Gas Infrastructure Cost

Building Block costs for gas infrastructure

AEMO

15 May 2025

→ **The Power of Commitment**

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The Power of Commitment

Executive summary

Background

The Australian Energy Market Operator (AEMO) requires a comprehensive dataset to support its forecasting and planning functions, particularly for the 2026 Integrated System Plan (ISP). This dataset will include costs and operating parameters for both natural gas and renewable gas infrastructure, such as hydrogen and biomethane technologies.

The data will inform a wide range of modelling and forecasting publications and is provided in 2024 Australian Dollars, reflecting costs appropriate for Australian conditions.

Scope

This report details cost information for natural gas and renewable gas infrastructure to be used in AEMO's forecasting and planning studies. The data will be critical for market simulation studies and the ISP, adhering to the Australian Energy Regulator's Forecasting Best Practice Guidelines. This report looks to provide data that is:

- Accurate and unbiased cost estimates for a typical Class 5 estimate.
- Defendable costs suitable for publication and stakeholder engagement.
- Disclosure of basic inputs, assumptions, and methodology.
- Effective stakeholder consultation and access to data and documentation.

Deliverables

The content includes infrastructure costs for the east coast gas system and interconnected Northern Territory gas system, along with a cost forecasting method extending to the financial year 2054/55. Specific requirements cover:

- Natural Gas Infrastructure: Costs and technical life for pipelines, processing facilities, compression facilities, storage facilities, and LNG import terminals.
- Renewable Gas Infrastructure: Costs and technical life for hydrogen and biomethane technologies, including transport and storage options.
- Cost Forecasting: Forecasts reflecting changes beyond inflation, considering factors like competition and resource availability.

All costs are provided with locational granularity, aligning with ISP subregions, and suitable for public sharing on AEMO's website.

GHD will provide two supporting datasets to accompany this detailed report which explains our assumptions and methodology. This ensures transparency to facilitates stakeholder engagement.

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1. Introduction

AEMO requires a comprehensive dataset to support its forecasting and planning functions related to the cost of expanding and operating traditional gas development infrastructure, as well as renewable gas options, and include a cost forecasting approach across the planning horizon to 2054 for use in the 2026 ISP.

This study by GHD provides the first study for AEMO with reliable and comprehensive data to support its critical energy infrastructure planning and forecasting activities.

The asset types reviewed in this study are:

1. Natural gas pipelines, processing facilities, compression facilities, storage facilities,
2. LNG import infrastructure and all associated equipment,
3. CCS-related infrastructure,
4. Converting existing natural gas infrastructure to a hydrogen blend,
5. New hydrogen transport options including trucking, pipelines, and salt cavern storage,
6. Biomethane production,
7. Coal seam gas desalination plants, and
8. Water pipelines related to desalination plants

Key information studied regarding these assets is understanding the capital cost for new plant and the expected technical lives for each asset type. However, regarding natural gas infrastructure already plays a critical part within the Australian energy market, additional information is provided for new natural gas infrastructure such as:

1. Lead time for building,
2. Operating cost,
3. Cost of upgrading the capacity,
4. Cost of refurbishing existing assets,
5. Cost of retirement and decommissioning, and
6. Expected technical life for existing natural gas pipelines

This report, and accompanying dataset, will be publicly shareable, free of confidential or commercial information that cannot be disclosed. This transparency is crucial for stakeholder engagement and ensuring that data can be widely accessed and utilised without legal or commercial restrictions.

1.1 Purpose of this report

This report, and accompanying dataset, provides detailed cost information for gas development infrastructure, such as pipelines, storage facilities, production/processing facilities, compression facilities, and LNG import terminals, as well as costs and operating parameters for renewable gas options like hydrogen and biomethane technologies. The cost forecasting methodology applied to these elements are also described in this report

1.2 Context

This report is the first compilation of gas infrastructure costs compiled for AEMO. At a conceptual level this report has the similar objective as the Transmission Cost Database (TCD), which helps guide AEMO in estimating the cost of new electricity transmission infrastructure.

The information in this report and supporting databases, is aligned as far as practical with the structure and forecasting methodology used for the TCD. However, there are fundamental differences that need to be understood when reading this report and using the supporting databases, these are:

- The TCD is a more mature database, being in its third iteration. In addition, the quantity of new project information available for Transmission infrastructure is significantly higher. Particularly due to the high volume of work being undertaken currently due to the energy transition. The optimal development path in the 2024 ISP lists the following number of major transmission projects, 5 as committed and anticipated, 5 as already actionable, 7 as newly actionable, and 5 as future ISP project. This provides the ability to interrogate Transmission project costs in a far more granular capacity than gas project costs. In comparison the number of major gas transmission or process plants being planned on the east coast of Australia is two gas processing plants that would supply the domestic market, and additional compression facilities as part of APA's East Coast Expansion, and a number of other assets proposed but not yet at FID. The ability to break down gas project costs into the same cost elements as the TCD, or to have similar asset granularity as the TCD, is not viable currently.
- With the inclusion of gas production assets in this report, the scope of this report covers a far wider range of assets than the TCD. Sourcing data as detailed as the TCD, for such a wide range of assets, presents challenges not dealt with in this project's timeframe.
- Gas production is significantly impacted by the geological nature at each gas reservoir. This will lead to material variance in production establishment and operating costs from asset to asset, and over the development of a project with these costs not fully known until operations commence and reliable production has been established. Presenting this range of costs, in a usable format for AEMO, that portrays the wide range of subsurface considerations, has not been established in this report. Therefore, the costs presented in this report are at a sufficiently high level to cover the most likely production establishment and operating costs. In general, the costs presented are appropriate for a Class 5 level estimate. However, users of this information need to be aware of the unique uncertainties involved in gas production facilities due to subsurface unknowns.
- Land and biodiversity costs have a far large impact on Transmission lines than on pipelines. Transmission lines have far larger footprint, as electricity easements typically need to be between 70 m to 90 m wide. It is generally also easier and cheaper to change pipeline routes, compared to electricity transmission routes, to avoid high-cost land or land that has significant community resistance. Therefore, the cost of land and biodiversity are included in the unit rates provided, as opposed to having ringfenced costs that can be distinctly altered by users.

1.3 Limitations

This report: has been prepared by GHD for AEMO and may only be used and relied on by AEMO for the purpose agreed between GHD and AEMO as set out in Master Suppliers Agreement signed between Australian Energy Market Operator GHD Pty Ltd on 9 July 2024.

GHD otherwise disclaims responsibility to any person other than AEMO arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described throughout this report. GHD disclaims liability arising from any of the assumptions being incorrect.

Accessibility of documents

If this report is required to be accessible in any other format, this can be provided by GHD upon request and at an additional cost if necessary.

GHD has prepared the costs estimates set out throughout this report using information reasonably available to the GHD employee(s) who prepared this report; and based on assumptions and judgments made by GHD. All cost related information being in real Australian Dollars for base estimates, with separate allowances for escalation or inflation.

The Cost Estimate has been prepared for the purpose of informing AEMO of current construction an operating costs of gas related infrastructure and must not be used for any other purpose.

The Cost Estimate is an estimate, relevant to Class 5 estimates only. Actual prices, costs and other variables may be different to those used to prepare the Cost Estimate and may change. Unless as otherwise specified in this report, no detailed quotation has been obtained for actions identified in this report. GHD does not represent, warrant or guarantee that the projects can or will be undertaken at a cost which is the same or less than the Cost Estimate.

Where estimates of potential costs are provided with an indicated level of confidence, notwithstanding the conservatism of the level of confidence selected as the planning level, there remains a chance that the cost will be greater than the planning estimate, and any funding would not be adequate. The confidence level considered to be most appropriate for planning purposes will vary depending on the conservatism of the user and the nature of the project. The user should therefore select appropriate confidence levels to suit their particular risk profile.

GHD excludes and disclaims all liability for all claims, expenses, losses, damages and costs, including indirect, incidental or consequential loss, legal costs, special or exemplary damages and loss of profits, savings or economic benefit, Client may incur as a direct or indirect result of Mater Cost Database for any reason being inaccurate, incomplete or incapable of being processed on AEMO's equipment or systems or failing to achieve any particular purpose. To the extent permitted by law, GHD excludes any warranty, condition, undertaking or term, whether express or implied, statutory or otherwise, as to the condition, quality, performance, merchantability or fitness for purpose of the Mater Cost Database.

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1.4 Assumptions

The following assumptions and limitations apply to this study:

- All cost related information being in real Australian Dollars for base estimates, with separate allowances for escalation or inflation.
- The asset types covered are only as specified in this document, gas distribution systems are not included in the pricing or services proposed.
- GHD is not responsible for any qualitative or quantitative errors in its report resulting from errors in the publicly available material used in the assessment.
- GHD cannot predict what will happen in the future, noting that there are known unknowns and unknown unknowns (e.g., possible future asset liabilities and defects) that can and will occur in the future.
- GHD does not represent, warrant, or guarantee that development of the assets can be achieved with the estimates provided.
- Consideration of the potential impacts of changing legislation including those relating to climate change and carbon emissions, has not been included in this study.
- CAPEX estimates will be provided as order of magnitude estimates (AACE Class 5 as per 18R-97: Cost Estimate Classification System as Applied in Engineering, Procurement and Construction for the Process Industries). OPEX considerations will be based on typical industry percentages.
- Costs in foreign currencies have been converted into AUD using the conversion rates in the table below. These ratios are the average exchange rates from June 2024[1].

Table 1 Currency conversion rates

Foreign currencies	Foreign currency to AUD	AUD to foreign
USD	1.5043	0.6648
EUR	1.6198	0.6174

[1] Data taken from Reserve Bank of Australia

1.5 Abbreviations and Acronyms

Table 2 Abbreviations and Acronyms List

Abbreviation / Acronym	Definition
AACE	Association for the Advancement of Cost Engineering
ACCC	Australian Competition and Consumer Commission
AD	Anerobic Digestion
AER	Australian Energy Regulator
AGS	Aboveground storage
APPEA	Australian Petroleum Production and Exploration Association
BoP	Balance of Plant
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CSG	Coal Seam Gas
CSTR	Continuously Stirred Tank Reactor
DN	Diameter Nominal
DOE	Department of Energy
FEED	Front End Engineering Design
FID	Final Investment Decision
FSRU	Floating Storage Regassification Unit
FTE	Full time effort
GSOO	Gas Statement of Opportunities
GWI	Global Water Intelligence
HDPE	High Density Polyethylene
IEA	International Energy Agency
LNG	Liquified Natural Gas
LPG	Liquid Petroleum Gas
MEG	Mono-ethylene Glycol
MIJ	Monolithic Insulation Joint
MIT	Mechanical Integrity Test
MMSCFD	Million standard cubic feet per day
MTPD	Maximum Tolerable Period of Disruption
MW	Megawatt
NGL	Natural Gas Liquids
OPEX	Operating Expenditure
OEM	Original Equipment Manufacturer
PJ	Petajoules
SEK	Swedish Krona
TEG	Tri-ethylene Glycol
TJ/d	Terajoules per day
tpa	tonnes per annum
UGS	Underground Storage
VTS	Victorian Transmission System
WTP	Water treatment plant

2. New Assets Capital Cost

2.1 General

This section is based on publicly available sources where this is readily available, where not then GHD experience in delivery of projects for clients has been utilised. There are a mix of project delivery experience in industry within the asset types, with broad categories as follows:

– Traditional asset types:
- Natural gas pipeline
- Natural gas production plant
- Natural gas compression
- Natural gas storage
- Coal seam gas water treatment plan
- Coal seam gas water pipeline

– Asset types new to Australia:
- LNG import facilities
- Carbon capture and storage
- Salt caverns
- Biomethane
- New asset types:
- Hydrogen blending
- Hydrogen

This level of history in delivery of these projects should be considered when considering the cost estimation. With new technologies and asset types new to Australia being considered more likely to have higher degree of uncertainty than when compared to traditional asset types.

An additional consideration is given to the facilities that interface with subsurface reservoirs, there is inherent variability in dealing with reservoirs, both in production and in storage operations. This uncertainty exists into the operating stage of these asset types, and owners of these assets typically carry a higher rate of return to cover this risk.

2.2 Natural Gas Pipelines

2.2.1 Buried Pipeline

Buried pipelines are essential for transporting natural gas between production facilities, storage locations and consumers.

Buried pipeline equipment include:

- Line pipe
- Coating
- Cathodic Protection
- Pipeline valves

- MIJs
- Cold field bends
- Induction bends
- Pig launchers and receivers

The costs provided in this section include the listed equipment along with construction and installation activities. In Australia, the governing standard nominated by the State Regulators for gas pipelines and associated gas facilities is the "AS 2885 Pipelines – Gas and liquid petroleum" suite of standards.

It should be noted that all states have their own requirement associated with pipeline licencing regimes, however these do not materially change the capital cost.

The two main cost elements for a pipeline are the tonnage of steel required in the form of line pipe and the construction of the pipeline. Each of these cost portions are typically in the order of 30% each of the overall capital costs for the establishment of a new gas pipeline.

The class 5 cost estimate base input cost for a pipeline is $75,000 per inch diameter by the number of kilometres of pipeline length. The inch diameter is the nominal outside diameter as specified in API Specification 5L for Line Pipe, noting this is not the actual outside diameter. The ratio can be converted utilise the metric outside diameter equivalent ($3,000 per mm diameter), however the industry typically uses the imperial version. This base calculation then has the factors nominated below applied to the base output.

These costs are based on internal pipeline cost estimation model. This model uses market costs for equipment to ensure it is relevant with current prices. Additionally, this model is calibrated using quotes from pipeline construction contractors to ensure they align with current construction costs.

Two approaches are provided for cost for a capacity, these are a nominal capacity per diameter for a nominal length, this is provided in the table below, and an online an online basic tool to estimate pipeline diameter for a given capacity, and then using the online tool for a specific set of conditions.

Table 3 *Pipeline Capacity per Diameter for Common Sizes for Nominated Lengths*

Nominal Pipeline Diameter (mm)*	Pipeline Length (km)	Nominal Capacity (TJ/day)	Estimated Capital Cost
DN250	100	67	$ 75,000,000
DN300	100	108	$ 90,000,000
DN350	100	140	$ 105,000,000
DN400	100	204	$ 120,000,000
DN450	100	284	$ 135,000,000
DN500	100	366	$ 150,000,000
DN250	300	38	$ 225,000,000
DN300	300	62	$ 270,000,000
DN350	300	80	$ 315,000,000
DN400	300	118	$ 360,000,000
DN450	300	164	$ 405,000,000
DN500	300	212	$ 450,000,000
DN250	500	29	$ 375,000,000
DN300	500	48	$ 450,000,000
DN350	500	62	$ 525,000,000
DN400	500	91	$ 600,000,000
DN450	500	127	$ 675,000,000

Nominal Pipeline Diameter (mm)*	Pipeline Length (km)	Nominal Capacity (TJ/day)	Estimated Capital Cost
DN500	500	164	$ 750,000,000

*The nominal pipeline diameter is not the actual outside diameter of the pipeline, the outside diameter is stipulated in API 5L. Publicly available tables of nominal outside to actual outside diameter are available from piping suppliers such as in the provided reference [2].

The above capacities we derived from utilising the online basic pipeline sizing tool is available CheCalc website[3].

The key assumptions used include the following:

- Inlet pressure 10,200 kPag
- Outlet pressure 6,000 kPag
- Flowing temperature 20 Degrees Celsius

The online basic pipeline sizing tool is available CheCalc website[4]. This uses simplified equations to size a gas pipeline, these equations have been used historically to size gas pipelines.

To utilise this tool to obtain an approximate gas pipeline diameter a conversion of the energy flow rate to volume flow rate is required. Where the approximate conversion rate is 1.0 MMSCFD is 1.059 TJ/day.

The other parameters are then entered dependent on the specific pipeline service parameters to obtain the required pipeline diameter. This diameter is then used to calculate the base cost using the $75,000 per inch diameter by the pipeline total length.

The cost of the steel tonnage is mainly affected by the market forces at the time of the procurement of the line pipe and is normally represented as cost per tonne. This figure is generally reflective of global steel demand, and this price needs to be considered as an influencing factor to the cost of line pipe.

The construction costs associated with a new gas pipeline build are the most variable and can increase the overall project costs materially dependent on the difficulties expected to be encountered during the build. The potential variances in the main attributes that affect the pipelines constructability are the difficulties that are expected to be encountered in:

- Terrain
- Location
- Length

The various project factors when then be applied as required dependent on the attribute being considered specific to the pipeline project. The application of the factors that are applied to the respective attributes nominated above are discussed below.

Terrain Factor

The terrain factor considers the terrain in which the pipeline is to be built, where construction productivity reduces with more difficult the terrain due to slower construction progress.

For the nominated build detail / description as described in the Adjustment Factors Table the terrain attribute adjustment factors applicable to the standard cost input would be expected to be as follows:

Table 4 Terrain Factors Table A

Detail / Description	Adjustment Factor	Description
Terrain Factor - Standard	1	If the terrain is flat or gently undulating where all work sites access can be easily established.
Terrain Factor - Medium	1.4	If the has steep hills and significant depressions or benching and excavation is only needed seldom (or can

[2] https://www.atlassteels.com.au/documents/Pipe_Dimensions_chart_rev_Jan_2012.pdf
[3] **CheCalc - Natural Gas Pipeline Sizing**
[4] **CheCalc - Natural Gas Pipeline Sizing**

Detail / Description	Adjustment Factor	Description
		be avoided with relative ease by relocating the planned structure to near vicinity).
Terrain Factor - Difficult	2	If the terrain topography gradient is rugged with steep incline and significant gullies or benching and excavation are frequently needed to obtain acceptable horizontal and vertical alignment.
Terrain Factor - Special	4	Use of this factor requires careful consideration of the actual special construction technique being applied and the factor being applied will be required to be adjusted accordingly and specialist assistance in determining the applicable adjustment factor is recommended. Situations where this factor would be applied is described below.

The adjustment factor needs to be applied to the length of pipeline construction affected and not the entire length.

The application of the special terrain factor would be applied where the pipeline is to be installed in areas such as large river crossings where directional drilling techniques are required to install the pipeline under the waterway, submerged crossing of an extensive waterway where dredging of the bottom of the waterway is required, areas where the pipeline traverses large quantities of extremely hard rock where blasting is required or where swampy semi-submerged grounds is encountered where mass mixing of the soils is required to stabilise the ground along with specialist machinery is required to avoid the bogging of equipment. This factor is generally applied where the installation techniques are extremely time consuming and where productivity factors are very low.

Location Factor

This factor considers the ease of access to project resources such as the supply of labour, plants, ports, and transportation facilities. This considers the distance and the ease of access to manpower, machinery and materials of construction.

For the nominated build detail / description as described in the Adjustment Factors Table the location attribute adjustment factors applicable to the standard cost input would be expected to be as follows:

Table 5 Location Factors Table A

Detail / Description	Adjustment Factor	Description
Location Factor – Urban	1	The Urban factor assumes that the works close to the supply of labour, plants, ports, transportation facilities, knowledge and any other required resources.
Location Factor – Regional	1.2	As a regional area is geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.
Location Factor – Remote	1.4	As a remote area is significantly geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.

The adjustment factor is typically applied to the entire length of the pipeline.

The Location Factor is not applicable to areas of suburbia and high-density population, estimation of costs for pipelines in this application are outside the scope of this report.

To estimate for an offshore pipeline, a location factor of 3 is recommended.

Length Factor

A length factor is applied for shorter length pipelines due to the ratio of fixed to variable becoming non-linear. This is due to fixed costs such as mobilisation and demobilisation, engineering, approvals, administrative and legal expenses that are normally ratioed across the much larger project variable costs, such as steel, labour, and machinery start to distort the Class 5 estimate basis of cost per inch kilometre cost basis. As a result, the shorter the pipeline than the base 100 km the more expensive the build is from a “Cost” per “Inch” per “Kilometre” perspective.

It is worth noting, significant effort was spent on calculating land and biodiversity costs for the TCD. However, land and biodiversity costs for a gas pipelines are materially less of a factor, compared to electricity transmission lines. High voltage electricity transmission lines typically require easement widths of between 70 m to 90 m. For a typical gas transmission pipeline, it is generally around 6 - 10 meters. In addition, ability to re-route gas pipelines is generally simpler, than for electricity transmission lines. Making it easier to avoid areas of high land costs or areas that have significant community resistance, such as high populated areas. With gas pipelines being buried, it also helps alleviate community resistance, reducing the costs associated with long term community engagement.

For the nominated build detail / description as described in the Adjustment Factors Table the length attribute adjustment factors applicable to the standard cost input would be expected to be as follows:

Table 6 Length Factors Table A

Detail / Description	Adjustment Factor	Description
Length Factor – > 100 km	1	This represents standard pipeline construction projects where the overall length is 100 km or longer where all the indirect project costs are distributed across the project.
Length Factor – < 100 km	1.2	This factor represents an increase in the ratio of variable vs fixed costs where the fixed cost become more significant in the total costs for shorter pipelines.

The application of the length factor is binary in nature where the pipeline is either shorter than or greater than 100 km.

2.2.2 Conversion of Existing Pipelines to Natural Gas Service

An alternative to building a new pipeline is conversion of a pipeline that was built to AS2885 Pipelines – Gas and liquid petroleum, or a suitable alternative prior to the development of AS2285. This process is called a conversion of service, and requires an engineering assessment to be completed to confirm that the pipeline will meet the relevant requirements of structural integrity and safety. This process has been used in North America on large pipeline systems, mostly to convert natural gas pipelines to crude oil service. However, there have been conversions for other fluid types.

In Australia, the vast majority of AS2885 pipelines are in natural gas service, with other fluids including crude oil, refined products, and high vapour pressure liquids. The other pipelines are generally not considered to be material for use in natural gas service due to various factors, mostly due to location and limited transportation capacity for natural gas service. Broadly, the main gas transmission systems in East Coast Gas System are able to have material capacity added via additional compression.

The conversion costs are specific to the asset and are dependant on the outcomes of the change of service engineering assessment. Therefore, it is not possible to provide direct costs.

2.2.3 Pipeline Stations

Pipeline stations are above ground facilities that are normally located on the inlets and outlets of a pipeline system and are generally used to control the delivery pressure and / or flow rate of gas into and out of the pipeline system.

The usual major components of a pipeline station are:

- Dry gas filter(s)
- Custody transfer metering
- Water bath heater(s)
- Pressure / flow control valving
- Associated supporting infrastructure such as control rooms, generators and utility supplies.

– Pipeline stations although essential for the operability of a pipeline system, they represent minimal capital expenditure is comparison the buried gas pipeline system.

From the recent GHD estimate and with the nominated through put of the station in terajoules per day a base outcome to utilise for the estimating pipeline station capital cost of $5.6 M for 100 TJ/day capacity.

A scaling factor of 0.6 [5] is to be applied for changes in facility capacity. A 0.6 factor has been applied as this is seen as reasonably representative for the scaling for a pipeline station. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility
- V2 = Capacity of proposed facility
- Alpha = Scale factor

2.3 Natural Gas Production Plant

2.3.1 Conventional Gas Plants

Conventional gas plants are above ground facilities that supply gas to a pipeline system. The purpose of the gas plant is to treat the raw natural gas sourced from the underground reservoir to sales gas pipeline quality requirements at the nominated delivery flow rates and pressures. This section only covers the production plants and does not include the wells and gathering systems.

A conventional gas production plant will include:

- Slug catcher
- Compression
- Dehydration units (TEG or molecular sieve)
- MEG units
- Produced water system and storage
- Cold vent and flare
- Pressure vessels
- Liquid hydrocarbon separation and storage (dependent on the reservoir fluids)
- Associated supporting infrastructure such as control rooms, pipework, generators and utility supplies.

As a conventional gas plant where hydrocarbon liquids are required to be processed, there is a variety of additional equipment required to purify the gas stream and separate the hydrocarbon liquids

From the recent GHD estimate and with the nominated through put of the plant in terajoules per day a base outcome to utilise for the estimating of other conventional gas facilities a capital cost of $235 M for 200 TJ/day capacity.

A scaling factor of 0.6 [6] is to be applied for changes in facility capacity. A 0.6 factor has been applied as this is seen as reasonably representative for the scaling for a base plant prior to other factors being applied. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility

[5] **Scale economies and the "0.6 rule" - ScienceDirect**
[6] **Scale economies and the "0.6 rule" - ScienceDirect**

- V2 = Capacity of proposed facility
- Alpha = Scale factor

This approach is shown to align to an industry accepted “Rule of Thumb”[7] for Class 5 estimation of total gas plant project cost is 3 to 5 times the major equipment cost.

Location Factor

The location factor considers the ease of access to project resources such as the supply of labour, plants, ports, and transportation facilities. This considers the distance and the ease of access to manpower, machinery and materials of construction.

For the nominated build detail / description as described in the Adjustment Factors Table the location attribute adjustment factors applicable to the standard cost input would be expected to be as follows:

Table 7 Location Factors Table B

Detail / Description	Adjustment Factor	Description
Location Factor – Urban	1	The Urban factor assumes that the works close to the supply of labour, plants, ports, transportation facilities, knowledge and any other required resources.
Location Factor – Regional	1.2	As a regional area is geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.
Location Factor – Remote	1.4	As a remote area is significantly geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.

2.3.2 Coal Seam Gas Plants

Coal seam gas (CSG) plants are above ground facilities that supply gas to a pipeline system. The purpose of the gas plant is to treat the raw CSG sourced from the underground coal seams to sales gas pipeline quality requirements at the nominated delivery flow rates and pressures.

A CSG production plant will include:

- Inlet Water Separation
- Compression
- TEG units
- Produced water system and storage
- Cold vent and Flare
- Pressure vessels
- Associated supporting infrastructure such as control rooms, pipework, generators and utility supplies.

Based on recent plant estimations and comparing to public data for coal seam gas facilities, the base case for the scaling equation is a capital cost of $38 M for 32 TJ/day capacity. A scaling factor of 0.5 is to be applied for changes in facility capacity. A 0.5 factor has been applied as this is seen as reasonably representative for the scaling for a base plant prior to other factors being applied, and is a lower scaling than a convention plant due to less leveraging of common equipment and infrastructure at the facility. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility

[7] **From Idea to Investment: Rules of Thumb for Project Costing | Process Group Limited**

- V2 = Capacity of proposed facility
- Alpha = Scale factor

This approach is shown to align to an industry accepted "Rule of Thumb"[8] for Class 5 estimation of total gas plant project cost is 3 to 5 times the major equipment cost.

Location Factor

The location factor considers the ease of access to project resources such as the supply of labour, plants, ports, and transportation facilities. This considers the distance and the ease of access to manpower, machinery and materials of construction.

For the nominated build detail / description as described in the Adjustment Factors Table the location attribute adjustment factors applicable to the standard cost input would be expected to be as follows:

Table 8 Location Factors Table C

Detail / Description	Adjustment Factor	Description
Location Factor – Urban	1	The Urban factor assumes that the works close to the supply of labour, plants, ports, transportation facilities, knowledge and any other required resources.
Location Factor – Regional	1.2	As a regional area is geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.
Location Factor – Remote	1.4	As a remote area is significantly geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.

2.4 Natural Gas Compression Facility

Compression Facilities are above ground facilities that are located on a pipeline or a stand-alone facility that services several pipelines. The primary function of these facilities is to boost the pressure of the gas to maintain a pipeline flow rate or to enable the gas to meet a pipeline receipt pressure.

These facilities include the following main equipment:

- Compressors
- Heat exchangers
- Fuel gas system
- Instrument air system
- Cold vent
- Pressure vessels, piping and valves
- Associated supporting infrastructure such as control rooms, pipework, generators and utility supplies

The cost range for a compression facility is $3,000,000/MW to $6,400,000/MW of installed compression power. This is based on industry rules of thumb for class 5 estimates [9] .

For this report, the following simplifications and assumptions are proposed to enable estimation of capacity of compressor stations and costs.

- Configuration is one duty and one standby compressor unit a compressor station, and a typical simple Australian mainline compressor station configuration, therefore used the high end of the industry cost range used
- One compressor vendor has been used for simplicity to provide turbine power selections, nothing there are multiple options available in the market

[8] **From Idea to Investment: Rules of Thumb for Project Costing | Process Group Limited**
[9] Costs from "The Palgrave Handbook of International Energy Economics" 2022.

- Only turbine driven compressors considered
- Turbine power linked to diameter range
- Pipeline diameter ranges are limited to most common size ranges for transmission pipelines in Australia
- Pipeline MAOP not considered, however pipelines assumed as operating between 10,000 kPag and 15,000 kPag
- This is based on long-distance pipelines that have typical pipeline diameter to pipeline length relationships
- Where these simplifications and assumptions are not valid it is recommended to have a specific engineering assessment completed to estimate compression requirements

The table below provides guidance for the capacity per compressor station as a percentage of the original pipeline capacity. The results from estimating the capacity per compressor station would need to be added to the original pipeline capacity with no mainline compressor stations.

Table 9 Compressor Station Estimation

Pipeline Diameter Range (mm)	Nominated Turbine Power (MW)	Compressor Station Capex	Assumed Compressor Station Spacing Range	Capacity Per Compressor Station*
DN250	1.85 (equivalent to a Solar Saturn 20)	$24 m	50 km to 80 km	Pipeline original capacity x (compressor station spacing/pipeline length)
DN300 to DN400	3.5 (equivalent to a Solar Centaur 40)	$45 m	80 km to 100 km	Pipeline original capacity x (compressor station spacing/pipeline length)
DN450 to DN600	5.7 (equivalent to a Solar Taurus 60)	$73 m	100 km to 150 km	Pipeline original capacity x (compressor station spacing/pipeline length)

*This is a simplification and assumes a linear capacity relationship with the addition of each compressor station.

Assumptions in using this information:

– Where a pipeline has an existing compressor station unit size, it should be assumed that this size is used for capacity expansion.

– This is for long-distance pipelines where the length is greater than 300 km. For shorter pipelines the capacity increase requires de-rating.

– Were a pipeline is partially looped it is recommended to have a specific engineering assessment completed to estimate compression requirements

Location Factor

This factor considers the ease of access to project resources such as the supply of labour, plants, ports, and transportation facilities. This considers the distance and the ease of access to manpower, machinery and materials of construction.

For the nominated build detail / description as described in the Adjustment Factors Table the location attribute adjustment factors applicable to the standard cost input would be expected to be as follows:

Table 10 Location Factors Table A

Detail / Description	Adjustment Factor	Description
Location Factor – Urban	1	The Urban factor assumes that the works close to the supply of labour, plants, ports, transportation facilities, knowledge and any other required resources.

Detail / Description	Adjustment Factor	Description
Location Factor – Regional	1.1	As a regional area is geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.
Location Factor – Remote	1.2	As a remote area is significantly geographically distanced from an urban area some adjustment is needed to the already estimated urban cost.

–

2.4.1 Compression Facility Flow Reversal

For the recent compressor facility flow reversal projects where GHD has were involved, the major equipment such as the compressor units and aftercoolers have not been replaced, however dependent on the process condition some compressor modifications may be required. There will be additional pipework, valves, metering, pipe support structures, civil works, instrumentation, and control system changes to enable a bidirectional compressor station.

CAPEX for a compressor facility flow reversal (compressor facility made bidirectional) is expected to be in the order of 10% of a new facility build of the same capacity.

2.5 Natural Gas Storage

This section covers natural gas storage facilities capital cost, this includes Underground Gas Storage (UGS), Aboveground Gas Storage (AGS), and pipeline line-pack storage (line-pack) laterals.

2.5.1 Underground Gas Storage

It is assumed that underground gas storage is based on depleted gas fields and associated production facilities. Currently there are no salt caverns in operation in Australia, and the location of potentially suitable geological formations is such that there appears to no reasonable reason to include this category of gas storage in this section. For underground gas storage facilities to be useful for Southern Eastern Australia winter peak gas demand, they need to be reasonably proximate to the demand centres. Remote gas storage has far smaller benefit in supporting winter peak gas demand.

Underground depleted reservoir gas storage facilities typically consist of the following main items:

- Bidirectional connecting pipeline and metering
- Injection compression
- Injection / withdrawal wells and monitoring wells
- Withdrawal gas conditioning and pipeline injection compression

The costs for UGS in the table below are based on modifying a depleted gas field to develop a gas storage facility. These costs are provided as unit costs for each main asset element. The withdrawal configuration is the determining factor for the capital costs, given it is typical that gas storage facilities are designed for 1:2 ratio on injection to withdrawal capacity. The gas storage volume is broadly not influential in capital costs, as the storage gas volume (working volume) is owned by the facilities users. The storage gas volume is set by the gas field used for storage, limited by the initial volume of the gas field prior to commencement of the original production.

Table 11 Estimated UGS capital costs inputs for 100-250 TJ/day range withdrawal [10]

Element	Typical Cost Rate	Comments
Transmission Pipeline Connection	$0.6 M – 0.9 M/km Pipeline $5.0 – 7.5 M Metering Station	Assumes typical class 600 pipeline connection

[10] Estimated costs from a GHD client confidential report on gas storage, completed in 2022.

Element	Typical Cost Rate	Comments
Surface Gas Compression and Conditioning Facilities	\$1.0 M – 1.25 M / TJ for 100-150TJ/day \$0.65 M - \$0.8 M / TJ for 200 – 250TJ/day	Note where more stringent processing and removal of significant LPG's and NGL's is required processing costs up to \$2.0 – \$2.2 M / TJ have been reported at 120 – 150 TJ/day
Wellhead and gathering	\$5 M / well \$1 M / gathering line	Assumes each well can flow up to 10 TJ/day on withdrawal Well costs assumed as a mix of recompletion of some existing wells and some new wells

Assumptions used in determining the cost ranges in the table above:

- Based on achieving a 100 TJ/day withdrawal rate, using a depleted gas field
- 10 wells with maximum capacity of 10 TJ/day, with a mix of existing wells recompleted for gas storage service and some new wells required
- New flowlines, average of 2 km in length
- New 100 TJ/day gas process facility, to achieve the required gas flow rates and reliability
- 30 km pipeline including custody metering to connect to existing gas transmission network
- There is a reuse of an amount of the existing asset and that no material additional civil works occurs the process facility.

Based on the above inputs and assumptions, the capital cost of a 100 TJ/day withdrawal facility would be approximately \$210 M.

A scaling factor of 0.6 [11] is to be applied for changes in facility capacity. A 0.6 factor has been applied as this is seen as reasonably representative for the scaling for a base plant. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility
- V2 = Capacity of proposed facility
- Alpha = Scale factor

The use of an unproduced field for underground gas storage is considered a limited scenario. This would generally only apply to a marginal gas field (small volume) that was in close proximity to an existing gas transmission system with available capacity that was proximate to winter peak demand locations. It is recommended to apply the scaling factor form the natural gas production plant section and use the public information the Golden Beach project for capital and withdrawal capacity as the base for scaling.

2.5.2 Aboveground Gas Storage

AGS is smaller scale liquified natural gas storage often located in close proximity to demand centres, providing rapid response to peaky loads or unforeseen supply demands or disruptions. AGS is able to start-up quickly in response to demand requirements. These facilities typically use a small-scale liquefaction plant to produce and store LNG from pipeline gas during low demand periods, which can then be revaporised directly back into a pipeline system. The overall cost of AGS is high compared to UGS due to the cost of liquefaction and ongoing boil-off gas management.

AGS storage facilities consist of the following main items:

- Connecting pipeline – liquefaction supply and reinjection point
- Gas conditioning and liquefaction facility

[11] **Scale economies and the "0.6 rule" - ScienceDirect**

- Storage Tank or Tanks (currently Australian facilities have one tank).
- Vaporisation facility
- Boil off gas recompression and reinjection

The storage tankage makes up the largest cost component of an AGS facility cost followed by gas conditioning and liquefaction, with the balance of plant and facilities relatively small. Note that this is different from LNG export facilities where liquefaction rates are substantially higher and storage volumes while large are not intended for long term thus total annual liquefaction capacity is multiples of the storage capacity, whereas in peak shaving the storage capacity is substantially larger than the liquefaction capacity with storage recharge typically being slow and undertaken over a long period in off-peak periods.

AGS capital cost are typically AU$250 M - $275 M per PJ of storage [12] in 2022 dollars with the following typical cost split, as shown in Table 12

Table 12 Estimated AGS capital cost proportions

Facility Component	Typical Proportion of Capex *
Storage	46-50%
Liquefaction	36-40%
Vaporisation and boil-off-gas system	10-14%
Pipeline Connection	2-4%

- *This assumes balance of plant is proportioned across these main facility components.

This is based on similar Australian AGS facilities with 150-250 ton/day liquefaction, and 100 – 200TJ/day vaporisation rates. Variability in some costs like liquefaction exist with consideration of front-end gas conditioning for liquefaction.

2.5.3 Linepack Laterals

Inter-day gas storage adjacent to the site of gas-fired power generation can greatly assist in managing variation in gas demand for power stations that operate irregularly. This type of storage is achieved via lateral pipelines that have a large storage to flowrate ratio. These are known as linepack laterals.

Pipeline linepack storage refers to a volume of gas that is stored at pressure within a gas pipeline and that can be withdrawn through pressure reduction from the pipeline. It takes advantage of the dynamic nature of compressible gas in a pipeline. Linepack lateral storage is typically in the 10 TJ to 25 TJ range. The table below provides a view of capital costs for linepack laterals for a set length and given energy storage quantity. The linepack lateral costs can be linearly extrapolated to the required length or storage volume for the given pipeline diameter, with compression costs held constant.

Where a linepack lateral is considered to be operated in a high-cycle fatigue range, then a 1.5 cost factor should be added to the costs defined below. A linepack lateral would be considered to be in a high-cycle fatigue range under the following criteria:

– Maximum pressure is at or above 14,000 kPag
– Minimum operating pressure is at or less than 40% of maximum operating pressure
– The number of pressure cycles over the life of the pipeline is anticipated to exceed 4,000 cycles

Table 13 Estimated pipeline linepack lateral capital costs for 20 TJ storage

Linepack Lateral Diameter (mm)	DN500 Diameter Lateral	DN750 Diameter Lateral	DN900 Diameter Lateral
TJ/km (approximate)	0.6	1.4	2.1

[12] Estimated costs from a GHD client confidential report on gas storage, completed in 2022.

Linepack Lateral Diameter (mm)	DN500 Diameter Lateral	DN750 Diameter Lateral	DN900 Diameter Lateral
Cost per kilometre	$96,000	$99,000	$100,000
Length to achieve 20 TJ storage	32.3 km	13.9 km	9.4 km
Pipeline Estimated Capital Cost	$61.9 m	$41.3 m	$33.8 m
Compression Estimated Capital Cost	$19.2 m	$19.2 m	$19.2 m
Total Estimated Capital Cost	$81.1 m	$60.5 m	$53.0 m

Assumptions:

- 20 TJ storage used as a nominal amount
- Compression is required. Assumed compression is reciprocating with a gas engine driver, and a power total power of 3 MW at a cost of $6,400,000/MW, resulting in capex of $19.2 M.
- Compressor sizing is limited by pipeline system inflow rate, and this is assumed as limited to such flow that a 3 MW compressor facility is sufficient. This flow is anticipated to be a maximum of 20 TJ/day at reasonably constant hourly rate.
- Recharge of full linepack storage occurs in low gas-transmission system demand periods.

2.6 Natural Gas LNG Import Facilities

The LNG import facilities cover only the LNG Floating Storage and Regasification Units (FSRU) type, and not the onshore LNG tank/s and gasification system for LNG import, as the current and proposed facilities in Australia are of the FSRU configuration. An FSRU is supplied from LNG tankers. The FSRU consists of insulated storage within the vessel, LNG vessel unloading system to receive LNG from import shipments, regassification unit, and flexible connecting hoses / couplings to onshore piping connection to pipeline meter station. The FSRU also requires a heat source to vaporise the LNG, most generally this is via the use seawater as a heat source, which requires environmental approval considerations. Seawater cooling typically requires the application of biofouling controls and temperature impacts to surrounding area. The LNG import facilities are demand balancing infrastructure and therefore located close to demand centres. With the three main characteristics being withdrawal capacity, working storage, and expandability. [13]

There are four proposed or developed storage facilities, which are all FSRU configuration, including one in NSW, two in Victoria and one in South Australia, with details provided in the table below. These FSRUs provide comparatively lower storage capacity compared to underground gas storage, typically 3-4 PJ, but high injection capacity of typically 300 – 600 TJ/d with turndown to 10% achievable, as they generally do not require gas conditioning treatment. FSRU storage and supply cost is comparatively high with LNG price set to international market with additional capital and OPEX cost for facility operation and maintenance (mooring, FSRU lease, and overhead and compliance costs).

Table 14 LNG Import Facilities - Developed and Proposed

Facility	Status	Location	Connection Point	Working Storage Capacity (PJ)	Withdrawal Capacity (TJ/d)	Proposed Online Year	CAPEX (AUD)
Port Kembla Energy Terminal	Developed	Port Kembla, New South Wales	Eastern Gas Pipeline at Kembla Grange	4	500	2026	$200 - $300 million[14]
Viva Energy	Proposed	Geelong, Victoria	VTS at Lara City Gate	3-4	500	2028	$250 million[15]

[13] Confidential report prepared by GHD for DCCEEW covering upstream production and gas storage infrastructure in 2023.
[14] Cost from article by Offshore Technology
[15] Cost from article by ABC

Facility	Status	Location	Connection Point	Working Storage Capacity (PJ)	Withdrawal Capacity (TJ/d)	Proposed Online Year	CAPEX (AUD)
Gas Terminal							
Vopak Victoria Energy Terminal	Proposed	Avalon, Victoria	VTS at Lara City Gate	~4	778	2028	TBC
Venice Energy Outer Harbour LNG Import Terminal	Awaiting FID, Stage 1 enablement works completed	Port Adelaide, South Australia	SEA Gas Pipeline	~3.5	386	2027	$250 million[16]

Given the similarities in the working storage and withdrawal capacities a nominal cost per facilities is provided. A scaling factor of 0.7 [17] is to be applied for changes in facility withdrawal capacity. Withdrawal capacity is used as the FRSU are typically leased and the capex is associated with the jetty, topsides, wharf, and onshore plant and equipment. It is noted that, with the main cost variable associated with the topsides and onshore plant and equipment sizing changing with changes in withdrawal rate, whereas the jetty and wharf costs are linked to the vessel and is typically relatively fixed.

Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility
- V2 = Capacity of proposed facility
- Alpha = Scale factor

2.7 Carbon Capture and Storage

2.7.1 General

This section is based on publicly available sources where this is readily available, where not then GHD experience in delivery of projects for clients has been utilised. Given the application of carbon capture and storage in Australia is limited in deployment to date. Therefore, these projects are considered more likely to have higher degree of uncertainty than when compared to traditional asset types in this report.

This section is based on the assumption that the CO_2 fluids meet a quality basis that avoids any specific materials requirements beyond that of pure CO2 that would increase the costs, and that CO2 injection is into suitable depleted oil and gas reservoirs.

2.7.2 Compression Facility

Compression facilities are above ground facilities that are located on the start of a pipeline, downstream of capture facility. The primary function of these facilities is to boost the pressure of the CO_2 fluid, typically to maintain a pipeline flow rate or to enable the gas to meet a required receipt pressure.

[16] Cost from article by Venice Energy
[17] **Scale economies and the "0.6 rule" - ScienceDirect**

"Fluid" describes the fact that the CO_2 is usually transported as a dense phase or supercritical fluid, where it has some characteristics of a liquid and some characteristics of a gas. CO_2 compression is challenging and requires more complex equipment than natural gas compression.

CO_2 usually requires the removal of water (dehydration) to prevent pipeline corrosion and may require other impurities to be removed. Such equipment is typically costed separately to compression but may be physically integrated with it (sometimes between "stages" of compression).

These facilities include the following main equipment:

- Compressors
- Drivers, e.g. gas turbines, steam turbines or electric motors
- Heat exchangers
- Fuel gas system
- Instrument air, seal gas, lube oil and other ancillary system
- Pressure vessels, piping and valves
- Associated supporting infrastructure such as control rooms, pipework, generators and utility supplies

– The estimate basis for a CO_2 compression facility utilises the cost approach for a natural gas compression facility however adjustment is needed to account for:

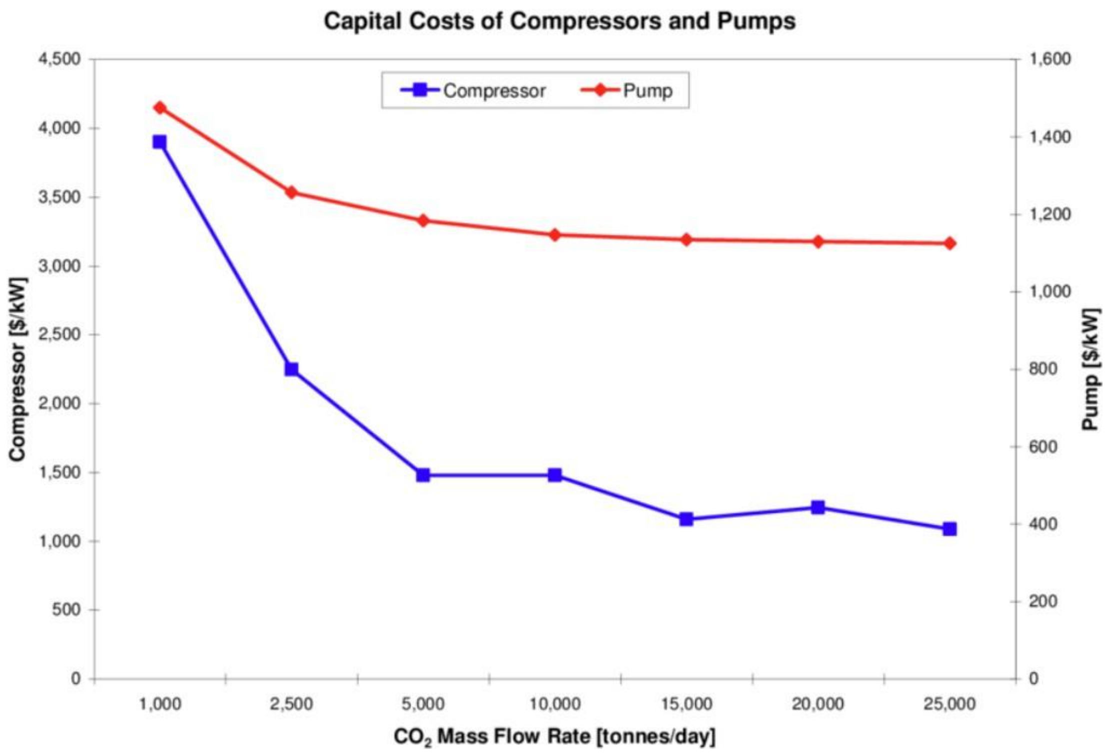
- Increased cost due to use of materials that resist corrosion for the compressor stages upstream of dehydration
- Increased cost due to use of different machine architecture to that employed in natural gas, for example integrally geared machines, and a relative absence of reciprocating types. Seal system complexity can be greater.
- Slightly reduced cost due to the removal of hazardous area (natural gas) compliance for electrical and instrumentation components.

– It is recommended to add an additional cost of $3009/kW[18] to the natural gas compression costs ($/MW installed) to account for the above factors.

– Recent compression purchase costs are generally commercially sensitive. McCollum & Odgen (2006) provided the following figure that shows the capacity vs cost per kw of power, whilst the absolute costs are out of date, the relationship is still valid.

[18] **Thunder Said Energy: Compressor Costs**

Figure 1 *Capacity vs Cost per kW*



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2.7.3 Pipelines

Buried pipelines are essential for transporting CO_2 between capture facilities and storage locations or consumers.

Buried pipeline equipment includes:

- Line pipe
- Coating
- Cathodic Protection
- Pipeline valves
- MIJs
- Cold field bends
- Induction bends
- Pig launchers and receivers
- Booster pumps (if required on longer distance pipelines)

The approach used for a CO_2 pipeline uses the same approach defined above for a natural gas pipeline with the following broad differences:

- Engineering cost is typically 50% higher than for natural gas pipelines due to the effort of engineering and specifying the pipe steel to withstand those failure modes that are made worse by the CO2 fluid. Noting that engineering cost is typically ~2% of the total cost metric.
- Line pipe steel cost is typically 20% higher than natural gas line pipe steel. Noting that steel cost is ~30% of the total cost metric.
- A corrosion allowance is assumed in the wall thickness of the pipeline. Therefore, a nominal 10% cost increase is applied to the steel cost.

Combining these factors results in an increase in the average cost on per inch diameter 10% above that for a natural gas pipeline. This correlates well to costs provided in a 2019 NPC study that cited CO2 pipeline costs in the US, when converted to Australian currency and escalating from 2019. The resulting cost is $82,500 per inch.km ($3,300 per mm.km).

2.7.4 Injection

This section assumes the injection of CO2 into depleted oil or gas reservoirs, where the former oil or gas wells are repurposed for CO2 injection.

An injection system is essential in distributing CO_2 from pipeline systems to the storage wells. In the context of this report an injection system includes the following:

- Injection flow lines, to distribute CO2 from the pipeline terminus to various wellhead locations
- Injection wells and well head facilities / completions
- Injection pumps (if required)
- Wellhead metering, utilities and controls
- Monitoring wells and monitoring instrumentation

The configuration of an CO_2 injection system for a carbon capture and storage (CCS) project will vary based on a number of factors, for simplicity of application for the purpose of this report a number of assumptions are made. The capital cost for the elements comprising a CO_2 injection system is provided in the table below.

Table 15 below provides building block cost data, although the exclusion of well drilling from the scope of this report means that the overall injection cost, which is governed by drilling is not shown. Also, a major variable is the number and spacing of injection wells and the required number of monitoring wells (which will typically be required by regulators to assure the safety and long-term security of the geo sequestered CO2).

Table 15 Injection System Cost Elements

System Element	Unit Cost	Assumption	Capital Cost
Well head metering and control skid	Per well	Assumes flow measurement, back-pressure control, instrumentation and telemetry	$3,000,000
Flowlines	per kilometre	Assumes a 6-inch buried flowline to connect the terminus of the transmission pipeline to each well head skid.	$600,000
Wellhead and well completion	Per well	Very approximate and depends greatly on depth. Assumes that drilling costs are excluded or that the well is a re-purposed oil/gas well.	$5,000,000
Other wellhead facilities	Per well	Contingency allowance for other equipment, such as CO2 monitoring	$2,000,000

As a general indication [19], provides Table 4 which indicates the overall storage costs of geo-sequestered CO2 to be US$28.1M/ton CO2 (2019) in a jurisdiction where high levels of monitoring would be required, as applicable to Australia and for a first-generation CCS project in the order of 1MTPA capacity. The above figure converts and escalates to approximately A$55M/tonne, which is consistent work that GHD has previously done to estimate the total cost of the CCS value chain in A$/tonne, and the proportion of this that is due to injection.

2.8 Hydrogen Blending

This section has not been populated due to very limited information available. Most of the proposed blending projects are still in the planning phase and haven’t progressed sufficiently to enable cost estimation information to be provided that has a sufficient level of confidence. It is recommended that this is reviewed in the future, and

[19] The Cost of CO2 transport and storage in global integrated assessment modelling Smith et al 2021 via International Journal of Greenhouse Gas Control 103367

included in future assessments if sufficient projects have been completed that provide a suitable level of confidence in cost estimation inputs.

Hydrogen blending into natural gas systems will reduce the energy delivery capacity of the system. Capacity reduction occurs due to two reasons: the first is the lower energy capacity of hydrogen on a volume basis, and the other is from a possible reduction in operating pressure (if it is necessary) due to the detrimental impacts on of hydrogen on steels used in the original natural gas asset construction.

2.9 Hydrogen

2.9.1 General

This section relates to projects involving 100% hydrogen transportation and consumption, as opposed to natural gas blending projects. This section is based on publicly available sources where this is readily available, where not then GHD experience in delivery of projects for clients has been utilised. Given the application of hydrogen in Australia has not been deployed to date in the asset categories covered in this report, therefore these projects are considered more likely to have higher degree of uncertainty than when compared to traditional asset types in this report.

2.9.2 Pipeline

Buried pipelines are essential for transporting hydrogen between production facilities and storage locations or consumers.

Buried pipeline equipment includes:

- Line pipe
- Coating
- Cathodic Protection
- Pipeline valves
- MIJs
- Cold field bends
- Induction bends
- Pig launchers and receivers
- Booster pumps (if required on longer distance pipelines)

The approach used for a hydrogen pipeline uses the same approach defined above for a natural gas pipeline with the following broad differences:

- Engineering cost is estimated as 20% higher than for natural gas pipelines due to the effort of engineering and specifying the pipe steel to withstand those failure modes that are made worse by the hydrogen. Noting that engineering cost is typically ~2% of the total cost metric.
- Line pipe steel cost is typically 20% higher than natural gas line pipe steel. Noting that steel cost is ~30% of the total cost metric.
- Pipe bending needs to be controlled in hydrogen pipelines, and this results in routing and other changes compared to a natural gas pipeline. This is estimated to increase construction costs by 10%.
- Pipeline construction costs are increased for hydrogen pipelines. This is estimated to increase construction cost by 20%.

Combining these factors and the lack of experience in this type of pipeline currently, results in an increase in the average cost on per inch diameter 25% above that for a natural gas pipeline. To estimate the capital cost, utilise the cost estimation method in the Natural Gas Pipelines section, applying the 25% increase, and then apply the derating factor for energy delivery capacity below. The resulting cost is $93,750 per inch.km ($3,750 per mm.km).

A hydrogen pipeline has a material reduction in energy transportation capacity when compared to the equivalent size natural gas pipeline. The changes are broadly as follows, noting these are general characterisations:

- Energy delivery capacity – a reduction in the order of 15% to 25% less energy delivery capacity for the same length, diameter, and operating pressure as a natural gas pipeline. This assumes pipeline operating pressure at 10,200 kPag.
- Compression power – in the order of three times the power requirements when compared to the same energy delivery rate as a natural gas compression facility.
- Linepack – it is noted that the linepack ability of hydrogen pipelines is very limited when compared to natural gas pipelines. Hydrogen compressibility is less favourable when compared to natural gas, the more favourable compressibility of natural gas is what provides signification linepack ability. Additionally, hydrogen pipelines are far more susceptible to cracking from pressure fluctuations than natural gas pipelines, therefore this reduces the linepack's availability of hydrogen pipelines.
- Pressure fluctuation range – hydrogen pipelines are more susceptible to cracking than natural gas pipelines, therefore a pressure fluctuation limit of 20% is assumed.

2.9.3 Trucking – Metal Hydride Storage

Metal hydride storage of hydrogen offers high volumetric energy densities and increased safety due to the hydrogen being chemically bound at low pressure. Different types of metal hydrides could be used for small to large scale as well as short to long-term hydrogen storage. Metal hydrides such as MgH_2, $NaAlH_4$, $LiAlH_4$, LiH, $LaNi_5H_6$, $TiFeH_2$, ammonia borane, and palladium hydride could be used to store hydrogen. These materials can absorb and release hydrogen under certain conditions, making them suitable for various applications, including stationary, marine, and transport sectors.

For trucking, metal hydrides offer a transport methodology that is not constrained by transport environment and paths. The vessel can be kept at ambient temperature and pressure, with no safety concerns. In addition, the transport capacity is 3 to 4 times higher per trailer compared to a gaseous tube trailer transporting hydrogen[20], leading to higher operation efficiency and potential overall reduction of transport cost. Hydrides store only about 2%-6% hydrogen by weight but have high volumetric storage densities[21]. Metal hydride transport costs tend to fall between those for liquid hydrogen transport and compressed gas transport. While metal hydride transport has a larger capital expense per truck, the hydrogen capacity per truck is greater compared to using compressed gas transport.

Metal hydride systems can be cost-effective for hydrogen storage, depending on the type of metal hydride utilised and its associated cost. Depending on the raw material price, the production costs can vary. Other than the cost of the storage material itself, the cost is further influenced by factors such as hydrogen uptake rates, operational cycles and the energy required to release hydrogen from the metal hydride. The long filling and extraction times due to slow kinetics is a significant disadvantage for this type of storage. Their economic viability depends on continued advancements in material science and system design. Extending charging times and increasing operating cycles could lead to significantly reduce the levelised cost of storage.

To recover the hydrogen from the metal hydride, heat must be added to break the bonds between the hydrogen and the metal. Typically, the heat required to release hydrogen make this type of storage uneconomical at present. The last 10% of hydrogen dissolved in the metal matrix is difficult to remove and represents strongly bonded hydrogen that cannot be recovered in the normal charge/discharge cycle.

Metal hydride systems require a much smaller footprint than compressed hydrogen gas storage and are safer than compressed hydrogen or liquid hydrogen storage systems.

From a publication by the Department of Energy (DOE) in 2018, metal hydride storage costs were the following. These numbers were all reported in US$ 2007 and converted to A$ 2024 numbers using chemical engineering plant cost index[22]. An exchange rate of US$:A$ of 1:0.72 was used.

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[20] Hydrexia Hydrogen Storage and Transport.
[21] Costs of Storing and Transporting Hydrogen.
[22] DOE. (2018). Hydrogen Storage Cost Analysis. Hydrogen Storage Cost Analysis; DOE Hydrogen and Fuel Cells Program FY 2018 Annual Progress Report,

Table 16 Metal Hydride storage system CAPEX

Specific equipment	US$/kWh (2007)	A$/kWh (2024)	Notes
Type 4 vessel for housing, fill receptable, integrated regulator block, in tank valve	8.95	18.90	Carbon fiber composite, aluminium bosses, HDPE liner.
In tank heat exchanger	>1.00	>2.11	Based on high volume tube quotes with a single bend, excluding assembly and coolant manifolds.
Metal hydride	2.70	5.70	5.6% metal hydride storage capacity assumed and 45.9 kg metal hydride per vessel with 4.6 kg expanded graphite.
Other BoP	To be defined		Additional costs for storage side coolant pump, valve and plumbing
Total	**Estimated 13**	**27.45**	

Metal hydrides undergo physical and chemical degradation during hydrogen loading, leading to a capacity loss over time[23]. Typically, metal hydrides could last up to 30 years. The vessels that are used to house the hydrides, these being Type IV vessels can also last up to 30 years[24].

Hydrexia's 40 ft metal hydride container can store 1,000 kg of hydrogen[25], while GKN reports a 20 ft container with 200 kg hydrogen storage[26].

The technology is currently at a Technology Readiness Level of 5-7, depending on the type of metal hydride utilised.

2.9.4 Salt Cavern

Caverns developed in salt deposits are used to store a wide variety of products, including crude oil, natural gas liquids, natural gas, and hydrogen. Salt cavern storage facilities are concentrated in North America and Europe, although salt cavern storage and salt deposits exist globally.

Salt cavern storage can be formed in large naturally occurring salt deposits underground by the solution mining (leaching) process. Solution mining to form a cavern storage space is done by drilling down into the earth at a suitable location, removing salt from the nominal centre of the salt structure creating a void space. Large amounts of water are required for the formation of the underground structure by leaching. Water used for leaching is typically from water supply wells or surface water sources. An economical source of water should be near the proposed site to maintain the economics of the site. The brine produced by the leaching process needs to disposed of in an appropriate manner. This can be *via* deep well injection with the appropriate permits or by release into a saltwater body of water, ideally an ocean.

Equipment, exclusive to developing and operating the cavern:

1. Storage Well. After cavern development, the leaching wellhead is replaced with a production wellhead and re-piped for product service. Ideally the well is left with components that have not been denuded by the leaching process. Piping sizes are determined by the expected operating cycle of the cavern.
2. Saltwater Disposal Wells. Saltwater disposal wells are used to dispose of brine created during cavern development. Brine flow rates are equal to the freshwater injection rate for leaching, so brine disposal facilities must be capable of handling high flow rates. Ocean discharge has also been used for brine disposal.
3. Fresh Water Supply Wells. Water wells are the most method for supplying fresh water for leaching, although surface water is also used.

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[23] Klopcic, N. et. Al. (2023). A review on metal hydride materials for hydrogen storage. Journal of Energy Storage 72 108456.
[24] [Type 4 pressure vessels for hydrogen storage - NPROXX](). Website accessed 24/03/2025.
[25] [Hydrexia Energy Technology Rolls out Industry-Leading Hydrogen Storage and Distribution Trailer_FuelCellChina, the Leading Information Hub of Hydrogen and Fuel Cell Industry around the Globe.]()
[26] GKN Hydrogen. Competitive Landscape H2 Storage Metal Hydride.

4. Leach Plant. The leach plant is operated during cavern development to solution mine the cavern. Typical leaching requirement are seven to ten volumes of water for every volume of cavern developed. Most large caverns require one to two years for development.
5. Compression equipment, typically reciprocating type. Suitable to reach the safe operating point of the cavern structure. Service description and flow rate will consider the cycle of operations expected of the rest of the site.

Typical cost ranges for hydrogen storage in salt caverns is summarised in the table below. These costs are from US projects that have been converted from USD to AUD. A location factor of 1.4 to 1.5[27] is recommended, however due to the lack of existing projects like this in Australia a factor of 1.5 is applied.

Table 17 Cost Ranges for Hydrogen Storage in Salt Caverns

Description	Cost	Year	Comments
Storage well	\$55.5 m - \$112.5 m	2024	Well pad, drilling, casing and completion. Includes wellhead and wing valves. Domal salt formation: 508 mm completion. 1,220 m total depth. Casing shoe at 610 m.
Saltwater disposal wells	\$11.3 m - \$22.5 m	2024	Well pad, drilling, casing and completion. Includes wellhead and wing valves, with instrumentation. 229 mm completion. 1,830 m total depth. Typically, multiple saltwater disposal wells are required.
Water supply wells	\$2.3 m	2024	Well pad, drilling, casing and completion. Includes wellhead and wing valves, with water pump and instrumentation. 229 mm completion. 457 m total depth.
Leach plant	\$100 m - \$124 m	2024	Includes leach pumps, brine solids separation facilities, brine injection pumps, and piping. Leaching pumps based on 13600 L/m and ANSI 600 discharge rating. Brine disposal pumps based on 13600 L/m and ANSI 600 discharge rating. Includes instrument and control, power, project indirects and contingency.
Leach plant and brine disposal operations	\$20 m – \$25 m	2024	20% of leach plant CAPEX. Assume 18 months to fully develop cavern
Hydrogen compression	\$225 m - \$338 m	2023	Includes reciprocating compressors, bottles, coolers, dehydration and related equipment, compressor building, inventory metering, and yard piping from interconnect manifold to wellhead. Includes instrumentation and control, power, indirect costs, and contingency.
Pipeline interconnect	\$2.9 m/km	2020	406 mm open cut rural
Total (without pipeline interconnect)	\$417 m – \$627 m	-	Doesn't include pipeline interconnect

Note: Cost basis assumes drilling, development, and conversion to hydrogen service for a single cavern. Top of cavern is at approximately 610 m bgs; bottom of cavern at 1,220 m bgs and cavern diameter of 61m.

The estimated cost for a facility is provided in the table below, noting the costs are converted from US Gulf Cost to an estimated equivalent cost in Australia. Assumptions are based on US projects, and the nominated assumptions used in the estimate include the following:

- Storage capacity of 8,000 tonnes, with two 4,000 tonne caverns
- Withdrawal rate of 750 tonne per day, with an inject to withdrawal ratio of 1:2
- Brine disposal wells rather than evaporation ponds
- Interconnecting pipeline of 3 km

[27] **LNG Plant Cost Escalation - Oxford Institute for Energy Studies**

Table 18 Estimated Capital Cost for a Nominal Salt Storage Facility

Description	Quantity	Capital Cost
Storage wells	2	$160 m
Saltwater disposal wells	3	$45 m
Water supply wells	2	$4 m
Leach plant	1	$110 m
Leach plant running costs to solution mine caverns	1	$20 m
Hydrogen compression facility	1	$250 m
Interconnecting pipeline	1	$10 m
Total		$599 m

2.10 Biomethane

2.10.1 General

This section is based on publicly available sources where this is readily available, where not then GHD experience in delivery of projects for clients has been utilised. Given the application of biomethane in Australia is limited in deployment to date, therefore these projects are considered more likely to have higher degree of uncertainty than when compared to traditional asset types in this report.

Biomethane is produced from wastes and biomass via anaerobic digestion, where the produced biogas is upgraded to comply with the specification as noted in "AS 4564 General Purpose Natural Gas" for injection into natural gas pipelines. Biogas upgrading and injection to the natural gas network is common practice in parts of the world such as Europe and the United States; for example, in Denmark, biomethane supplied almost 40% of the gas demand in 2023[28]. In Australia, the first biogas to biomethane for pipeline injection, Jemena's Malabar biomethane project, started up in NSW in June 2023. It has the potential to produce up to 110 TJ/a of biomethane. It is also the first renewable gas project in Australia to receive GreenPower Renewable Gas Certification[29]. When the biomethane generated at Malabar is combusted, it reduces greenhouse gas emissions by over 90% compared to natural gas combustion, including combustion emissions and embodied emissions associated with the production process.

A wide variety of feedstocks could be used in anaerobic digestion to produce biogas. Utilising wastes and residues as feedstocks avoids land use issues and other disadvantages associated with energy crops grown solely for energy production. These are typically targeted for anaerobic digestion (rather than specific energy crops). They can be grouped into four broad feedstock categories: crop residues, animal manure, the organic fraction of municipal solid waste, including industrial waste, and wastewater sludge. Crop residues include residues from the harvesting of wheat, corn, rice, sugar cane, soybean and others. Animal manure includes manures from livestock including cattle, pigs, poultry and sheet, and in the case of some animals, the bedding that is collected with the manure. The organic fraction of municipal solid waste is the collective name for food and green wastes, paper and cardboard and wood that is not otherwise utilised. Industrial waste from the food processing industry is also included in this category. Lastly, wastewater sludge is the semi-solid organic matter from municipal wastewater treatment plants.

A potential alternative route is gasification of woody biomass, which is recalcitrant to anaerobic digestion, and methanation of the produced synthesis gas for biomethane production. This has not been covered din this report due to the limited application globally.

[28] IEA Outlook_for_biogas_and_biomethane
[29] Malabar Biomethane Project Receives GreenPower Certification | Jemena

Another potential source of biomethane is landfill gas facilities, where gas is produced from the decomposition of organics within landfill waste over a long duration. Landfills are capped and the gas captured via a “well” network from the decomposing wastes. The concentration of landfills close to urban areas presents an opportunity for landfill gas to be recovered, treated and injected into the existing natural gas distribution network. Landfill gas typically offers a readily available, low investment source of biomethane in the short term. As organics currently sent to landfill are expected to be phased out in the near future, this will severely impact the opportunity to produce landfill gas, with landfill gas expected to decline to low levels over the next 10 to 15 years.

2.10.2 Production

Anaerobic digestion facilities for biogas production and upgrading to biomethane include the following main equipment:

- Feedstock receival and storage. For solids, feedstocks are transported to site in covered trucks and tipped into feedstock bunkers. Liquid feedstocks can be transported to site in road tankers and pumped into storage.
- Feedstock pretreatment, which depends on the type of feedstock and its condition. Size reduction (crushing) could be completed, other pre-treatment such as thermal hydrolysis could also be applied to enhance substrate degradation in the anaerobic digestion process and therefore process efficiency. If more than one type of feedstock is used, mixing of feedstocks is completed.
- Anaerobic digesters. There are a wide range of digester configurations available for anaerobic digestion. The types of feedstock available is the main driver in the selection of digester configuration. The most commonly used digesters include covered lagoons, plug flow digesters and continuously stirred tank reactor (CSTR) digesters. The process can either be wet or dry, depending on the water content of the feedstock. Typically, digesters function better when they are heated, and therefore process heat is applied, usually as steam or hot water that is indirectly applied to the process (via external heat exchangers or internal coils).
- Treatment of biogas. Biogas typically consists of 50-60 vol % methane, 30-45 vol % CO2, sulphur mainly in the form of H2S, siloxanes, entrained particular matter, and trace compounds such as ethylbenzene and halogenated compounds. The gas is also saturated with water. Gas treatment broadly consists of pre-treatment and biomethane upgrader unit. Pre-treatment typically includes a biogas blower, cooling, moisture removal, desulphurisation and siloxanes removal, while upgrading consists of CO2 removal and compression to pipeline injection pressure. Desulphurisation is accomplished through biological desulphurisation, water or chemical scrubbing or adsorption on a solid sorbent, while siloxane removal is usually done through adsorption onto activated carbon or silica gel. Biogas upgrading at this scale typically consists of selective polymer membranes, pressure swing adsorption or amine scrubbing.
- Pipeline injection skid. This skid typically includes the odorant system, pressure regulation, sample point (to take gas samples for analysis), metering equipment and isolation valves to shut injection when required.
- Emergency flare.
- Power and heat generation. Typically accomplished through a gas engine or combined heat and power system or biogas boiler (for process heat only).
- Digestate treatment. Dewatering of the digestate extracted from the digested is typically dewater through centrifuge or screw press. Digestate utilisation options include direct land application, drying and pelletising and composting.
- Liquid fraction digestate treatment. Includes biological treatment using sequencing batch reactors.

. Facility capacity is driven by feedstock availability within a range, with 50-80 km being the historic range within which feedstock would be sourced. Feedstocks are wet and have low bulk density and are therefore expensive to transport over long distances.

Anaerobic digestion facilities are classified as small, medium or large facilities [30] with capacity ranges are provided in Table 17. There are a few very large anerobic digestion (AD) facilities in the world currently, notably the Toronto

[30] Global Methane Initiative. (October 2016). Overview of Anaerobic Digestion for Municipal Solid Waste.

Disco Road facility with a capacity of 75,000 tpa feedstock and the Total Energies BioBearn AD facility in France that has a capacity of 220,000 tpa of feedstock[31]

CAPEX for AD installations and gas treatment for different types of facilities and capacities are shown in Figure 2. A large number of data points were gathered from GHD internal project estimates built up from vendor quotations, and a number of published reports [32, 33, 34,35].

The CAPEX for a large facility has a typical CAPEX breakdown as follows:

- 35% for civils, formwork, concreting and site preparation
- 10% for feedstock receival, storage and preprocessing
- 20% for the digesters
- 5% for digestate handling
- 10% for BoP
- 5% for electrical, cabling and controls and
- 15% for engineering, project management and commissioning.

In addition, CAPEX is also required for gas treatment units to remove impurities, water and CO_2.

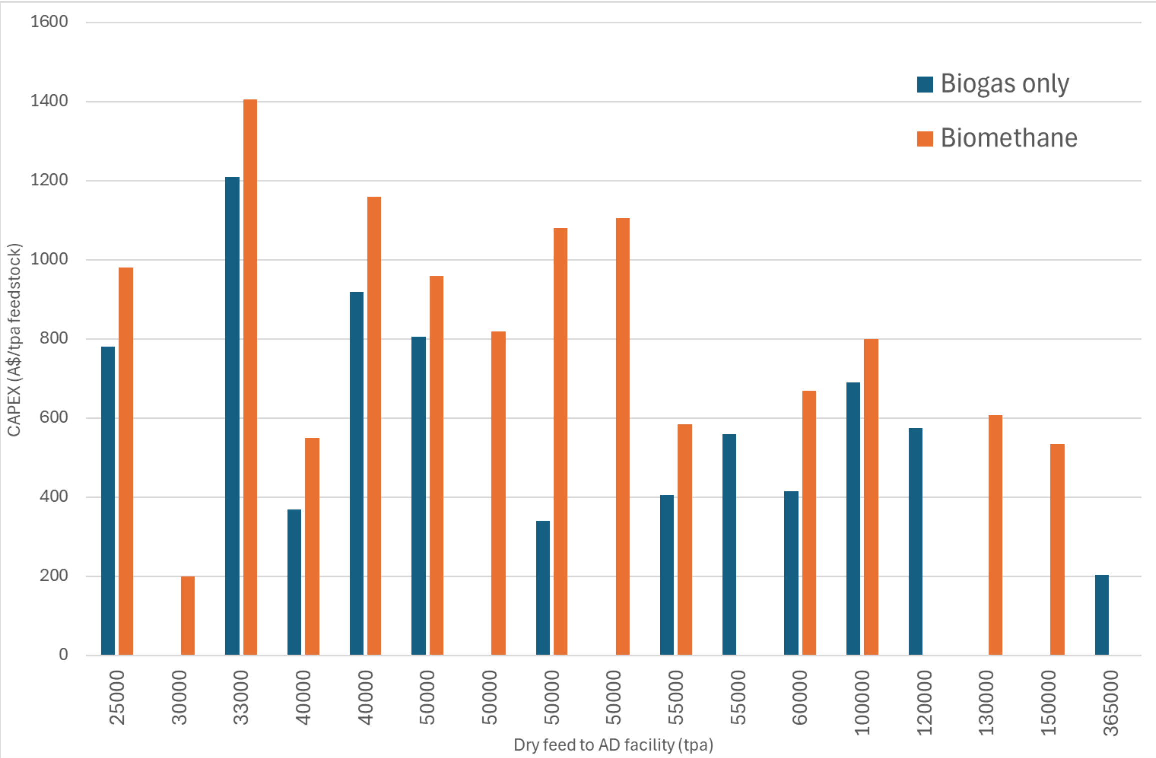
A summary of facility capacities with corresponding cost range per size category is provided in Table 17. It should be noted that feedstock feed systems, digesters and digestate handling systems are typically modular and have specific maximum capacity, beyond which point a duplicate system would be added to achieve additional capacity, while gas treatment units scale with volume.

Table 19 Anaerobic digestion and biomethane production facility capacity ranges with accompanying CAPEX ranges

Facility description	Feedstock capacity (dry tpa)	Biomethane production (PJ/a)	CAPEX range ($ M)	CAPEX range (A$ / dry tpa)
Small facility	10,000 - 30,000	0.04 – 0.12	21 – 33	1,100 – 2,100
Medium facility	30,000 – 60,000	0.12 – 0.24	33 - 43	717 – 1,100
Large facility	60,000 – 140,000	0.24 – 0.56	43 – 71	507 – 717
Very large facility	200,000+	1.0+	85+	425

[31] BioBéarn: TotalEnergies' largest anaerobic digestion unit in France | TotalEnergies.com
[32] McKendry P (2019) Overview of Anaerobic Digestion and Power and Gas to Grid Plant CAPEX and OPEX Costs. Int J Bioprocess Biotech 02: 109
[33] Ibarra-Esparza, F.E. et. Al (2023). Implementation of anaerobic digestion for valorizing the organic fraction of municipal solid waste in developing countries: Technical insights from a systematic review. Journal of Environmental Management, Volume 347.
[34] Outlook for biogas and biomethane | IEA 2020.
[35] Enea Consulting. (2019). Biogas opportunities for Australia.

Figure 2 ***CAPEX benchmarking for AD facilities, with/without biomethane upgrading***



Biomethane facilities typically have an asset life of 15 to 20 years[36]. Some types of digesters (and specifically fixed dome digesters) have a longer lifetime than others.

There are limited prospects for major reductions in the cost of producing biomethane. The technologies for biomethane are relatively mature although there may be higher potential to bring down the cost of biomass gasification. Larger facilities could also provide some economies of scale for both production routes.

2.11 Coal Seam Gas

2.11.1 Water Treatment Plants

The vast majority of water treatment plants (WTP) in the CSG industry, in terms of capacity, treat produced water which result from gas well development. The produced water is typically brackish in salinity and therefore, for the majority of water re-use or disposal routes, needs to be desalinated with appropriate pretreatment. Other infrastructure relating to the water treatment plants include brine ponds which store and concentrate (via solar evaporation) the resultant saline waste stream which is typically called "brine".[37] The typical industry planned disposal route for the intrinsic dissolved salt within the brine is via "salt encapsulation". This involves end-of-life crystallisation and then disposal of the salt via an onsite managed waste facility (i.e. either creation of a dedicated landfill or conversion of brine ponds to landfill). The default approach for mixed salt crystallisation is thermal crystallisation however some CSG producers are investigating the potential for solar crystallisation via the conversion of their existing brine ponds. Most net present cost assessments show the end-of-life management of salt to be relatively small fraction of the overall whole-life costs (i.e. at year 20 to 40), therefore they have not been accounted for in the below cost curve.[38] There is an intrinsic risk that practical realities (e.g. crystallisation needing to occur earlier in the life of a project or that solar crystallisation not being possible) and regulation may drive up the end-of-life costs. However, the brine produced from the WTP does needs to be stored prior to being managed

[36] AGIG & Blunomy. (2024). Biomethane Potential in AGIG's Network Catchment and Associated Co-benefits
[37] DERM (Queensland Government), 2023. Coal seam gas brine management action plan, Brisbane, QLD, Australia APPEA (Australian
[38] Petroleum Production and Exploration Association), 2018. Queensland Gas: end to-end water use, supply and management, Brisbane, QLD, Australia.

end-of-life, therefore early to mid-project life brine project life WTP brine pond storage requirements have been accounted for.

A literature review was undertaken to identify publicly available information which summarises the total installed costs. This included various reports from APPEA, AER, ACCC, and the Global water intelligence (GWI) Desalination Database. It was not possible to locate cost information in any of these documents or databases; this type of information is considered commercially sensitive by the CSG companies. Therefore, GHD has utilized its own water treatment plant cost database which includes a recent cost estimate for water treatment plants (including brine evaporation ponds). Normally it is preferred that costs are derived from delivered plant total installed cost, however few CSG water treatment plants have been delivered in the last 10 years. Not only is access to this detailed data significantly limited outside of the CSG companies themselves (due to the commercially sensitive nature of this information) a significant amount of inflation has occurred in the last 10 years in terms of the supply of water treatment plants in general which has outpaced most cost indices. Therefore, a cost curve has been developed based on the most recent detailed costs estimate available i.e. an AACE Class V estimate from 2025 for a mid-sized CSG WTP resulting from a Pre-FEED level design.

The WTP cost curve provided includes the total installed cost for the WTP and the early to mid-project life WTP brine pond costs. The total installed cost includes direct, indirect and contingencies (some of which may be CSG producer specific but are generally consistent for WTPs and brine ponds). It excludes wellfield gathering system infrastructure (e.g. wellheads, pipelines, storages), power generation or transmission, roads to site etc. It also does not take into account the near project end-of-life or end-of-life costs related to salt management.

The WTP cost curve developed is based on a power relationship to account for economies of scale and is shown below[39].The power exponent of 0.74 is based on a database of 90 brackish water reverse osmosis plants and accounts for a degree of modularity. The 10.4 [$M] coefficient has been derived from the basis cost. This dataset provides a robust foundation for estimating cost trends across different plant capacities, ensuring that the economies of scale are appropriately captured.

$$WTP\ Total\ Installed\ CAPEX\ (\$M) = 10.3\ \times (WTP\ Feed\ Capacity[ML/d])^{0.74}$$

The WTP brine pond cost curve has been developed on the basis of the project reference cost outlined above and related to the WTP feed capacity. A ratio between WTP feed capacity and brine pond volume (which assumes a ideal modularity) was developed by examining the majority of the current and planned QLD CSG industry WTPs and their respective WTP and brine pond capacities. An approximate ratio of 200 ML of brine pond capacity per ML/d WTP feed capacity was derived whilst the 2025 cost estimate basis project unit cost for brine ponds was approximately $0.05 M per ML of storage. It is noted that this ratio can vary significantly depending on a range of factors such as local topography, local geology, local weather / climate, CSG producer brine pond standards / strategy (e.g. preferred depth to area ratio or wall angle) and overall water strategy, CSG produced water, CSG WTP recovery etc. The resultant WTP brine pond cost curve is shown below

$$WTP\ Brine\ Pond\ Total\ Installed\ CAPEX\ (\$M) = 10.0 \times (WTP\ Feed\ Capacity[ML/d])$$

The combined WTP plus WTP brine pond cost curve is follows.

$$\begin{aligned} &WTP\ plus\ WTP\ Brine\ Pond\ Total\ Installed\ CAPEX\ (\$M) \\ &\qquad = 10.3\ \times (WTP\ Feed\ Capacity[ML/d])^{0.74}\ +\ 10.0 \times (WTP\ Feed\ Capacity[ML/d]) \end{aligned}$$

Indicative water-to-gas production ratios for coal seam gas projects in the Surat and Bowen Basins have been provided based on selected CSG project related lifetime cumulative water production and average gas production data. The water-to-gas ratio (i.e. ML of water per TJ of gas production) for each project was calculated by dividing cumulative water production by average gas production over the project life, using publicly available data and project documentation. The Senex project, located in the Surat Basin, is estimated to produce 5,300 ML of water over 26 years, with average gas production of 53.1 TJ/day, resulting in a water-to-gas ratio of 0.011 ML/TJ[40] . A confidential project, also located in the Surat Basin, is expected to produce 3,500 ML of water over 25 years, with cumulative gas production of 45 TJ/day, yielding a water-to-gas ratio of 0.009 ML/TJ[41]. The Arrow Surat project is estimated to produce 510,000 ML of water over 40 years, with average gas production of 1,215 TJ/day, resulting in

[39] Wittholz, Michelle, Brian O'Neill, Chris Colby, and David Lewis. 2008. “Estimating the cost of desalination plants using a cost database.” *Desalination* 10-20.
[40] Senex Energy Limited, 2023. CSG Water Management Plan – PL 445 and PL 209 (Attachment K), Queensland, Australia.
[41] GHD, 2024. Range Water Treatment Plant Concept Design and Cost Estimates, Queensland, Australia.

a water-to-gas ratio of 0.029 ML/TJ[42]. The Arrow Bowen project, located in the Bowen Basin, is projected to produce 153,000 ML of water over 36 years, with average gas production of 2,120 TJ/day, yielding a water-to-gas ratio of 0.005 ML/TJ; the average gas production for Arrow Bowen was calculated using an assumed gas rate of 0.53 TJ/well (and a project well number of 4000 wells), based on a mid-level production estimate from a KPGM report[43][44]. These datasets are reasonably aligned in terms of water production per well and gas production per well ratios across comparable project scales. Therefore, it is estimated that the typical water-to-gas production ratio for the Surat Basin ranges from 0.01 to 0.03 ML/TJ in the Surat Basin and 0.003 to 0.015 ML/TJ in the Bowen Basin respectively.

It is noted that the water to gas ratio is averaged over the project, however WTP Feed Capacity is based on peak water production i.e. the production of water for a well field often peaks near the beginning of a project and then declines over the project life with some attenuation of the peak due to pondage. It is recommended that a WTP Feed Capacity (accounting for attenuation of the peak from pondage) to average water production factor is used at a ratio of approximately 3:1 to 4:1 (based on the confidential project referred to above). This means that the WTP Feed Capacity will be approximately three to four times higher than the average water production, therefore for the purpose of this report is it recommended to use a 3.5:1 ratio for estimation purposes. It is noted that a project well field water profile is very dependent on the project specific well field drilling plan and has a high level of variability between projects. The capacity assessment of water treatment per unit of gas production is provided in the table below.

Table 20 CSG Water Treatment Capacity per Unit of Gas Production

Basin	Average Water Rate Range ML/TJ of Gas Production	Peak Capacity Factor	Recommended Sizing ML/TJ of Gas Production
Surat Basin	0.010 to 0.030	3.5	0.070
Bowen Basin	0.003 to 0.015	3.5	0.032

2.11.2 Water Pipeline

Buried water pipelines are essential for transporting produced water from nodal and production facilities to water treatment facilities. The majority of the produced water pipelines are buttwelded HDPE pipe, ranging in sizes from 110 mm to 630 mm and located in regional Queensland.

The pipeline equipment includes:

- Line pipe
- Pipeline section valves

The costs provided in this section include the listed equipment along with construction and installation activities. The two main cost elements for a pipeline are line pipe and the construction (jointing and laying, installation of fittings, trenching, back filling and restoration).

The AACE class 5 HDPE pipeline total CAPEX estimate range is shown **in table 21** in dollars per metre. The pipe mm is the nominal outside diameter.

These costs are based on an internal pipeline cost estimation model and aligned with current construction costs.

[42] Queensland Government, 2013. Surat Gas Project EIS Assessment Report, Brisbane, QLD, Australia.
[43] Queensland Government, 2014. Bowen Gas Project EIS Assessment Report, Brisbane, QLD, Australia.
[44] Department of Resources (Queensland Government), 2021. Bowen Basin Underground Water Impact Report – Final Report, Brisbane, QLD, Australia.

Table 21 Costs- HDPE SDR 11 Water Pipelines

Megalitres per day	Pipe Size PE100, SDR11 (mm)	Pipe Supply[45] ($/m)	Install [46] ($/m)	Indirects[47] ($/m)	Total CAPEX Supply, Install & Indirects ($/m)
0.5	**110**	26	158	65	249
1.5	**180**	71	162	81	314
4.5	**315**	217	174	137	528
9.2	**450**	443	242	240	925
18.0	**630**	869	396	443	1708

The installation costs associated with a pipeline construction are variable and can increase the overall project costs. The variances that affect the pipelines construction cost are:

- Terrain
- Location
- Length

Various project factors can be applied dependent on the attribute being considered specific to the pipeline project. The application of the factors that are applied to these attributes are discussed below.

Terrain Factor

The terrain factor considers the terrain in which the pipeline is to be built, where construction productivity reduces with more difficult the terrain due to slower construction progress. The terrain adjustment factors applied to the standard cost input is as follows:

Table 22 Terrain Factors Table B

Detail / Description	Adjustment Factor	Description
Terrain Factor - Standard	1	If the terrain is flat or gently undulating where all work sites access can be easily established.
Terrain Factor - Medium	1.4	If the has steep hills and significant depressions or benching and excavation is only needed seldom (or can be avoided with relative ease by relocating the planned structure to near vicinity).
Terrain Factor - Difficult	2	If the terrain topography gradient is rugged with steep incline and significant gullies or benching and excavation are frequently needed to obtain acceptable horizontal and vertical alignment.
Terrain Factor - Special	4	Use of this factor requires careful consideration of the actual special construction technique being applied and the factor being applied will be required to be adjusted accordingly and specialist assistance in determining the applicable adjustment factor is recommended. Situations where this factor would be applied is described below.

The adjustment factor needs to be applied to the length of pipeline construction affected and not the entire length.

The application of the special terrain factor would be applied where the pipeline is to be installed in areas such as large river crossings where directional drilling techniques are required to install the pipeline under the waterway, submerged crossing of an extensive waterway where dredging of the bottom of the waterway is required, areas where the pipeline traverses large quantities of extremely hard rock where blasting is required or where swampy semi-submerged grounds is encountered where mass mixing of the soils is required to stabilise the ground along

[45] Include regional delivery
[46] Excavation method is based on excavators and not pipe plough or bucket wheel trenchers
[47] Indirects were based on 35% of pipe supply and install, however will vary depending on project and will significantly increase if FiFO or construction camp are required. The indirects include: investigations, approvals, engineering, common distributables, and owner's costs.

with specialist machinery is required to avoid the bogging of equipment. This factor is generally applied where the installation techniques are extremely time consuming and where productivity factors are very low.

Location Factor

This factor considers the ease of access to project resources such as the supply of labour, plants, ports, and transportation facilities. This considers the distance and the ease of access to manpower, machinery and materials of construction. The water pipeline costs provided are based on regional areas where the site within 6 hours driving radius of established depots and regional towns with accommodation facilities and other public infrastructure. The majority of the produced water pipelines are located in regional areas and no additional location factors are required.

Length Factor

Given the typical short length of these types of pipelines when compared to gas pipelines, no length factors are required.

3. Natural Gas Operational Cost

3.1 General

The cost base for natural gas assets is well understood and can be presented in various forms. Where possible this has been presented as a percentage of capital costs, which supports understand for new assets. Additionally, some of the operational costs have been provided in a unit cost basis to enable application to existing assets where availability of equivalent capital cost is not available. Operational costs can vary depending on economies of scale with ownership of multiple gas assets, this would tend to reduce the total operational cost per asset, however this is dependent on numerous factors and this has not been incorporated in this assessment.

3.2 Natural Gas Pipelines

Operational cost for pipelines is combined to cover the buried pipeline and the pipeline stations. Two approaches are provided to cover an estimating approach for future pipelines and another for existing pipelines.

For future pipelines, the OPEX estimating has been based on a high-level assessment suitable for Class 5 estimate, based on previous work for an Australian government department [48]. The OPEX estimating utilises OPEX as 2% of Capex. This includes annual OPEX and an annualised allowance for sustaining capital. It is noted that this doesn't include compression, this is covered in a following section in this report.

For existing pipelines, the following is the recommended approach. Table 23 compares transmission pipeline OPEX costs per km or a selection of pipelines. It is noted this range is large at $9,000/km to $29,000/km, however a figure around $25,000/km is seen by GHD as broadly representative where the pipeline systems in Australia that include a reasonable level of compression. It is noted that the Amadeus Gas Pipeline is largely in remote locations, with a low level of compression, hence resulting in a materially lower OPEX compared to the other two pipelines in the table.

Table 23 Transmission pipeline OPEX costs compared to pipeline length

Factor	Roma to Brisbane Pipeline	Victorian Transmission System	Amadeus Gas Pipeline
Length* (km)	984	2267	1626
OPEX[49] (2013 AUD)	$28,000,000	$49,000,000	$16,000,000
OPEX / km	$28,455	$21,614	$9,840

*Pipeline lengths include pipeline laterals and looping lengths.

[48] Costs from a confidential report on gas supply options, completed in 2021
[49] Costs from Australian Energy Regulator "State of the energy market 2024"

3.3 Natural Gas Production Plant

3.3.1 Conventional Gas

OPEX has been based on a high-level assessment suitable for Class 5 estimate, based on previous work. The Opex estimating utilises the following factor:

- Opex as 12% of Capex, which includes sustaining capital costs.

3.3.2 Coal Seam Gas

OPEX has been based on a high-level assessment suitable for Class 5 estimate, based on previous work. The Opex estimating utilises the following factor:

- Opex as 8% of Capex, which includes sustaining capital costs.

3.4 Natural Gas Compression Facility

Two approaches are provided to cover an estimating approach for future compression and another for existing compression.

For future compression, the OPEX has been based on a high-level assessment suitable for Class 5 estimate, based on previous work for an Australian government department [50]. The Opex estimating utilises the following factors:

- Compressors - Opex as 4% of Capex.
- Compressors – Sustaining capital cost of 9% of Capex assumed as being required every 10 years. This is for replacement of components of the compression facility that would have reached end of useable life.

For existing compression, a rate of $37,000/MW to $45,000/MW per annum of installed compression capacity is considered a reasonable basis. This was validated from the 2021 OPEX of the Winchelsea compressor station [51].

Fuel gas is not included in the OPEX costs for either method.

3.5 Natural Gas Storage

3.5.1 Underground Gas Storage

Operating costs vary annually between $4 M - $8 M/annum [52] , assuming the asset is incorporated with existing energy infrastructure operator asset portfolio. Higher facility usage increases the annual operating costs, and the larger the size of the facility the higher the costs.

3.5.2 Aboveground Gas Storage

Operational costs include utilities, operations and maintenance activities, and operational personal, it excludes energy costs for liquefaction, pumping and compression which are assumed as recovered under the facility use charge. Operating costs for an AGS facility sizes are provided in the table below.

Table 24 AGS Operating Costs [53]

Item	120MTPD	250MTPD	Comments
O&M (excl Labour and Electricity)	$4 – 6 M	$6- 9 M	Annual maintenance including consumables

[50] Costs from a confidential report on gas supply options, completed in 2021
[51] Costs from public report prepared for AER, "Operating Expenditure Review Winchelsea Compressor"
[52] Estimated costs from a GHD client confidential report on gas storage, completed in 2022.
[53] Estimated costs from a GHD client confidential report on gas storage, completed in 2022.

Item	120MTPD	250MTPD	Comments
Labour	5 FTE over 3 shifts 24/7	7 FTE over 3 shifts 24/7	Assume standalone facility operated by existing energy utility operator
Total	$5.5 - $7.5 M per annum	$8.1 - $11.1 M per annum	

4. Natural Gas Capacity Upgrade Cost

4.1 General

This section focuses on material capacity increments as a result of expansion projects. This section is based on an assumption that capacity upgrade is typically a percentage increase that is less than the base asset capacity, and the associated incremental costs. Where capacity is increased above the based asset capacity, these projects are typically a new asset constructed beside an existing asset.

In this section de-bottlenecking is not covered, as estimating the cost is typically facility specific and the capacity increase is relatively small and generally ranges from 2% to 5% over a period of time.

4.2 Natural Gas Pipelines

– This section describes the methodology for expanding a pipeline capacity.

4.2.1 Buried Pipeline

There are generally two methods of increasing a pipeline's throughput these are:

- Installation of pipeline mainline compression facilities
- Looping of the pipeline

– Usually pipeline compression faculties are used as the first option to increase the pipelines throughput. Pipeline looping is generally used where large increases of pipeline system capacity is required. Pipeline looping is where parallel pipeline is installed, generally in the same pipeline easement. The new sections of pipeline looping may be of the same or larger diameter and can be partial looping or fully duplicate the existing pipeline.

– The construction rate of a looped pipeline is slower that a new pipeline installation, due to the safety requirements when construction activities occur in close proximity to an existing live gas pipeline. These additional measures increase the installation cost of a looped pipeline due to the additional time required to construct and that looping tends to be for shorter sections than the original pipeline where the ratio of indirect cost on the looping project is higher, resulting in lower economies of scale.

For a partially looped pipeline the costs for the looping are anticipated to be 17% [54] higher than that of a new pipeline construction on a per kilometre basis. For the purpose of this report, it is expected that looping will only be for partial lengths of an existing pipeline, with any one looping project to duplicate less than 30% of an existing pipeline length. It is also assumed for the purpose of this report, that the looped pipeline is the same diameter as the original pipeline. For simplicity, the increase in capacity can be assumed to be linear to the percentage of length of looping installed as an approximation method, covered by the following formula: capacity increase = (loop length/original pipeline length) x original pipeline capacity.

Pipeline compression is the usual method for increasing pipeline throughput where large scale increases of capacity is not required. Once the power requirement is known from the pipeline model, the cost for the new compressor station is calculated as per section 2.4 Natural Gas Compression Facilities.

[54] APLNG Pipeline Project Looping and Expansion Desktop Review

4.2.2 Pipeline Change of Service to Natural Gas

A pipeline change of service occurs when a pipeline designed to convey petroleum or related fluids has a change of the fluid the pipeline was originally designed to convey to another petroleum or related fluid. This approach has been used on a number of pipelines internationally, however has had limited application in Australian to date.

When changing a liquids pipeline to gas service, there are numerous engineering considerations, however the most important are pipe steel fracture toughness, minimum temperature limits of the pipe steel, and energy release rate from potential defects. These critical factors could result in a material reduction in maximum allowable operating pressure when converting to natural gas service.

Cost ranges for pipeline change of service can vary significantly, with expected costs ranging from 10% to 30% of the costs of a new equivalent pipeline system.

4.2.3 Pipeline Stations

Where a pipeline station is to have increased flow capacity the cost of a new station is calculated as per section 2.2.2 Pipeline Stations. This cost is then multiplied by the percentage increase in flow rate to approximate the costs of the upgrade.

4.3 Natural Gas Production Plant

This section describes the methodology for estimating the costs of expanding natural gas production plants.

4.3.1 Conventional Gas

For the capacity of a conventional gas plant to be expanded the following major equipment capacity would require increase to facilitate the upgrade:

- Compression equipment
- TEG Unit(s)
- Pressure vessels
- Expansion of the firefighting systems
- Additional pipework, valves, structural steel and foundations

The cost to increase capacity should utilised the same process as defined in Section 2.3 utilising at proportionate basis, with the addition of a brownfields cost. For brownfields conventional gas plant upgrades an estimated 30% increase applied to additional capacity to add to the total estimated cost to allow for the lower labour productivity when construction activity occurs at an operating facility.

4.3.2 Coal Seam Gas

For the capacity of a coal seam gas plant to be expanded the following major equipment capacity would require increase to facilitate the upgrade:

- Compression equipment
- TEG Unit(s)
- Pressure vessels
- Additional pipework, valves, structural steel and foundations

The cost to increase capacity should utilised the same process as defined in Section 2.3 utilising at proportionate basis, with the addition of a brownfields cost. For brownfields conventional gas plant upgrades an estimated 30% increase applied to additional capacity to add to the total estimated cost to allow for the lower labour productivity when construction activity occurs at an operating facility.

4.4 Natural Gas Compression Facility

The cost range for a new natural gas compression facility is $3,000,000/MW to $6,400,000/MW of compression power. This is based on industry rules of thumb for class 5 estimates [55]. For a typical Australian brownfield compression facility, for the expansion of the facility $3,000,000/MW should be utilised as the majority of ancillary equipment is already installed.

In the case of a natural gas compression facility the additional major equipment to facilitate the upgrade would be:

- Compression equipment
- Pressure vessels
- Additional pipework, valves, structural steel and foundations to connect the new compressor units

4.5 Natural Gas Storage

4.5.1 Underground Gas Storage

Onshore capacity upgrade in this context is an increase in the injection/withdrawal rates, and not the storage volume. The storage volume is based on the depleted gas field that was used and is essentially fixed. Therefore, this section will focus on upgrade to the injection/withdrawal rates.

The capacity upgrade cost is based on step changes i.e. additional well/wells and connecting piping to the plant, as well as more compression/gas processing. It is assumed that existing UGS have been designed with capacity balancing across the main elements of the system, that is the capacity of the plant is matched to that of the wells. Therefore, the capacity increase is proportional to the capital cost of the plant as per Section 2.5.1, with the addition of productivity factor due to completing works at an operating plant. For all brownfields conventional gas plant upgrades an estimated 20% of the upgrade cost, representing the labour cost, should have a 30% increase applied to this portion to allow for lower labour productivity at an operating facility.

4.5.2 Aboveground Gas Storage

Capacity upgrade cost in this context could be an increase across any or a combination of the following:

- Liquefaction rates
- Regasification rates
- Storage volume – achieved with the addition of new LNG storage tank/s

The storage tankage makes up the largest cost component of an AGS facility cost followed by gas conditioning and liquefaction, with the balance of plant and facilities relatively small.

– To assess the relative costs of the main section of the facility requiring expansion the total cost for the expansion requires calculation using typical costs nominated above and the application of the nominated percentages of the cost from the table below. It is noted that there are limitations to the sizing of equipment increases, and a simplified approach is provided in this report.

Table 25 Aboveground Storage Expansion

Asset Area	Base Case	Cost Rate	
Storage tank	1.5 PJ storge	$69 M per each additional 0.5 PJ of storage	
Liquefaction	12 TJ/day	$14.4 M per each additional 3 TJ/day of liquefaction capacity	
Vaporisation and boil off gas	120 TJ/day	$42 M per each additional 30 TJ/day of vaporisation capacity	

[55] Costs from “The Palgrave Handbook of International Energy Economics” 2022.

– The cost rate is taken as the higher end of the range of the new asset costs, to account for lower efficiencies for construction at an operating facility.

5. Natural Gas Refurbishment Cost

5.1 General

This section covers the refurbishment of natural gas assets. The definition of refurbishment for each asset type is defined in each sub-section. Broadly, refurbishment in the context of this report is the work associated with returning the asset to an as-new condition that provides an equivalent level of performance and reliability.

The estimated costs associated with the refurbishment of natural gas assets is heavily dependent on the actual works to be undertaken during the facility shut down and turnaround. As such a portion of the expected capital cost of the new facility is used as a basis of estimate.

5.2 Natural Gas Pipelines

5.2.1 Buried Pipeline

The refurbishment of a buried gas pipeline in the context of this report is the replacement of the coating replacement for nominated sections of pipeline. From historical observation of natural gas pipeline repair activities, it estimated that sections of an existing pipeline undergo coating replacement after a period of 30 to 50 years after being put into service. However, with the coating technology developments since the early 2000's the time frames for this requirement for recoating during the life of the pipeline are expected to significantly extend or may not be required at all.

The process to recoat an operating pipeline requires management and control that is substantively greater than constructing a new pipeline, including:

- Extensive planning prior to the field works inclusive of land holder liaison and liaison with other 3rd parties that are responsible for 3rd party assets that are crossed by the pipeline.
- Excavation of an operating pipeline requires the presence of the pipeline's licensee representative at all times during the excavation.
- The location of the pipeline requires positive identification every 20 m, usually by vacuum truck with the pipeline location being marked.
- The pipeline excavations are normally carried out as daily subsections of the overall section to be recoated in a daylight work period with consideration of the free-spanning ability of the specific pipeline without temporary supports.
- Mechanical excavation is prohibited within one meter of the pipeline, with the remainder of the trench spoil either removed by hand digging or use of a vacuum truck. This often involves benching of the trench or shoring to prevent trench collapse during the works.
- Once the pipeline is exposed the existing coating requires removal without damage to the pipeline metal and once exposed the pipeline is grit blasted to the coating manufactures requirement which also requires inspection to confirm these requirements have been met.
- The new coating is then applied by specialist contractors and time allowed for the recoated pipeline section to cure.
- The pipeline is then backfilled and the ground reinstated.

– As the recoating is a labour-intensive process is estimated that the typical refurbishment cost for the replacement of pipeline coating is $250,000 per kilometre, and is somewhat independent of pipeline diameter.

5.2.2 Pipeline Stations

For gas pipeline stations refurbishment, the following items would be considered to require replacement or renewal:

- Pipeline station control system and instrumentation (due to equipment obsolescence)
- Sandblasting and recoating of all aboveground pipework in-situ
- Replacement of pipeline station components that can only be replaced during shutdown conditions.

These refurbishment works could be expected to be in the order of 10% of the capital cost of an equivalent new pipeline station.

5.3 Natural Gas Production Plant

This section discusses refurbishment activities and estimated costs associated with refurbishments of natural gas production plants.

5.3.1 Conventional Gas

Conventional gas production facilities generally produce natural gas along with varying quantities of hydrocarbon liquids.

The refurbishment items that may require refurbishment during a period of plant shutdown are:

- Compressor units
- Compressor air cooled heat exchangers
- TEG reboiler fuel gas trains
- MEG regeneration fuel gas trains
- Low pressure flare tips and fuel gas trains
- Slug catchers
- Produced water storage tanks
- Produced water pipework
- Control and shutdown systems (due to electronic obsolescence)
- Factory recalibration of custody transfer metering
- Hydrocarbon liquid handling tanks
- Tanker product loading systems
- Firefighting systems.

The estimated cost for a conventional gas plant shutdown refurbishment is in the order of 10% of the cost of the capital of a new plant of similar throughput. This is a high-level estimate based in the proportion of items from a capital cost estimate for a new facility, each plant would vary depend on many factors over the operating life that could increase the costs.

5.3.2 Coal Seam Gas

Coal seam gas production plants differ from conventional gas production facilities, as no hydrocarbon liquids are produced, which leads to a less equipment on site that requires refurbishment during a plant shutdown and also that the equipment on site is not as exposed to the more severe services encountered in a conventional gas plant.

The equipment normally would require refurbishment in a CSG facility generally include:

- Compressor units

- Compressor air cooled heat exchangers
- TEG reboiler fuel gas trains
- Produced water pipework
- Control and shutdown systems (due to electronic obsolescence)
- Factory recalibration of custody transfer metering

As such, the estimated cost of a CG plant shutdown is expected to be in the order of 5% of the plant CAPEX due the reduced equipment required for refurbishment. This is a high-level estimate based in the proportion of items from a capital cost estimate for a new facility, each plant would vary depend on many factors over the operating life that could increase the costs.

5.4 Natural Gas Compression Facility

A natural gas compression facility in normal operation handles only natural gas at sales gas quality so there is no or limited facilities required to handle any impurities present in the product streams encountered in other facilities, so there is minimal equipment on site in comparison to a conventional gas processing facility.

This scenario of minimized equipment leads to a lesser capital cost for the initial facility establishment, however the major equipment such as the compression is the major factor in the capital cost the refurbishment of this major item during a plant shutdown period is expected to be 7.5% of the CAPEX cost of a new facility.

5.5 Natural Gas Storage

5.5.1 Underground Gas Storage

As an underground gas storage facility is effectively the same as a conventional gas production facility, with the exception of the gas flow being bidirectional to cater for gas withdrawal and gas injection modes the refurbishment costs associated with a conventional gas production plant in section 5.3.2 should be applied.

5.5.2 Aboveground Gas Storage

For above ground storage the following items are including in the refurbishment, it is expected that the LNG storage tanks will not require refurbishment:

- Liquefaction equipment
- Vaporisation equipment

The liquefaction equipment major equipment items includes: high-capacity compressors, heat exchangers and potentially turboexpanders. As the liquefaction process is the second largest component of the overall cost as percentage of capital for a new facility can be assumed as 30%. It is therefore expected that the refurbishment of these items would be in the order of 5% of the capital of a new facility.

For the regassification the typical major equipment items that are required to be refurbished are vaporisers, boil-off gas compressors and heat exchangers. This equipment could be assumed as 10-15% of the required capital for an overall expansion. It is therefore expected that the refurbishment of these items would be in the order of 3% of the capital of a new facility.

6. Natural Gas Decommissioning Cost

6.1 General

This section covers the decommissioning and retirement of the natural gas infrastructure. This is also commonly called abandonment of infrastructure.

6.2 Natural Gas Pipelines

Abandonment cost for pipelines is combined to cover the buried pipeline and the pipeline stations. In Australia it is typical to use abandonment provisioning estimation via industry practice guidelines including:

- Australian Standard AS2885.3, Pipelines – Gas and Liquid Petroleum, Part 3: Operations and Maintenance, and reference APGA Environmental Code of Practice, Revision 5, 2022
- Pipeline Abandonment utilising the processes defined by the Canadian Energy Regulator [56], as the methodology and costing process is used as a benchmark in the pipeline industry.
- Technical guide for end-of-life pipeline decommissioning and abandonment, Future Fuels CRC RP3.2-08, September 2021.

Broadly the following is the approach used to develop the costs:

- Decommissioning in place is considered the most cost effective and environmentally sound solution.
- Pipeline purged to gas free, cleaned (liquids and solid materials disposed), pipeline sections under roads, track, water course crossings, concrete grouted.
- Facilities removed to 750 mm below grade and surfaces restored to match surrounds - equipment removed and disposed of, stored or sold.
- Pipeline markers and above ground signage removed.

Estimated costs for typical cross-country pipelines is $5,000 per inch. kilometre basis.

6.3 Natural Gas Production Plant

6.3.1 Conventional Gas

Conventional gas plant decommissioning estimate is based on $16 M for 50 TJ/day capacity. A scaling factor of 0.8 is to be applied for changes in facility capacity. A 0.8 factor has been applied as this is seen as reasonably representative for the scaling due to the low scale efficiencies for decommissioning. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility
- V2 = Capacity of proposed facility
- Alpha = Scale factor

6.3.2 Coal Seam Gas

Coal seam gas plant decommissioning estimate is based on $8 M for 50 TJ/day capacity. A scaling factor of 0.8 is to be applied for changes in facility capacity. A 0.8 factor has been applied as this is seen as reasonably representative for the scaling due to the low scale efficiencies for decommissioning. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility
- V2 = Capacity of proposed facility
- Alpha = Scale factor

[56] https://www.cer-rec.gc.ca/en/applications-hearings/pipeline-abandonment/

6.4 Natural Gas Compression Facility

Abandonment cost for compression facilities is based upon the relevant items from the following estimation via sections from the Canadian Energy Regulator Abandonment Cost Estimates [57] where sections are relevant to compression facilities. This source is used as it has been extensively utilised for several decades in Canada, and is broadly accepted by government, industry, and pipeline customers.

The following items are covered in the costs:

- Removal:
- Mobilisation and demobilisation of equipment and personnel
- Removal of buildings and equipment
- Excavation of piping and appurtenances to allow for removal of underground appurtenances
- Removal of underground appurtenances
- Stockpiling, loading, hauling, and disposal of removed piping, appurtenances, buildings, and equipment
- Backfill and compaction of disturbed soils
- Remediation:
- Remediation of contaminated soil, sediment and/or groundwater, where necessary, including monitoring and testing. Includes, but is not limited to: excavation; hauling, and disposal of contaminated soil; backfilling; field sampling and analytical testing; and, follow-up monitoring
- Reclamation and restoration:
- Assess, reclaim and restore the ground surface to equivalent land use of adjacent lands (or other relevant reclamation objective such as critical habitat for specified wildlife species at risk, landowner requests, Indigenous cultural values, etc.)
- Alleviate any noted soil and/or vegetation issues (e.g., sub-soil compaction, subsidence)
- Seeding
- As relevant, planting of trees and shrubs to restore critical habitat for wildlife species at risk and implementing access control measures
- Erosion control measures
- Weed control
- Monitoring (e.g., up to five years) to confirm reclamation objectives are met
- Estimated costs for typical compressor facility in a rural location is $3 M to $4 M per compression facility [58].

6.5 Natural Gas Storage

6.5.1 Underground Gas Storage

Underground gas storage decommissioning costs are similar to conventional gas plant decommissioning. The estimate is based on $12 M for 50 TJ/day capacity. A scaling factor of 0.8 is to be applied for changes in facility capacity. A 0.8 factor has been applied as this is seen as reasonably representative for the scaling due to the low scale efficiencies for decommissioning. Appling the scaling relationship given by $C1/C2 = (V1/V2)^{Alpha}$, where:

- C1 = Cost of known facility
- C2 = Cost of proposed facility
- V1 = Capacity of known facility

[57] Canade Energy Regulator: Five Year Review of Abandonment Cost Estimates and Set-Aside and Collection Mechanisms 2021
[58] Canade Energy Regulator: Five Year Review of Abandonment Cost Estimates and Set-Aside and Collection Mechanisms 2021

- V2 = Capacity of proposed facility
- Alpha = Scale factor

6.5.2 Aboveground Gas Storage

For the costs associated with decommissioning an aboveground storage facility the main consideration is the size of the facility, however the overall complexity of the two existing facilities are considered similar.

The decommissioning process involves removing natural gas from the facility including pipe work, equipment and storage tanks and de-energising the equipment prior to demolition works proceeding.

GHD has undertaken a decommissioning cost estimate for an aboveground gas storage facility that is representative of the current aboveground gas storage facilities in Australia. The Class 5 estimate for demolition of the facility indexed to 2024 is $12 m.

7. Natural Gas Project Lead Times

The asset project lead times for the nominated gas infrastructure is provided in Table 26. This is based on historic information, current planning timelines, and observed recent trends. The lead times provided in the table are indicative, and each phase has an amount of overlap. The total lead time consider this and provides typical overall lead time. It is noted that projects can stall in the early phase until sufficient commercial alignment exists to move into the approvals and engineering phases. Impacts on lead times from jurisdictional issues are provided after the table covering the base case project lead times.

Broadly, overall project lead times have tended to increase, influenced by the following factors:

- Increasing environmental lead times in some jurisdictions.
- Increasing challenges in some financing aspects of projects [59] [60].
- Some asset developers are increasing their requirements for Final Investment Decision, specially around having all relevant government approvals in place.

Table 26 Natural Gas Infrastructure Project Lead Times

Asset Type	Initial Development Lead Time	Approvals Lead Time*	Engineering and Procurement Lead Time	Construction Lead Time	Total Lead Time
Natural Gas Pipeline	18 months	12 months[61]	12 – 18 months[62]	12 months on the base 100 km pipeline	60 months
Natural Gas Production Plant – Conventional Gas	24 months	18 months	24 months	24 months[63]	90 months
Natural Gas Production Plant – Coal Seam Gas	18 months	18 months	12 months	18 months	66 months
Natural Gas Compression Facility	6 months	12 months[64]	12 months	12 months	42 months

[59] Risks Facing New LNG Projects On The U.S. Gulf And East Coasts
[60] Financing Natural Gas as a Keystone of the Energy Transition | Energy Council
[61] Based on Jemena northern gas pipeline project
[62] Based on Jemena northern gas pipeline project
[63] Oxford Economics Report: 2025 IASR Planning and Installation Cost Escalation Factors
[64] Based on Jemena northern gas pipeline project

Asset Type	Initial Development Lead Time	Approvals Lead Time*	Engineering and Procurement Lead Time	Construction Lead Time	Total Lead Time
Natural Gas Storage – Underground	18 months	24 months	24 months	18 months[65]	84 months
Natural Gas Storage – Aboveground	18 months	18 months	18 months	18 months[66]	72 months

* Approval lead times are the shortest lead times **in Table 26.**

Additional lead times may be incurred through land access issues, environmental, cultural heritage, regulatory and local council approval processes.

AER gives an estimated access approval time of 6 months that can take up to 13 months. It is assumed that these projects are "green fields" projects without prior approvals in-place and an environmental impact study is needed. These studies typically take from 18 to 24 months to complete before being submitted for approval.

Jurisdictional impacts on lead times are covered in the table below, the factors are based on observed differences in states or territories on the approval lead times. The factor represents the difference in approval lead time provided in the table above, the difference should be added to the total lead time for a project in the table above.

Table 27 Jurisdictional Impacts on Lead Times

Jurisdiction *	Pipeline	Production Plant	Compression Facility	Storage Underground	Storage Aboveground
Victoria	18 – 30 months[67] [68]	18 months[69]	18 months[70]	30 months	18 months
New South Wales	12 – 28 months [71] [72]	24 months	17 months[73]	30 months	20 months [74]
Queensland	15 months	15 months[75]	15 months[76]	24 months	18 months
South Australia	12 months	20 months	12 months	24 months	20 months
Northern Territory	15 months	24 months	12 months	24 months	24 months
Australian Federal	15 months[77]	12 months[78]	12 months[79]	36 months[80]	24 months

- * Jurisdictions relevant to the East Coast Gas Market. ACT and Tasmania not included as not relevant to the asset types.

[65] Estimate taken from Iona gas storage facility construction time
[66] Based on construction time for Darwin LNG Project
[67] Western Outer Ring Main Gas Pipeline
[68] Crib Point gas import jetty and Crib Point Pakenham pipeline
[69] Golden Beach Gas Project
[70] Golden Beach Gas Project
[71] Kurri Kurri Lateral Pipeline Project | Planning Portal - Department of Planning and Environment
[72] Queensland-Hunter Gas Pipeline | Planning Portal - Department of Planning and Environment
[73] Kurri Kurri Lateral Pipeline Project | Planning Portal - Department of Planning and Environment
[74] Newcastle Gas Storage Facility | Planning Portal - Department of Planning and Environment
[75] Duration taken from MyMinesOnline median duration for approval for 2022 and 2024
[76] Duration taken from MyMinesOnline median duration for approval for 2022 and 2024
[77] Sourced from EPBC Act Public Portal
[78] EPBC Act Public Portal
[79] EPBC Act Public Portal
[80] EPBC Act Public Portal

8. Asset Technical Life – New Infrastructure

The expected technical life for the nominated infrastructure assets is provided in table 23 below. It is noted that there are numerous factors that can influence an assets technical life, and the ranges presented below are considered representative.

Table 28 Gas Infrastructure Technical Life

Asset Type	Expected Asset Technical Life (Years)	Comments
Natural Gas Pipeline	80 - 100	
Natural Gas Production Plant – Conventional Gas	40 – 50	Typically limited by gas field life
Natural Gas Production Plant – Coal Seam Gas	20 - 30	Typically limited by reserves volume in proximity to the plant.
Natural Gas Compression Facility	30 – 40	Life limited by technological improvements, technical obsolescence of OEM on control, electronic systems, and safety systems. Assumes major overhauls not exceeding 10 years of turbines and compressors.
Natural Gas Storage – Underground	50 - 70	
Natural Gas Storage – Aboveground	50 - 70	
Natural Gas LNG Import Facility	50 - 70	
Carbon Capture Storage Compression	20 – 30	Life limited by technological improvements, technical obsolescence of OEM on control, electronic systems, and safety systems. Assumes major overhauls not exceeding 10 years of turbines and compressors. Typically, more complex compression equipment than used in natural gas compression, resulting in a shorter asset technical life.
Carbon Capture Storage Pipelines	80 - 100	Assumed as the same as for natural gas pipelines. This assumes gas quality is managed to prevent internal corrosion.
Carbon Capture Storage Injection	20 – 30	Life limited to reservoir storage capacity
Hydrogen Blending Buried Pipeline	20 – 30	Assumed life, limited current information as new application.
Hydrogen Blending Pipeline Stations	20 – 30	Assumed life, limited current information as new application.
Hydrogen Blending Compression	20 – 30	Assumed life, limited current information as new application.
Hydrogen Blending Storage	Not available	Assumed as underground storage only, as hydrogen will stay in gas phase for aboveground storage (LNG). Currently the suitability of long-term operation of hydrogen blends in underground storage is subject of ongoing research, specifically focusing on the reservoir implications. The impact on gas process equipment, piping and wells is understood. It is expected that the life will be less than for natural gas service.
Hydrogen Pipeline	20 - 50	Life of pipeline highly dependent on pressure cycles, pressure cycling range, and operating pressure.
Hydrogen Metal Hydride	Up to 30 years	Metal hydrides could last up to 30 years. The vessels that are used to house the hydrides, these being Type IV vessels can also last up to 30 years.
Hydrogen Salt Cavern	50+	Salt caverns in hydrogen service have shown more than 50 years operating life.

Asset Type	Expected Asset Technical Life (Years)	Comments
Biomethane Production	15 - 20	Biogas and biomethane facilities typically have an asset life of 15 to 20 years.
Coal Seam Gas Desalination Plant	10 – 20	Major refurbishment typically required after this period.
Coal Seam Gas Water Pipeline	20 - 50	HDPE PE100 typically has a design life of 100 years. However, this may be reduced by: Cyclic loading during operation, poor installation, poor pipe bedding and backfill and exposure to chemicals. The fittings on a pipeline such as valves typically have a service life of 15-25 years however this could be extended through regular servicing and maintenance.

9. Existing Gas Pipelines – Expected Technical Life

The expected technical life of existing gas pipelines is provided in the table below. This is focused on the major gas pipelines in the east coast gas system, aligned with those major pipelines defined in AEMO's Gas Statement of Opportunities. Gas pipeline technical life is typically considered to be at least 80 to 100 years [81] , assuming sound maintenance practices, and a suitable level of sustaining capital expenditure over the asset life. The remining technical life in this report is likely to differ from that reported by asset owners, commercial regulators, and technical regulators, as their basis is likely to different from that used in this report. Factors such as market demand for the transportation services, the life of gas fields that supply the pipelines, and asset specific integrity and maintenance requirements can materially impact the expected technical life either indirectly or directly.

*Table 29 Expected Technical Life – Major Gas Transmission Pipelines**

Pipeline Name	Location	Year Operations Commenced ***	Current Age (Years)	Expected Remaining Technical Life Low (Years)	Expected Remaining Technical Life High (Years)
South West Queensland Pipeline	Queensland, South Australia	1996	29	51	71
Moomba – Sydney Pipeline	New Soth Wales, South Australia, Queensland	1974	51	29	49
Sout West Pipeline	Victoria	1991	34	46	66
Northern Gas Pipeline	Northern Territory, Queensland	2019	6	74	94
Moomba – Adelaide Pipeline System	South Australia	1969	56	24	44
Eastern Gas Pipeline	Victoria, New South Wales	2000	25	55	75
Port Campbell to Adelaide Pipeline (SEA Gas Pipeline)	Victoria, South Australia	2004	21	59	79
Amadeus Gas Pipeline	Northern Territory	1986	39	41	61
Carpentaria Gas Pipeline	Queensland	1998	27	53	73

[81] Add in reference

Pipeline Name	Location	Year Operations Commenced ***	Current Age (Years)	Expected Remaining Technical Life Low (Years)	Expected Remaining Technical Life High (Years)
Victoria Northern Interconnect	New South Wales, Victoria	2015^	10	70	90
Longford – Melbourne Pipeline	Victoria	1969^	56	24	44
Roma Brisbane Pipeline	Queensland	1969	56	24	44

* Listing and naming convention as stated in Section 3.3.1 of 2024 GSOO. A selection of other pipelines as listed in table 7 of the 2024 GSOO have been included, where these are considered material over the planning horizon defined in this report.

**Data sourced from asset owner's website.

^Data sourced from article by The Australian Pipeliner.

10. Availability of Salt Caverns

There are no operational salt caverns in Australia. Salt caverns are used in several countries, including the USA [82] to store petroleum including natural gas, liquified petroleum gas, crude oil, as well as hydrogen in several locations in the US Gulf Coast area, and Europe as covered in 2.9.4 Salt Cavern. The focus of salt caverns for this report is in relation to hydrogen storage.

Australia has limited potential for the application of salt caverns when compared to countries where salt caverns have been used extensively. The CSIRO published a peer-reviewed paper on potential salt cavern locations [83] in 2023, titled Australian salt basins – options for underground hydrogen. The abstract states that the study correlates paleogeography and paleoclimate reconstructions with evidence of salt in wells, and in geophysical and geochemical data. This means that the outcome is identifying areas that may be suitable, however there is substantive work required to convert this into a determination of what areas would be a suitable play for salt cavern storage.

The locations that may be prospective for salt caverns are identified as:

Onshore Basins

- Adavale Basin Queensland (North West of Charleville)
- Officer Basin Western Australia (North East of Kalgoorlie)
- Amadeus Basin Northern Territory (South of Alice Springs)
- **Offshore Basins**
- Polda Basin South Australia (North West of Port Lincoln)

For this report, the basins of interest are those that may have a connection to the East Coast Gas Market, therefore most prospective basin from this perspective is the Adavale Basin. Whist there is no current gas production in the Adavale Basin, there has been recent exploration activity in this basin, and the basin is transected by a small capacity natural gas pipeline. The South West Queensland Pipeline traverses the southern edge of the Adavale Basin.

[82] Fact Sheet: Underground Natural Gas Storage Caverns | PHMSA
[83] CSIRO PUBLISHING | The APPEA Journal: Australian salt basins – options for underground hydrogen storage

11. Cost Forecasting 2024 to 2055

11.1 Cost representation

GHD's approach to representing average price changes of gas infrastructure costs is similar to the approach used for electricity transmission capital expenditure in the 2025 Transmission Cost Database (TCD). Cost elements are grouped together in broad categories where they are likely to experience similar price changes over time. Each cost element category is assigned a fixed combination of underlying price changes, where:

- the change in price of any cost element category is represented by a weighted combination of changes in various published price indices;
- the published price indices represent the cost of major component materials of each cost element; and
- the weights assigned to each component price are representative of the proportion of each component and are fixed on the basis that the cost elements include universal, mature technologies.

The change in cost of a category over a specified period may be calculated using *Equation 1*, as the summation from *i* to *j* of component prices *p* using weights *w*, where %Δ shows a percentage change.

$$\%\Delta cost_e = \sum_{i=1}^{j} w_i \%\Delta p_i$$

Equation 1 Calculation of cost element price changes

The detailed cost representation is shown below in Table 1 to 4.

- Table 30 shows major gas infrastructure cost element categories and included subcategories
- **Table 31** shows the major components used to construct each cost element category, including equipment, materials and indirect project costs including design, construction and project management etc.
- Table 32 shows published price indices that best represent the major component costs and historical sources of those price indices
- Table 33 shows the weights used to combine the price indices to represent the in put costs of each cost element category.

We have selected ten price escalators to be used in various combinations to represent the cost element categories. However, land value will be escalated differently for each Australian state covered.

Table 30 Cost element grouping across subcategories

Cost element categories	Subcategories
Buried pipeline	Gas pipeline – buried pipeline Carbon capture and storage – pipeline Carbon capture and storge – injection Hydrogen transport pipeline
Facility	Production plant – Conventional Gas Production plant – Coal Seam Gas Compression facility Storge – Underground (depleted reservoir) Storage – Aboveground (LNG) Carbon capture and storage – compression Biomethane production CSG desalination plant

Cost element categories	Subcategories
Import facility	LNG import facility
Hydrogen blending pipeline	Gas pipeline – Buried pipeline
Hydrogen blending facility	Gas pipeline – Pipeline station Process facility Compression Storage
Hydrogen transport	Trucking – metal hydride storage
Hydrogen storage salt cavern	Salt cavern
Coal Seam Gas water pipeline	CSG water pipeline

Table 31 Cost elements

Cost element categories	Associated cost components
Buried pipeline	Imported steel (pipe)
Facility	Imported steel (piping) Australian-sourced equipment Imported equipment
Import facility	Australian-sourced equipment Imported equipment
Hydrogen blending pipeline	Imported steel
Hydrogen blending facility	Imported steel (piping) Australian-sourced equipment Imported equipment
Hydrogen transport	Diesel Australian-sourced equipment Imported equipment
Hydrogen storage salt cavern	Imported steel (piping) Australian-sourced equipment Imported equipment
Coal Seam Gas water pipeline	Plastic piping Australian-sourced equipment Imported equipment
Indirect costs	General capital expenditure (catch-all) Construction labour Design and project management labour Land value Environmental offsets

Table 32 Component prices

Component price	Source	Description
General capital expenditure	ABS, Australian National Accounts, 5206.0 (Table 5)	Implicit Price Deflator for Gross Fixed Capital Formation
Imported steel	ABS, International Trade Price Indexes, 6457.0 (Tables 14 and 15)	22 Fabricated metal product manufacturing
Plastic piping	ABS, Producer Price Indexes, 6427.0 (Table 12)	1912 Rigid and semi-rigid polymer product manufacturing
Australian-sourced equipment	ABS, Producer Price Indexes, 6427.0 (Table 12)	2451 Pump and compressors manufacturing

Component price	Source	Description
Imported equipment	ABS, International Trade Price Indexes, 6457.0 (Tables 4 to 6)	Machinery and industrial equipment
Diesel	ABS, Producer Price Indexes, 6427.0 (Table 12)	1701 Petroleum refining and petroleum fuel manufacturing
Construction labour	ABS, Producer Price Indexes, 6427.0, Construction output (Table 17)	3109 Other heavy and civil engineering construction
Design & project management labour	ABS, Producer Price Indexes, 6427.0, Professional, scientific and technical services output (Table 24)	6923 Engineering design and engineering consulting services
Exchange rate	Reserve Bank of Australia, Indicative monthly exchange rates	AUD/USD exchange rate
Land value	Australian Government Department of Agriculture, Fisheries and Forestry (DAFF), ABARES Farmland Price Indicator	Mean farmland values by State

Table 33 Weights of each component price in each cost element category

Cost element category	General capital expenditure	Imported steel (piping)	Plastic piping	Australian-sourced equipment	Imported equipment	Diesel	Construction labour	Design & project management labour	Exchange rate	Land value
Buried pipeline	0.1	0.3				0.1	0.2	0.1	0.2	
Facility	0.1			0.1	0.2	0.1	0.2	0.1	0.1	0.1
Import facility	0.1			0.1	0.1	0.1	0.3	0.1	0.1	0.1
Hydrogen blending pipeline					0.1		0.5	0.3	0.1	
Hydrogen blending facility					0.3		0.5	0.1	0.1	
Hydrogen transport	0.1				0.8				0.1	
Hydrogen storage salt cavern					0.3	0.2	0.3		0.1	0.1
Coal Seam Gas water pipeline	0.1		0.4			0.1	0.3	0.1		

11.2 Modelling price change

We project future cost element category price changes by applying the fixed weights as shown above to projected future values of the component prices. The trajectory of each component price is projected in a manner consistent with our understanding of price determination and using an econometric model alongside a set of reasonable input assumptions.

Our approach to projecting component prices draws on an abundant literature on general price forecasting and previous attempts to forecast Australian manufacturing prices[84]. From this we generally consider the following concepts:

- The rate of increase in prices is an expression of excess demand

[84] E.g., Shepherd, David, and Ciaran Driver (2003) "Inflation and Capacity Constraints in Australian Manufacturing Industry", The Economic Record, Vol. 79, No. 245, June, pp 182-195.

- Changes in input costs can take time to be passed on as changes in output prices
- Imported inflation is highly significant for Australia
- Inflation expectations may be influential in determining actual outcomes and explaining persistently high or low actual inflation

This approach implicitly reflects any future assumptions about supply chain constraints that could elevate gas infrastructure capital costs

Our econometric models include data that represents the above concepts, to the extent that they can be empirically justified, for each of the first eight component prices shown in **Table 32**. Meanwhile the exchange rate will be determined exogenously land values will be determined by their long-term historical growth rates.

11.3 Price index forecasting

11.3.1 Inputs

Our preliminary development of individual econometric models uses an auto-regressive distributed lag (ARDL) structure that:

- easily facilitates the inclusion of lagged dependent variables, representing backwards-looking inflation expectations;
- lagged explanatory variables, representing progressive impacts over time due to “sticky” input costs; and
- thorough statistical testing for the persistence of a long-run relationship.

The inputs selected for each model will be chosen from those shown in **Table 34** on the basis of economic interpretation and statistical significance. Our models will generally use quarterly observations between September 1998 and December 2024. The number of dependent variable and dynamic regressor lags, both set at a maximum of 4, will be chosen automatically on the basis of the Akaike information criterion (AIC). The long-run cointegrating coefficients for each model will be assessed for significance and the Bounds Test F-statistic. The final selected models will be re-estimated as a system using Seemingly Unrelated Regression (SUR). The SUR method estimates the parameters of all equations simultaneously, so that the parameters of each single equation also take the information provided by the other equations into account. This results in greater efficiency of the parameter estimates, because additional information is used to describe the system.

Table 34 Data used as potential model inputs

Name	Description	Justification	Source of historical data
EXPECT	Expected inflation rate	Expectations influence price setting	RBA
UR	Unemployment rate, persons	Historical empirical inverse relationship between inflation and the unemployment rate (the Phillips Curve)	ABS
DFD	Domestic Final Demand	An increased rate of change of domestic spending puts upward pressure on prices	ABS
CONSTRUCTION_VOL	Engineering construction activity (real $’000)	An increased rate of change in engineering construction activity puts upward pressure on prices of sector-specific inputs	ABS
ULC	Non-farm unit labour costs (index)	Manufacturing and construction input costs will feed through to output costs	ABS
CRUDE	Brent oil price (USD/bbl)	Many manufactured goods are energy intensive, and the oil price represents a major international cost input	EIA (USA)

Name	Description	Justification	Source of historical data
USD	USD/AUD exchange rate	An increase in the exchange rate represents falling prices of imported goods	RBA
IMPORTS	Imported goods and services price deflator (index)	The cost of imported goods and services is a major component of domestic inflation	ABS
METALS	Commodity price index (base metals AUD)	The price of domestically produced basic metal products competes with imported products	RBA

11.3.2 Results

The linear equations for each dependent variable were generally constructed in logarithmic difference terms, where the independent (left hand side) variables used in each model were selected by testing their economic and statistical significance. All models, as required by the ARDL structure, included a lagged dependent variable (i.e., the previous period's value of itself) and contemporaneous and up to four lagged values for each included independent variable.

Table 35 shows the input variables that were included in each equation. There is no equation for the exchange rate as that is projected as an input assumption that it will revert to an average level and remain constant for much of the forecast period. We included a dummy variable for the introduction of GST in 2000, but this was only strongly significant for our DIESEL equation.

Table 35 Selected input variables for each equation

	Lagged dependent variable	EXPECT/100	1/UR	DFD	CONSTRUCTION_VOL	ULC	100*CRUDE/AUD	CRUDE	AUD	IMPORTS	GST
General capital expenditure	√	√	√			√				√	
Imported steel	√		√					√		√	
Plastic piping	√		√			√				√	
Australian-sourced equipment	√		√						√		
Imported equipment	√				√					√	
Diesel	√		√				√				√
Construction labour	√	√		√		√				√	
Design & project management labour	√			√		√			√		

The estimated models provide evidence that:

- General capital expenditure is positively correlated to inflation expectations, the inverse of the unemployment rate, unit labour costs and import prices.
- Imported steel is positively correlated to the inverse of the unemployment rate, the oil price and import prices.
- Plastic piping is positively correlated to the inverse of the unemployment rate, unit labour costs and import prices.
- Australian sourced equipment is positively correlated to the inverse of the unemployment rate and inversely correlated with the exchange rate.
- Imported equipment is positively correlated to the volume of construction work and import prices.

- Diesel is positively correlated to the inverse of the unemployment rate, the price of oil in Australian dollars, and the introduction of GST also had a small but significant impact.
- Construction labour is positively correlated to inflation expectations, domestic economic activity, unit labour costs and import prices.
- Design and project management is positively correlated to domestic economic activity, unit labour costs, and inversely correlated with the exchange rate.

The actual number of dependent variable and dynamic regressor lags, was chosen on the basis of the Akaike information criterion (AIC). The long-run cointegrating coefficients for each model were assessed for significance, and observation of the Bounds Test F-statistic generally suggested a strong long-run association between the dependent variable and the chosen drivers. The final selected models were then re-estimated as a system using Seemingly Unrelated Regression (SUR). The SUR method estimates the parameters of all equations simultaneously, so that the parameters of each single equation also take the information provided by the other equations into account. This results in greater efficiency of the parameter estimates, because additional information is used to describe the system.

Table 36 shows summary statistics for each individual equation, explained below. Probabilities shown are in the range zero to one

- R squared is low in all cases, which is reflective of a relationship that does not explain all the detailed quarterly variations in the data.
- The Durbin-Watson (DW) statistics are close to 2, showing low serial correlation at one lag which is to be expected for an equation including a lagged dependent variable. However, the F-statistic generated from a Lagrange Multiplier (LM) test picks up serial correlation at multiple lags (4 in this case). A high probability is associated with there being no serial correlation, hence this is not of concern in most cases shown in Table 36. The presence of serial correlation does not cause bias in the coefficient estimates (and therefore is not of grave concern in a model used for forecasting), although it may may affect the calculation of statistical significance.
- The Breusch-Pagan-Godfrey test for homoscedasticity produces an F-statistic and an observations-times-R-squared number, which are associated with a Chi-Square probability. In this case a high probability indicates a high chance that the equation is homoscedastic. In many cases in Table 36 there is insignificant homoscedasticity, meaning that the variance of the residual is not constant and calculated t-statistics may appear more significant than they really are.
- The Bounds test F-statistic is used to determine if there is a long-run relationship between the variables in an ARDL equation. If the F-statistic is above the critical range (or bounds) it suggests the presence of cointegration, which means that, as the sample increases, the coefficient estimates converge to their true values more rapidly than if cointegration was not present. All the values in the table are significantly above the bounds, which supports a reliable long-run relationship between the dependent variables and the chosen driver variables.

Table 36 Summary statistics for each equation [EXAMPLE ONLY]

	Adjusted R squared	DW statistic	LM (4) F-statistic probability	Breusch-Pagan-Godfrey Chi-Square probability	Bounds test F-statistic (10% critical value range)
General capital expenditure	0.5828	2.2063	0.2561	0.5500	17.12 (2.37-3.20)
Imported steel	0.8147	2.1045	0.7679	0.0809	122.69 (2.37-3.20)
Plastic piping	0.2961	1.8326	0.0378	0.1050	17.53 (2.37-3.20)
Australian-sourced equipment	0.0721	1.9072	0.2513	0.0040	39.85 (2.63-3.35)
Imported equipment	0.6903	1.9668	0.5423	0.0042	14.44 (2.63-3.35)

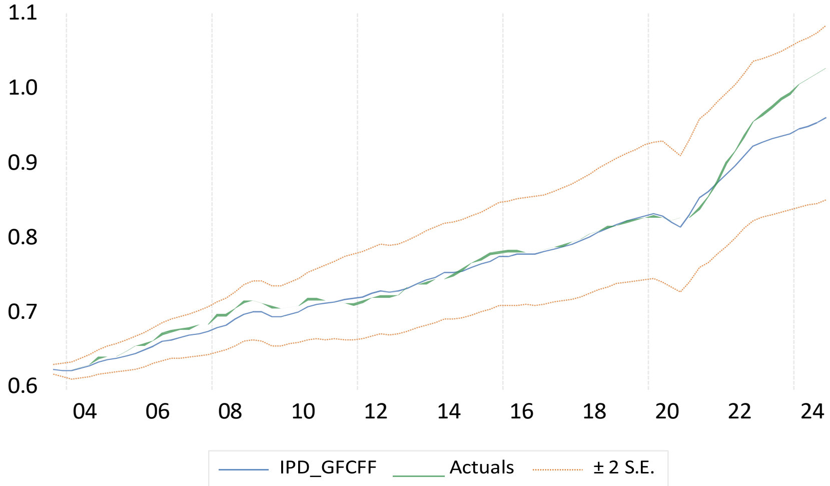
	Adjusted R squared	DW statistic	LM (4) F-statistic probability	Breusch-Pagan-Godfrey Chi-Square probability	Bounds test F-statistic (10% critical value range)
Diesel	0.8657	2.1944	0.0990	0.3544	73.09 (2.63-3.35)
Construction labour	0.4831	1.8677	0.7412	0.2779	17.98 (2.37-3.20)
Design & project management labour	0.4440	1.9818	0.0584	0.0023	22.19 (2.37-3.20)

We tested the long-run forecasting performance of each equation by re-estimating it using only data to 2014, then producing an out-of-sample forecast using historical input data for the last 10 years. This is the equivalent of having made a forecast 10 years ago with perfect foresight of the input data. The resulting forecasts are illustrated in the following figures. The closer the forecast (green line) remains to the actual (blue line) the more accurate the forecast. A generally stable forecast should remain within the 2-standard error (red) band. The historical forecast performance shown is an indication but not a guarantee of future forecasting performance, and future performance also depends on the accuracy of our assumptions about future values of the input variables.

The forecasting performance is also evaluated below in the boxes accompanying each figure. These boxes show mean accuracy measure, such as absolute percentage error (MAPE), and the proportions of the Theil inequality coefficient, including the bias component which should be low for a reliable forecast in the long run.

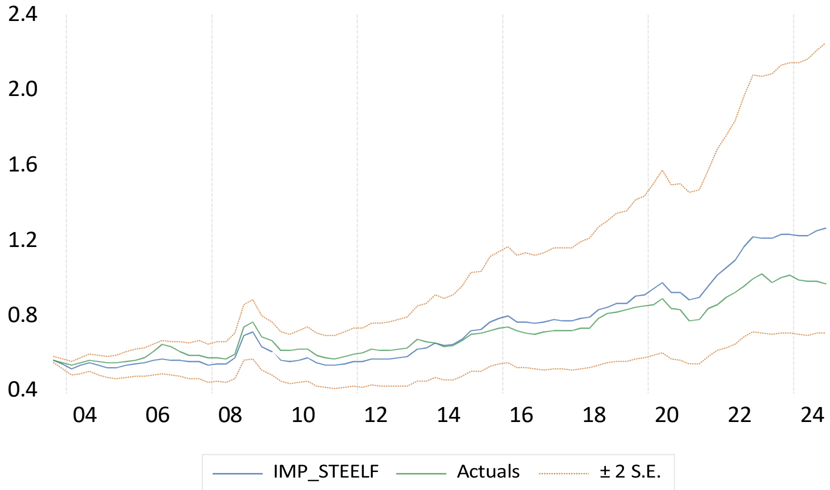
Each of our forecast models generally follows its actual long-run path within a 2-standard error (95% probability) band over the 10-year horizon and bias is in an upward direction for some forecasts and downwards for others.

Figure 3 ***Long-run forecast performance out-of-sample, general capital expenditure***



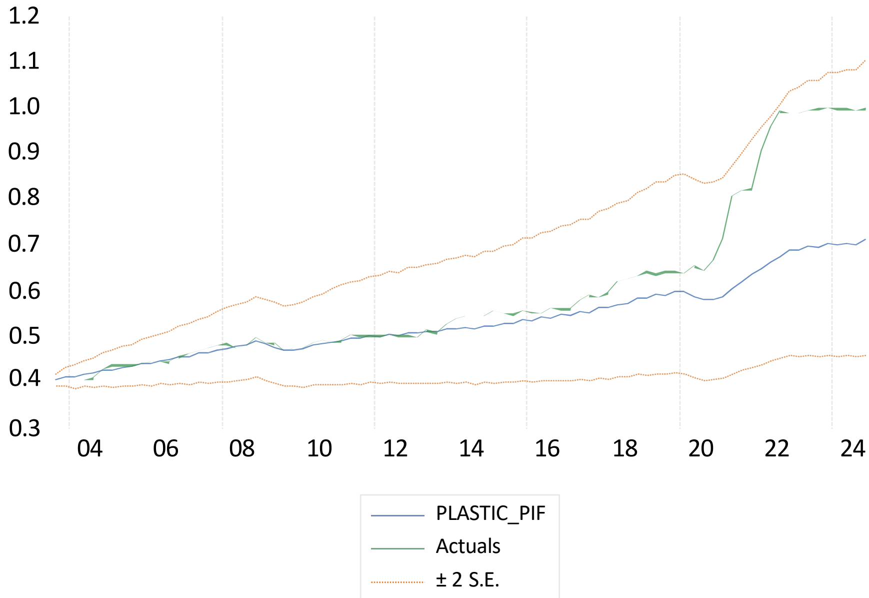
Forecast: IPD_GFCFF	
Actual: IPD_GFCF	
Forecast sample: 2003Q3 2024Q4	
Included observations: 86	
Root Mean Squared Error	0.019754
Mean Absolute Error	0.012032
Mean Abs. Percent Error	1.429276
Theil Inequality Coef.	0.012780
Bias Proportion	0.276559
Variance Proportion	0.272191
Covariance Proportion	0.451250
Theil U2 Coefficient	2.444102
Symmetric MAPE	1.451182

Figure 4 ***Long-run forecast performance out-of-sample, imported steel***



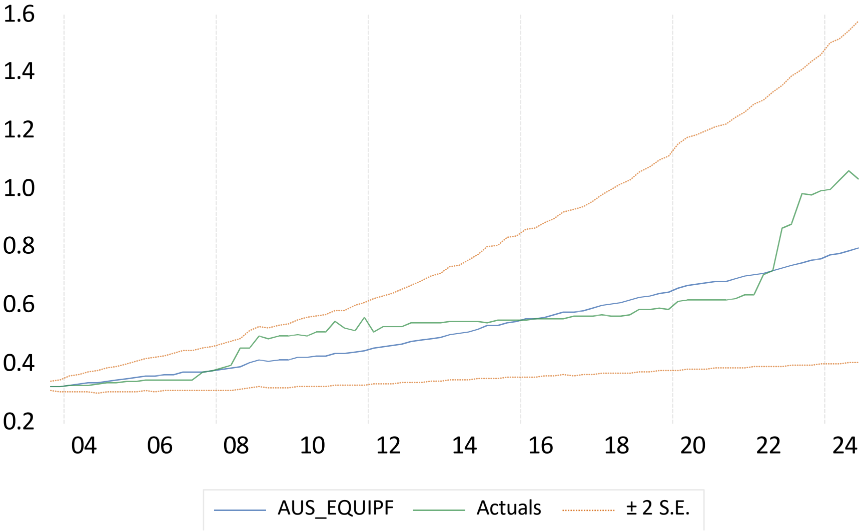
Forecast: IMP_STEELF	
Actual: IMP_STEEL	
Forecast sample: 2003Q3 2024Q4	
Included observations: 86	
Root Mean Squared Error	0.097245
Mean Absolute Error	0.070070
Mean Abs. Percent Error	8.761584
Theil Inequality Coef.	0.064221
Bias Proportion	0.118066
Variance Proportion	0.777491
Covariance Proportion	0.104444
Theil U2 Coefficient	2.645546
Symmetric MAPE	8.422682

Figure 5 ***Long-run forecast performance out-of-sample, plastic piping***



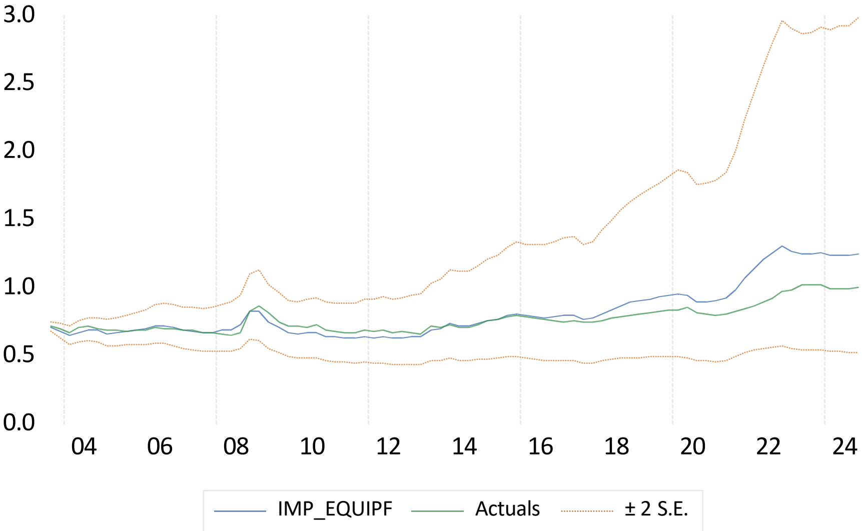
Forecast: PLASTIC_PIF	
Actual: PLASTIC_PIPE	
Forecast sample: 2003Q3 2024Q4	
Included observations: 86	
Root Mean Squared Error	0.121231
Mean Absolute Error	0.066155
Mean Abs. Percent Error	8.080733
Theil Inequality Coef.	0.104263
Bias Proportion	0.290038
Variance Proportion	0.637856
Covariance Proportion	0.072106
Theil U2 Coefficient	5.146177
Symmetric MAPE	9.061832

Figure 6 Long-run forecast performance out-of-sample, Australian sourced equipment



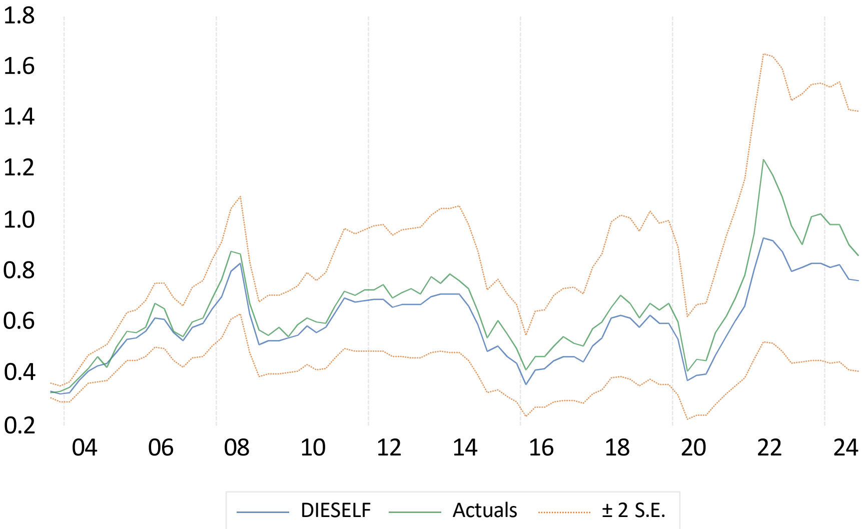
Forecast: AUS_EQUIPF	
Actual: AUS_EQUIP	
Forecast sample: 2003Q3 2024Q4	
Included observations: 86	
Root Mean Squared Error	0.085595
Mean Absolute Error	0.057965
Mean Abs. Percent Error	9.019814
Theil Inequality Coef.	0.076405
Bias Proportion	0.124096
Variance Proportion	0.189661
Covariance Proportion	0.686242
Theil U2 Coefficient	2.895318
Symmetric MAPE	9.528267

Figure 7 Long-run forecast performance out-of-sample, Imported equipment



Forecast: IMP_EQUIPF	
Actual: IMP_EQUIP	
Forecast sample: 2003Q3 2024Q4	
Included observations: 86	
Root Mean Squared Error	0.114429
Mean Absolute Error	0.073879
Mean Abs. Percent Error	8.731539
Theil Inequality Coef.	0.071344
Bias Proportion	0.193691
Variance Proportion	0.692430
Covariance Proportion	0.113879
Theil U2 Coefficient	3.515993
Symmetric MAPE	8.119416

Figure 8 Long-run forecast performance out-of-sample, diesel



Forecast: DIESELF	
Actual: DIESEL	
Forecast sample: 2003Q3 2024Q4	
Included observations: 86	
Root Mean Squared Error	0.084981
Mean Absolute Error	0.065026
Mean Abs. Percent Error	9.066357
Theil Inequality Coef.	0.065552
Bias Proportion	0.578369
Variance Proportion	0.233199
Covariance Proportion	0.188432
Theil U2 Coefficient	1.030059
Symmetric MAPE	9.644687

Figure 9 Long-run forecast performance out-of-sample, construction labour

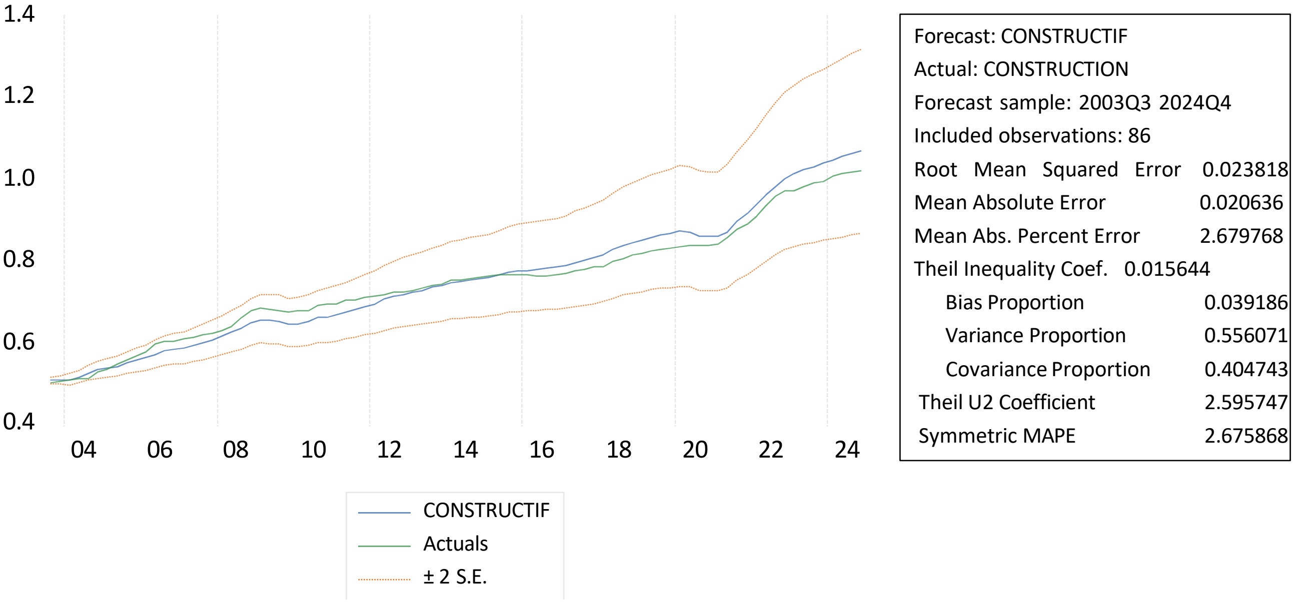
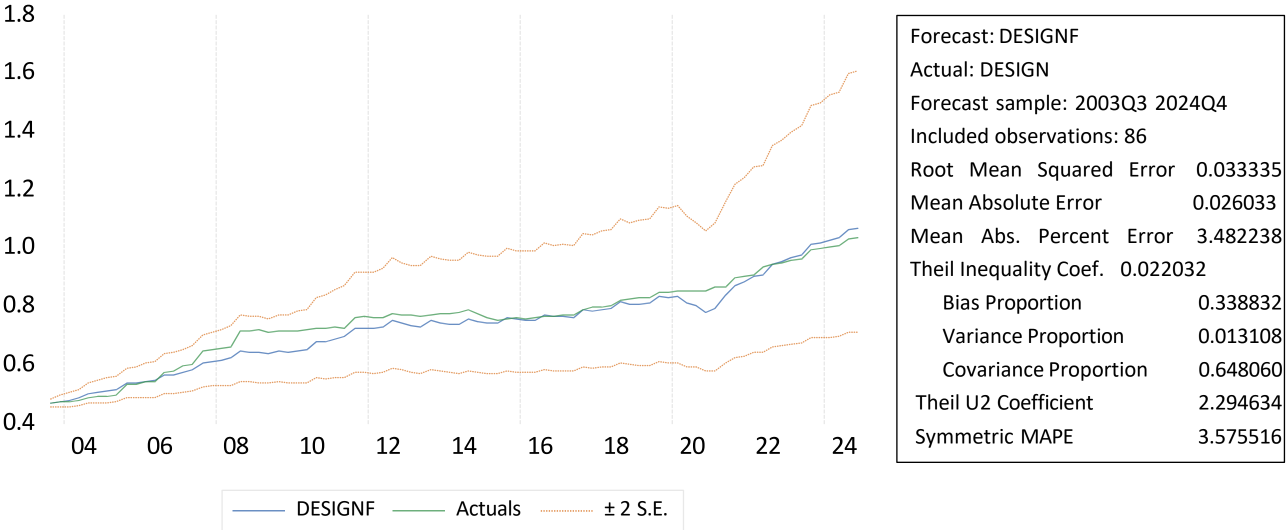


Figure 10 Long-run forecast performance out-of-sample, design and project management



11.3.3 Exchange rate and land values

The exchange rate may be influential in determining some of our modelled prices and will be determined by assuming a return to its long-run value sourced from economic forecasts commissioned by AEMO for the current ISP Inputs and Assumptions.

Land values are subject to different inflationary pressures to manufactured inputs and may be dominated by long cycles. We chose to project land values escalators by applying a constant growth rate, which we calculated by drawing a regression through the logarithms of the most recent 20 years of actual data, the slope of which represents the annual growth rate.

11.3.4 Forecast price escalators

Our price index forecasts are presented in Table 37 and the resulting cost element forecast are presented in Table 38 below. We present all indices with a common base of 1.000 in 2023/24, the last full year for which historical data are available. Section 12.5 provides guidance to applying these cost escalators to derive forecast cost element prices.

Table 37 Modelled price indices and projections (real prices index 2023/24 = 1)[85]

	Imported steel (piping)	Plastic piping	Australian-sourced equipment	Imported equipment	Diesel	Construction labour	Design & project management labour	Exchange rate
2013/14	0.889	0.713	0.730	0.953	1.037	1.004	1.038	1.872
2014/15	0.895	0.722	0.715	0.959	0.824	0.997	1.005	1.652
2015/16	0.933	0.708	0.705	0.998	0.614	0.977	0.968	1.414
2016/17	0.911	0.721	0.710	0.952	0.644	0.977	0.975	1.461
2017/18	0.916	0.750	0.707	0.937	0.731	0.985	0.996	1.473
2018/19	0.998	0.779	0.705	0.971	0.815	0.998	1.008	1.332
2019/20	1.043	0.779	0.725	1.001	0.700	1.003	1.024	1.232
2020/21	0.975	0.852	0.742	0.962	0.626	1.014	1.032	1.372
2021/22	0.992	0.989	0.732	0.958	1.029	1.014	1.025	1.238
2022/23	1.032	1.035	0.899	1.010	1.080	1.011	0.991	1.064
2023/24	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2024/25	0.953	0.988	1.016	0.956	0.792	0.991	1.005	0.991
2025/26	0.966	1.008	1.047	0.939	0.637	0.993	1.015	0.980
2026/27	0.992	1.014	1.078	0.942	0.592	1.003	1.030	0.918
2027/28	0.990	1.022	1.094	0.923	0.542	1.012	1.049	0.945
2028/29	0.994	1.030	1.109	0.907	0.483	1.022	1.066	0.981
2029/30	1.005	1.039	1.123	0.911	0.497	1.033	1.081	0.930
2030/31	1.010	1.050	1.134	0.906	0.504	1.042	1.097	0.893
2031/32	1.015	1.059	1.148	0.900	0.491	1.052	1.114	0.865
2032/33	1.023	1.069	1.162	0.896	0.482	1.062	1.131	0.837
2033/34	1.028	1.077	1.176	0.889	0.472	1.071	1.145	0.814
2034/35	1.035	1.085	1.188	0.885	0.461	1.077	1.152	0.789
2035/36	1.043	1.093	1.200	0.881	0.441	1.081	1.159	0.764
2036/37	1.052	1.101	1.212	0.877	0.423	1.086	1.165	0.741
2037/38	1.060	1.109	1.224	0.873	0.405	1.091	1.172	0.718
2038/39	1.069	1.117	1.236	0.869	0.387	1.096	1.178	0.696
2039/40	1.077	1.125	1.248	0.865	0.370	1.101	1.185	0.674
2040/41	1.086	1.133	1.260	0.861	0.354	1.106	1.192	0.654
2041/42	1.095	1.141	1.272	0.857	0.339	1.111	1.198	0.633
2042/43	1.104	1.150	1.284	0.853	0.324	1.115	1.205	0.614
2043/44	1.113	1.158	1.296	0.850	0.309	1.120	1.212	0.595
2044/45	1.123	1.167	1.309	0.846	0.295	1.125	1.219	0.577
2045/46	1.132	1.175	1.321	0.843	0.282	1.130	1.225	0.559
2046/47	1.142	1.184	1.334	0.839	0.269	1.135	1.232	0.542
2047/48	1.152	1.192	1.347	0.836	0.257	1.140	1.239	0.525
2048/49	1.162	1.201	1.359	0.833	0.245	1.145	1.246	0.509
2049/50	1.172	1.210	1.372	0.830	0.234	1.150	1.253	0.493
2050/51	1.182	1.219	1.385	0.827	0.223	1.156	1.260	0.478
2051/52	1.193	1.227	1.398	0.824	0.213	1.161	1.267	0.463
2052/53	1.204	1.236	1.412	0.821	0.203	1.166	1.274	0.449
2053/54	1.215	1.246	1.425	0.818	0.193	1.171	1.281	0.435

[85] This table does not show land price indices for each state.

Table 38 Gas infrastructure cost element indices and forecasts (real prices index 2023/24 = 1)[86]

	Buried pipeline	Facility (NSW)	LNG import facility (NSW)	Hydrogen blending pipeline	Hydrogen blending facility	Hydrogen transport	Hydrogen storage salt cavern (NSW)	Coal Seam Gas water pipeline
2013/14	1.150	1.006	1.011	1.096	1.079	1.049	1.029	0.894
2014/15	1.081	0.963	0.967	1.061	1.052	1.032	0.969	0.871
2015/16	1.016	0.919	0.917	1.020	1.026	1.040	0.910	0.835
2016/17	1.023	0.927	0.930	1.022	1.018	1.008	0.916	0.844
2017/18	1.039	0.938	0.943	1.033	1.021	0.997	0.933	0.868
2018/19	1.048	0.949	0.952	1.031	1.024	1.010	0.956	0.893
2019/20	1.032	0.938	0.938	1.032	1.027	1.024	0.934	0.885
2020/21	1.035	0.954	0.959	1.050	1.036	1.007	0.937	0.911
2021/22	1.053	0.990	0.995	1.034	1.021	0.990	1.014	1.005
2022/23	1.032	1.005	1.005	1.010	1.014	1.014	1.026	1.024
2023/24	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2024/25	0.962	0.950	0.953	0.992	0.982	0.964	0.922	0.972
2025/26	0.949	0.935	0.941	0.993	0.978	0.949	0.886	0.966
2026/27	0.944	0.935	0.941	0.997	0.979	0.945	0.878	0.969
2027/28	0.948	0.937	0.946	1.008	0.982	0.933	0.871	0.971
2028/29	0.954	0.941	0.952	1.020	0.988	0.924	0.864	0.974
2029/30	0.952	0.946	0.958	1.025	0.991	0.921	0.870	0.983
2030/31	0.950	0.951	0.964	1.030	0.992	0.914	0.873	0.993
2031/32	0.949	0.954	0.969	1.037	0.994	0.906	0.872	1.000
2032/33	0.948	0.959	0.975	1.044	0.997	0.901	0.874	1.008
2033/34	0.947	0.963	0.981	1.049	0.998	0.893	0.874	1.014
2034/35	0.945	0.966	0.985	1.051	0.998	0.887	0.874	1.018
2035/36	0.942	0.968	0.988	1.053	0.997	0.881	0.872	1.021
2036/37	0.940	0.970	0.991	1.054	0.997	0.875	0.871	1.025
2037/38	0.938	0.973	0.995	1.056	0.996	0.870	0.870	1.028
2038/39	0.936	0.976	0.999	1.058	0.996	0.864	0.870	1.032
2039/40	0.934	0.979	1.003	1.060	0.996	0.859	0.870	1.036
2040/41	0.932	0.983	1.008	1.062	0.996	0.854	0.870	1.040
2041/42	0.931	0.987	1.013	1.064	0.996	0.849	0.871	1.043
2042/43	0.930	0.992	1.018	1.066	0.996	0.844	0.872	1.047
2043/44	0.929	0.997	1.024	1.068	0.996	0.839	0.874	1.051
2044/45	0.929	1.002	1.030	1.071	0.996	0.835	0.876	1.056
2045/46	0.928	1.008	1.036	1.073	0.996	0.830	0.879	1.060
2046/47	0.928	1.014	1.043	1.075	0.997	0.826	0.882	1.064
2047/48	0.928	1.020	1.051	1.078	0.997	0.821	0.885	1.069
2048/49	0.928	1.027	1.058	1.081	0.998	0.817	0.889	1.073
2049/50	0.929	1.035	1.067	1.083	0.999	0.813	0.893	1.078
2050/51	0.930	1.042	1.075	1.086	1.000	0.809	0.898	1.082
2051/52	0.931	1.050	1.084	1.089	1.000	0.805	0.904	1.087
2052/53	0.932	1.059	1.094	1.092	1.001	0.802	0.909	1.092
2053/54	0.933	1.068	1.103	1.095	1.002	0.798	0.916	1.097

[86] This table only shows the index for NSW where the cost index varies by state due to different rates of land cost escalation.

12. Using the Databases

12.1 General

Two supporting databases are provided as outputs to this study. The first is the Master Cost Database, this database summarises the cost of developing projects, carried out under a typical Business as Usual (BAU) scenario to provide a base case class 5 cost estimate. The second is the Adjustment Factors Database, this provides a set on adjustment factors and risk factors that need to be applied to the Master Cost Database, to cater for project specific attributes. These adjustment factors and risk factors will either increase or decrease the base case cost for projects from the BAU case. For example, the location factor accounts for a project being located in Urban, or Regional, or Remote area. While the cultural risk factor accounts for a project having either Low, BAU, or High impact due to cultural heritage.

The values applied to the adjustment factors and risk factors are specific to the asset covered in this study and will be different to other energy assets and the supply chains in these markets. In broad terms the current gas market activities in Australia are considered to be in BAU market conditions, and the current costs are considered to be reasonably representative of long-range average market conditions.

The Master Cost Database contains a variety of asset types from those that have a long history of design, construct and operate, to newer asset types that have some assets in operations, and others that have not yet been deployed in Australia, and others that have limited deployment globally. Judgment should be applied with consideration to the level of maturity of various asset types.

12.2 Base Costs

The Master Cost Database provides a summary of the base case cost for developing all assets listed in this report. The project costs are broken down into the following headings:

- Initial Capital Cost – For All Asset Types
- Yearly Operating Cost - For Natural Gas Only
- Cost of Capacity Upgrade - For Natural Gas Only
- Cost of Refurbishment - For Natural Gas Only
- Decommissioning Cost - For Natural Gas Only

12.3 Adjustment Factors

The following adjustment factors are included to be used to increase or decrease the project cost to cater for project specific factors, namely:

- Terrain Factor
- Location Factor
- Length Factor
- Diameter Factor
- Scaling Factor

Descriptions and notes explaining each adjustment factor is captured in the database.

The following adjustment factors were considered and not included with the risk factor table. The basis for not including is provided in the following.

Proportion of environmentally sensitive areas - For gas pipelines and facilities these are “business as usual” costs, and location routing/siting assessments avoid environmentally sensitivity areas as much as possible, along with a number of other items, to reduce issues that could increase the uncertainty of obtaining regulatory approvals. This has been standard practice for a long time in the gas industry. Therefore, costs for environmentally sensitivity areas are typical and built into the typical cost ranges, and generally not a material separate cost factor.

12.4 Risk Factors

The following risk factors are included to be used to increase or decrease the project cost to cater for project specific risks, namely:

- Macroeconomic influence
- Market activity
- Cultural heritage
- Geotechnical findings
- Weather delays

Descriptions and notes explaining each risk factor is captured in the database.

The following risk factors were considered and not included with the risk factor table. The basis for not including is provided in the following.

Project complexity – The asset types are broken down into a suitable level of asset type granularity such that assets with inherent project complexity are sufficiently separated. The overall process plant requirements are broadly the same for each asset type, hence limited impact on project complexity across that asset type.

Compulsory acquisition – This approach is generally not used and is typically managed for pipeline infrastructure through the route selection process.

Environmental offset risks - These are considered “business as usual” costs for gas infrastructure. Typically, location routing assessments avoid, as much as possible environmentally sensitive areas, as well as a number of other constraints. This approach has been standard practice for a long time in the gas industry. Therefore, as for a typical project these costs are built into the typical cost ranges, rather than something that gets adjusted. This issue is an important consideration in project planning including the regulatory approvals requirements and processes.

Scope and technology risks – In the Oil & Gas and petrochemical industry scope and technology risk is managed by the accuracy range of the cost estimate in the project phase (or estimate class) as defined in the per AACE guideline.

Project overhead risks – The gas market is considered to be a “business as usual” phase. The likelihood of material increases in overhead costs is low. Overhead costs are included in overall metrics and a relatively small proportion of the cost, the largest cost volatility in gas projects occurs from equipment, materials and labour.

A similar costing exercise has been carried out for the TCD, it is worth explaining differences in the risk factors and values applied between the two.

One point of difference is that no risk factors are included in this report for **Unknown risks**. In the TCD **Unknown risks** are factors used to adjust total project costs, as more mature and accurate CAPEX cost estimates are available, reducing the amount needing to cater for **Unknown risks.** Both the TCD and this report’s primary focus is to help inform AEMO compile Class 5 level CAPEX estimates for new infrastructure. However, AEMO is able to collect and apply more accurate CAPEX estimates for new transmission infrastructure. This is currently not available to AEMO for new gas infrastructure. Therefore, this report does not provide functionality to adjust total project costs for **Unknown risks.**

Other points of general difference between gas and electricity infrastructure expansion in Australia currently, is the material difference in market activity. As described in section 1.2 there is significant more demand for new electricity transmission infrastructure, due to the energy market transition, then there is for new gas infrastructure. This creates different cost pressures for design, procurement, project overheads, installation and commissioning between the two. Therefore, values applied to similar risks between the two are different, with the gas market having lower risk values for **Market Activity**. In addition, for new gas infrastructure a far higher proportion of equipment generally needs to be supplied internationally, a risk factor for Macroeconomic Influence has been included for this report.

12.5 Price escalation

Indices in Table 37 and Table 38 are set to 1.000 in 2024/25. In the construction of an index series, initial data is generally drawn from a reference period which by convention is generally set to 100, Further index numbers are generated using observed changes in quantities and prices in subsequent periods and by linking the data for each period using either the Laspeyres, Paasche, Fisher or Törnqvist method[87].

The reference periods for each of the indices we have used vary, so we rebased them to a common period in order to derive meaningful weighted combinations. We chose the latest historical observation full financial year (2023/24) as the base period, so that forecasts of the indices, once produced, could be directly combined to form cost element forecasts without having to rebase each index.

Now that a full set of forecasts exists, the data in Table 37 and Table 38 could be rebased to any year *y* by dividing all numbers in each column of the tables by the respective value for the chosen year *y*, thereby making year *y* = 1.

Regardless of the base year, changes in prices or costs are effected by multiplying a base year cost by the respective index for any chosen future year and dividing by the base year index number. For example, a buried pipeline with a cost of $50.00 million in 2024/25 will have a predicted cost in 2029/30 of (0.952*$50.00 million/0.962) or $49.48 million (with reference to Table 38).

12.6 Worked Example

This initial gas costing study is not released with a tool to automate the calculation of a Class 5 level estimate, similar to the TCD. There are however similarities to the TCD, that need to be applied manually, when estimating the CAPEX for new gas infrastructure.

Step 1 - determine the base cost for new gas infrastructure using the Mater Cost Database.

- Select the ‘Category’ and ‘Subcategory’ of asset needing to be estimated.
- Understand the capacity of gas production or transport or storage expected.
- For natural gas, the following three ‘subcategories’ Gas pipelines, Production plant for conventional gas, and Production plant for Coal Seam Gas each have scaling factors. These need to be applied to assets larger than a certain capacity, to reduce base cost unit rates. This accounts for CAPEX efficiencies gained when building larger capacity assets.
- Multiply the unit rates determined by the capacity expected.

Step 2 – adjust the base cost for project unique attributes using the Adjustment Factors Database.

- Select the ‘Category’, ‘Subcategory’ and ‘Detail’ for the asset needing to be adjusted.
- Understand the projects specific attributes that impact CAPEX I.e. Terrain Factor, Location Factor, Length Factor, Diameter Factor, Scaling Factor, and apply the factors provided to increase or decrease the base cost.
- If multiple attributes are selected, their factors are summated to get a total adjustment value.

Step 3 – further adjust the updated base cost for project unique risks, again using the Adjustment Factors Database.

- Select the ‘Category’, ‘Subcategory’ and ‘Detail’ of asset needing to be adjusted.

[87] Refer to Australian Bureau of Statistics at: **https://www.abs.gov.au/statistics/detailed-methodology-information/concepts-sources-methods/consumer-price-index-concepts-sources-and-methods/2018/price-index-theory**

- Understand the projects specific risks that impacts CAPEX I.e. Macroeconomic influence, Market activity, Cultural heritage, Geotechnical findings, Weather delays, and apply the factors provided to increase or decrease the updated base cost.
- If multiple risks are selected, their factors are summated to get a total adjustment value.

NOTE: There are differences to the TCD, the TCD only provides data to estimate new CAPEX for new Transmission infrastructure costs, while this gas report also provides Yearly Operating Cost, Cost of Capacity Upgrade, Cost of Refurbishment, and Decommissioning Cost for natural gas.

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