



# 9 Greenhouse Gas Management



## 9 GREENHOUSE GAS MANAGEMENT

### 9.1 Introduction

The use of liquefied natural gas (LNG) as an energy source has a number of advantages. The primary advantage is that the quantity of greenhouse gases (GHGs) emitted over the full life cycle (production, processing, transportation, and end-use combustion) is significantly less than the comparable life-cycle emissions from either coal or fuel oil as a means of delivering the same amount of energy. Nevertheless, the GHG emissions of LNG at the production stage are relatively high in comparison with those of other industries. INPEX recognises the potential for GHGs to impact on the environment on a global scale through their contribution to the phenomenon of global warming and is committed to actively promoting the reduction of GHGs across its operations in a safe, technically and commercially viable manner.

This chapter of the draft environmental impact statement (Draft EIS) for the Ichthys Gas Field Development Project (the Project) describes INPEX's approach to GHG management by:

- defining greenhouse gases and their global warming potentials
- giving an overview of INPEX's GHG policy position and management strategies
- discussing the Project's legislative and policy context for both the Commonwealth and Northern Territory governments.
- estimating the GHG emissions from the Project and discussing the measures the Project has already taken to minimise GHG emissions
- discussing further GHG emission reductions that INPEX is considering through:
  - technical abatement (beyond that already committed to)
  - offsetting by biosequestration
  - offsetting by geosequestration
  - purchase of emission credits
- comparing GHG emissions from the Ichthys Project with the emissions of other LNG projects
- discussing how GHG emissions from LNG production and use compare with emissions from alternative hydrocarbons such as coal and fuel oil
- describing how the Project has incorporated predicted climate-change scenarios in its planning and design.

### 9.2 Definition of greenhouse gases and global warming potentials

Greenhouse gases absorb and emit radiation in the thermal infrared range. Elevated concentrations of GHGs in the earth's atmosphere have the effect of heating up the atmosphere, creating an "enhanced greenhouse effect."

Global warming potential (GWP) is a measure of how much a given mass of a GHG will contribute to global warming if released into the earth's atmosphere. GWP is a relative scale which compares the mass of the GHG in question with that of the same mass of carbon dioxide (CO<sub>2</sub>), which has been conventionally assigned a GWP value of 1.

The expression "carbon dioxide equivalent" (CO<sub>2</sub>-e) is a measure, using CO<sub>2</sub> as the standard, used to compare the GWPs of the different GHGs. For example, since the IPCC (2007) lists the GWP for methane (CH<sub>4</sub>) over a 100-year period as 21, this means that the emission of 1 Mt of methane is equivalent to the emission of 21 Mt of carbon dioxide.

Table 9-1 shows the 100-year GWPs of the six types of GHGs listed by the Commonwealth Government's Department of Climate Change<sup>1</sup> (DCC 2009a). These were adapted from the GWPs listed in the Second Assessment Report of the Intergovernmental Panel on Climate Change in 1995 and quoted in IPCC (2007).

**Table 9-1: 100-year global warming potentials of greenhouse gases**

Gas	Global warming potential in CO <sub>2</sub> -e
Carbon dioxide (CO <sub>2</sub> )	1
Methane (CH <sub>4</sub> )	21
Nitrous oxide (N <sub>2</sub> O)	310
Perfluorocarbons (PFCs)	6500–9200
Hydrofluorocarbons (HFCs)	140–11 700
Sulfur hexafluoride (SF <sub>6</sub> )	23 900

Source: DCC 2009a and IPCC 2007.

<sup>1</sup> The Commonwealth's Department of Climate Change (DCC) became the Department of Climate change and Energy Efficiency on 8 March 2010.

### 9.3 INPEX greenhouse gas policy position and interim management strategy

INPEX recognises the potential for GHG emissions to impact on the environment through their contribution to global warming and is committed to managing its GHG emissions by:

- actively promoting the reduction of GHG emissions across its operations in a safe, technically and commercially viable manner
- seeking increasing energy efficiency, reducing resource consumption and reducing its overall GWP footprint.

There are a number of alternatives available for applying INPEX's policy objectives to GHG management, with varying costs and risks. As the Commonwealth Government's policy and legislative landscape is still evolving, INPEX continues to explore all practical GHG management alternatives in order to be well prepared to respond when the legislative process becomes clearer. Furthermore, the development of a portfolio approach to GHG mitigation may afford the lowest risk and cost approach for the Project, avoiding a reliance on any single solution. The main opportunities under consideration are as follows:

- engineering abatement
- biosequestration
- geosequestration
- buying offset credits on the open market.

#### Engineering abatement

Engineering abatement opportunities that will reduce GHG emissions and improve energy efficiency are being identified and assessed by INPEX's onshore and offshore facility engineering teams. Options that are safe, technically and commercially viable are likely to be incorporated into facility design. INPEX will also monitor and review technological developments and operational practices to identify GHG emission reduction opportunities during the Project's design phase and through its operational life.

#### Biosequestration

Biosequestration is the process of converting a chemical compound through biological processes to a chemically or physically isolated or inert form. With respect to GWP reduction, the term is most commonly used to refer to the "locking", through photosynthesis, of the carbon in atmospheric CO<sub>2</sub> into plant biomass (usually trees). Biosequestration offsets the effect of the CO<sub>2</sub> and other GHGs released into the earth's atmosphere by the development of natural gas fields and the burning of fossil fuels.

In Australia, the primary approach so far has been to plant "carbon sink" forests of fast-growing long-lived trees. At this stage, the number of accredited biosequestration service providers in the country is limited, though there are likely to be more in the future.

In 2008 INPEX initiated a "Biosequestration Assessment Project" with a pilot program involving the planting of 1.4 million trees to better understand the potential for biosequestration to offset large volumes of CO<sub>2</sub>.

Related to the biosequestration approach is the improvement of forestry and land management practices to reduce CO<sub>2</sub> emissions. ConocoPhillips, for example, as Operator of the Darwin LNG plant, uses improved fire-management practices in savannah as a contribution to managing its CO<sub>2</sub> emissions. Similar options are being assessed by INPEX. At this stage, however, fire-management offsets are not recognised under the Kyoto Protocol<sup>2</sup> and may therefore not be compliant with Australia's proposed Carbon Pollution Reduction Scheme (CPRS) legislation.

#### Geosequestration

Geosequestration is the process of injecting CO<sub>2</sub> into deep geological formations for secure, long-term storage. The technique is also called "carbon (dioxide) capture and storage" (CCS). The technology for CO<sub>2</sub> injection is familiar to oil and gas companies, and has been used as an enhanced hydrocarbon recovery technique for many decades. The Sleipner Project in Norway, for example, is currently utilising this technology and the proposed Gorgon Project in Western Australia has adopted this technology for GHG management. The potential for geosequestration is being examined by INPEX for the Ichthys Project.

#### Buying offset credits on the open market

The following CO<sub>2</sub> offset credits are available for sale on the international market:

- certified emission reductions (CERs) from clean development mechanism (CDM) projects
- emission reduction units (ERUs) from joint implementation (JI) projects
- European Union allowances (EUAs) under the European Union Emissions Trading Scheme Phase 2 (EU ETS II)
- voluntary emission reductions (VERs)
- removal units (RMUs).

These credits may be acceptable as offsets in

<sup>2</sup> The Kyoto Protocol is an agreement made under the United Nations Framework Convention on Climate Change (UNFCCC). Countries that ratify the protocol commit to reduce their emissions of CO<sub>2</sub> and other GHGs or to engage in activities such as emissions trading if they maintain or increase emissions of these gases. The protocol was adopted in Kyoto, Japan on 11 December 1997 and entered into force on 16 February 2005. As of November 2009, 187 states had signed and ratified the protocol.

Australia. However, this will only be known when details of the proposed CPRS and its associated legislation are finalised.

#### 9.4 Greenhouse gas management plan

INPEX will produce a detailed GHG management plan prior to the commissioning of the onshore facilities. The plan will include an updated GHG emission estimate forecast and will consolidate INPEX's plan for technical abatement and offsets.

#### 9.5 The legislative context: government positions on greenhouse gas management

The Commonwealth and Northern Territory governments are developing a suite of policy, strategy and legislative documents related to GHG management. As the policy and legislative landscape is still evolving, INPEX's approach has been to advance understanding of a range of practical alternatives to reduce and offset CO<sub>2</sub>-e emissions in order to be well prepared to react positively once GHG management requirements and options become clearer.

##### 9.5.1 Commonwealth Government position

The Commonwealth Government proposes to implement a "cap-and-trade" CO<sub>2</sub>-e emissions reduction scheme. The scheme would require significant emitters to acquire carbon emission permits. The Government proposes to cap the total number of tonnes of CO<sub>2</sub>-e for which permits can be acquired each year, and then gradually lower the cap over the following years and thus lower GHG emissions over time.

The CPRS proposed by the government has been incorporated into a White Paper published by the Department of Climate Change (DCC 2008). This document proposes that Australia should reduce its CO<sub>2</sub>-e emissions by between 5% and 25% below 2000 levels by 2020 and 60% below 2000 levels by 2050. To achieve these goals, the government proposes to require all facilities with direct emissions of 25 000 t of CO<sub>2</sub>-e per year or more to acquire a permit or establish an offset for each tonne of CO<sub>2</sub> emitted and acquit that permit at the end of the financial year.

The government expects that some trade-exposed activities in the economy will partially qualify for administratively allocated permits on the basis that these activities might be unable to pass on the costs of the emissions trading scheme and that this could affect their international competitiveness. The intention of providing allocated permits for a portion of the GHG emissions is that companies engaged in activities such as LNG production should not be encouraged

to relocate to countries that are not subject to GHG management controls, thereby displacing income and jobs from Australia without concomitant global GHG reduction benefits. However, the government's "emissions-intensive trade-exposed" (EITE) assistance program does propose that all entities conducting activities that generate significant GHG emissions should bear at least a proportion of the carbon costs.

##### 9.5.2 National initiatives

The National Greenhouse and Energy Reporting System (NGERS) operates under the auspices of the DCC and requires facilities that emit more than 25 000 t of CO<sub>2</sub>-e per annum to report their CO<sub>2</sub>-e emissions. This is the proposed mechanism whereby facilities will report under the CPRS. INPEX will report emissions from the Project facilities under the NGERS following Project start-up.

##### 9.5.3 Northern Territory Government position

The Northern Territory Government's objective for managing GHG emissions from new and expanding operations is to minimise GHG emissions to a level that is as low as practicable. This objective is contained in the *NT Environmental impact assessment guide: greenhouse gas emissions and climate change* (NRETAS 2009). This Draft EIS has been prepared in accordance with this guide.

#### 9.6 Project greenhouse gas emissions

##### 9.6.1 Overview

Over its 40-year lifetime, INPEX expects the Project to emit about 280 Mt of CO<sub>2</sub>. This amounts to an average annual emission of about 7.0 Mt. About 278 Mt will be emitted during the operations phase. On average, 2.4 Mt/a of reservoir CO<sub>2</sub> and 4.6 Mt/a of combustion CO<sub>2</sub> will be emitted from offshore and onshore power generation, compression, and other combustion sources. Approximately 2 Mt will be produced during the construction phase.

INPEX has estimated Ichthys Project GHG emissions in order to evaluate options for minimising GHGs and to satisfy the information requirements of the Commonwealth and Northern Territory governments. The methodology employed to calculate Project GHG emissions is consistent with the methodology described in the Commonwealth's publication *National greenhouse accounts (NGA) factors* (DCC 2009a).

As with other liquefied and domestic gas production projects (e.g. the Bayu-Undan – Darwin LNG, North West Shelf, Pluto and Gorgon projects, among many others), the Ichthys Project's GHG production will be made up almost entirely of CO<sub>2</sub> as opposed to other GHGs. These CO<sub>2</sub> emissions will be produced

almost exclusively during the operations phase from a combination of offshore and onshore combustion sources and from CO<sub>2</sub> that is naturally present in the gas and condensate reservoirs.

### Greenhouse gases other than CO<sub>2</sub>

In the gas production process, combustion of hydrocarbons in equipment such as gas turbines, burners, heaters, boilers and flares will result in the formation of CO<sub>2</sub> and water. Small amounts of methane (CH<sub>4</sub>) will also be released in the exhaust gases as a result of incomplete fuel combustion. Even smaller quantities of nitrous oxide (N<sub>2</sub>O) will also be formed during fuel combustion by the reaction of nitrogen and oxygen. However, these two combustion by-products will contribute less than 5% of the total Project CO<sub>2</sub>-e GHG emissions. As any combustion source will co-produce these two by-products, there is very little opportunity to significantly reduce Project-wide GHG emissions by trying to minimise CH<sub>4</sub> or N<sub>2</sub>O emissions from equipment such as gas turbines. Turbines from different manufacturers will also produce similar trace amounts of CH<sub>4</sub> and N<sub>2</sub>O in proportion to the fuel consumed.

As with other gas projects, the Ichthys Project will use small quantities of hydrofluorocarbons (HFCs) in air-conditioners, and will also use small quantities of sulfur hexafluoride (SF<sub>6</sub>) in circuit-breakers and electrical switchgear. All these uses will employ very small volumes, in closed tightly controlled systems with very little leakage. So even if the GWPs of HFCs and SF<sub>6</sub> are very large, the emissions to atmosphere will be very small, perhaps of the order of a few kilograms over the life of the Project, compared with c.278 Mt of CO<sub>2</sub>. The Project's use of air-conditioners, for example, will be negligible in comparison with Northern Territory, Australian, or worldwide use of air-conditioners and HFCs.

The relative amounts of CO<sub>2</sub> and other GHGs to be produced by the Project are presented in Figure 9-1.

### Construction (pre-operations) phase emissions

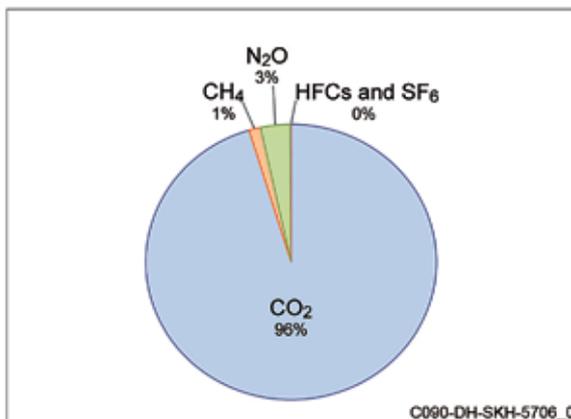


Figure 9-1: Project emissions of CO<sub>2</sub> compared with other greenhouse gases

The construction phase of the Project will contribute less than 0.5% of the total GHG emissions (Figure 9-2). The drilling of the 50 wells in the Ichthys Field is expected to emit <1 Mt of CO<sub>2</sub>-e. Emissions from all other construction sources, including the clearing of vegetation, are also expected to be <1 Mt, for a total of 2 Mt CO<sub>2</sub>-e, at most, prior to operations. In the case of construction emissions, there is very little opportunity for INPEX to change the energy efficiency of drilling rigs, pipelay barges, installation support vessels and other equipment that will be leased from world markets for relatively short periods of time.

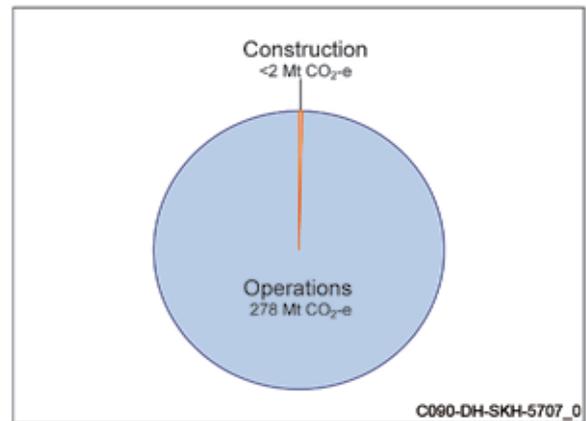


Figure 9-2: Project emissions of CO<sub>2</sub>-e during the construction and operations phases

### Conclusion

For the reasons described above, INPEX has focused attention on estimating and minimising CO<sub>2</sub> emissions during the operations phase<sup>3</sup>. Efforts to reduce already very low emissions of GHGs other than CO<sub>2</sub> during the operations and construction phases will be made, but will occur during the detailed design and construction phases of the Project.

### 9.6.2 Operational greenhouse gas emissions

#### Overview

Figure 9-3 provides an estimate of CO<sub>2</sub> emissions over the Project's 40-year life. The emissions are shown on an annual average basis; during any given year they may be slightly higher or lower depending on the timing of planned and unplanned equipment shutdowns and maintenance works. The figure was developed by considering annual emissions from the three main CO<sub>2</sub> source categories: reservoir CO<sub>2</sub>, offshore combustion, and onshore combustion.

<sup>3</sup> The "operations phase" here is taken to include the first year of commissioning, when reservoir fluids are introduced into the offshore and onshore facilities. Commissioning emissions are included in subsequent operations-phase CO<sub>2</sub> estimates. Commissioning will last for only a few months, whereas operations will last for the rest of the 40 years.

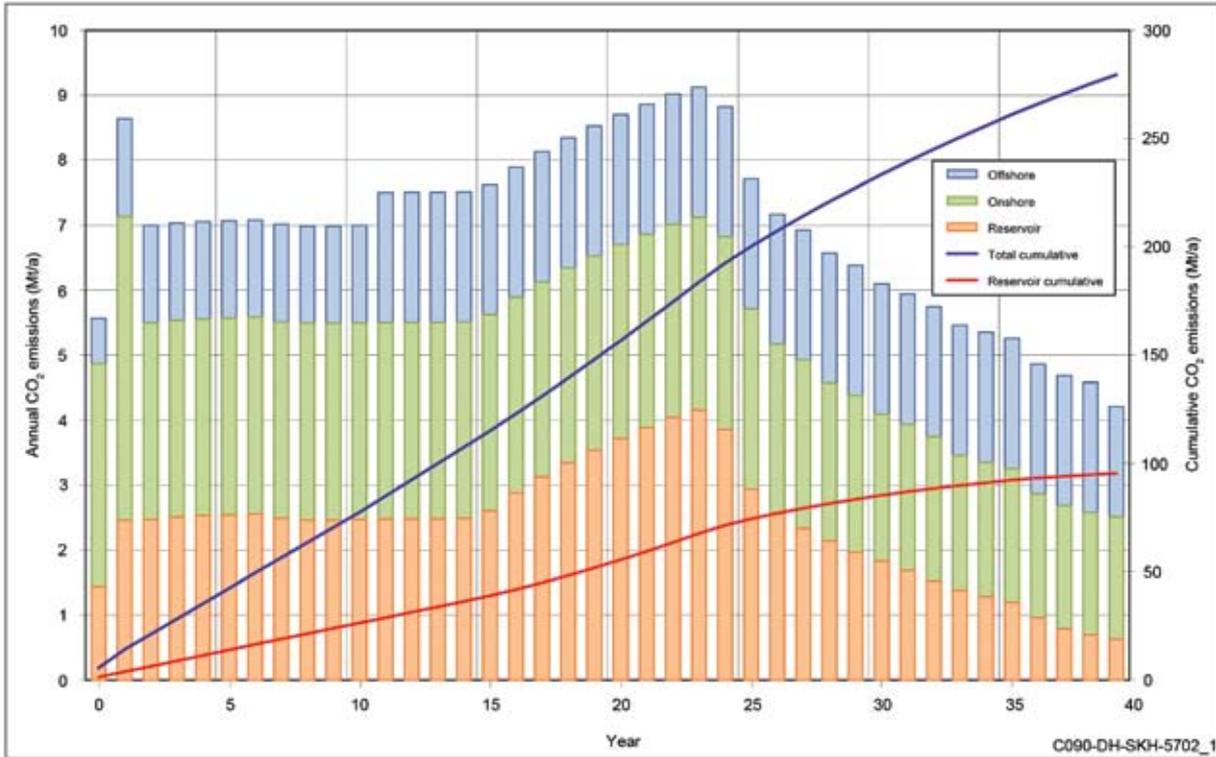


Figure 9-3: Estimated annual CO<sub>2</sub> emissions over the Project’s 40-year operational life

INPEX plans to commission its first onshore LNG train and its offshore central processing facility (CPF) and floating production, storage and offtake (FPSO) facility within five years of the final investment decision (FID) being made; the second LNG train will be commissioned one year later. Offshore and reservoir CO<sub>2</sub> emissions in the first year of operation will be about half those of Year 2 onwards because gas will only be supplied to one onshore train. Onshore combustion emissions, however, may be higher in years 1 and 2 than in subsequent years, since during commissioning a much larger amount of gas than normal will need to be flared onshore to accomplish the initial “cool-down” of the two LNG trains.

The two reservoirs which make up the Ichthys Field are in the Brewster Member and the Plover Formation. The CO<sub>2</sub> content in the reservoirs averages about 8% in the Brewster reservoir and 17% in the Plover reservoir. Reservoir CO<sub>2</sub> emissions will remain at c.2.5 Mt/a until Year 16 since gas from the Brewster reservoir will be used for approximately the first 15 years. From Year 16 until Year 23, however, reservoir CO<sub>2</sub> emissions will gradually increase to c.4.1 Mt/a as Brewster gas begins to run out and the Project begins processing increasing amounts of Plover gas along with available Brewster gas in order to continue producing 8.4 Mt/a of LNG and maintain the required LNG production levels. From around Year 24 onwards, reservoir CO<sub>2</sub> emissions will gradually decrease as the Project slowly runs out of gas and continues to produce LNG, but at rates below the 8.4 Mt/a plateau.

Thus, based on the current design and operating assumptions, total CO<sub>2</sub> emissions over the 40-year operations period will be c.278 Mt.

Figure 9-4 shows that reservoir CO<sub>2</sub> emissions will account for approximately 34% of the Project’s total CO<sub>2</sub> emissions and that offshore and onshore combustion processes will account for approximately 26% and 40% of the total CO<sub>2</sub> emissions respectively.

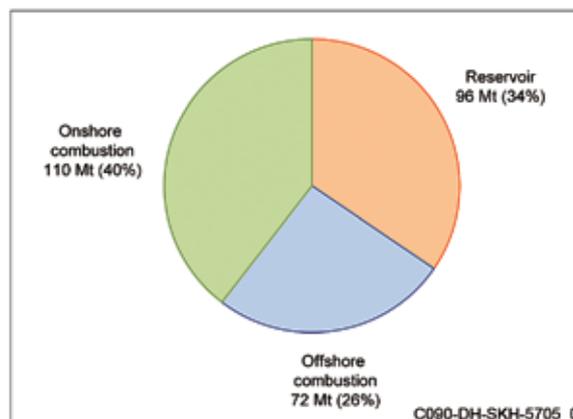


Figure 9-4: Overview of the contributions of reservoir, offshore combustion and onshore combustion CO<sub>2</sub> emissions to the 40-year Project total

Table 9-2 provides more detail on the contributions to expected reservoir, offshore combustion and onshore combustion CO<sub>2</sub> emissions.

Table 9-2: Estimated average annual CO<sub>2</sub> emissions during the operations phase<sup>4</sup>

Source	Approx. power requirement	Approx. heating requirement	40-year annual average (Mt/a)	40-year totals (Mt)
<b>Reservoir</b>				
Brewster	n.a.	n.a.	1.4	56
Plover	n.a.	n.a.	1.0	40
<b>Reservoir total</b>	<b>n.a.</b>	<b>n.a.</b>	<b>2.4</b>	<b>96</b>
<b>Offshore combustion*</b>				
CPF—export gas compression (four RB211 turbines)	100 MW	n.a.	0.5	20
CPF—inlet gas compression (three RB211 turbines)	0 initially; 75 MW from Year 12	n.a.	0.3 <sup>†</sup>	12
CPF—power generation (three RB211 turbines)	75 MW	n.a.	0.3	12
FPSO—power generation (four RB211 turbines)	100 MW	n.a.	0.5	20
FPSO—fired heating for monoethylene glycol (MEG) regeneration, condensate heating and stabilisation	n.a.	60 MW	0.2	8
<b>Offshore total</b>	<b>275–350 MW</b>	<b>60 MW</b>	<b>1.8</b>	<b>72</b>
<b>Onshore combustion<sup>‡</sup></b>				
Refrigerant compressor turbines (four Frame 7 turbines)	280 MW	n.a.	1.4	55
Power generation turbines (nine Frame 6 turbines, eight running)	220 MW	n.a.	0.9	35
Acid gas removal unit (AGRU) incineration	n.a.	40 MW	0.1	4
Hot-oil furnaces and possibly steam boilers	n.a.	80 MW	0.2	7
Flares (all)	n.a.	n.a.	0.2	9
<b>Onshore total (excluding reservoir)</b>	<b>500 MW</b>	<b>120 MW</b>	<b>2.8</b>	<b>110</b>
<b>Total for Project</b>			<b>7.0</b>	<b>278</b>

\* Rolls-Royce RB211 turbines are assumed for offshore use for estimation purposes only. Turbine choice is subject to technical assessment in the detailed-design phase.

<sup>†</sup> CO<sub>2</sub> emissions will be zero for approximately the first 11 years, 0.5 Mt/a for the next 29 years, and will average to 0.3 Mt/a over 40 years.

<sup>‡</sup> General Electric Frame 6 and Frame 7 turbines are assumed for onshore use for estimation purposes only. Turbine choice is subject to technical assessment in the detailed-design phase.

n.a. = not applicable.

<sup>4</sup> Assuming LNG production of 8.4 Mt/a until the end of the plateau is reached.

Figures 9-5 and 9-6 delineate the sources of the Project's expected CO<sub>2</sub> emissions in more detail.

The following assumptions were made in estimating operations-phase CO<sub>2</sub> emissions:

- The Project facilities will operate for 40 years.
- During the 40 years, the facilities will on average be available for production around 90% of the time, that is, for 330 days per year. During some years (those with few shutdowns), production will be higher and the associated CO<sub>2</sub> emissions may therefore be around 10% higher than the levels shown in Figure 9-3 and Table 9-2.
- To prevent CO<sub>2</sub> from freezing during the liquefaction process (which would cause blockage and failure of the cryogenic equipment), the reservoir CO<sub>2</sub> will be removed from the gas stream in an acid gas removal unit (AGRU) prior to the gas entering the liquefaction equipment. The CO<sub>2</sub> will be emitted to atmosphere after it has passed through an acid gas incinerator unit where hydrogen sulfide (H<sub>2</sub>S) and small amounts of absorbed hydrocarbons will be converted to sulfur dioxide (SO<sub>2</sub>) and CO<sub>2</sub>.
- The offshore CPF will use gas turbines for export gas compression and power generation from the start of the Project, with additional turbines being added for inlet compression from Year 12.

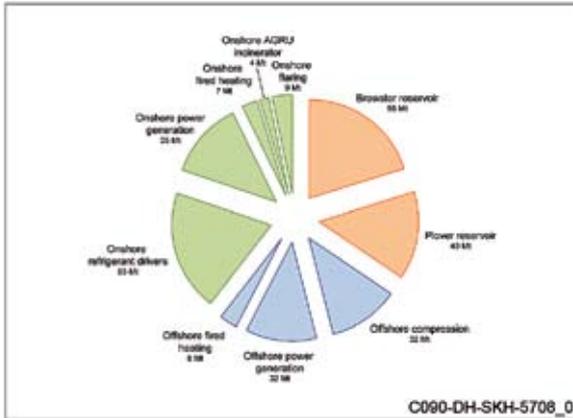


Figure 9-5: Sources of CO<sub>2</sub> emissions (in Mt) over the 40-year life of the Project

- The offshore FPSO facility will also have power generation capacity that will be supplied by gas turbines and will require fired heating for condensate stabilisation and monoethylene glycol (MEG) regeneration.
- The onshore plant will use four gas turbine drivers for refrigerant propane and mixed refrigerant compression loops (GE Frame 7 or equivalent); these turbines will be operating continuously at 100% design load.
- The onshore plant will also use nine open-cycle industrial gas turbines (GE Frame 6 or equivalent) for power generation, with an operating philosophy of eight running and the ninth as backup. Loads on these will be variable.
- Waste-heat recovery systems will be installed on offshore and onshore facilities to minimise the need for fired heating during normal operations.
- The emissions from minor vented and fugitive sources will be minimal compared with the reservoir and combustion emissions and are not included in the operational GHG emission estimate.
- Emissions of GHGs other than CO<sub>2</sub> will also be minimal and have been excluded from the estimates.

### 9.7 Project greenhouse gas emissions relative to Australian and Northern Territory emissions

Table 9-3 compares the Project's estimated GHG emissions with 2007 Australian and Northern Territory GHG emissions. The relative contribution of the Project's GHG emissions compared against 2007 levels is 1.2% of the Australian CO<sub>2</sub>-e emissions and 30% of the Northern Territory's CO<sub>2</sub>-e emissions.

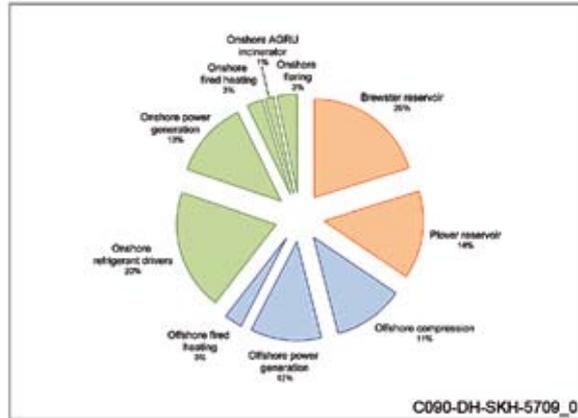


Figure 9-6: Sources of CO<sub>2</sub> emissions (%) over the 40-year life of the Project

Table 9-3: Project greenhouse gas emissions relative to the greenhouse gas emissions for Australia and the Northern Territory in 2007

	CO <sub>2</sub> -e emissions (Mt/a)	Percentage of 2007 Australian GHG emissions	Percentage of 2007 Northern Territory GHG emissions
Australian GHG emissions (2007)	597.2	n.a.	n.a.
Northern Territory GHG emissions (2007)	17.2	2.9	n.a.
Ichthys Project total GHG emissions (40-year annual average)	7.0	1.2	n.a.
Ichthys Project onshore GHG emissions (40-year annual average)*	5.2	n.a.	30

Source: DCC 2009b.

\* Onshore CO<sub>2</sub>-e emissions include onshore combustion emissions (2.8 Mt/a) and reservoir emissions (2.4 Mt/a). Even though reservoir CO<sub>2</sub> emissions will be sourced from Commonwealth waters outside the Northern Territory, the reservoir CO<sub>2</sub> will be emitted to atmosphere in the Northern Territory.

n.a. = not applicable.

## 9.8 Minimising Ichthys Project greenhouse gas emissions

This section outlines the options that INPEX is investigating for minimising the Project's GHG emissions through technical abatement measures.

INPEX recognises that the management of GHGs is an important consideration in the planning and design of the Project. The following range of energy-efficient technologies has been identified for use on the Project:

1. the selection of activated methyldiethanolamine (aMDEA) as the CO<sub>2</sub> removal solvent
2. the selection of energy-efficient turbines for compressor drivers and power generation
3. the incorporation of waste-heat recovery units to minimise the need for supplemental fired heating

4. the employment of other technical improvements, including onshore AGRU flash-gas recovery and offshore flare-gas recovery
5. the possible implementation of combined-cycle power generation onshore.

The technologies described in this section have either already been integrated into the design or are being assessed for their suitability, taking into account possible constraints such as technical feasibility and risk, safety hazard risk, economic and schedule constraints, and various environmental considerations.

The capacity of each of these measures to influence the GHG emission intensity of the Project is shown in Figure 9-7.

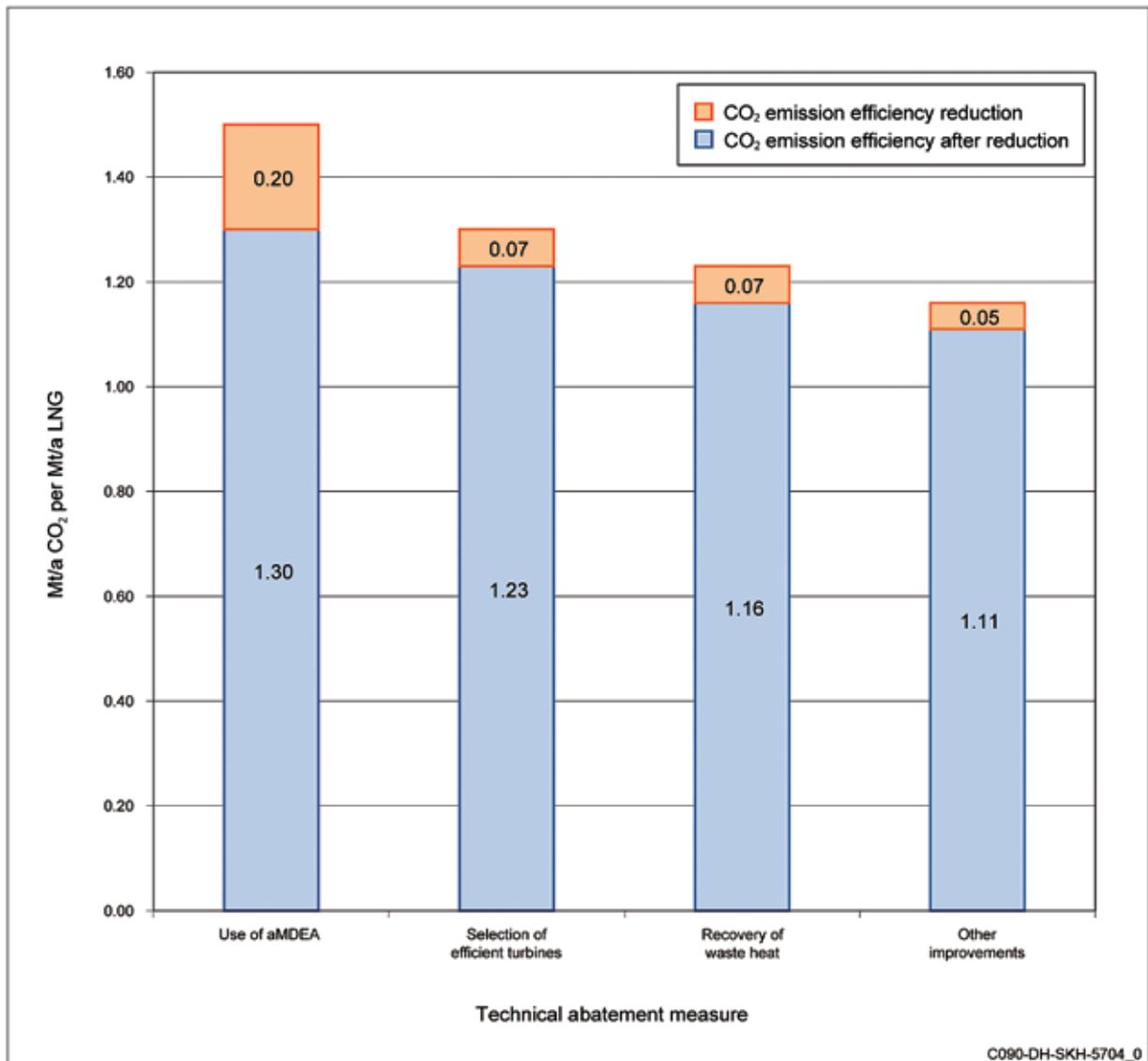


Figure 9-7: Project CO<sub>2</sub> emission reduction measures

### 1. The selection of aMDEA as the CO<sub>2</sub> removal solvent

INPEX estimates that using aMDEA rather than other possible solvents will reduce CO<sub>2</sub> emissions by 0.2 Mt/a of CO<sub>2</sub> per Mt/a of LNG produced.

This equates to a CO<sub>2</sub> reduction of c.50 Mt over 40 years (assuming a 40-year average production rate of 6.3 Mt/a of LNG)<sup>5</sup>.

The CO<sub>2</sub> found naturally in the gas from the reservoirs has to be taken out of the hydrocarbon gas stream prior to liquefaction. If CO<sub>2</sub> were to remain in the gas stream, it would freeze inside the cryogenic equipment and cause blockage and failure. In order to remove the CO<sub>2</sub>, the gas flows upwards against a downward flow of solvent in the absorber of the acid gas removal unit (AGRU) unit. Heat from the gas turbines, using a circulating hot-oil system, is then used to drive off the CO<sub>2</sub> from the solvent so that the solvent can be reused.

To minimise the co-absorption of CH<sub>4</sub> from the AGRU, aMDEA has been selected as the preferred solvent for the removal of acid gases such as CO<sub>2</sub>. The advantage of aMDEA is that it co-absorbs significantly smaller quantities of hydrocarbons than traditional solvents in the process of absorbing the CO<sub>2</sub> from the feed-gas stream. This in turn reduces the quantities of CH<sub>4</sub> and other hydrocarbons flashed or vented from the flash vessels and regenerator column during the regeneration process. The vented CO<sub>2</sub> stream is then directed to the AGRU incinerator which converts any remaining CH<sub>4</sub> to CO<sub>2</sub>, which has a lower GWP. Flash-vessel vapours will also be directed to the incinerator. The use of aMDEA also reduces regeneration energy and has proved its usefulness in the field. The Project has also chosen a two-step rich-aMDEA flash process configuration for solvent regeneration; this also reduces the regeneration energy required.

### 2. Selection of energy-efficient turbines

INPEX estimates that selection of energy-efficient turbines for both the offshore and the onshore facilities will reduce CO<sub>2</sub> emissions by 0.07 Mt/a of CO<sub>2</sub> per Mt/a of LNG produced. This equates to a CO<sub>2</sub>-e reduction of c.18 Mt over 40 years (assuming a 40-year average production rate of 6.3 Mt/a of LNG).

#### 2a. Onshore refrigeration compressor drivers

The turbines used for driving liquefaction process refrigerant compressors are the largest users of energy in the LNG supply chain. Consequently, the choice of turbine technology will have a significant impact on the Project's GHG emissions.

<sup>5</sup> The Ichthys Project expects to produce an average of 8.4 Mt/a of LNG for approximately the first 23 years of operation. But during the following 17 years, the Project expects production to gradually decline as gas reserves become depleted. The 40-year total LNG production is expected to be 252 Mt. The 40-year average LNG production rate is expected to be c.6.3 Mt/a.

Turbine selection has been conducted with an integrated approach to GHG emissions savings. This involves matching the demand for process heat with appropriate turbine selection. The process heat demand of the Ichthys LNG process is significant because of the high reservoir CO<sub>2</sub> content of the gas. This process heat needs to be sourced from fired heaters, or from waste-heat recovery units, or from a combination of the two. Studies indicate that the heat in the exhaust from process driver turbines fits well with the heat demand of the process and that an integrated solution of industrial turbines and waste-heat recovery units will yield a very efficient LNG plant. It is estimated that it will be only later in the Project's life, when the gas extraction rate from the Plover reservoir is at its peak, that the process driver turbines will not be able to supply sufficient heat and necessitate the supply of extra process heat.

#### 2b. Onshore power generation

INPEX will select General Electric (GE) Frame 6 or equivalent turbines for power generation. These are more efficient than the GE Frame 5 and other power generation turbines selected by other operators in the past.

#### 2c. Offshore compressor drivers

INPEX plans to select aeroderivative turbines for offshore export and inlet compressor drivers. This will help to increase energy efficiency.

#### 2d. Offshore power generation

INPEX also plans to select aeroderivative turbines for offshore power generation purposes.

### 3. Incorporation of waste-heat recovery units

INPEX estimates that recovery of waste heat, both offshore and onshore, will reduce CO<sub>2</sub> emissions by 0.07 Mt/a of CO<sub>2</sub> per Mt/a of LNG produced. This equates to a CO<sub>2</sub>-e reduction of around 18 Mt over 40 years (assuming a 40-year average production rate of 6.3 Mt/a of LNG).

Heat is required for many processes in the offshore and onshore gas production processes. The greatest onshore demand comes from the AGRU and the greatest offshore demand comes from the condensate-processing and MEG-regeneration processes.

In order to meet the heat demand, INPEX plans, wherever practicable, to install waste-heat recovery units on both the offshore and onshore turbines. Recovered waste heat reduces the need for operational fired heaters and boilers which would be additional sources of GHG.

The Project has designed the main refrigerant turbines onshore to incorporate waste-heat recovery systems that will provide process heat for the onshore plant. Significantly, about 360 MW of heat will be recovered, reducing fuel use by 12 million standard cubic feet of gas per day.

The current best-practice LNG driver turbine technology in Australia is to incorporate direct-drive gas turbines to power refrigerant compressors with waste-heat recovery units. This technology is currently utilised on the North West Shelf Project's fourth and fifth LNG trains and by the ConocoPhillips Darwin LNG plant; it is also proposed for the Pluto and Gorgon projects. However, in the case of the North West Shelf and Pluto projects, and to a lesser extent the Darwin LNG plant, the opportunity for heat recovery is not as great as for the Ichthys and Gorgon projects because Ichthys and Gorgon have the largest concentrations of CO<sub>2</sub> in their reservoir gases. The biggest source of waste-heat demand in an LNG plant is for the regeneration of the rich aMDEA or other AGRU solvent. The fact that the Ichthys and Gorgon gas fields have much higher CO<sub>2</sub> content in their gas than is the case with the North West Shelf, Pluto and Darwin LNG projects puts them in a better position to use more open-loop turbine waste heat than the other operators.

#### 4. Other energy-efficiency measures

INPEX estimates that other energy-efficiency measures will reduce CO<sub>2</sub> emissions by an additional 0.05 Mt/a of CO<sub>2</sub> per Mt/a of LNG produced. This equates to a CO<sub>2</sub>-e reduction of c.13 Mt over 40 years (assuming a 40-year average production rate of 6.3 Mt/a of LNG).

##### 4a. Flaring

The offshore and onshore gas-processing facilities will be designed to avoid continuous intentional flaring during operations. The following design measures are proposed:

- Boil-off gas compressors will be sized to recover boil-off gas from the LNG tanks during holding mode and for full recovery of vapours during shiploading, rather than directing emissions to flare or vent.
- Waste streams will be recovered back into the process by reclaiming propane and light and heavy mixed refrigerant to the most reasonably practicable extent during shutdowns.
- The gas-processing plant will be designed for reliability and stability in order to minimise process and safety trips which would cause depressurisation of the whole facility and the associated flaring. Where necessary, spare equipment has been specified so that the failure

of one piece of equipment can be offset by running the spare equipment.

- Options for flare-gas recovery for unintentional releases to flare headers are being investigated for the offshore and onshore flare systems to try to capture emissions to atmosphere from leakages and purge gas.

##### 4b. Operational controls—monitoring

An important part of any abatement process is the effective collection of accurate data to allow calculation of plant performance. To achieve this, the process monitoring and control system that will be installed as part of the overall facilities will have a provision to collect and monitor data required to calculate plant emissions and efficiencies.

This will include the ability to undertake an overall material balance of the process plant, that is, to determine how much feedstock enters the plant and how much leaves the plant in terms of product (LNG, liquefied petroleum gas (LPG) and condensate) or is consumed as fuel or lost to the flare.

The value of such a monitoring system is that it can be used to give timely warning to the whole operations team when flaring is occurring or gas turbine performance is dropping below desirable levels and thus allow for management responses.

##### 4c. Fugitive emission sources

Fugitive emissions are relatively minor contributors to overall GHG emissions at modern facilities. Measures that eliminate sources of fugitive emissions include the following:

- the installation of floating roofs on condensate storage tanks
- the specification of dry gas seals for centrifugal compressors.

##### 4d. Alternative energy

The use of solar collectors is being considered for the off-site accommodation village in Darwin. However, INPEX does not plan to further consider solar collectors on administration and other buildings within or near the LNG plant because surplus electrical capacity from the plant's power generation turbines will be adequate to supply such electricity.

#### 5. Combined-cycle power generation

Combined-cycle power generation is being considered for the onshore facilities. If INPEX proceeds with this proposal it would reduce CO<sub>2</sub> emissions by an additional 0.07 Mt/a of CO<sub>2</sub> per Mt/a of LNG produced. This would equate to a CO<sub>2</sub>-e reduction of c.18 Mt over 40 years (assuming a 40-year average production rate of 6.3 Mt/a of LNG).

For onshore power generation, a configuration of open-cycle Frame 6 turbines has been evaluated as a base case. INPEX continues to investigate the selection of combined-cycle gas turbines (CCGTs) for power generation for the LNG process.

As with the discussion on process turbine selection, the selection of CCGTs would be based on integrated GHG reduction benefits. Some nuisance low-pressure gas streams that would not be reasonably processed could also be directed to the CCGT complex to raise more steam to generate power.

The use of CCGTs would involve installing fewer turbines and relying on one or more steam turbines downstream of the open-loop power generation turbines to recover additional waste heat as steam.

Since the liquefaction process is at the heart of LNG production, the choice of turbines will be an area of extensive research in order to secure the best technological, safety, economic and GHG outcome. A decision on final design will be made following the front-end engineering design (FEED) phase of the Project.

### Summary

INPEX has identified and committed to technical-abatement and energy-efficiency measures that will reduce CO<sub>2</sub> emissions by around 100 Mt over the Project's 40-year life. Investigation of measures to reduce emissions by a further approximately 18 Mt is continuing.

## 9.9 Benchmarking

This section benchmarks the Project's expected GHG emissions against the performance of other LNG projects.

### 9.9.1 Overview of world LNG projects

Table 9-4 provides an overview of worldwide LNG projects and the technologies they use. This table and the previous section on technical abatement demonstrate that the Project has either already adopted, or continues to consider, technology options that are as energy-efficient or more energy-efficient than those adopted by other LNG operators.

### 9.9.2 Benchmark greenhouse gas efficiency of the Ichthys Project against other LNG projects

The Project's expected GHG emission efficiency can be compared with other major LNG and associated hydrocarbon liquids projects worldwide (existing and planned) through a number of benchmarking methods.

Kilograms of CO<sub>2</sub>-e per megawatt hour (MW·h) of electricity produced in Asia is one such efficiency benchmark, often used to compare the use of LNG with the use of fuel oil and coal to produce the same amount of electricity in Asia. Figure 9-8 compares the expected GHG emissions of the Ichthys Project with estimated GHG emissions from historical Australian LNG projects (existing and under construction). The exact efficiencies of various LNG projects are difficult to determine from publicly available data, and vary based on assumptions about aspects such as when and how much export compression will be needed and when decline from a production plateau will occur as field productivity declines and so on. But how the Ichthys Project will compare with other LNG projects can be assessed reasonably accurately, as described in the following subsections.

### 9.9.3 Ichthys Project greenhouse gas emissions compared with other projects

#### Discussion

The biggest differences in CO<sub>2</sub> emissions efficiencies between LNG projects typically arise in relation to the following factors:

- the proportion of CO<sub>2</sub> naturally present in the reservoir gases used to make the LNG
- the nature of the offshore facilities (and their associated combustion CO<sub>2</sub> emissions) needed to get the gas to the liquefaction facility via a gas export pipeline and, in many cases, to remove a portion of the hydrocarbon liquids first.

As described in the section *Onshore combustion emissions* below, CO<sub>2</sub> emission efficiency at the liquefaction stage is not a particularly distinguishing factor.

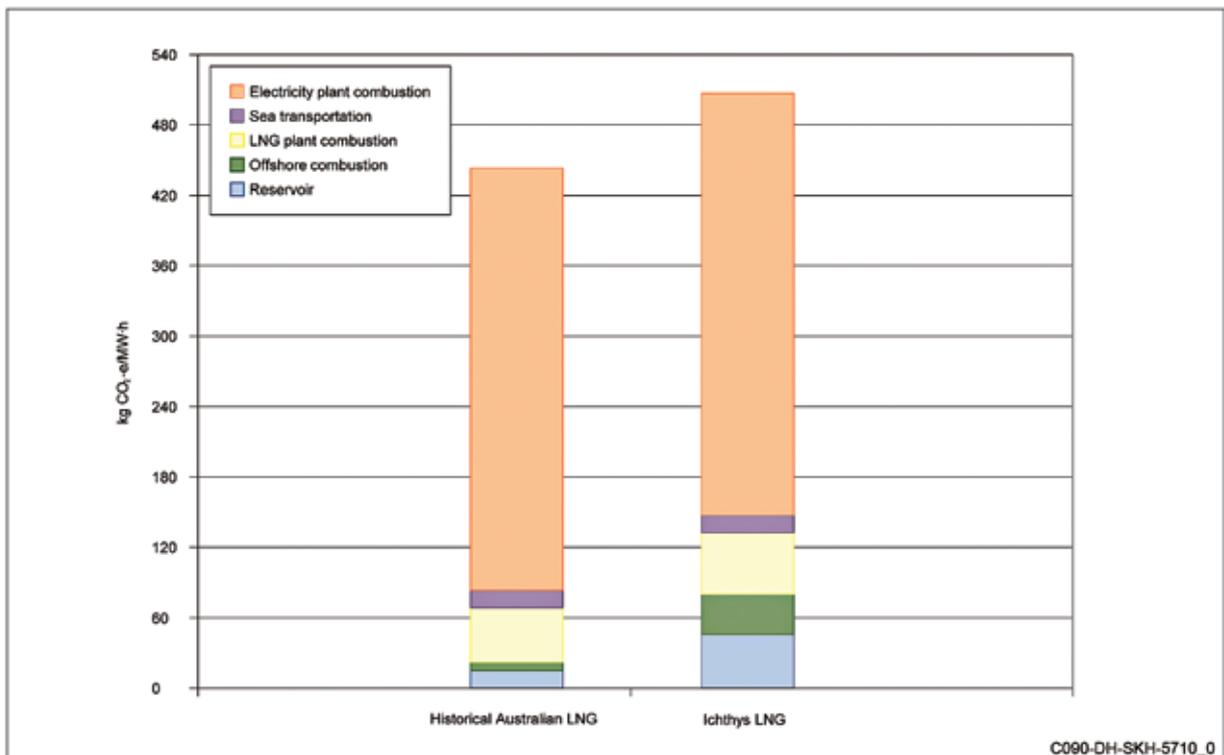
Figure 9-8 reflects the fact that the Ichthys Field's Brewster and Plover gas reservoirs have higher reservoir CO<sub>2</sub> levels than the gas fields that have historically supplied other LNG plants both in Australia and elsewhere. In addition, the Project will need relatively energy-intensive offshore facilities because of a combination of factors: deeper water at the field location, a greater distance between the field and the LNG plant, and the need to remove condensate from the gas at the offshore facility.

These two factors—higher reservoir CO<sub>2</sub> and the requirement for more energy-intensive offshore facilities—mean that the Ichthys Project will emit more CO<sub>2</sub> per unit of LNG or total liquid hydrocarbon produced than other projects undertaken so far, even though efficient technologies have been specified for both offshore and onshore operations, as evidenced by the mitigation technology comparisons made in Table 9-4. Future projects around the world, including

**Table 9-4: Comparison of technologies employed by existing and planned major LNG plants worldwide**

Project	Capacity (Mt/a)	Commissioning date	Reservoir CO <sub>2</sub> (mol %)	Aeroderivative turbines		Combined-cycle gas turbines		Waste-heat recovery		aMDEA solvent
				Process	Power	Process	Power	Process	Power	
Ichthys LNG	8.4	c.2016	8 Brewster 17 Plover	No	Under consideration	No	Under consideration	Yes	Under consideration	Yes
Gorgon LNG	15	c.2013	14 Gorgon 0.5 Jansz	No	No	No	No	Yes	No	Yes
Pluto LNG	4.2	c.2010	1.7	No	No	No	No	Yes	Yes	Yes
Karratha gas plant (train 5)	4.5	2008	<2	No	No	No	No	Yes	No	Yes
Snøhvit, Norway	4.3	2007	5.7	Electrical drive	Yes	Electrical drive	No	Yes	No	Yes
Darwin LNG	3.7	2006	6.0	Yes	No	No	No	Yes	No	Yes
Karratha gas plant (train 4)	4.5	2004	<2	No	Yes	No	No	Yes	No	Yes
Atlantic LNG	15.1	2005	0.8	No	No	No	No	Yes	No	No
Oman LNG	6.9	2001	1.0	No	No	No	No	No	No	Yes (No)*
Nigeria LNG	6.1	2000	1.8	No	No	No	No	No	No	Yes
RasGas, Qatar	6.4	1999	2.3	No	No	No	No	No	No	No
Qatargas (trains 1–2)	4.8	1993	2.1	No	No	No	No	No	No	No
Karratha gas plant (trains 1–3)	7.5–8	1989 (trains 1–2); 1992 (train 3)	<2	No	No	No	No	No	No	Yes (No)*

\* Not originally, but currently Yes.



Adapted from APPEA 2009, J.P. Morgan Equity Research 2008, and Pace 2009.

**Figure 9-8: CO<sub>2</sub>-e emission benchmarking on the basis of electricity generated per MW-h**

those in the Browse Basin, are likely to more closely resemble the Ichthys Project than already operating projects. They will often have higher CO<sub>2</sub> content in their feed gas and they will be located in deeper water in more remote locations.

The following subsections elaborate further on expected Project GHG emissions compared with the GHG emissions of other LNG facilities.

### Reservoir CO<sub>2</sub>

As Table 9-4 shows, the Brewster and Plover reservoirs have high CO<sub>2</sub> content in comparison with other currently producing gas fields in Australia and around the world. Most other existing LNG projects have had access to gas supplies with low reservoir CO<sub>2</sub> content. There is a general trend towards higher CO<sub>2</sub> content in reservoir gas between the early 1990s and projects planned for the future.

### Offshore combustion emissions

Figure 9-8 and Table 9-2 also show the significance of needing energy-intensive offshore facilities.

The Project's requirement to have an offshore FPSO for the treatment, storage and offloading of condensate and for the separation and regeneration of large quantities of MEG from produced water to prevent hydrate formation increases the overall energy needs offshore and also increases CO<sub>2</sub> emissions from offshore. These sorts of technical issues combine to make the Project's offshore emissions comparatively greater than those of existing projects.

### Onshore combustion emissions

The Ichthys Project will have emissions from its onshore gas-processing plant very similar to other LNG projects on the basis of megatonnes of CO<sub>2</sub> emitted per megatonne of LNG produced—this is to be expected. Over their lifetimes, most large LNG projects will emit roughly 0.4 Mt/a of CO<sub>2</sub>-e from compressor-driver and power generation turbines (together with minor emissions from other sources) in order to liquefy each megatonne of natural gas into LNG. This is equivalent to saying that, worldwide, most large LNG facilities will on average use roughly 10% of the incoming gas to liquefy and export the remaining 90% as LNG. The 10% of gas used is combusted to CO<sub>2</sub> and emitted in turbine and other exhausts<sup>6</sup>.

6 The molecular weight of CO<sub>2</sub> is 44. Assuming that the fuel gas is CH<sub>4</sub> (methane) with a molecular weight of 16, then combusting 0.1 Mt of fuel gas to liquefy 0.9 Mt of gas into LNG will generate  $(0.1 \times 44)/16 = 0.275$  Mt of CO<sub>2</sub>. This 0.275 Mt of CO<sub>2</sub> divided by 0.9 Mt of LNG gives a ratio of 0.31. This ratio is typical at the plateau of LNG production. Later in facility life, CO<sub>2</sub> emissions per megatonne of LNG produced will increase. Factoring in this decreasing efficiency and other minor GHG sources (such as fired heaters, incinerators and flares) yields an average lifetime onshore plant efficiency of roughly 0.4 Mt of CO<sub>2</sub> per megatonne of LNG.

The efficiency is better in the early years when production will plateau—around 7–8% will be used to liquefy the remaining 92–93%. But efficiency will fall away later in field life as most equipment will need to keep running even as LNG production gradually declines.

### Sea transportation and electricity-plant combustion emissions

For the purposes of comparing expected Ichthys Project CO<sub>2</sub> emissions with those of other Australian LNG projects, sea transport (ship fuel) and efficiencies at gas-fired power stations in Asian markets will not be a distinguishing factor. These factors, however, can be large if LNG is compared with coal, as described in the following subsection.

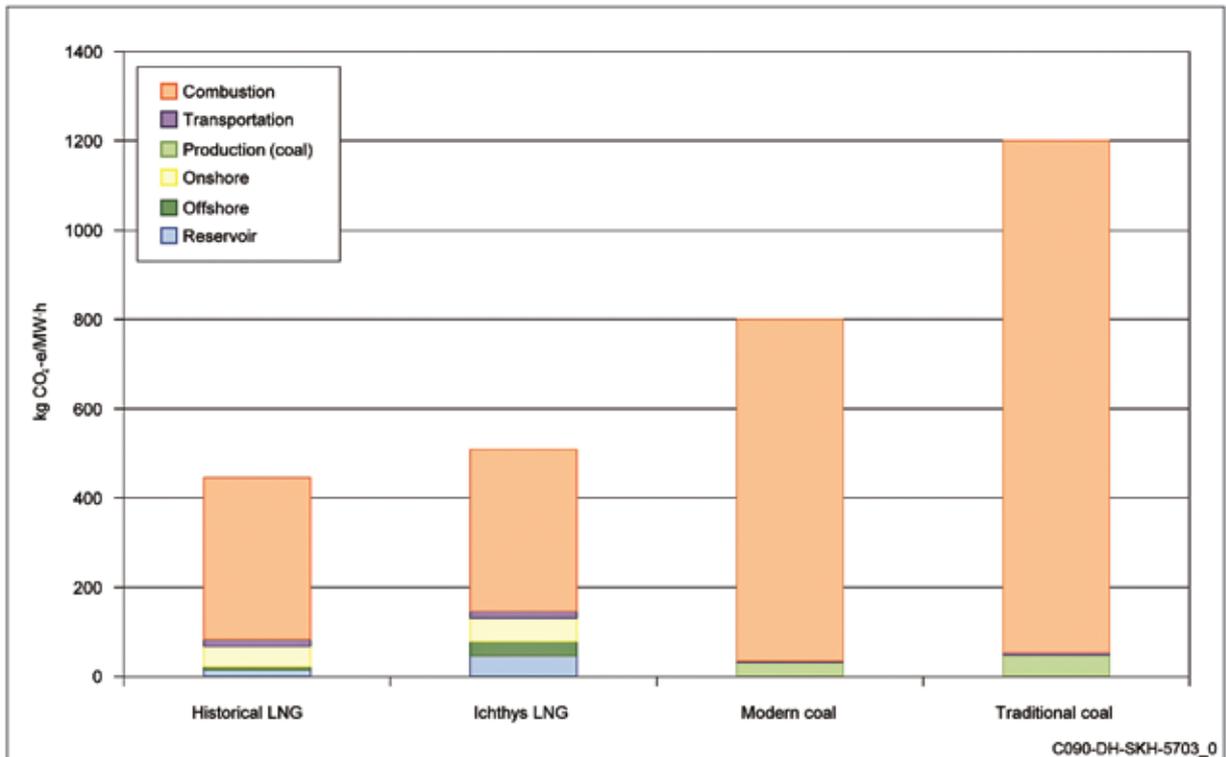
Ichthys LNG shipped from Darwin to Asian markets traverses a similar distance when compared with LNG from the Darwin LNG plant, the North West Shelf Project, or the various other projects presently under development in Western Australia, the Northern Territory and Queensland. Differences in efficiencies between different gas-fired power plants in Asia and elsewhere are also outside INPEX's control.

## 9.10 Greenhouse gas impacts of using LNG instead of coal for electricity generation

Use of LNG as an energy source has a number of advantages. The primary advantage is that the quantity of GHGs emitted over the full life cycle (production, processing, transportation, and combustion at end use) is significantly less than the comparable life-cycle emissions from either coal or fuel oil, as a means of delivering the same amount of energy.

Figure 9-9 illustrates a life-cycle GHG emission comparison for the use of LNG and coal to generate the same amount of electricity.

This figure shows that even if there were to be a factor of two or three differences in production, processing, and transportation efficiencies between different LNG projects, and if these emissions were not offset, the overall impact would be relatively minor compared with the end-use combustion efficiency difference between LNG and coal. This is attributable to a number of factors. Combustion of natural gas is more thermodynamically efficient than the combustion of carbon on a weight basis. In addition, natural gas, when regasified from LNG, contains essentially no water or inerts. In contrast, coal can contain significant amounts of water and inerts. The water and inerts all need to be heated in a power-plant boiler in the electricity generation process and there is an overall loss of efficiency.



Sources: adapted from APPEA 2009, J.P. Morgan Equity Research 2008, and Pace 2009.

Figure 9-9: Life-cycle CO<sub>2</sub>-e emissions from the use of LNG and coal to produce electricity

Electricity produced from LNG generates 40–60% less CO<sub>2</sub> than electricity produced from coal. Every tonne of LNG used to generate electricity averts the emission of up to 4 t of CO<sub>2</sub> when compared with coal-fired electricity generation. Ichthys LNG will be marketed to the Asia-Pacific region and will in large part be used for power generation. In a global context, the use of Ichthys LNG to generate electricity in Asia will therefore likely result in a significant reduction in CO<sub>2</sub> emissions.

### 9.11 Carbon sequestration alternatives (offsets)

The Commonwealth Government’s Carbon Pollution Reduction Scheme White Paper defines carbon sequestration as “the long-term storage of carbon dioxide in the forests, soils, oceans or underground in depleted oil and gas reservoirs, coal seams and saline aquifers” (DCC 2008).

Carbon sequestration can be an effective strategy for mitigating GHG emissions and INPEX is undertaking detailed evaluation of both biosequestration and geosequestration options. Sections 9.11.1 and 9.11.2 provide a summary of the benefits and risks of these options and summarises the work undertaken to date and planned into the future to continue the evaluation.

#### 9.11.1 Biosequestration

Biosequestration is a means of offsetting CO<sub>2</sub> emissions by planting trees which “lock” the carbon in atmospheric CO<sub>2</sub> into plant biomass through photosynthesis at one location while CO<sub>2</sub> emissions to atmosphere are taking place at another. In this way, trees store carbon in their roots, trunk, branches and leaves. They are, in effect, a “carbon sink”.

An advantage of biosequestration is that it can often include secondary benefits such as biodiversity improvement, soil salinity remediation and water quality and quantity improvement. Plantings in farming regions can also significantly reduce soil erosion caused by both wind and rainfall. Plantings can also attract social benefits such as providing additional income for farmers and rural communities, offering increased opportunities for Aboriginal employment and contributing to regional economic development. The industry, however, is in its infancy and there are currently only a limited number of accredited service providers available in the Australian market. There are, however, extensive tracts of Kyoto-compliant land suitable for plantings, particularly in temperate regions of Australia and relatively large plantings for biosequestration purposes are already in place. Most plantings focus on mallee eucalypts as they grow rapidly (even in lower rainfall areas), have high resistance to drought, pests and diseases, and can recover rapidly after fire.

Biosequestration risks include limitations on nursery space for raising seedlings and planting capacity of accredited service suppliers. It is also important to understand the potential errors in actual, versus predicted, carbon sequestration rates. Reliable data for growth rates of many species in different soil and rainfall conditions are limited and predictions are based on growth-rate models. In addition, taxation rules are yet to be clarified for this industry and this provides considerable uncertainty in comparative commercial evaluation with other GHG offset options.

It is a commercial necessity that extensive due-diligence and risk-assessment exercises are conducted prior to committing to any large-scale biosequestration option. To this end INPEX is conducting such exercises on potential service suppliers and has initiated a biosequestration assessment project which will provide vital information on details such as seedling survival rates, tree growth rates and logistic and operational factors relating to large-scale plantings.

#### Biosequestration assessment project

In order to more fully understand the potential for biosequestration, INPEX initiated a biosequestration assessment project in 2008, with an indicative budget of A\$4.6 million, to trial plantings of two species of mallee on previously cleared farmland in Western Australia. This pilot project is expected to offset over 450 000 t of CO<sub>2</sub>-e over 40 years through the planting of approximately 1.4 million trees.

The assessment project was established on a suitable scale to fully test the capacity of potential service providers and the chosen contractor's management abilities to source appropriate land, establish seedling supplies and mobilise labour. Most importantly, the trial will also be able to provide vital information on actual versus predicted seedling survival and tree growth rates. To date approximately 650 ha of *Eucalyptus loxophleba* (York gum) and *E. polybractea* (blue mallee) have been planted in south-west Western Australia.

INPEX is encouraging new service providers to enter the market and welcomes the introduction of a wider range of tree species for biosequestration plantings to improve biodiversity benefits. A number of smaller areas on the lands planted out for the biosequestration assessment project were cleared after 31 December 1989 and were therefore not suitable for plantings compliant with the Kyoto Protocol. INPEX has planted mixed species in these areas including *Eucalyptus wandoo* (wandoo), *E. occidentalis* (flat-topped yate), *E. marginata* (jarrah), *E. rudis* (flooded gum), *E. cornuta* (yate), *Corymbia*

*calophylla* (marri), *Acacia acuminata* (jam wattle), and *A. saligna* (orange wattle). These species will provide biodiversity improvements and allow information on the growth and carbon sequestration rates of a broader range of species to be determined.

INPEX has also met with representatives from the Northern Territory Government to identify biosequestration opportunities in the Territory and will continue to evaluate these opportunities.

#### Aboriginal cooperation—improved savannah burning practice

ConocoPhillips currently has engaged in a project with local Aboriginal people in the Northern Territory to foster amended or improved savannah burning practices across the West Arnhem Land Plateau.

CSIRO research has shown that fires early in the dry season generate far less GHG than the bigger and hotter fires that occur later. The difference in emissions is now being measured by the West Arnhem Land Fire Abatement Project partnership, which means people in northern Australia can reduce climate-change pollution by managing fire better.

Originally developed to reintroduce traditional Aboriginal bushfire management to the plateau and to get local Aboriginal people back to the land, this unique partnership of Aboriginal expertise, fire-management science and private enterprise is now delivering a substantial income to traditional landowners, reducing GHG emissions and providing a carbon offset for a large LNG plant in Darwin.

Although these efforts would not be recognised as offsets under the currently proposed CPRS, INPEX sees involvement in such schemes as regionally beneficial both from a social and from an environmental perspective.

#### 9.11.2 Geosequestration

Geosequestration of CO<sub>2</sub>, also known as carbon (dioxide) capture and storage, is the process of capturing CO<sub>2</sub> from industrial processes and injecting it deep underground for long-term storage in secure geological formations. The primary purpose is to reduce GHG emissions to the earth's atmosphere. Geosequestration may offer significant promise for reducing the net greenhouse emissions from oil & gas projects.

Geosequestration is best suited to applications where there are significant point-source GHG emissions such as industrial processing (including LNG production), electricity generation, and petroleum operations and where there is a suitable geological formation or storage reservoir nearby.

The most obvious advantage of geosequestration is that provided the correct geology can be identified, it allows for long-term disposal of CO<sub>2</sub> into geological reservoirs. It also avoids utilising a potentially limited resource—land—for acquitting carbon permit liabilities.

Disadvantages include high costs both for evaluating suitable disposal locations and for the necessary infrastructure to facilitate reinjection. In addition, significantly more energy use is required for capture, transport, injection and monitoring. Legislation has only recently been passed to facilitate carbon storage in Commonwealth waters and a corresponding offshore acreage release process has started. No legislation had been prepared at the time of writing to facilitate carbon capture and storage in Northern Territory and Western Australian lands and waters. Taxation and liability issues remain uncertain, adding to the commercial uncertainty of the geosequestration option.

#### Geosequestration research and technology

Although geosequestration of CO<sub>2</sub> is a relatively new concept, much of the technology that is required in a CO<sub>2</sub> injection system is being applied in a range of industries, including the oil & gas industry. The drilling and operating of injection wells is currently being used for enhanced oil recovery, including c.20–30 Mt/a of CO<sub>2</sub> being injected for enhanced oil recovery in the United States and about 1.7 Mt/a of CO<sub>2</sub> being reinjected from the Sleipner field in the North Sea and the Snøhvit field in the Barents Sea.

In Australia, the Gorgon Joint Venture decision to geosequester the reservoir CO<sub>2</sub> on Barrow Island off the north-west coast of Western Australia has initiated the largest CO<sub>2</sub> geosequestration project in the world. The Gorgon project plans to reduce emissions from the project by c.3.36 Mt of CO<sub>2</sub>-e per annum by injecting CO<sub>2</sub> into an aquifer underlying the joint venture's LNG plant on Barrow Island (Chevron 2008).

In addition, there are research programs being conducted around the world to investigate the viability of CO<sub>2</sub> injection underground. INPEX is a strong supporter of research programs such as Australia's Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) and Geoscience Australia, both of which are undertaking geosequestration research. In addition, INPEX has joined the Global Carbon Capture and Storage Institute, an Australian-sponsored global initiative that seeks to promote emerging technologies in carbon capture and storage on an industrial scale to enable quick uptake of these technologies by industry.

#### Assessment of potential CO<sub>2</sub> injection site

INPEX has established a dedicated team to evaluate disposal of reservoir CO<sub>2</sub> by injection into a subsurface formation.

For geosequestration of CO<sub>2</sub> into a potential sink reservoir to be successful in the long term, a number of geological criteria must be satisfied. The reservoir must have:

- sufficient capacity—the reservoir must have sufficient volumetric storage capability, together with a conservative safety margin, to ensure that a build-up of pressure would not compromise the integrity of the reservoir seals
- sufficient permeability—the geology must include an appropriate combination of a sandstone and, where appropriate, another porous lithology reservoir
- sufficient security—there must be a low risk of migration out of the reservoir; the sealing horizon must be demonstrated from capillary pressure measurements (or field tests) to be fundamentally impervious to vertical CO<sub>2</sub> migration (typically claystone or shale, whether calcareous or non-calcareous)
- sufficient depth—the depth must be great enough to ensure that the CO<sub>2</sub> enters into a dense liquid state (supercritical), thereby maximising the storage potential of the injection reservoir.

Other considerations are the desirability of minimising the distance from the CO<sub>2</sub> capture point for operability and economic reasons and to reduce the energy required (and therefore further GHG emissions) to export and inject the CO<sub>2</sub>.

As both the onshore and nearshore areas near Darwin have unsuitable geology for geosequestration purposes, suitable reservoirs would need to be identified some distance from the onshore processing plant at Blaydin Point.

Should a potentially suitable area be identified, evaluation using the existing available geological information would need to be undertaken to determine whether or not the area would meet key geological and technical requirements. If the criteria were met, exploration could be undertaken to further evaluate the potential sink reservoir, after successfully bidding for an associated carbon capture and storage permit.

Current assessment of the geosequestration option indicates that the cost could be prohibitively high because of the remoteness of potential injection locations from the LNG plant. Substantially more work is required before the technical suitability of

injection locations can be demonstrated. Nevertheless, INPEX continues to investigate this option and may consider its implementation if technical feasibility and commercial viability can be established.

### Conceptual geosequestration infrastructure

As the reservoir CO<sub>2</sub> will be extracted from the gas stream at the onshore gas plant, a pipeline would need to be installed between the onshore gas plant and an injection facility in the target area.

A conceptual injection facility would consist of either an offshore wellhead platform or subsea-completed wells. One or more injection wells capable of meeting injectivity requirements for disposal of reservoir CO<sub>2</sub> would be required, along with one or more observation wells, to monitor the movement and dispersion of the CO<sub>2</sub> plume within the geological formation. It is expected that approximately 70 MW of additional power would be required at the onshore processing plant for the purpose of dehydrating, compressing and transporting the reservoir CO<sub>2</sub> to the injection site. The onshore processing plant plot area contains sufficient space to allow for the future collection, dehydration, compression and transport of reservoir CO<sub>2</sub> for a potential geosequestration option.

### 9.12 Summary of greenhouse gas abatement measures

There are a number of alternatives available to INPEX for GHG management, all with varying costs and risks. As the policy landscape is still evolving and legislation is yet to be finalised, INPEX is exploring all practical alternatives in order to be well prepared to respond once legislative requirements become clear. To this end INPEX is developing a portfolio of GHG mitigation opportunities, which may afford the lowest risk and cost approach for the Project, and avoid a reliance on any single solution. The main opportunities under evaluation include the following:

- the adoption of additional engineering abatement techniques (e.g. the incorporation of energy-efficiency measures into the design)
- biosequestration (carbon capture through tree plantings)
- geosequestration (permanent storage of reservoir CO<sub>2</sub> into underground reservoirs)
- the purchase of offset credits on the open market.

Prior to starting the commissioning of the off- and onshore facilities, INPEX will produce a detailed GHG management plan that will provide an updated GHG emission forecast and consolidate plans for technical abatement and offset measures.

A Provisional Greenhouse Gas Management Plan has been provided as Annexe 8 to Chapter 11 *Environmental management program*.

### 9.13 Impacts of climate change

International climate-change scenarios predict higher temperatures, more droughts and floods, rising sea levels, and more extreme weather events.

More specific to the Northern Territory, the following impacts are predicted:

- an increase in average annual temperatures
- a rise in sea level
- an increase in storm-surge inundations.

The influence of these factors has been or will be incorporated into Project designs. For example, the LNG plant will be built at least 7 m above Highest Astronomical Tide (HAT) to protect against the possibility of gradually increasing seawater levels and storm surges expected over the 40-year life of the facility. This basis assumes a 1-in-1000-year storm event, together with a 0.2 m allowance for global warming and an additional 0.3 m for contingency. In addition, the fin-fan coolers used to remove waste heat from the LNG plant's liquefaction refrigerant loops have a 2 °C temperature margin built in to take into account a combination of hot-air circulation and gradually increasing ambient temperatures between now and the end of the Project.

### 9.14 Summary

- The Ichthys Project supports reduction of global GHG emissions by displacing more emission-intensive fuels, such as coal or oil, for power generation in Asia.
- The proposed Ichthys facilities incorporate technologies and design practices that will ensure that energy is utilised efficiently and that GHG emissions are minimised.
- The Ichthys Project will comply with any legislation introduced in Australia to manage GHG emissions, such as the proposed Carbon Pollution Reduction Scheme, by acquiring permits for CO<sub>2</sub> emissions.
- Geosequestration of reservoir CO<sub>2</sub> is under investigation but requires further definition. The remoteness from Darwin of potentially suitable injection sites identified to date may make the costs of such a scheme prohibitive.
- INPEX initiated a reforestation pilot project in 2008 to gain an understanding of the potential of biosequestration for offsetting CO<sub>2</sub> emissions.
- INPEX continues to assess GHG abatement options in order to define an appropriate plan to manage GHG emissions, taking into account the costs and risks associated with each option.

## 9.15 References

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