BENNETT RESOURCES

Valhalla Gas Exploration and Appraisal Program

Greenhouse Gas Environmental Management Plan

BNR_HSE_MP_014

VERSION HISTORY				
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Acronym / abbreviation

Terms / acronym	Definition / expansion
ACCU	Australian Carbon Credit Units
API	American Petroleum Institute
bbl	Barrel, a unit of volume for crude oil and petroleum products
BNR	Bennett Resources Pty Ltd
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CO_2e/GJ	Carbon dioxide equivalent per gigajoule
e.g.	For example
EMP	Environmental Management Plan
EP 371	Exploration Permit 371
EP Act	*(WA) Environmental Protection Act 1986*
EPA	(WA) Environmental Protection Authority
ESD	Environmental Scoping Document
FullCAM	Full Carbon Accounting Model
FY	Financial year
GHG	Greenhouse Gas
GHGEMP	Greenhouse Gas Management Plan
GJ/kL	Gigajoule per kilolitre
ha	Hectare
HFS	Hydraulic Fracturing Stimulation
i.e.	That is
kg/m^3	Kilogram per cubic metre
kL	Kilolitres
km^2	Square kilometres
kWh	Kilowatt per hour
LNG	Liquified Natural Gas
m	Metres
m^3	Cubic metres
ML	Megalitres
MMscf/d	Million standard cubic feet per day
NGER	National Greenhouse and Energy Reporting
NOx	Nitrogen Oxides

Terms / acronym	Definition / expansion
N_2O	Nitrous Oxide
PV	Photovoltaic
Proponent	Bennett Resources Pty Ltd
Proposal	Valhalla Gas Exploration and Appraisal Program
tC/ha	Tonnes of carbon per hectare
tCO_2e	Tonnes of carbon dioxide equivalent
tCO_2e/ha	Tonnes of carbon dioxide equivalent per hectare
tCO_2/tCH_4	Tonnes of carbon dioxide equivalent per tonnes of Methane
tCO_2e/d	Tonnes of carbon dioxide equivalent per day
tpa CO_2-e	Tonnes of carbon dioxide equivalent per annum
US EPA	Environmental Protection Agency of the United States
WA	Western Australia
%	Percentage
~	Approximately

1 Executive summary

This Greenhouse Gas Environmental Management Plan (GHGEMP) has been prepared by Bennett Resources (BNR) to support the assessment, approval and implementation of the Valhalla Gas Exploration and Appraisal Program (the Proposal) under Part IV of the *Environmental Protection Act 1986* (EP Act).

Bennett Resources referred the Proposal to the Environmental Protection Authority (EPA) under Part IV of the EP Act on 24 December 2020 (EPA Assessment Number 2281). The EPA has decided to assess the Proposal at a level of Public Environmental Review.

This GHGEMP has been written in accordance with the "Instructions on how to prepare Environmental Protection Act 1986 Part IV Environmental Management Plans" (EPA 2021a), the Greenhouse Gas Emissions Environmental Factor Guideline (EPA 2023) and the GHG EMP Template (EPA 2023). An executive summary of this GHGEMP is provided in Table 1-1.

Table 1-1: Executive summary of the GHGEMP

Proposal title	Valhalla Gas Exploration and Appraisal Program (EPA Assessment Number 2281)
Proponent name	Bennett Resources Pty Ltd
Proposal Description and Scope	The Proposal is to complete an unconventional exploration and appraisal drilling and hydraulic fracture stimulation (HFS) program on Petroleum Exploration Permit EP 371 in the Canning Basin.
Purpose of the GHGEMP	The purpose of this GHGEMP is to support the assessment, approval, and implementation of the Proposal under Part IV of the EP Act, and to provide management and monitoring actions for Greenhouse Gas (GHG) emissions resulting from the Proposal that are aligned with the intent of BNR's Climate Change Policy, and the Western Australian Government Climate Policy (WA Government 2020). Monitoring of greenhouse gas emissions will be undertaken in accordance with the Valhalla Monitoring Plan.
Emissions estimates	It is expected that the proposal will comprise scope 1 emissions only. During phase one, maximum emissions will be <200,000 tCO_2e/year During phase two, maximum emissions will be <600,000 tCO_2e/year A maximum emissions estimate for the full program is 1,603,293 tCO_2e.
Trajectory of emissions reductions	In alignment with BNR's Climate Change Policy (Appendix A) and the requirements of ESD Item 78, the long-term environmental outcome is to avoid, reduce, or mitigate 100% of scope 1 GHG emissions by 2050. This GHG EMP commits to avoid, reduce, or mitigate 43% of scope 1 GHG emissions by the end of year 5 (anticipated to be around 2030). No scope 2 or scope 3 emissions are expected to be produced through this proposal.
Other statutory decision-making processes which require reduction in GHG emissions	The trajectory of emissions, which is expected to reduce to zero after seven years from the commencement of the proposal, is consistent with the EPA's GHG objective to reduce net GHG emissions in order to minimise the risk of environmental harm associated with climate change, and with ESD item 78.
Key components in the GHEGEMP	The long-term environmental outcome for this GHGEMP is to avoid, reduce, or mitigate 100% of Scope 1 GHG emissions from the Proposal by 2050. This long-term outcome is supported by a single interim environmental outcome of the GHGEMP, to avoid, reduce, or mitigate 43% of Scope 1 GHG emissions from the Proposal by the end of the 5th year of the Proposal. These environmental GHGEMP outcomes and their associated indicators, response actions, monitoring and reporting requirements, are defined in Table 5-1 and Table 5-2.
GHGEMP reviews and reporting	This GHGEMP is intended to be dynamic and may be updated to reflect changes in management practices and the natural environment over time. It will be reviewed on a five-yearly cycle.
Proposed construction / commencement date	TBC – within Calendar Year 2025.

EMP required pre-construction / commencement?	Yes ☒ No ☐
Proposed project end of life/decommissioning date	TBC – within Calendar Year 2032

2 Context, scope and purpose

2.1 Proponent, Proposal Description and Scope

Bennett Resources Pty Ltd (BNR), a wholly owned subsidiary of Black Mountain Energy Pty Ltd, is the proponent for the Proposal.

The Proposal is to complete an unconventional exploration and appraisal drilling and Hydraulic Fracture Stimulation (HFS) program within Petroleum Exploration Permit EP 371 (EP 371) in the Canning Basin, within the Shire of Derby / West Kimberley in Western Australia (WA).

The intent of the Proposal is to evaluate the large tight gas resource in the region which has the potential to offer long-term energy security to Australia. The onshore Canning Basin is an early Ordovician to early Cretaceous aged geological basin that covers approximately 430,000 km^2 in the West Kimberley region. The Proposal is targeting hydrocarbons present from the Laurel through to the Devonian Formations, ranging from 2,000 m to 5,000 m below ground level. The main target is the Laurel Formation, with hydrocarbons present at depths between 2,000 m and 4,000 m below ground level.

Table 2-1 provides a summary of the Proposal.

Table 2-1: Summary of the Proposal

Proposal title	Valhalla Gas Exploration and Appraisal Program (EPA Assessment Number 2281)
Proponent name	Bennett Resources Pty Ltd (BNR)
Short description	The Proposal is to undertake an unconventional exploration and appraisal drilling program within EP 371, located in the Canning Basin, West Kimberley of Western Australia. The Proposal includes the construction of up to 20 exploration wells within 10 well sites. The intent of the Proposal is to further appraise the extent of the tight gas reservoir in the Laurel Formation with hydrocarbon shows present at depths in the order of 2,000 m to 4,000 m below ground level. The exploration and appraisal program is expected to commence in 2024 or 2025.
Purpose of the GHGEMP	To meet the Environmental Scoping Document (ESD) Item 78: *Provide a greenhouse gas management plan, in accordance with EPA guidance, which demonstrates the proposal's trajectory towards net zero emissions by 2050.* The goal of ensuring new zero emissions by 2050 is in line with the Western Australian Government's Climate Policy, released in November 2020, which commits the government to working with all sectors of the economy to achieve net zero greenhouse gas emissions by 2050.

2.2 Purpose of the GHGEMP

The purpose of this GHGEMP is to support the assessment, approval, and implementation of the Proposal under Part IV of the EP Act, and to provide management actions for Greenhouse Gas (GHG) emissions resulting from the Proposal that are aligned with the intent of BNR's Climate Change Policy, and the Western Australian Government Climate Policy (WA Government 2020). Monitoring of greenhouse gas emissions will be undertaken in accordance with the Valhalla Monitoring Plan.

The elements have been identified as having the potential to affect the Key Environmental Factor – Greenhouse Gas Emissions include:

- well testing (resulting in gas and condensate flaring)
- diesel fuel usage
- land clearing and fugitive emissions.

BNR has developed this GHGEMP to meet the Environmental Scoping Document (ESD) Item 78:

> *Provide a greenhouse gas management plan, in accordance with EPA guidance, which demonstrates the proposal's trajectory towards net zero emissions by 2050.*

The goal of ensuring new zero emissions by 2050 is in line with the Western Australian Government's Climate Policy, released in November 2020, which commits the government to working with all sectors of the economy to achieve net zero greenhouse gas emissions by 2050.

3 GHGEMP components

This section of the GHGEMP identifies the emissions estimates, trajectory of emissions reductions and mitigation measures adopted to avoid, reduce or offset emissions.

3.1 Emissions estimates

3.1.1 Scope 1 emissions

An emissions inventory of direct Scope 1 GHG emissions is provided in Table 3-1 The methodologies used to calculate this inventory are provided in Appendix B. As detailed in Appendix B, the main sources of Scope 1 GHG emissions are (per well):

- gas and condensate flaring, comprising up to approximately 88,428 tCO_{2-e} (or 93.1%) of Scope 1 GHG emissions
- diesel fuel usage, comprising up to approximately 3,300 tCO_{2-e} (or 6.3%) of Scope 1 GHG emissions
- land clearing and fugitive emissions, comprising up to approximately 337 tCO_{2-e} (or 0.6%) of Scope 1 GHG emissions.

Table 3-1: Scope 1 GHG inventory

CO2 emissions per exploration and appraisal well	**Input parameter**	**Phase I – 6 wells (tCO_{2-e})**		**Phase II – 14 wells (tCO_{2-e})**		**Calculation reference**
		~60 days flaring	**~90[1] days flaring**	**~60 days flaring**	**~90 days flaring**	
Flare (per well)						
Gas	Phase I: 5.9 mmscf/d Phase II: 10.7 mmscf/d	29,747	44,620	53,948	80,921	NGER Guidelines (Government of Australia 2008) Section 3.44
Condensate	Phase I: 118 bbl/d Phase II: 214 bbl/d	2,760	4,140	5,005	7,507	NGER Guidelines (Government of Australia 2008) Section 3.52
Diesel usage (per well)						
Site preparation	20	54	54	54	54	NGER Guidelines (Government of Australia 2008) Section 2.41 with Table in Schedule 1 Part 3.
Drilling operations	316	857	857	857	857	
HFS operations	510	1,382	1,382	1,382	1,382	
Site reinstatement	20	54	54	54	54	
Transport (vehicles/rigs)	344	931	931	931	931	
Site power	8	15	22	15	22	

[1] BNR has estimated that to collect the required data, the well must be flowed during the period of maximum gas concentration for up to 90 days.

CO2 emissions per exploration and appraisal well	Input parameter	Phase I – 6 wells (tCO_{2-e})		Phase II – 14 wells (tCO_{2-e})		Calculation reference
		~60 days flaring	~90[1] days flaring	~60 days flaring	~90 days flaring	
Land clearing (per well)						
Land clearing emissions	5.1 ha per well 56.3 tCO2-e/ha	287	287	287	287	FullCAM Model (Australian Government 2020)
Fugitive emissions (per well)						
Drill cuttings	Gas 0.12 tonnes	30	30	30	30	Based on volumes of drill cuttings and Valhalla gas saturation
Waste water	2 ML produced formation water	20	20	20	20	API GHG Emissions Methodologies for Oil and Gas (API 2009)
Total GHG emissions per well (tCO_{2-e})		**36,136**	**52,936**	**62,582**	**92,065**	**Scope 1 (direct emissions)**
Total emissions exploration and appraisal program (tCO_{2-e})	Phase I–6 wells Phase II–14 wells	216,814	314,378	876,144	1,288,915	Scope 1 (direct emissions)

To understand annualised emissions totals, an emission timeline has been developed for the Proposal. This is based upon the assumption that Phase I will take three years and Phase 2 will take an additional four years. Figure 3-1 provides annual GHG emission forecasts for the Proposal.

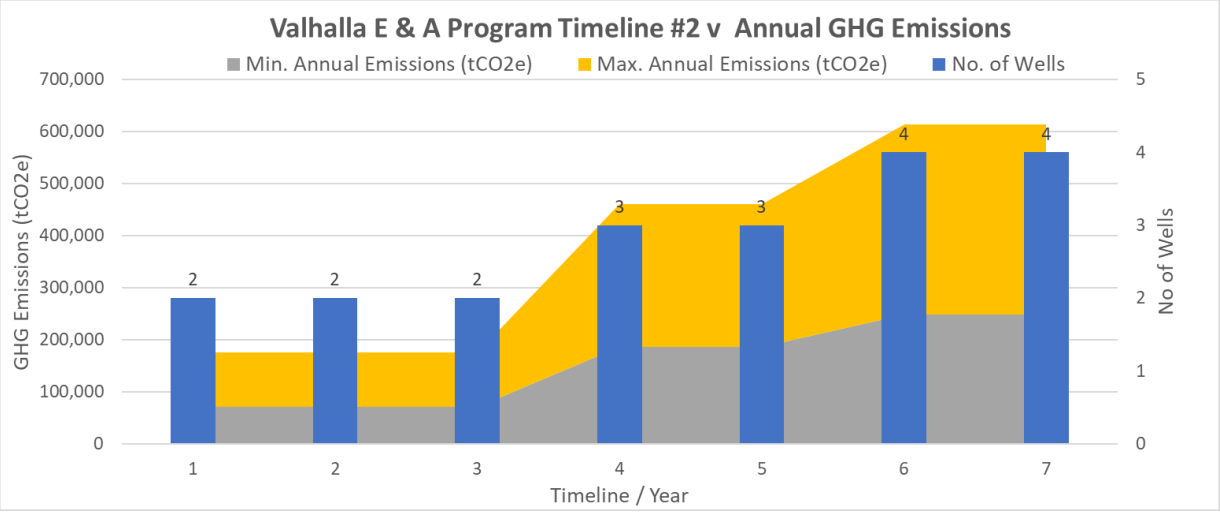

Figure 3-1: Timeline for overall scope 1 GHG emissions of the Valhalla E&P Program

3.1.2 Scope 2 emissions

As the Proposal does not intend to import power from third parties, no Scope 2 emissions are expected.

3.1.3 Scope 3 emissions

Although no Scope 3 emissions are expected, BNR is maintaining the possibility of selling condensate collected during the well test program to third parties as a recommended GHG mitigation measure. Through the implementation of this mitigation, BNR would avoid emissions associated with flaring of condensate during well testing. The quantity of Scope 3 emissions associated with the transportation and utilisation of condensate as a fuel was calculated on the basis that all condensate produced from the well tests for a maximum 90-day test period was captured and transported to Singapore via Wyndham where it was assumed to be processed and consumed. The Scope 3 emission inventory is provided as Table 3-2.

Table 3-2: Scope 3 GHG inventory

Scope 3 emissions per well	~60 days flaring	~90 days flaring
Condensate Volume (bbls)	222,240	333,360
Condensate Transport Emissions (tCO_2e)	13,952	20,928
Condensate Consumption Emissions (tCO_2e)	91,571	137,356
Total Scope 3 Emissions (tCO_2e)	105,523	158,284

3.2 GHG emissions benchmarking

As required under ESD Item 77, BNR completed an emissions benchmarking assessment to understand how the Proposal compares to other HFS projects. Specifically, BNR benchmarked the Proposal emissions against the following projects:

- Buru – Canning Basin – TGS14 Project
- Origin – Betaloo Basin – Valkerri Project
- Origin – Betaloo Basin – Kyalla Project
- Santos – McArthur Basin EP161 Project
- Imperial – McArthur Basin – Carpinteria 1.

In order to benchmark projects for their GHG emissions, typically, GHG emissions intensity values are calculated on a 'tCO_2e per tonne of product' basis for manufacturing projects or 'tCO_2e per kWh' basis for power generation projects such that project emissions can be compared. GHG emission intensities from gas exploration projects can be compared on both a 'per well per test day' and 'per well test' basis to benchmark the Proposal.

GHG emissions intensities on a 'per well per test day' basis for the Proposal is shown in Figure 3-2. The results indicate more emissions from the Valhalla well tests per day are expected due to the higher well test flow rates per day.

It should be noted that the Origin and Santos test programs are planned for a significantly longer period, up to 12 months compared to 2-3 months for the Valhalla Gas Exploration and Appraisal Proposal. Therefore, another comparison was made based on the planned minimum and maximum total emissions per well. Figure 3-3 provides planned total emissions per well. The results indicate that wells associated with Phase I of the Proposal are comparable with the permitted / planned total emissions of other projects in the Beetaloo Basin in the Northern Territory. Phase II wells from this Proposal are higher than the other projects due to their potentially higher flow test rates.

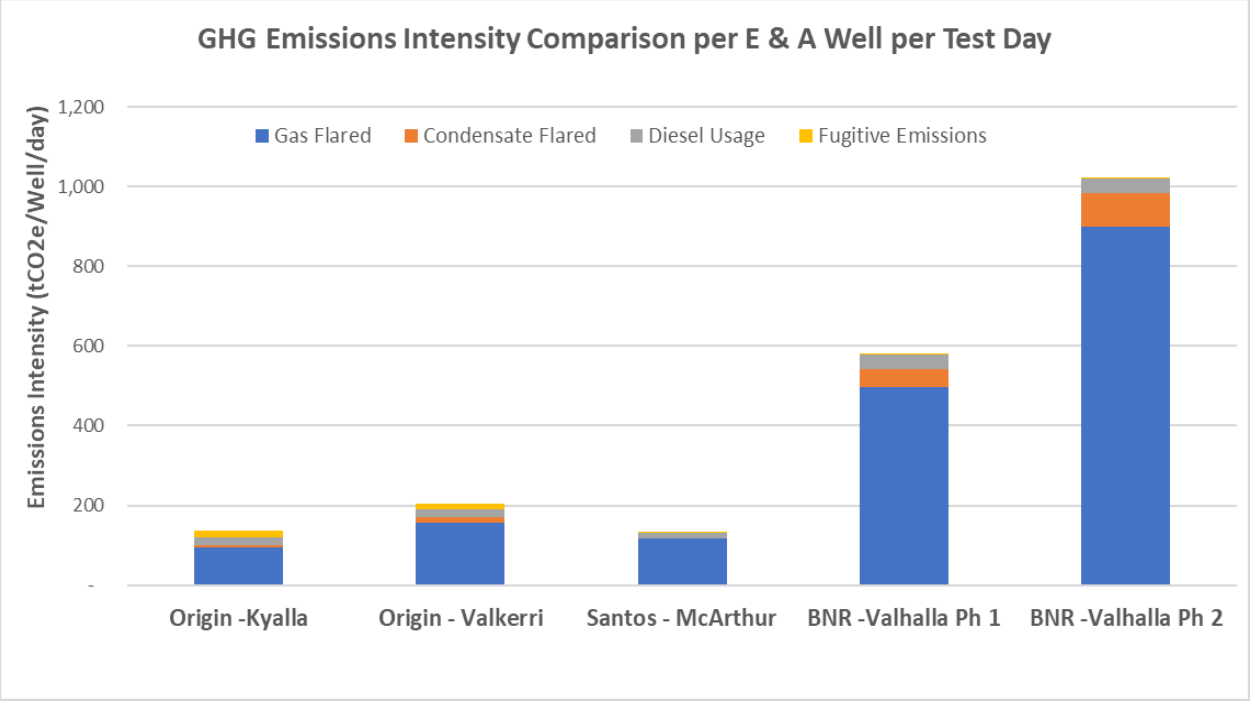

Figure 3-2: Benchmarking GHG emissions of the Valhalla Gas Exploration and Appraisal Program per well per test day

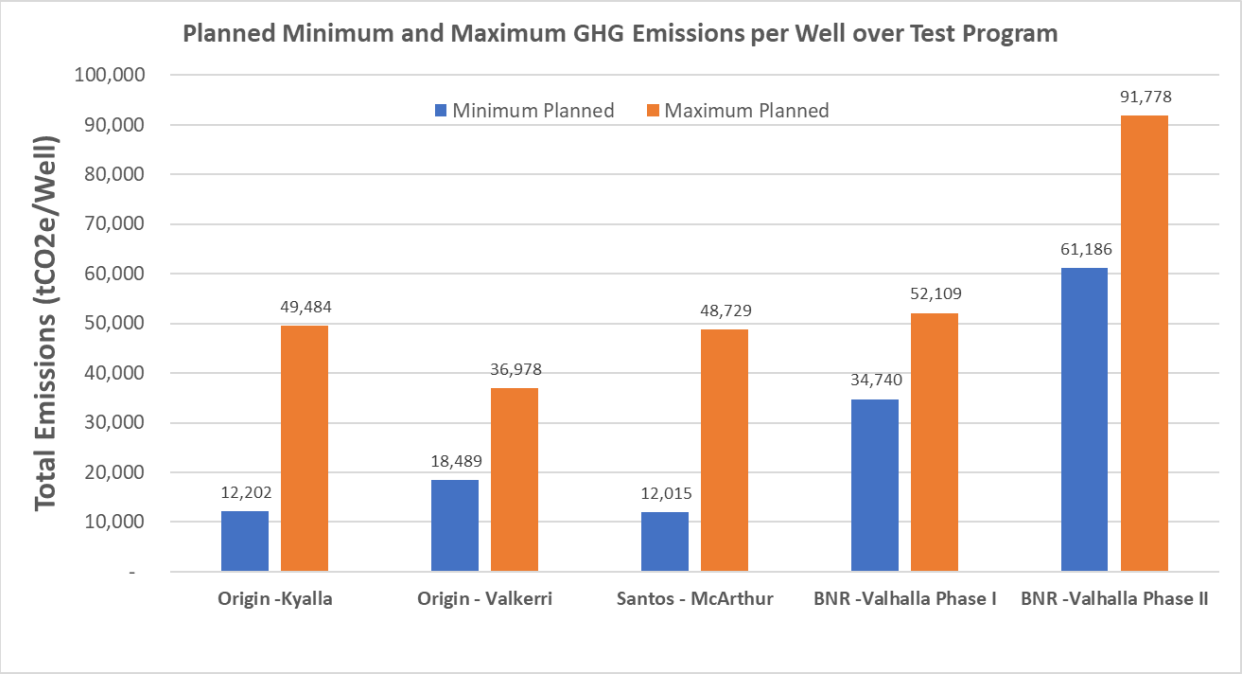

Figure 3-3: Benchmarking GHG emissions of the Valhalla Gas Exploration and Appraisal Program for planned total emissions per well

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3.3 Trajectory of emissions reductions

BNR considers the use of an outcome based GHGEMP appropriate as GHG emissions can be, and are required to be, measured and/or quantified. Monitoring of GHG emissions will enable BNR to inform future field plans whilst demonstrating if interim and long-term environmental outcomes have been met. Given the nature of the Proposal which is limited to a seven-year exploration program, BNR plans to use the information gathered during this to inform GHG abatement opportunities for future field development.

In alignment with BNR's Climate Change Policy (Appendix A), the Western Australian Climate Policy (DWER 2020) and the requirements of ESD Item 78, the long-term environmental outcome for this GHGEMP is to avoid, reduce, or mitigate 100% of Scope 1 GHG emissions by 2050.

To support this long-term environmental outcome, the following interim outcome has been defined for this GHGEMP: to avoid, reduce, or mitigate 43%[2] of Scope 1 GHG emissions by the end of the year five (Figure 3-4).

On the basis that this GHGEMP will be reviewed on at least a five-yearly cycle (Section 7), the interim and long-term environmental outcomes are considered appropriate to meet BNR's and the State government's targets to achieve net zero emissions by 2050.

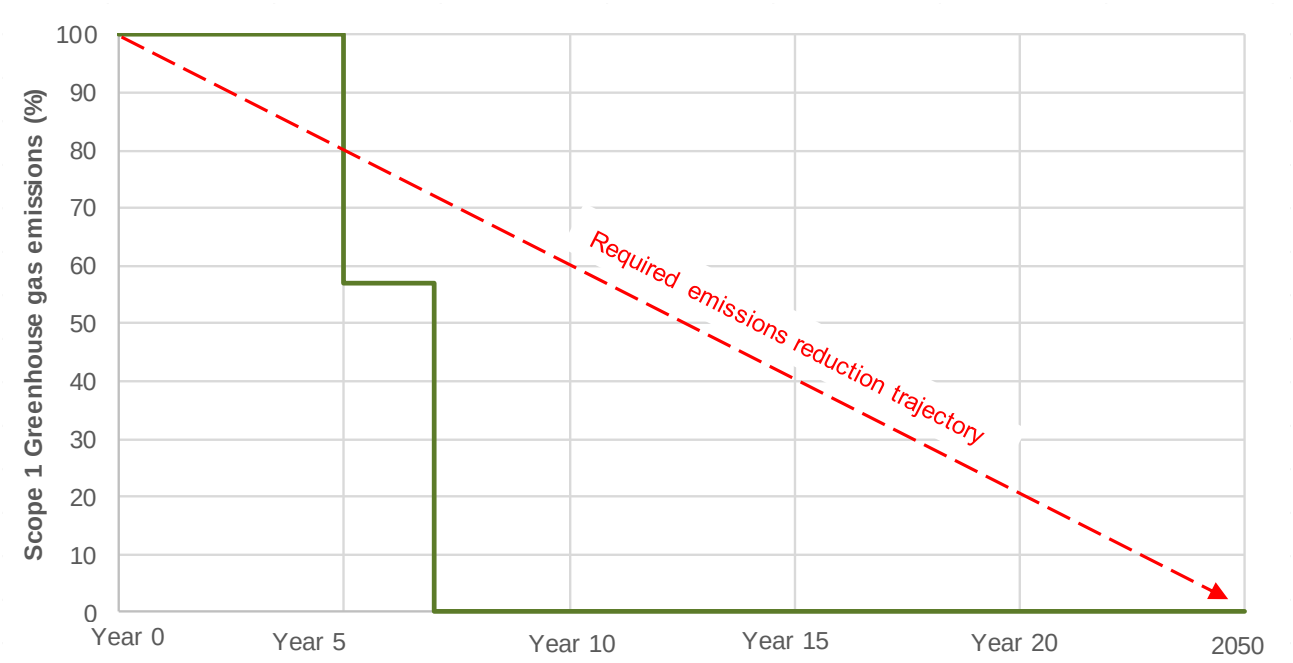

Figure 3-4: GHGEMP environmental outcomes for the Proposal

[2] Australia was a signatory to the Paris Agreement, which entered into force in 2016, and committed to reducing GHG emissions by 26–28% below 2005 levels by 2030. Subsequently, the Climate Change Bill, which passed the Senate in 2022, sets Australia's greenhouse gas emissions reduction targets at a 43% reduction by 2030 and net zero by 2050. Consequently, BNR has updated the interim GHG target with the emission reduction requirements set by the Climate Change Act.

3.4 Mitigation measures adopted to avoid, reduce or offset scope 1 emissions

3.4.1 Consideration of the mitigation hierarchy

In line with the EPA's mitigation hierarchy for GHG emissions (avoid, reduce, or offset) (EPA 2021b), BNR has identified and assessed a range of emission mitigation opportunities. This assessment was facilitated by an independent GHG emissions consultant. The summary of the options and outcomes of the assessment are provided in Table 3-3.

Table 3-3: Emission avoidance and reduction

Option	Description	Estimated tCO2e mitigated for the Proposal	Mitigation hierarchy	Supporting details	Outcome
Well design – Horizontal vs Vertical	Single well pad vertical designs result in significantly more land clearing given the land required to install a single well is the same as that required for multiple wells. The use of efficient multi-well pad horizontal shale development results in a 50%-60% reduction in land use.	2,300 tCO_2e	Avoid	The Valhalla Exploration and Appraisal program utilises 10 well pads for drilling 20 wells, implementing an efficient multi-well drilling technique to minimise land clearing. The minimisation of land clearing reduces the impact associated with GHG emissions associated with the removal of vegetation. A total land cleared for the 20 well program is <110 ha of which 40 ha is associated with the well sites, therefore reducing overall land cleared by around 40%.	Selected
Flaring vs Venting	Gas flaring is carried out in accordance with Code of Practice requirements and as per US EPA 40 Code of Federal Regulations 63.11, with a flare tip combustion efficiency of 98%. Flaring converts methane to carbon dioxide and water, thus significantly reducing methane emissions. Carbon dioxide has a global warming potential 25 times lower than methane over a 100-year span, therefore the removal of methane is preferable.	10,000 tCO_2e	Avoid	Gas venting is avoided during the well completions and well tests and only permitted for operational or safety reasons. Two separate vertical stacks, one for flowback high pressure gas and a second low pressure flare to manage tank vapours (off storage tanks) would be used to ensure all methane at site is flared.	Selected
Selection of efficient diesel generators	The Tier 4 diesel engines have 90% lower NOx and particulate matter emissions compared to Tier 3 engines and are fuel efficient resulting 15% GHG emissions reduction.	25,000 tCO_2e	Reduce	BNR will utilise the latest efficient units with highest emission standards for the Proposal. Specifically, these are currently industry best practice.	Selected
Condensate capture for sale or other use	The well test fluids during the exploration and appraisal program could be passed via a sand trap and 3-phase separator to remove water and condensate from the gas where the condensate could be stored and trucked out of site for sale to a refinery.	129,943 tCO_2e	Avoid	BNR is currently evaluating options for the sale of condensate produced from the well tests via Wyndham Port to Singapore, where Buru Energy already exports its oil.	Under consideration
Renewables (power generation)	The use of renewable energy such as solar photovoltaic (PV) for powering the drilling and HFS activities are impracticable because of	19,740 tCO_2e	Avoid	The solar PV power also needs to be supported with large batteries that can store energy to be supplied during the nights, therefore resulting in significantly higher costs. Furthermore, the rigs and HFS units need to be re-located to various sites	Not considered for use

Option	Description	Estimated tCO2e mitigated for the Proposal	Mitigation hierarchy	Supporting details	Outcome
	the finite period of drilling, and the requirement for continuous drilling.			during the drilling program which will make the use of renewable energy impracticable. A better alternative would be to use grid power, if available, for drilling, while the grid is supported by renewable power. The Canning Basin and Valhalla region do not have such a grid to support the project.	
Renewables (lighting towers)	The use of solar powered lighting units reduces the emissions associated with diesel powered towers.		Avoid	Solar powered lighting towers with battery backup are planned to be used in the project as shown along with other solar power based instrumentation and monitoring systems.	Selected
Gas capture for sale or other use	The Canning Basin does not have any gas infrastructure such that the flow test gas can be treated and sent to a gas pipeline for sale. Therefore, the only possibility would be to capture the gas as Compressed Natural Gas (CNG) or utilising micro Liquified Natural Gas (LNG) facilities and supply it to energy users				
Compressed Natural Gas	The well test gas would be required to be dehydrated and compressed to around 250 bar to be stored in high pressure storage bullets which can then be used in gas engines for power generation in well test sites instead of diesel.	1,398,814 tCO_2e	Avoid	CNG can also be transported to power stations in Broome, Derby and other west Kimberley towns to replace LNG trucked from Karratha at present. CNG could also be used in dual-fuel engines for the drilling and HFS within the Valhalla Gas Exploration and Appraisal Program if equipment with suitable engine specifications is available locally. At present the sale of gas as CNG is considered unviable due the associated cost of capture, treatment and transportation to markets located far from the Valhalla field.	Not selected for use
Micro LNG	A relocatable micro LNG plant could also be used to capture the well head gas (as used in some US shale gas operations) if this equipment were available in the Australian market. The use of micro LNG option would require the well head gas to be pre-treated such that water, CO_2 and freezable heavy hydrocarbons are removed from the gas to allow liquefaction of the gas.			LNG produced can be stored in transportable International Organization for Standardization containers and shipped to markets. CryoboxTM is a micro LNG technology, and other similar flare gas liquefaction technologies that provide relocatable pre-treatment units as used in the US shale gas industry. At present, the sale of LNG to local power stations is considered unviable with existing gas offtake contracts in place with power plant operations and the inability for the project proponents to commit to a fixed volume based on LNG supply contracts from the gas exploration and appraisal program.	Not selected for use

3.4.2 Key assumptions and uncertainties

Table 3-4 details the key assumptions and uncertainties that BNR has identified with respect to the proposed approach to managing GHG emissions.

BNR has proposed environmental outcomes, and associated monitoring and response actions, in consideration of the current state of GHG policies and available technical advice. An adaptive management approach has been proposed that allows for changes to this GHGEMP if required in the future to remain aligned with contemporary policies and scientific advice.

Table 3-4: Assumptions and uncertainties

Assumptions and uncertainties	Comment
Emission estimates	As the Proposal is an exploration and appraisal project, the quantity of emissions estimates is based upon a historic understanding of the Laurel Formation in EP 371. The nature and quantity of emissions may differ to the estimations provided given the purpose of the Proposal is to further understand and evaluate the Laurel Formation.
State and Commonwealth GHG policies	State and Commonwealth government policies and targets continue to evolve.
Market price carbon emissions	At this current time, there is no uniformly applied (i.e. on unit of carbon emitted) market price for carbon emissions (i.e. a carbon levy) within Australia.

3.5 Mitigation measures adopted to avoid, reduce or offset scope 2 emissions

This proposal will not produce scope 2 emissions, so mitigation measures are not required

3.6 Mitigation measures adopted to avoid, reduce or offset scope 3 emissions

Scope 3 emissions are not expected to be produced at this time. However, one of the mitigation measures being considered to reduce scope 1 emissions is to sell condensate through Wyndham to Singapore. This measure would produce more emissions overall (see Table 3 2, above), however would reduce scope 1 emissions. This project has no measures to mitigate scope 3 emissions other than a commitment to adopt best practice, should scope 3 emissions occur due to the sale of condensate.

3.7 Other statutory decision-making processes which require reduction in GHG emissions

The emissions reduction targets as specified in the Climate Change Bill have been considered and adopted within this GHGEMP.

3.8 Consistency with other GHG reduction tools

This GHGEMP is consistent with BNR's climate change policy.

3.9 Offsets

3.10 Overview

Following the mitigation hierarchy, GHG emissions should preferentially be managed via avoidance or reduction measures. However, where further reductions are required, carbon offsets will be considered as a mitigation option. This may include both Australian and international carbon offsets.

BNR acknowledges that carbon offsets may be necessary to meet the environmental outcomes defined within this GHGEMP. Where and when required, BNR will acquire carbon offsets that meet the contemporary Australian acceptability standards (e.g., they should meet offset integrity principles and be based on clear, enforceable, and accountable methods).

At the time of writing, acceptable Australian carbon offsets may include:

- Australian Carbon Credit Units (ACCUs) issued under the Commonwealth Carbon Credits (Carbon Farming Initiative) Act 2011
- eligible offsets under the standard Climate Active Carbon Neutral Standard for Organisations (Climate Active 2020), in addition to ACCUs include:
    - verified emission reductions issued under the Gold Standard
    - verified carbon units issued under the Verified Carbon Standard
    - certified emissions reductions issued as per the rules of the Kyoto Protocol from Clean Development Mechanism projects
    - removal units issued by a Kyoto Protocol country on the basis of land use, land use change and forestry activities under Article 3.3 or Article 3.4 of the Kyoto Protocol.

Many offset projects also deliver social, economic, or environmental outcomes in addition to emission reductions (Climate Active 2019).

3.11 Preferred Offsets and Availability

In the event annual Scope 1 GHG emissions exceed 43 % of the estimated baseline emissions by the end of the 5th year of operations, the purchase of appropriate offsets will be undertaken to reach this outcome. Given the expected GHG emissions for phase one of the project are 52,936 tCO_2e per well, and for phase two 92,065 tCO_2e (Table 3-1), the expected maximum carbon offsets needed, after the fifth year of operations, would be 22,763 tCO_2e/well in phase one, and 39,588 tCO_2e/well in phase two.

BNR expects that ACCUs would be the offsets most likely to be applied to the Proposal, if required, and is confident that sufficient availability will exist. In 2023, 17.2 million ACCUs were issued by the Clean Energy Regulator, with at least 20 million ACCUs expected to be issued in 2024 (CER 2024).

The fastest growing types of ACCU projects are human induced regeneration (HIR) projects which more than doubled between 2022 and 2023, and reforestation projects which increased by 38% over the same period.

3.12 Projects operating beyond 2050

This proposal is expected to be completed within seven years of its commencement, so will not be in operation in 2050.

4 Adaptive Management, Continuous Improvement and Review of the GHGEMP

A monitoring program (as described in Table 5-1 and Table 5-2, and in the Valhalla Monitoring Plan) is required to measure the effectiveness of the response actions as defined in this GHGEMP. The outcomes of the monitoring program will contribute to ongoing improvements in response actions to ensure an adaptive management approach is adopted.

BNR will implement an adaptive management framework that allows BNR to adapt and implement improvements as a result of monitoring against trigger and threshold criteria detailed in this document.

The following approaches will apply:

- monitoring data will be systematically evaluated
- the effectiveness and relevance of trigger level and threshold contingency actions will be evaluated to determine if any changes to response actions are required
- increased understanding of the hydrogeological regimes based on additional internal and external studies will be incorporated into the monitoring and management approach when newer relevant information becomes available where applicable.

Adaptive management practices that will be assessed as part of this approach may include:

- evaluation of the monitoring program, data and comparison to baseline data and reference sites on an annual basis to verify whether responses to project activities are the same or similar to predictions
- evaluation of assumptions and uncertainties of the management and monitoring program
- re-evaluation of the risk assessment and revision of risk-based priorities as a result of monitoring outcomes
- review of data and information gathered over the review period that has increased understanding of site environment in the context of the regional ecosystem
- assessment of changes which are outside the control of the project and the response actions identified.

5 Reporting

This section of the GHG EMP identifies the legal provisions (components) that BNR will implement to ensure that the environmental outcomes are met during implementation of the Proposal.

In accordance with the guideline “Instructions on how to prepare Environmental Protection Act 1986 Part IV Environmental Management Plans” (EPA 2021), this section identifies the indicators that will be used to measure performance and the monitoring that will be undertaken in relation to these indicators. It defines the response actions (trigger level and contingency actions) that will be undertaken if the indicators are exceeded.

Table 5-1 and Table 5-2 detail the components of this GHGEMP for each of the interim and long-term environmental outcomes.

BNR will report annually and will make reports publicly available on its website.

Table 5-1: GHG EMP components – Interim 1 environmental outcome

EPA factor/s and objective/s	GHG Emissions – To reduce net GHG emissions to minimise the risk of environmental harm associated with climate change			
GHG EMP outcome/s	Interim 1: To avoid, reduce, or mitigate 28% of Scope 1 GHG emissions from the Proposal by the end of the 5th year of operations			
Key environmental values	**Carbon budget**			
Key impacts and risks	Contribution to Western Australia's GHG emissions, contribution to climate change and the risks to the environment from climate change			
Indicators	Response actions	Monitoring	Timing and Frequency	Reporting
Trigger criteria Annual Scope 1 GHG emissions from the Proposal are above the estimated baseline emissions: • Phase I (>52,936 tonne per well CO_2-e). • Phase II (>92,065 tonne per well CO_2-e).	**Trigger level action** If annual Scope 1 GHG emissions are above the estimated baseline emissions, then an investigation into the cause of the increased emissions will be undertaken and completed within the subsequent 12-month period and corrective actions implemented.	**Indicator** Scope 1 GHG emissions. **Method** GHG emissions will be monitored via various means including diesel inventories and flow meters.	• Diesel inventories will be maintained for all well sites on an annual basis. • Quantity of GHG associated with flaring activities will monitored continuously. • Total Scope 1 GHG emissions will be calculated annually (based on financial year schedule) during operations.	Routine reporting – Annual Compliance Assessment Report to the DWER Compliance Brach Exceedance reporting to DWER Compliance Branch – exceedance of the threshold criteria and contingency actions that have been implemented – within 5 days.
Threshold criteria Annual Scope 1 GHG emissions from the Proposal are not 43% below the estimated baseline emissions by the end of the 5th year of operations. • Phase I (>30,174 tonne per well CO_2-e). • Phase II (>52,477 tonne per well CO_2-e).	**Threshold contingency actions** If annual Scope 1 GHG emissions are not 43 % below the estimated baseline emissions by the end of the 5th year of operations, then: • within the subsequent 6-month period, net emissions for the Proposal will be decreased by the purchase of appropriate offsets to reduce Scope 1 emissions to at or below 57% of the estimated baseline emissions • net emissions for the Proposal will be maintained at or below 57 % of the estimated baseline emissions (by reductions or offset purchases) until the Proposal is complete.			

Table 5-2: GHG EMP components – Long-term environmental outcome

EPA factor/s and objective/s	GHG Emissions – To reduce net GHG emissions to minimise the risk of environmental harm associated with climate change			
GHG EMP outcome/s	Long-term: To avoid, reduce, or mitigate 100% of Scope 1 GHG emissions from the Proposal by 2050			
Key environmental values	**Carbon budget**			
Key impacts and risks	Contribution to Western Australia's GHG emissions, contribution to climate change and the risks to the environment from climate change			
Indicators	Response actions	Monitoring	Timing and Frequency	Reporting
Threshold criteria Annual Scope 1 GHG emissions from the Proposal are not 43% below the estimated baseline emissions by the end of the 5th year of operations. • Phase I (>30,174 tonne per well CO_2-e). • Phase II (>52,477 tonne per well CO_2-e). Methane levels above the detection limit (i.e. the laboratory LOR) of 3.3 mg/m^3 following the completion of the Proposal.	**Threshold contingency actions** If annual Scope 1 GHG emissions are not 100 % below the estimated baseline emissions by FY 2050 of operations, then: • within the subsequent 6-month period, net emissions for the Proposal will be decreased by the purchase of appropriate offsets to reduce Scope 1 emissions to at or below 0 tpa CO_2-e • net emissions for the Proposal will be maintained at 0 tpa CO_2-e (by reductions or offset purchases) for the life of the Proposal. If methane levels above the detection limit (i.e. the laboratory LOR) of 3.3 mg/m^3 are recorded following the completion of the Proposal, implementation of contingency measures will occur within 30 days of the exceedance including: • identify the reason for the exceedance and determine direct correlation to well site fugitive gas emissions, existing land use, or natural variation and review management measures with an adaptive management response • re-examine monitoring results (QA/QC) to validate data. • where the exceedance was not caused by the assets, no further action required • where the threshold exceedance can be attributed to the assets, implement adaptive management response that may include investigating assets to confirm if gas leakage is occurring and determine how leakage can be remediated, remediate assets to prevent further gas leakage and fugitive emissions, continue sampling/monitoring post remediation until at least two consecutive results reflect no significant deviation from ambient (baseline) samples.	**Indicator** Scope 1 GHG emissions. Methane emissions **Method** GHG emissions will be monitored via various means including diesel inventories and flow meters. In accordance with the Valhalla Monitoring Program, methane levels will be sampled at each well site using 24-hour air canisters. The location of methane emission monitoring will be based upon the location of the potential fugitive methane emissions arising post-activity.	• Diesel inventories will be maintained for all well sites on an annual basis. • Quantity of GHG associated with flaring activities will be monitored continuously. • Total Scope 1 GHG emissions will be calculated annually (based on financial year schedule) during operations. • Biennial methane sampling (pre-impact and post activity) at each well	Routine reporting – Annual Compliance Assessment Report to the DWER Compliance Brach

6 Stakeholder consultation

Consistent with the EPA's expectations for this GHGEMP to align with the principles of environmental impact assessment, BNR consulted with stakeholders during the development of the EPA referral. Engagements relevant to this GHGEMP are presented below in Table 6-1.

Table 6-1: Stakeholder engagement relevant to this GHGEMP

Stakeholder	Method of engagement	Date of engagement	Summary of engagement
EPA	Meeting	24 Nov 2021	Discussed the Environmental Management Plan (EMP) guidelines and new structure.
EPA	Email correspondence	8 May 2024	GHG EMP guidelines and new structure

For a full summary of stakeholder engagement records refer to the BNR Environmental Review Document (BNR_HSE_MP_013).

Any additional consultation regarding this GHGEMP will be captured in subsequent revisions.

7 Changes to GHGEMP

This GHGEMP is intended to be dynamic and may be updated to reflect changes in management practices and the natural environment over time. It will be reviewed on a five-yearly cycle. This approach will allow flexibility to adopt new approaches / management measures. The effectiveness and relevance of trigger level and threshold contingency actions will be evaluated on an annual basis, and any amendments to response actions will be completed on an as-needed basis. This will include:

- amendment of response actions that are not achieving the desired outcomes
- monitoring that identifies additional impacts requiring additional response actions or changes to existing response actions
- changes to relevant legislation that may affect the implementation of response actions
- improvements to management practices to achieve a greater environmental outcome
- updates to trigger and threshold criteria following the completion of baseline sample collection prior to commencing any groundwater extraction.

Specifically, a table summarising the changes following the template provided as Table 7-1 will be developed. This table will clearly indicate location and reason/s for changes. A tracked change version of the revised GHGEMP will be provided for all minor, non-structural changes to the document.

Table 7-1: GHGEMP review template

Complexity of changes	Minor revisions ☐		Moderate revisions ☐		Major revisions ☐
Date revision submitted to EPA	DD/MM/YYYY				
Is the change proposed to be implemented under condition C3-3? If so, the proponent must provide a copy to the CEO at least 20 days before commencing implementation			Yes ☐		No ☐
Proponent's operational requirement timeframe for approval of revision	< One Month ☐		< Six Months ☐		> Six Months ☐
Reason for Timeframe					None ☐

Item number	GHGEMP section number	GHGEMP page number	Summary of change	Reason for change	New or increased adverse impacts to the environment? Risk to the achievement of limits, outcomes or objectives?
1.					
2.					
3.					

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Western Australian Government. 2020. *Western Australian Climate Policy, a plan to position Western Australia for a prosperous and resilient low-carbon future*.

Appendix A BNR Climate Change Policy

CLIMATE CHANGE POLICY

Black Mountain Exploration (BME) is committed to achieve the best possible balance between economic development and protection of the environment.

BME acknowledges the scientific consensus on climate change and the diverse effects that climate change may have on its customers, businesses, the economy and the communities in which it operates.

BME recognises that business has an important role to play in addressing climate change, and that its actions may deliver economic, social and environmental benefits over the long term. BME is committed to proactively managing the risks and to realising business opportunities associated with climate change. This policy applies to all BME activities.

BME will achieve net zero by 2050 by:

- Identifying opportunities to reduce Scope 1, 2 and 3 emissions through investments in research and technology, alternate energy sources, transport efficiency and process optimisation;
- Identifying and prioritising opportunities to leverage existing proven technology in renewable energy to reduce carbon emissions from power consumption;
- Exploring opportunities to minimise our consumption and contribution to waste;
- Adopting technology improvements as they become available and reasonably practicable to apply;
- Continuing to assess the acquisition or development of projects that have the potential to contribute to decarbonisation locally and globally (including offsets);
- Wherever possible and practicable, driving BME's emissions per unit of production below the mean of comparable peers;
- Being an active participant in various industry working groups; and
- Ensuring adequate resources are available to implement this policy including developing a broad ranging education and awareness campaign for our workforce and developing measures that will help guide our progress.

BME will strive to protect the environment and create sustainable businesses for future generations.

It is the responsibility of all employees, contractors and suppliers to comply with the requirements of this policy.

It is the responsibility of managers and supervisors to ensure this policy is implemented, reinforced and maintained through active leadership.

Samantha Richardson
Chief Operating Officer
Black Mountain Exploration Pty Ltd
28 June 2021

Revision date:
28 June 2022

Appendix B GHG Inventory Methodology

VALHALLA GAS EXPLORATION PROGRAM
GHG MANAGEMENT REPORT

REPORT PREPARED TO SUPPORT ENVIRONMENTAL REVIEW DOCUMENT WA EPA

NIM GNANENDRAN, PH.D.
NIMBLENG ENERGY CONSULTANTS
Perth, Western Australia.

JULY 23, 2021

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Executive Summary

The Valhalla Gas Exploration and Appraisal Program (Proposal) was referred to the EPA by Bennett Resources (BNR) under section 38 of the WA Environmental Protection Act 1986 (EP Act) on 24 December 2020. The EPA determined that the Proposal should be assessed under Part IV of the EP Act at the level of assessment of Public Environmental Review on 3 February 2021.

As part of the review the EPA has provided a draft Environmental Scoping Document that requires the Proposal EIA documentations to include detailed estimates of greenhouse gas emissions (Scope 1, Scope 2 and Scope 3), a benchmarking exercise comparing emissions from the Proposal to other similar exploration and appraisal projects, along with a GHG emissions reduction assessment for the Proposal. NimblEng Energy Consultants were contracted by BNR to complete these tasks such that it can form part of the GHG Management Program for the EPA submission. The GHG emissions estimations were carried out based on updated Proposal information. The key changes compared to the 2020 Referral relates to the following which has led to a marked increase in GHG emissions:

- introducing options to the time period for the two proposed phases, with Phase I consisting of 6 wells drilled over 1-3 years and Phase II consisting of 14 wells drilled over 2-4 years;
- the proposed Well Test rate was increased from 2.5 mmscf/d to 5.9 mmscf/d for the Phase I wells and 10.7 mmscf/d for Phase II for the test period of 60-90 days per well;
- the condensate production was estimated based on condensate to gas ratio of 20 bbls/mmscf resulting in 118 bbl/d in Phase I and 214 bbl/d in Phase II during well testing.

Direct GHG emissions sources from the Proposal (Scope 1) were categorized into the following:

- Land clearing;
- Diesel fuel usage;
- Fugitive emissions; and
- Well Test gas flaring.

GHG emissions from each category was estimated based on accepted methodologies used by the WA EPA and EPA NT for exploration and appraisal projects involving hydraulic fracture stimulation (HFS). The GHG emissions were calculated based on a per well, per day rate and then total emissions were estimated based on the minimum and maximum number of Well Test days. The variable nature of drilling campaigns in an exploration and appraisal program does not allow the project proponents to commit to fixed annual emission rates rather, provide a range of estimated emissions based on the drilling program envisaged. The success of the Phase I program is key to the continuation of the Phase II drilling campaign. Therefore, annual emissions estimates are provided as a 3-year program (Timeline #1) and a 7-year program (Timeline #2) with the minimum and maximum emission each year. The total GHG emissions range from 1,082,000 to 1,592,600 tCO_2e over the 20-well exploration and appraisal program.

A benchmarking exercise comparing direct emissions from the Valhalla Proposal along with three recently approved HFS based exploration projects in the NT was carried out. The results indicate the total emissions from these projects are comparable with Phase I of the Valhalla project, but Phase II emissions remained high due to the higher well test rates planned for the Valhalla Proposal.

GHG Emissions Reduction Assessment for the Proposal was based on number of RECs (Reduced Emissions Completions) proposed by the WA Scientific Inquiry into Fracking and the Code of Conduct in NT. The key focus of the emissions reduction relates to the capture and utilisation of the well test gas and condensate produced. The project proponents are currently evaluating options to export the condensate from the drilling program and capture part of the gas and utilise it in dual fuel engines on site to power the drilling and HFS operations.

In line with meeting the state NetZero 2050 target, the WA EPA has set a NetZero emissions trajectory to reduce or offset emissions on a year-on-year basis for new projects with annual emission of more than 100,000 tCO2e. This report provides a quantitative estimate of GHG emissions that could be considered as above the NetZero 2050 trajectory for the Proposal that would be required to be offset by the proponents. Depending on how the EPA would assess the Valhalla exploration and appraisal program, the Proposal may or may not be required to offset carbon emissions due to the exploratory nature of the Proposal.

1 Background

The Valhalla Gas Exploration and Appraisal Program (Proposal) is located approximately 51 km Northwest of the townsite of Fitzroy Crossing (Shire of Derby-West Kimberley) in the Canning Basin Region in the State of Western Australia. It is located within the Petroleum Lease EP 371. Bennett Resources wholly owns the exploration lease which encompasses the proposed Valhalla Gas Exploration and Appraisal Program in its entirety[1].

The Proposal is to complete an unconventional gas exploration and appraisal drilling and Hydraulic Fracture Stimulation (HFS) program within Petroleum Exploration Permit EP 371 (EP 371). The Proposal includes the construction of up to 20 exploration wells within 10 well sites and is expected to commence in 2023 or 2024. The exploration program will be carried out in two phases where 6 wells will be drilled in the initial phase and based on the results the next 14 wells will be drilled in the second phase of the program.

On 24 December 2020, the Proposal was referred to the Environmental Protection Authority (EPA) under Section 38 of the Environmental Protection Act 1986. The Chairman of the EPA determined that the Proposal was required to be assessed via a Public Environmental Review. Subsequently, the EPA Services drafted an Environmental Scoping Document (ESD), which is yet to be finalised. The draft ESD provides details on the requirements to conduct GHG estimates (scopes 1, 2 & 3) and an Emissions Reduction Assessment for the Proposal. The assessment will inform (and be presented in) the Valhalla Environment Review Document (ERD)and GHG Management Plan (GHGMP).

1.1 Study Objective

The aim of this study is to provide a Greenhouse Gas emission estimate review and emissions reduction assessment for the Valhalla Gas Exploration and Appraisal Program. The study will address the following:

- Review of the GHG estimates already presented in the document “Valhalla Gas Exploration and Appraisal Program Section 38 Referral – Supporting Information Document” (BNR_ENV_RE_002), Section 6.3. Provide advice in regard to the adequacy of the estimates (including calculation methodology) and suggest any required updates to the estimates.
- Undertake a benchmarking exercise to compare GHG emission estimates against other HFS exploration projects.
- Conduct an Emissions Reduction Assessment with the intention of identifying options that the Company could implement to mitigate GHG Emissions to ALARP.

Further to the above the study will address EPA’s Environmental Scoping Document requirements,

Item No.	EPA ESD Requirement
74	Provide credible estimates of scope 1, scope 2 and scope 3 greenhouse gas emissions (annual and total) in tonnes of carbon dioxide equivalent (CO2-e) over the life of the proposal. Detail methods used to estimate emissions.
75	Provide a breakdown of estimated scope 1 and scope 2 greenhouse gas emissions in tonnes of CO2-e by all sources. Consider all proposed activities in determining the sources of emissions (e.g. clearing of land, site preparations, drilling operations,

	hydraulic fracture stimulation operations including flaring, potential leakage etc).
76	Provide calculations and calculation methodology for determining estimated emissions of CO2-e for all sources.
77	Benchmark the proposal's emissions against other hydraulic fracture stimulation exploration projects. Information which supports that the identified projects are comparable to the proposal should be included.
78	Provide a greenhouse gas management plan, in accordance with EPA guidance, which demonstrates the proposal's trajectory towards net zero emissions by 2050. The plan should include at a minimum: a) information required by 74 to 77 above. b) a graph and table showing regular targets reflecting an incremental reduction in emissions towards net zero emissions by 2050. Where the proposed emissions reduction targets do not demonstrate a trajectory towards net zero by 2050, articulate clearly a compelling reason why it is not possible to achieve this. c) mitigation (avoidance, reduction, offset) measures to be implemented with associated timeframes and evidence to demonstrate that the interim and long-term targets will be met. Where it is proposed that, following implementation of the avoidance and reduction measures, authorised offsets will be applied to meet the targets, evidence which supports that the mitigation measures are capable of achieving the stated targets is not required. d) Analysis of other potential abatement measures (e.g. renewables) relevant to the proposal that are not proposed to be implemented which provides the rationale to support that these measures are unable to be implemented. e) reporting requirements for publicly and periodically reporting against the stated targets.

1.2 Project Location

Access to the Proposal area is via the Great Northern Highway and Calwynyardah-Noonkanbah Road from the township of Fitzroy Crossing. A map of the Proposal area is provided in Figure 1-1.

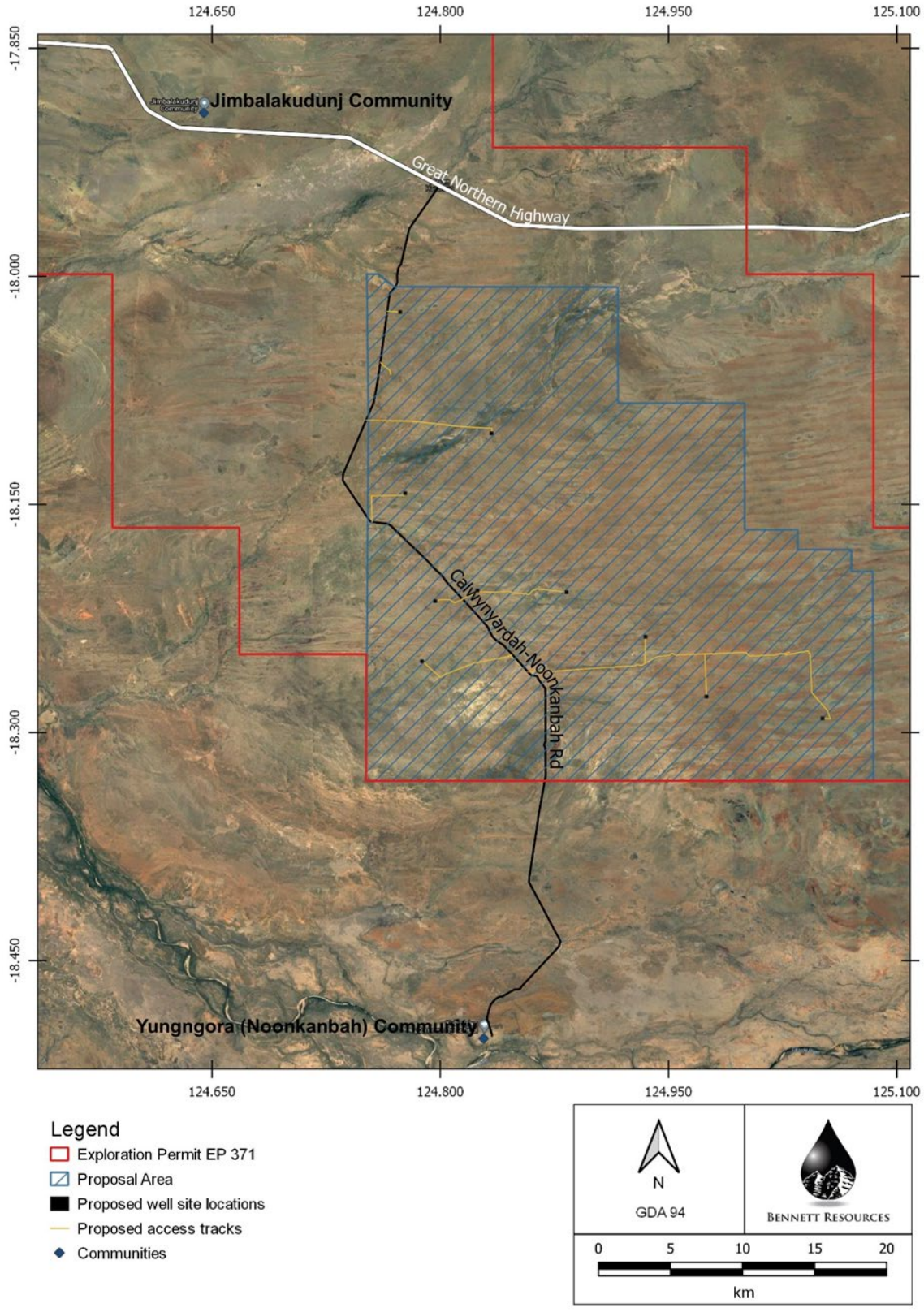


Figure 1-1: Valhalla Project Location

1.3 EPA Technical Guidance on GHG Mitigation

The WA EPA have provided a technical guidance for GHG emissions which is periodically updated from time to time for new or expanding operations with a GHG mitigation hierarchy of *avoid, reduce and offset*[2]. The Australian Government's principal mitigation initiative is currently the Emissions Reduction Fund (ERF) and the associated safeguard mechanism. The safeguard mechanism applies to facilities with direct emissions (scope 1) in excess of 100,000 tonnes CO2e per annum and requires liable entities to keep emissions at or below a predetermined (historical or calculated) emissions baseline. The EPA's objective is to ensure that the mitigation hierarchy is applied such that greenhouse gas emissions from proposals are avoided or reduced, and residual emissions offset, in the planning, design and operational stages. The Valhalla Gas Exploration and Appraisal Drilling Program will abide by the EPA guidelines to reduce GHG emissions according to the mitigation hierarchy during the project lifecycle.

1.4 Project Assumptions

The following GHG Emissions estimates in Table 1-1 was provided by BNR as part of the Valhalla E & A Program EPA referral submission. As noted in the table significant part of the emissions are associated with the flaring of the well test gas during the appraisal period.

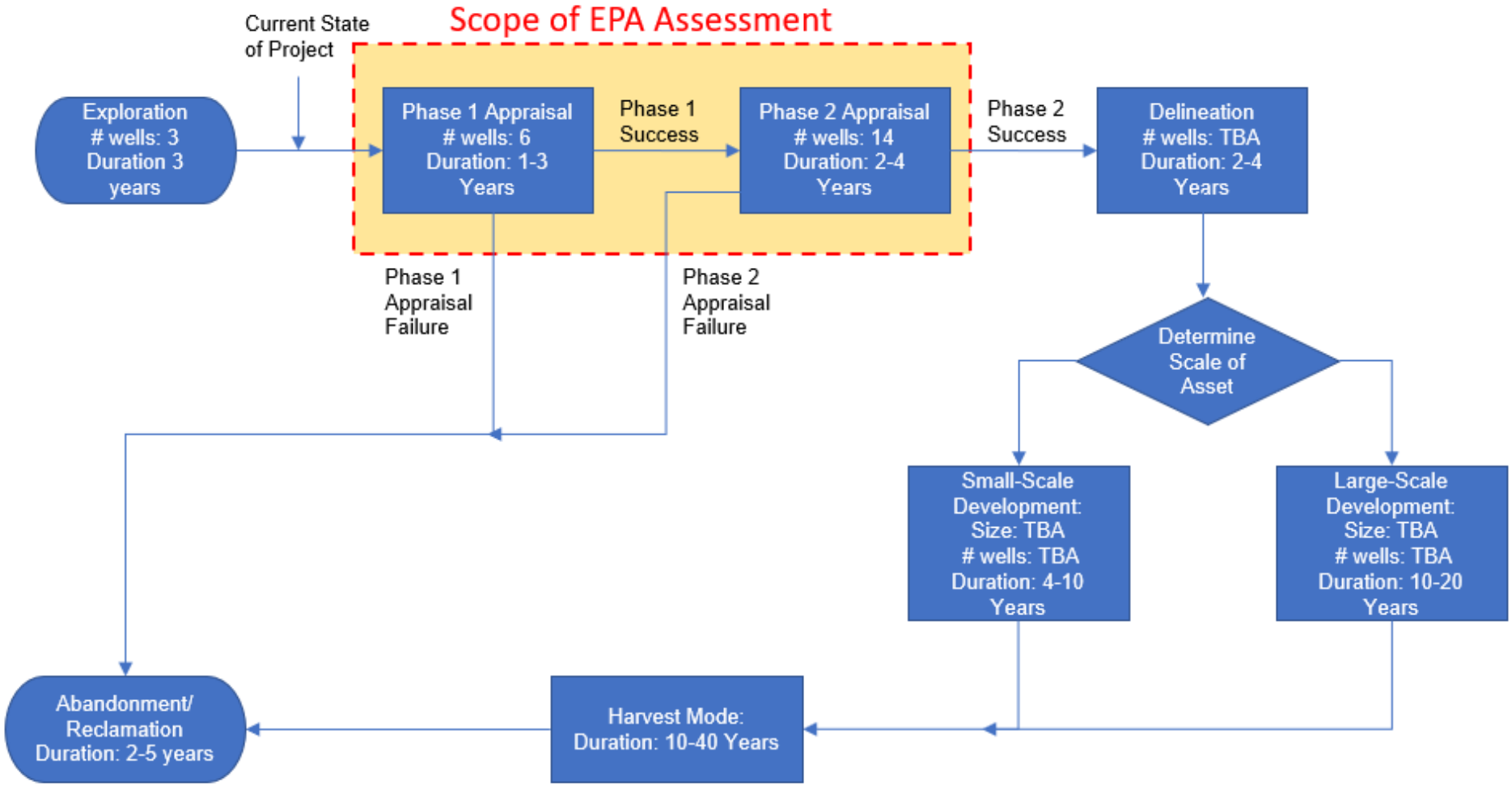
Table 6-9: Scope 1 GHG calculations per well

Activities	Emission source	Volume estimates (per well)		Total Scope 1 emissions per well (t CO_2-e)
Site preparation operations	Combustion emissions from diesel	20 m³		54
Drilling operations	Combustion emissions from diesel during mobilisation	10 m³		27
	Combustion emissions from diesel during Drilling operations	379 m³		1,023
HFS operations	Combustion emissions from diesel during mobilisation	20 m³		54
	Combustion emissions from diesel during HFS operations	300 m³		809
	CH_4 emissions during well testing	**Gas Flow rate**	**Period of Flaring**	<15,000
		~2.5 MMCFGPD	~90 days	
Site reinstatement	Combustion emissions from diesel	20 m³		54
			Total	**17,021 t CO_2-e**

Table 1-1: Current EPA Referral Submission for Valhalla E & A Program

During the period of GHG emissions evaluation, BNR advised the following key changes, which formed the basis of this study.

(1) A Well test gas flow Rate 5.9 mmscf/d will be required to evaluate the 6 Wells from Phase I.
(2) A Well test gas flow Rate 10.7 mmscf/d will be required to evaluate the 14 Wells from Phase II.
(3) A condensate to gas ratio (CGR) of 20 bbl/mmscf was assumed for the Valhalla reservoirs.
(4) A minimum test period of 60 days and maximum test period of 90 days is required per well.
(5) The following Road Map was provided for Valhalla Gas development:


Current State of Project
Scope of EPA Assessment
Exploration # wells: 3 Duration 3 years
Phase 1 Appraisal # wells: 6 Duration: 1-3 Years
Phase 1 Success
Phase 2 Appraisal # wells: 14 Duration: 2-4 Years
Phase 2 Success
Delineation # wells: TBA Duration: 2-4 Years
Phase 1 Appraisal Failure
Phase 2 Appraisal Failure
Determine Scale of Asset
Small-Scale Development: Size: TBA # wells: TBA Duration: 4-10 Years
Large-Scale Development: Size: TBA # wells: TBA Duration: 10-20 Years
Abandonment/ Reclamation Duration: 2-5 years
Harvest Mode: Duration: 10-40 Years

2 Review of GHG Emission Estimates

Based on the proposed activities associated with the Valhalla gas exploration and appraisal drilling program greenhouse gas emissions were estimated based on four activities as listed below,

(1) Land Clearing.
(2) Diesel Fuel Emissions.
(3) Fugitive Emissions.
(4) Well Testing Flaring.

These activities are directly associated with the operation of the proponent and are deemed as Scope 1 emissions. Indirect emissions associated with the Valhalla Exploration and Appraisal Drilling/HFS Operations Program is considered as Scope 2 emissions, such activities may include importation of power or other offsite energy supply activities related to the project. Scope 3 emissions are associated with all other indirect emission such as export of products from the project. The Valhalla Gas E & A program, at present, does not have the necessary infrastructure nor a market to export the gas or condensate from the project and intends to flare these hydrocarbons on site. Therefore, as a base case, no Scope 3 emissions are expected from the project. At present BNR is evaluating the possibility of selling the condensate after completing the initial appraisal wells and establishing a better understanding of the condensate volumes. Therefore, for completeness of this report Scope 3 emissions from condensate sale are also provided.

2.1 Land Clearing

The estimated land cleared for the 10 well sites (with 2 wells per site), access tracks and camp sites are tabulated below.

Land area	ha
Well Sites	40.1
Access Tracks	59.1
Camp Sites	2.8
Total	102

Table 2-1: Valhalla Exploration and Appraisal Drilling Program land clearing estimate

Forests, bushlands, grasslands and other vegetation, known as carbon sinks, remove carbon dioxide from the atmosphere. When such carbon sinks are cleared for industrial activity the associated loss of carbon sinks are counted as part of the greenhouse gas emissions estimate of the project. The Full Carbon Accounting Model (FullCAM) is a calculation tool for modelling Australia's GHG emissions from the land sector[3]. FullCAM is used in Australian National Greenhouse Gas Accounts for the land use change and forestry sectors. The FullCAM model estimates carbon stock change in ecosystems by considering above and below ground biomass, standing and decomposing debris and soil carbon resulting from land use activities. The latest version of the FullCAM model published in September 2020 was used for this estimate. Based on the spatial data input for the site location (Lat -18^{o} N, Long 124^{o} E), the following carbon mass estimate for calculated from the FullCAM model.

Component	(tC/ha)
Carbon mass of trees	16.4
Carbon mass of debris	13.9
Carbon mass of soil	25.9
Total Carbon mass on-site	56.3

Table 2-2: Site Carbon Mass Estimate

Based on the total land area cleared the total carbon emissions associated with land clearing is 5744 tCO2e and the average per well carbon emissions for the 20 well program is estimated as 287 tCO2e/well.

2.2 Diesel Fuel Emissions

The exploration and appraisal drilling program will involve several activities such as, site preparation, mobilisation of the drilling rig(s), drilling and completion of the exploration wells, mobilisation of the hydraulic fracturing rigs, hydraulic fracturing operations, testing of the wells, camp setup and operations of the camp during the drilling programs, transport of the workforce to and from site, and after the drilling activities are complete the reinstatement of the site. These activities are expected to be powered using diesel fuel for vehicle and in diesel engines. The following table provides an estimate of diesel fuel usage for these activities,

Per Well Data	Volume, KL
Site Preparation	20
Drilling Operations	316
HFS Operations	510
Site Reinstatement	20
Transport	344
Camp Site	8
Total	**1218**

Table 2-3: Diesel Fuel Usage per Well

The emissions from diesel fuel usage is estimated from National Greenhouse and Emissions Reporting (Measurement) Determination (2008) as updated in July 2020 and made under subsection 10(3) of the National Greenhouse and Energy Reporting Act 2007 [4]. Section 2.41 Method 1 of the NGER along with Fuel combustion emissions factors in Schedule 1 Part 3 for diesel fuel energy content factor and GHG emission factors as shown below,

Fuel	Energy Content	Emissions Factors (kgCO2e/GJ)		
	(GJ/ KLit)	CO2	CH4	N2O
Diesel	38.6	69.9	0.1	0.2

Table 2-4: NGER Emission Factors for Diesel Emissions

Based on the above emission factors average carbon emissions from diesel fuel usage per well was estimated as 3,300 tCO2e/Well.

2.3 Fugitive Emissions

Fugitive emissions include gas lost directly to atmosphere through uncontrolled sources during the drilling and HFS operations. The American Petroleum Institute produced a Compendium of greenhouse gas emission methodologies for the oil and natural gas industry[5]. Several methodologies used here are based on US EPA GHG estimation tables and has been also used by proponents who have filed their application for HFS projects in the Northern Territory under their new Code of Practice. The following sources were considered the main fugitive emissions sources as part of the greenhouse gas management program,

(i) Well completions: Completing new gas wells involves producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed

for these high liquid flow rates and three-phase (gas, liquid, and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids, and sand are captured, and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from several hours to several weeks, during which time a substantial amount of gas may be released to the atmosphere or flared. Based on the following table from API compendium 25.9 tonnes/completion day of fugitive emissions was assumed.

Table 5-23. Production Segment CH_4 Emission Factors for Maintenance and Turnaround Activities

Source	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis of Factor [c]	Uncertainty [d] (±%)
Vessel blowdowns	78 scfy/vessel	0.0015 tonnes/vessel-yr	78.8 mole %	326
Compressor starts [e]	8,443 scfy/compressor	0.1620 tonnes/ compressor-yr	78.8 mole %	190
Compressor blowdowns	3,774 scfy/compressor	0.07239 tonnes/ compressor-yr	78.8 mole %	179
Gas well workovers [f] (tubing maintenance)	2,454 scf/workover	0.04707 tonnes/workover	Not given	924
Oil well workovers [f] (tubing maintenance)	96 scf/workover	0.0018 tonnes/workover	Not given	Not available
Gathering gas pipeline blowdowns	309 scfy/mile	0.00593 tonnes/mile-yr 0.00368 tonne/km-yr	78.8 mole %	39.5
Onshore gas well completion [g]	$1,712\times10^3$ scf/ completion-day	25.9 tonne/completion-day	78.8 mole %	Not available
Offshore gas well completion [g]	$\sim8,700\times10^3$ scf/ completion-day	131.5 tonne/completion-day	78.8 mole %	Not available
Oil pump stations (maintenance) [h]	1.56 lb/yr-station	7.076E-04 tonnes/station-yr	Not given	Not available

Footnotes and Sources:

[a] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities, Final Report*, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary, Final Report*, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Uncertainty based on a 95% confidence interval.

[e] An EPA Gas STAR paper on engine starts reports that typical production compressor engine start-ups vent 1,000 to 5,000 scf of gas with each start-up attempt (EPA Gas STAR, PRO Fact Sheet No. 101, September 2004). This equates to 0.015 to 0.076 tonnes CH_4/start-up attempt assuming 78.8 mole % CH_4 in the gas.

[f] Factor taken from: Tilkicioglu, B.H. *Annual Methane Emission Estimate of the Natural Gas Systems in the United States*, Phase II, Pipeline Systems Incorporated (PSI), September 1990. An EPA Gas STAR paper on installing plunger lift systems in gas wells presents a gas well workover emission factor of 2000 scf CH_4/workover, which equates to 0.0384 tonnes CH_4/workover (EPA Gas STAR, Lessons Learned - Installing Plunger Lift Systems in Gas Wells, October 2003). Gas STAR also reports that the number of gas well workovers conducted in a year typically ranges from 1 to 15.

[g] EIA, U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, December 2001. Cites data for initial rates of production for completions in 2000. Offshore factor interpolated from chart "Initial Flow Rates of New Natural Gas Well Completions, 1985-2000." The total gas basis was converted to a CH_4 basis assuming 78.8 mole % CH_4 in production using the GRI/EPA average CH_4 composition for production operations.

[h] Tilkicioglu, B.H and D.R. Winters. *Annual Methane Emission Estimate of the Natural Gas and Petroleum Systems in the United States*. Pipeline Systems Incorporated (PSI), December 1989.

Table 2-4: Fugitive Emissions from Onshore Wells (API –Compendium of greenhouse gas emission methodologies for the oil and natural gas industry Table 5-23)

Based on discussions with BNR, it was confirmed that RECs (Reduced Emissions Completions) will be used and no cold venting will occur during well completions and negligible amount of fugitive emissions are expected from well completions activities.

(ii) Drill cuttings: Drill cutting generated during the drilling into hydrocarbon formation contain methane and other hydrocarbons. These cutting produce gaseous emissions from thermal desorption. The quantity of gas absorbed in the drill cuttings are estimated based on cutting volume, porosity and gas saturation.
In order to estimate the fugitive gas emission from drill cutting BNR indicated a total volume of 156m3 was used with a porosity of 8% and a gas saturation of 46.5%. The methane quantity associated with the drill cuttings was estimated as 1.18 tonnes per well and the associated GHG emission was estimated as 29.6 tCO2e, assuming a 25tCO2e/tCH4 as per NGERs.

(iii) Wastewater Storage: Emissions from wastewater recovered from flowback and held in storage tanks can be estimated using Compendium of greenhouse gas emission methodologies for the oil and natural gas industry Table 5-10. An emissions factor of 0.39896 tonnes of methane/ML of produced water was used.
In order to estimate the fugitive emissions from wastewater, BNR indicated a 2 ML per well would be recovered. Therefore, methane emissions were estimated at 0.78 tonnes per well and the associated GHG emissions was estimated as 19.5 tonnes CO2e, assuming 25 tCO2/tCH4 as per NGERs.

Table 5-10. Produced Salt Water Tank Methane Flashing Emission Factors

Separator Pressure (psi)	Produced Water Salt Content	GRI/EPA Emission Rate [a], Original Units (10^6 lb CH_4/yr)	Water Tank Emission Factor	
			tonnes CH_4 /1000 bbl produced water [b]	tonnes CH_4 /1000 m^3 produced water
50	**20%**	**1.6**	**0.0015**	**0.009185**
250	20%	10.8	0.00986	0.06200
250	10%	16.4	0.0150	0.09414
250	2%	19.4	0.0177	0.11137
250	**Average of 10.7% [c]**	**--**	**0.0142**	**0.08917**
1000	20%	38.8	0.0354	0.22273
1000	10%	58.7	0.0536	0.33697
1000	2%	69.5	0.0634	0.39896
1000	**Average of 10.7% [c]**	**--**	**0.0508**	**0.31955**

Footnotes and Sources:
[a] Emission factors developed from Table 5-5 of Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary, Final Report*, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.
[b] Process simulation modeling based on 1990 annual salt water production of 497 million barrels from Energy Environmental Research Center, 1995.
[c] Average of emission factors at 20, 10, and 2% salt.

Table 2-5: Fugitive Emissions from Produced Water Storage (API –Compendium of greenhouse gas emission methodologies for the oil and natural gas industry Table 5-23)

2.4 Well Testing Flare

As part of the drilling program the exploration and appraisals wells are flow tested over a minimum of 60 days and a maximum period of 90 days and at an average flow rate of 5.9 mmsc/d for the 6 wells in Phase 1 and 10.7 mmscf/d for the 14 wells in Phase 2 to evaluate the commercial viability of the Valhalla

shale gas formation. The produced hydrocarbons from the well tests are directed towards a flare with a minimum destruction efficiency of 98% to ensure maximum practical combustion of the hydrocarbons. Methane has a hydrocarbon potential 25-times more than CO2 and hence gas is flared during all well tests to reduce greenhouse gas emissions. The expected condensate to gas ratio (CGR) in the Valhalla formation is around 20 bbl/mmscf, hence a condensate flow rate of 118 bbl/day is expected during Phase I of the well testing program and 214 bbl/d during Phase II of the well testing program. The condensate is assumed to be flared at site as a base case, while BNR is investigating the possibility of trucking the condensate out of site for sale.

The greenhouse gas associated with the flaring of the gas and condensate is estimated based on National Greenhouse and Emissions Reporting (Measurement) Determination (2008) as updated in July 2020 and made under subsection 10(3) of the National Greenhouse and Energy Reporting Act 2007 [4]. Section 3.44 Method 1 of the NGER along with Fuel combustion emissions factors as shown below,

Fuel	Emissions Factors (tCO2/t Gas flared)		
	CO2	CH4	N2O
Gas Flared	2.8	0.933	0.026
Condensate Flared	3.2	0.009	0.060

Table 2-6: NGER Emission Factors for Gas and Condensate Flared

The amount of gas flared was estimated based on an expected gas composition of CH4 87 mol%, C2 5.5 mol%, C3 2.7 mol% and inerts 4.8 mol% and the average density of gas of 0.79 kg/m3 at standard conditions. The average density of the condensate was assumed to be 750 kg/m3.

Based on the above emission factors and the estimated weight of gas and condensate flared per day of well testing along with GHG emissions associated with the gas and condensate flaring per day per well is shown in Table 2-7 below.

Emissions per Well per day	Phase I	Phase II
Gas Flared (tonnes/d)	131.9	239.2
Condensate Flared (tonnes/d)	14.1	25.5
GHG Emissions from Gas flared (tCO2e/d)	496	899
GHG Emissions from Condensate flared (tCO2e/d)	46	83

Table 2-7: Quantity of Gas and Condensate Flared and associated GHG Emissions.

A minimum and maximum emissions per well is based on the minimum well test period of 60 days and a maximum well test period of 90 days.

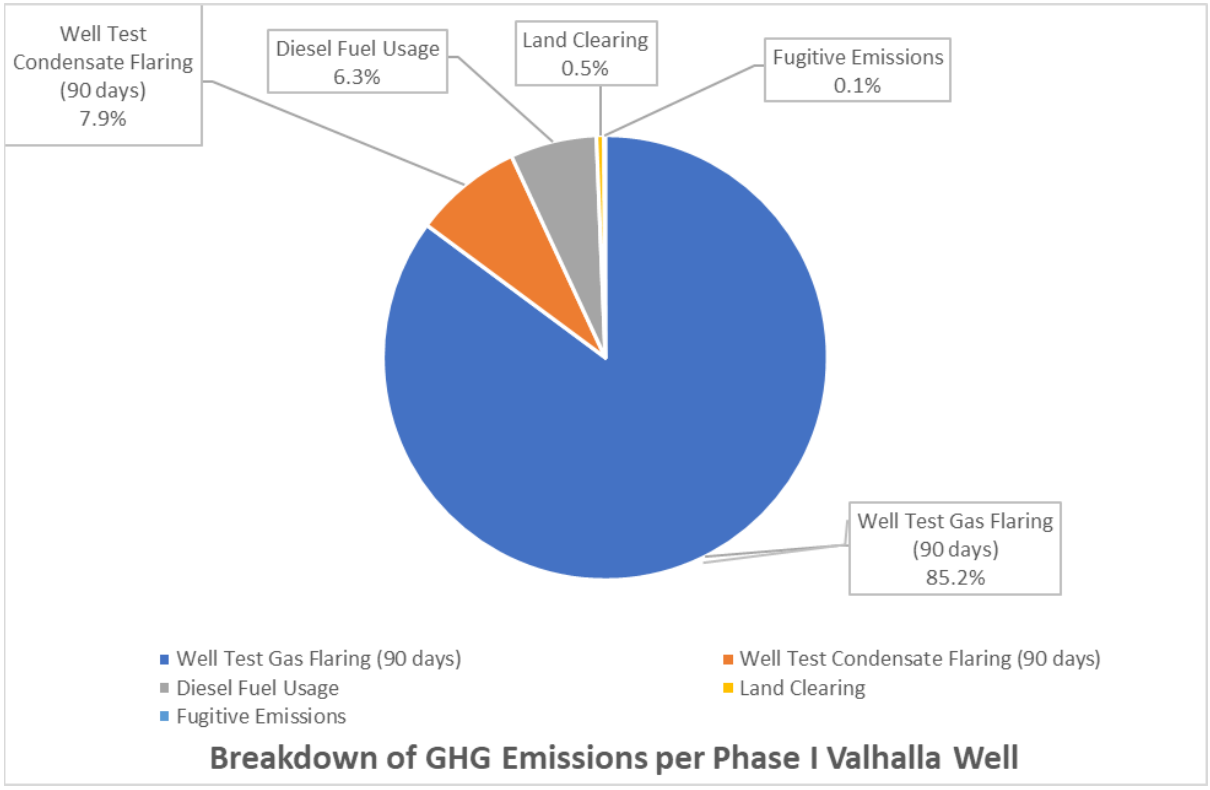
2.5 Summary of Scope 1 GHG Emissions

Based on the above GHG emissions calculations, results are presented for a single well and for the total number of wells over the minimum 60 day and maximum 90-day test period for Phase I and Phase II of the Valhalla Exploration and Appraisal program in Table 2-7 below,

CO2 Emissions per E&A Well	Input Parameter	Phase I - 6 Wells (t CO2e)		Phase II - 14 Wells (t CO2e)		Calculation Reference
		60 days Well Test	90 days Well Test	60 days Well Test	90 days Well Test	
Land Clearing (per well)						
Land Clearing Emissions	5.1 ha per Well, 56.3 tCO2e/ha	287	287	287	287	FullCAM Model (2020) https://www.industry.gov.au/data-and-publications/full-carbon-accounting-model-fullcam
Diesel Emissions (per well)						
Site Preparation	20	54	54	54	54	National Greenhouse and Energy Reporting Guidelines (https://www.legislation.gov.au/Details/F2017C00508) Section 2.41 with Table in Schedule 1 Part 3.
Drilling Operations	316	857	857	857	857	
HFS Operations	510	1,382	1,382	1,382	1,382	
Site Reinstatement	20	54	54	54	54	
Transport (Vehicles/Rigs)	344	931	931	931	931	
Site Power	8	15	22	15	22	
Well Test Flare (per well)						
Gas	Ph I: 5.9 mmcsf/d Ph II: 10.7 mmscf/d	29,747	44,620	53,948	80,921	National Greenhouse and Energy Reporting Guidelines (https://www.legislation.gov.au/Details/F2017C00508) Section 3.44.
Condensate	Ph I : 118 bbl/d Ph II : 214 bbl/d	2,760	4,140	5,005	7,507	National Greenhouse and Energy Reporting Guidelines (https://www.legislation.gov.au/Details/F2017C00508) Section 3.52.
Fugitive Emissions (per well)						
Drill cuttings	Gas 0.12 tonnes	30	30	30	30	Based on volume of drill cuttings and Vallhalla gas saturation.
Waste Water Tank	2 ML flowback	20	20	20	20	API GHG Emissions Methodologies for Oil and Gas, Table 5-10
Total GHG Emissions per Well (tCO2e)		**36,136**	**52,396**	**62,582**	**92,065**	Scope 1 (direct emissions)
Total Emissions E&A Program (tCO2e)	**Ph I 6 Wells Ph II 14 Wells**	**216,814**	**314,378**	**876,144**	**1,288,915**	Scope 1 (direct emissions)

Table 2-7: Valhalla E & A Program GHG Emissions Summary

The results can be represented in a pie-chart for comparison of various sources of GHG emissions per well as shown in Figure 2-1 below.



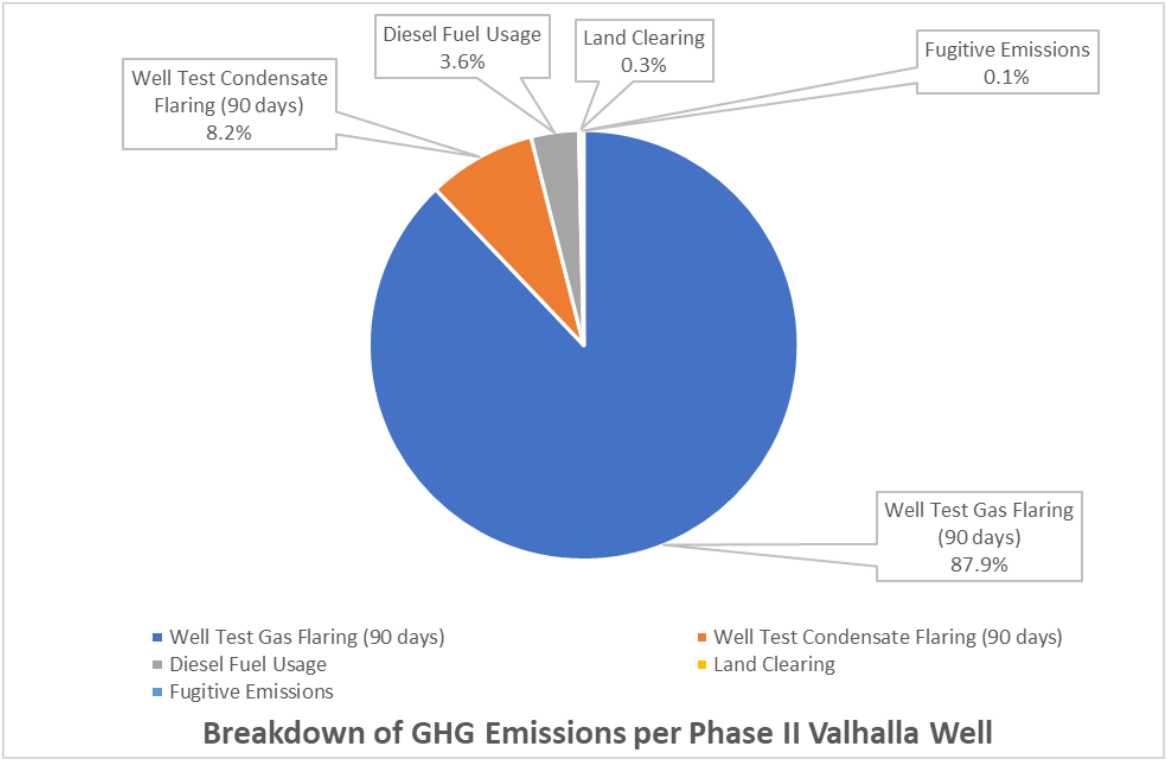


Figure 2-1: Breakdown of GHG Emissions per for 90-day Well Test for Phase I and Phase II of the Project

2.6 Project Overall Direct GHG Emissions (Scope 1)

The overall timeline of the Valhalla E & A Program could be between 3-7 years, where Phase I could take from 1-3 years and Phase II could take from 2-4 years depending on several technical and commercial factors. Therefore, two timelines and the associated GHG emissions for each of these timelines are provided below. Timeline #1 is an optimistic scenario where Phase I will be competed in Year 1 and Phase II will be completed in Year 2 and Year 3 of the Program. Timeline #2 is a resource constraint scenario where Phase I will take 3 years and Phase 4 will take another 4 years of the Program. Figure 2-2 provides annual GHG emissions for Timeline #1 and Figure 2-3 provides annual GHG emission for Timeline #2 for the Valhalla E & A Program.

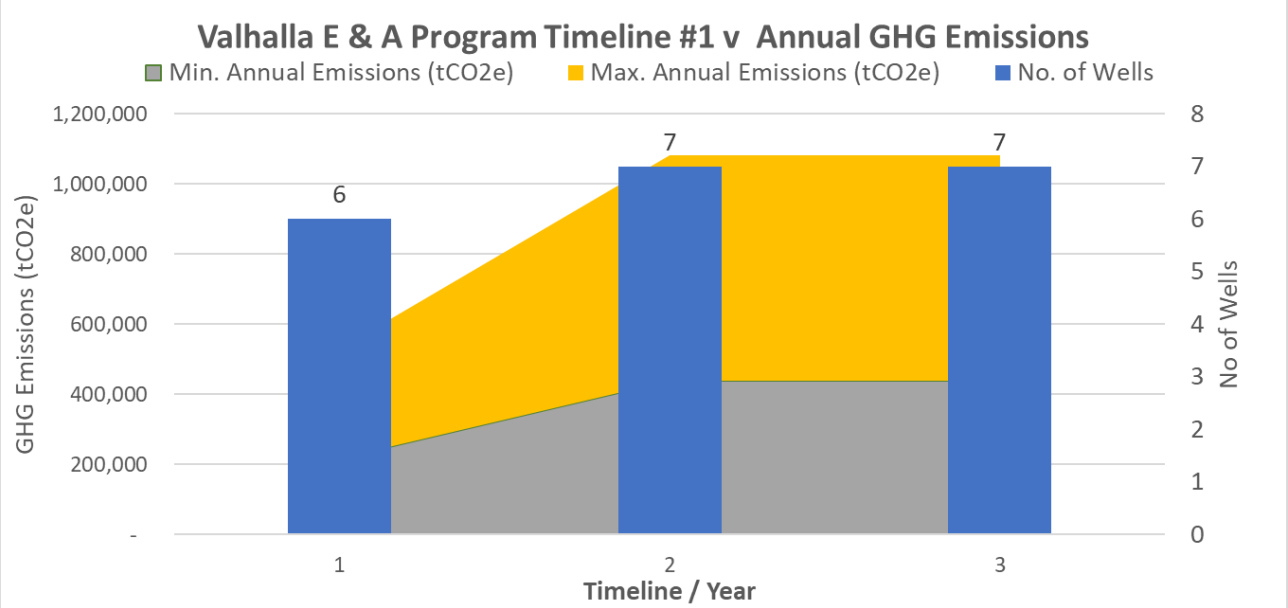


Figure 2-2: Timeline #1 for Overall Scope 1 GHG Emissions of the Valhalla E&P Program

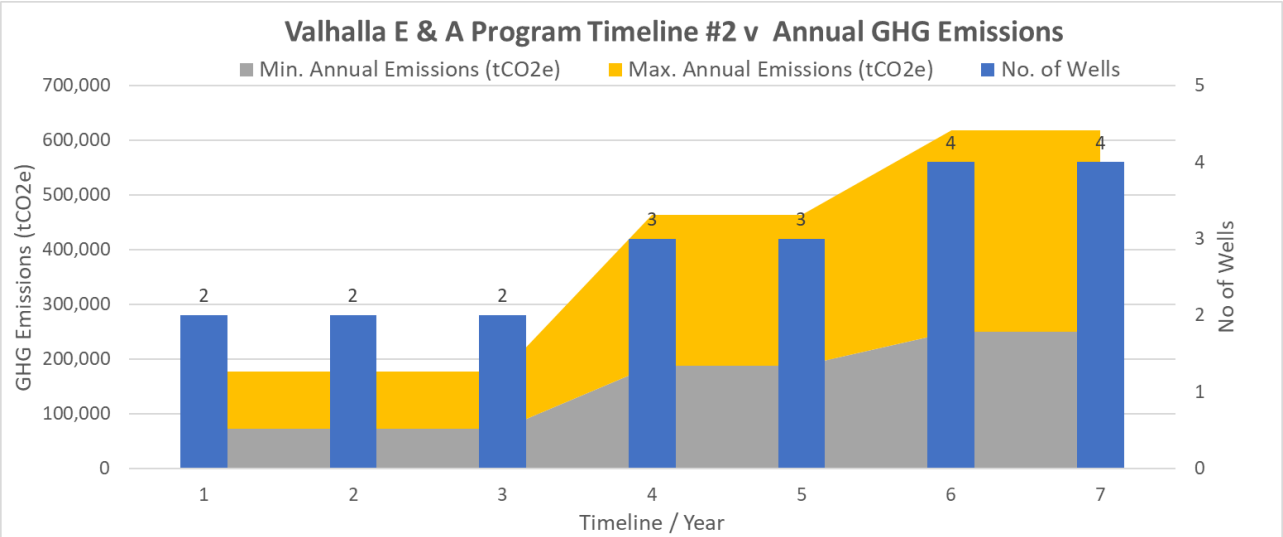


Figure 2-3: Timeline #2 for Overall Scope 1 GHG Emissions of the Valhalla E&P Program

2.7 Project Scope 2 Emissions

Indirect emissions from the generation of purchased energy consumed by a company is classified as Scope 2 emissions. The Valhalla Gas Exploration and Appraisal Program is intended to evaluate the quality of the gas field with drilling of exploration and appraisal wells, hydraulic fracture stimulation and flow tests. The E & P program does not intend to import power from third parties hence no Scope 2 emissions are envisaged as part of the project.

2.8 Project Scope 3 Emissions

All other indirect emissions not included in Scope 2 emissions that occur during the 7-years of the project is classified as Scope 3 emissions. The possibility of selling the condensate collected during the well test program to third parties rather than being flared at site is currently being evaluated as a recommended greenhouse gas mitigation measure. The emissions associated with the transportation and utlisation of condensate as a fuel is considered Scope 3 emissions for the project. For the purpose of this estimate the condensate produced from the well tests (minimum 60 day test period, maximum 90 day test period) was assumed to be collected and shipped from site. The condensate collected over the 7-years of the E & A program was assumed to be shipped from Wyndham to Singapore where it was assumed to be processed and consumed. A transportation emission factor of 130gCO2e/tonne/km of condensate[6]. Fuel combustion emissions from the condensate was estimated based on NGERs Method 2.41 – Schedule 1 Table Part 3 assuming the properties of Kerosene [4] along with a 10% factor for emission associated with the refining and selling of the condensate.

Scope 3 Emissions	**Min**	**Max**
Condensate Volume (bbls)	222,240	333,360
Condensate Transport Emissions (tCO2e)	13,952	20,928
Condensate Consumption Emissions (tCO2e)	91,571	137,356
Total Scope 3 Emissions (tCO2e)	105,523	158,284

Table 2-8: Scope 3 Emissions from Valhalla E & A Program

There are also other Scope 3 indirect emissions associated with the project including employee commuting, business travel and purchase of goods and services, which are considered minimal for the purpose of this estimation.

2.9 Breakdown of GHG Emissions

The results for the GHG emissions for the Valhalla E & A Program can be summarized as below considering both the condensate flaring and condensate sale option.

GHG Emissions (tCO2e)	**Condensate Flared**		**Condensate Sold**	
	Min	**Max**	**Min**	**Max**
Scope 1	1,082,222	1,592,556	995,593	1,462,614
Scope 2	-	-	-	-
Scope 3	-	-	105,523	158,284
Total Emissions(tCO2e)	**1,082,222**	**1,592,556**	**1,101,116**	**1,620,898**

Table 2-9: Overall Project Emissions from Valhalla E & A Program

It should be noted that the overall emissions with the condensate sale options is higher due to transportation and processing emission of the condensate. But the condensate would be utilized for an energy application rather than flared at site as a waste product displacing emissions from another source.

3 GHG Emissions Benchmarking

As part of the GHG emissions benchmarking exercise, carbon emissions from the Valhalla Exploration and Appraisal Program activities were compared with previous Buru Energy HFS exploration and appraisal drilling activity in the Canning Basin along with the recently approved drilling and HFS projects in the McArthur and Beetaloo sub-basins in the Northern Territory. A brief description of the other projects used for the benchmarking exercise is provided below with focus on critical emission sources such as the gas and condensate flare rates.

3.1 Buru – Canning Basin - TGS14 Project

Buru Energy carried out a HFS program in four wells Yullaroo-3, Yullaroo-4, Valhalla North-1 and Asgard-1 Wells in 2014, these wells were constructed in 2012/13 and the integrity of the wells were assessed prior to the HFS program in 2014 [7]. The activities for Tight Gas Pilot Exploration Program (TGS14) consist of hydraulic fracturing to stimulate the vertical component of the tight gas reservoir, the well flowed back and the resultant flow of gas and liquid hydrocarbons from the well was then measured and analysed over a period of time. The maximum well test flow rate of 2 mmscf/d was used during the tests where gas was flared over the 3-month testing period. Condensate removed from the well test separator was stored on site and trucked out for sales.

3.2 Origin - Betaloo Basin – Valkerri Project

Origin filed an Environmental Management Plan (EMP) for drilling, HFS and well testing of Velkerri 76 S2 exploration well on EP 76 in the Betaloo Basin in the Northern Territory in accordance the NT Petroleum (Environment) Regulations 2016, Code of Practice: Onshore Petroleum Activities in the Northern Territory [8]. The exploration well will consist of 2000-3000 m vertical component and horizontal section of 3000 m. The well testing program is planned for 3-12 months. A well testing rate of 2.5 TJ/d is envisaged with 37.5 bbl/d of condensate produced. The condensate will be flared along with the well test gas in a vertical flare.

3.3 Origin - Betaloo Basin – Kyalla Project

Origin has also filed EMP for a multi-well drilling, stimulation and well testing program in Kyalla 117 N2 [9]. Origin obtained approval for the Kyalla 117 N2-1H well in 2019 and have applied for Kyalla 117 N2-2H and Kyalla N2-3H drilling, HFS and well testing to utilise multi-well pads to improve efficiency and reduce environmental footprint in 2021. The program is intended to optimise multi-well pad layout of surface operations for potential future development scenario with the core objective of minimising the environmental footprint, including minimising land clearance, maximising water reuse and reducing greenhouse gas emissions. The exploration well will consist of 1500 m lateral length for 1H well and 2800 m lateral length for 2H and 3H wells. The well testing program is planned for 3-6 months. A well testing rate of 1.5 TJ/d is envisaged with 15 bbl/d of condensate produced. The condensate will be flared along with the well test gas in a vertical flare.

3.4 Santos – McArthur Basin EP161 Project

Santo has filed an EMP for a multi-well drilling, stimulation and well testing program with Tanumbirini 1, Tanumbirini 2H and Inacumba 1/1H wells in 2019[10]. The exploration well will consist of 2000 m lateral length for both wells. The well testing program is planned for 3-12 months. A well testing rate of 1.55 mmscf/d is planned with condensate produced will be trucked out of site and not flared.

3.5 Imperial – McArthur Basin – Carpinteria 1

Imperial filed an EMP with NT EPA for the drilling of the Carpentaria 1 well in EP 187 in the McArthur Basin for the vertical pilot well and with no HFS activities [11]. The drilling program will include inflow and production testing of the vertical zone where gas would be flared at 1.2 mmscf/d over a 90 day period.

3.6 Comparison of HFS Exploration and Appraisal Projects

A comparison table is provided summarizing project datal along with the Valhalla E & A Project.

Project	List of Wells	No of Wells	Lateral Drilling, m	HFS	Gas Flare Rate	Condensate Flare Rate	Test Period
Origin -Kyalla	Kyalla 117 N-1H Kyalla 117 N-2H Kyalla 117 N-3H	3	1500-1800	Y	1.5 TJ/d	15 bbl/d	3-12 months
Origin - Valkerri	Velkerri 76 S2	1	3000	Y	2.5 TJ/d	37.5 bbl/d	3-6 months
Santos - McArthur	Tanumbirini x 2 Inacumba x 1	3	2000	Y	1.55 mmscf/d	NA	3-12 months
Imperial - Carpenteria 1	Carpenteria 1	1	NA	N	1.2 mmscf/d	NA	3 months
Buru-TGS14	Yulleroo 5 Yulleroo 6 Valhalla North 1 Asgard 1	4	NA	Y	2 mmscf/d	NA	3 months
BNR -Valhalla	Phase I - Refer ERD	6	1500	Y	5.9 mmscf/d	118 bbl/d	2-3 months
	Phase II- Refer ERD	14	3000	Y	10.7 mmscf/d	214 bbl/d	2-3 months

Table 3-1: Exploration & Appraisal Project Comparison Summary

3.7 Benchmarking Exercise

All Exploration and Appraisal projects are different and have unique components, for the purpose of this benchmarking comparison, the exploration wells with horizontal drilling and HFS was compared with the Valhalla E & A Program, hence the BuruTGS14 and Imperial Carpinteria 1 programs were not used for the benchmarking exercise.

In order to benchmark projects for their GHG emissions, typically, GHG emissions intensity values are calculated on a 'tCO2e per tonne of product' basis for manufacturing projects or 'tCO2e per kWh' basis for power generation projects such that project emissions can be compared. GHG emission intensities from gas exploration projects cannot be compared on such a basis. Therefore, couple of methods were used to benchmark the Valhalla E & A program gas exploration project emissions along with the Origin and Santos exploration programs. GHG emissions intensities on a per Well per Test Day for the Valhalla wells along with other projects is shown in Figure 3-1. The results clearly indicate significantly more emission from the Valhalla well tests per day due to its higher well test flow rates per day. It should be noted that the Origin and Santos test programs are planned for a significantly longer period from up to 3-12 months compared to 2-3 months for Valhalla. Therefore, another comparison could be made based on the planned minimum and maximum total emission per well from these exploration and appraisal programs. Figure 3-2 provides planned total emission per well from these projects.

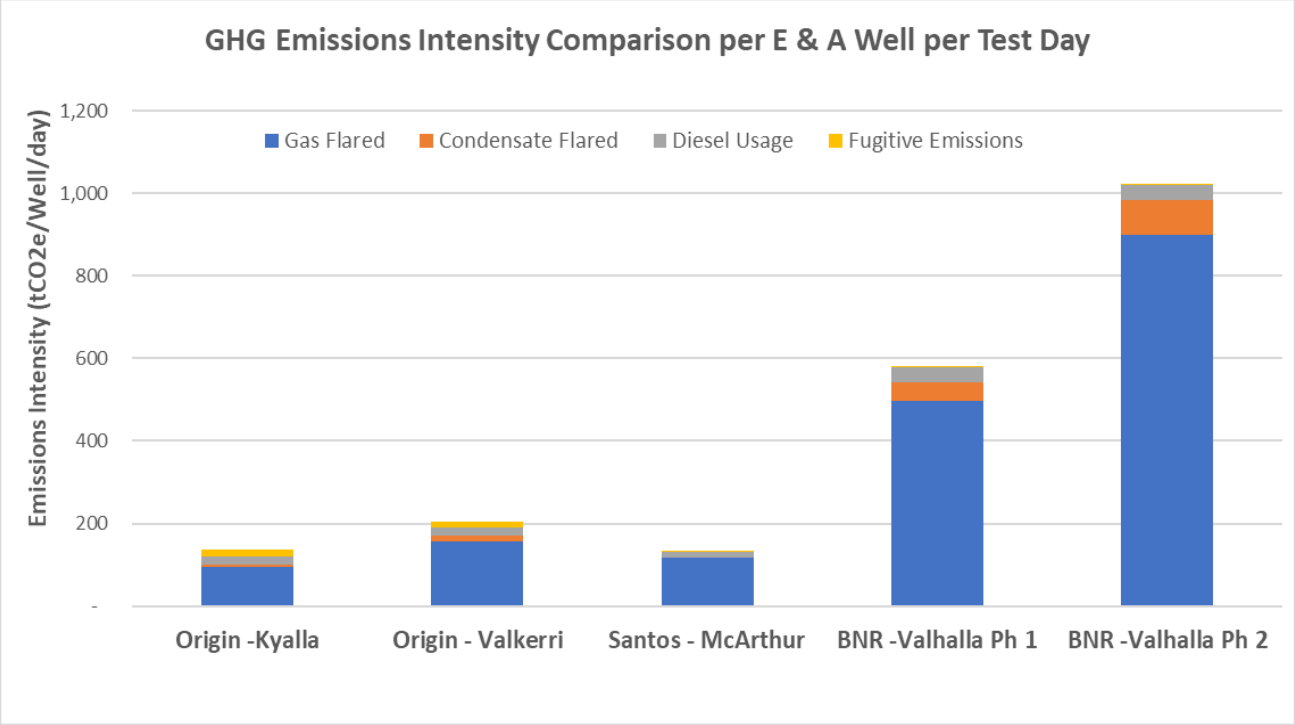


Figure 3-1: Benchmarking GHG Emission of the Valhalla E&P Program per Well per Test Day

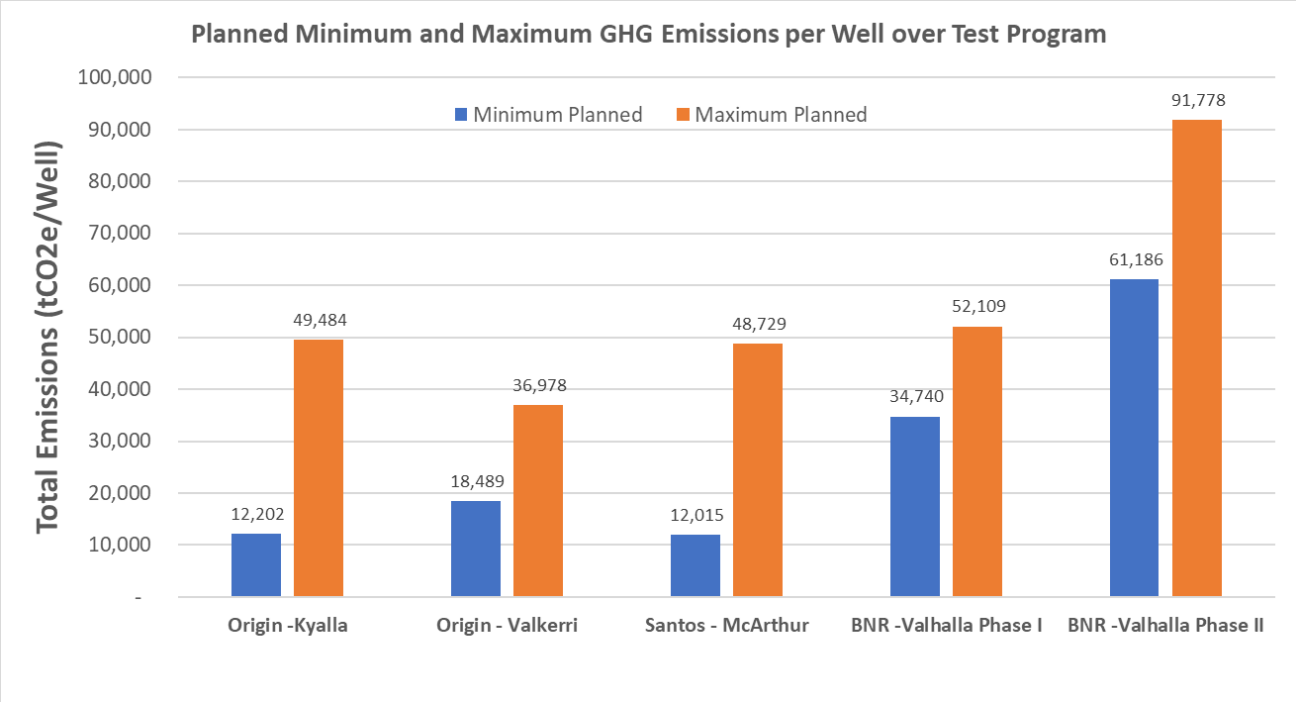


Figure 3-2: Benchmarking GHG Emission of the Valhalla E&P Program for planned toral emissions per Well

The results indicate the Valhalla Phase I emissions are compatible with the permitted/planned total emissions of other projects in the Beetaloo Basin in the NT. The Valhalla Phase II emissions are higher

than the other projects due to its higher flow test rates which is at the later part of the project. It should be also noted that Origin-Kyalla prgram is based on 3 wells, Origin-Valkerri program is based on 1 well and Santos-McArthur program is based on 2 wells while Valhalla Phase I is based on 6 wells and Valhalla Phase II is based on 14 wells. The Valhalla E & A program provides a complete scale of the development program for the Valhalla field while the other project proponents have only provided the very early part of their E & A program.

3.8 GHG Emissions comparison with State and National Emissions

The following table provides a comparison of the total Valhalla E & A program GHG emissions from the 20-well program over the proposed two timelines as a percentage of the state and national GHG emissions.

	mtCO2e	**% of State Emissions**	**% of National Emissions**
Annual WA State Emissions[1] (2019)	91.85		
Annual Australian National Emissions[2] (2019)	529.30		
Valhalla - Timeline #1 (3 Years)	1.59	0.58%	0.10%
Valhalla - Timeline #2 (7 Years)	1.59	0.25%	0.04%

[1] Based on 2019 WA GHG emissions. [2] Based on 2019 National GHG Emissions.

Table 3-2: GHG Emissions compared to State and National Emissions

The GHG emissions from the Valhalla E & A program contributes to a small fractional increase in the state GHG emissions and a much smaller fractional increase in the national GHG emissions.

4 GHG Emissions Reduction Assessment

This section outlines the measures incorporated into the Valhalla Exploration and Appraisal Program to reduce GHG emissions and reduce overall carbon footprint of the project. The following measures have been evaluated for the drilling and HFS operations as Reduced Emissions Completions (RECs), as recommended in the WA Scientific Inquiry into Hydraulic Fracking for the mitigation of greenhouse gas emissions.

4.1 Use of single pad for multiple horizontal drills.

Single well-pad vertical designs result in significantly less land clearing. The use of efficient multi-well pad horizontal shale development results 50%-60% reduction in land use as shown in Figure 4-1.

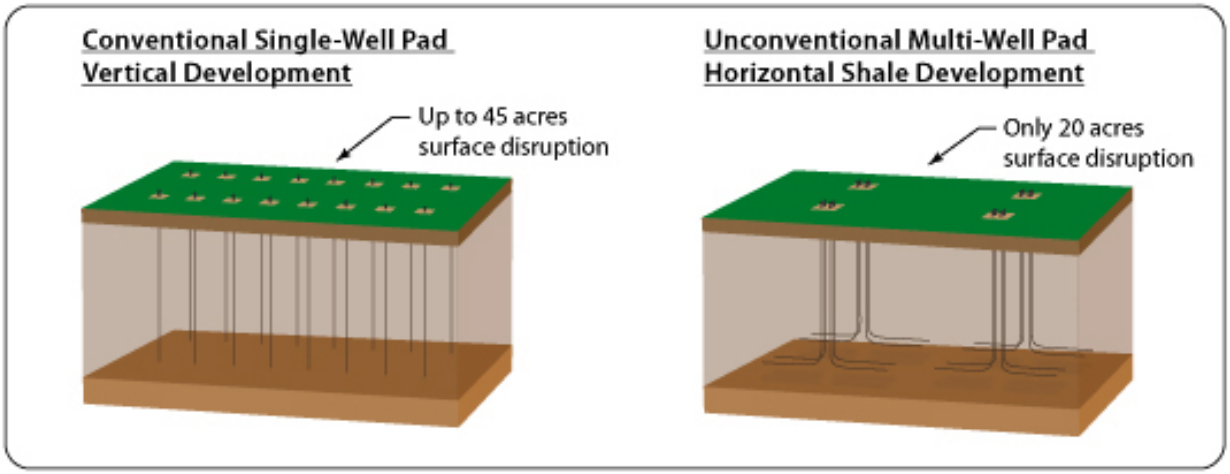


Figure 4-1: Single v Multi Well Pad designs

The Valhalla Exploration and Appraisal program utilizes 10 well pads for drilling 20 wells, implementing an efficient multi-well drilling technique to minimize land clearing. The minimization of land clearing reduces the impact associated with GHG emissions associated with the removal of vegetation. A total land cleared for the 20 well program is 102 ha of which 40 ha is associated with the well sites, therefore reducing overall land cleared by around 40%.

4.2 Use of latest (Tier 4 – US or Stage V -EU) diesel engines.

The diesel engines used for the drilling and HFS operations will employ the latest efficient units with highest emission standards. The Tier 4 diesel engines have 90% lower NOx and PM emission compared to Tier 3 engines and are fuel efficient resulting 15% GHG emissions reduction. In Europe, Stage V is the latest and the strictest tier of these regulations for emissions with regards to upstream oil and gas applications.

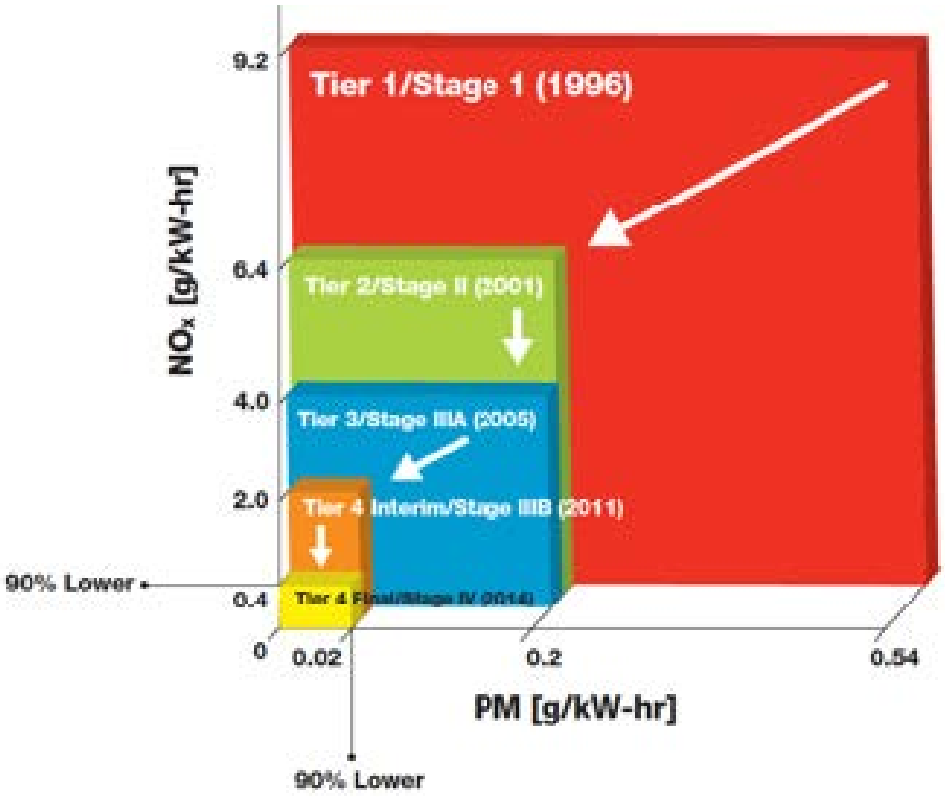


Figure 4-2: Tier 4 Diesel Engine Performance

4.3 Collection and sale of condensate.

As recommended by the WA Hydraulic Fracking Inquiry Report the well construction activities Reduced Emissions Completions (REC) should be employed where feasible so that gas and condensate is captured for sale or other use. The well test fluids during the exploration and appraisal program could be passed via a sand trap and 3-phase separator to remove water and condensate from the gas where the condensate could be stored and trucked out of site for sales to a refinery. BNR is currently evaluating options for the sale of condensate produced from the well tests via Wyndham Port to Singapore, where Buru Energy already exports its oil.

4.4 Flare Design

Gas venting is avoided during the well completions and well tests and only permitted for operational or safety reasons. Gas flaring is carried out in accordance with Code of Practice requirements and as per US EPA 40 CFR 63.11, with a flare tip combustion efficiency of 98%. Two separate vertical stacks, one for flowback high pressure gas and a second low pressure flare to manage tank vapors (off storage tanks) would be used to ensure all methane at site is flared. Both flare systems would utilize an auto-ignite system, gas assist, and a single pilot.

Figure 4-3: Multi-Stack Vertical Flare for low-pressure and high-pressure gas

4.5 Gas Capture

The Canning Basin does not have any gas infrastructure such that the flow test gas can be treated and sent to a gas pipeline for sale. Therefore, the only possibility would be to capture the gas as Compressed Natural Gas (CNG) or utilising Mini-LNG facilities as described below and supply it to energy users in the Kimberley.

4.5.1 Compressed Natural Gas

The well test gas would be required to be dehydrated and compressed to around 250 bar to be stored in high pressure storage bullets which can then be used in gas engines for power generation in Well Test sites instead of diesel. CNG can also be transported to power stations in Broome, Derby and other west Kimberley towns to replace LNG trucked from Karratha at present. CNG could also be used in duel-fuel engines for the drilling and HFS operations within the Valhalla E & A Program if equipment with suitable

engine specifications is available locally. At present the sale of gas as CNG is considered unviable due the associated cost of capture, treatment and transportation to markets located far from the Valhalla field.

Figure 4-4: CNG utilisation in duel-fuel engines (Source: GTUIT)

4.5.2 Micro LNG

A relocatable micro-LNG plant could also be used to capture the well head gas (as used in some US shale gas operations) if this equipment were available in the Australian market. The use of micro-LNG option would require the well head gas to be pretreated such that water, CO2 and freezable heavy hydrocarbons are removed from the gas to allow liquefaction of the gas. The LNG produced can then be stored in transportable ISO containers and shipped to markets.

Cryobox™ is a mini-LNG technology and other similar flare gas liquefaction technologies that provides relocatable pre-treatment units as used in US shale gas industry [12].

Figure 4-5: Well head gas capture via Mini-LNG (Source: CryoBox)

At present the sale of LNG to local power stations is considered unviable with existing gas offtake contracts in place with power plant operations and the inability for the project proponents to commit to a fixed volume based LNG supply contract from the gas exploration and appraisal program.

4.5.3 Renewables

The use of renewable energy such as solar PV for powering the drilling and HFS operations are impracticable as significant number of solar panels will be required to be placed over a large area. The solar PV power also need to be supported with large batteries that can store energy to be supplied during the nights. Therefore, resulting in significantly higher costs. Further, the rigs and HFS units need to be re-located to various sites during the drilling program which will make the use of renewable energy impracticable. A better alternative would be to use grid power if available, for the drilling operations, while the grid is supported by renewable power. The Canning Basin and Valhalla region does not have such a grid to support the project. However, solar powered lighting towers with batteries backup are planned to be used in the project as shown in Figure 4-5 along with and other solar power based instrumentation and monitoring systems.

Figure 4-5: GHG Mitigation Measures for the Projects

4.6 GHG Mitigation Summary

The 7-year 20 well Valhalla Gas Exploration & Appraisal program provides the complete scale of the planned drilling and HFS activities associated with the evaluation of the Valhalla formation. Significant part of the GHG emission of an exploration and appraisal drilling program is associated with the well test flow rates and the duration of the well tests. The overall GHG emission estimates are also dependent on the number of wells drilled in Phase I and Phase II of the program with potentially multiple drilling campaigns. The total number of wells drilled will highly depend on the success of each drilling campaign.

The maximum direct emission from the Valhalla E & A program was estimated as 1,597,856 mtCO2e over the 7 years. The following GHG mitigation measures in accordance with the EPA hierarchy of avoid, reduce, offset GHG emissions are discussed below.

4.6.1 GHG Emissions Avoided

By incorporating industry best practice design the following measures were utilized in the Valhalla E & A program to minimize GHG emissions,

(1) Multi-pad Well design: The Valhalla E & A program utlises 2 horizontal wells per well pad to minimize land clearing. The estimated GHG emission avoided is 2,300 tCO2e for the project.
(2) Dual-stack LP/HP Flare: Separate Low Pressure (LP) and High Pressure (HP) flares are used as part of the design to combust tank vapours and well test gas separately ensures any low pressure methane emissions on site is avoided. The estimated GHG emission avoided is 10,000 tCO2e.

4.6.2 GHG Emissions Reduction

The following GHG emission reduction measures are currently being assessed to further reduce project GHG emissions.

(1) Condensate Sale: The sale of condensate produced during the well tests currently being actively pursued by BNR as discussed previously. This would avoid up to 129,943 tCO2e of GHG emissions on site during the project period.
(2) Dual-Fuel Engines: The capture, dehydration, compression and storage of well test gas would allow it to be used in dual-fuel engines reducing the use of diesel and the associated emissions during the drilling and HFS operations. The estimated GHG reduction is around 33,500 tCO2e over the project life.

Further to the above, it is envisaged the well test rates, well testing period and the number of appraisal wells can be reduced with learnings from each drilling/HFS campaign in Valhalla which will significantly reduce gas and condensate flaring and associated emissions.

Figure 4-6 provides a summary of GHG mitigation measures considered part of the GHG reduction exercise.

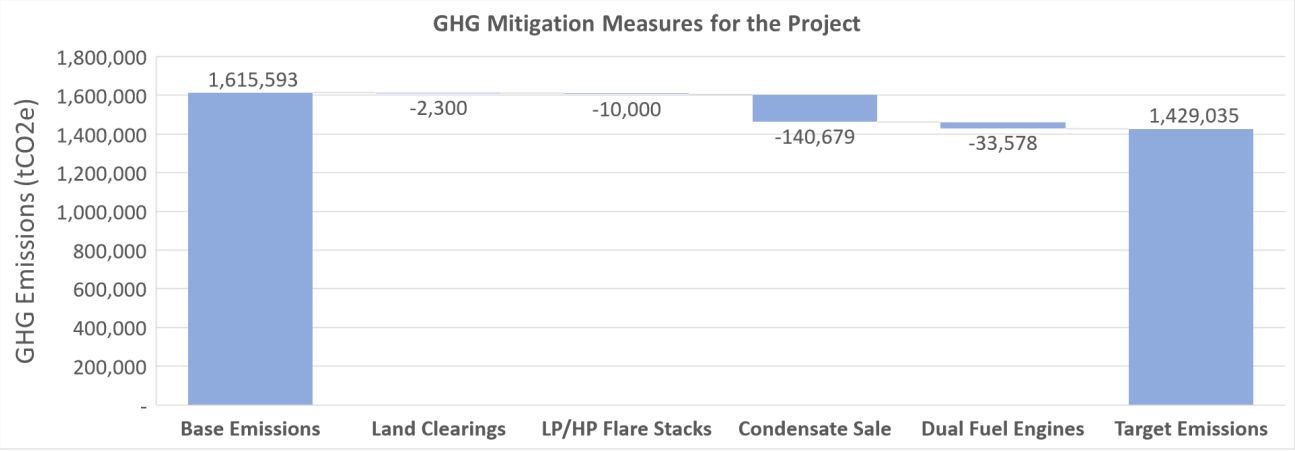


Figure 4-5: GHG Mitigation Measures for the Projects

The following section provides more details of the GHG offset requirements along with an estimate of GHG estimate for the project.

5 Valhalla E&A Program GHG Emissions v EPA NetZero 2050 Target

The WA EPA has been actively pursuing GHG emissions reduction in the state as the emissions from the state have increased by 11% in the past decade, mainly due to the commissioning of new LNG projects in the northwest of the state. The WA EPA has mandated emissions reduction targets for projects with more than 100,000 tCO2e/year of GHG emissions. The EPA has requested project proponents demonstrate a trajectory of carbon emissions reductions towards NetZero by 2050. Refer to ESD Requirement 78 for Valhalla Project.

5.1 Valhalla NetZero Targets

The two possible Program timelines considered for the Valhalla E & A program are, Timeline #1 - 3 years from 2024 and Timeline #2 – 7 years from 2024 are shown in Figure 5-1 along with the EPA NetZero 2050 trajectory based on the year 2020 baseline set by the EPA. Based on the EPA assessment of exploration phase emissions of a shale gas development, the project would have to either reduce or offset the emission above its target emissions as shown in Figure 5-1 for each of the years of the Valhalla E&A Program.

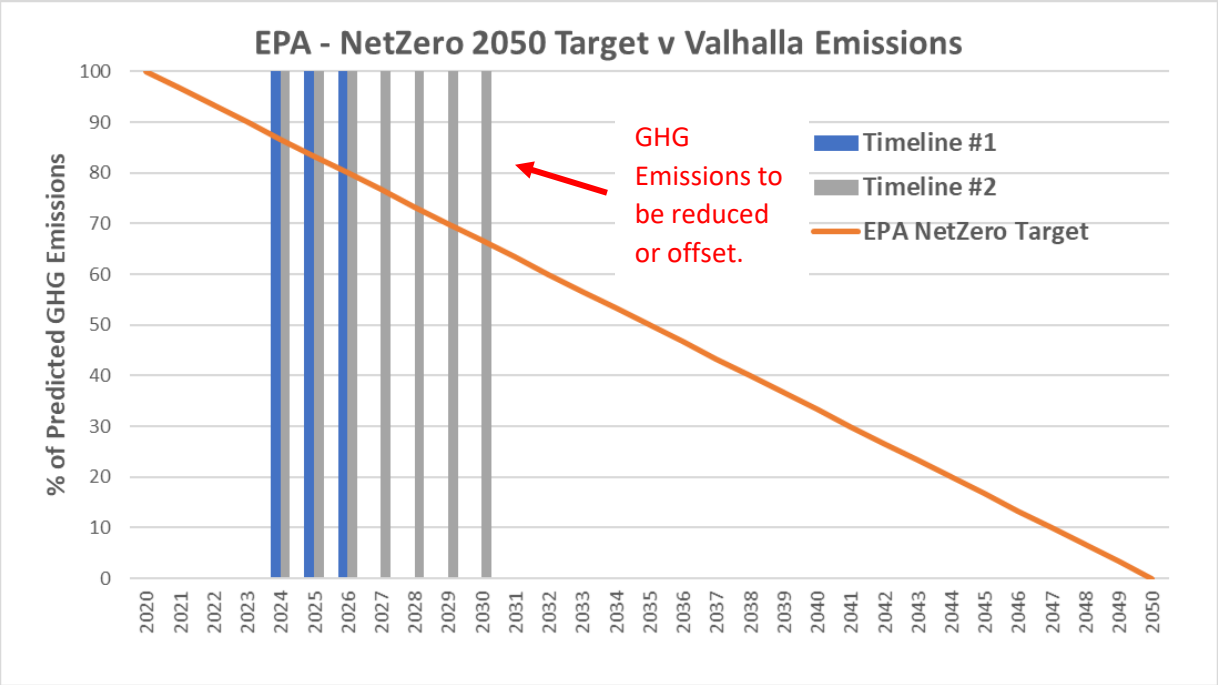


Figure 5-1: EPA NetZero Target v Valhalla Emissions

Table 5-1 provides a quantitative estimate of maximum GHG emissions and the reductions/offsets that could be mandated by EPA under the NetZero 2050 trajectory for the Valhalla E & A program under each of the two timelines considered. Depending on how EPA would assess a shale gas exploration project, BNR may or may not be required to offset part of the GHG emissions associated with the Valhalla E & A program beyond the annual EPA NetZero targets.

It should be noted that the GHG emissions offset/reduction quantities are much less for the optimistic drilling program Timeline #1 from 2024-2026 compared to Timeline #2. Hence, it would be beneficial for BNR to commit to a faster overall development timeline in a NetZero carbon environment.

Year		Timeline #1				Timeline #2			
		No of Wells	Max.Annual Emissions	Reduction Target	Reduced Emissions	No of Wells	Max.Annual Emissions	Reduction Target	Reduced Emissions
			tCO2e	%	tCO2e		tCO2e	%	tCO2e
1	2024	6	314,378	13	41,913	2	104,793	13	13,971
2	2025	7	644,457	17	107,399	2	104,793	17	17,464
3	2026	7	644,457	20	128,879	2	104,793	20	20,956
4	2027					3	276,196	23	64,439
5	2028					3	276,196	27	73,645
6	2029					4	368,261	30	110,467
7	2030					4	368,261	33	122,742
Total		**20**	**1,603,293**		**278,190**	**20**	**1,603,293**		**423,684**

Table 5-1: Annual GHG Emissions and Targeted Emission reduction under EPA NetZero 2050

The EPA NetZero target and the offset/reduction requirement information can be shown below in a graphic form over the two proposed Timelines as show in Figure 5-2 and 5-3 below.

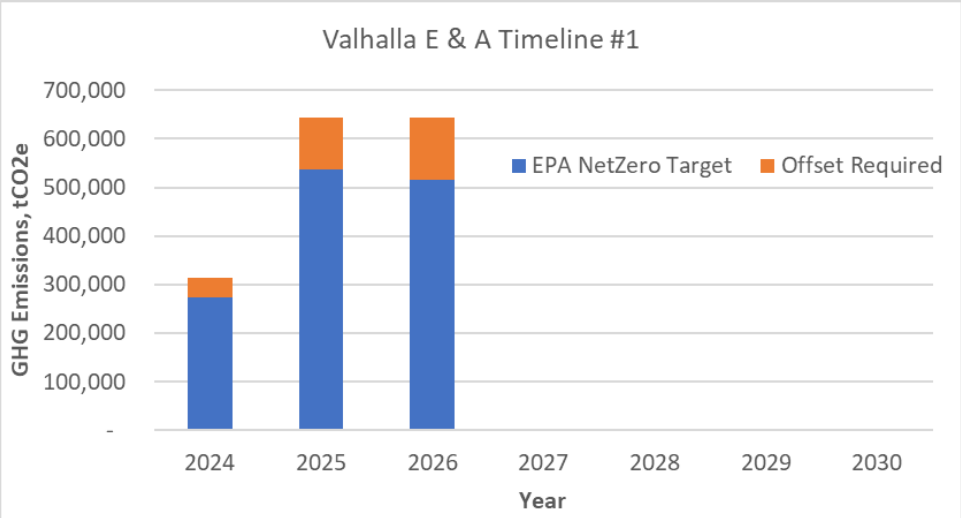


Figure 5-2: Timeline #1 - EPA NetZero Target v Emissions Offsets

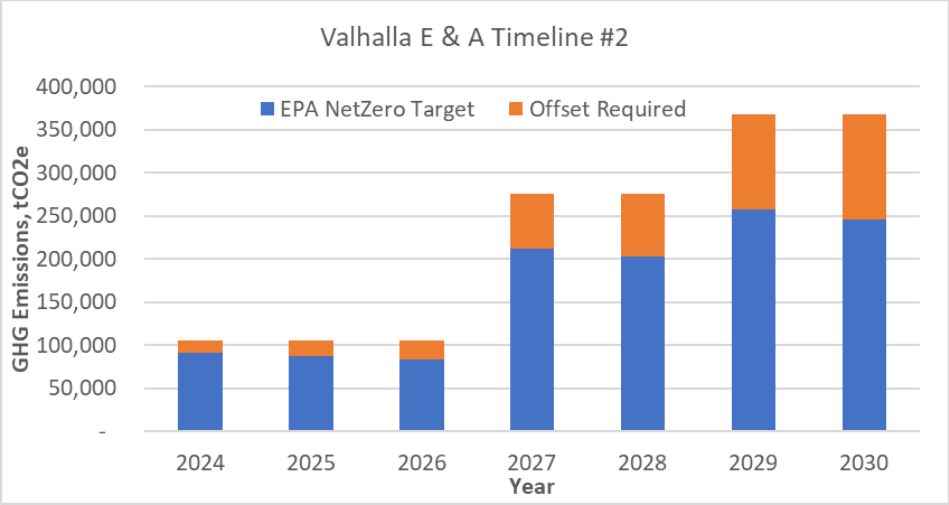


Figure 5-3: Timeline #2 - EPA NetZero Target v Emissions Offsets

EPA requires that the project proponents provide compelling reasons for not meeting the NetZero 2050 trajectory. As described in sections 4.5 and 4.6 reasonably practical measures such as sale of condensate and the use of dual fuel engines is currently evaluated and may be undertaken at some point to minimize GHG emissions if appropriate equipment is available and reasonably practicable to apply. This will enable the project to reduce annual emission by around 8-10%. The capture and sale of all well test flow gas is not viable due to a lack of gas markets close by and the unpredictable nature of an exploration and appraisal drilling program which cannot commit to the sale of fixed volumes and time frames unlike in a gas plant. BNR will be required to assess annual emissions and when deemed to have exceeded the EPA NetZero 2050 trajectory targets the project proponents could utilize authorized offsets mechanisms to meet these targets.

5.2 GHG (carbon) Offsets

The EPA advises that where carbon offsets are to be implemented, they should meet offset integrity principles and be based on clear, enforceable and accountable methods. For example, the EPA recognises Australian Carbon Credit Units(ACCUs) issued under the Carbon Credits (Carbon Farming Initiative) Act 2011 (Cth) as meeting these standards. Compliance offsets under the Safeguard Mechanism, as well as voluntary offsets purchased to reduce residual emissions, may contribute to a proponent's Greenhouse Gas Management Plan and will be recognised by the EPA [2].

BNR Climate Change Policy (June 2021) has committed to NetZero by 2050 and the Valhalla E & A Program is committed to progressively reduce emissions over the years to achieve this target. Depending on how EPA would assess a shale gas exploration project, BNR may or may not be required to offset part of the GHG emissions associated with the Valhalla E & A program beyond the EPA NetZero targets via an accredited Australia Carbon abatement program.

5.3 GHG Emissions Reporting

The WA EPA supports the requirements for proponents to periodically report against their interim targets as outline in their GHG Management Plan. EPA prefers this reporting to be aligned with the five-year milestone set out in Article 4 of the Paris Agreement. The EPA will also consider undertaking its own periodic statewide reporting, under section 16(i) of the EP Act, to provide public advice on GHG emissions and the progress of mitigation measures developed and implemented by major proposals within WA [2]. The Valhalla E&A program will meet all state and national GHG emissions reporting requirements.

It should be noted that corporate reporting thresholds for GHG emissions are much lower under the National Greenhouse and Energy Reporting Act 2007 (NGER Act) where 25,000 tCO2 per facility and 50,000 tCO2 per corporate group is mandated.

6 Concluding Remarks

The Valhalla E & A Program GHG emissions estimate was carried out based on the information provided by BNR for the drilling program and the HFS operations. The calculations and other relevant information are provided in a separate spreadsheet (NimblEng Valhalla GHG Emissions Estimate Rev G) as part of this report.

Hydraulic Fracture Stimulation (HFS) or fracking of shale gas formations has been carried out in Australia for over the past 50 years, with over 900 production wells have been fracture stimulated in the Cooper-Eromanga Basin in South Australia and Queensland[13]. Out of the 10,664 CSG wells drilled in Queensland, 8.8 percent have been hydraulically fractured within the Surat and Bowen Basins up until December 2017 [14]. The lifting of the moratorium on HFS in 2019 in Northern Territory has seen projects in the Beetaloo Basin ramp up over the past couple of years under the new Code of Conduct set by the NT Government. Similarly, the WA government is working on introducing its own Code of Conduct for the Shale Gas industry based on the WA Scientific Inquiry on Hydraulic Fracturing. One of the main concerns related to the shale gas industry has been associated with the GHG emissions during exploration, appraisal and development activities of the upstream sector due to the higher number of wells associated with shale gas projects and the flaring associated with the development compared to conventional gas field developments. Therefore, it is essential for the project proponents to tackle this issue early in the project and provide adequate GHG mitigation measures throughout the lifecycle of the project.

The WA EPA Assessment of the Valhalla Gas E & A program will be the first hydraulic fracturing project in WA since the lifting of the moratorium. The Environmental Protection Act process requires that proponents prepare detailed Environmental Impact Assessment (EIA) information that provides the public and regulatory agencies with the data they require to decide on project approval. The Environmental Management Plan (EMP) documents filed by proponents in the Beetaloo Basin in NT EPA over the past 3 years provides good guidance for projects in WA with respect to their EMPs.

The Valhalla E&A program annual emission could range from 100,000 – 600,000 tCO2e per year depending on the number of wells drilled in a year, and the total GHG emissions could range from 1,093,000 to 1,603,300 tCO2e depending on the number of test days utilised per well. In comparison the recently approved Waitsia Stage 2 Gas Project with a 250 TJ/d export capacity has annual emissions of 300,000 tCO2e/y, and the proposed Pluto LNG Train 2 has annual emissions of 1,465,000 tCO2e/yr. Therefore, one would expect EPA to scrutinise the Program's GHG emissions and proposed mitigation measures in detail. The Waitsia Stage 2 Gas Plant Project has committed to offset all CO2 associated with the feed gas from the onset of the project and has committed to further reduce emissions as per the Figure 6-1 in line with EPA's NetZero 2050 trajectory [15]. Woodside's 2 train Pluto LNG facility has committed to reduce or offset emissions in order to meet WA EPA NetZero 2050 target as shown in Figure 6-2 [16].

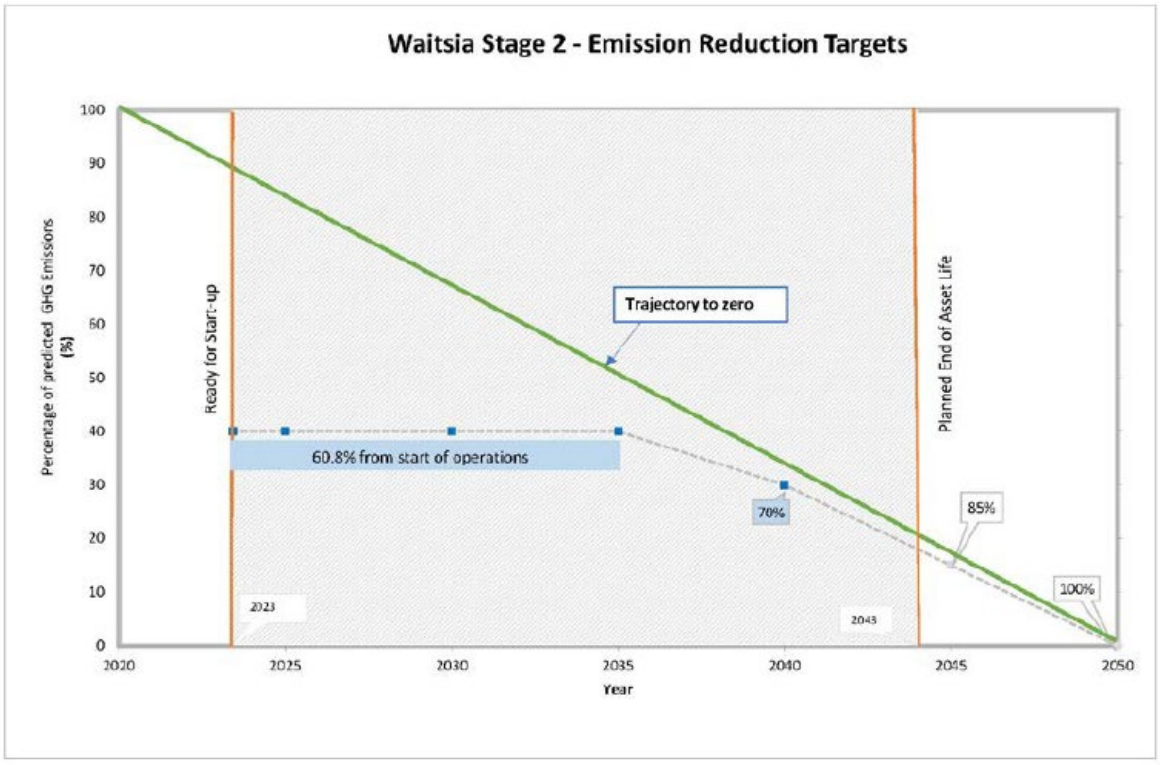


Figure 6-1: Waitsia Stage 2 Gas Plant NetZero Target (Mitsui E &P 2020)

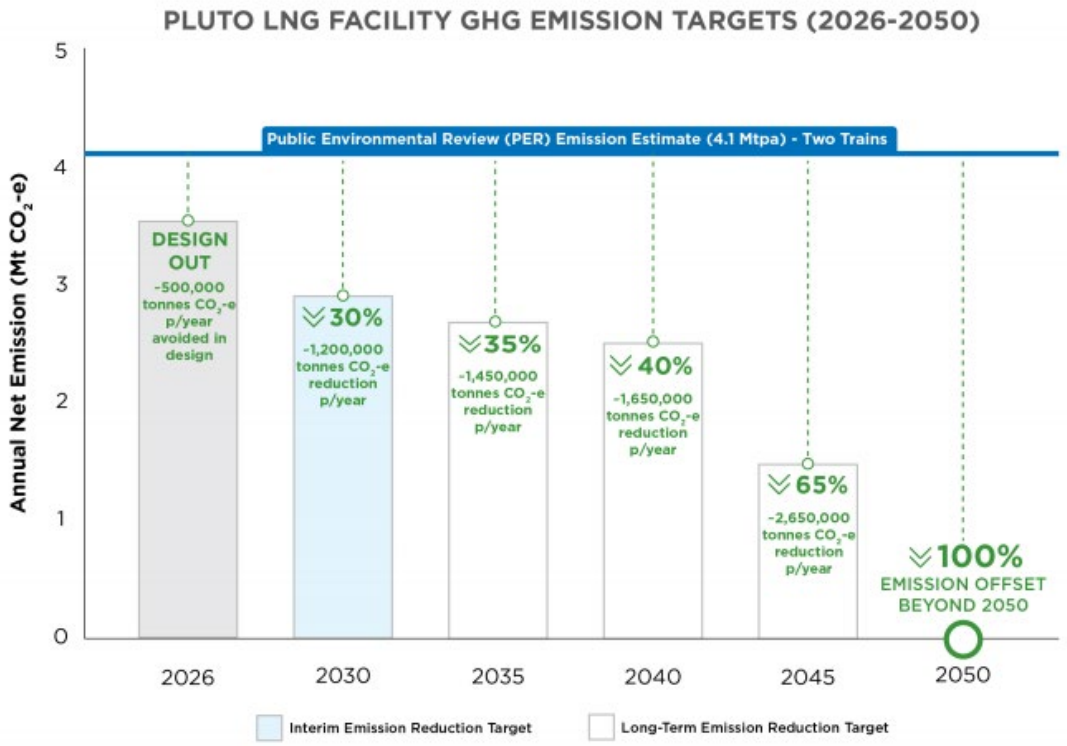


Figure 6-2: Pluto LNG Train 2 NetZero Target (Woodside, 2021)

The nature of an exploration and appraisal program does not allow project proponents to provide firm annual emissions estimate unlike a gas plant or an LNG plant. When developing a gas field, the execution and evaluation of each drilling campaign plays a significant role in subsequent drilling campaigns, number of wells, duration of the well tests and associated GHG emissions. The uncertain nature of the drilling campaigns does not allow project proponents to commit to upfront investment in gas and condensate capture and sales infrastructure from the onset of the exploration program. Therefore the Valhalla project proponents will be required to carefully evaluate capital costs of various capture options and ensure reasonably practical measures are undertaken to reduce emissions as much as possible while providing offsets when EPA NetZero emissions targets are deemed to be exceeded. This is also in line with other project in WA who are drilling conventional exploration and appraisal wells in the state and are currently flaring gas at the exploration phase of their projects. One possible alternative for BNR is to negotiate with EPA and agree to 'carry forward' mechanism for the carbon emissions from the exploration and appraisal phase in full or in part to the production phase and offset these emissions at the later part of the project.

Based on the current maximum flare rates over the 20 well E & A program a volume of nearly 17 bcf of gas and 334,000 bbls of condensate could be flared. At a sale price of 2 $/GJ for gas and 30 $/bbl for condensate puts the value of these hydrocarbons around $ 45 million. The maximum emissions above the EPA NetZero trajectory that requires to be offset could be as high as 423,700 tCO2e over the project life, which at a carbon price of $50/tonne could cost over $21 Million for the project. The Australian Carbon Credit Units (ACCUs) are currently trading at $21/tCO2e and several operators are currently using a carbon price of up to $80/tCO2e as part of their project costs to account for carbon emissions costs. BNR should carefully assess the impact of carbon price for the entire project while evaluating the GHG emissions reduction measures such as capture and utilization of gas as CNG or LNG from the project over the exploration, appraisal and development phase.

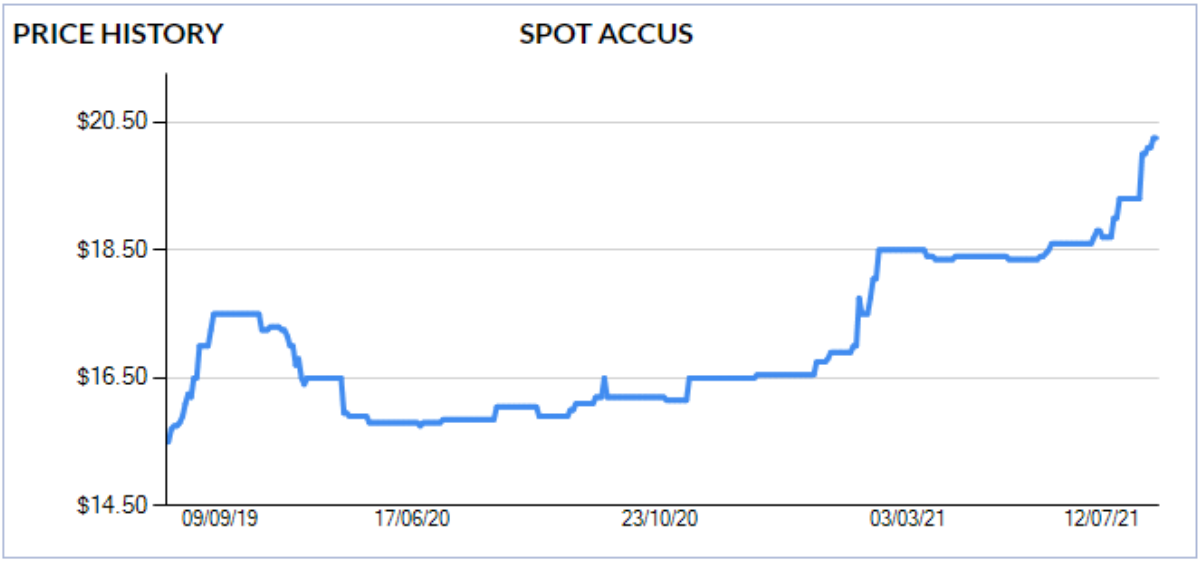


Figure 6-3: Australian Carbon Credit Units Price (July, 2021))

The Western Kimberley region utilises LNG trucked from Karratha (located nearly 1000km away) in Power plants in Broome, Derby and other remote towns. These power plants are operated by Energy

Developments Limited (EDL) who also operate the mini-LNG plant in Karratha to produce and supply LNG via multi-trailer trucks to these power plants. The total gas demand of these power plants range from 6-10 TJ/d. EDL is a potential customer if part of the gas can be captured and sold as LNG at an appropriate price.

The NetZero 2050 target set by the West Australian government has been a challenge for all gas developers in the state. The carbon abatement associated with the shale gas well tests during the exploration, appraisal and development phase of the project creates a bigger challenge in developing the Canning Basin due to the lack of existing gas infrastructure and a pipeline to market. The Canning Basin shale gas project proponents need to look at innovative concepts to capture this gas and get it to market as opposed to flaring at site where economically feasible. This would also help overcome public perceptions and regulatory pressures while providing confidence to the industry in setting a pathway for low-carbon shale gas development in the state. BNR is uniquely positioned to bring their US expertise in developing state-of-the-art low-carbon footprint shale development to Australia compared to other local shale developers.

7 Reference

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Appendix C Third party independent review of the GHG EMP