SEPTEMBER 2023

4.

Cost and Economic Aspects

Comparing high voltage overhead and underground transmission infrastructure (up to 500 kV)

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Contents

List of Figures

List of Tables

Acknowledgements

We would like to acknowledge the contributions of:

Susantha Wanniarachchi

For his help in seeking copyright for the images included in the document

Members of Powerlink's Customer Panel

Who guided us through the research design elements of the project

Report Reviewers

Who generously gave up their time to provide much needed feedback on the report and chapters

Abbreviations and Acronyms

Abbreviation	Description
AC	Alternating Current
ACSR	Aluminium conductor steel-reinforced cable (or conductor)
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
AVP	AEMO Victorian Planning
CBA	Cost Benefit Analysis
CIGRE	International Council on Large Energy Systems
DC	Direct Current
EHV	Extra High Voltage—consensus for AC Transmission lines is 345kV and above
EIS	Environmental Impact Assessment
EIR	Environmental Impact Review
EIS	Environmental Impact Statement
ELF	Extremely low frequency
EMF	Electromagnetic Fields
ENA	Electricity Networks Australia
EPR	Ethylene propylene cable
EPRI	Electrical Power Research Institute
GIL	Gas Insulated Line
GC	Gas cable
HDD	Horizontal Directional Drilling
HPOF	High-pressure oil-filled cable

Abbreviation	Description
HTLS	High Temperature Low Sag Conductors
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ICNIRP	International Commission on Non-Ionizing Radiation Protection
ISP	AEMO's Integrated System Plan
NEM	National Electricity Market
OH	Overhead
OHTL	Overhead transmission line
PRISMA	Preferred Reporting Items for Systematic Reviews and Meta-Analyses
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test—Transmission
ROW	Right of Way (e.g. easement)
SCOF	Self-contained oil-filled cable
SLO	Social Licence to Operate
UG	Underground
UGC	Underground cable
UGTL	Underground transmission line
XLPE	Cross-linked polyethylene

1.

Introduction

This study aims to investigate the benefits and trade-offs between overhead and underground transmission line infrastructure, specifically focusing on issues associated with under-grounding new transmission infrastructure. It seeks to establish a clear and consistent approach to the evaluation of overhead lines and underground cable transmission, including the consideration of community concerns around the need for new transmission infrastructure to connect large renewable energy generation projects. It does this through systematic reviews of the literature as well as incorporating experiences of Transmission Network Service Providers (TNSPs) in Australia and overseas. The study has a particular focus on 500kV infrastructure which is expected to be the system voltage for high-capacity transmission lines in Australia going forward.

Historically, transmission networks in Australia developed from the need to transfer large amounts of power from large coal fired power stations, typically co-located near coal reserves, over long distances to major cities and industrial load centres. In contrast, the proposed large scale renewable generation facilities, mainly solar and wind farms, require greater land areas and are largely being located in greenfield areas with little or no existing transmission network infrastructure. These new developments are naturally creating community interest and concerns around a range of potential impacts, including but not limited to: visual amenity; environment; Traditional Owner lands; agricultural land use; and social licence to operate concerns. This has led to questions surrounding when it is appropriate to underground transmission infrastructure and the likely implications of doing so.

There have been many studies by government bodies, TNSP's, industry organisations and stakeholders comparing the cost of overhead and underground cable transmission either generally or for a specific project. Based on published literature including Parsons Brinkerhoff [1] and AEMO [2], the ratios are generally in the range of 3 to 20 depending upon type of construction, route length and other project specific factors.

To ensure the most up to date and objective information was used to form the basis of any comparisons, the research included both systematic literature reviews of published papers using the PRISMA methodology. The literature review focused on the technical and economic aspects of HV transmission infrastructure. The technical and economic literature review is contained in Appendix A of *Chapter 3 - Technical Aspects*. A purposeful search of additional published materials included: i) reference books and major reports from the leading electrical engineering research organisations of CIGRE and EPRI[1]; and ii) standards, reports, and reference material from electrical industry sources; Australian and international Transmission System Operators; the Australian Energy Market Operator (AEMO); the Australian Energy Market Commission (AEMC); and other federal, state, and local government reports.

A detailed review of HVDC transmission costing and economics is not within the scope of this study, however information from the literature reviews will be presented and discussed.

[1] CIGRE Green Books Overhead Lines International Council on Large Electric Systems (CIGRE) Study Committee B2: Overhead Lines. Springer Reference.
CIGRE TB 680—Implementation of Long AC HV and EHV Cable System. CIGRE, 2017. EPRI Underground Transmission Systems Reference Book. Electric Power Research Institute, 2015.
EPRI AC Transmission Line Reference Book 200kV and above, 2014 Edition.
EPRI Underground Transmission Systems Reference Book: 2015.

2.

Transmission Lines in Australia

Traditionally, electricity transmission network planning has involved evaluation of options to address forecast needs and limitations on the network including power demand, connection of new customer loads, new energy generation and storage developments, replacement of ageing infrastructure and decommissioning of redundant network. Options are typically evaluated on an economic basis over an expected lifetime using net present value calculations based on underlying assumptions of capital, operating and maintenance costs, demand growth, inflation rates and other factors. The costs that are broadly considered across the lifetime of an overhead or underground transmission line project are summarised in Table 1.

Table 1. Transmission Line Whole of Life Cost Elements

Lifecycle Phase	Cost Components
Planning, Design and Approvals	Planning and preparatory activities including consultation and engagement. Design and survey Environmental offsets Social licence Property—easements, right of way, landholder payments
Construction	Procurement of plant and materials Construction (civil, structural, electrical) Commissioning
Operating and Maintenance	Ongoing compliance costs Transmission line energy losses Preventative—Inspection, condition monitoring, testing, component replacement Corrective—defect repairs, component replacement or refurbishment Emergency—repairs after faults, severe weather damage
End of Life	Decommissioning Recovery of assets Land remediation

HVAC transmission line development options considered will be either be (1) overhead, (2) underground or (3) hybrid overhead/underground. HVDC technologies may also be considered, typically for projects involving long land or submarine routes not requiring future connections to the line along the route.

There have been many studies by government bodies, TNSPs, industry organisations and stakeholders comparing the cost of overhead and underground cable transmission lines either generally or for a specific project. The cost ratio of underground to overhead transmission in these studies are generally in the range of 3 to 20 depending upon project specific factors.

Some of these studies are referenced in section 4 - Transmission Line Cost Estimating Methodologies.

An independent UK industry report by Parsons Brinkerhoff and endorsed by the Institution of Engineering and Technology (UK) "Electricity Transmission Costing Study An Independent Report" [1] stated in its conclusions: *"Cost ratios are volatile, and no single cost ratio comparing overhead line costs with those of another technology adequately conveys the costs of the different technologies on a given project. Use of financial cost comparisons, rather than cost ratios, are thus recommended when making investment decisions."*

3.

Australian NEM Regulatory Framework for Economic Assessment of Projects

In Australia, under the National Electricity Law, TNSPs must undertake the Australian Energy Regulator's (AER) Regulatory Investment Test for Transmission (RIT-T) when potential solutions to reinvest in network assets or increase the capacity of high voltage transmission network are over a $7 million threshold, as defined in the National Electricity Rules. The Australian Energy Regulator (AER) is responsible for ensuring that RIT-T provisions are complied with, while the Australian Energy Market Operator (AEMO) is responsible for coordinating the overall planning of the national grid in conjunction with the state and regional TNSPs.

Regulatory Framework—the National Electricity Rules and prescribed supporting documents such as the AER's Cost benefit analysis guidelines[2] outline what costs and market benefits are included and excluded from economic assessment of projects. Costs include:

- costs incurred in constructing or providing the projects;
- operating and maintenance costs in respect of the projects;
- the cost of complying with laws, regulations, and applicable administrative requirements in relation to the construction and operation of the projects;
- any other class of costs specified in the CBA guidelines;
- or that AEMO determines to be relevant, and the AER agrees in writing before AEMO publishes the draft ISP.

A Market Benefit can currently only be considered in the assessment if it can be measured as a benefit to generators, DNSPs, TNSPs and consumers of electricity.

Non-Market Benefits—AEMO's 2023 Transmission Expansion Options Report August 2023 [2] states: *"Where an impact, or cost, is not included as a relevant consideration in the regulations, the regulations do not permit these matters to be considered, which includes matters like broader social and environmental impacts . Similarly, the regulations do not allow consideration of wider benefits of building or maintaining transmission infrastructure such as increased regional jobs, local manufacturing, utilisation of local contractors, training and apprenticeships, or economic opportunities unlocked or facilitated by the projects."*

This excludes, for example, considering the improved visual amenity of an underground transmission line compared to an overhead line as a social benefit in a RIT-T or ISP assessment.

In response to the increasing community and stakeholder concerns over significant transmission infrastructure programs to facilitate connection of renewable generation, many TNSPs —internationally and in Australia are now introducing incentive payments to landholders for hosting overhead transmission line infrastructure in addition to legal compensation required for easements or access rights[3]. In the case of Queensland's framework, adjoining landholders within 1 km radius of the transmission line are also entitled to payments based on property size.

The new landholder incentive payments are an initiative to improve social licence. However, the costs should be included in the RIT-T economic assessment of project options as initial costs or on-going operational costs depending on the specific arrangements for a project and land holders.

[2] https://www.aer.gov.au/taxonomy/term/1364.
[3] https://www.energyco.nsw.gov.au/sites/default/files/2023-01/overview-strategic-benefit-payments-scheme.pdf. https://www.powerlink.com.au/sites/default/files/2023-05/SuperGrid-Landholder-Payment-Framework.pdf.

4. Transmission Line Cost Estimating Methodologies

Project cost estimation is complex, and methodologies vary between organisations. Cost estimates transition from a low level of accuracy to higher accuracy as a project progresses through its life from concept to construction. This section provides an overview of transmission project cost estimating in the planning phase with reference to the approaches used by 1) AEMO for the Integrated System Plan; and 2) Parsons Brinkerhoff's Transmission Costing Study Report for the UK Industry.

4.1 AEMO's Transmission Cost Database

AEMO's approach to transmission project costing for the ISP is described in documents published on its website [3] [2]. The AER RIT-T Application Guidelines[4] provide guidance for AEMO and TNSPs on the types of options and costs to be considered for application in RIT-T.

AEMO has adopted the Association for Advancement of Cost Engineering (AACE) International classification system for estimates. This is used in many industries for defining the level of accuracy of a cost estimate, based on the amount of design work that has been done. This system defines a series of 'classes' of estimates, ranging from Class 5 (least accurate) to Class 1 (most accurate). Cost estimates progress from a very early development stage with little design or information known (least accurate) to a fully costed and engineered estimate built up over years (most accurate)

AEMO's has defined 2 stages of class 5 accuracy estimates for its application:

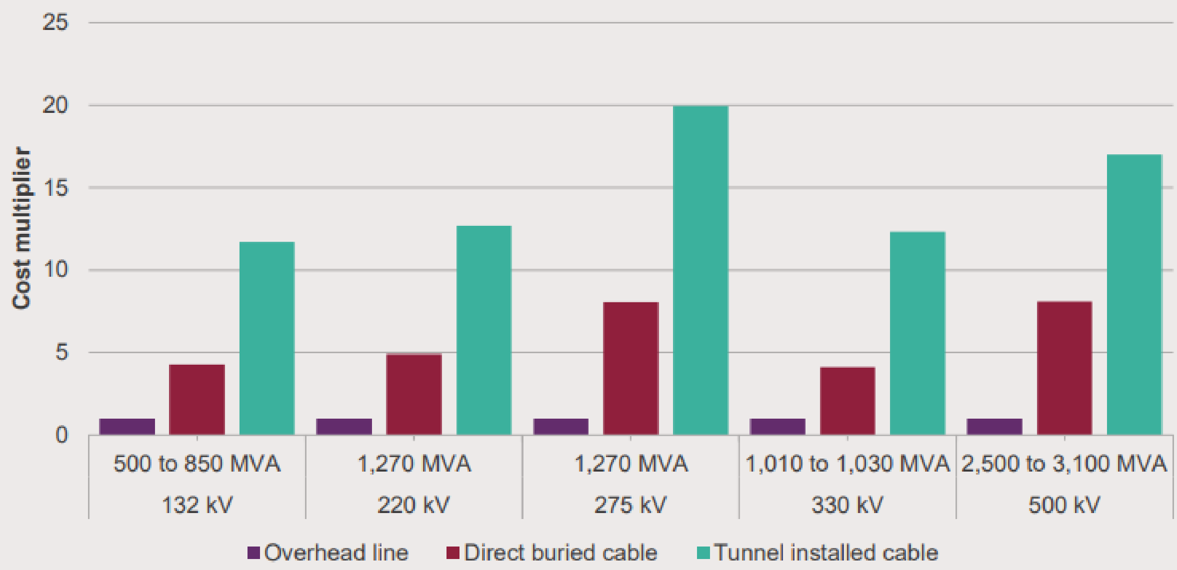
- Class 5b—concept level scoping with no site-specific review or TNSP input
- Class 5a—Screening level scoping including high level site-specific review and TNSP input.

TNSPs are responsible for the higher accuracy estimate as risks and uncertainties are resolved, and the project progresses through its development stages.

AEMO has produced cost estimates for future ISP projects using a Transmission Cost Database (TCD)[5] tool, which is designed to produce Class 5a estimates. The TCD produces Class 5a estimates (concept type) and a manual adjustment is made to produce Class 5b estimates. Cost estimates are broken down into several components with adjustment factors for project specific requirements and addition of risks and indirect costs as outlined in Table 2.

The TCD includes cost estimates for overhead transmission lines and underground cables, both of which vary significantly with voltage level and capacity. Figure 1 shows a comparison of these cost estimates for given voltage levels and power transfer capacities [2, p. 34]. The HVAC option is included as a reference point. The costs of underground cables are approximately four to 20 times higher than overhead lines depending on the type of installation. Direct buried cables are at the lower end of this range, while tunnel installed cables are at the upper end.

[4] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018.
[5] https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.



Notes:

- This chart shows cost factor increases relative to the respective overhead option on a generic unit cost basis. Underground 500 kV HVAC options cost more than 275 kV HVAC options, but the cost factor increase is higher when undergrounding a 275 kV HVAC option compared to undergrounding a 500 kV HVAC option.
- This chart has been prepared using AEMO's Transmission Cost Database and may not provide an appropriate comparison for all projects due to local circumstances.
- This cost comparison is indicative of the variable per unit cost of overhead lines and underground cables. The total project cost is sensitive to factors such as terrain, geotechnical constraints, and fixed cost factors associated with transition stations.
- Tunnel installed cable design is most applicable to underground cable projects in urban areas while direct buried cable can be suitable for projects in rural or remote areas. For greenfield transmission projects in rural or remote areas it is appropriate to compare overhead with direct buried cable.

Figure 1. Indicative Unit Cost Multiplier from HVAC Overhead Lines to HVAC Underground Cables (AEMO 2023 Transmission Expansion Options Report [2, p. 34])

Table 2. Cost Breakdown Structure adapted from—AEMO 2021 Transmission Cost Report[6]

Phase Cost Categories	Cost Components / Factors	
Capital Costs - Planning, Design, Approvals and Construction	Building Blocks	Plant and materials Civil and structural works Testing and commissioning Secondary systems Contractor project management and overheads Environmental offsets Design and survey Easement / property Electrical works
	Adjustment Factors	Location (Regional / distance factor) Location wind loadings Terrain Delivery timetable Greenfield / brownfield Project network element size Jurisdiction Proportion of environmentally sensitive area Contract delivery model
	Known Risks	Compulsory acquisition Environmental offsets Macroeconomic influence Market activity Cultural heritage Geotechnical findings Outage restrictions Project complexity Weather days
	Unknown Risks	Plant procurement Productivity / labour Project overhead Scope and technology
	Indirect Costs	Project development Works delivery Land and environment Procurement Stakeholder and community engagement Insurance
Operating and Maintenance Costs	1% of the total capital cost per annum is assumed as operation and maintenance cost for each transmission project. If more detailed information is provided from a TNSP, and AEMO is satisfied with the evidence provided, this may take precedence over the 1% assumption.	

[6] https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-report.pdf?la=en.

The TCD has gone through a calibration process through a comparison with a selection of large-scale transmission projects and following calibration, the TCD was found to be within +/- 15% of the benchmark reference cost estimates. However, AEMO acknowledged there were several limitations identified with the use of the TCD as follows:

- The property and environmental offsets reference costs were found to have errors for overhead projects of +/- 15% and should not be relied on.
- The output is Class 5a estimate (which can be adjusted for Class 5b) and therefore suitable only for estimating the costs of network options which are in the very early stages of development for use in the ISP modelling.
- The TCD is not suitable for Class 4 or better estimates—these should be produced by the TNSPs.
- The accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits.
- The output represents Australian construction environment, asset and design standards, industry and business practices, regulatory framework, commercial rules, labour laws, and safety regulations in 2021.
- The output represents stable macroeconomic (forex, commodity, labour and wage price indices, social and political) conditions that Australia has experience in recent years up to 2021.
- The output represents efficient preliminary investigation, project development, project management, competitive tendering, site management and contractual arrangements.

4.2 Parsons Brinkerhoff's Transmission Costing Study Report (UK)

This report was completed in 2012 and is published on the Institution of Engineering and Technology (UK) website[7]. Although actual costs quoted in the PB report have escalated since publication, the report is referenced by UK TNSP—National Grid in current publications[8] and the principles and methodology, and findings of the report are still considered relevant today.

The report focussed on the *"build costs"* and *"ongoing operational costs including maintenance and losses"* for 400kV infrastructure. Social and environmental costs associated with transmission were not evaluated in the study.

Comparison Costing Model—The costing model for the study considered the following:

- Lifetime costs were evaluated using the net present value of "Build" and "Operating Costs".
- A 40-year life was assumed for all technologies and a discount rate of 6.25%.
- Cost estimates for 3km, 15km, and 75km route lengths were prepared.
- For each route length option double circuit lines for low (3190 MVA), medium (6389 MVA) and high (6930 MVA) power transfer options were evaluated.
- Cost sensitivities to variable assumptions were presented.

The cost breakdown structure used for costing study is summarised in the table below.

A summary of the costs per km and ratio of options compared to an overhead line from this study is provided in Table 4. Cost ratios of the underground options compared to overhead varied from 4.6 to 14.2 depending on the line route length, power transfer capacity and type of underground system.

The HVDC options in this study only considered subsea cables of 2 different AC/DC converter technologies. Land based HVDC lines were not considered in this study.

[7] https://www.theiet.org/impact-society/factfiles/energy-factfiles/energy-generation-and-policy/electricity-transmission-costing/.
[8] https://www.nationalgrid.com/sites/default/files/documents/39111-Undergrounding_high_voltage_electricity_transmission_lines_The_technical_issues_INT.pdf.

Table 3. Cost Breakdown Structure adapted from Electricity Transmission Costing Study (2012) [1]

Phase Cost Categories	Cost Components / Factors	
	HVAC Overhead	HVAC Underground
Fixed Build Costs	Mobilisation extras	Cable terminal compound Cable terminations and testing
Variable Build Costs	Foundations Tower materials Conductors + OPGW Access roads total Insulators + fittings materials Erection of towers + stringing Engineering & safety Project launch + mgmt. (10%) Build contingency (10%)	Special constructions (6.4%) Special constructions (6.4%)—£1.6m Build contingency (15%)—£3.7m On route cable system materials—£6.3m On route cable installation—£11.5m Reactor costs—£1.0m Project launch + mgmt. (20%)
Variable Operating Costs	Cost of power losses (power stations) Cost of energy losses (fuel) Operation & maintenance	Cost of power losses (power stations) Cost of energy losses (fuel) Operation & maintenance

Table 4. Cost Comparison Table for 400kV Transmission Lines, adapted from Electricity Transmission Costing Study (2012) [1]

Transmission Line Parameters		Overhead	Underground - Direct Buried		Underground - Tunnel		HVDC +/-400kV DC (LCC)[1]		HVDC +/- 320kV DC (VSC)[2]	
Length (km)	Power Capacity (MVA	Cost (GB £-Million/ km)	Cost (GB £-Million/ km)	Ratio cf. Overhead	Cost (GB £-Million/ km)	Ratio cf. Overhead	Cost (GB £-Million/ km)	Ratio cf. Overhead	Cost (GB £-Million/ km)	Ratio cf. Overhead
3	3190	2.4	12.8	5.3	34.0	14.2				
3	6380	4.2	22.6	5.4	42.3	10.1				
3	6930	4.2	24.0	5.7	43.0	10.2				
15	3190	2.3	10.6	4.6	22.4	9.7				
15	6380	4.1	19.4	4.7	29.6	7.2				
15	6930	4.1	20.8	5.1	30.3	7.4				
75	3190	2.2	10.3	4.7	20.5	9.3	13.4	6.1	16.4	7.5
75	6380	4.0	18.9	4.7	27.5	6.9	22.0	5.5	31.9	8.0
75	6930	4.0	20.3	5.1	28.2	7.1				

1 HVDC sub-sea cable using Line Commutated Converters
2 HVDC subsea cable using Voltage Source Converters

Cost sensitivities were evaluated in the study. Using the example of a 15km high-capacity transmission line comparing direct buried underground cable to an overhead line a cost sensitivity analysis is shown in Figure 2. From these results it is noted that:

(a) The lifetime cost of overhead is most sensitive to 2 main factors:
- the assumption of average circuit loading which determines the losses component of operating costs;
- actual route length variations.

(b) The lifetime cost of direct buried underground is most sensitive to 4 main factors:
- actual route length variations;
- cable installation base costs;
- terrain (urban vs rural);
- cable system material base costs.

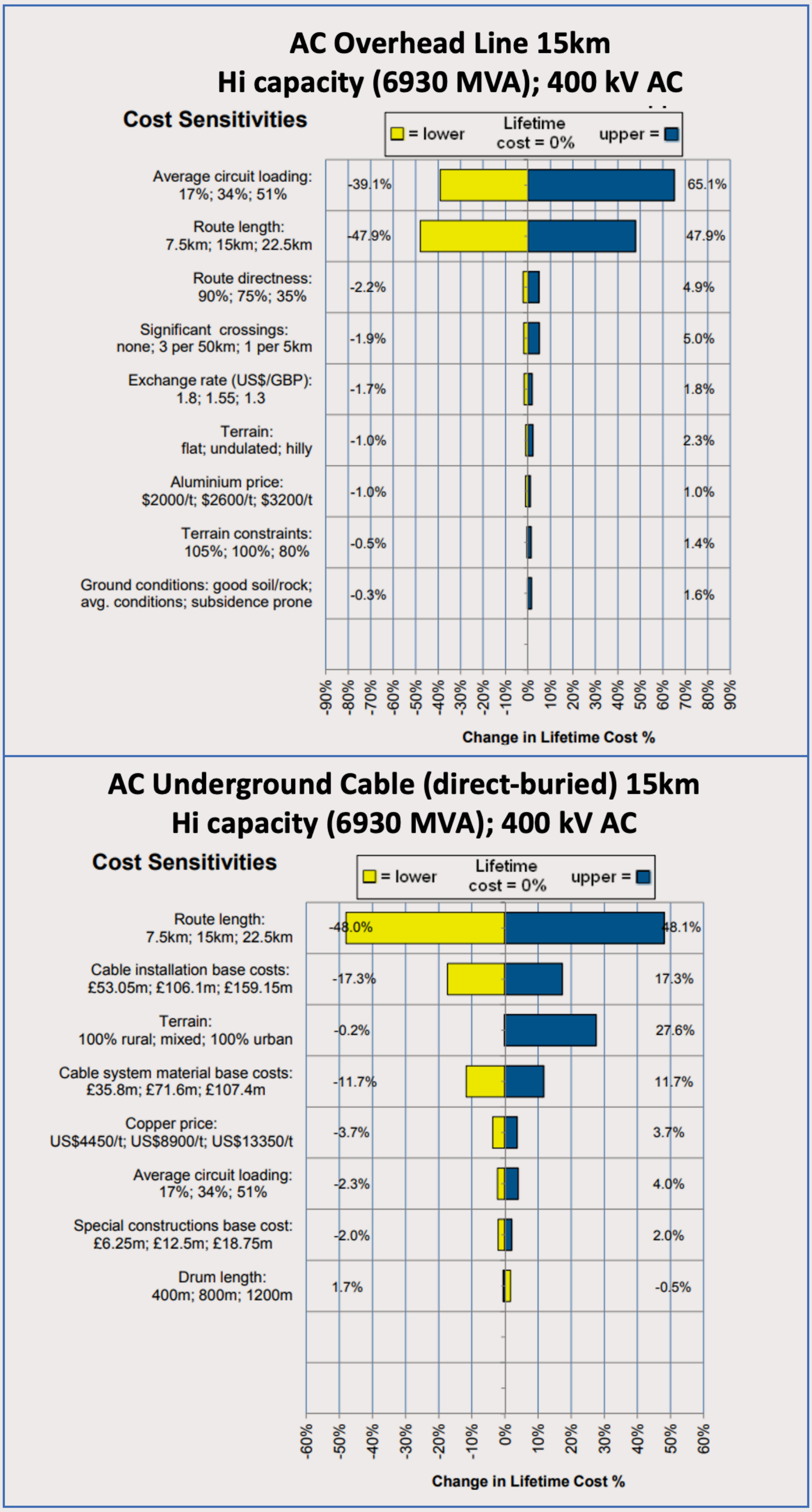


Figure 2. Cost Sensitivities for 400kV AC Direct Buried Underground Compared To Overhead Transmission Line (Electricity Transmission Costing Study (2012) [1])

For ease of reference, we have inserted the summary of relevant findings of this study below [1, p. viii]:

- *"No one technology can cover, or is appropriate in, every circumstance, and thus financial cost cannot be used as the only factor in the choice of one technology over another in a given application.*
- *Costs per kilometre, for all technologies, tend to fall with increasing route length, and tend to rise with circuit capacity.*
- *For typical National Grid system circuit loadings, the inclusion of operating costs in the technology comparisons does not significantly affect the overall differences in cost between the technologies. However, they do affect the cost ratios considerably, rendering the ratios a misleading measure when making investment decisions.*
- *Overhead line (OHL) is the cheapest transmission technology for any given route length or circuit capacity, with the lifetime cost estimates varying between £2.2m and £4.2m per kilometre; however, OHL losses are the most sensitive to circuit loading.*
- *Underground cable (UGC), direct buried, is the next cheapest technology after overhead line, for any given route length or circuit capacity. It thus also represents the least expensive underground technology, with the lifetime cost estimates varying between £10.2m and £24.1m per kilometre.*
- *For the options using a deep tunnel, the largest single cost element is invariably the tunnel itself, with costs per kilometre ranging from £12.9m to £23.9m per kilometre, depending upon overall tunnel length.*
- *The 75km high voltage direct current (HVDC) connections are estimated to cost between £13.4m and £31.8m per km and are thus more expensive than the equivalent overhead or direct buried transmission options. However, long HVDC connections are proportionally more efficient than short connections.*

We also offer two notes of caution:

- *Cost ratios are volatile, and no single cost ratio comparing overhead line costs with those of another technology adequately conveys the costs of the different technologies on a given project. Use of financial cost comparisons, rather than cost ratios, are thus recommended when making investment decisions.*
- *The transmission technologies may not all be able to use the same route as each other, so circuit lengths may vary between technologies for a given application. We therefore recommend that actual practicable routes be identified when comparing total lifetime costs of each technology for specific investment decisions."*

4.3 Industry Cost Estimation Practices

Transmission Network Service Providers project cost estimation practices are characterised as follows (based on Authors' industry experience):

- The standard building block cost estimates are based on recent projects where the design experience and construction practices are well known and involve the application of the organisations design and construction standards.
- The cost estimates are refined as a project progresses through its life cycle, consistent with the Association for Advancement of Cost Engineering (AACE) International classification system for estimates.
- If the transmission projects involve new structures, new line components and new construction practices need to be employed, then costs are escalated for example by 50% of the standard cost estimate.
- Budget cost estimates are usually obtained from preferred manufacturers, suppliers, and contractors in the planning phase before formal procurement for the project is initiated.

For an overhead transmission line, significant cost increases will be incurred if the new project involves new structures and technologies such as:

- New higher strength and height structures that incur finite element designs and structural testing will incur related costs.
- New conductor designs (e.g. high temperature, larger size, additional bundles) may require stress—strain, and creep tests to derive the relevant design parameters and new fittings for the conductor.
- New insulator assemblies (e.g. pivoting horizontal vee assemblies) will require finite element analysis and combined loading assessment.
- New construction practices (e.g. stringing, jointing and terminating conductors) may be required for the conductors and associated fittings.

Similarly for an underground transmission line, significant cost increases will be incurred if the project involves new cable technologies as follows:

- New cable design (increase in conductor size, change in insulation type, change in insulation thickness, inclusion of fibre optic cable in core) will require a desk top design analysis.
- New cable designs will also require special witness testing, during manufacture, and during type and routine testing.
- New cable designs may require new joints and terminations to be developed.
- New cable designs may also require changes to construction practices (e.g. increase cable pulling, reduction on cable radius, jointing and terminating cables).

5.

Cost Comparison – Overhead and Underground Cable Transmission Lines

This section provides an overview of the cost elements and estimated costs for Australian projects based on current NEM information and recent consultation with industry parties currently involved in transmission line projects. The costs quoted are only for general comparison purposes between overhead and underground technologies and should not be applied to specific projects.

Cost estimates and economics for HVDC options are not within the scope of this report, however comments relative to HVAC options have been included based on references.

5.1 Capital Investment Costs

The cost elements, variable factors and risks associated with capital or investment costs for a transmission line project are summarised in the table below.

HVDC Transmission generally becomes more economic for longer route interconnector transmission lines.

HVDC overhead and underground lines are generally lower cost per km to construct compared to equivalent rated HVAC, but the significant costs of AC/DC converter terminal stations must be included in the total project cost. There is a "break even distance" for the cost of HVDC versus HVAC transmission. This is illustrated in the diagram by Stan et al., in Figure 5 [4]. The "break even distance" will depend on project specific parameters such as power transfer capacity, number of circuits, system voltage, converter technology, installation conditions and environmental factors

Some economic, environmental, and social advantages are that HVDC line corridor width for overhead and underground can be reduced significantly, reducing the cost of those components of the capital costs not to mention reducing overall impacts on communities and individual landholders.

Table 5. Capital Investment Cost Elements, Factors and General Comparative Cost Estimates

Cost Elements	Variable Factors and Risks impacting on Costs	HVAC Overhead Transmission Line	HVAC Underground Transmission Line
Planning **Social licence—consultation and engagement.** **Design and survey** **Approvals** **Environmental offsets** **Property—easements, right of way, landholder payments** **Procurement of plant and materials** **Construction (civil, structural, electrical)** **Commissioning** **Indirect / overhead costs**	Route length Voltage Power transfer capacity Single vs double circuit Location (e.g. Urban, Rural) Topography Geotechnical Land—cost and payments Environmental Social and community sensitivities Resource market (labour, materials) Workplace health and safety Delivery model Approval delays	Indicative costs for double circuit OHTL, route 50–100km, excluding property and environmental offsets: 275kV: \$2M to \$3M per km •500kV: \$5M to \$6M per km	Indicative costs for double circuit UGTL typical 40km length excluding property and environmental offsets: 275kV: \$10 to \$15M per km 500kV: \$25M to \$30M Million per km

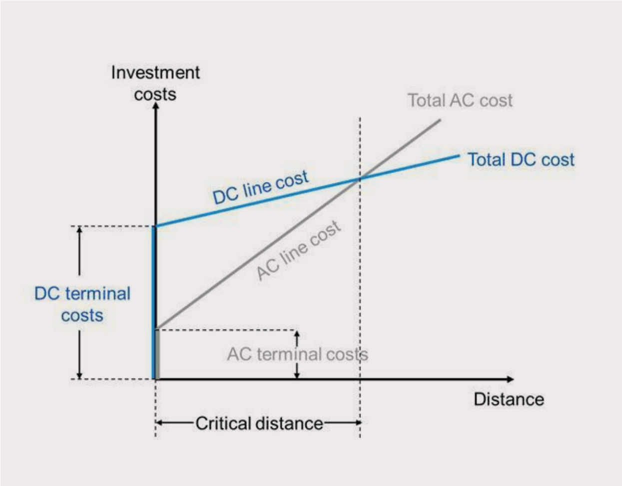


Figure 3. HVDC Transmission Line Economics (Stan et al [4])

HVDC Transmission generally becomes more economic for longer route interconnector transmission lines. HVDC overhead and underground lines are generally lower cost per km to construct compared to equivalent rated HVAC, but the significant costs of AC/DC converter terminal stations must be included in the total project cost. There is a "break even distance" for the cost of HVDC versus HVAC transmission. This is illustrated in the diagram by Stan et al., in Figure 3 [4]. The "break even distance" will depend on project specific parameters such as power transfer capacity, number of circuits, system voltage, converter technology, installation conditions and environmental factors.

Some economic, environmental, and social advantages are that HVDC line corridor width for overhead and underground can be reduced significantly, reducing the cost of those components of the capital costs not to mention reducing overall impacts on communities and individual landholders.

HVDC and HVAC overhead and break-even point examples:

Break even distances for the cost of HVDC versus HVAC overhead have been estimated from data available from references (see Table 6). These estimates suggest it is in the range of 600km to 700km.

Acaroğlu et al [5], reported a cost ratio for HVDC underground to HVDC overhead of around 5, and a cost ratio for HVDC underground to HVAC overhead of 3.3 for a 1500MW, 1000km case study. The Suedlink 2 x 2000MW 700km underground HVDC project in Germany is currently estimated to cost €11B ($18.3B AUD). This is equivalent to around $26.1M AUD per km.

The economic feasibility for application of HVDC compared to HVAC, ultimately depends on project specific requirements, factors and constraints which determine whether HVDC should be considered. Regulatory investment test requirements also need to be satisfied.

Table 6. Comparison of HVDC Break-Even Distances Using Data from Different Sources

Data Source	System	Break-even distance HVDC vs HVAC overhead	Cost ratio HVDC Underground vs HVAC Overhead
Acaroğlu et al [5]	1500 MW, +/- 320kV HVDC	650 km	4.6
Weimers, ABB Power Technologies [6]	3500 MW, +/- 500kV HVDC	600 km	Not available
Australian references - AEMO cost database and "Western Victorian Transmission Network Project—High Level HVDC Alternative Scoping Report"[7]	2500MW, +/- 525 kV HVDC	615 km	4.0

5.2 Maintenance Costs

A summary of typical transmission line maintenance cost elements is provided in the table below.

The literature review reported a finding that the factors which impact the O&M costs are age of the line, weather conditions and length of the line. In [9], the O&M costs are assumed as 1.5% and 0.15% of capital investment cost for OHTL and UGTL respectively.

HVDC Transmission - Maintenance requirements for overhead and underground line components of HVDC are expected to be similar of HVAC overhead and underground. However, the additional maintenance requirements associated with AC/DC converter stations would be significant resulting in overall higher lifetime maintenance requirements.

Table 7. Summary of Transmission Line Maintenance Cost Elements

Cost Element	HVAC Overhead Transmission Line	HVAC Underground Transmission Line
Planned Maintenance Patrols and Inspections Testing Replacement of components Vegetation maintenance Access track maintenance	**Indicative costs:** 0.5 to 1% of capital cost per km per annum for up to 20 years. 1 to 2% of capital cost per km per annum during mid life. 5 to 10% of capital costs for mid-life replacement of certain line components (e.g., insulators).	**Indicative costs:** Expenditure per km per annum is typically around 40% of comparative overhead line but can be similar if the patrol specification and frequency of patrols is frequent.
Unplanned Maintenance Unreliability—forced outages Corrective maintenance and repairs	**Includes cost of:** Responding to forced outages, and repairs to damaged or faulty components e.g., conductors, insulators, supporting structure Minor repairs —performed with live line techniques so no outage or loss of supply time. Major repairs—require a circuit outage, but typically there is no loss of supply due to redundancy planning requirements (N-1 criteria)	**Includes cost of:** Responding to forced outages, and repairs to damaged or faulty components e.g joints, terminations, cable dig-in damage by 3rd party Repairs to damaged cable, replacement of faulty cable joints and terminations require a circuit outage but typically there is no loss of supply due to redundancy planning requirements (N-1 criteria).
Indicative Total Operating and Maintenance Costs [9] **(Excluding losses)**	Around 1.5% of Capital Investment Cost.	Around 0.15% of Capital Investment Cost.

5.3 Operating Costs - Energy Losses

Energy Losses refers to energy lost as heat to the atmosphere from conductors and other components of a HV transmission system. The main causes of losses in transmission lines are:

(1) Conductor losses are the largest source of transmission losses and are due to current flow in a conductor and the resistance of the conductors. For a 3 phase (wire) system power loss due to current flow in a conductor is derived from Ohm's Law.

PL = 3 x I^2 x R where:

PL = Losses in Watts;

I = current flowing in each of the three conductors in Amps;

R = Resistance of the conductor in Ohms (R is proportional to the length of the line).)

Resistive power losses can also be caused by "**skin effect**" which is additional resistance due to the tendency of more current to flow near the outer surface of a conductor.

(2) Dielectric losses result when an AC electric field interacts with a dielectric material such as insulation causing energy heat loss in the dielectric. Dielectric losses do not occur in HVDC lines under normal operating condition.

(3) Corona Losses—can occur in HV overhead lines when the ionization of air molecules in the vicinity of high-voltage conductors occurs due to the presence of a strong electric field (above the critical surface voltage gradient) and leads to the generation of charged particles (electrons and positive ions). These charged particles move and collide with other air molecules, causing energy dissipation through several mechanisms, including resistive effects. HVDC lines generally have very minimal corona losses due to lower electric field strengths.

(4) Inductive losses occur when transmission lines induce current in nearby conductors or metallic objects. This includes the metallic sheaths of cables. Generally, these losses are minimised by earth bonding arrangements.

In whole of life costing analysis typically only conductor losses are evaluated as the other losses are usually insignificant in comparison. Losses in other system components such as AC/DC converters required for HVDC systems are significant and must be included.

The **Cost of Energy Losses** is the sum of two components:

(1) Annual cost of energy losses is the cost of the energy (MWh) lost from the transmission line over a year.

Annual cost of energy losses = Energy lost per annum (MWh) X Energy Cost ($/MWh)

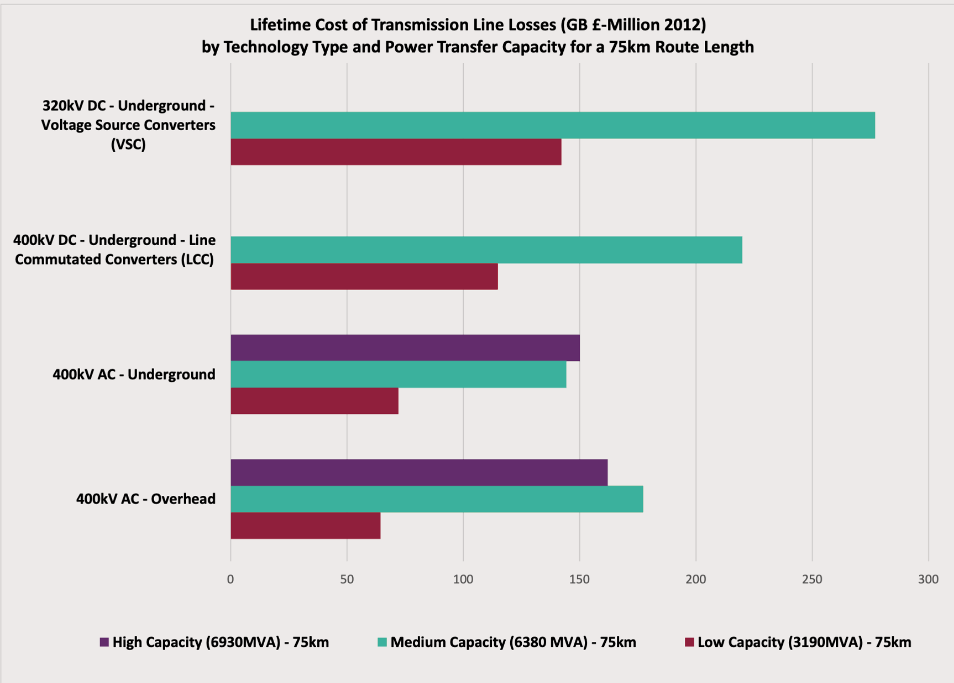


Figure 4. Comparison of Lifetime Cost of Losses, Adapted from Transmission Costing Study (2012) [1].

The energy lost per annum is calculated by assuming an average load flowing the line over a year to determine the losses.

(2) Peak Power Loss Cost ($/MW) is the cost to supply the peak losses (MW) that occur when the transmission line is carrying its peak load in each period (e.g. year).. This represents the amount of additional generation capacity that must be available just to supply peak losses. *Peak Power Loss Cost = Peak Power Loss (MW) X Power Demand Charge ($/MW)*

The above is a simplified explanation, but actual calculations involve sub-calculations to determine annual average and peak loads for the transmission line. The cost of losses is then evaluated on Net Present Value basis over the assumed life span of the transmission line with year-by-year changes due to demand growth or other events.

The graph in Figure 4 provides a comparison of losses for HVAC and HVDC overhead and underground transmission lines using data from the PB Transmission Costing Study (2012).

For HVDC transmission systems, losses in the AC/DC converters can account for up to 50% or more of total lifetime losses.

An example of a net present value calculation of losses over 20 years for an overhead and underground transmission lines with the same loading is provided in *Table 8. Net Present Value calculation of energy losses—OHTL and UGTL comparison* below. In this example the cost of losses for overhead line is about twice that of the underground line.

The difference in cost of losses largely depend on the conductor size selection for the line. While OHTL are generally designed for load factors less than 0.5 (N-1 planning criteria), UGTL may be required to operate at higher load factors (because of the highest cross section cable employed—other measures used to bring load back to rating under contingencies). If losses for the overhead transmission are considered significant, the overhead conductors can be oversized at a modest cost for the losses to be in a similar range to the underground transmission.

5.4 End of Life Costs

A summary of the considerations and costs at end of life is provided in the table below. Generally, end of life costs are considered insignificant in the lifetime costing based on NPV, unless there is a known requirement for the lifespan of the transmission line.

HVDC Transmission - end of life costs are expected to be like HVAC overhead or underground respectively. Easement corridors would be typically much narrower resulting in lower costs for that element. However, converter station decommissioning recovery would be an additional cost element.

5.5 Lifetime Costs

Lifetime costs are evaluated as a net present value (NPV) of the costs described in the preceding sections, i.e.:

1. capital investment cost;
2. operating and maintenance cost per annum;
3. cost of energy losses per annum with annual load growth factor applied;
4. end of life cost.

Key assumptions included in the NPV calculation are:

- expected asset life span, e.g., OHTLs—60 years, UGTLs—40 years;
- financial discount rate or internal rate of return, e.g., 5 to 6%.

Worked examples of lifetime costs for 275kV overhead and underground transmission lines are shown in Table 10. In this example the ratio of initial capital expenditure when comparing underground to overhead was 5, but over a 40-year period the ratio reduced to 2.9.

The literature review reported that it has been observed that the life cycle costs of underground transmission lines (UGTL) are significantly higher compared to overhead lines, primarily due to the high capital costs associated with underground installations. Overall, the life cycle costs of UGTL are two to six times more than OHTL [9].

Table 8. Net Present Value calculation of energy losses—OHTL and UGTL comparison

Cost of Losses for Single Circuit Overhead Transmission Line

Input Data:			
Load growth factor p.a.	1.02		
Cost of Energy (cents/kWh)	7.5		
Cost of Gen Plant ($/KW)	1000		
DC Resistance of Conductor (ohms/ km at 20 deg C)	0.0180	Thermal coeff =	0.00368
AC Resistance of Cable (ohms/km at 35 deg C)	0.0196	Rac/Rdc =	1.03
Length of Line (km)	1		
Load Factor	0.4		
Discount Rate	0.05		

Year	**1**	**2**	**3**	**4**	**5**	**...**	**20**	**NPV Totals**
Load (A) =	600	612.00	624.24	636.72	649.46		874.09	
Energy Loss (kW)	4	5	5	5	5		9	
Annual Energy Losses (kWhr)	38498	40053	41671	43355	45106		81704	
Cost of Energy Losses ($)	$2,887	$3,004	$3,125	$3,252	$3,383		$6,128	
PV of Energy Losses ($)	$2,750	$2,725	$2,700	$2,675	$2,651		$2,309	$50,472
Demand Cost	$21,128	$21,982	$22,870	$23,794	$24,755		$44,841	
PV of Demand Cost	$20,122	$19,938	$19,756	$19,575	$19,396		$16,900	$369,337
								$419,809

Assumptions:
Cost of Energy based on renewables in range of $50 to $100 per MWh
Cost of Generation based on $1000 M for 1000 MW plant
Conductor resistance based on Sulphur 61/3.75 AAAC conductor (673 mm2) = .0511 ohms/km

Cost of Losses for Single Circuit Underground Cable (Cross bonded System)

Input Data:			
Load growth factor p.a.	1.02		
Cost of Energy (cents/kWh)	7.5		
Cost of Gen Plant ($/kW)	1000		
DC Resistance of Cable (ohms/ km at 20 deg C)	0.009	Thermal coeff =	0.00368
(ohms/ km at 20 deg C)		Rac/Rdc =	1.03
AC Resistance of Cable (ohms/km at 35 deg C)	0.009782		
Length of Cable (km)	1		
Load Factor	0.4		
Discount Rate	0.05		

Year	**1**	**2**	**3**	**4**	**5**	**...**	**20**	**NPV Totals**
Load (A) =	600	612.00	624.24	636.72	649.46		874.09	
Energy Loss (kW)	2	2	2	2	3		5	
Annual Energy Losses (kWhr)	19249	20027	20836	21677	22553		40852	
Cost of Energy Losses ($)	$1,444	$1,502	$1,563	$1,626	$1,691		$3,064	
PV of Energy Losses ($)	$1,375	$1,362	$1,350	$1,338	$1,325		$1,155	$25,236
Demand Cost	$10,564	$10,991	$11,435	$11,897	$12,378		$22,420	
PV of Demand Cost	$10,061	$9,969	$9,878	$9,788	$9,698		$8,450	$184,669
								$209,905
							OHTL / UGTL Cost of Losses Ratio	**2.0**

Assumptions:
Cost of Energy based on renewables in range of $50 to $100 per MWh
Cost of Generation based on $1000 M for 1000 MW plant
Cable resistance based on 2000 mm2 copper = .009 ohms/km

Table 9. Summary of Transmission Line End of Life Cost Elements

Cost Element	HVAC Overhead Transmission Line	HVAC Underground Transmission Line
Decommissioning Disconnection Recovery and Assets Scrap value if applicable. Land remediation	Dependent on the line materials and scrap value of components (conductors and steel tower members) Indicative costs: Can be in range of 30 to 40% of cost of building a new line. However, on a PV basis over a life of 70+ years for the overhead line, the costs are considered insignificant.	Cable typically left in ground unless specific environmental requirements. Above ground accessories, terminations and equipment recovered and scrapped. Cable can be removed from ducts or tunnels if required. Indicative costs: Very low cost unless cable needs to be removed from ground.

Table 10. Lifetime Cost Example - 275kV OHTL and 275kV UGTL Comparison

	Annual Costs	Years 0	1	…	40	…	60	NPV Totals
DOUBLE CIRCUIT 275 KV OVERHEAD								
Initial Planning, Easements Acquisition and Design Costs		$300,000						$ 300,000
Materials and Construction Cost		$1,700,000						$ 1,700,000
Preventative Maintenance Cost p.a.	$20,000		$20,000		$20,000		$20,000	$ 1,200,000
Recovery Cost					$100,000		$800,000	$ 900,000
Losses			$17,400		$17,400		$17,400	$ 1,044,000
Reliability Differential			$27,500		$27,500		$27,500	$ 1,650,000
Present Value (PV) of Costs at 60 years		$2,000,000	**$63,119**		**$47,017**		**$72,331**	**$ 4,414,988**
Present Value (PV) of Costs at 40 years								**$ 3,755,954**
Note: Expected life of 60 years								
DOUBLE CIRCUIT 275 KV UNDERGROUND								
Initial Planning, Easements Acquisition and Design Costs		$500,000						$ 500,000
Materials and Construction Cost		$9,500,000						$ 9,500,000
Preventative Maintenance Cost p.a.	$50,000		$50,000		$50,000			$ 2,000,000
Recovery Cost					$500,000			$ 500,000
Losses			$8,400		$8,400			$ 336,000
Present Value (PV) of Costs		$10,000,000	**$55,619**		**$79,318**			**$ 11,073,113**
Note: Expected life of 40 years								
Results:								
Ratio UGTL to OHTL Initial Capital Costs =	**5.0**							
Ratio UGTL to OHTL Total Costs at 40 yrs =	**2.9**							
Assumptions								
Internal Rate of Return	5.0%							

6.

Australian Market Trends—What will affect Delivery of Transmission Infrastructure Projects

Key Challenges—Infrastructure projects in Australia are facing challenging times because of global and national economic factors. Infrastructure Australia's Infrastructure Market Capacity 2020 Report [10] reported key challenges as:

- Demand driven risks have increased over the last 12 months ($15B of new projects in 1 year).
- Supply side risks have surged in 2021–22 (effects of COVID-19, Ukraine War, labour shortages).
- Increasing project costs and complexities, plus truncated risk allocation and planning practices are driving insolvencies and consolidation, thus threatening capacity.
- The market is arguably at capacity, so project slippage is now expected.
- Construction sector multifactor productivity has stagnated for 30 years.

Workforce Demand—A joint report by the Institute for Sustainable Futures, University of Technology Sydney (ISF) in collaboration with AEMO [11] was undertaken to support the 2020 AEMO Integrated System Plan. The study developed workforce projections for different growth scenarios. The projection for the mid-range scenario is shown in Figure 5. Although transmission represents only a small segment of the market, competition from other segments for the same type of resources will occur, particularly for the largest category of labour—trades and technicians.

Cost Projections—AEMO have presented cost projections for transmission infrastructure in the Draft 2023 Transmission Expansion Options Report [2] as illustrated in Figure 6.

AEMO also stated in the report: "This cost forecast does not address the future cost of biodiversity offsets, as AEMO's position is to address this through operational expenditure given the nature of jurisdictional schemes."

The large projected increases in easement and property costs reflects increased landowner payment schemes which provide payments of around $200,000/km in New South Wales and Victoria and $300,000/km in Queensland[9].

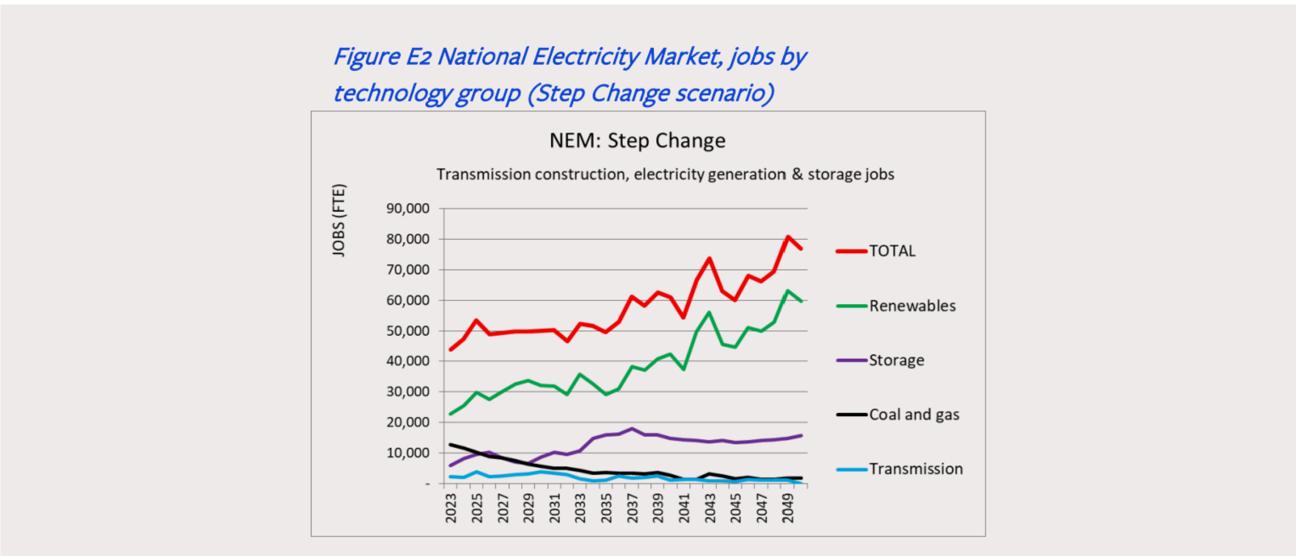


Figure 5. Projections for Jobs by Technology Group in Australian NEM (Rutovitz et al [11, p. 5])

9 https://reneweconomy.com.au/landowners-set-for-huge-windfall-as-queensland-accelerates-its-supergrid-transition/

Project Timeframes—Delays in delivery of transmission infrastructure is now considered to be one of the biggest challenges in meeting renewable energy targets. Apart from supply chain and workforce constraints and increasing costs—approvals and community opposition is delaying many projects. Gaining community acceptance or social licence has become critical for major transmission projects. There has been much commentary in recent media on this topic[10 11].

Undergrounding of transmission lines has become a significant issue in stakeholder and community engagement as evidenced in current Australian NEM projects (i.e., Humelink, Western Renewables Link) and overseas, as presented in the case studies in this report. HVDC is also being seen as a feasible alternative to AC transmission.

Figure 11 **Forecast cumulative cost changes for transmission projects: plant, materials, and easement and property costs, in real terms**

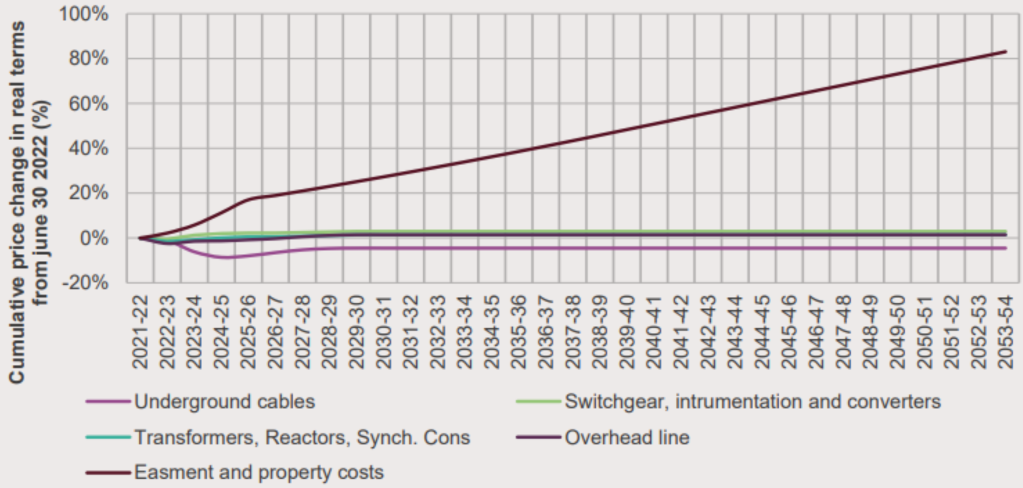


Figure 12 **Forecast cumulative cost changes for transmission project cost components: construction, services and secondary (electrical) systems, in real terms**

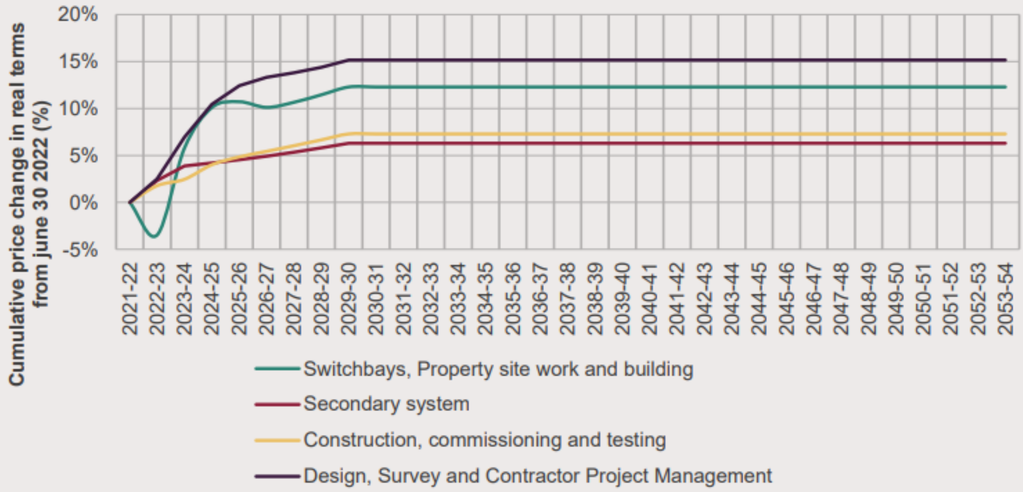


Figure 6. Projected Cost Increases for Transmission Infrastructure (AEMO [2, p. 38])

[10] https://reneweconomy.com.au/broken-regulations-not-community-opposition-are-delaying-transmission/.
[11] The Australian, June 9, 2023—Transmission line delays are putting a handbrake on renewable electricity supply.

7.

Conclusions

7.1 Key Findings

1. It is difficult to get accurate cost estimates for 500kV transmission infrastructure in Australia due to the lack of recent projects at this voltage, current global and local economic factors influencing the cost and availability of resources.
2. There have been many studies by government bodies, TNSP's, industry organisations and stakeholders comparing the cost of overhead and underground cable transmission either generally or for a specific project. Based on published literature including Parsons Brinkerhoff [1] and AEMO [2], the ratios are generally in the range of 3 to 20 depending upon type of construction, route length and other project specific factors. The Parson Brinkerhoff transmission costing study from the UK is often referred to by industry for its methodology for evaluating lifetime costs. This study concluded "Cost ratios are volatile, … Use of financial cost comparisons, rather than cost ratios, are thus recommended when making investment decisions." A lower cost ratio of 3 to 5, for example would tend to apply for the lowest cost option of direct buried underground, or long cable routes (with better economies of scale). A ratio of 5 to 10 would correspond to higher cost options of cable in ducts or for shorter lengths of underground cable. A higher ratio of 10 to 20 would tend to apply to more expensive cable tunnel installations.
3. HVDC Transmission generally becomes more economic for longer route interconnector transmission lines due to the high costs of AC/DC converter terminal stations that need to be included in HVDC projects. There is a "break even distance "for the cost of HVDC versus HVAC transmission. As an indication, based on data from Acaroğlu et al [5], ABB [6], Amplitude Consultants [7], and the AEMO Transmission Cost Database, the break-even cost for HVDC overhead transmission is around at a route length of around 600 to 700 km when compared to an 500kV HVAC line. The cost ratio of HVDC underground to HVDC overhead is around 5, and the cost ratio of HVDC underground to HVAC overhead was 3.3 for a 1500MW, 1000km case study [5].
4. There is no doubt that transmission infrastructure projects are facing several challenges because of global and national factors. Reports published by Infrastructure Australia [10] and AEMO [11] highlight challenges such as:
    - Demand driven risks have increased over the last 12 months.
    - Supply side risks have surged in 2021-22 (COVID-19, Ukraine War, labour shortages)
    - Increasing project costs and complexities
    - The market is arguably at capacity, so project slippage is now expected.
    - Availability of skilled labour resources in the energy industry
    - Internationally, many countries have similar large scale grid expansion programs linked to renewable energy targets and requiring the same material and labour resources.
    - Delays in gaining approvals due to social licence issues and other factors tend to exacerbate the cost challenges.

7.2 Comparison Table – Economic Factors of HV Transmission Infrastructure

A summary comparing the economic factors of overhead and underground infrastructure is presented in Table 11 below.

Table 11. Comparison of HV Overhead and Underground Cable Transmission Lines

	Factor	HVAC Overhead	HVAC Underground	HVDC Overhead	HVDC Under-ground
	Technical Factors - System Design, Installation and Performance				
1	**Capital Investment Costs:** Planning Social licence - consultation and engagement. Design and survey Approvals Environmental offsets Property – easements, right of way, landholder payments Procurement of plant and materials Construction (civil, structural, electrical) Commissioning Indirect costs (overheads)	Indicative costs for double circuit OHTL, route 50-100km, including project construction (materials, labour and plant) and excluding property and environmental offsets: 275 kV: $2M to $3M per km 500 kV: $5M to $6M per km	Indicative costs for double circuit UGTL typical 40 km length including project construction (materials, labour and plant) and excluding property and environmental offsets: 275 kV: $10 M to $15M per km 500 kV: $25M to $30M per km	Project costs were not in the scope of this study. “Break even” distance for HVDC overhead comparted to HVAC overhead is around 600 to 650km for EHV.	
2	**Operating and Maintenance:** Planned maintenance. Corrective maintenance Unplanned maintenance	**Indicative costs:** 0.5 to 1% of capital cost per km per annum for up to 20 years. 1 to 2% of capital cost per km per annum during mid life 5 to 10% of capital costs for mid-life replacement of certain line components (e.g., insulators).	**Indicative costs:** Expenditure per km per annum is typically around 40% of comparative overhead line but can be similar if the patrol specification and frequency of patrols is frequent.	HVDC Transmission lines – Maintenance requirements for overhead and underground line components are expected to be similar to HVAC overhead and underground. However, the additional maintenance requirements associated with AC/DC converter stations would be significant resulting in overall higher lifetime maintenance requirements.	
3	**Operating - Energy Losses**	Cost of losses depend on conductor size selection. Typically, overhead lines losses can be 1.5 to 2.5 times greater than an equivalent underground line.	Cost of losses depend on conductor size selection. Typically, underground cable losses will be less than an equivalent overhead line. Reactive compensation losses need to be considered for longer route lengths (e.g., > 10km).	Losses for HVDC systems can be up to twice that of the equivalent HVAC overhead or underground system due to the additional losses from the AC/DC converter.	
4	**Lifetime Cost:** Net Present Value (NPV) of: Capital Investment cost. Operating and Maintenance costs over life Cost of energy losses with annual load growth factor applied over life. End of life cost (not significant) Key assumptions included in the NPV calculation are: Expected asset life span e.g., OHTLs – 60 years, UGTLs – 40 years. Financial discount rate or internal rate of return e.g., 5 to 6%	275 kV OHTL PV costs at 40 years indicates the following: $3.76 M (Initial cost of $2 M + $1.76 M for maintenance and operating costs (losses and unreliability). It should be noted that 40 years is typically only half the life of an overhead line.	275 kV UGTL PV costs at 40 years indicates the following: $11.1 M (Initial cost of $10 M + $1.0M of maintenance It should be noted that 40 years is typically only 70% life of underground transmission line. The UGTL to OHTL lifetime cost ratio at 40 years is around 2.9. Lifetime costs have been performed for 275 kV transmission (because parameters for OHTL and UGTL were known). It is expected that the UGTL to OHTL lifetime cost ratio for a 500 kV line at 40 years would be similar to 275 kV transmission.	Not in scope of this study.	

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