CHAPTER 8 - GAS AND ELECTRICITY TRANSMISSION COMPARATIVE CASE STUDY

Summary

This chapter presents a cost analysis of building gas and electricity transmission infrastructure to support a 1,000 MW combined-cycle gas turbine (CCGT), highlighting the need to coordinate electricity and gas transmission expansion to deliver a national energy network with optimal gas and electricity transmission infrastructure.

The 2010 NTNDP identified gas powered generation (GPG) development as an important theme in the transition to a lower carbon dioxide equivalent (CO2-e) emission energy environment. Following on from this finding, the 2011 NTNDP compared electricity and gas transmission infrastructure characteristics and related issues (such as costs, timeliness, reliability, and environmental planning requirements).

Indicative capital cost estimates for electricity and gas connections were evaluated for three distances:

- At 100 kilometres, electricity connection costs $135 million to $185 million, and gas connection costs $60 million to $120 million.
- At 250 kilometres, electricity connection costs $350 million to $480 million, and gas connection costs $150 million to $305 million.
- At 500 kilometres, electricity connection costs $725 million to $975 million, and gas connection costs $305 million to $610 million.

Gas transmission infrastructure is cheaper and also has a smaller visual impact and typically shorter lead times between environmental planning and approvals, and practical completion.

A number of considerations arise from significant infrastructure investment of this scale:

- Opportunities to connect future generation capacity and loads.
- Gas resource depletion, which may reduce the useful life of a pipeline.
- Investment decisions based on efficient cost recovery may not deliver outcomes offering the greatest net energy market benefits.

AEMO will continue to work with industry to identify the best energy market outcomes in the following ways:

- By modelling gas and electricity transmission options to meet needs identified in the NTNDP.
- Through modelling scenarios that include depletion of particular gas sources to understand how this affects the relative net benefits of gas and electricity transmission augmentation.
- By using both the Electricity Statement of Opportunities (ESOO) and Gas Statement of Opportunities (GSOO) to examine gas and electricity transmission augmentation options to promote joint gas and electricity planning.
8.1 Introduction

The 2010 NTNDP identified GPG development as an important part of the transition to a lower CO2-e emission intensive environment, with the prominence of gas in every NTNDP scenario raising important issues relating to gas and electricity transmission interaction.

In recent years, gas pipelines have been built to transfer gas to GPG closer to existing electricity transmission networks. Exploring alternative approaches, AEMO subsequently examined the differences between building electricity transmission lines and gas pipelines to deliver GPG output to a major electricity load centre, providing high-level design and indicative cost estimates for the cases examined (and forming the basis for modelling gas generation in future NTNDP studies).

In terms of location, GPG can either be closer to gas production sources and its output transferred via electricity transmission lines, or it can be closer to the existing electricity transmission network and its fuel supplied by gas pipelines. Two case studies were considered involving a 1,000 MW combined-cycle gas turbine (CCGT) (corresponding to a typical configuration comprising two 500 MW generating units):

- The first case study examines a GPG-near-gas-source location requiring a 100 km, 250 km, or 500 km electricity transmission line.
  - Figure 8-1 shows the diagram for the electricity transmission case study.
- The second case study examines a GPG-near-electricity-transmission-network location requiring a 100 km, 250 km, or 500 km gas pipeline.
  - Figure 8-2 shows the diagram for the gas transmission case study.
Case study commonalities

Costs that have been excluded from the estimates because they are common to both the electricity and gas transmission case studies include the following:

- The cost of plant at the receiving end substation for transmission line connection (electricity transmission case study) and the cost of plant for generator connection (gas transmission case study).
- The capital costs of establishing the gas production facility, power station, generating units, and generating unit transformers.

Section 8.6 includes diagrams that identify the plant that is not common to both electricity and gas case studies. The costs of this plant have been included in the case study estimates.

8.2 Electricity transmission case study

8.2.1 Indicative cost estimates for electricity transmission

Table 8-1 lists the plant and indicative cost estimates for transmission line lengths of 100 km, 250 km, and 500 km, which derive from the 2010 NTNDP’s NEMLink study and AEMO’s own electricity cost estimate data. This case study applies a uniform cost per kilometre for electricity transmission line. The cost of transmission line is significant in terms of the overall cost, and as a result a range of unit costs for transmission line have been applied in the estimates.

Two options were also explored for the 250 km line. Option 1 has an intermediate switching station. Option 2 has series capacitors at the receiving end, but no intermediate switching station.

Table 8-1 — Indicative electricity transmission cost estimates ($ million)

<table>
<thead>
<tr>
<th>Plant</th>
<th>100 Kilometres</th>
<th>250 Kilometres</th>
<th>500 Kilometres</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Option 1</td>
<td>Option 2</td>
<td></td>
</tr>
<tr>
<td>330 kV double circuit overhead transmission line with a capacity of 1,245 MVA for each circuit</td>
<td>100–150</td>
<td>250–375</td>
<td>250–375</td>
</tr>
<tr>
<td>Sending-end substation</td>
<td>30</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Receiving-end substation, shunt capacitors, and dynamic reactive power compensation</td>
<td>5</td>
<td>45</td>
<td>10</td>
</tr>
<tr>
<td>Series capacitor compensation</td>
<td>-</td>
<td>-</td>
<td>60</td>
</tr>
<tr>
<td>Intermediate switching station</td>
<td>-</td>
<td>30</td>
<td>-</td>
</tr>
<tr>
<td>Total electricity transmission cost estimate</td>
<td>135–185</td>
<td>355–480</td>
<td>350–475</td>
</tr>
</tbody>
</table>

A detailed design may identify larger conductor sizes, and therefore a higher cost than assumed by these cost estimates. The longer the electricity transmission line, the greater the potential for economies of scale, which reduces a project’s total cost.

1 An intermediate switching station controls transmission line reactance and capacitance to control voltage drop or voltage rise (or both).
8.2.2 Electricity transmission design

The case study’s 1,000 MW CCGT is connected by a double circuit transmission line. If a transmission circuit trips as a credible contingency, the remaining parallel circuit can transfer generation from both 500 MW generating units with no loss of supply. This reflects a typical NEM design approach.

The two transmission technologies currently in use involve:
- Alternating current (AC) transmission.
- High voltage direct current (HVDC) transmission.

AC transmission

New generation can be relatively easily accommodated by an AC transmission network. Significant power transfers over very long distances impose power system transient and voltage stability limitations, which can be overcome by adding series and shunt capacitor compensation or intermediate switching stations (or both).

At voltage levels of 330 kV or higher, significant issues are not expected for transfers of 1,000 MW over a distance of 500 km.

HVDC transmission

Over long distances, HVDC transmission is used in overhead, underground, or submarine cable applications, joining systems with different frequencies and augmenting AC transmission networks without increasing the fault levels.

While not imposing power system transient and voltage stability limitations, long-distance HVDC transmission presents other technical difficulties, and significant additional costs when adding one or more new connections along its route, with each new connection point requiring a direct current (DC) to AC converter and an inverter station.

In general, compared to AC transmission lines, HVDC lines become more cost effective over longer distances with no tapping points. As a result, the case study only considers an AC transmission option.

Transmission network connections

The connection configuration for the electricity transmission case study involves a 330 kV double circuit, AAAC (all aluminium alloy conductor) transmission line 100 km, 250 km, or 500 km long, with a summer rating of 1,245 MVA. Additional plant, such as an intermediate switching station, capacitors, or static VAR compensators (SVC) are included as required, depending on the length of the transmission line, to manage voltage stability and reactive power requirements.

Single line diagrams for each connection scenario are included in Section 8.6.1.
### 8.3 Gas transmission case study

#### 8.3.1 Indicative cost estimates for gas transmission

Table 8-2 lists the plant and indicative gas pipeline cost estimates for pipeline lengths of 100 km, 250 km, and 500 km. Pipeline costs are based on industry feedback and publicly available information involving several Australian pipeline projects commissioned within the last five years (with lengths ranging from 60 km to 830 km). This case study applies a uniform cost per kilometre for gas pipeline. The cost of gas pipeline is significant in terms of the overall cost, and as a result a range of unit costs for gas pipeline have been applied in the estimates.

For the 500 km gas pipeline, two options were explored. Option 1 excludes compressor stations. Option 2 includes compressor stations.

#### Table 8-2 — Indicative gas transmission cost estimates ($ million)

<table>
<thead>
<tr>
<th>Plant</th>
<th>100 Kilometres</th>
<th>250 Kilometres</th>
<th>500 Kilometres</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Option 1</td>
<td>Option 2</td>
<td>Option 1</td>
</tr>
<tr>
<td>Pipeline</td>
<td>60–120</td>
<td>150–305</td>
<td>305–610</td>
</tr>
<tr>
<td>Compressor station</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total gas transmission cost</td>
<td>60–120</td>
<td>150–305</td>
<td>305–610</td>
</tr>
</tbody>
</table>

---

a. Pipeline lengths may be larger than route lengths due to varying terrain, and although this has not been factored into the estimate, no material change is expected.

b. Compressor station cost estimates derive from industry feedback, a study undertaken in Australia, and a conceptual engineering impact study for a pipeline in North America.

Pipeline building costs vary significantly according to the length and the physical characteristics of the route. The longer the pipeline, the greater the potential for economies of scale, which reduces a project’s total cost. Specific factors affecting the cost include soil type, underground water level, the number of river or stream crossings, the vicinity to urban areas, and local climate and weather patterns during the construction.

The available pressure from the gas production facility at the start of the pipeline is assumed to be 15,000 kPa. Fuel for compression at the production facility is likely to incur further cost, which is not significant enough to change the magnitude of the cost estimate for a pipeline system, and so is excluded from the estimate.

---


5 Assuming a compressor unit operating throughout the year using gas at a rate of 1,600 standard cubic feet per minute (SCFM), and a gas price of 10 $/GJ, the fuel cost estimate is approximately $5.6 million a year. For a short distance pipeline, for example 100 km, the compression required at the production facility may be substantially less than the assumed pressure of 15,000 kPa.
8.3.2 Gas transmission design

Four gas transmission scenarios were considered:

- Scenario 1 is a 100 km, 400 mm Nominal Bore (NB) pipeline without compression.
- Scenario 2 is a 250 km, 400 mm NB pipeline without compression.
- Scenario 3 is a 500 km pipeline with two options:
  - Option 1 is a 400 mm NB pipeline without compression.
  - Option 2 is a 300 mm NB pipeline with two compressor stations of two compressors each (with a 4,500 kW capacity rating) with redundancy, at 200 km and 400 km.

Unlike electricity transmission lines, energy can be stored in a gas pipeline as linepack. As a result, a gas supply disruption is unlikely to result in instantaneous loss of generation, making a single gas pipeline a practical consideration.

Line diagrams for each connection configuration are included in Section 8.6.2.

The maximum pressure available at the supply point and the minimum pressure requirement at the CCGT plant determine the pipeline’s diameter. For simplicity, the design is optimised for a uniform pipeline diameter for the entire distance.

The number and location of compressor stations is determined in conjunction with the pipe to minimise the compressor requirement and pipe diameter. Compressor units are considered with redundancy, with each compressor station having two compressors (one operating, another for back up).

The following additional key assumptions are made for the system design:

- The fuel is coal seam gas (CSG) with a heating value of 37.5 MJ/m³ and specific gravity of 0.55.
- The load (demand) needs a consistent amount of gas, 24 hours a day (referred to as a flat profile).
- The two 500 MW generating units operate at the same time.
- The pipeline’s maximum allowable operating pressure is 15,300 kPa.
- The supply pressure from the source (gas production facility) is available at 15,000 kPa (requiring significant compression at the gas production plant to compress gas from the low CSG field pressure to pipeline pressure).
- The minimum pressure requirement at the CCGT plant gate is 3,500 kPa.
8.4 Other considerations

This section provides information about other considerations in gas and electricity transmission designs including environmental considerations, reliability and access to additional new generation, ongoing operation and maintenance, and the possible impacts on the electricity transmission network.

8.4.1 Environmental

Electricity transmission

Overhead transmission lines can be constructed across most types of terrain. In general, a 60 metre wide easement is likely to be required to build a 330 kV double circuit transmission line \(^6\), and the associated community consultation and planning permission may have a lead time of several years.

Locating GPG at a major load centre may also be environmentally unacceptable. Where this is the case, GPG can be located near a strong part of the existing electricity transmission network. In some cases, a short length of new transmission line may be required, adding to gas transmission option costs.

Gas transmission

Easements for building gas pipelines are generally 20 to 30 metres wide during construction, although extra space is usually required at road or stream crossings or for special soil conditions. The permanent easement is usually 15 to 25 metres wide.

Pipelines are generally underground (apart from their markers \(^7\)), and the associated community and planning permission may have a shorter lead time compared to overhead electricity transmission lines. Compressor station noise and visibility can, however, affect communities. These are usually addressed by using sound-deadening materials for compressor buildings and planting trees around the compressor stations.

8.4.2 Reliability and access to additional new generation

Electricity transmission

Overhead transmission line forced outages are mainly influenced by extreme weather conditions such as lightning, cyclones, and bushfires. Local connection provides a more reliable supply than remote connection over long distances, and generally avoids power system transient and voltage stability limitations. Local connection can also increase fault levels due to low impedance between the generating end and receiving end. The effect of increased fault levels depends on the fault level capability and limitations of the existing plant. In some cases, fault level reduction at critical locations can add significant costs.

Remote connection has the advantage of enabling additional new generation (of any technology) and loads along the route. The most economic approach will involve estimating the extent of any additional generation, given this impacts transmission line design, requiring a potentially higher voltage level and current-carrying capacity.

The 330 kV voltage level and 1,245 MVA capacity for each circuit that the cases assume leaves little spare capacity to accommodate additional new generation.

---


\(^7\) White-coloured posts to identify the location of the easement and pipeline that warn against unauthorised excavation.
Gas transmission

Gas pipeline forced outages are mainly influenced by corrosion and third party damage (for example, unauthorised digging). Unlike the electricity transmission network, however, energy can be stored in gas pipelines as linepack, which makes it likely that GPG can still be supplied for short periods if gas production stops.

Similarly, depending on the location of a rupture, supply is still possible for a short period while repair is underway, providing there is sufficient time to reschedule generation.

Although it is possible to connect additional GPG along a pipeline’s route (via branching and using additional compressors to boost capacity), additional electricity transmission lines are still required for power transfer.

8.4.3 Operation and maintenance

For these high level studies, operation and maintenance costs and transmission losses have not been included in the cost estimates for either electricity or gas transmission, but would need to be considered when selecting a preferred option.

Typical electricity transmission network losses (in the form of heat) range from 4% – 5%.

Typical unaccounted for gas (UFG) is approximately 0.5%, including leakage and mismatched meter readings. A fraction of the gas injected into a pipeline (typically less than 2%) is often also used for compressor and heater fuel, which also reduces gas amounts at the receiving end.

8.4.4 Impact on the electricity transmission network

The electricity and gas transmission case studies deal with connecting a single generator to the electricity transmission network. In both cases, the associated electricity assets would be considered connection assets and the costs would be borne by the connecting generator.

However, the results can be extended to consider using gas transmission as an alternative to augmenting the shared electricity transmission network\(^8\) in the case where the augmentation is driven by GPG.

For example, in the Northern New South Wales (NNS) zone, where there are significant gas reserves but limited electricity transmission capacity to connect significant amounts of new generation, the alternatives include the following:

- Augment the electricity transmission network from the NNS zone to Sydney.
- Build gas infrastructure that enables generation to connect closer to Sydney’s 500 kV electricity transmission network.

As a result, future AEMO studies will (where appropriate) actively consider gas pipelines as well electricity transmission augmentation.

\(^8\) This refers to transmission network assets that are not connection assets.
8.5 Differences between electricity and gas transmission

Table 8-3 contrasts the salient features of electricity and gas transmission for a 1,000 MW CCGT, supplied by a gas production facility 100 km, 250 km, or 500 km from the electricity transmission network.

### Table 8-3 — Electricity and gas transmission

<table>
<thead>
<tr>
<th></th>
<th>Electricity Transmission</th>
<th>Gas Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Type of construction</strong></td>
<td>Overhead transmission line.</td>
<td>Underground gas pipeline with ground-level facilities.</td>
</tr>
<tr>
<td><strong>Planning criteria</strong></td>
<td>Double circuit transmission line.</td>
<td>Single gas pipeline.</td>
</tr>
<tr>
<td><strong>Design — 100 km</strong></td>
<td>A 100 km double circuit transmission line plus shunt capacitor at the receiving end.</td>
<td>A single gas pipeline without compressor stations.</td>
</tr>
<tr>
<td><strong>Design — 250 km</strong></td>
<td>Option 1 - a double circuit transmission line, one intermediate station, shunt capacitors, and SVC at the receiving end. Option 2 - a double circuit transmission line, series compensation, and shunt capacitor at the receiving end.</td>
<td>A single gas pipeline without compressor stations.</td>
</tr>
<tr>
<td><strong>Design — 500 km</strong></td>
<td>A double circuit transmission line, one intermediate station, series compensation, shunt capacitors, and SVC at the receiving end.</td>
<td>Option 1 – a continuous, larger diameter pipeline. Option 2 – a smaller diameter pipeline with compressor stations.</td>
</tr>
<tr>
<td><strong>Indicative capital cost estimate — 100 km</strong></td>
<td>$135 million to $185 million.</td>
<td>$60 million to $120 million.</td>
</tr>
<tr>
<td><strong>Indicative capital cost estimate — 250 km</strong></td>
<td>$350 million to $480 million.</td>
<td>$150 million to $305 million.</td>
</tr>
<tr>
<td><strong>Indicative capital cost estimate — 500 km</strong></td>
<td>$725 million to $975 million.</td>
<td>$305 million to $610 million.</td>
</tr>
<tr>
<td><strong>Easement width</strong></td>
<td>60 metres.</td>
<td>15 to 25 metres.</td>
</tr>
<tr>
<td><strong>Access to new generation along the route</strong></td>
<td>Additional generation can be connected given sufficient transmission line capacity.</td>
<td>Additional GPG can be connected given sufficient pipeline capacity.</td>
</tr>
<tr>
<td><strong>Asset life</strong></td>
<td>Electricity transmission lines and gas pipelines have similar asset lifetimes.</td>
<td>Electricity transmission lines and gas pipelines have similar asset lifetimes.</td>
</tr>
</tbody>
</table>
8.6 Electricity and gas case study diagrams

8.6.1 Electricity transmission single line diagrams

Figure 8-3 — 100 km

Figure 8-4 — 250 km, Option 1

Figure 8-5 — 250 km, Option 2
8.6.2 Gas transmission diagrams

Figure 8-7 — 100 km, 250 km, 500 km, Option 1

Figure 8-8 — 500 km, Option 2

Figure 8-9 — Electrical connection of GPG in gas transmission case study
[This page is left blank intentionally]