exploration Association, submission 1251 (**APPEA submission 1251**); Origin submission 1248; Pangaea submission 1147; Santos submission 1249.)

see Chapter 14 in Section 14.7.5), with the caveat that if the Government lifts the moratorium, specific recommendations must be implemented prior to any further drilling and hydraulic fracturing occurring. Further details are provided in Chapters 15 and 16.

***Recommendation 7.5***

***That before any further production approvals are granted, a regional water assessment be conducted as part of a SREBA for any prospective shale gas basin, commencing with the Beetaloo Sub-basin. The regional assessment should focus on surface and groundwater quality and quantity (recharge and flow), characterisation of surface and groundwater-dependent ecosystems, and the development of a regional groundwater model to assess the effects of proposed water extraction of the onshore shale gas industry on the dynamics and yield of the regional aquifer system.***

## 7.5 Water quantity

The Panel's first environmental objective in assessing the water-related risks of any onshore shale gas industry in the NT is to ensure surface and groundwater resources are used sustainably.

There is considerable concern in the community that any onshore shale gas development in the Territory will use greater volumes of groundwater than can be sustained without causing adverse effects on groundwater levels both locally and regionally. As noted previously, it is unlikely that adequate reliable surface water resources exist in the Beetaloo Sub-basin, or other prospective regions of the NT, to sustain the annual water use requirements of an onshore shale gas industry.

To assess the potential scale of risks to groundwater resources, the Panel sought information on the potential water use by a shale gas development in the Beetaloo Sub-basin consisting of 1,000 to 1,200 hydraulically fractured wells (see Section 7.3.1.4). The Panel also sought information on the potential for the gas companies to reuse some of the treated or untreated wastewater (flowback or produced water), or to use more saline groundwater from deeper aquifers. Both these options are technically feasible, but whether they are adopted will depend upon detailed site investigations, consideration of possible environmental impacts, regulatory requirements, and cost.

Below the Panel has assessed the following risks to surface and groundwater resources that may arise in connection with the development of an onshore shale gas industry in the NT: first, unsustainable water extraction for well drilling and hydraulic fracturing; and second, potential adverse effects to surface or groundwater supplies from seismic activity caused by hydraulic fracturing or reinjection of wastewaters.

### 7.5.1 Unsustainable use of surface water

The Panel has concluded that the temporary nature of the surface water resources (rivers, streams and waterholes) in the semi-arid and arid regions of the NT makes it unlikely that surface waters are suitable for hydraulic fracturing. Additionally, such use would be undesirable because of the importance of these temporary systems to the functioning of aquatic ecosystems. The major companies with petroleum exploration permits in the Beetaloo Sub-basin area (Origin, Pangaea and Santos) have all assumed in their submissions that they will not use surface water resources for hydraulic fracturing.[163]

The Panel has assessed the likelihood that the gas companies will use an excessive amount of surface water for hydraulic fracturing as 'low'. This is because there is an insufficient amount of surface water available for much of the year and, when it is available, it is unreliable. However, there is still a possibility that any onshore shale gas development may seek to use surface water resources in wetter areas outside the Beetaloo Sub-basin, where surface water resources may be available during the wet season.

The Panel has assessed the consequences of excessive use of surface water resources as 'medium', an assessment primarily based on the unacceptable impacts that a lack of water may have on aquatic ecosystems, wildlife, and stock requirements. These impacts could occur during the wet season if the flow regimes of streams were changed, at the end of the wet season

163 Origin submission 153, pp 46, 85-86; Santos submission 168, p 95; Pangaea submission 220, p 8.

when less water may be available for waterholes and permanent aquatic refuges, and during the dry season where water may exist for short periods of time in waterholes and refuges.[164] This is further discussed in Section 7.7.1. In the absence of any information to the contrary, the Panel considers that these seasonally available surface water resources are critical for the maintenance of floodplain and riparian ecological processes.

Although according to the Panel's risk assessment methodology the risk to surface water supplies rates is 'low' (likelihood - 'low', consequence - 'medium'), the Panel's view is that the use of surface water resources for hydraulic fracturing should be prohibited for two reasons. First, because the resource will only potentially be available for part of the year (the wet season) with implications for the dry season if excessive amounts are extracted, particularly near the end of the wet, leaving less water to fill wetlands and waterholes. And second, because the timing and volume of stream flows during the wet season is highly variable, making the development of rules around when, and if, extraction should commence and conclude in any given year quite complex (for example, each river system will require its own set of rules), which will be challenging to regulate. However, to ensure that surface water resources are not used for hydraulic fracturing, it will be important that the use of surface water for hydraulic fracturing is prohibited.

In summary, the Panel's assessment is that there is a low risk that there will be insufficient surface water available for the environment, current water uses, and future water uses as a result of hydraulic fracturing operations. However, to mitigate this risk completely, the use of surface water should be prohibited.

***Recommendation 7.6***

***That prior to the grant of any further exploration approvals, the use of all surface water resources for any onshore shale gas activity in the NT be prohibited.***

### 7.5.2 Unsustainable use of groundwater

The Panel has assessed both the regional and local impacts of excessive groundwater use by any potential onshore shale gas industry.

#### *7.5.2.1 Regional impacts*

The Panel has assessed the risk that any onshore shale gas industry will use an excessive amount of groundwater, which could result in an unacceptable reduction in the amount of water available regionally for stock and domestic use, use by other industries, and for the maintenance of a healthy environment.

As discussed previously, groundwater is likely to be the most economically viable water source for hydraulic fracturing in semi-arid and arid areas of the NT. It is possible that water could be transported to well sites, but this would be an expensive operation for total water supply.

Industry experience is reasonably consistent on the volumes of water needed for well drilling and hydraulic fracturing, although the actual volumes can change depending upon the particular conditions at a site. There appears to be a consensus of around 1-2 ML for well drilling and around 1-2 ML for each hydraulic fracturing stage, or around 10-20 ML per well for a 10-stage fracturing operation (see above Section 7.3). For example, Origin suggests that it will require 50-60 ML for drilling and stimulation per well, based on a 20-40 stage hydraulic fracturing program per well, while noting that the industry is employing longer laterals with an increased numbers of hydraulic fracturing stages.[165]

To assess the likelihood that a possible shale gas industry could use excessive volumes of groundwater, the Panel compared the above indicative volume of water with the volume being recharged annually into the various aquifers in the Beetaloo Sub-basin (as presented in Section 7.3.1).

In summary, for the northern section of the Beetaloo Sub-basin (Mataranka to Daly Waters) the Panel is aware of three estimates for the recharge rate that range from 100,000 ML/y[166] to 330,000 ML/y. The Panel has no estimates for the recharge rate of the CLA in the southern part of

164 ACOLA Report, p 115; King et al. 2015.
165 Origin submission 153.
166 Fulton and Knapton 2015; GHD 2016, Appendix A; Bruwer and Tickell 2015.

the Beetaloo Sub-basin (around Elliott),[167] although the available evidence suggests there is very little recharge in this region.[168]

As noted in Section 7.3.1.4 above, the gas industry's 25 year development scenario of between 1,000 and 1,200 wells, associated with around 150 well pads, would require an average of 2,500 ML/y (up to 5,000 ML/y at peak demand between years five and nine) of water for well drilling and hydraulic fracturing.

From a regional perspective, the use of up to 5,000 ML/y from the groundwater system appears to be a relatively small proportion (<5%) of the suggested recharge rate of 100,000 to 330,000 ML/y of the northern section.[169] However, as indicated above, additional information will be required to better define the recharge rates and sustainable yields in the Beetaloo Sub-basin, particularly in the southern part of the basin where the extraction of 5,000 ML/y may well represent unsustainable use of the groundwater resource. This may also be the case in other arid and semi-arid prospective basins in the NT, and assessment of the sustainable yield of these groundwater systems is needed to inform understanding of the potential impacts of onshore shale gas production in these regions.

Based on this information, the Panel considers that it is unlikely that any onshore shale gas industry will use an unacceptably high amount of groundwater in the northern part of Beetaloo Sub-basin (that is, north of around Daly Waters) or in other regions where there is similarly relatively high rainfall. The Panel has been unable to form a view on this matter for the southern part of the basin because there is not enough information available.

The consequences of excessive use of groundwater resources in the northern Beetaloo Sub-basin have been assessed as 'medium' for domestic and pastoralist use and for any ecosystems shown to be groundwater dependent or groundwater influenced, with the caveat that additional information is required to identify groundwater-dependent or groundwater-influenced ecosystems. However, the consequences associated with extracting water from the Gum Ridge Aquifer in the southern part of the Beetaloo Sub-basin are more serious given the expected very low recharge rate in this area. In effect, this would amount to 'mining' a slowly recharged or potentially non-renewable resource.

Accordingly, on the basis of the available evidence, the Panel has assessed the resultant risk in the northern part of the Beetaloo Sub-basin and other regions with similar or higher rainfall as 'low' (likelihood - 'low', consequences - 'low' to 'medium'), but notes that there is considerable uncertainty associated with this assessment. For the southern Beetaloo Sub-basin, and other semi-arid to arid regions, the Panel's view is that groundwater extraction for shale gas production should be prohibited until the groundwater resource is better understood. This better understanding should emerge from the SREBA recommended for the Beetaloo Sub-basin and other prospective regions (see ***Recommendation 7.5***).

The Panel also notes that if this greater knowledge of the groundwater resources, particularly in the southern Beetaloo Sub-basin, indicates a high risk of unsustainable use of the surface aquifers by the shale gas industry, the possible use of deeper groundwater for hydraulic fracturing could be considered. Both Origin and Pangaea have indicated to the Panel that this could be an option.[170] Pangaea provided quite detailed information about the Jamison sandstone aquifer system that was identified in its lease area at depths of 200-500 m below the surface.[171] Further, Origin stated that,

> *"there is insufficient data on the permeability and storage of the deep, saline aquifers at this time to know whether they could be suitable for usage in hydraulic fracturing and other development activities; however, the data that are available are not encouraging regarding the suitability of deeper, saline aquifers. The Bukalara Sandstone, however, is a freshwater aquifer that in the Beetaloo area is used in a very small number of water bores north of Origin's permits and is not used by landholders in the core area of Origin's permits."* [172]

167 DENR submission 428, p 14.
168 Tickell and Bruwer 2017.
169 DENR submission 230, Addendum 1.
170 Origin submission 433, pp 32-33; Pangaea submission 427, pp 12-13.
171 Pangaea submission 427, pp 12-13.
172 Origin submission 433, pp 32-33.

The Panel's assessment is that the risk of unsustainable use of groundwater in the northern part of the Beetaloo Sub-basin and other regions with similar or greater rainfall is 'low', assuming a WAP is established for the basin and the 80:20 sustainable extraction rule is applied to any water extraction licence granted to a gas company. However, the risk for the southern part of the Beetaloo Sub-basin, and other potential shale gas producing basins in semi-arid and arid regions of the NT, cannot be assessed without additional information.

The Panel has concerns regarding two aspects of the management of the Beetaloo Sub-basin groundwater resources. First, there is no WCD that covers the full extent of the Beetaloo Sub-basin. The current Daly-Roper WCD should be extended south to include all the Beetaloo Sub-basin (**Figure 7.6**) and one or more separate Beetaloo WAPs developed. Other WAPs will also need to be declared for shale gas producing regions prior to gas production. This will provide the necessary legislative controls over the allocation of groundwater resources to the shale gas and other industries.

Second, the Panel has assumed that DENR will apply the current groundwater allocation rule used for arid regions of the NT to the Beetaloo Sub-basin, which would mean it would be permissible to use 80% of the storage capacity of the aquifer for consumptive uses over a period of 100 years.[173] If this rule was applied to an onshore shale gas industry, or any other extractive use in the region, this would again essentially permit 'mining' of the groundwater resource, and would be ecologically unsustainable, since the recharge rate of the groundwater in this southern part of the CLA aquifer system is very slow.

It is the Panel's view that sustainable extraction limits should be set on the basis of the outputs from a regional numerical groundwater model developed as part of the SREBA to manage poorly understood groundwater systems.

***Recommendation 7.7***

***That in relation to the Beetaloo Sub-basin:***

- ***the Daly-Roper WCD be extended south to include all of the Beetaloo Sub-basin;***
- ***that WAPs be developed for each of the northern and southern regions of the Beetaloo Sub-basin;***
- ***the new northern Sub-basin WAP provides for a water allocation rule that restricts the consumptive use to less than that which can be sustainably extracted without having adverse impacts on other users and the environment; and***
- ***the southern Sub-basin WAP prohibits water extraction for any onshore shale gas production until the nature and extent of the groundwater resource and recharge rates in that area are quantified.***

***That in relation to other shale gas basins with similar or greater rainfall than the Beetaloo Sub-basin, WCDs be declared and WAPs be developed to specify sustainable groundwater extraction rates for shale gas production activities that will not have adverse impacts on existing users and the environment.***

***That in relation to other potential shale gas basins in semi-arid and arid regions, all groundwater extraction for any shale gas production activities be prohibited until there is sufficient information to demonstrate that it will have no adverse impacts on existing users and the environment.***

#### *7.5.2.2 Local impacts*

The Panel has examined the risk that water use by any onshore shale gas industry will cause an unacceptable local drawdown of an unconfined or confined aquifer,[174] making it difficult for groundwater to be extracted for use in townships, on pastoral leases, by ecosystems or for cultural purposes. At the local scale, aquifer drawdown (that is, lowering of the water level) could be substantial, depending on the rate of pumping, the spatial extent of the bore field, and the flow rate (transmissivity) within the aquifer. The Panel has assessed that an unacceptable drawdown would occur if the groundwater dropped below the level where existing water supply bores could access water with current reliability.

173 DENR submission 230, Appendix A.
174 'Unconfined aquifers' are those into which water seeps from the ground surface directly above the aquifer; 'confined aquifers' are those in which an impermeable dirt/rock layer exists that prevents water from seeping into the aquifer from the ground surface located directly above.

Origin has provided some evidence of the fast recovery of the local drawdown of the Gum Ridge Aquifer when used to provide water for the hydraulic fracturing of the Amungee NW-1H well in 2016.[175] Water was extracted from a bore field consisting of three bores at a combined rate of 7.5-10 L/s, with a total water volume of around 10 ML extracted over a 38 day period (from 1 August to 7 September 2016). The local aquifer drawdown at the extraction well during pumping was around 2.6 m, with the aquifer level rebounding to the pre-pump level almost immediately after pumping was stopped. Additionally, there was no response noted during the period of pumping in the water level at an observation bore located three km away.

DENR also provided the Panel with modelled estimates of the local drawdown for a scenario with four bores in a square formation 1.5 km apart, pumping at a rate of 10 L/s over a period of 60 days.[176] This equates to an extraction rate of around 52 ML/d or a total volume of around 208 ML, which is about a 12 times higher extraction rate than used for the Amungee well above. **Table 7.6** shows the results, which indicate that the drawdown at each bore and the lateral extent of the drawdown are dependent upon the aquifer, whether it is confined or unconfined and the assumed hydraulic parameters for the aquifer. The extent of drawdown is greatest in the confined aquifer. DENR indicated that the time for these aquifers to recover back to the pre-pump level would be around 60 days.

**Table 7.6:** Theoretical estimates of the local drawdown in three aquifer types for a bore field of four bores (in square formation 1.5 km apart) pumping at 10 L per second for 60 days. Source: DENR.[177]

| Aquifer | Transmissivity ($m^2$/d) | Storage coefficient (%) | Drawdown at each bore (m) | Drawdown at 1 km from each bore (m) | Maximum drawdown distance (km) |
|---|---|---|---|---|---|
| Unconfined Anthony Lagoon | 530 | 2 | 1.9 | 0.2 | 1.8 |
| Unconfined Gum Ridge | 1,100 | 4 | 0.9 | 0.08 | 1.9 |
| Confined Gum Ridge | 1,100 | 0.001 | 0.9 | 0.7 | 10.4 |

These calculations suggest that for aquifers in the Beetaloo Sub-basin, except for the confined sections of the Gum Ridge aquifer, the local drawdown for a pumping scenario is around 10 times greater than expected for the scenario outlined in Section 7.3.1.4 and would be minimal further than 1 km from the bore field, and that the recovery after pumping ceased would be relatively rapid. These estimates are based on the cumulative effects of pumping from a bore field of only four bores, and will be improved as further baseline information on the various aquifers, and more detail on likely water extraction scenarios, are obtained. In other regions of the NT, understanding the significance of potential impacts of groundwater extraction upon local groundwater levels will require adequate baseline information and consideration of the effects on a case-by-case basis.

Therefore, the Panel's assessment is that the likelihood of excessive local drawdown of the groundwater beyond about a 1,000 m radius of a bore field extracting water for the purpose of hydraulic fracturing is 'low'. However, the consequences of excessive local drawdown on surrounding water supply bores has been assessed as 'medium', given that if this occurred, either townships or pastoralists could run out of drinking water or stock water for periods of time.

The Panel has assessed the risk of local drawdown greater than one m in water supply bores greater than 1,000 m from a shale gas groundwater bore field as 'low' (likelihood - 'low', consequences - 'medium'), although there is still uncertainty in these figures and the risk assessment given that only results from one field trial and modelled data are available.

The Panel considers that this uncertainty can be partially addressed if the following measures are implemented:

- no onshore shale gas water extraction bore field should be located within 1 km of groundwater users unless additional information indicates that a different buffer zone is appropriate or 'make good' arrangements can be negotiated with groundwater users to ensure maintenance of water supply;

175 Origin submission 153, pp 87-88; Origin submission 433, p 75.
176 DENR submission 230, Addendum 1. Assumes the aquifers are homogeneous and isotropic.
177 DENR submission 230, Addendum 1.

- the proposed new WAP (see ***Recommendation 7.7***) includes provisions that adequately control the rate, volume and location of water extraction by the gas companies to minimise impacts;
- gas companies are required, at their expense, to monitor drawdown in local water supply bores; and
- if this drawdown is found to be excessive (that is greater than 1 m), a 'make good' requirement should be invoked requiring the reduction or termination of groundwater pumping, or the making of other arrangements to ensure the affected bores can access the groundwater (for example, by either relocating the bores or increasing their depth).

Origin submitted that it *"is committed to making impacted stakeholders whole if they are impacted by our activities. If a landholder's business or well-being is adversely impacted, we commit to remediating and/or compensating for the financial loss or loss of amenity experienced."* [178] However, all 'make good' commitments by gas companies must be enforceable (see Chapter 14).

***Recommendation 7.8***

***That the following measures be mandated to ensure that any onshore shale gas development does not cause unacceptable local drawdown of aquifers:***

- ***that prior to the grant of any further exploration approvals, the extraction of water from water bores to supply water for hydraulic fracturing be prohibited within at least 1 km of existing or proposed groundwater bores (that are used for domestic or stock use) unless hydrogeological investigations and groundwater modelling, including the SREBA, indicate that a different distance is appropriate, or if the landholder agrees to a variation of this distance;***
- ***that relevant WAPs include provisions that adequately control both the rate and volume of water extraction by the gas companies;***
- ***that gas companies be required, at their expense, to monitor drawdown in local water supply bores; and***
- ***that gas companies be required to immediately 'make good' and rectify any problems if the drawdown is found to be excessive.***

### 7.5.3 Unacceptable changes to surface or groundwater flows due to possible seismic activity caused by hydraulic fracturing

The Panel has examined the risk of changes to the flow regimes of surface and groundwater as a result of seismic activity (earth movements) resulting from hydraulic fracturing. Such changes would be unacceptable if these earth movements resulted in surface water or groundwater moving from one area to another with unintended outcomes. For example, water could become unavailable for use if it migrates to an area that is not easily accessible. Further, low quality water could migrate into high quality water systems (or the reverse) meaning that water can no longer be used for its original purpose. The movement of fracking fluids from the shale layer to a surface aquifer is discussed in Section 7.6.5.

The available evidence relating to induced seismic activity from the hydraulic fracturing process is that while low level seismic activity can be associated with hydraulic fracturing, the magnitude of this activity is likely to be very small, with minimal or no damage to surface infrastructure.[179] The UK Royal Society identified two types of seismicity associated with hydraulic fracturing: microseismic events are a routine feature of hydraulic fracturing and are due to the propagation of engineered fractures; and larger (generally rare) seismic events induced by hydraulic fracturing in the presence of a pre-stressed fault.[180] Hydraulic fracturing induced seismic activity and fault reactivation has been recently reported for the Sichuan Basin in China.[181]

The factors affecting seismicity induced by hydraulic fracturing include:[182]

- **the strength of the shale:** the stronger the rock, the greater the magnitude of the seismic event;

178 Origin submission 153, p 46.
179 Costa et al. 2017; Davies et al. 2013; Royal Society Report, p 41; UK Task Force on Shale Gas 2015, 2nd Interim Report, p 9; BC Oil and Gas Commission 2012; Clarke et al. 2014; Schultz et al. 2015; Westwood et al. 2017.
180 Royal Society Report, p 41.
181 Lei et al. 2017.
182 Royal Society Report, p 42.

- **fault properties:** the magnitude of the induced seismicity depends upon the surface area of the fault (the larger the fault the greater the seismicity) and the degree to which the fault is pre-stressed; and
- **pressure constraints:** the magnitude of induced seismicity is affected by pressure changes in the shale formation near the well, with the volume of injected fluid and injection rate generating higher pressures, and the volume and rate of flowback fluid reducing pressures.

The US experience is that seismicity levels vary with the individual shale gas basins, reflecting a combination of the depth of the shale layer and the local geology, particularly the degree of faulting in the area.[183] This suggests that while there is a moderate likelihood of localised low level seismic activity occurring, the consequences of significant impacts, that is, impacts that measurably alter volumes of surface or groundwaters, are very low.

The UK Royal Society identified three measures to mitigate possible induced seismicity as a result of hydraulic fracturing:[184]

- initial surveys to characterise stresses and identify faults - this is already a requirement of hydraulic fracturing operations in the NT;[185]
- pre-fracturing injection testing - to better characterise the particular shale formation, a small pre-fracturing injection test with microseismic monitoring can be employed; and
- monitoring of seismicity - magnitude 1.7 $M_L$ ($M_L$ is the local magnitude scale = Richter scale) is taken as the cut off criterion and if the magnitude is above 1.7 $M_L$ injection is stopped and monitoring continued.

The Panel's assessment is that the risk to the flow regimes of either surface or ground waters due to possible seismic activity caused by hydraulic fracturing is 'very low'. Existing shale gas industry requirements (listed above) are sufficient to minimise the risk of seismicity.[186]

### 7.5.4 Unacceptable changes to surface or groundwater flow due to possible seismic activity caused by reinjection of wastewater

The Panel has examined the risk of unacceptable changes to surface or groundwater flows as a result of seismic activity resulting from injecting wastewater into deep aquifers or conventional reservoirs.

There is potential for seismic activity, particularly fault reactivation, to be caused by the injection of large volumes of waste (for example, hundreds of ML) in deeper aquifers. This is most likely to occur through the reactivation of pre-existing weak faults that were not previously mapped, or whose physical properties and strength are not understood.[187]

There is a direct correlation reported between deep well reinjection and felt seismic activity.[188] Most recently, the US Geological Survey reported that reinjection of wastewater into depleted conventional reservoir wells (Class II aquifers) is the primary cause of the recent increase in low intensity earthquakes in certain areas of the central US.[189]

In the NT, the only current onshore conventional gas operations are in the Amadeus Basin, and these are the only conventional gas reservoirs that could be available for the disposal of flowback fluids or other wastewaters. It is possible that gas companies could seek to reinject treated or untreated wastewater into deep saline aquifers. The Panel has no information on the potential for seismic activity due to injection of wastewater into deep aquifers in the NT.

DPIR has indicated that while it *"does not support flowback water disposal, or any other wastewater, into freshwater aquifers … If proven safe and environmentally responsible to do so under certain conditions, safeguards and water quality requirements, deep aquifers may be considered for use for the disposal of wastewater, but only if water in the receiving aquifer is non-potable and is not connected to any other aquifer system."* [190]

183 Warpinski et al. 2012; USGS 2017.
184 Royal Society Report, pp 43-44.
185 DPIR submission 226.
186 Royal Society Report, pp 40-45; USGS 2017; UK Government 2017.
187 Drummond 2016.
188 ACOLA Report; US EPA 2016a; Costa et al. 2017; USGS 2017.
189 USGS 2017.
190 DPIR submission 424, p 10.

The Panel is unable, on the evidence available, to assess the risk of seismic activity caused by the injection of shale gas wastewater into deep aquifers. Before such activity is permitted, there must be comprehensive reservoir (aquifer) engineering studies and baseline studies undertaken to determine pre-existing subsurface stress conditions. Further, injection activities need to be managed to ensure that the volumes of wastewater being injected did not exceed the critical pressures likely to trigger the reactivation of pre-existing faults,[191] or impact on usable groundwater resources (see Section 7.6.4 for a discussion of the more general issue of reinjection into aquifers).

In view of the uncertainty regarding the operational reinjection of hydraulic fracturing wastewaters, the Panel is of the view that in order for this practice to be permitted, exhaustive investigations are required to demonstrate that seismic activity is unlikely to occur for the particular activity, and for these investigations to be approved by the regulator.

***Recommendation 7.9***

***That prior to the grant of any further exploration approvals, the reinjection of wastewater into deep aquifers and conventional reservoirs and the reinjection of treated or untreated wastewaters (including brines) into aquifers be prohibited, unless full scientific investigations determine that all risks associated with these practices can be mitigated.***

### 7.5.5 Unacceptable changes to the flow characteristics of surface waters due to the discharge of wastewaters

There is a risk of unacceptable changes to the flow characteristics of normally ephemeral surface waters due to the discharge of wastewaters, which may be particularly significant in semi-arid and arid regions. This risk is discussed below in Section 7.6.7 as part of the assessment of the risk of contamination of surface waters due to discharge of wastewater.

## 7.6 Water quality

The Panel's second environmental objective in assessing the water-related risks of an onshore hydraulic fracturing shale gas industry in the NT is to ensure the quality of surface and groundwaters (aquifers) is maintained in an acceptable condition for all users (see **Table 7.5**).

The experience from overseas, especially in the US, is that onshore shale gas operations produce considerable volumes of wastewater, which pose a risk of contamination of surface and groundwaters.[192] The composition of these wastewaters (hydraulic fracturing fluids, flowback and produced water), and their management and potential reuse, has been detailed in Chapter 5.

Petroleum companies in the NT are required to disclose to DPIR, and to the general public, *"specific information"* regarding the chemicals used in the hydraulic fracturing process.[193] But the Panel is of the opinion that the regulatory framework must make it abundantly clear exactly what information must be disclosed. Presently this is not the case. This includes all chemicals that are proposed to be used, the reason for their use, and the measures by which the risks associated with their release into the environment (including spills) will be managed by the company and regulated.

The chemicals used by Origin for the hydraulic fracturing of the Amungee NW-1H well were disclosed and are documented for reference in **Table 7.7**. The Material Safety Data Sheets (**MSDS**) and other relevant human and aquatic ecosystem toxicological data for these chemicals are compiled in the *Beetaloo Project Hydraulic Fracturing Risk Assessment Amungee NW-1H* recently prepared by AECOM for Origin (Section 7.4.2.2).[194] Of the 40 chemicals (excluding water) in this list, 19 were also assessed as part of the NCRA (Section 7.4.2.3).[195]

191 Drummond 2016.
192 US EPA 2016a.
193 Schedule, cl 342(4).
194 Origin submission 466.
195 Australian Department of the Environment and Energy a-f.

**Table 7.7:** Total masses of chemicals used for hydraulic fracturing of the Amungee NW-1H well. Source: Origin.[196]

| CAS[a] Number | Chemical name | Mass (kg) | Mass (%) |
|---|---|---|---|
| | Water | 10,633,220 | 89 |
| 14808-60-7 | Quartz, Crystalline silica (proppant sand) | 1,204,412 | 10 |
| 9000-30-0 | Guar gum | 20,619 | 0.173 |
| 67-48-1 | 2-hydroxy-N,N,N-trimethylethanaminium chloride | 17,736 | 0.149 |
| 7647-01-0 | Hydrochloric acid | 5,665 | 0.048 |
| 107-21-1 | Ethylene glycol | 4,107 | 0.035 |
| 31726-34-8 | Polyethylene glycol monohexyl ether | 2,436 | 0.021 |
| 1319-33-1 | Boronatrocalcite | 5,051 | 0.042 |
| 1310-73-2 | Sodium hydroxide (impurity) | 2,491 | 0.021 |
| 7783-20-2 | Ammonium sulfate | 880 | 0.007 |
| 91053-39-3 | Diatomaceous earth, calcined | 389 | 0.003 |
| 7789-38-0 | Sodium bromate | 1,764 | 0.015 |
| 38193-60-1 | Acrylamide, 2-acrylamido-2-methylpropanesulfonic acid, sodium salt polymer | 649 | 0.005 |
| 129898-01-7 | 2-Propenoic acid, polymer with sodium phosphinate | 1,106 | 0.009 |
| 1330-43-4 | Sodium tetraborate | 425 | 0.004 |
| 7647-14-5 | Sodium chloride | 223 | 0.002 |
| 61789-77-3 | Dicoco dimethyl quaternary ammonium chloride | 102 | 0.001 |
| 10043-35-3 | Boric acid | 133 | 0.001 |
| 10377-60-3 | Magnesium nitrate | 78 | 0.0007 |
| 110-17-8 | Fumaric acid | 133 | 0.001 |
| 10043-52-4 | Calcium Chloride | 113 | 0.001 |
| 7704-73-6 | Monosodium fumarate | 133 | 0.001 |
| 57-13-6 | Urea | 43 | 0.0004 |
| 136793-29-8 | Polymer of 2-acrylamido-2-methylpropanesulfonic acid sodium salt and | 70 | 0.0006 |
| 26172-55-4 | 5-chloro-2-methyl-2h-isothiazolol-3-one | 42 | 0.0004 |
| 67-63-0 | Propan-2-ol | 20 | 0.0002 |
| 7631-86-9 | Non-crystalline silica (impurity) | 61 | 0.0005 |
| 7786-30-3 | Magnesium chloride | 39 | 0.0003 |
| 2682-20-4 | 2-methyl-2h-isothiazol-3-one | 13 | 0.0001 |
| 111-46-6 | 2,2''-oxydiethanol (impurity) | 12 | 0.0001 |
| 7757-82-6 | Sodium sulfate | 10 | 0.00008 |
| 595585-15-2 | Diutan gum | 6.6 | 0.00006 |
| 14464-46-1 | Cristobalite | 7.6 | 0.00006 |
| 79-06-1 | 2-Propenamid (impurity) | 2.1 | 0.00002 |
| 7447-40-7 | Potassium chloride (impurity) | 3.5 | 0.00003 |
| 67762-90-7 | Siloxanes and silicones, dimethyl, reaction products with silica | 1.2 | 0.00001 |
| 63148-62-9 | Dimethyl siloxanes and silicones | 1.2 | 0.00001 |
| 64-02-8 | Tetrasodium ethylenediaminetetraacetate | 1.4 | 0.00001 |
| 7758-98-7 | Copper (II) sulfate | 1.2 | 0.00001 |
| 540-97-6 | Dodecamethylcyclohexasiloxane | 1.2 | 0.00001 |
| 541-02-6 | Decamethyl cyclopentasiloxane | 1.2 | 0.00001 |
| 556-67-2 | Octamethylcyclotetrasiloxane | 1.2 | 0.00001 |
| | TOTAL | **11,902,200** | **100** |

[a] A CAS Registry Number, also referred to as 'CASRN' or 'CAS Number', is a unique numerical identifier assigned by the Chemical Abstracts Service to every chemical substance described in the open scientific literature (https://www.cas.org/content/chemical-substances/faqs).

196 Origin submission 153, pp 343, 344.

Currently, however, the identity and concentrations of geogenics (chemicals extracted from the shale as a result of the hydraulic fracturing and gas extraction process) do not currently require disclosure. In its joint submission with DENR to the Panel, DPIR indicated that it considers that full public disclosure of the composition of wastewater is in the public interest and aligns with government policy and, following industry consultation, plans to make the information publicly available.[197]

The Panel also notes that Dr Tina Hunter has recommended that, *"the NT Department of Resources should mandate full, transparent disclosure of all chemicals used in NT fracking operations. This disclosure should be made available on the NT DoR website, and should provide detailed information on the chemicals used and location of use."* [198]

Origin has provided details of the sampling program and chemical analysis of flowback water produced from the hydraulic stimulation of the Amungee NW-1H well.[199] Assessments of the geogenic chemicals (including NORM) that were measured are also included in the risk assessment completed by AECOM.[200] The inclusion of geogenics in this risk assessment represents a first for the Australian onshore gas industry.

The Origin flowback water monitoring results are from a single location in the Velkerri B shale, and ongoing sampling of additional stimulation activities will be required to fully characterise the spatial variability of flowback water quality in this formation. The Panel also notes that the gas produced from the Amungee well was 'dry' gas. That is, it did not contain a significant component of liquid hydrocarbons. Origin stated in its announcement of a material gas resource to the Australian Stock Exchange in February 2017 that the product from the Amungee well contained approximately 92% methane, 3% ethane and 5% carbon dioxide and other inerts.[201] In the event that a 'wet' gas containing hydrocarbon condensate was produced, then the flowback and produced waters would likely contain substantially higher concentrations of hydrocarbons.[202]

Notwithstanding these caveats, it is instructive to provide a summary of the findings for flowback water from the Amungee well because it can assist in informing the Panel's assessment. Flowback water was slightly alkaline (pH 8) and about as salty as seawater, with the maximum recorded electrical conductivity and total dissolved solids 72 mS/cm and 49,200 mg/L, respectively, with more detailed water quality indicators being that:

- sodium chloride was the dominant salt, with relatively low magnesium, potassium, calcium, bicarbonate, fluoride, sulfate and carbonate levels;
- elevated barium and boron levels were observed, which is consistent with a shale source rock;
- NORM levels were found to be at the lower end of those typically observed in US shales;
- low levels of phenolic compounds and C10-C40 hydrocarbons were found, with semi-volatiles such as polycyclic aromatic hydrocarbons absent; and
- BTEX compounds were measured at trace levels.[203] Of these, benzene was the most abundant with a maximum concentration of 6 µg/L. As a point of comparison the *Australian Drinking Water Quality Guidelines* specify that it should not be detected in drinking water at more than 1 µg/L,[204] noting that flowback water is not of potable quality.

The results from the Amungee NW-1H flowback water sampling program provide increased confidence that treated flowback water from the Velkerri B shale formation could have a high potential for reuse in hydraulic fracturing operations. The majority of the compounds and parameters analysed in this flowback water were at the lower end of the concentration range reported from the US Marcellus and Barnett shale regions.[205]

197 Department of Primary Industry and Resources and Department of Environment and Natural Resources, submission 492 (**DPIR and DENR submission 492**), p 5.
198 2012 Hunter Report, Recommendation 1, p 15.
199 Origin submission 433, pp 20-26; For a full data set see Origin submission 433, Appendix 1.
200 Origin submission 466.
201 Origin 2017, announcement to ASX 15 February, 2017.
202 Goldstein et al. 2014.
203 Benzene was not detected in the hydraulic fracturing fluid so must have come from the shale: Origin submission 433, p 23.
204 NHMRC 2016, Table 10.6, p 177.
205 Origin submission 433, Appendix 1.

*Recommendation 7.10*

***That prior to the grant of any further exploration approvals, the following information about hydraulic fracturing fluids must, as a matter of law, be reported and publicly disclosed before any exploration activities and production activities are carried out:***

- ***the identities, volumes and concentrations of chemicals (including environmentally relevant chemical species present as contaminants in the bulk chemicals) to be used;***
- ***the purpose of the chemicals;***
- ***how and where the chemicals will be managed and transported on-site, including how spills will be prevented, and if spills do occur, how they will be remediated and managed; and***
- ***the laws that apply to the management of the chemicals and how they are enforced.***

***That the following information about flowback and produced water must be reported and publicly disclosed online as soon as it becomes available:***

- ***the identity and concentrations of chemicals and NORMs found in that water;*** [206]
- ***how and where the chemicals and NORMs will be managed, transported and treated, including how spills will be prevented, and if spills occur, how they will be remediated and managed; and***
- ***the laws that apply to the management of the chemicals and NORMs and how they are enforced.***

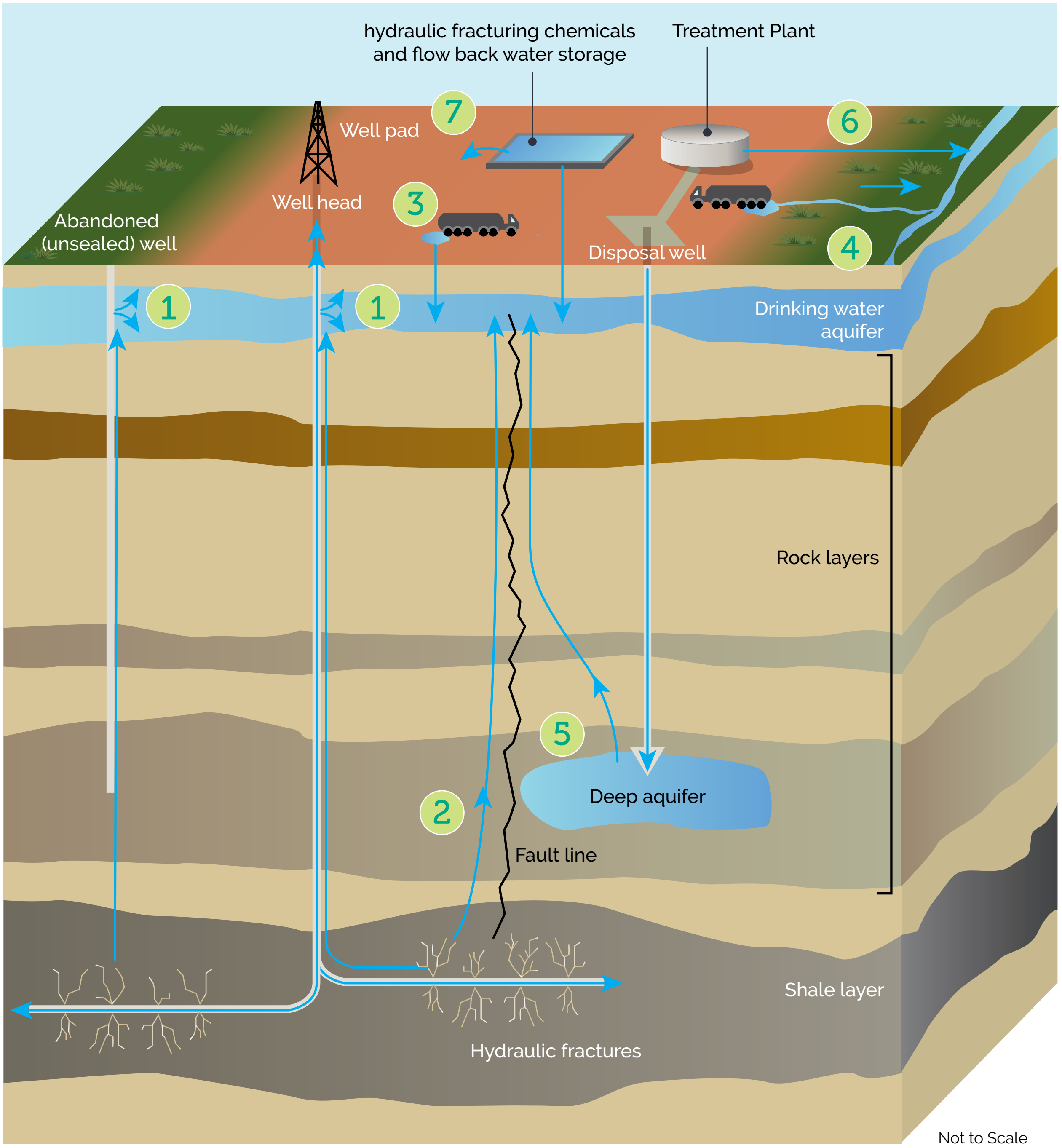
There are eight potential pathways by which onshore hydraulically fractured shale gas wastewater may contaminate groundwater or surface water (see **Figure 7.10**):

- **path 1:** leakage of hydraulic fracturing fluid, flowback or produced water, or methane from operating or abandoned wells;
- **path 2:** contamination of shallow groundwater through fractures induced by the hydraulic fracturing process by propagation of the fractures to the surface, connection of the fractures with faults, or by connection of the fractures with abandoned and unsealed deep exploration wells;
- **path 3:** surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water at the well site or other handling facility within the well pad area;
- **path 4:** surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water within the well pad that is washed off-site into a waterbody;
- **path 5:** reinjection of untreated wastewater to deep aquifers, with fault reactivation and induction of seismic activity with possible opening up of a communication pathway to the surface and/or disruption of surface flow pathways;
- **path 6:** direct discharge of treated or untreated wastewaters to surface waters or drainage lines;
- **path 7:** overtopping or failure of wastewater storage ponds or pits containing drilling fluids; and
- **path 8:** spills during transport of chemicals of wastewater from either road transports or pipelines (not shown).

The Panel has used the available evidence to assess the potential risks to the quality of surface and groundwater resources from each of these pathways, and the possible mitigation measures to reduce these risks (the risks to aquatic ecosystems are covered in Section 7.7).

206 See Australian Department of the Environment and Energy 2017c, Appendix A, for guidance on chemical species to be measured.

**Figure 7.10**: Schematic of the potential contamination pathways from a shale gas site.



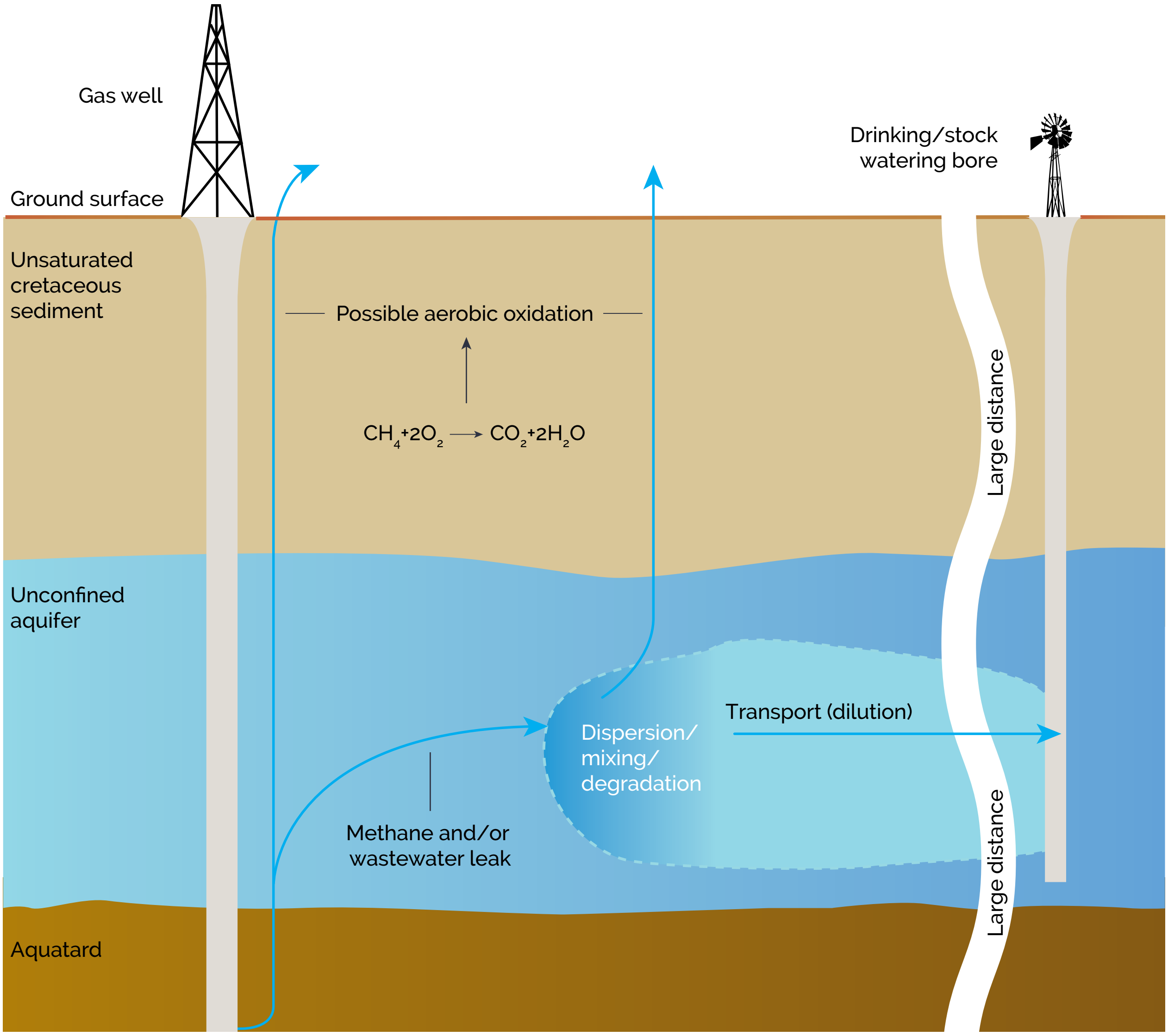

Path 1 - leakage of either hydraulic fracturing fluid, flowback or produced water, or methane from operating or abandoned wells;
Path 2 - contamination of shallow groundwater via fractures induced by the hydraulic fracturing process;
Path 3 - surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water at the well site or other handling facility within the well pad;
Path 4 - surface spills of chemicals, hydraulic fracturing fluid, flowback water or produced water within the well pad that is washed off-site into a waterbody;
Path 5 - reinjection of untreated wastewater to deep aquifers, with possible seismic activity and fault reactivation;
Path 6 - direct discharge of treated or untreated wastewaters to surface waters or drainage lines;
Path 7 - overtopping or failure of wastewater storage ponds;
Path 8 - spills during transport of chemicals or wastewater from either road transports or pipelines (not shown).

### 7.6.1 Unacceptable groundwater contamination due to leaky wells (pathway 1)

The Panel has considered the risk that groundwater could be contaminated as a result of leaky wells, and cause possible unacceptable changes[207] if this water is used for drinking or stock watering (the risk of unacceptable changes to aquatic ecosystems is covered in Section 7.7.2).

The Panel has distinguished between leaky wells that only leak methane, and those that leak both methane and wastewater.[208] Because it is a gas, methane can escape more easily than a fluid. Possible pathways for the migration of methane and formation water adjacent to a well are shown in **Figure 7.11**. Methane may contaminate surface aquifers and additionally vent to the atmosphere and contribute to the greenhouse gas impacts from shale gas operations (see Chapter 9).

**Figure 7.11:** Schematic of the potential pathways for methane and contaminated wastewater entering an unconfined aquifer from a leaky well.




The design, construction and operation of hydraulically fractured shale gas wells is covered in Chapter 5. As noted in that Chapter, it is now standard practice for a well to be lined with multiple layers of piping (casing), and with a specialised cement layer between each of the pipes and also between the outer pipe and the rock strata. These multiple casing strings are designed to prevent migration of fluids and gases between the well and an aquifer, while the cement layer is designed to isolate potential sources of saline water, hydrocarbons, flowback and produced water, from migrating up the outside of the well and contaminating freshwater aquifers.

207 See **Table 7.4**.
208 Dusseault and Jackson 2014.

The greatest potential for contamination of freshwater aquifers from a leaky well is if the leak occurs in the section of the well where it goes through the aquifer.[209] This can occur as a result of casing failure that occurs when the system is under maximum pressure during the hydraulic fracturing operation. It is this type of failure that has the greatest potential to quickly release large volumes of contaminants directly into the aquifer. The evidence presented in Chapter 5 has shown that the likelihood of this occurring is 'low'.

The second possible mechanism for contamination of groundwater is the upward migration of fluids as a result of faults in the integrity of the casing and/or cement seal around the well.

There has been considerable effort over the past decade by both the gas industry and regulators in Australia, the US and elsewhere, to improve the design, construction and operation of onshore shale gas wells. The evidence relating to the incidence of well leakage and other well failures is outlined in Chapter 5, and this demonstrates that the incidence of these issues has markedly declined as more modern methods of design, construction and regulation are implemented and is now relatively low.[210]

It is critical when assessing well performance that like is compared with like. In particular, the method and complexity of construction (that is, the category or standard of construction as discussed in Chapter 5 and illustrated in **Table 5.2**) is crucial. Comparing performance statistics through time can be misleading. It is clear that wells are now being increasingly completed to higher standards and are performing much better than those completed to lower standards. In this context, the Panel notes that the Amungee well was a Category 9 well with cement casing along the full length of the well casing to the surface.

A key distinction must also be made between the detection of methane at the surface and/or in groundwater, and the potential for that groundwater to be contaminated by chemicals from the formation water or fracturing fluids, which would cause it to become unsuitable for use for drinking or stock watering, or for general environmental use.

#### *7.6.1.1 Contamination by methane*

Methane in water is not classified as a toxic substance,[211] in contrast to various other chemicals (for example, heavy metals, metalloids and organic compounds) that may be in formation water. The limits for many (but not all) of these toxicants for human health, stock watering, agriculture and aquatic ecosystems are documented in Australian water quality guidelines.[212]

A highly quoted work on the topic of detection of methane contamination associated with shale gas wells was published by Osborn et al. in 2011, and was followed up by a publication by Jackson et al. in 2013.[213] These studies show there was methane contamination of drinking water in aquifers overlying the Marcellus and Utica shale formations of north-eastern Pennsylvania and upstate New York that was associated with shale gas extraction. Specifically, the closer (within around 2 km) a drinking water well was to an active hydraulic fracturing operation, the higher the measured methane concentration compared with non-hydraulic fracturing locations. However, it should be noted that the averages reported in these studies for sites both near and far from drilling were not materially different for groundwater in those locations sampled prior to the commencement of shale gas development.[214]

Methane has been detected in groundwater adjacent to shale gas bores in the Denver-Julesburg basin of north-eastern Colorado with a frequency that suggests a low to medium likelihood of occurrence.[215] The most recently published work on this subject concluded that most of this methane was microbially generated and likely to have come from shallow coal seams that occur in the basin, and not from the deep shale gas formations. Only 0.06% of sampled bores contained methane at depth.[216] The reason that methane was able to migrate upwards was because these shallow coal seams had not been effectively sealed off as part of the well construction process, thereby indicating the need for much closer attention to be paid to the identification of and planning for isolation of such sources during the well design phase of operations.

209 ACOLA Report; US EPA 2016a.
210 ACOLA Report; Origin submission 153; Santos submission 168; US EPA 2016a; Dusseault and Jackson 2014; King and King 2013.
211 US EPA 2016a, pp 9-46.
212 ANZECC 2000; NHMRC 2016.
213 Osborn et al. 2011; Jackson et al. 2013.
214 Vidic et al. 2013.
215 Ingraffea et al. 2014; Jackson et al. 2013.
216 Sherwood et al. 2016.

These near well detections of methane are consistent with the buoyant nature of the gas and its consequent physical behaviour, initially rising vertically close to a wellbore.[217] As the methane (in dissolved or free form) enters the groundwater it will be transported laterally, with the concentration decreasing with distance from the well as a function of dispersion, dilution, and attenuation by bacterial processes. If sufficient oxygen is present, methane can be oxidised to carbon dioxide and water (**Figure 7.11**).[218] Methane can also be oxidised under anaerobic (no oxygen) conditions if sufficient dissolved sulfate is present in the groundwater.[219]

The Panel is unable to assess the potential for microbial decomposition of methane within NT aquifers because there is insufficient information on depth profiles of dissolved oxygen and sulfate concentrations in aquifers. This information is needed to determine the thickness of aquifers likely to be able to sustain either aerobic or anaerobic degradation pathways.

As noted above, methane is not considered to be a toxic component in groundwater, however, the presence of methane can be an explosion hazard. Explosions can occur if methane accumulates to a sufficient concentration in an enclosed space (for example, in the air gap above the water in a water bore or the headspace in a tank). In this context, the US Department of the Interior advises (based on guidance developed by the US Geological Survey (**USGS**))[220] owners of wells with dissolved methane concentrations greater than 28 mg/L (approximately the solubility limit at ground surface) to immediately contact their local authorities to obtain assistance and guidance in venting the wellhead and for other possible remediation alternatives. It also recommends that methane concentrations ranging from 10 to 28 mg/L in water signify an action level where the situation should be closely monitored (and with concentrations less than 10 mg/L no action is required) other than periodic monitoring to see if methane concentrations are increasing.

These guidance values for methane concentrations are based on the potential for explosion risk under certain circumstances. They are not environmental or health risk guidelines based on the occurrence of methane in the groundwater. However, if the rate of methane flux is so high that it bubbles to the surface, or if there is a leaky well head, then there is the potential for fire at the surface. This is also an issue for greenhouse gas emissions (Chapter 9). In both cases rapid action is needed to stop the flow.

One issue that requires additional research is what happens to methane in groundwater when it is degraded by the action of special bacteria that are present and what are the consequences for groundwater quality. The aerobic (oxygen present)[221] oxidation of methane produces carbon dioxide, while the anaerobic (no oxygen present)[222] oxidation in the presence of sufficient sulfate generates bicarbonate and sulfide. While there is evidence that the oxidation of methane in groundwater can have secondary impacts on water quality close to a well, the available data suggests that this effect is of limited extent.[223]

The Panel is not able to provide any further assessment of the potential significance of the issue of methane oxidation in NT groundwaters for two reasons: first, there is insufficient data available on oxygen and sulfate concentration profiles in these aquifers and second, the occurrence of these processes and the potential for adverse impacts on groundwater quality will be very location specific. Additional information should become available as part of the SREBA recommended in Section 7.4.3 (***Recommendation 7.5***).

Rapid methods for determining methane concentrations in water are now available.[224]

#### *7.6.1.2 Contamination by wastewater*

Despite Osborn et al. having found elevated methane adjacent to shale gas wells, the authors also categorically state that they *"found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids."* [225] Specifically, there was no evidence of contamination of the shallow drinking water wells near active drilling sites from deep brines and/or fracturing fluids, with the concentrations of salts measured in these wells being consistent with the baseline historical water quality data. This conclusion is consistent with other published work.[226]

217 Dusseault and Jackson 2014.
218 Cahill et al. 2017.
219 Van Stempvoort et al. 2005; Schout et al. 2017.
220 Eltschlager et al. 2001.
221 Cahill et al. 2017.
222 Van Stempvoort et al. 2005.
223 Cahill et al. 2017; Van Stempvoort et al. 2005.
224 Gonzalez-Valencia et al. 2014.
225 Osborn et al. 2011, p 8175.
226 Vidic et al. 2013.

Recent comprehensive research using an array of geochemical fingerprinting techniques has also concluded that there is a lack of evidence for contamination of groundwater resources by deep water from shale gas formations.[227] Importantly, this study found that where there was evidence of aquifer contamination, the signature of the contaminants was consistent with that of surface spills of flowback or produced water, and not leakage from wells. That is, the contamination had occurred as a result of surface spills rather than from upwards migration through the well bore (see Section 7.6.3 for discussion of surface spills).

A recent study by CSIRO as part of the NCRA of chemicals associated with extraction of CSG (see Section 7.4.2.3 and Chapter 4 for a description of the NCRA) used computer modelling to investigate the possibility that chemicals remaining underground after hydraulic fracturing could return to the near surface environment and contaminate groundwater.[228] This study was undertaken for CSG, where the gas is extracted from a coal seam aquifer that is much closer to the surface than for a non-aquifer shale gas formation, accordingly, the results of the CSIRO study provide a more conservative assessment of likely risk given the much greater distance between the (near surface) aquifers and the very deep shale gas formations.

The following four plausible transport release scenarios for movement of chemicals from depth to near surface were developed and assessed by the CSIRO:

- **pathway 1:** fracture growth into an overlying aquifer - this scenario considered hydraulic fracture fluid loss into an overlying aquifer and site conditions that favour height growth of a vertical hydraulic fracture upward towards and into a shallower aquifer (equivalent to Path 2 in **Figure 7.10**);
- **pathway 2:** fracture growth into a well through pre-fracturing permeability and new fractures - this involves two wells within the same coal seam connected by a pre-existing hydraulic fracture (equivalent to abandoned exploration well path in **Figure 7.10**);
- **pathway 3:** well rupture during injection - this scenario considers rupture of a cased well during a fracturing injection operation (equivalent to Path 1 in **Figure 7.10**); and
- **pathway 4:** fracture growth into a fault - assessment of leakage potential through a fault that connects the coal seam to an overlying aquifer (equivalent to Path 2 in **Figure 7.10**) .

The CSIRO assessment concluded that these pathways are either unlikely (high to very high confidence for pathway 3), or extremely unlikely (less than 5% probability for pathways 1, 2 and 4), in an Australian context. Therefore, it is unlikely that chemicals remaining underground after hydraulic fracturing will reach surface aquifers in concentrations that would be unacceptable for domestic or stock water or aquatic ecosystems.

In summary, therefore, the Panel finds that based on the available evidence, the likelihood of contamination of NT groundwaters by the upward migration of contaminated fluids as a result of hydraulic fracturing is 'very low', whereas the likelihood of contamination by methane is 'low' to 'medium'. The consequence to water quality (specifically the impact on groundwater used for drinking or stock watering) from the occurrence of methane is rated as 'low' because methane in water is non-toxic. However, the presence of methane above a threshold value (10-28 mg/L) could result in an explosion risk under certain, albeit unlikely, circumstances.

The Panel has determined that contamination of groundwater is unacceptable if the concentration of chemicals (toxicants) in the groundwater exceeds human and stock health levels by the time the plume reaches any population centre or pastoral property drinking water or stock watering bore.[229] Currently, there is insufficient information available to assess whether this situation could arise as a result of any onshore shale gas industry in the NT. This requires site-specific modelling to be undertaken, a task that is not simple as noted by DENR for the Beetaloo Sub-basin when it stated that,

> *"the issue of water quality modelling and monitoring in karstic environments is problematic. Generally, without knowledge or mapping of the karstic features and structures near to the source of contamination, the immediate fate and transport of dissolved constituents is difficult to predict on a local scale. Further, study would need to be undertaken to characterise the advection, dispersion and diffusive properties of such aquifers to enable the modelled prediction of movement of a contaminant plume on a larger scale."* [230]

227 Harkness et al. 2017.
228 Mallants et al. 2017.
229 ANZECC 2000; NHMRC 2016.
230 DENR submission 428, p 15.

In practice, a rigorous groundwater monitoring system should be in place to provide early detection of any contamination, with rapid implementation of assessment and remedial action of the types summarised by Origin.[231] Origin indicated to the Panel that if a substantial spill of wastewater occurred, remediation would be undertaken using a variety of methods underpinned by an understanding of human and environmental risks. The process consists of three stages:

- **stage 1:** a detailed site investigation that uses intrusive methods to collect samples from the source and subsurface in accordance with Australian Standards (AS4482);
- **stage 2:** health and environment risk assessment performed in accordance with the National Environment Protection (Assessment of Site Contamination) Measure 1999; and
- **stage 3:** implementation of the remediation action plan and subsequent adherence to monitoring plans to demonstrate that remediation has been successful.

Remediation options that can potentially be adopted include:

- monitored natural attenuation, whereby the contaminants naturally reduce in concentration through dilution, adsorption on the mineral matrix, or biological degradation within an aquifer. This is an appropriate approach where there are a lack of nearby groundwater users and high potential for contaminants to be attenuated by natural processes;
- source removal, including installation of pump and treat systems to extract water from the aquifer for treatment on-site to meet water quality criteria before the treated water is disposed of off-site; and
- in-situ flushing, whereby uncontaminated water is pumped into the aquifer downgradient of the source where dilution, desorption, solubilisation and/or flushing of the contaminants can occur, followed by extraction of the flush water if needed.

Additionally, in response to a request from the Panel, Santos provided information on possible methods for remediation of aquifers that become contaminated from either leaky wells or surface spills of wastewater.[232] Santos' policy is to focus on avoiding the likelihood of contamination, but if contamination does occur, its remediation methods focus on the water-soluble chemicals, with extraction and treatment of the contaminated groundwater the most effective means of remediation.

In the specific case of the Beetaloo Sub-basin, the general movement of groundwater in the CLA is towards the north and is generally very slow. Estimates indicate that it would be only metres per year in the northern Beetaloo Sub-basin and considerably less in the southern Beetaloo Sub-basin.[233] This slow rate of movement means that it would take decades for water containing contaminants to travel even 100 m. Therefore, provided a leak is detected early by monitoring systems installed close to well pads, there is enough time to undertake remedial action before the contaminated plume reached domestic drinking or stock watering bores. However, as discussed in Section 7.3.1.3, considerably faster rates of up to 1,000 m/y have been measured in the northern CLA around Katherine, consistent with the preferential flow that can occur through limestone aquifers and through sinkholes and cavities. This would require more rapid remediation responses. However, with appropriately located monitoring systems and appropriate offset distances, any contamination is still likely to be detected in time to avoid domestic or stock water bores.

The Panel's view is that monitoring of key water quality indicators in the groundwater in close proximity (that is within 10-20 m) to each planned well or well pad is essential, and that this monitoring should commence prior to any well drilling, with subsequent monitoring being particularly focussed on the hydraulic fracturing stages. To this end, multi-level monitoring bores must be installed in advance (at least six months) prior to the drilling of a gas well and designed to ensure full vertical coverage of any aquifer(s) currently supplying, or potentially being able to supply, water for environmental or consumptive (stock or domestic) uses. The bore array must have a level of vertical resolution at least sufficient to be able to identify whether a leak of fluid or gas is occurring in the top, middle or bottom zones of an aquifer. At a minimum, electrical conductivity should be measured in real-time as an indicator providing 'early warning' of contamination, with the results telemetered from the site to the regulator and made available

231 Origin submission 433, pp 27-28.
232 Santos submission 420, p 4.
233 DENR submission 429.

to the public. The use of telemetry for other parameters should be reviewed every five years or as technological improvements become available. Additionally, other water quality indicators determined by the regulator must be measured quarterly, with the results made publicly available within one month of sampling. The combination of continuous and randomised spot monitoring should continue for three years, after which time its fitness for purpose should be reviewed by the regulator.

If the electrical conductivity or other measurements suggest that a leak has occurred, or is occurring, more detailed investigations must commence immediately, with remediation to be initiated as soon as practicable. Parameter values for setting action thresholds should be determined from the data collected during the SREBA, and reviewed periodically by the regulator.

The text above specifically refers to the installation and monitoring of all new exploration wells. However, there are already a number of explorations wells (including the Amungee NW-1H well) that exist. The Panel recommends that these wells also require the installation of multilevel bores prior to the approval of either first time or repeat hydraulic fracturing activity.

Notwithstanding monitoring systems being in place, a further level of protection should be provided by locating well pads a minimum distance from water extraction bores. Data from the US suggest the minimum offset distance between well pads and stock or domestic bores is 1 km.[234] Recent work by CSIRO on assessing groundwater transport away from CSG wells has suggested that 2 km is an appropriate minimum distance.[235] While these potential offsets are based on areas of particular hydrogeology in the US and from CSG fields in Queensland, they are nevertheless consistent with the maximum offsets in place for a number of jurisdictions.[236]

For shale gas developments in the NT, the minimum offset distance should be established on a region specific basis by the application of findings from groundwater modelling, and consideration of the potential for transport of contaminants, as well as the likely maximum drawdown extent as discussed in Section 7.5.2. However, as a default, and as a matter of caution, the Panel recommends that an offset distance of 1 km be used.

***Recommendation 7.11***

***That prior to the grant of any further exploration approvals, in order to minimise the risk of groundwater contamination from leaky gas wells:***

- ***all wells subject to hydraulic fracturing must be constructed to at least Category 9 (or equivalent) and tested to ensure well integrity before and after hydraulic fracturing, with the integrity test results certified by the regulator and publicly disclosed online;***
- ***a minimum offset distance of at least 1 km between water supply bores and well pads must be adopted unless site-specific information of the kind described in Recommendation 7.8 is available to the contrary;***
- ***where a well is hydraulically fractured, monitoring of groundwater be undertaken around each well pad to detect any groundwater contamination using multilevel observation bores to ensure full coverage of the horizon, of any aquifer(s) containing water of sufficient quality to be of value for environmental or consumptive use;***
- ***all existing well pads are to be equipped with multilevel observation bores (as above);***
- ***as a minimum, electrical conductivity data from each level of the monitor bore array should be measured and results electronically transmitted from the well pad site to the regulator as soon as they are available. The utility of continuous monitoring for other parameters should be reviewed every five years or as soon as advances in monitoring technology become commercially available; and***
- ***other water quality indicators, as determined by the regulator, should be measured quarterly, with the results publicly disclosed online as soon as reasonably practical from the date of sampling. This monitoring regime should continue for three years and be reviewed for suitability by the regulator.***

234 Osborn et al. 2011; Hill and Ma 2017.
235 Mallants et al. 2017.
236 NSW Chief Scientist and Engineer 2014.

### 7.6.2 Unacceptable groundwater contamination due to faulty decommissioned or abandoned wells (pathway 1)

The Panel has assessed the risk that groundwater could be contaminated from a decommissioned or abandoned leaky well, with unacceptable adverse effects on domestic drinking water or stock watering supplies. The process for decommissioning any onshore shale gas wells when production has ceased is discussed in Section 5.3.2.5.

An extensive review of decommissioned wells by NSW's Chief Scientist noted that, *"if designed, constructed and abandoned to best practice, wells that are decommissioned to current standards have a low likelihood of environmental damage, but that there is uncertainty in relation to the potential long-term impacts. Studies of CO2 subsurface storage wells suggest that cement would be able to isolate CO2 and upper aquifers over the long-term (1,000+ years), but there is scope for additional research to assess specifically the impact of abandoned CSG wells over extended timeframes. Legacy wells that have been abandoned may have been constructed or abandoned to inferior standards, increasing the likelihood of well integrity failure and consequences to the environment."* [237]

The Panel notes that even if well integrity degrades in abandoned wells over the long term, there is unlikely to be a hydraulic driver for leakage into groundwater supplies. Any fluid flow as the result of well integrity failure is likely to be towards the depressurised shale rocks (that is, downwards) rather than away from it (see Section 5.3.2.5 and Appendix 14, Sections 2, 5.14 and 8). Thus, the likelihood of groundwater contamination due to faulty abandoned wells is considered to be 'very low'.

The consequences of such contamination on human and stock drinking water supplies have been discussed above in Section 7.6.1. The consequences to water quality from methane were rated as 'low'. The consequences of other wastewater or geogenic chemicals to drinking water supplies will require detailed site-specific computer modelling to answer, but is likely to be 'low' given the very slow groundwater travel time and the attenuation processes (for example, dispersion, dilution, and microbial decomposition) occurring in the aquifer.

The Panel's overall assessment is that the risk of contamination of aquifers due to faulty abandoned wells is 'low' given the very low probability of this occurring with implementation of world leading practice design and at least current Category 9 construction standards being mandated, and provided that the well passes a rigorous integrity test prior to being decommissioned (see Chapter 5 and ***Recommendations 5.1*** and ***5.2***). In the event that a well does not pass this final integrity test, remedial action needs to be taken to address any identified issues prior to approval being given to decommission and abandon the well.

The question of who should pay for long-term monitoring of abandoned wells and for cleaning up any leaks that may occur is addressed in Chapter 14.

### 7.6.3 Unacceptable groundwater contamination due to surface spills of wastewater and fracking chemicals (pathways 2, 3 and 8)

The Panel has examined the risk that spills of wastewater and/or fracturing chemicals could cause unacceptable contamination of surface or groundwater systems. These spills can occur both on-site and off-site (transport and pipelines).

#### *7.6.3.1 On-site spills*

The likelihood of spillage of wastewaters is always present in resource extraction operations, and there are numerous examples of spillage from the onshore shale gas industry in the US,[238] and the CSG industry in Australia.[239]

With onshore shale gas operations there is potential for on-site accidental leaks and spills of chemicals, hydraulic fracturing fluids, flowback or produced water, including:[240]

- the loss of stored flowback or produced fluids due to the failure of wastewater storage ponds;

237 NSW Chief Scientist and Engineer 2014.
238 US EPA 2016a, Section 7.4; Maloney et al. 2017.
239 Santos 2012.
240 Santos submission 168, p 99.

- the spillage, overflow, water ingress, or leaching from cuttings/mud pits;
- the spillage of fracking fluids or component chemicals during preparation or use;
- the spillage of flowback or produced fluids during transfer to storage;
- the spillage of flowback or produced fluids during transfer from storage to tankers for transport; and
- the spillage of flowback or produced fluids during transport to wastewater treatment works.

The Panel has considered two factors in assessing the likelihood of a wastewater spill contaminating an aquifer: first, the likelihood of a spill actually occurring, and second, the likelihood that the contaminants would pass through the surface soil and rock layer to an the aquifer.

The evidence available to the Panel is unequivocal. On-site spills of chemicals and wastewater are very likely to occur on onshore shale gas well pads.[241] The causes of these spills are generally container and equipment failures, human error, blowouts, pipeline leaks, and inappropriate dumping or disposal of wastewater.[242] The spills are mostly relatively small in volume (that is, less than 1,000 L), confined to the well pad area (84% according to the US EPA) and capable of being rapidly cleaned up. The US EPA has noted that of the produced water spills (typically the largest volumes spills), 63% have resulted in soil contamination, 8% reached surface water resources, and 0.4% were documented as reaching groundwater.[243]

The largest spills can come from the failure (leakage), or overtopping of wastewater containment ponds, or from the rupture of pipelines transporting wastewater. The likelihood of leakage from containment ponds can be mitigated by the use of double lined systems with leak detection. However, there is still the very real possibility of overtopping of storage ponds during the wet season. Santos proposes to allow at least 0.3 m freeboard (distance between the water level and the top of the pond) to minimise the risk of pond overtopping during the wet season, however, it provides no detail on how this will be guaranteed.[244] Origin proposes that *"any open storage (tanks, pits, etc) that are in use to contain fluids other than fresh water during the wet season must have a freeboard equal to 150% of the maximum recorded frequency, duration, intensity event in that region to prevent overflow from any rainfall event."* [245] However, past experience with extreme weather events in the NT has shown that design must be based on the maximum probable precipitation event, coupled with an appropriate wet season maximum operating level. World leading practice is moving towards the use of closed tanks for the storage of wastewaters, which removes the risk of overtopping caused by input of rainwater.[246]

The likelihood of the occurrence of spills can be reduced with world leading practice chemical spill and wastewater containment facilities, well maintained equipment and comprehensive management strategies.

The Panel notes that even if a wastewater spill does occur, it will nevertheless need to penetrate the soil and rock layer to reach the groundwater, and that concentration of chemicals in the wastewater will be dependent on:

- the volume of spill;
- the depth to groundwater;
- the permeability of the rocks between the surface and the groundwater table;
- the interaction (sorption, microbial decomposition) of contaminants within the soil zone to reduce concentrations; and
- the effectiveness of engineering measures and clean up procedures to mitigate the possible transport of contaminants.

The Panel received two submissions that modelled the likelihood of a surface spill of wastewater reaching the CLA in the Beetaloo Sub-basin. The first, a report by EHS Support,[247] provided a modelled assessment of the rate of infiltration for three spill scenarios (1,000 L, 100,000 L and 1,000,000 L) through approximately 80 m-thick soil and rock layer (cretaceous siltstones and

241 Maloney et al. 2017; Patterson et al. 2017; US EPA 2016a.
242 US EPA 2016a, pp 7-42.
243 US EPA 2016a, Appendix A, p 18.
244 Santos submission 168, p 99.
245 Origin submission 476, p 2.
246 BHP 2016, p 5.
247 Santos submission 420, Appendix A, Report by EHS Support (**EHS Support 2017**).

mudstones) to the underlying aquifer in the vicinity of the Santos Tanumbirini exploration well. In this context, it should be noted that 10,000 L is considered to be a 'large' spill based on data from the US.[248] A number of even larger spills do occur noting that, for example, in North Dakota in 2015 there were 12 releases of 79,000 L or more out of a total of 609 spills.[249] The US data confirmed that the range of volumes spanned by the EHS Support assessment were realistic.

In the absence of any mitigation or management, the EHS modelling suggests that it would likely take at least 10 y for the 1 ML (1,000,000 L) spill to reach the groundwater. During this time, many of the concentrations of many of the organic and inorganic contaminants would be reduced by various attenuation pathways (microbial decomposition, adsorption to soil particles) during their through the soil layer.[250]

The second assessment, undertaken by Cloud GMS,[251] considered a different scenario and used a different modelling approach to that used by EHS Solutions.[252] It modelled the likely effect of leakage from a drill mud pit extending over 60 days, consistent with an unconstrained leakage for the entire operational life of the pit. This was a much larger volume of infiltration than the maximum modelled by EHS Solutions (35 ML, compared with 1 ML). However, the conclusions of the two studies were similar insofar as in this part of the Beetaloo Sub-basin, it would be unlikely that a large surface spill or leak of wastewater would reach the groundwater table in a period of less than 10 years.[253]

Cloud GMS also modelled what might happen if the entire load of a B-Double Tanker was to be discharged in this location as a result of a transport accident. Since the volume of the tanker (50,000 L) represents only one-thousandth of the volume in the simulated leak from the pits, the conclusion that this spill would not reach the groundwater table was consistent with the EHS Solutions assessment. Overall, Cloud GMS concluded that "based on the scenarios considered the likelihood of surface spillage migrating to the water table is low taking into account the water table depth (greater than 60 m), spill volumes, likely timeframe for spill containment/remediation and existing controls".[254]

The Panel notes that neither assessment factored in the potential effect of a major rainfall event following the spill. This could be an issue for a spill or leak that occurs toward the end of the dry (before clean up can occur) or during the wet. Additionally, DENR noted that, *"if a spill occurred in an area where the sediments overlying the karstic limestone were thin, or near a sinkhole, then infiltration could occur within days."*[255]

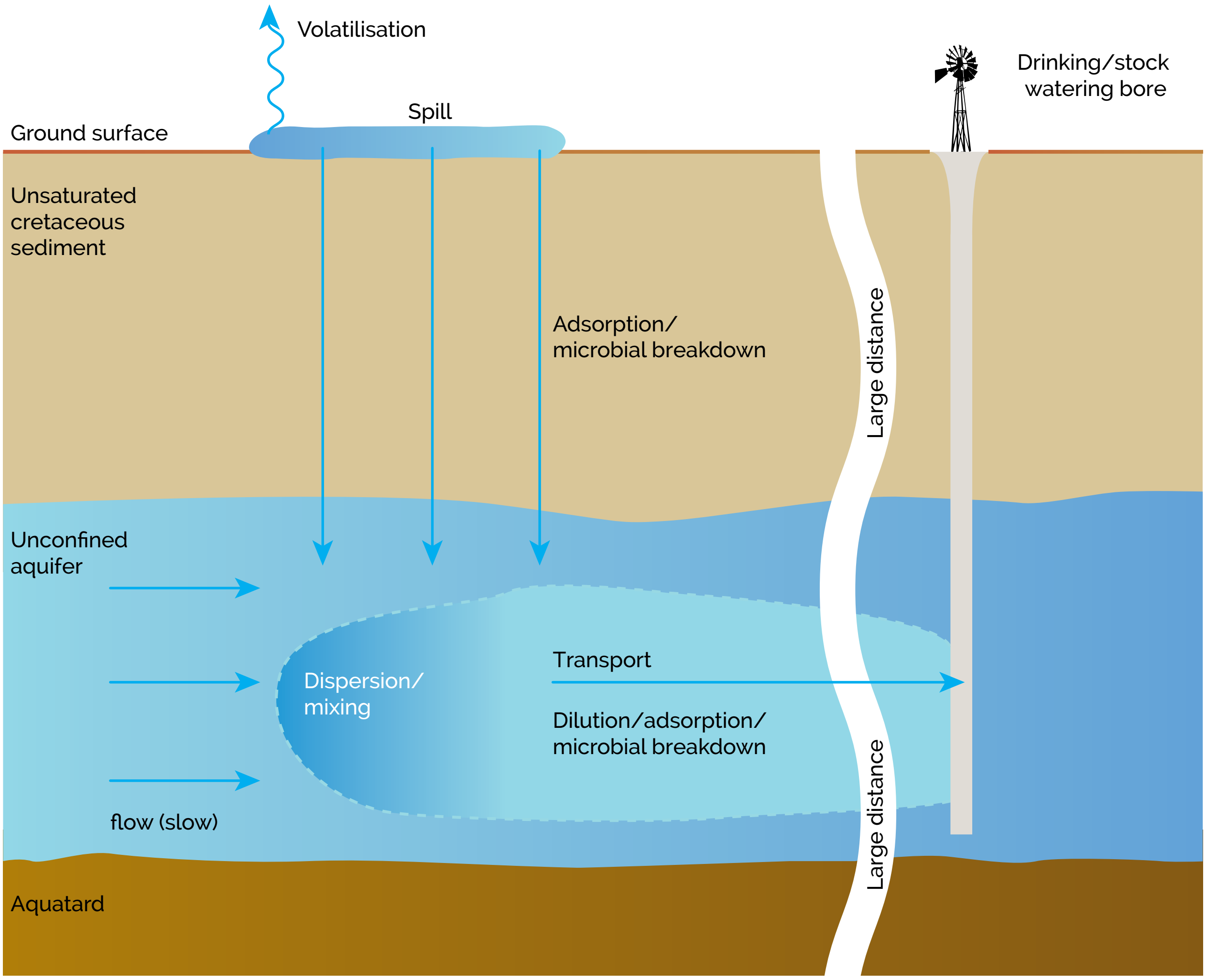
The downward transport of a surface spill to the groundwater will be location specific. The closer the groundwater is to the surface, and the more permeable the horizons from the surface to the aquifer, the higher the risk that the aquifer may be contaminated before remedial action could be effectively implemented. Each prospective gas producing region in the NT will need to be assessed separately based on site-specific characteristics.

While the Panel's assessment is that the likelihood of on-site spills occurring is 'high', the probability that these spills will contaminate groundwater aquifers is 'low', particularly in the Beetaloo Sub-basin. There is, however, one caveat on this finding, namely, that there may be preferential pathways in certain karst regions of the NT.

The consequences if a spill of wastewater reached an aquifer would be the same as those discussed above in Section 7.6.1. That is, the contaminants would be transported slowly within the aquifer (perhaps 1-2 m/y),[256] diluted by mixing, and the concentrations of many organic chemicals reduced by microbial degradation (**Figure 7.12**).

248 Maloney et al 2017; US EPA 2016a.
249 US EPA 2016a, pp 7-26.
250 McLaughlin et al. 2016.
251 Origin Energy Ltd, submission 469 (**Origin submission 469**), Appendix 3, Beetaloo Basin - Groundwater Impact Risk Assessment, prepared by Cloud GMS, September 2015, Appendix D. (**Cloud GMS 2015**).
252 Origin Amungee NW-1H Environmental Management Plan, Appendix 5.
253 Cloud GMS 2015; EHS Support 2017.
254 Cloud GMS 2015, p D21.
255 DENR submission 429, p 3.
256 DENR submission 429, pp 2-3.

**Figure 7.12:** Schematic of the potential pathways for an on-site spill of contaminated wastewater through the soil/rock layer to an unconfined aquifer and then within the aquifer.




The US EPA notes two reasons why the issue of aquifer contamination can be problematic.[257] The first is that groundwater contamination can only be detected if monitoring bores are installed in the area where contamination is most likely to occur, and the second is that groundwater contamination is difficult and expensive to remediate (see also discussion in Section 7.6.1).

The Panel considers that it is essential that a comprehensive wastewater spills containment and management plan is prepared by gas companies for each well pad using a rigorous set of world leading practice guidelines, with these waste management plans approved and enforced by the regulator.

In New Zealand, three levels of containment are required for all oil and gas sites to manage possible spills: the first is a containment of wastewater in tanks (and not ponds), the second consists of bunds around the site and the third consists of a stormwater pond to collect rainwater that falls on the site.[258] Additionally, some sites now have a geomembrane or low permeability compacted clay layer over the well site to reduce the probability of spills penetrating into the soil and rock layer overlying the aquifer. A rigorous groundwater monitoring program for each well pad (as recommended in Section 7.6.1) must be established, with the data made publicly available online as soon as reasonably practicable. In the case of any contamination, the gas company must act immediately to fix any problems.[259]

Secondary containment measures should also be put in place on work sites to mitigate the risk of a spill in the event that the primary containment fails, by preventing or mitigating any uncontrolled release of chemicals to the ground and to waterways. This can be achieved, for example, by constructing bunded working areas designed to contain maximum probable precipitation events and engineered above ground ponds with sufficient freeboard, or closed tanks.

257 US EPA 2016a.
258 NZ Report 2014, pp 51-52.
259 Ms Justine Johnson, submission 537.

The Panel has little information regarding what, if any, wastewater treatment facilities will be employed by the gas companies. Decisions about wastewater treatment must be made strategically, taking into account any development of the industry on a regional scale, and taking into account the views of landholders, local communities and the environment (see ***Recommendation 5.5***).

The Panel has also identified poor practices that can occur with the transport of wastewater (Section 5.8.2), and has recommended that a framework for managing wastewater transport be developed to include an auditable chain of custody system for any transport of wastewater (including by pipelines) that enables source-to-delivery tracking of consignments of wastewater (see ***Recommendation 5.5***).

*Recommendation 7.12*

***That prior to the grant of any further exploration approvals, to reduce the risk of contamination of surface aquifers from on-site spills of wastewater:***

- ***the EMP for each well pad must include an enforceable wastewater management plan and spill management plan;***
- ***enclosed tanks must be used to hold all wastewater; and***
- ***the well pad site must be bunded to prevent any runoff of wastewater, and be treated (for example, with a geomembrane or clay liner) to prevent the infiltration of wastewater spills into underlying soil.***

*Recommendation 7.13*

***Upon a gas company undertaking any exploration activity or production activity, monitoring of the groundwater must be implemented around each well pad to detect any groundwater contamination, adopting the monitoring outlined in Recommendation 7.11. If contamination is detected, remediation must commence immediately.***

### *7.6.3.2 Spills during transportation*

The Panel has assessed the risk of contamination of surface waters due to off-site spills during transportation of chemicals and wastewater associated with any onshore shale gas hydraulic fracturing operations.

The development of any onshore shale gas industry in the NT requires that fracturing chemicals and fluid additives be transported to the various drill sites. This gives rise to a risk that spills may occur during transportation. The conduct of such transport is regulated by the *Australian Code for the Transport of Dangerous Goods by Road and Rail*, a code that is given legal effect to in the NT by the *Transport of Dangerous Goods by Road and Rail (National Uniform Legislation) Act 2010* (NT), which is administered by NT Worksafe.

Additionally, if wastewater is transported by pipeline for reuse, or to a treatment plant, there is a risk that spills may occur due to broken pipelines. Pipelines carrying waste require an approval from the NT EPA under the *Waste Management and Pollution Control Act 201*6 (NT) (**Waste Management Act**).

### Road and rail transport

The largest number of road traffic accidents occurs during the dry season in the NT because of the heavy traffic caused by an influx of tourists.[260] However, it is during the wet season that road transport accidents are most problematic, with any spilt contaminants potentially being washed overland to ecologically important temporary or permanent waterbodies. These waterbodies are also more likely to be affected during the wet season by sediment-laden runoff coming from unsealed roads and pipeline corridors (see Section 7.6.9).

The Panel notes that 15 of the 113 chemicals used for the extraction of CSG and assessed by the NCRA were identified as being of potential concern in the event of a direct (unmitigated) release of the chemical(s) to an aquatic ecosystem occurring as the result of a transport accident (spill).[261] These were the only circumstances identified in that assessment that could allow CSG

260 https://dipl.nt.gov.au/transport/transport-statistics-surveys-and-research/road-toll-statistics.
261 Australian Department of the Environment and Energy 2017a-f.

chemicals (and by implication some of those used for shale gas extraction, as documented in the list of chemicals used for the Amungee NW-1H fracturing operation) to potentially occur in surface water at concentrations toxic to aquatic organisms. The findings from the NCRA study underscores the importance of handling and transporting all chemicals in accordance with the relevant Territory (and State if being transported to or from the NT) regulations and industry codes of practice.

Current industry practice for the transportation of chemicals requires that both primary and secondary containment measures are in place.[262] Primary containment ensures that additives are stored and transported in properly designed materials (for example, high density polyethylene thermoplastic material) and protected by a steel cage to maintain the structural integrity of the container. Secondary containment measures should also be put in place to mitigate the risk of a spill in the event the primary containment failed. For example, Origin arranged for additives transported to the Amungee NW-1H lease to be transported in trucks that had secondary containment on the trailer beds.[263]

In Chapter 8, the Panel has noted that Pangaea has proposed the installation of a public benefit multi-user rail siding on the Adelaide to Darwin railway line that, *"would allow the efficient carriage of consumables, drill bits and other equipment for the entire Beetaloo Basin, lowering the use of trucks on main roads and highways."* [264] This suggestion warrants further consideration.

***Recommendation 7.14***

***That the Government, having regard to the measures detailed in Recommendation 5.5, undertakes a review to determine whether:***

- ***restrictions need to be placed on the transport of hydraulic fracturing chemicals and wastewater during the wet season, particularly on unsealed roads, to avoid the risk of spills; and***
- ***rail transport of some or all of the hydraulic fracturing chemicals and other consumables required, be used to avoid the risk of spills.***

### Pipelines

The other possible source of off-site spills is from broken pipelines carrying flowback or produced water for recycling or to a central treatment plant. The US EPA noted that pipeline spills can be very large, with the largest documented spill occurring in North Dakota, where approximately 11 ML of wastewater spilled from a broken pipeline and affected surface water and groundwater.[265] The Panel has been told that gas pipelines will be buried,[266] but it is possible wastewater pipelines will be on the surface.

The Panel's assessment is that the likelihood of an off-site pipeline leak is 'low', provided that pipelines (gas and wastewater) are buried and that robust pipeline construction and management guidelines are developed and enforced by the regulator. The Panel also notes that pipelines carrying wastewater would also require an approval from the EPA under the Waste Management Act. The consequences if a spill does occur will depend upon the volume of the spill, the speed and effectiveness of clean up procedures and the time of year the spill occurs. If a pipeline spill occurs during the wet season, the clean up will be more difficult, and there will be a greater likelihood of contaminants being more widely dispersed and perhaps reaching a surface waterbody, albeit in a more dilute form.

## 7.6.4 Unacceptable contamination of surface aquifers due to the reinjection of treated or untreated wastewater (pathway 5)

The Panel has examined the risk of contamination of surface aquifers due to the reinjection of treated or untreated wastewater into other aquifers or wells associated with extraction of oil and gas from conventional reservoirs. Reinjection of wastewater is common practice by shale gas companies overseas, particularly in the US, where the US EPA found that in 2012 around 93% of

262 Origin submission 153, p 82.
263 Origin submission 153, p 82.
264 Pangaea submission 427, p 12.
265 US EPA 2016a, pp 7-26.
266 Origin submission 433, p 49.

the flowback and produced water from the oil and gas industry in that country was injected into Class II wells associated with conventional oil and gas reservoirs.[267] The US EPA also reported that this practice had been associated with seismic activity in several States.[268]

For this reason, the onshore shale gas industry in the US is now focussed on reusing more of its wastewaters for well drilling and hydraulic fracturing, or on treatment to reduce the volume requiring ultimate disposal. For example, in the Marcellus shale basin, approximately 90% of the flowback and produced water (around 3.2 ML per well) is reused for hydraulic fracturing, with this recycle component making up around 14% of the 16-18 ML per well currently used for fracturing.[269]

There has been a limited pre-feasibility assessment on reinjecting CSG produced water in Queensland, which the Panel understands has now been discontinued due to technical issues.[270]

However, the Panel is also aware that managed aquifer recharge (**MAR**) is practised in many areas of Australia and overseas. MAR involves the injection of water of compatible chemistry into aquifers, which requires both an aquifer with suitable permeability and structural integrity to receive injected waters, and for the waters to have a suitable chemical composition so that there are no adverse chemical reactions with aquifer materials leading either to clogging of the injection bore or aquifer, or to the liberation of other chemicals in the aquifer material.[271]

In its submission to the Panel, Origin noted that is has not considered or planned for reinjection of flowback fluid and that it would not consider this option *"except where the water is treated to the same standard as the aquifer water and regulatory approval is provided"*.[272]

The Panel has insufficient information regarding any potential reinjection of wastewaters in the Beetaloo Sub-basin (or elsewhere) to make an assessment of the contamination risk associated with this practice. The information required to support an assessment of the risk caused by this practice would include the quality and volume of the treated or untreated wastewater to be reinjected, the composition of water in the target aquifer, the potential to influence other connected aquifers and the long-term changes in water quality in the target aquifer if reinjection occurred. Additionally, geological modelling of the actual site where reinjection is proposed needs to be undertaken before any approval to carry out such activity was granted. Accordingly, the Panel considers that the risks of contamination from reinjection of wastewater, were it to occur, are insufficiently understood, and therefore, it should not be permitted (see ***Recommendation 7.9***).

### 7.6.5 Unacceptable contamination of surface aquifers due to induced connectivity between hydraulically fractured shale rock formations and overlying aquifers

Claims were made both in written submissions and during community consultations that surface aquifers could be contaminated as a result of the hydraulic fracturing process by fracturing fluids travelling through the rock strata from the fractured shale area vertically to overlying aquifers containing high quality water.[273]

Movement of fluid between the shale layer and an aquifer requires both a physical pathway (for example, interconnecting pores within the rock matrix, or a fracture or fault in the rock) and a driving force.[274] Additionally, the potential for fluid migration will be different in the period following initiation of fracturing and prior to gas production, and after fracturing is complete and during production when the pressure in the fractures is reduced.[275]

The US EPA identified four possible pathways by which hydraulic fracturing fluids could migrate from the fractured shale region into a surface aquifer:[276]

- the migration of fluids out of the gas production zone through pore spaces in the rock;
- the migration due to fracture outgrowth out of the production zone;
- the migration through fractures intersecting with geological features such as permeable faults or pre-existing natural features; and
- the migration through fractures intersecting with nearby wells.

267 US EPA 2016a.
268 US EPA 2016a.
269 US EPA 2016a.
270 Healthy Headwaters 2011.
271 This is discussed in some detail in NRMMC 2009.
272 Origin submission 153, p 84.
273 Lock the Gate Alliance Northern Territory, submission 171 (**Lock the Gate submission 171**), p 10.
274 US EPA 2016a, pp 6-38.
275 US EPA 2016a, pp 6-39.
276 US EPA 2016a, pp 6-44.

In addition to the need for a physical pathway between the shale layer and the aquifer and a driving force, the potential for fluid migration will be different during hydraulic fracturing compared to the period after fracturing is complete and the pressure in fractures is reduced.[277]

The evidence is that it is highly unlikely that fracking fluids could reach a surface aquifer through the first potential pathway.[278] The large vertical separation distance (1,000 to 3,000 m) between the shale layer and the aquifer, together with the very low permeability of the intervening rock strata, make this a highly unlikely pathway without some fractures assisting the transport process.[279]

The second potential pathway is for fractures to extend out of the shale production zone into another formation. Again, the likelihood of fractures growing out of the shale rock region for distances of 1,000 to 3,000 m is extremely low.[280] For example, the majority of fractures in the Marcellus shale basin were found to have heights of less than 100 m, although fracture lengths up to approximately 600 m have been recorded.[281]

However, as Lock the Gate Alliance Northern Territory (**Lock the Gate**) has noted in its submission, if there is a fault between the fractured region and the aquifer, this may provide a preferred pathway between the shale layer and the aquifer for fluid flow during the hydraulic fracturing operation.[282] US EPA, Reagan et al. and Westwood et al. have discussed this possibility in detail[283] and have concluded that the risk is low.

According to Origin, Pangaea and Santos, the location of faults is taken into consideration during the design and construction of each well and the gas companies actively avoid faults because their occurrence can seriously compromise the effectiveness of the hydraulic fracturing operation, as well as being a potential environmental risk.[284] This was the case for the Origin Amungee NW-1H well, where a section of the horizontal bore was not fractured because of the inferred existence of a small fault system.[285] Origin told the Panel that,

> *"prior to conducting the HFS operation at Amungee NW-1H Origin assessed the risk of induced connectivity between the hydraulically fractured shale formation and the aquifers. The risk was assessed as follows: first, what is the vertical offset between the target zone and the aquifers; second, are there barriers to fracture height growth between the target zone and aquifers; and third, do the barriers contain the fracture height growth for the designed pumping schedule?"* [286]

The other possible pathways identified above, that is, fractures intersecting with other wells (including active and abandoned wells), are not likely given that there are currently very few deep wells drilled in the NT. However, this is very unlikely to be an issue in the NT given the very low number of deep wells that have been drilled, and moreover, because those that exist are well documented. The US EPA has documented situations where unintended interactions between fractured wells on multi-well pads, called 'frac hits', can occur, most commonly if the lateral separation between wells is less than around 340 m.[287]

The Panel notes that apart from the hydraulic fracturing phase, simple groundwater hydraulics mean that it is highly unlikely that water would flow from the depressurised shale gas aquifer to an overlying aquifer that remains pressurised. The only hydraulically plausible opportunity for limited fluid migration along faults is during the intense pressurisation of the actual hydraulic fracturing. However, it is considered that with close monitoring and management of the pressurisation to ensure that only the desired interval is fractured, this scenario can be prevented. Accordingly, there is a low likelihood of aquifer contamination as the result of groundwater flow through faults as the result of, or exacerbated by, hydraulic fracturing.

The Panel has therefore assessed this risk as 'low', given the vertical distance between the fractured rocks and surface aquifers, and the hydraulic potential for flow between fractured rocks and surface aquifers, provided that fracturing operations avoid proximity to faults.

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277 US EPA 2016a, pp 6-39.
278 Origin submission 153, p 70; Fisher and Warpinski 2012; Flewelling and Sharma 2014.
279 APPEA submission 215; Origin submission 153, p 69; Santos submission 168.
280 US EPA 2016a, pp 6-57; Reagan et al. 2015.
281 US EPA 2016a, pp 6-53; Davis et al. 2012.
282 Lock the Gate submission 171, p 10.
283 US EPA 2016a, pp 6.66-6.69; Reagan et al. 2015; Westwood et al. 2017.
284 Origin submission 153; Santos, submission 168; Pangaea submission 220.
285 Origin submission 153, p 72; IESC 2014.
286 Origin submission 153, p 72.
287 US EPA 2016a, pp 6-71.

*Recommendation 7.15*

***That gas companies must submit details of the locations of all faults that could compromise well integrity. The occurrence of any faults must be addressed in the well design plan submitted to the regulator for approval. The details of all faults and the well design plans must be publicly disclosed online as soon as they are available.***

### 7.6.6 Unacceptable contamination due to changed groundwater pressures as the result of groundwater extraction for hydraulic fracturing

Extraction of water required for hydraulic fracturing from local groundwater can result in a decrease in the groundwater pressure in a particular aquifer, which may result in underlying or overlying groundwater bodies flowing into the aquifer and possibly changing its water quality. This is a potential issue of concern in some CSG operations.[288]

The Panel is aware that the volumes of water involved in the hydraulic fracturing of shale are likely to be much less than those involved in CSG operations, where the latter need to extract a substantial volume of groundwater before gas can be developed. Onshore shale gas operations require only the volume of water required for hydraulic fracturing, and if significant recycling of flowback water is possible (see the discussion above in Section 7.3), the volume of groundwater required can be reduced.

While excessive use of groundwater for hydraulic fracturing has the potential to change groundwater pressures sufficient to impact groundwater flow pathways, and potentially aquifer water quality, it is not possible to quantify this risk to groundwater quality without considering the local hydrogeology and applying site specific predictive computer modelling. This potential risk has not been considered in any of the gas companies' submissions.

Accordingly, the Panel considers that the risks of contamination from possible changed groundwater pressures are insufficiently understood and that, therefore, appropriate local and regional groundwater modelling is required prior to any production approvals being granted (see Chapter 16).

*Recommendation 7.16*

***That appropriate modelling of the local and regional groundwater system must be undertaken before any production approvals are granted to ensure that there are no unacceptable impacts on groundwater quality and quantity. This modelling should be undertaken as part of a SREBA.***

A related issue raised during the community consultations was the possible cross-contamination between two shallow aquifers during the well-drilling process. In the Beetaloo Sub-basin, this is possible if gas companies need to drill through the Anthony Lagoon and Gum Ridge aquifers (see **Figure 7.7a**) to reach the Velkerri shale deposit below.

Origin faced this risk when drilling the Beetaloo W-1 well, which is located approximately 85 km south of the Amungee NW-1H well.[289] To mitigate the cross-flow risk, Origin used two casing strings to protect the aquifers: first, an outer hole was drilled (using the metal casing) to below the upper Anthony Lagoon aquifer; and second, the next hole was drilled inside this outer casing to below the Gum Ridge aquifer. In this way, both aquifers were protected from cross-contamination during the drilling.[290]

### 7.6.7 Unacceptable contamination of surface waters due to the discharge of treated or untreated wastewater (pathway 6)

The Panel has assessed the risk of contamination of surface waters due to the discharge of treated or untreated wastewater from shale gas hydraulic fracturing operations. The discharge of treated shale gas wastewaters to permanently flowing waterways is relatively common practice overseas, although it is decreasing as more flowback and produced water is reused in the hydraulic fracturing process.[291] However, in the Beetaloo Sub-basin, and other semi-arid and arid regions of the NT, surface waters are only present for short periods of time during the wet

288 IESC 2014.
289 Origin submission 1248, pp 16-18.
290 Origin submission 1248.
291 US EPA 2016a.

season. Some larger water bodies, such as Lake Woods and Longreach Waterhole, near Elliott, can persist for multiple years, although satellite imagery from Geoscience Australia indicates that water in these two water bodies was only present for approximately 20% of the time between 1987 and the present.

The Panel considers that the discharge of any onshore shale gas wastewaters to temporary surface waters is problematic because it is difficult to predict the behaviour of any contaminants discharged to such systems. In particular, the variable nature of these temporary streams (and temporary waterholes) makes it likely that discharged contaminants would be trapped in the waterholes left after the temporary streams ceased to flow.

In its submission to the Panel, DPIR indicated that discharge of hydraulic fracturing shale gas wastewaters to waterways are not permitted, stating that,

> *"current practice requires that wastewater from hydraulic fracturing activities is fully contained on site. The fluids may be held in double high density polyethylene (HDPE) lined evaporation ponds. Evaporation may be aided with sprinklers or other devices to accelerate evaporation rates. Concentrated waste fluids must be collected and transported to a licenced waste treatment facility in accordance with the Waste Management and Pollution Control Act. Certificates of acceptance of waste fluids by the treatment facility must be provided to the Department."* [292]

The Panel has serious concerns regarding any discharge of untreated or treated wastewaters to temporary surface waters, particularly in the Beetaloo Sub-basin and other semi-arid and arid regions. The Panel notes that none of the gas companies have indicated that they would seek to discharge wastewaters (treated or not) to either drainage lines or waterways when these are present.

***Recommendation 7.17***

***That prior to the grant of any further exploration approvals, the discharge of any onshore shale gas hydraulic fracturing wastewater (treated or untreated) to either drainage lines, waterways, temporary stream systems or waterholes be prohibited.***

### 7.6.8 Adverse effects of linear infrastructure on the quality and distribution of surface waters across the landscape

The Panel has assessed the risks to the quality and distribution of surface waters across the landscape from the linear infrastructure that would be needed by any onshore shale gas industry in the NT.

The establishment of any onshore shale gas industry in the NT will require the construction of roads and pipelines (linear infrastructure) across the landscape. These and associated activities (for example, borrow pits excavated for the purpose of providing material for road construction) have the potential to interrupt water flows in the wet season and to increase erosion, with a resultant increase in sediment loads entering streams. Additionally, seismic survey lines can also have similarly disruptive effects, unless properly rehabilitated. Evidence from overseas indicates that well pad development causes far less disruption to the landscape than the extensive network of pipelines and roads required by shale gas development.[293] The construction of roads and other linear infrastructure can also affect small-scale water flows that can play important roles in terrestrial landscapes.

Participants at a community consultation session in Wadeye on 27 March 2017 told the Panel of one instance where the improper location of road embankments by the gas industry in the NT caused a backup of water and altered flow patterns across the landscape. Recent work published by CSIRO has indicated that subsidence of improperly backfilled and compacted buried CSG pipeline corridors resulting in increased erosion is a common occurrence in southwest Queensland.[294] The recent publication *On New Ground – Lessons from development of the world's first export coal seam gas industry*, by the Queensland Gasfields Commission makes specific

292 DPIR submission 226, p 5.
293 Drohan and Brittingham, 2012.
294 Vacher et al. 2016.

mention of erosion problems with installation of pipelines and other infrastructure during the wet season.[295] In addition, it is more likely that increased damage to unsealed roads will occur during intense wet season rainfall events in the Top End, with consequent increased potential for erosion and sediment runoff. Unsealed road crossings are particularly at risk of this occurring (see also Chapter 8).

A relevant study on the effects of road traffic on downstream sediment load (turbidity) and its implication for aquatic life in the NT was conducted in 1997 at an unsealed road crossing over Jim Jim Falls Creek located in Kakadu National Park.[296] A continuously logging data recorder was used to measure the downstream pulses of turbidity as vehicles passed over the crossing. Additionally, the abundance and diversity of fish and benthic macroinvertebrate populations were measured upstream and downstream of the crossing. The study concluded that a threshold level of turbidity for effects on invertebrates and fish was less than 30 NTU and that management strategies should aim to achieve levels below this value. Further, the study found that a turbidity monitoring program should be established to evaluate the effectiveness of any remedial measures implemented. Although the results from this older study are location specific, they do indicate the need for care to be taken in reducing vehicle-induced sediment scouring during periods when water is flowing. This study further indicates the need to more generally minimise erosion from road alignments where the runoff can enter streams.

The impacts on landscape and erosion processes by construction activities associated with the CSG industry in Queensland have been the subject of recent research by CSIRO.[297] It was noted that although industry and pipeline manufacturing guidelines exist on leading practice for effective pipeline installation, soil management, and re-compaction during backfilling, incidences of pipeline subsidence, and surface and tunnel erosion were quite common across the Surat and Bowen Basins.[298] The depression zone caused by subsidence (or tunnel erosion) increased the potential for additional runoff volumes by changing the natural flow of surface water from upslope catchment areas. As a result, substantial volumes of water can be added from the upslope catchment area, which increases the erosion potential. In addition to subsidence and tunnel erosion on trench lines contributing to increased potential for erosion at the field and catchment scales, impacts from soil surface disturbance (for example, vegetation clearance, compaction and soil mixing, or layer inversion) on right of ways can further exacerbate erosion processes. The Panel has assessed the likelihood of road and pipeline construction changing water flows across the landscape, and, therefore, increasing erosion, as ‘medium’.

The Panel has assessed the consequences associated with the disruption of landscape surfaces and increased erosion ‘low’ to ‘medium’, noting that the effects will depend strongly on the size of the region affected, and that these effects will likely be cumulative as the footprint of any shale gas industry expands.

The Panel has received submissions from Pangaea and Origin indicating that they adhere to the various codes of practice for the construction of roads and pipelines, and therefore, no issues are likely to arise.[299] However, community representations to the Panel, together with the extensive data that CSIRO has obtained from southern Queensland, suggests that adherence to construction guidelines does not always occur.[300] In particular, the high intensity and long duration of rainfall events in the NT means that much greater attention needs to be paid to reducing the potential for erosion and disruption of surface water flows during the wet season.

It has been noted by CSIRO[301] that knowledge of existing overland surface flow is essential to reduce impacts from the development of service roads, culverts, well pads, and pipeline corridors. It suggests that surface flow models derived from fine scale digital elevation models are an appropriate tool for monitoring impact of the wider gas industry footprint on surface hydrology, in identifying potential problems during early negotiation with landholders, and in planning and design of future infrastructure.

The Panel is of the view that the acquisition of this information is an essential component of the baseline information required before any onshore shale gas production can occur. The advent of

295 Queensland Gasfields Commission 2017, p 60.
296 Stowar et al. 1997.
297 Poulton et al. 2015; Vacher et al. 2014; Vacher et al. 2016.
298 Vacher et al. 2016.
299 Pangaea submission 220, Appendix 1, pp 51-54; Origin submission 153, pp 249-289.
300 Vacher et al. 2016.
301 Poulton et al. 2015.

(relatively) low cost LIDAR-capable drone technology over the past five years has revolutionised the capability of industry to easily and rapidly acquire high vertical resolution terrain data over lease areas.

Given that the impacts from roads and pipelines are likely to be cumulative, the design of these networks should be planned from the earliest stages of development and at a landscape scale, to avoid unforeseen consequences arising from the incremental (piecemeal) addition of linear infrastructure. This consideration applies to both individual operating leases and to the totality of operations on leases that together cover broad areas of catchment systems. A landscape-scale approach to design of infrastructure is especially critical for regions that have episodically flowing streams and which therefore typically do not receive as much consideration as systems in which water flow occurs for longer periods.[302] Chapter 14 discusses area-based regulation.

***Recommendation 7.18***

***That to minimise the adverse impacts of any onshore shale gas infrastructure (roads and pipelines) on the flow and quality of surface waters, the Government must ensure that:***

- ***landscape or regional impacts are considered in the design and planning phase of development to avoid unforeseen consequences arising from the incremental (piecemeal) rollout of linear infrastructure; and***
- ***roads and pipeline corridors must be constructed to:***
  - ***minimise the interference with wet season surface water flow paths;***
  - ***minimise erosion of exposed (road) surfaces and drains;***
  - ***ensure fauna passage at all stream crossings; and***
  - ***comply with relevant guidelines such as the International Erosion Control Association Best Practice for Erosion and Sediment Control and the Australian Pipeline Industry Association Code of Environmental Practice 2009.***

## 7.7 Aquatic ecosystems and biodiversity

Some of the major features of aquatic ecosystems in the NT were summarised in Section 7.2.3, where it was noted that most of the permanent or semi-permanent surface water bodies in the NT are found in the northern, high-rainfall regions (the Top End). The Panel has little specific information about the aquatic ecosystems sustained by those temporary surface water bodies, or about groundwater-dependent ecosystem in the Beetaloo Sub-basin, or elsewhere in the semi-arid and arid regions of NT.[303]

Accordingly, the Panel has recommended that a SREBA be undertaken before any approval is granted for hydraulically fractured shale gas production in the NT (see ***Recommendation 7.5***). These assessments should focus on improving the knowledge and understanding of water resources (surface and groundwater), aquatic ecosystems (surface and GDEs), and terrestrial ecosystems in potential shale gas basins in the NT.

Below, the Panel provides an assessment of the risks to aquatic ecosystems from any onshore shale gas industry, first, from over-extraction of water for hydraulic fracturing, and second from contaminated wastewater.

### 7.7.1 Water quantity

Water extraction can have potentially serious impacts on rivers, wetlands and other water-dependent ecosystems, including on aquatic wildlife.[304] Regulation and water extraction can affect all components of the natural flow regime of rivers, and result in ecological degradation.[305] For example, excessive water extraction can potentially cause perennial rivers to become intermittent or temporary,[306] and can have major ecosystem impacts on intermittently flowing rivers by decreasing the period of hydrological disconnection between deep-pool refugia during the wet season, or increasing the risk of poor water quality during the dry-wet transition phase.[307]

302 Acuna et al 2017.
303 Duguid et al. 2005.
304 Bunn and Arlington 2002; Burton et al. 2014; King et al. 2015.
305 Burton et al. 2014; King et al. 2015, pp 744-747.
306 Warfe et al. 2011; King et al. 2015.
307 King et al. 2015, p 747.

Tropical savannah rivers are characterised by highly seasonal and predictable flow regimes, but with high interannual variation in the magnitude, timing, and duration of low flows.[308] King et al. 2015 identified three phases of the seasonal flow regime for perennial and intermittent rivers in tropical savannah climates: the wet-dry transition, the dry season and the dry-wet season transition.[309] These hydrological phases are each ecologically important in different ways and will be affected differently by water extraction.

Similarly, adverse effects on the aquatic ecology may occur with discharges to a perennial or intermittent river, depending upon when the discharge occurs. For example, a discharge made towards the end of the wet season can extend the duration of flow and alter the ecosystem development over the wetting-drying cycle.

The Panel has recommended in Section 7.5.1 that extraction of surface water resources for hydraulic fracturing for shale gas should not be permitted in the NT (***Recommendation 7.6***).

The Panel has also assessed the risk of water extraction to groundwater-dependent ecosystems. There was considerable community concern that excessive groundwater extraction from the CLA aquifer could adversely affect the two largest permanently flowing rivers in the NT, namely, the Daly and Roper Rivers.[310] Both these rivers are located north of the Beetaloo Sub-basin, but have their dry-season flows maintained by groundwater inflows from the CLA.[311] There is evidence that the CLA is very important for the Roper River system, sustaining Elsey National Park, Mataranka thermal pools, Red Lily Lagoon and the riparian vegetation along the Roper River.[312]

The importance of Elsey National Park (including Bitter Springs, Mataranka thermal pool and John Hauser Drive) as a tourist venue can be judged by the large number of annual visitors: 156,000 in 2015 and 171,000 in 2016.[313] Accordingly, the community is understandably concerned about the risks to these systems. As the owners of Bitter Springs Cabins and Camping at Mataranka told the Panel, *"we have based on two sets of springs, the Rainbow Springs which is at Mataranka Homestead and the Bitter Springs. They're both in Elsey National Park, just different sides. We all work off the Tindall Water Basin, the water system. Without them we are all out of work as water goes. All the town and other people in the area, we're basically nothing. So basically everybody's employed by those businesses so the whole town's finished if we lose our water, which is spring fed. That's the start. If the springs stop flowing the town will die and we all rely on the water in the springs, the river system, the ground water to survive as it all is one of the same."* [314]

The Panel has been provided with evidence showing that recharge of the CLA in Roper River region occurs locally (within 50 km of the river) during the wet season.[315] If this is the case, water extraction from this aquifer in the Beetaloo Sub-basin, approximately 150-200 km away, is unlikely to have an effect on groundwater inflows to the Roper River since the very low flows in the CLA (estimated to be metres per year) mean that this water would take hundreds to thousands of years to reach the Roper River.[316] However, as discussed Section 7.3.1.1, this may not be the case for any onshore shale gas development (for example, by Hancock Prospecting) closer to the Roper River.[317] Lock the Gate, therefore, has called for further study of the groundwater recharge areas in this region of the Roper River.[318]

Given its importance, the Panel is of the view that the boundary of the Beetaloo Sub-basin SREBA (see ***Recommendation 7.5***) should be expanded to include this region.

***Recommendation 7.19***

***That the SREBA undertaken for the Beetaloo Sub-basin must take into account groundwater-dependent ecosystems in the Roper River region, including identification and characterisation of aquatic ecosystems, and provide measures to ensure the protection of these ecosystems.***

308 King et al. 2015, p 744.
309 King et al. 2015, pp 747-753.
310 Somers submission 377.
311 Bruwer and Tickell 2015; DENR submission 230, Addendum 2.
312 Bruwer and Tickell 2015.
313 DTC 2017.
314 Somers submission 377, p 1.
315 Bruwer and Tickell, 2015; A Knapton submission 426, p 3.
316 A Knapton submission 426, p 3.
317 Hancock Prospecting submission 461, pp 1-3.
318 Lock the Gate Alliance Northern Territory, submission 437 (**Lock the Gate submission 437**), p 1.

The northern region of the NT has many GDEs, both aquatic and terrestrial, that may be affected by groundwater extraction.[319] However, this does not appear to be the case in the semi-arid and arid region of the Beetaloo Sub-basin, where the Panel has evidence that there are very few, if any, surface GDEs because the groundwater is typically greater than 30 m deep and is not connected to the surface.[320]

Previously, the Panel (Section 7.2.3) identified the increasing awareness in a number of jurisdictions in Australia of the importance of protecting stygofauna, the subterranean fauna that live in aquifers. The Panel is not aware, however, of any detailed baseline survey of subterranean aquatic ecosystems in the Beetaloo Sub-basin and recommends that such a study be included as part of any SREBA.

***Recommendation 7.20***

***That the Beetaloo Sub-basin SREBA must identify and characterise all subterranean aquatic ecosystems, with particular emphasis on the Roper River region.***

### 7.7.2 Water quality

The effective management of wastewaters (flowback and produced water) is a particularly important issue for aquatic ecosystems and their biodiversity.

#### *7.7.2.1 Surface water ecosystems*

As discussed above in Section 7.6, contamination of aquatic systems can occur during either the wet or dry season through discharges of contaminated wastewaters, accidental spills of contaminated wastewaters, or accidents during the transport of chemicals or wastewater.[321] The Panel has recommended that the discharge of treated or untreated shale gas wastewater to surface water systems should be prohibited (***Recommendation 7.17***).

Spills that occur during the dry season, if not cleaned up, can result in contaminated water produced from dissolution of salts on the soil surface being flushed into temporary water bodies during the wet season. Increased erosion and transport of sediments into waterways due to the construction of roads and pipelines can also impact aquatic ecosystems.[322]

There has been limited study of the effects of contaminants on temporary water ecosystems, these being the main surface water bodies likely to be present in the Beetaloo Sub-basin and other semi-arid and arid regions on the NT. Two studies are available that have described potential effects from agricultural, urban land-uses and mining on temporary waters in Queensland and South Australia.[323] The Panel notes that there have been calls for regulatory agencies across Australia to give greater focus on the protection and management of these systems, similar to that afforded to perennial waters.[324]

The Panel has assessed the risks to surface water ecosystems from shale gas fracturing wastewater contaminants to be 'low', provided discharge of wastewaters to surface water bodies is prohibited and effective management practices are in place to prevent any accidental spills from well pads, road tankers or pipelines from entering these water bodies.

#### *7.7.2.2 Groundwater-dependent ecosystems*

The Panel has also considered the possible risks to GDE from contaminated aquifers. The two most likely mechanisms by which aquifers could be contaminated are, first, from leaky wells, and second, from on-site spills of chemicals or hydraulic fracturing wastewater (see Sections 7.6.1, 7.6.2 and 7.6.3). In both these cases, the Panel's assessment is that the likelihood of groundwater contamination is 'low', provided the design, construction and operation of hydraulically fractured wells follows regulatory guidelines, on-site wastewater management is effective and enforced, and any accidental spills are rapidly remediated.

319 BOM 2017.
320 DENR submission 230, Addendum 1, p 2; DENR submission 428, p 16.
321 Burton et al. 2014.
322 Entrekin et al. 2011.
323 Ramsay et al. 2012; Botwe et al. 2015.
324 Acuna et al. 2014.

The Panel is not able to comment on the potential consequences to any stygofauna present if an aquifer is contaminated because there is no toxicity data available for these animals. However, as stated above, a more detailed assessment of stygofauna should be part of the recommended strategic regional environmental baseline assessments recommended by the Panel.

### 7.7.3 Aquatic biodiversity

The Panel has not been able to assess the risk of any shale gas development to aquatic biodiversity in the NT because of the limited knowledge relating to NT aquatic biodiversity.

Having said this, biodiversity in surface waters should be adequately protected if the Panel's recommendations prohibiting the shale gas industry extracting surface water (***Recommendation 7.6***) and discharging treated or untreated wastewater into drainage lines, waterways or temporary stream systems (***Recommendation 7.17***) are accepted.

However, an assessment of the possibility that groundwater biodiversity (stygofauna and GDEs) may be affected by over extraction or contamination of groundwater can only be done after the recommended SREBA is completed (***Recommendation 7.5***).

## 7.8 Conclusion

The sustainable management of surface and groundwater resources is crucial to the development of any onshore shale gas industry in the NT. The Panel assessed the risks relating to the protection of three water-related environmental values: water quantity, water quality, and aquatic ecosystems. The Panel has focussed its attention on the Beetaloo Sub-basin because this is the most prospective shale gas region in the NT and its water resources have been comparatively well studied. This case study allows the Panel to draw a number of the conclusions that have broad relevance across the NT.

In total, the Panel assessed 20 water-related risks using the risk assessment framework detailed in Chapter 4. For most of these risks, the Panel identified mitigation measures, which if introduced and rigorously enforced will reduce these risks to an acceptable level.

However, the Panel has identified four high-priority issues from the 20 assessed in respect of which there is insufficient information to enable a full risk assessment to be conducted for the development of a mature onshore shale gas industry. These are: sustainable groundwater use; contamination of groundwater with hydraulic fracturing fluids and wastewater from leaky wells; groundwater contamination from on-site surface spills of wastewater; and the effect of these water quantity and quality issues on either surface and/or groundwater-dependent ecosystems.

The Panel has determined that detailed SREBAs are needed to provide the necessary data and knowledge. The Beetaloo Sub-basin should be the first priority for such a SREBA, and this must be undertaken before any production licences are granted for the purpose of any onshore shale gas industry in the NT.