TRANSMISSION OF CO_2 AND ENERGY

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TRANSMISSION OF CO_2 AND ENERGY

Background to the Study

Emissions of greenhouse gases to the atmosphere can be reduced by capture and storage of CO_2. This technique consists of three main stages; capture of CO_2 at power stations and other fuel conversion plants, transmission of CO_2 between the place where it is captured and the place of where it is to be stored and storage of CO_2 underground or in the deep ocean. IEA GHG has carried out several studies on capture of CO_2 and storage of CO_2 but has so far carried out little work on CO_2 transmission.

This study provides a spreadsheet-based model for initial assessment of the costs and performance of CO_2 and energy transmission systems. The model covers pipeline transmission of CO_2, natural gas, hydrogen, methanol and distillate oil and AC and HVDC transmission of electricity. It can be used to calculate the costs and performance of onshore and offshore pipelines and to assess the sensitivity to a wide range of factors, such as flowrate, pipeline diameter, pressure, terrain and country. It can also be used to assess different pipeline configurations, such as dedicated single pipelines or pipeline grids including trunk lines.

The model employs user-friendly input and output screens and is designed to be used by people who have little experience of pipeline and electricity transmission. The cost estimation is based on industry standard sizing techniques and the contractors' in-house estimating methods using industry norms. The model should only be used for initial assessment of options. More detailed site specific studies would need to be carried out for real transmission projects.

The study was carried out by Woodhill Engineering Consultants based in the UK. Information on electricity transmission was provided by Mott MacDonald, also based in the UK. The study was funded by the members of the IEA Greenhouse Gas R&D Programme. Statoil kindly provided additional sponsorship for the study.

This report summary written by IEA GHG is followed by Woodhill's report. MottMacDonald's report is included as Annex A. The overall report, the model and a help file are available on CD-ROM.

Results and Discussion

Technical aspects of pipeline transmission
As background to the estimation of costs and performance, an assessment was made of pipeline and equipment requirements for CO_2 and hydrogen service.

In the presence of moisture, CO_2 can dissolve in water forming carbonic acid and cause corrosion of carbon and low alloy steels. CO_2 corrosion has been studied extensively and the precautions needed to satisfactorily transport CO_2 in carbon steel lines are reasonably well documented. Without free water in the system, carbon steel should not corrode and is an acceptable material for CO_2 pipelines.

CO_2 captured in gasification plants may contain some H_2S, which may cause sulphide stress cracking and hydrogen induced cracking and may impose constraints on a pipeline's material specification.

Problems with transportation of hydrogen only occur if there is a mechanism that produces atomic hydrogen (H^+), as this may cause hydrogen induced cracking or hydrogen embrittlement. Molecular hydrogen (H_2) may be transported without problems in standard low-alloy carbon steel lines irrespective of the gas pressure provided that the conditions are dry and under 220°C. Transmission of hydrogen using existing pipeline systems and booster stations which were originally designed for natural gas raises concerns such as compressor and materials suitability, process control, hydrogen containment and detection, compressor power requirements, and equipment re-certification. However, this is not one of the options considered in the assessment model.

The report provides general guidelines for materials and equipment for CO_2 and H_2 service; specific cases should be reviewed on a case-by-case basis to ensure the materials and equipment are acceptable.

Cost and performance modelling software

The modelling software is based on Microsoft Excel and can be run on a conventional Windows-based PC. The user is able to specify up to 10 "assets" - these can be pipelines, energy conversion plants or wells for CO_2 underground storage. The costs and performance of each of these individual assets are calculated and overall costs, energy consumptions and greenhouse gas balances are calculated. The results are presented in tables and graphs. To enable different options to be compared easily, up to 5 cases, each consisting of up to 10 assets can be modelled and the results of each of the cases can be compared graphically.

Pipelines

For each pipeline, the user specifies the following information:
- Throughput (kg/s)
- Length (km)
- Onshore or offshore
- Type of terrain
- Country/region
- Type of fluid (CO_2, natural gas, hydrogen, methanol or distillate oil)
- Pipeline inlet pressure
- Number of booster compressor/pumping stations or minimum distance between booster stations
- Compressor/pumping station inlet and outlet pressures
- Is an inlet booster compressor required?
- Pipe diameter (optional)

There are two options for sizing the pipeline. The user can specify the minimum distance between booster stations and the model will select an appropriate pipe diameter. Alternatively, the user can select a pipe diameter and number of booster stations and the model will calculate the pipeline pressure drop. Booster compressors for fuel pipelines are assumed to be driven by gas turbines which burn part of the fuel being transported and CO_2 pipeline booster compressors are assumed to be electrically driven.

The model calculates the following information for each pipeline:
- Capital cost
- Fixed operating cost
- Variable operating cost
- Booster compressor power consumption and CO_2 emissions

Electricity transmission lines

For electricity transmission lines, the user specifies the following:

- Capacity (MW)
- Length (km)
- Onshore or offshore
- Type of terrain (onshore)
- Country/region
- AC or DC
- Whether or not sub-stations are included
- Type of substation (indoor or outdoor)
- Number of transmission circuits and level of security

The model will select the most appropriate transmission voltage and conductor size and then predict capital and operating costs and electricity losses. The study report provides background information on AC and high voltage DC (HVDC) transmission, to enable non-expert users of the software to specify appropriate transmission systems. The cost information on HVDC is based on “voltage source converter” (ABB Light) technology at 100 MW and conventional thyristor HVDC valves at high power levels, because practical experience of voltage source converters is limited above 100 MW.

Energy conversion plants

Simple algorithms for calculation of costs and performance of energy conversion plants are included to enable overall energy delivery schemes to be modelled. The types of energy conversion plants currently included in the model are:

- Combined cycle power generation plants
- Natural gas-based hydrogen production plants
- Natural gas-based methanol production plants
- Coal fired power plants.

CO_2 capture is included where appropriate, i.e. in all cases except hydrogen fired combined cycle power plants. The user specifies the useful energy output from the plant and the software calculates the fuel feed rate and the quantity of CO_2 captured. Each energy conversion plant asset includes its own CO_2, hydrogen or methanol output pipeline or electricity output transmission line.

Underground CO_2 storage

Simple algorithms for calculation of costs of wells to inject CO_2 underground (onshore or offshore) are also included. The user specifies the depth of the injection wells, the injection pressure and the throughput per well, which in practise will depend on the geology of the underground reservoir. The model calculates the capital cost, fixed operating cost and variable operating cost. The model does not at present include data for direct ocean injection of CO_2, because the costs of dispersion nozzles etc. are very uncertain. The CO_2 storage feature of the model could be expanded in future if adequate data becomes available.

Cost and performance predictions

The main aim of this study is to provide cost data and assessment software; use of this data and software will be part of subsequent studies. However, as an illustration, IEA GHG has used the model to estimate the costs of pipeline and electricity transmission systems for a range of distances, sizes and types of power plant.

Transmission for a 500 MWe gas fired power plant

IEA GHG’s technical and economic assessments are based on 500 MWe power plants. Figure 1 shows the costs of transporting natural gas to a 500 MW_e combined cycle power plant with CO_2 capture and the costs of transporting the electricity and CO_2 produced by the plant. The quantity of CO_2 transported, assuming 85% CO_2 capture, is about 1.5 million tonnes/year. The costs are based on IEA GHG’s standard assessment criteria, including an annual discount rate of 10% and a plant life of 25 years. The onshore transmission of natural gas and CO_2 is assumed to be across cultivated land in Europe. The natural gas pipeline is designed for a maximum pressure of 90 bar, normal for natural gas transmission. The CO_2 pipelines are designed for a higher pressure rating of 140 bar, to ensure the CO_2 remains in the dense phase. Booster compressors are included for the onshore pipelines but not for the offshore CO_2 pipeline, because offshore booster compressors and their power supply would be expensive. Instead of adding booster compressors, the diameter of the offshore CO_2 pipeline is increased with length, to reduce the pressure drop per km.

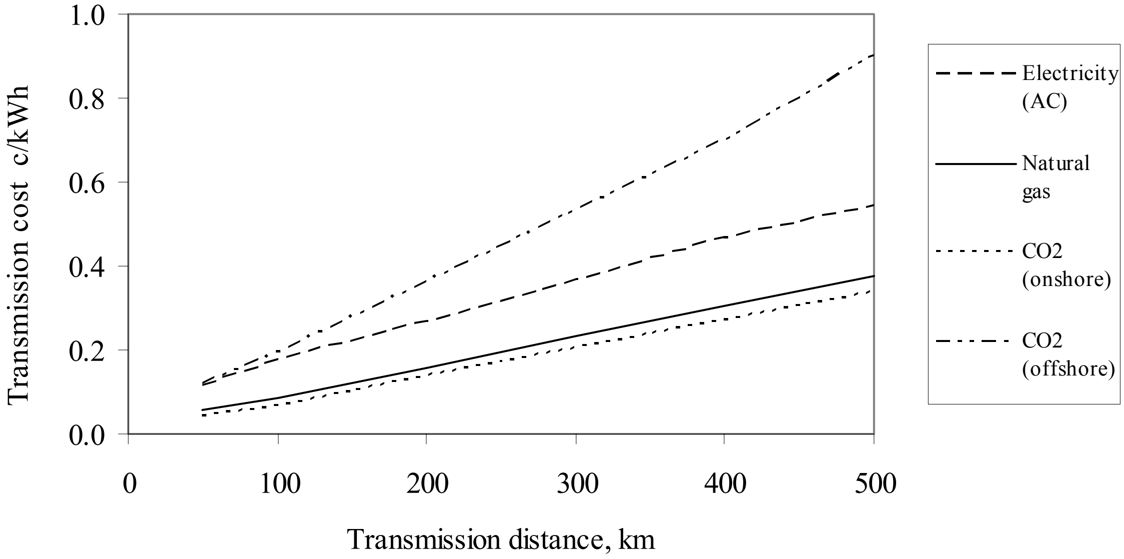

Figure 1 Costs of natural gas and CO_2 pipelines and electricity transmission lines - 500MWe plant

The cost of transmitting the CO_2 captured in a 500 MW gas fired power plant over a distance of 300km onshore would be about $6/tonne of CO_2 transported, equivalent to 0.2 USc/kWh of electricity generated. For comparison, the cost of CO_2 capture would be 1.1 c/kWh (see IEA GHG report PH3/14). Offshore transmission would be more expensive; $15/tonne of CO_2 for 300km, equivalent to 0.5 c/kWh.

The specific cost of CO_2 transmission in larger pipelines would be lower, as shown by figure 2.

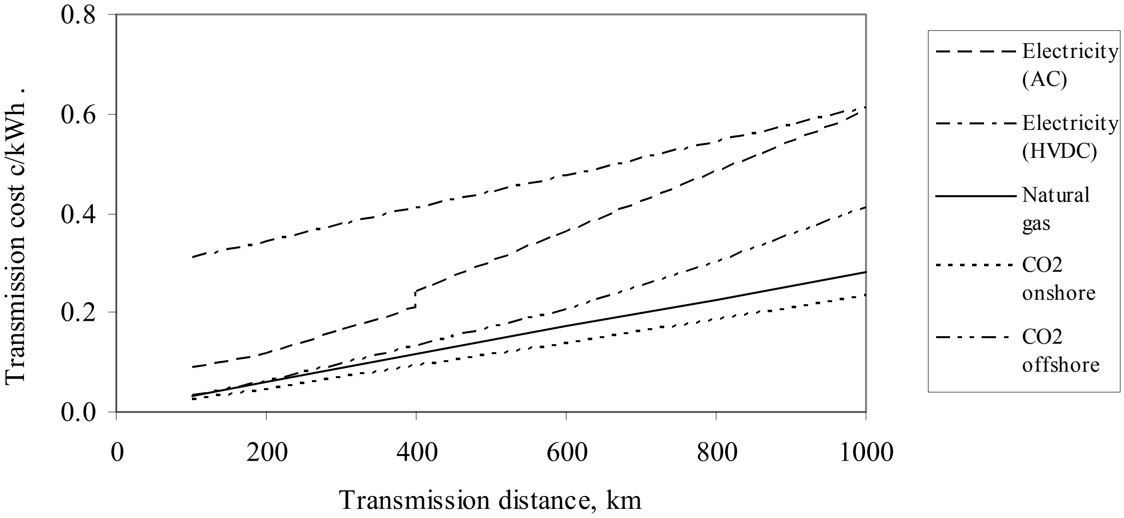

Figure 2 Costs of natural gas and CO_2 pipelines and electricity transmission lines - 5000MWe

The cost of transmitting CO_2 from 5000 MW of gas fired power generation for 300 km onshore in a single pipeline would be about $2/t CO_2, equivalent to 0.07 c/kWh. It would therefore be worthwhile building trunk pipelines for long distance transmission of CO_2, as is the case for natural gas. When the first plants with CO_2 capture are being built it may be advantageous to install large trunk CO_2 pipelines in the expectation that other plants may be built which could utilise the spare capacity in the pipeline. This may be cheaper in the long run than for each plant to build its own small dedicated pipeline.

For short transmission distances, high voltage DC transmission is more expensive than AC transmission, because of the high cost of the AC/DC converters at the ends of the transmission line. In the case shown in figure 2, HVDC transmission would be cheaper than AC transmission for distances of more than 1000 km. The discontinuity in the cost line for AC transmission in figure 2 is because the number of transmission circuits has to be increased as the distance increases.

Figures 1 and 2 show that electricity is more expensive to transmit than the natural gas feedstock to a power plant. This means that for gas fired power generation without CO_2 capture, the least cost option would normally be to locate a power station near to electricity consumers rather than near to the source of the natural gas. The situation may be different for plants with CO_2 capture, depending on the location of the CO_2 store. The combined cost of transmitting natural gas and CO_2 is broadly similar to the cost of transmitting electricity over a given distance, depending on distance and capacity, so if CO_2 has to be stored in an underground reservoir close to the source of the natural gas it may be cheaper to locate the power station close to the gas/storage field, rather than the electricity consumers.

Coal fired power generation

More CO_2 is captured per kWh of electricity generated in coal fired power stations than in gas fired power stations, because of the higher carbon content of the fuel and the lower thermal efficiency. For plants with post-combustion capture, over twice as much CO_2 is captured per kWh in a coal fired plant (see IEA GHG report PH3/14). The cost of transmitting CO_2 would increase by less than this because of economies of scale in the pipeline, provided the pipeline is not already at its maximum feasible size. The cost of transmitting CO_2 for 300km onshore would about $4/tonne of CO_2, (equivalent to 0.3 c/kWh) for a single 500 MWe power plant or $2/tonne of CO_2 (0.13 c/kWh) for 5000 MWe.

Long distance transmission

IEA GHG report PH3/22 shows that there is a large potential to store CO_2 in depleted oil and gas reservoirs (120 Gt in depleted oil reservoirs and 800 Gt in depleted gas reservoirs). Such reservoirs may be preferred because they are perceived to be more secure stores for CO_2 than saline aquifers. Most of the storage capacity for depleted oil and gas reservoirs would be in the Middle East and the Former Soviet Union. A typical transmission distance between Western Europe and the main reservoirs in the Former Soviet Union and the Middle East would be 5000 km. The cost of transmitting CO_2 in large diameter pipelines would be about $25/tonne of CO_2, equivalent to about 0.9 c/kWh for gas fired power generation or 2.2 c/kWh for coal fired generation, which is similar to the cost of CO_2 capture.

Another possibly attractive option for long distances transmission would be to use ships for transportation of compressed/liquefied natural and CO_2 but assessment of this option was beyond the scope of this study.

Hydrogen transmission

There is increasing interest in hydrogen as an energy carrier, particularly for use in fuel cells for road transport and small scale combined heat and power generation. In the very long term, hydrogen may be produced from renewable energy sources but at present this would be very expensive. The most effective way to build up the infrastructure for use of hydrogen, while avoiding emissions of CO_2 to the atmosphere, would be to produce hydrogen from fossil fuels and store the resulting CO_2.

The cost of transmitting hydrogen from a natural gas based hydrogen plant over a given distance would be slightly less than the cost of transmitting the natural gas feedstock. This implies that it would be cheaper overall to build natural gas-based hydrogen plants close to the source of natural gas. If captured CO_2 could be stored in nearby depleted natural gas reservoirs, then it would be even more attractive to build the hydrogen plants close to the source of the natural gas.

Wind energy

The main aim of this study is to provide information relevant to capture and storage of CO_2. However, the model can also contribute to assessment of renewable energy schemes. As an example, figure 3 shows how the costs of electricity generated from wind would depend on transmission costs. Areas with high average wind speeds are often remote from areas of large energy consumption. There is therefore a choice between building wind turbines in low wind speed areas close to electricity consumers or in high wind speed areas remote from consumers. Figure 3 shows how the delivered cost of wind energy depends on the transmission distance and the wind turbine load factor. For example, the delivered cost of electricity from a wind farm with a load factor of 35% and a transmission distance of 1000km would be about the same as from a wind farm with a load factor of 25% and a transmission distance of 200km. Figure 3 is based on a wind farm cost of $1000/kW, 20 year life and 10% DCF. The transmission line is assumed to be a 500 MW AC line and it is assumed that it is sized to cope with the maximum turbine output. It has been suggested that the overall cost of delivered electricity may be lower if the transmission system was undersized and the output of the turbines was partly curtailed during periods of peak potential generation.

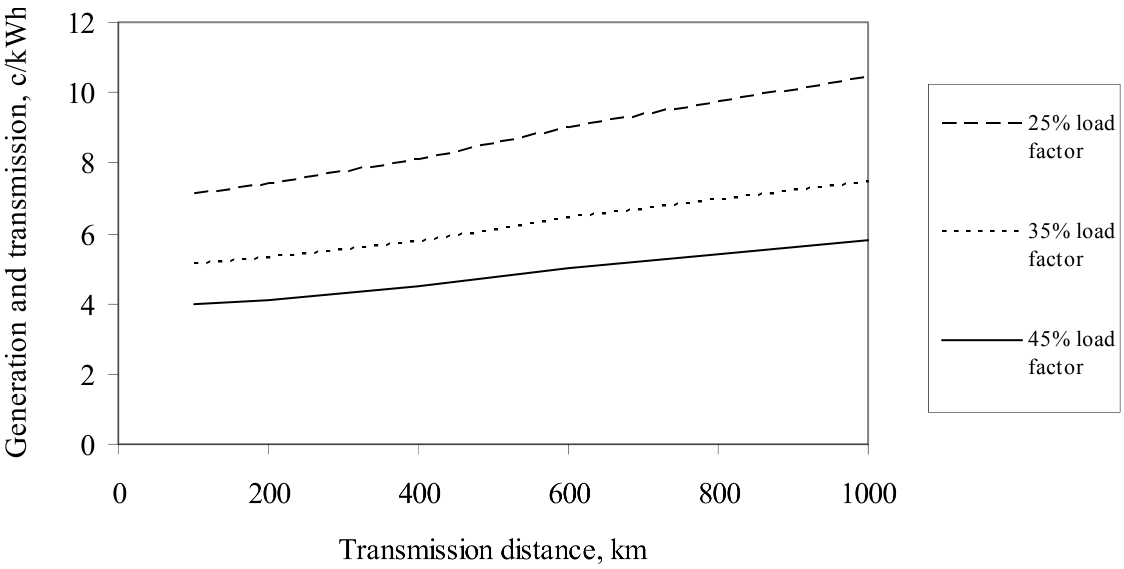

Figure 3 Costs of generating and transmitting electricity from wind farms -500MWe transmission

Expert Reviewers' Comments

A draft version of the report was sent for review to 11 experts, mainly members of IEA GHG's Executive Committee associated with the oil/gas and power industries. The model and report were modified in the light of comments received, most of which were requests for minor changes to make the model easier to use. In the light of comments, the model was also expanded to include higher pressure pipelines and coal fired power stations.

Major Conclusions

A computer model has been developed for screening assessment of costs and performance of pipelines and electricity transmission systems. Pipelines for transmission of CO_2, natural gas, hydrogen, methanol and distillate oil, and AC and HVDC electricity transmission can be assessed. The model also includes simple algorithms for prediction of the costs of energy conversion plants and CO_2 underground storage wells. The model includes user-friendly input and output screens model and is designed to be used by people who have little expertise on pipeline and electricity transmission systems.

Sample calculations using the model indicate the following:

The CO_2 output from a 500 MWe base load natural gas fired power station with CO_2 capture would be about 1.5Mt/y. The cost of transmitting this CO_2 for 300 km onshore would be typically $6/t of CO_2, equivalent to 0.2 c/kWh. Increasing the pipeline size by a factor of 10 would reduce the cost to $2/t of CO_2. The cost of a 300km offshore pipeline for a 500MW plant would be $15/t of CO_2.

The cost of transmission of CO_2 from a 500MW coal fired plant in a 300 km onshore pipeline would be $4/t of CO_2, equivalent to 0.3 c/kWh. The cost would be $2/t of CO_2 for 5000MW of coal fired plant.

The cost of transmitting the natural gas feedstock to a gas fired combined cycle plant is broadly similar to the cost of transmitting captured CO_2. The electricity output is more expensive to transmit than either the natural gas feedstock or CO_2 output. The combined cost of transmitting natural gas and CO_2 would be broadly similar to the cost of transmitting electricity.

Transmission of hydrogen from a natural gas-based hydrogen plant would be slightly cheaper than transmission of the natural gas feedstock. Natural gas should therefore be converted to hydrogen close to natural gas reservoirs, particularly if the CO_2 from the hydrogen plant could be stored in the gas reservoirs.

For wind power, the transmission cost usually has a less significant impact on the costs of electricity generation than the wind turbine load factor. It would therefore be worthwhile building wind turbines remote from electricity consumers if this enabled the turbines to be built in areas with significantly higher wind speeds.

Recommendations

It is recommended that the IEA Greenhouse Gas R&D Programme's Executive Committee should discuss whether they would want the model to be enhanced to include other options. Some suggestions are given below.

- The model could be expanded to include ship transport of LNG/CNG and CO_2, possibly in the same type of ship. Liquefaction and storage facilities would need to be included as part of ship transport schemes.

- Ship and rail transport of coal and liquid fuels could be included.

- More detailed estimation of the performance and costs of underground CO_2 storage could be included in the model if the necessary information is available. Ocean injection of CO_2 could also be included.

The model can be used to assess a variety of energy and CO_2 transmission options, based on the locations of real energy sources, energy conversion plants and potential CO_2 storage reservoirs. This will help to derive cost curves for CO_2 capture and storage.

DOCUMENT SUBMITTED TO

IEA GREENHOUSE GAS R&D PROGRAMME

PIPELINE TRANSMISSION OF CO_2 AND ENERGY

TRANSMISSION STUDY - REPORT

PREPARED BY

WOODHILL

PIPELINE TRANSMISSION OF CO_2 AND ENERGY

TRANSMISSION STUDY - REPORT

submitted to

IEA Greenhouse Gas R&D Programme
Stoke Orchard
Cheltenham
Gloucestershire GL52 7RZ

by

Woodhill Engineering Consultants
St Andrew's House
West Street
Woking
Surrey GU21 1EB
Tel: +44 1483 717600
Fax: +44 1483 717630
www.woodhill.co.uk

REVISION RECORD

This document is issued in accordance with the Woodhill Quality Management System. Revisions may comprise a complete issue, or issue of individual pages as noted in the table below.

C	28 Feb 02	Third Issue	All	MMB	DJF	WAH
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TABLE OF ABBREVIATIONS

ANSI	American National Standards Institute
BS	Booster Station
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CDM	Construction and Design Management
COSHH	Control of Substances Hazardous to Health
CH_4	Methane
CO_2	Carbon dioxide
Fe	Iron
GHV	Gross Heating Value
HIC	Hydrogen Induced Cracking
HYSYS	Proprietary software for process simulation (Hyprotech)
H^+	Hydrogen (atomic)
H_2	Hydrogen (molecular)
H_2S	Hydrogen sulphide
IPB	Initial Pressure Boost
LHV	Lower Heating Value
MW	Molecular Weight
NACE	National Association of Corrosion Engineers
ND	Nominal Diameter
OPEX	Operating expenditure
PC	Personal Computer
PHAST	Proprietary software for modelling of fire and explosions (DNV)
PIPESIM	Proprietary software for pipeline hydraulic simulation (Baker Jardine)
SMR	Steam Methane Reforming
SSC	Sulphide Stress Cracking
USD	United States Dollars
VHN	Vickers Hardness Number

LIST OF KEY FIGURES AND TABLES

Section 3

Section 4

SUMMARY

This report presents an assessment of energy transmission and CO_2 capture. The forms of transmitted energy include: hydrocarbon gas (e.g. natural gas); liquid fuels (e.g. methanol, distillate fuels); hydrogen gas; electricity. Coal has also been considered as a power station fuel, but coal transportation has not been assessed. The capture of CO_2 includes gathering, transmission and storage. The metallurgy of existing hydrocarbon pipelines has been assessed for use with hydrogen and CO_2.

The report also provides supporting information for a PC based model (the Model) for the high-level cost estimation of energy transmission and CO_2 capture. The Model can be used for the comparison of options for energy distribution, including, for example, the conversion of natural gas to liquid fuel and the options for the conversion of fuels to electricity. The Model also includes the capture of CO_2 gathering. A separate Electrical Transmission Study [1] was provided by the IEA and the results have been incorporated into the Model.

The pipeline metallurgy assessment concludes that CO_2 should not cause corrosion of carbon and low-alloy steel lines provided the gas is dry. Hydrogen can cause corrosion if there is a mechanism that produces atomic hydrogen (H^+) as this may cause hydrogen induced cracking or hydrogen embrittlement. Molecular hydrogen (H_2) may be transported without problems in standard low-alloy carbon steel lines irrespective of the gas pressure provided that the conditions are dry and under 220°C. The presence of H_2S can cause sulphide-stress cracking and hydrogen-induced cracking and imposes constraints on a pipeline's material specification. The report provides general guidelines for materials and equipment for CO_2 and H_2 service, and specific cases should be reviewed on a case-by-case basis for acceptability. Requirements for H_2S service should be to NACE standard MR0175[2].

The use of existing hydrocarbon pipeline equipment (for example Booster Stations) for hydrogen raises concerns such as materials suitability, process control, hydrogen containment and detection, compressor performance and power requirements, and equipment re-certification. These need to be studied on a case-by-case basis.

The cost estimation in the Model is based on industry standard sizing techniques and in-house estimating methods using industry norms. Estimates from the Model are in year 2000 USD, consistent with the Electrical Transmission Study[1].

The Model can be used to provide high-level cost estimates for the evaluation of various options for energy transmission and CO_2 capture. The Model runs in Microsoft Excel version 97 or higher, and is supported by a comprehensive help file.

1. INTRODUCTION

This report presents an assessment of energy transmission and CO_2 capture. The forms of transmitted energy include: hydrocarbon gas (e.g. natural gas); liquid fuels (e.g. methanol, distillate fuels); hydrogen gas; electricity. Coal has also been considered as a power station fuel, but coal transportation has not been assessed. The capture of CO_2 includes gathering, transmission and storage. The metallurgy of existing hydrocarbon pipelines has been assessed for use with hydrogen and CO_2.

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The Scope of Work is detailed in Section 2.

The methods considered for energy transportation include gas or liquid hydrocarbon fuels, hydrogen, or electricity. Incorporated into the Model are the various processes required to link these methods of energy and CO_2 transport, listed below:

- Power Stations (fuels to electricity).
- Synthesis Plants (gaseous fuel to liquid fuel or hydrogen).
- CO_2 Storage Facilities (Injection Wells Sites).
- Pipelines for fuel and CO_2 transport.
- Electrical Transmission Systems for electricity transport.

The Model can be used to assess the minimisation of CO_2 emissions. This minimisation is performed via capture and storage of the CO_2 associated with the use of fossil fuels for power generation.

Further details are discussed in Section 3. Cost estimation details are contained in Section 4.

2. SCOPE OF WORK AND BASE DATA

2.1 Scope of Work

The detailed scope of work for this project is contained in Technical Specification IEA/CON/00/63[3].

The initial scope was extended to include the supply of modelling software for cost estimation of energy conversion, transmission and distribution systems and CO_2 capture for comparison of cases and options. The scope was also extended to include coal fired power stations, although the transport of coal has not been studied.

2.2 Base Data

Base data is divided into technical and commercial considerations.

2.2.1 Technical Data

The general technical basis of the Model was from the IEA Technical Specification IEA/CON/00/63[3]. In addition to this document, various sources have been used to provide data for the study and the Model as summarised in Section 6.

2.2.2 Commercial Data

Commercial data have been developed based on in-house methods using industry norms. The Model provides estimates for the comparison of options and more precise engineering will be needed for detailed cost estimates. Estimates from the Model have been provided in year 2000 USD, consistent with the Electrical Transmission Study[1].

In addition, some cost data have been provided by IEA and incorporated into the Model. This information is referenced in Section 4.

3. TECHNICAL ASSESSMENT

This section includes technical discussion of the following:

- CO_2 Quality
- CO_2 Gathering
- Hydrogen Transmission
- H_2S Implications
- Safety Requirements
- The Energy Distribution and CO_2 Capture Model:
  - Project Settings
  - Electrical Power Generation Plant Asset
  - Fuel Synthesis Plant Asset
  - CO_2 Storage Facility Asset
  - Pipeline Branch Asset
  - Pipeline Hydraulic Sizing Methodology

3.1 CO_2 Quality

In the presence of moisture, CO_2 can dissolve in water forming carbonic acid and cause corrosion of carbon and low alloy steels. CO_2 corrosion has been studied extensively, and the precautions needed to satisfactorily transport wet CO_2 in carbon steel lines are reasonably well documented[4,5].

CO_2 should not cause corrosion of carbon and low-alloy steel lines, provided the gas is dry. Operating below 60% relative humidity normally provides a margin to avoid moisture condensation or dropout from the gas phase. Without free water in the system, carbon steel should not corrode and is an acceptable material for CO_2 pipelines.

The CO_2 produced in the power station as a result of combustion, will be mixed with water (also a product of combustion) and nitrogen. The process for extracting the CO_2 from exhaust gases has been assumed to use amine absorption, followed by glycol dehydration to produce dry CO_2 gas.

Treatment costs for drying the CO_2 are included in the Model as a rolled up cost incorporated in to the cost of the power generation plants.

Other impurities that may be present in the CO_2 include hydrogen sulphide (H_2S), which is discussed in Section 3.4.

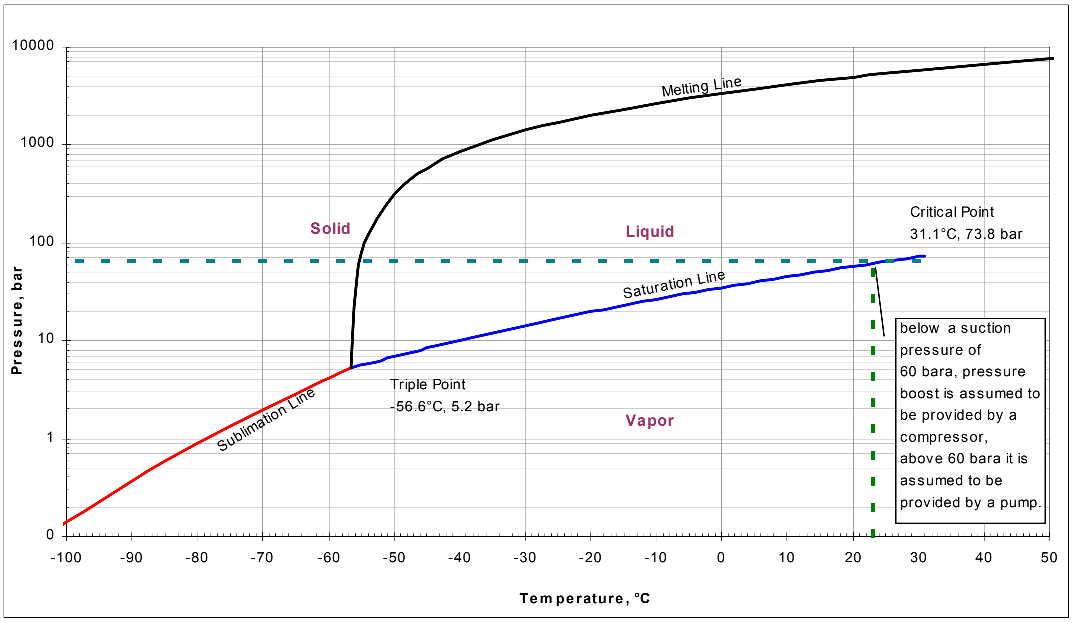
3.2 CO_2 Gathering

The process of gathering CO_2 from various point sources via a collection system has been evaluated. From a conceptual standpoint, a CO_2 gathering network is no more complicated than a typical gas-gathering network, common in the hydrocarbon industry. The general considerations of pressure containment, materials, and impact on the environment are all common design concerns. Particular to CO_2 gathering are the concerns associated with the CO_2 itself. These concerns include phase behaviour, materials, and safety issues.

Phase Behaviour

The phase behaviour of CO_2 can cause considerable process concerns, particularly with respect to possible phase changes (refer to Figure 3.1 below). It is assumed that that following capture, CO_2 is dried and its pressure boosted to achieve a dense phase fluid for efficient pipeline transport to a storage site[26]. At pressures and temperatures above the critical point, CO_2 will exist as in the dense phase region. To determine whether a pump or compressor is required to achieve the pressure boost the Model assumes a nominal pressure below which CO_2 exists as a gas and above which CO_2 exists as a liquid. This pressure is 60 bara, corresponding to an inlet temperature of 23°C.

Figure 3.1 CO_2 Phase Diagram



below a suction pressure of 60 bara, pressure boost is assumed to be provided by a compressor, above 60 bara it is assumed to be provided by a pump.

As CO_2 passes along the pipeline, the change in pressure and temperature may cause liquid dropout, which may complicate detailed design issues, however, this is inherently a case-by-case issue and should be addressed as such.

For this reason, the Model does not restrict temperature and pressure ranges for CO_2 service. However, the user must be aware that phase behaviour issues exist which should be taken into account.

The Model is arranged such that a gathering system may be simply described by means of a network of lines carrying CO_2 (refer Section 3.6.5). The user is responsible for mapping out the gathering system and checking that the input data (i.e. flowrates and distances) used in each line is consistent with the overall requirements for the system.

Details regarding the assumptions relating to the hydraulic sizing of the lines may be found in Section 3.6.5.

Materials and Safety Issues

As indicated by the CO_2 Phase Diagram above, at very high pressures or low temperatures CO_2 can freeze. Clearly this is of concern in environments with low ambient temperatures or if there is a rapid pressure decrease in the pipeline e.g. from a leaking valve. Consideration should therefore be given to ensuring that where necessary the pipeline material specification is suitable for potential low temperature service (e.g. ASTM A333.)

Further materials considerations are discussed in Section 3.1.

Transmission pipeline safety issues are discussed in Section 3.5.4.

3.3 Hydrogen Transmission

Hydrogen transportation in existing pipelines has been assessed. Several significant metallurgical considerations (such as hydrogen induced cracking) need to be taken into account when designing pipelines for hydrogen service[4,5,6]. In addition, process considerations relating to the changeover from natural gas to hydrogen service would require evaluation on a case-by-case basis

3.3.1 Considerations of Hydrogen Transportation

Atomic hydrogen (H^+) is capable of diffusing through steel. Problems with the transportation of hydrogen can occur if there is a mechanism that produces atomic hydrogen.

Molecular hydrogen (H_2) may be transported without problems in standard low-alloy carbon steel lines irrespective of the gas pressure provided that the conditions are dry, liquid free, and under 220°C (refer to standard curves showing operating limits for carbon and low alloy steels in contact with H_2 at high temperatures and pressures[6]).

The primary process through which hydrogen causes material failure is hydrogen induced cracking (HIC). This can occur when atomic hydrogen diffuses into the material and reforms as microscopic pockets of molecular hydrogen gas. These pockets can result in the material blistering, fissuring or flaking, and can ultimately lead to failure.

3.3.2 Mechanisms for Hydrogen Induced Cracking

There are two primary mechanisms for HIC:

1) HIC Due to Wet Conditions

HIC can occur due to corrosion that is promoted under wet conditions. Many forms of corrosion include an oxidation reaction that can release atomic hydrogen (H^+) in the presence of an electrolyte. The overall anodic and cathodic reactions are:

$$Fe \rightarrow Fe^{2+} + 2e^- \qquad \text{and}$$

$$2H^+ \rightarrow 2e^- + H_2 \text{ (gas)}$$

The atomic hydrogen can diffuse into the material and accumulate at voids or at non-metallic inclusions where the atoms can re-combine to form molecular H_2 gas. Since molecular hydrogen cannot diffuse, the concentration and pressure of hydrogen within a void or at a non-metallic inclusion increases which eventually leads to blistering, flaking and finally rupture. This mechanism can occur when water is present. The electrolytic activity of the water can be increased by acidic gases such as hydrogen sulphide (H_2S) and carbon dioxide (CO_2).

Atomic hydrogen can diffuse through steel even at room temperature and hence within the temperature range that is within standard operating conditions for most pipelines.

2) HIC Due To Elevated Temperatures

Above 220°C moisture does not need to be present to provide a source for disassociating hydrogen. Above this temperature the dissociation of molecular hydrogen into atomic hydrogen becomes significant and the limits regarding tolerable pressure at this temperature are defined in the standard curves[6] for the behaviour of this system.

Under these conditions, atomic hydrogen can combine with carbides or dissolved carbon (indicated as $C_{(Fe)}$) within the steel to form methane by the following reaction. This is termed decarburisation.

$$C_{(Fe)} + 4H^+ \leftrightarrow CH_4$$

Since atomic hydrogen readily diffuses in steel, cracking can result from the formation of methane in internal voids within the steel that can cause the material to blister and flake. In addition decarburisation and loss of strength and ductility of the steel can occur due to the reaction with carbon with a consequent loss of strength. Chromium and molybdenum additions to the steel improve its resistance to cracking in hydrogen environments.

At low or ambient temperatures this phenomenon does not occur and the presence of atomic hydrogen is determined by the presence of moisture in the system as described above.

At elevated temperatures water or water vapour present in the hydrogen gas stream can also cause decarburisation by the reaction:

$$C_{(Fe)} + H_2O \leftrightarrow H_2 + CO$$

In addition, if steel is exposed to high temperature water vapour it can react as follows:

$$Fe + H_2O \leftrightarrow FeO + H_2$$

Thus in hydrogen-water environments both decarburisation and oxidation can occur.

At low or ambient temperatures this phenomenon does not occur and the presence of atomic hydrogen is determined by the presence of moisture in the system as described above.

3.3.3 Hydrogen Embrittlement

In addition to HIC, atomic hydrogen can also embrittle carbon steel by interfering with the normal process of plastic flow (i.e. the deformation of the steel on a granular level, due to continuous strain). This is associated with the interstitial solution of atomic hydrogen in ferrite (alpha iron) or martensite. For this interference to occur the atomic hydrogen must have time to diffuse to the site of the plastic strain. These embrittling effects are maximised when a saturated solution of hydrogen in alpha iron exists.

Hydrogen embrittlement is therefore most likely to occur at low strain rates and at temperatures between -100°C and +120°C. At high strain rates, such as impact loading or in hardness testing, the dissolved hydrogen has no effect on steel behaviour, as movement of the steel is too rapid for hydrogen diffusion and interaction. At temperatures below -100°C the hydrogen diffusion rate is low and above +120°C the diffusion rate is such that the hydrogen escapes from the steel as rapidly as it enters.

Thus, in summary, if a steel is charged with atomic hydrogen and strained at an appropriate rate and temperature, it cannot locally accommodate the strain at a notch or stress raiser by plastic deformation, and consequently a crack is initiated and brittle fracture can result.

Molecular hydrogen does not cause embrittlement of steel.

3.3.4 Preferred Materials for Hydrogen Service

Specifications for carbon steel lines in hydrogen service normally include requirements for a reduced sulphur content and a limit on the maximum material hardness. In addition, alloying with chromium, molybdenum, vanadium, titanium, etc. generally improves the resistance of the steel towards attack in hydrogen service.

Sulphur in steel is usually present as sulphide non-metallic inclusions (mainly manganese sulphide). These inclusions are potential sites for the accumulation of hydrogen and hence for the development of fissures, blisters etc. These can possibly lead to ultimate fracture and failure. Reducing sulphur to a minimum will help to protect against HIC.

Another beneficial measure to promote HIC resistance is calcium treatment during steel production. This promotes the formation of rounded sulphide inclusions which are more resistant to elongation during the rolling of pipe or plate (for seam welded pipe). The rounded inclusions in turn will be more resistant to the initiation and development of fissuring than elongated inclusions, should uptake of atomic hydrogen occur in service.

Hence low-sulphur steel alloyed with calcium treatment is desirable for protection against HIC. This is an accepted part of the steel specification when designing for sour service in the processing industry.

A factor for protection against hydrogen embrittlement HIC (see Section 3.3.3) is the hardness of the material. Should the material have a Vickers Hardness Number (VHN) greater than 300, the tendency for the material to fail due to plastic straining when there is significant absorption of atomic hydrogen, is greater than with a softer material.

3.3.5 Conditions Preferred for Hydrogen Service

To avoid the mechanisms for HIC detailed above, the operating conditions in a hydrogen transportation line should take account of the following:

1) Dry conditions. The hydrogen should be water dry. Operation below 60% relative humidity is normally accepted as providing sufficient margin for avoidance of moisture and water dropout.

2) Operating temperature below 220°C to avoid any significant dissociation of molecular hydrogen into atomic hydrogen.

3.3.6 Concerns with Existing Pipeline Systems

The option to transfer hydrogen using existing transmission systems originally designed for natural gas service presents a number of issues. These systems include pipelines and associated Booster Stations. The issues with this concept are discussed below.

Material Concerns

Existing steel pipelines may be used for hydrogen transportation, provided that the hydrogen is dry and the pipeline is designed for the appropriate level of pressure containment. As detailed above, a margin of less than 60% relative humidity is considered reasonable for operational dryness requirements. Pressure containment depends upon the current limits of the installation, as they may be notably different from the original design of the system due to corrosion, erosion, etc.

Existing pipelines originally designed for sour service will provide additional protection against HIC and hydrogen embrittlement in the event that the operating conditions of the pipeline deviate from the recommended levels. This is due to the metallurgy of the systems that protect against HIC and hydrogen embrittlement as described above.

Process / Performance Concerns

Utilising existing pipelines and booster compression stations for hydrogen transport via hydrogen combustion raises performance issues, in addition to metallurgical considerations. Although analysis would need to be on a case-by-case basis, some general comments may be made.

Although there are some common concerns, these issues may be divided into the areas of piping, power generation and compression. Many of the issues are due to the physical properties of hydrogen. Hydrogen is relatively light, small on a molecular level, and has a high calorific value.

Process Plant Piping Concerns

During hydrogen pipeline specification, reference should be made to ANSI B31.3: Petroleum Plant and Refinery Piping. The use of existing natural gas plant and piping for hydrogen service could be extremely difficult due to area classification, flanged joints, snuffing requirements, use of threaded joints etc.

Power Generation – Turbine Operation

The use of hydrogen as a fuel in turbines originally designed for hydrocarbon gas raises several issues[7]. Investigations and pilot scale operations are currently underway to evaluate hydrogen as a fuel for turbines [8,9].

The calorific value of hydrogen is such that the control of the turbine's fuel firing system would require re-calibration. The response of the control valves would need to be of considerably higher precision than those installed for hydrocarbon gas, and the control system (response sensitivity, deadbands, etc.) would require detailed evaluation.

The burners within the turbine's combustion system would also require analysis, and probably re-sizing. Burners are typically designed for a specific molecular weight of gas to ensure an optimum flame distribution. Due to the difference in molecular weight (more than eight-fold), it is very unlikely that the original burners could be employed for hydrogen service.

Hydrogen is an explosive gas. Therefore, all the detection and monitoring equipment at the existing site would require review. It is possible that re-calibration of the existing equipment for hydrogen is possible. However, it is likely that replacement of the detectors would be necessary.

As hydrogen is relatively small on a molecular level, its use raises further challenges for sealing and containment. It is possible that the existing seals provided for natural gas service would not provide sufficient containment. In this case the sealing systems would require re-assessment and possible replacement for hydrogen service. The containment of hydrogen has been found to be an issue in practice with hydrogen-rich fuels[7], and it is expected that the same concerns would arise when using pure hydrogen.

Equipment originally designed for hydrocarbon gas, which is then re-used for hydrogen service may require re-certification. Re-certification would necessitate that the equipment passes the appropriate performance and safety requirements.

Compressor Performance

Issues regarding the performance of a compressor are inherently case-by-case considerations and only general comments may be made at this stage.

Current technology for compressing hydrogen generally utilises small-capacity positive displacement machines (e.g. reciprocating compressors)[10]. Although positive displacement machines are used in natural gas service, centrifugal compressors are more common, particularly in natural gas transmission systems where high flowrates are required[11].

Unfortunately, centrifugal compressors are not generally suitable for hydrogen compression as the pressure rise per stage is very small due to the low molecular weight of the gas. A centrifugal compressor specified for new service as booster compression could require approximately 16 impellers[10] (assuming a compression ratio of approximately 1.8:1). It is unlikely that this requirement could be incorporated into an existing machine.

An existing reciprocating compressor may provide sufficient head for transportation, however, reciprocating machines are typically used for relatively low flow services[11]. In this case, it is likely that a large additional number of reciprocating machines operating in parallel would be required.

Hence, it is likely that an existing compressor system which was originally specified for natural gas transmission would be unsuitable for hydrogen transport. In this case the compressors would require replacement.

Although the compression machinery is a fundamental element of a compression station, replacement of this equipment may not commercially negate reuse of the site. The existing infrastructure with its utility services and other ancillary resources could possibly be used depending on the requirements for the new service.

3.4 H_2S Implications

It is possible that hydrogen sulphide (H_2S) may be present in the transmission systems. The presence of H_2S can present additional considerations for material choice. Of primary concern is the occurrence of sulphide stress cracking (SSC) as well as hydrogen induced cracking (HIC) as discussed in Section 3.3.

Corrosion under wet conditions with the presence of H_2S leads to the generation of atomic hydrogen as simply expressed by the following equation:

$$H_2S + Fe \rightarrow FeS_x + 2H^+$$

The degree of SSC attack on steel can vary, mainly because the mechanism of sour corrosion depends upon numerous factors such as:

- pH level
- Chloride ion concentration (if present in the water)
- Oxygen, CO_2 and H_2S in the solution
- Composition, microstructure, and hardness of the steel
- Level of applied stress
- Temperature (carbon steel has a maximum sensitivity to SSC at around 25°C)
- Pressure
- Flow rate of the solution present

For the situation where H_2S is present, the National Association of Corrosion Engineers (NACE) Standard MR-0175[2] should be used. This standard deals with required material properties, particularly hardness, for various systems and conditions relating to SSC.

The main recommendation of this standard is that the hardness of carbon and low alloy steels should not exceed 22 Rockwell C (equivalent to 248 VHN) for resistance to SSC under sour conditions. The standard defines sour gas systems having an H_2S partial pressure of greater than 0.0034 bara (0.05 psia).

It should be noted that the NACE MR-0175 recommended hardness is lower than that mentioned in Section 3.3.3 above for resistance to hydrogen embrittlement. Thus conformance to NACE MR-0175[2] for SSC requirements should also achieve resistance to hydrogen embrittlement.

The differences between SSC and HIC and a comparison of the major features of each of these forms of attack are given in the table below.

Table 3.1 Comparison of SSC and HIC

Sulphide Stress Cracking	**Hydrogen Induced Cracking**
Application of external stress is normally necessary	No external stress is required
Cracking is generally orientated perpendicular to the direction of the applied stress	Cracking always has significant components in the rolling direction but may propagate in a stepwise fashion
Generally occurs in higher strength materials and largely controlled in practice by limitation of the steel hardness	Cracking occurs in both high and low strength steels and this cannot be avoided by control of hardness
Can take place in the presence of very small levels of H_2S	In all probability to a significant extent only in severe environments
Not normally associated with non-metallic inclusions but requires a susceptible microstructure	Generally associated with non-metallic inclusions such as manganese and calcium sulphides. Cracking can occur at bands of hard transformation products in macroscopically lower strength materials

3.5 Safety Requirements

All assumptions and designs within the Model are based on current design practices reflecting the relevant safety and environmental standards for a typical installation in Western Europe. These practices are discussed in general below.

Design standards may vary across worldwide locations, and this will impact the commercial considerations for the installation. This impact is incorporated into the Model by use of a country factor applied to the cost estimates. These factors are consistent with the Electrical Transmission Study[1].

A safety and environmental review should be conducted at each phase of the development. The following areas have been identified for the purpose of this study:

- Drilling –onshore and offshore
- Construction
- Operation
- Pipeline Related Considerations

3.5.1 Drilling – Onshore and Offshore

The major factors affecting safety and environment during onshore and offshore drilling are:

- Location
- Containment (noise, disposal of cuttings, etc.)
- Emergency response.

The selection of site location and timing of drilling activities could have an impact on environmental features such as wildlife and fauna. The noise associated with drilling operations could have an impact on wildlife activities in environmentally sensitive areas. For these reasons an Environmental Impact Assessment should be performed before site selection and drilling activities commence.

The issue of containment generally refers to aquifer contents (mostly expected to be saline at various concentrations). However, there may also be more hazardous issues such as pockets of hydrogen sulphide, gas, or other potentially dangerous substances. Provision for handling these substances must be assessed at an early stage in the design to minimise potential for personnel exposure.

In addition to aquifer contents, the presence of on-site materials such as drilling muds, cuttings, etc. could also be an issue under containment of hazardous substances. The hazards associated with the use and handling of these substances should be assessed and addressed as outlined by the relevant legislation such as the Control of Substances Hazardous to Health (COSHH). Disposal of these materials should be in accordance with relevant legislative requirements taking account of local considerations.

Emergency response arrangements include site fire fighting, evacuation of site personnel in an emergency and where appropriate, warning or evacuation of local communities following an incident.
The emergency response for an onshore drilling site could be handled either by liaison with local authorities, or by a dedicated on-site arrangement. Offshore operations would necessarily require on-site provision for emergency response, personnel refuge and evacuation facilities to the appropriate legislation and standards.

3.5.2 Construction Safety

The UK basis for the primary consideration of safety practices relating to construction, operation and maintainability is compliance with the Construction, Design and Management (CDM) Regulations. Although applicable regulations may vary across different worldwide locations, they should address the safety and environmental issues of construction and commissioning including construction methods, permit-to-work systems, personnel competence, etc.

Further consideration must be given to interim protection of the site for factors such as emergency response, noise, disposal of waste, etc. These would be managed either by liaison with local authorities, or by a dedicated on-site arrangement. Offshore sites have additional concerns relating to limited area, personnel location and refuge, emergency response, etc.

3.5.3 Operation

Following construction, the continued impact on the environment should be monitored against the relevant practices and regulations. The original design should ensure that the relevant standards are met and, if appropriate, allowance is made for future expansion of the site.

Facility design would be required to address numerous issues to ensure safe and environmentally conscientious operation, including but not limited to:

- Firewater/fire fighting provision on site
- Emergency response (either with or without local authority liaison)
- Sight layout and equipment spacing (vs commercial aspects)
- Control room sighting and protection
- Effect of adjacent facilities (domino effect, escalation of incidents to other sites, and inter-dependencies of the sites if appropriate)
- Routine and non-routine emissions

These apply to both onshore and offshore installations.

3.5.4 Pipelines

Three phases have been identified below for pipeline operations:

- Design
- Construction
- Operation

The design of a pipeline should reflect the requirements of the appropriate regulations and standards. These requirements typically include:

- Pressure and inventory containment (wall thickness, over-pressure protection systems, etc.)
- Resistance to degradation (either internal due to process conditions e.g. corrosion, or external due to environmental conditions)
- Protection from damage (burying the line or installation with a bounded area, e.g. wayleaves)
- Appropriate monitoring facilities and safety systems (such as over-pressure protection)
- Location considerations including availability of local access routes for the selected pipeline routing

The construction phase should address the issues of construction and commissioning including construction methods, permit-to-work systems, personnel competency, etc. Offshore pipelines will require additional considerations regarding manning and personnel refuges due to the typically remote nature of the work.

Safe and responsible operation of a pipeline should include regular inspection and maintenance of the line. External inspection of the line may be visual and internal inspection may be performed by automated methods such as intelligent pigging.

Additional CO_2 Pipeline Considerations

The general safety considerations for CO_2 pipeline design, construction, and operation are outlined above. In particular for this study, the requirement for stop valves (isolation valves) in CO_2 pipelines has been reviewed. Stop valves may be required in a pipeline system to limit the amount of pipeline contents that may escape to atmosphere, should pipeline containment fail (e.g. pipeline rupture, etc.)

Should a pipeline rupture, the contents will eventually be released into the local environment. In the case of CO_2, the contents are neither flammable nor explosive. However, elevated concentrations of CO_2 in an atmosphere can cause concerns. These are summarised, details from the Fire Protection Handbook[19]:

Table 3.2 Effects of CO_2 on Humans

% in Atmosphere	Effect
0.03	None (normal CO_2 concentration level in atmosphere)
Up to 7	Increase in breathing rate (this may increase the intake of other toxic substances should they be present)
7 – 25	Slowdown in breathing
Over 25 – 30	Narcotic effect whereby breathing may stop immediately.

Note that these effects vary between individuals and between instances for the same individual. It is generally accepted that a level of 6-7% CO_2 is considered to be the threshold limit where harmful effects become noticeable in human beings. At CO_2 concentrations over 9%, most people lose consciousness within a short time.

Simulation of a CO_2 pipeline rupture was performed to indicate the possible outcome from such an event. The simulation assumed a buried pipeline with a rupture site located on the top of the line. This situation reflected a vertical impact, which may be expected during excavation or similar third party or natural activities. (The simulation was performed using PHAST v6.00.)

The results initially indicated that the effects were extremely local to the rupture site. The main flow direction was vertical. The CO_2 was then found to disperse rapidly in air.

Based on this review, the inclusion of isolation valves in the CO_2 transmission lines to reduce the hazard associated with a loss of containment event does not appear to be warranted. However, detailed assessment of this requirement would necessarily be performed on a case-by-case basis at the planning stage of pipeline design. This would require a quantitative risk assessment for the occurrence of the incident considering pipeline location, local sensitivities, and expected incident frequencies.

It should also be noted that whilst installation of stop valves will limit the pipeline inventory released in a given loss of containment event, it could also provide a leak source from an otherwise welded pipeline. The detailed case-by-case assessment mentioned above should also consider the increased relative leak frequency as a result of installing stop valves (if required), against the pipeline leak frequency without stop valves.

The inclusion of stop valves would also require an automated system for pressure monitoring and valve activation under sudden pressure loss. This system would require additional certification and maintenance considerations and may also introduce operability problems.

3.6 Energy Distribution and CO_2 Capture Cost Estimation Model

The Model covers the full range of assets included in the scope for energy distribution systems. The Model allows the user the overall flexibility to develop a case for energy distribution involving the following assets, which are described below in Sections 0 to 3.6.5.

- Electrical Power Generation Plant
- Fuel Synthesis Plant
- CO_2 Storage Facility
- Pipeline Branch

Prior to definition of the assets, the overall settings for the project are established. These are discussed below.

3.6.1 Project Settings

The project settings are separated into technical considerations, commercial considerations and further defaults. Technical issues are discussed below, and commercial considerations are given in Section 4.

Technical

The user may set the world location choosing from one of the locations below. These choices are in accordance with the Electrical Transmission Study[1].

- Europe
- UK
- USA / Canada
- S. America
- N. Africa
- Equatorial Africa
- S. Africa
- Russia
- Middle East
- Indian Sub-cont.
- SE Asia (exc. Japan)
- Japan
- China / C. Asia
- Australia / NZ

Further Defaults

A selection of default values used by the Model which can also be reviewed and changed by the user are given below.

- asset cost look-up tables, CAPEX, fixed OPEX and variable OPEX (see Section 4.2)
- molecular weight, kg/kgmol
- liquid density, kg/m^3
- calorific value, MJ/kg
- power station CO_2 generated, kg CO_2/ kg Fuel
- power station CO_2 capture efficiency, %
- synthesis plant production rate, kg Product / kg Feed
- synthesis plant CO_2 generated, kg CO_2/ kg Natural Gas Feed
- synthesis plant CO_2 capture efficiency, %

3.6.2 Electrical Power Generation Plant Asset

This asset comprises the following elements:

- Power Station
- CO_2 Export Pipeline
- Electrical Transmission System

Each of these elements is defined individually within the set-up of the Electrical Power Generation asset. The Power Station has been designated as using Combined Cycle Gas Turbine (CCGT) technology. As an intrinsic element of this study, all Power Stations incorporate recovery of CO_2 from the exhaust gases of the plant. The CO_2 recovery process is assumed to use amine absorption[12,13,14].

This designation of the Electrical Power Generation Plant asset along with the CO_2 recovery process is based on the following assumptions:

- Essentially complete combustion of fuel
- CO_2 is recovered at atmospheric pressure
- Recovery of CO_2 from the exhaust gases is variable with a default value of 85%[27]

The governing factor for sizing the Power Station is the required electrical output from the plant. This specification defines the relevant flowrates of the associated fuel and CO_2 pipelines.

The Power Station may use one of the following fuels:

- Natural gas
- Distillate
- Methanol
- Hydrogen
- Coal

The Model determines the rate of fuel required based on the Lower Heating Value (LHV) of the relevant fuel. The LHV is the heating value of a fuel when the water produced as part of the combustion process is not condensed. This is the usual circumstance when burning fuels, hence the LHV is the more appropriate value to use for combustion calculations rather than the Gross Heating Value (GHV). The GHV includes the latent heat of condensation of the water produced during combustion. The following table summarises the values of LHV used in the Model as typical figures for each fuel.

Table 3.3 Fuel Heating Values

Fuel	LHV (MJ/kg)
Natural Gas (95 wt.% methane, 5 wt.% ethane)	50.1 [24]
Distillate	42.4 [25]
Methanol	19.9 [24]
Hydrogen	121.1 [24]
Coal	25.9 [28]

The user may set the value of the Power Station's overall thermal efficiency to reflect the expected conversion of heat into electrical power. This is a user input to allow incorporation of known performances of power stations.

The overall thermal efficiency of combined cycle gas turbine power plants is typically between 56% and 58%. However, for power plants utilising CO_2 capture by means of amine scrubbing this overall efficiency has been found to fall to approximately 50%[12]. This reflects the additional energy required for regeneration of the amine used for absorption, and the subsequent dehydration of the CO_2. The overall impact of this is an increase in fuel use of approximately 15% to provide the same electrical power as a CCGT power plant without CO_2 recovery.

The CO_2 emissions from the Power Station are calculated from the reaction stoichiometry and an efficiency factor applied to determine the amount of CO_2 generated that is captured. Table 3.4 summarises these values.

Table 3.4 Power Station CO_2 Emission Rates

Fuel	**CO_2 Generation Rate (kg/kg fuel)**	**CO_2 Capture Efficiency (%)**
Natural Gas	2.8	85
Distillate	3.2	85
Methanol	1.4	85
Hydrogen	0	N/A
Coal	2.4 [28]	85

The CO_2 produced from the Power Station is sent to storage via a pipeline. The pipeline functionality is identical to a Pipeline Branch asset, as described in Section 3.6.5.

The definition of the Electrical Transmission System was provided by IEA and has been incorporated into the Model. All references to the functionality of this module are made to the Electrical Transmission Study[1].

3.6.3 Fuel Synthesis Plant Asset

This asset comprises the following elements:

- Fuel Synthesis Plant
- Fuel Export Pipeline

The Fuel Synthesis Plant will manufacture either methanol or hydrogen. Both these products are synthesised from a natural gas feedstock. The process assumes that natural gas feedstock[16,17] is converted to synthesised fuel at the following conversion efficiencies[17] on an energy basis. These have then been converted to a mass ratio for product : feedstock.

Table 3.5 Fuel Synthesis Plant Conversion Rates

Synthesised Product	**Conversion Efficiency – Energy Basis (%)**	**Mass Ratio Product : Feedstock**
Methanol	68	1.71
Hydrogen	59	0.24

The synthesised fuel is exported from the plant via pipeline. The pipeline functionality is identical to a Pipeline Branch asset, as described in Section 3.6.5.

The CO_2 emissions from the Fuel Synthesis Plant are calculated from the reaction stoichiometry and an efficiency factor applied to determine the amount of CO_2 generated that is captured. Table 3.6 summarises these values.

Table 3.6 Fuel Synthesis Plant CO_2 Emission Rates

Fuel	CO_2 Generation Rate (kg/kg Natural Gas Feed)	CO_2 Capture Efficiency (%)
Methanol	0.84	85
Hydrogen	2.60	85

The Fuel Synthesis Plant is not assumed to include a CO_2 storage pipeline. If required a separate Pipeline Branch asset (as described in Section 3.6.5) can be defined to simulate CO_2 export. The CO_2 produced from the Fuel Synthesis Plant and if applicable, the CO_2 from the IPB on the fuel export line are calculated by the Model and displayed on the Asset Definition form (refer to Appendix A).

3.6.4 CO_2 Storage Facility Asset

This asset includes the following elements:

- CO_2 Storage Wells
- CO_2 Pipeline leading to well (Optional)

CO_2 injection is assumed to take place into CO_2 retaining aquifers. In general these are considered to be saline aquifers with sufficient retention such that seepage of CO_2 back to the atmosphere is negligible. A second option is the use of redundant hydrocarbon reservoirs that have ceased production and proved to be non-communicating with other locations. The choice of a suitable aquifer is influenced by many factors such as well performance, location, etc., and is beyond the scope of this study.

Aquifers may be located either onshore or offshore and are assumed to be approximately 1000m in depth. The Model characterises the performance of the aquifer by input of a "rate per well" figure. This represents the combination of various factors such as porosity, permeability and injectivity. The Model then determines the number of wells required by dividing the required overall injection rate by the rate per well.

The Model allows the user to specify whether there is a pipeline leading to the CO_2 Storage Wells. If a pipeline is required the user must specify the pressure required at the top of the injection well. The default value suggested by the Model is 80 bara. The pipeline functionality is identical to a Pipeline Branch asset, as described in Section 3.6.5.

3.6.5 Pipeline Branch Asset

The asset definition for an Electrical Power Generation asset includes a CO_2 storage pipeline, similarly the CO_2 Storage Facility asset includes an optional CO_2 pipeline and the Fuel Synthesis Plant asset includes a fuel export pipeline. Additional pipelines are defined by using the Pipeline Branch asset.

Pipelines are defined in the same manner whether they are assumed to be part of an asset or a Pipeline Branch asset.

A Pipeline Branch asset is comprises the following:

- Pipeline: Offshore Branch
  Onshore Branch
  Onshore with Onshore Storage
  Onshore with Offshore Storage
- Initial Pressure Boost (IPB) Facilities
- Booster Stations

The user can choose to size the pipeline and calculate the number of Booster Stations by using an automatic sizing routine or by setting them manually. The table below shows which inputs are required for each route.

Table 3.7 Pipeline Sizing Input Data

Input	Manual	Automatic	Notes
Fluid	Yes	Yes	Preset if associated with an asset.
Mass Rate	Yes	Yes	Preset if associated with an asset.
Terrain	Yes	Yes	Onshore lines only.
Service Description	Yes	Yes	Dependent on fluid type.
Pipeline ND	Yes	No	-
Length (Onshore/Offshore)	Yes	Yes	Dependent on Service Description.
Pipeline Inlet Pressure	Yes	Yes	Required if IPB not specified. When IPB is selected, pressure = IPB outlet pressure.
CO_2 Well Inlet Pressure	Yes	Yes	For CO_2 Storage Facilities only.
IPB Requirement	Yes	Yes	-
IPB Pressures	Yes	Yes	Only if IPB selected.
Number of Booster Stations	Yes	No	-
Booster Station Pressures	Yes	Yes	Only if Booster Stations > 0 or automatic calculation.
Minimum Distance Before A Booster Station Is Required	No	Yes	-

The sizing routine produces the following output:

- Pipeline ND
- Pipeline Inlet Pressure
- Pipeline Outlet Pressure
- Number of Booster Stations
- Distance Between Booster Stations
- IPB Facility and Booster Station Duties

The Pipeline ND, inlet and outlet pressures are also presented on the main Asset Definition form.

Initial Pressure Boost Facility and Booster Station Duties

The IPB Facility and Booster Station power requirements are based on the relationships shown below:

For Pumping Facilities, power is calculated from the following formula[11]:

$$P = \frac{Q.\Delta p}{36\eta}$$

where,
P = power, kW
Δp = pressure drop, bar
Q = liquid flowrate, m3/h
η = efficiency, % (assumed to be 75%)

For Compression Facilities, power is calculated using the following formulas[11]:

$$H_{is} = \frac{Z_{avg} R T_1}{M.(k-1)/k} . \left[\left(\frac{P_2}{P_1} \right)^{\frac{(k-1)}{k}} - 1 \right]$$

where,
H_{is} = Isentropic Head, Nm/kg
z_{avg} = average compressibility factor
R = universal gas constant, 8.314 kJ/kmole.K
T_1 = absolute temperature, K
M = molecular mass
P_1= suction pressure, bara
P_2 = discharge pressure, bara
k = isentropic exponent , Cp/Cv

and,

$$G_p = \frac{w.H_{is}}{\eta_{is}}$$

where,
G_p = gas power (excluding mechanical losses), kW
w = weight flow, kg/h
η_{is} = isentropic efficiency, % (assumed to be 75%)

Cost estimation of the facilities is performed based on the calculated power requirement. These estimates are based on in-house data and are reasonable for comparative analysis as per the scope of the Model (refer to Section 4).

Booster Station Specification

For gas line Booster Stations a minimum inlet pressure of 30 bara is recommended. At pressures below this arrival velocities are likely to be high and lead to unreasonably large pipeline diameters. For CO_2 lines, as discussed in Section 3.2, if the CO_2 fluid enters the booster station below 60 bara the Model will assume that the CO_2 exists as a gas and a compressor will be assumed. Above 60bara the CO_2 is assumed to be a liquid and a pump will be provided for pressure boost.

Liquid lines may be run down to relatively low pressure before booster pumping, as liquids are effectively incompressible and do not exhibit the same increase in fluid velocities at lower pressures. For liquid lines, 6 bara is expected to be the minimum arrival pressure for overcoming resistance at the inlet of a Booster Station.

In the case of fuel or feedstock transmission lines, the power generation for Booster Stations is assumed to utilise combustion of the flowing fuel in the pipeline. The additional amount of fuel required for a Booster Station was considered negligible relative to the amount of fuel flowing in the transmission line. Based on this assumption, the additional fuel required for a Booster Station was considered not to affect the hydraulic sizing of the line.

Initial Pressure Boost and Booster Station Emissions

The requirement for Booster Stations along a pipeline length is a result of the hydraulic design of the line. The presence of these Booster Stations will result in additional CO_2 emissions if the power to operate the stations is derived from a CO_2 producing fuel source. The CO_2 emissions from pressure boost facilities are dependent on the type of driver used. The fluid being transferred and the location of the facility determine the driver type. The following table summarises the type of compression driver for each asset type.

Table 3.8 IPB Facility and Booster Station Compressor/Pump Driver Fuel Type

Asset Type	IPB Facility	Booster Station
Electrical Power Generation Plant (CO_2 export pipeline)	Electric (from Power Station supply)	Electric
Fuel Synthesis Plant (fuel product pipeline)	Natural gas	Synthesis plant fuel product
CO_2 Storage Facilities	Electric	Electric
Pipeline Branch: Natural Gas	Natural gas	Natural gas
Distillate	Distillate	Distillate
Methanol	Methanol	Methanol
Hydrogen	Hydrogen	Hydrogen
CO_2	Electric	Electric

The amount of CO_2 generated at the stations is effectively an additional environmental cost for the transportation of the fuel. Given the structure of the Model only CO_2 generated from a Synthesis Plant IPB will potentially be captured and commingled with the CO_2 from the plant. The Capture Efficiency is assumed to be the same as for the Synthesis Plant. CO_2 generated from all other IPBs and BS will be reported assuming a potential Capture Efficiency of 100%. The impact of these considerations has been quantified for this study as follows:

Table 3.9 IPB Facility and Booster Station CO_2 Emissions

Fuel Type System	CO_2 Generation Rate (kg/MW)
Natural Gas	0.18
Distillate	0.25
Methanol	0.24
Hydrogen	N/A
CO_2	N/A

These figures are based on the assumptions of the performance of the electrical power generation stations used in the Model. A figure of 30% thermal efficiency, typical of turbines firing either gaseous or liquid fuels, was used to generate the values above.

Booster stations required for CO_2 gathering and transmission clearly cannot combust the flowing fluid in the line (CO_2) to generate power. In this case the power for CO_2 transmission line Booster Stations is assumed to be provided from off-site (e.g. the local electrical grid). Unless the user explicitly specifies dedicated infrastructure to provide this power over the length of the CO_2 transmission line (e.g. a natural gas fuel line or electrical transmission line), the impact of any additional CO_2 production due to the transport of CO_2 cannot be assessed.

Should the user require that power for Booster Stations along fuel transmission lines is also taken from an external source to the Model (e.g. the local electricity grid), they may ignore the figures generated in the summary table. At this stage the Model will not automatically change the estimated CO_2 generation figures based on this requirement.

3.6.6 Pipeline Hydraulic Sizing Methodology

This section describes the methodology used to size pipelines when the automatic line sizing option is selected.

For improved clarity of the Model, secondary factors such as detailed pipeline routing, which may influence the sizing of a pipeline, have been excluded. The Model is intended only for high-level review examinations, for which a further level of detail would be inappropriate.

Design Pressures

The Model automatically selects the appropriate design rating for the pipelines based on the maximum pressure in the pipeline i.e. the maximum of the pipeline inlet pressure and the pressure after pressure boost.

Three piping classes will be used:

- ANSI Class 600#, for pressures up to 90 bara
- ANSI Class 900#, for pressures up to 140 bara
- ANSI Class 1500#, for pressures up to 225 bara

Design Criteria

During line sizing several design criteria such as pipeline outlet pressure and arrival velocity are applied.

For Liquid lines:

- If Booster Stations are not required, the calculated pipeline outlet pressure must be greater than or equal to 6 bara. This minimum pressure is considered necessary for any pipeline reception facilities.

- If Booster Stations are required, the calculated pipeline outlet pressure must be greater than 6 bara and greater than the Booster Station inlet pressure specified by the user.

- The length between Booster Stations must be greater than the specified *'Distance before a Booster Station is required'*

For Gas lines:

- If Booster Stations are not required, the calculated maximum velocity in the line (i.e. the velocity at the outlet of the pipeline) must be less than 20 m/s. This limitation reflects reasonable first-pass design conditions addressing excessive pressure drop at the outlet section of the pipeline and possible erosional considerations for clean gases.

- If Booster Stations are required, the calculated maximum velocity in the line (i.e. the velocity at the outlet of the pipeline) must be less than 20 m/s and the calculated pipeline arrival pressure must be greater than the Booster Station inlet pressure specified by the user.

- The length between Booster Stations must be greater than the specified *'Distance before a Booster Station is required'*

The hydraulic design information is summarised in the table below:

Table 3.10 Pipeline Hydraulic Design Criteria

Fluid System	Design Criterion*
Liquid (Distillate, Methanol)	No BS: 6 bara at pipeline outlet With BS: above user defined BS inlet pressure
Gas (Natural Gas, Hydrogen)	No BS: <20 m/s at pipeline outlet With BS: above user defined BS inlet pressure
CO_2	No BS: <20 m/s at pipeline outlet With BS: above user defined BS inlet pressure

*BS = Booster Stations

Pipeline Sizing Routine

The pipeline sizing routine uses this information to determine a diameter for the line based on the following logic:

Step 1

An initial estimate of the line size is based on the hydraulic relationships below. Both relationships are sourced from Crane[18].

For liquid lines,

$$\Delta p = 2.252 \frac{f.L.\rho.Q^2}{d^5}$$

where,

Δp = pressure drop, bar
f = friction factor
L = pipeline length, km
ρ = fluid density, kg/m³
Q = flowrate, lpm
d = pipeline internal diameter, mm

This is a form of the Darcey formula, which is valid for the flow of any single phase liquid in a pipe. The user inputs the pipeline length, flowing rate, and fluid choice. The fluid choice determines the density value to be used and other fluid-related variables. The Model assumes a friction factor of 0.015, generally indicative of turbulent flow. For the pipeline systems that the Model is expected to be used for, this value is relatively conservative in that it is likely to slightly oversize a liquid line rather than undersize it.

For gas lines,

$$q = 1.361 \times 10^{-7} \sqrt{\left[\frac{P_1^2 - P_2^2}{f.L.S}\right] d^5}$$

where,

q = standard gas flowrate, standard m^3/h (at 101.325 kPa(abs) and 15°C)
P_1 = pipeline inlet pressure, Pa(abs)
P_2 = pipeline outlet pressure, Pa(abs)
f = friction factor
L = pipeline length, km
S = gas specific gravity relative to air (relative density)
d = pipeline internal diameter, mm

This relationship is a simplified version of the complete isothermal equation for compressible flow, and a reasonable assumption for the flow of gases in a long pipeline. As per liquid lines, the friction factor used in this relationship is 0.015, indicative of the expected flowing conditions in the line.

A liquid velocity of 5 m/s and a gas velocity of 15 m/s at 40 bara are used in the above equations for an initial sizing estimate. This estimate is then used to select the closest nominal diameter pipe size from a look-up table of pipeline diameters. The look-up table ranges from a nominal diameter of 50 mm (2 inches) to 2000 mm (80 inches).

(Note that this initial estimate differs from the final line sizing criterion of 20 m/s at the actual outlet conditions as the former is considered appropriate for an initial estimate, and the latter as a final check of the selected pipeline hydraulics. In addition, should the line lead to a CO_2 injection well, the sizing estimate is based on 3 m/s at the CO_2 injection pressure.)

Step 2

Using the user defined inlet pressure and the selected nominal diameter, the pipeline outlet pressure is calculated. For a gas line the density of the fluid at the outlet conditions is also calculated and the velocity of the fluid exiting the line is determined. The results are then checked against the design criteria. If the criterion is satisfied then the line size is accepted and the routine finished. If the criterion is not satisfied, then the diameter is increased to the next nominal diameter pipe size and the criterion rechecked. If the design criterion is not satisfied within two increments of standard diameter size from the initial diamter estimate then Booster Stations are are considered to be required.

Step 3

Initially one Booster Station is added.

Distance between Booster Stations = (pipeline length/(no. of Booster Stations +1))

If the distance is less than the user specified *'Distance before a Booster Stations is required'*, the sizing routine does not add a Booster Station but increases the line size until the sizing criterion is met.

If the distance is greater that the 'Distance before a Booster Station is required' the routine effectively restarts the sizing from Step 1 assuming a new line length equal to the distance between the Booster Stations. If at the end of Step 2 a solution is not found another Booster Station is added and the process repeated until a solution is reached which satisfies the design criteria. Should the distance between Booster Stations reduce below the 'Distance before a Booster Station is required', then the routine returns to Step 2 using the next standard pipe size, with the number of Booster Stations re-initialised to one.

Depending on the pipeline service type the above routine is modified as follows:

Onshore Branch Line

An onshore branch line is sized specified as per the above routine.

Offshore Branch Line

As Booster Stations along an offshore pipeline are considered impractical, an offshore branch line runs the above sizing routine without installing Booster Stations. To account for this the sizing routine will increase the diameter as required until a solution is reached.

Onshore Line with Onshore Storage

An onshore CO_2 storage line is specified as per the above description with the addition that the outlet pressure from the line must be greater than or equal to the required CO_2 injection pressure.

Onshore Line with Offshore Storage

An onshore line with offshore storage is a hybrid of an onshore line and an offshore line. The routine will assess the onshore section and install Booster Stations if required as per the above sizing routine. However, as offshore Booster Stations are impractical, sufficient pressure must be available from the onshore section to satisfy the offshore pressure drop and the required CO_2 injection pressure. Should this not be the case, the size of the line is increased and the routine re-run. This is performed until a solution is reached.

4. COST ESTIMATION

This section discusses the following issues relating to cost estimation:

- General
- Project Settings
- Totalised Asset Costs
- Power Station
- Fuel Synthesis Plant
- CO_2 Storage Facilities
- Transmission Pipelines
- Pumping and Compression Facilities

4.1 General

The Model determines the Capital Expenditure (CAPEX) and both the fixed and variable Operating Expenditure (OPEX) for each asset.

The cost estimation is based on data provided by IEA and in-house data and estimation methods. The Model provides cost estimates in year 2000 USD, consistent with the Electrical Transmission Study[1].

4.2 Project Settings

Before running the Model the user should review the Project Settings sheet. This sheet allows the user to define project specific values that are to be applied to each Case in the Portfolio. At present these values are:

- Asset Location
- CO_2 Storage Costs (see Section 4.8)
- Economic Parameters
- Further Defaults

Asset location

The geographical location of the project has an impact on the CAPEX and OPEX. A location factor is applied to take into account the affect on local costs. The location factors used are consistent with the Electrical Transmission Study[1] and are listed below.

Table 4.1 Location Factors

Country	Location Factor
Europe	1.0
UK	1.2
USA / Canada	1.0
S. America	0.8
N. Africa	0.8
Equatorial Africa	0.9
S. Africa	0.7
Russia	0.7
Middle East	0.9
Indian Sub-cont.	0.7
SE Asia (exc. Japan)	0.8
Japan	1.0
China / C. Asia	0.7
Australia / NZ	1.0

Economic Parameters

The following economic parameters are used to enable CAPEX and OPEX of a project to be determined. The default values used in the Model are given below.

- Annual Capital Charge Factor: A factor applied to the CAPEX to determine an Annual Capital Charge in USD millions / year. The default value is 1.
- Load Factor: A availability factor applied to the number of hours a year to determine the operating hours a year. The default value is 100%

- Fuel Costs: The variable OPEX of a facility is based on the cost of fuel/feed or electricity consumed by the facility. The default costs used by the Model are listed below:

Table 4.2 Fuel Costs

Fuel	Cost
Natural Gas	2.14 USD/GJ
Distillate	4.19 USD/GJ
Methanol	11.40 USD/GJ
Hydrogen	6.97 USD/GJ
Coal	1.06 USD/GJ
Electricity	5.04 cents/kWh

Further Defaults

The CAPEX and OPEX cost look-up data from each asset (with the exception of the IPB and BS variable OPEX) can be reviewed and changed by the user in the 'Further Defaults' sheet. (see Section 3.61)

4.3 Totalised Asset Costs

The totalised costs for each asset are compiled from their component costs e.g. an Electrical Power Generation asset will comprise the following:

- Power Station cost
- Electrical Transmission System cost
- CO_2 pipeline, IPB Facility and Booster Station costs

The costs for Power Stations, Fuel Synthesis Plants, Compression Facilities and Pumping Facilities have been developed for expected ranges of operation.

The limits for the cost ranges are summarised in Table 4.3.

Table 4.3 Facility Cost Ranges

Asset Component	Fuel Type	Look-up Range
Power Station	- Natural gas - Distillate - Methanol - Hydrogen	All plants 10 MW to 3000 MW
Fuel Synthesis Plant	- Methanol - Hydrogen	10 to 120 kg/s 10 to 60 kg/s
Compression Facilities (IPB and Booster Stations)	-	10 to 120 MW
Pumping Facilities (IPB and Booster Stations)	-	50 kW to 2 MW

For each of the above asset components a look-up table of costs has been created to cover the cost range, e.g. for a Power Station the CAPEX, OPEX and Variable OPEX are listed as a function of Plant Power (MW).

If the user defines a facility whose size is between two of the specified values, linear interpolation is used to determine the intermediate cost.

If the user defines a facility whose size is outside the given range, linear extrapolation is used to determine the cost using the appropriate end of the existing cost data.

An exponential method[21], is used in a number of cases to describe how the CAPEX and fixed OPEX varies in relation to the facility size.

Where:

$$C = C_r\left(\frac{S}{S_r}\right)^n$$

C = estimated cost at required size
C_r = reference cost
S = required size
Sr = reference size
n = scale exponent

The scale exponent can be derived from historical data for similar plants. The exponents used for particular equipment/facilities are discussed in the following sections.

4.4 Power Station

The electrical power generation cost estimates are based on the IEA data [20, 27, 28] for a natural gas fuelled and coal fired electrical power station as shown below.

Table 4.4 Cost of Power Stations

Plant Type	Reference Size (MW)	Capital Cost (USD/kWout)	Annual Operating Costs (USD/kWout/year)	
			Fixed	Variable (excl. fuel)
Natural gas combined cycle with CO_2 separation	500	825	27	7
Coal fired	362	1856	69	23

CAPEX

The CAPEX costs for power stations of other fuels (ie methanol, distillate, and hydrogen) are based on the CAPEX cost for a natural gas power station i.e. a factor is applied to the natural gas CAPEX to determine the CAPEX of each of the alternative fuels. The factors are shown in the table below:

Table 4.5 Power Station CAPEX Factors

Plant Type	Capital Cost Factor
Distillate fuelled	1.0
Methanol fuelled	1.0
Hydrogen fuelled	0.525

The scaling exponent used for the power station CAPEX[27] is 0.835 for all fuels (refer Section 4.3).

Fixed OPEX

The fixed OPEX costs for methanol, distillate and hydrogen fuelled power plants are determined by the same method used in the CAPEX cost estimation. The factors used are shown in the table below. Table 4.6 Power Station Fixed OPEX Factors

Table 4.6 Power Station Fixed OPEX Factors

Plant Type	Fixed OPEX Factor
Distillate fuelled	1.0
Methanol fuelled	1.0
Hydrogen fuelled	1.0

The scaling exponent used for the power station Fixed OPEX is 0.5 for all fuels (refer Section 4.3).

Variable OPEX

The variable OPEX costs given by IEA[20] in Table 4.5 are assumed to exclude fuel cost.

The variable OPEX costs (excluding fuel) for methanol, distillate and hydrogen fuelled power plants are determined by the same method used in the CAPEX cost estimation. The factors used are shown in the table below.

Table 4.7 Power Station Variable OPEX Factors

Plant Type	Variable OPEX Factor
Distillate fuelled	1.0
Methanol fuelled	1.0
Hydrogen fuelled	1.0

The quantity of fuel used per year by a power station is calculated using the following formula:

Fuel per year, GJ/year = Fuel rate, kg/s x *LHV, MJ/kg* x *3600* x *24* x *Load Factor, %* x *365 /1000*

This is then multiplied by the Fuel Cost, (refer to Table 4.2,) to determine the total fuel cost per year.

The cost of fuel per year is then added to the Variable OPEX (excluding fuel) to give the total power station Variable OPEX.

4.5 Fuel Synthesis Plant

Synthesis of the following fuels is discussed below.

- Methanol
- Hydrogen

4.5.1 Methanol

The methanol synthesis plant costs are based on the conventional technology of Steam Methane Reforming (SMR)[16] and are presented in the table below.

Table 4.8 Steam Methane Reforming Plant Cost

Production Rate (te/day)	CAPEX (USD millions)	Annual Operating Costs (USD/te)	
		Fixed	Variable
2500	300	-	-
12500	1150	-	-
9000	-	10	10

SMR plants have a maximum production rate of around 35 kg/s (3000 te/d). Technology is available for plants up to 104 kg/s (9000 te/d) e.g. Starchem Technology[16], which has a lower CAPEX and OPEX in comparison to SMR, but this has not be allowed for in the Model. Consequently the data for SMR is extrapolated for product rates up to 120 kg/s (10368 te/d).

CAPEX

The CAPEX is determined by interpolation of the CAPEX values listed above in Table 4.8. The formula used to estimate the CAPEX is:

$$\text{CAPEX, USD millions} = 0.085 \times \text{Methanol Production Rate, te/day} + 87.5$$

Fixed OPEX

The fixed OPEX is determined from the reference size of a 9000 te/day synthesis plant, refer to Table 4.8. The scaling exponent used for the methanol plant fixed OPEX is 0.5 (refer Section 4.3).

Variable OPEX

The variable OPEX cost given in Table 4.8 is assumed to exclude fuel cost. As for the fixed OPEX, the scaling exponent used for the methanol plant fixed OPEX (excluding fuel costs) is 0.5.

The quantity of fuel used per year by a methanol synthesis plant is calculated using the following formula:

Feed per year, GJ/year = Feed rate, kg/s x *LHV, MJ/kg* x *3600* x *24* x *Load Factor, %* x *365 /1000*

The feed consumed per year is multiplied by the Fuel Cost, (refer to Table 4.2,) to determine the total fuel cost per year. The total synthesis plant Variable OPEX is the summation of the fuel cost per year and the Variable OPEX (excluding fuel).

4.5.2 Hydrogen

The Hydrogen Synthesis plant cost estimates are based on the IEA[22] data for a plant producing hydrogen from natural gas, including separation of CO_2. The hydrogen output is sufficient for a 500MW gas fired combined cycle plant. The costs are summarised in the table below.

Table 4.9 Cost of Hydrogen Synthesis

Plant Type	Capital Cost (USD/kWout)	Annual Operating Costs (USD/kWout/year)	
		Fixed	Variable
Hydrogen Synthesis Plant with CO_2 separation	375	15	4

CAPEX

To fuel a 500 MW power station it was estimated that 8.8 kg/s of hydrogen would need to be synthesised. This was assumed to be the reference size for the hydrogen synthesis plant costs.

The scaling exponent used for the hydrogen synthesis plant CAPEX[27] is 0.835 (refer Section 4.3).

Fixed OPEX

The fixed OPEX is determined from the reference size of a 8.8 kg/s of hydrogen synthesis plant, refer to Table 4.9. The scaling exponent used for the hydrogen synthesis plant OPEX is 0.5 (refer Section 4.3).

Variable OPEX

The variable OPEX cost given in Table 4.9 is assumed to exclude fuel cost. As per the fixed OPEX, the scaling exponent used for the methanol plant variable OPEX (excluding fuel costs) is 0.5.

The quantity of fuel used per year by a hydrogen synthesis plant is calculated using the following formula:

Feed per year, GJ/year = Feed rate, kg/s x LHV, MJ/kg x 3600 x 24 x Load Factor, % x 365 /1000

The feed consumed per year is multiplied by the Fuel Cost, (refer to Table 4.2,) to determine the total fuel cost per year. The total synthesis plant Variable OPEX is the summation of the fuel cost per year and the Variable OPEX (excluding fuel).

4.6 CO_2 Storage Facilities

CO_2 may be stored in an onshore or offshore well (see Section 3.6.4).

The total onshore storage cost is calculated as follows:

Storage Cost = (Cost per well x number of wells)

This assumes that the exit pressure from the CO_2 gathering network is sufficient to all injection into an aquifer/disused well i.e. no booster compression is required.

The total offshore storage cost is calculated as follows:

Storage Cost = (Cost per well x number of wells) + cost of wellhead platform + offshore pipeline cost + booster station cost (if required)

CAPEX

The default CO_2 injection well costs[23] are given in the table below. These costs may be adjusted by the user in the Project Settings form and are not affected by the location factor.

Table 4.10 Storage Facility CAPEX

Offshore well drilling costs	USD 1443/metre
Onshore well drilling costs	USD 216/metre
Wellhead platform costs	USD 14 million

Fixed OPEX

The fixed OPEX assumed as a part of the storage facilities is given in the table below.

Table 4.11 Storage Facility OPEX

Offshore well OPEX	USD 1 million/year
Onshore well OPEX	USD 0.2 million/year
Wellhead platform OPEX	Based on an estimate of USD 0.28 million for a USD 14 million platform, i.e. 2% CAPEX

The wellhead platform OPEX is a nominal figure assuming a minimal number of visits are required for general maintenance and inspection.

4.7 Transmission Pipelines

An in-house review of pipeline transmission systems was performed. Following this it was apparent that a relatively simple pipeline cost module could be used without loss of precision in the overall accuracy of the Model. All pipelines are assumed to be carbon steel.

CAPEX

Many factors were considered to be common for the expected service of the pipelines in the Model, such as materials, basic engineering definition, etc. In-house estimates of several pipeline services indicated this assumption was reasonable. The summary of this information is presented below.

Table 4.12 Onshore Pipeline Cost Estimating Basis

ANSI Class	Cost Relationship: *(Cost [USD] = f(L[km], D[in])*
600#	$(0.0634 \times L + 0.8529) + (0.0011 \times L - 0.00002) \times D + (0.000271 \times L - 0.000007) \times D^2$
900#	$(0.0619 \times L + 0.8529) + (0.00115 \times L - 0.00001) \times D + (0.000299 \times L + 0.00003) \times D^2$
1500#	$(0.057 \times L + 1.8663) + (0.00129 \times L) \times D + (0.000486 \times L + 0.000007) \times D^2$

A set of pipeline costing runs was performed in-house for the three ANSI piping classes and the above cost relationships developed. Each of the above equations reflects the relationship for a distributed set of pipeline costs.

The equations are generally considered to have good correlation and were considered acceptable in the context of the Model. The cost estimates are then factored based on the terrain choice consistent with the Electrical Transmission Study[1]. Terrain and the associated cost factors are reproduced below.

Table 4.13 Terrain Factors from the Electrical Transmission Study[1]

Terrain	**Cost Factor**
Cultivated Land	1.10
Grassland	1.00
Wooded	1.05
Jungle	1.10
Stony Desert	1.10
<20% Mountainous	1.30
>50% Mountainous	1.50

Table 4.14 Offshore Pipeline Cost Estimating Basis

ANSI Class	**Cost Relationship:** *(Cost [USD] = f(L[km], D[in])*
600#	$(0.4073 \times L + 4.6936) - (0.0018 \times L + 0.01132) \times D + (0.000297 \times L + 0.000217) \times D^2$
900#	$(0.4061 \times L + 4.6926) - (0.00174 \times L + 0.01133) \times D + (0.000325 \times L + 0.000169) \times D^2$
1500#	$(0.4048 \times L + 4.6946) - (0.00153 \times L + 0.0113) \times D + (0.000511 \times L + 0.000204) \times D^2$

As for onshore pipeline estimates, an-house set of pipeline costs was performed for the three ANSI piping classes and the above cost relationships developed. Each of the above equations reflects the relationship for a distributed set of pipeline costs.

The above offshore cost equations are based on current "S-type" pipelay technology. This pipelay method is typically limited to water depths of 600 – 800 m.

The equations are generally considered to have good correlation and were considered acceptable in the context of the Model.

OPEX

By reviewing the OPEX of a number of pipeline operating scenarios a relationship was developed for determining the OPEX of for both gas and liquid onshore pipelines. The equations used in the Model for costing the onshore pipeline OPEX are given in the table below.

Table 4.15 Onshore Pipeline OPEX (USD)

Gas Line OPEX	120000 + (23213D+899L-259269) +(39305D+1694L-351355)+24000
Liquid Line OPEX	120000 + 0.61(23213D+899L-259269) +0.7(39305D+1694L-351355)+24000

Where L in pipeline length in km, and D is nominal pipeline size in inches

Offshore pipeline OPEX is based on the assumptions outlined in the table below.

Table 4.16 Offshore Pipeline OPEX

Survey vessel	Speed	6 km per day
	day rate	14,000 USD/d
	Mob/demob	70,000 USD
Repair vessel	Interval	every 10 years
	Cost	98,000 USD/km
Intelligent Pigging	Interval	every 4 years
	day rate	14,000 USD/d
	Cost	700 USD/km
	Once off fee	120000 USD

4.8 Pumping and Compression Facilities

Pumping or compression facilities may be specified as part of fuel and CO_2 transmission pipelines. Costs have been developed for both initial and booster facilities by review of in-house cost data, the results of which are presented in the following sections.

Estimation of the cost is based on the required power for pumping/compression.

4.8.1 CAPEX

Pumps

The capital cost of pumping facilities is modelled by using the equations given in the table below. IPB facilities on a pipeline branch are costed as though they were BS facilities.

Table 4.17 Pumping Facility Costs (USD millions)

Asset Type	IPB Facility	Booster Station
Electrical Power Generation Plant CO_2 export pipeline	0.98 P + 0.06	7.82 P + 0.46
Fuel Synthesis Plant Methanol product pipeline	0.97 P +0.06	7.73 P + 0.46
CO_2 Storgae Facilities	0.98 P + 0.06	7.82 P + 0.46
Pipeline Branch		
CO_2	7.82 P + 0.46	7.82 P + 0.46
Distillate	8.50 P + 0.50	8.50 P + 0.50
Methanol	7.73 P + 0.46	7.73 P + 0.46

The capital cost of compression facilities are modelled by using the equations given in the table below:

Table 4.18 Compression Facility Costs (USD millions)

Asset Type	IPB Facility	Booster Station
Electrical Power Generation Plant CO_2 export pipeline	$5.590 + 0.509P - 0.006 P^2$	$6.388 + 0.581P - 0.008 P^2$
Fuel Synthesis Plant Hydrogen product pipeline	$24.902 + 0.549P - 0.005 P^2$	$28.460 + 0.628P - 0.005 P^2$
CO_2 Storage Facilities	$5.590 + 0.509P - 0.006 P^2$	$6.388 + 0.581P - 0.008 P^2$
Pipeline Branch		
CO_2	$6.388 + 0.581P - 0.008 P^2$	$6.388 + 0.581P - 0.008 P^2$
Natural Gas and Hydrogen	$28.460 + 0.628P - 0.005 P^2$	$28.460 + 0.628P - 0.005 P^2$

Where P is the pump/compressor power in MW.

The Summary output from the Model (refer to Appendix A) shows the pumping/compression facility power (in MW) for 1 x 100% train. The pumping/compression facility cost is based on the provision of 2 x 100% trains.

If the compressor gas power exceeds 40MW, the turbine frame size required will exceed that of current technology. Hence, the flowrate through the compressor is split and 2 x 50% machines will be assumed. Similarly if the gas power exceeds 80MW, 3 x 33% machines will be required.

Fixed OPEX

The fixed OPEX has been developed on a case by case basis from the following costs:

- Personnel
- Administration & Overheads (administration, warehousing, corporate structure, infrastructure and overheads)
- Planned Facilities Maintenance/Inspections
- Spares
- Miscellaneous

The results are shown as discrete costs per MW pump/compression power in the cost look-up tables (see Section 4.3).

Variable OPEX

The variable OPEX is assumed to be the fuel costs of the pumping/compression facility. The variable OPEX is calculated when the Model is run and thus does not appear in the cost look-up tables.

Table 4.19 shows the assumptions made for the calculation of Variable OPEX

Table 4.19 IPB and BS Facility Variable OPEX Costs

Asset Type	IPB Facility	Booster Station
Electrical Power Generation Plant - CO_2 pump - CO_2 compressor	Electrical power supplied from the power station and assumed to be included in the power station OPEX.	Electric power supplied by an external supplier. Cost based on cost of electric.
Fuel Synthesis Plant - Methanol pump - Hydrogen compressor	Power supplied from the synthesis plant and assumed to be included in the plant OPEX.	Fuel is used from pipeline. Assume cost to be negligible.
CO_2 Storage Facilities - CO_2 pump - CO_2 compressor	Electric power supplied by an external supplier. Cost based on cost of electric.	Electric power supplied by an external supplier. Cost based on cost of electric.
Pipeline Branch - Natural Gas compressor - Distillate pump - Methanol pump - Hydrogen compressor	Fuel is used from pipeline. Assume cost to be negligible.	Fuel is used from pipeline. Assume cost to be negligible.
- CO_2 pump - CO_2 compressor	Electric power supplied by an external supplier. Cost based on cost of electric.	Electric power supplied by an external supplier. Cost based on cost of electric.

5. CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The following conclusions have been made:

1. The Model is designed as a high level analysis tool for the comparison of various energy transport development cases.
2. Cost data has been developed based on in-house methods and industry norms. Estimates from the Model have been provided in year 2000 US dollars.
3. CO_2 should not cause corrosion of carbon and low-alloy steel lines provided the gas is dry. Operating below 60% relative humidity normally provides a margin to avoid moisture condensation or dropout from the gas phase. Without free water in the system carbon steel should not corrode and is an acceptable material for CO_2 pipelines.
4. Problems with the transportation of hydrogen can only occur if there is a mechanism that produces atomic hydrogen. Molecular hydrogen (H_2) may be transported without problems in standard low-alloy carbon steel lines irrespective of the gas pressure provided that the conditions are dry, liquid free, and under 220°C.
5. Steels alloyed with chromium, molybdenum, vanadium, titanium, etc. generally have higher resistance to hydrogen attack.
6. The use of existing compressors (originally designed for hydrocarbon gas) for hydrogen raises concerns including:
   - compressor suitability (e.g. centrifugal machines unlikely to be suitable)
   - materials suitability
   - process control
   - hydrogen containment and detection
   - compressor power requirements
   - equipment re-certification
7. The presence of H_2S may cause sulphide stress cracking and hydrogen induced cracking.
8. The CO_2 pipeline operating pressure and temperature should be reviewed in detail from an operability viewpoint to determine whether transportation of CO_2 as a liquid is preferable to transportation as a dense phase or gas.

5.2 Recommendations

The following recommendations have been made:

1. The Model provides basic engineering and cost information for the comparion of options.
2. Specific requirements for materials and equipment for CO_2 and H_2 service should be reviewed on a case-by-case basis for acceptability.
3. Reference should be made to NACE standard MR0175[2] for H_2S service requirements.

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APPENDIX A

Model Installation Details

The Model ("2164bac8300d(IEA-cost model).xls") runs within Microsoft Excel version 97 or higher, and is supported by a comprehensive help file ("IEACostModelrevd.hlp").

The following steps outline the procedure for the installation and running of the Model.

1. Copy the files "2164bac8300d(IEA-cost model).xls" and "IEACostModelrevd.hlp" from the CD-ROM to the appropriate directory on the hard drive or network drive. Ensure that both these files are contained in the same directory.

2. Open the file "2164bac8300d(IEA-cost model).xls" by either double clicking on the file when in Windows Explorer, or by using the Open command in Microsoft Excel.

3. Review the Project Settings by clicking on the "Project Settings" button or selecting it from the drop down "Cost Estimation Model" menu on the main toolbar. Change the values as required.

4. Start the Model by clicking on the "Run Model" button or selecting it from the "Cost Estimation Model" menu on the main toolbar.

5. Choose whether to use the data from the last saved case as a starting point for the new run or open the Model with the default settings. The program will allow up to 5 Cases to be defined, each Case consisting of up to 10 assets. Define a Case by activating the appropriate assets and selecting their type and required service (refer to the online help). On finishing the Case definition either; skip to the next Case, define the Case from scratch or copy the Case definition to the next Case (refer to the online help).

6. When all Cases have been defined, exit the Asset Definition window and proceed with costing the case (refer to the online help).

7. View the results by clicking on the "View Results" button or by the "Cost Estimation Model" menu.

8. Save the file as required. Note that if the file is saved to a different directory, the associated help file "IEACostModelrevd.hlp" must be copied to the same directory. This help file must not be renamed.

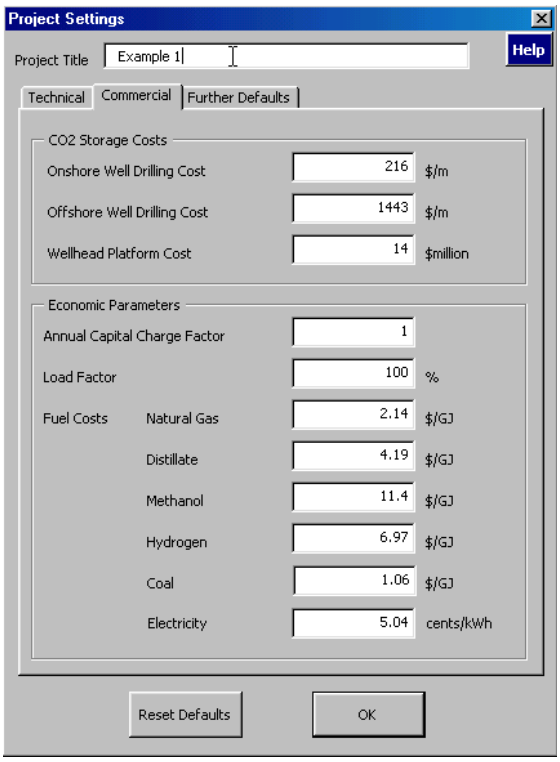
9. The online help file may be accessed during runtime by clicking on the "Help" button in the top-right corner of the active window or when in the main window, from the drop-down "Cost Estimation Model" menu.

The diagram below outlines the Model operation.

Figure A1 Model Operation

Review Project Settings

- Enter Project Title
- Enter technical and commercial settings or choose default settings



Project Title: Example 1

CO2 Storage Costs

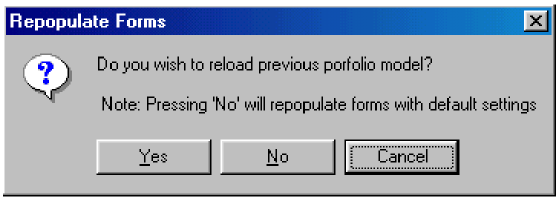
Onshore Well Drilling Cost	216	$/m
Offshore Well Drilling Cost	1443	$/m
Wellhead Platform Cost	14	$million

Economic Parameters

Annual Capital Charge Factor		1	
Load Factor		100	%
Fuel Costs	Natural Gas	2.14	$/GJ
	Distillate	4.19	$/GJ
	Methanol	11.4	$/GJ
	Hydrogen	6.97	$/GJ
	Coal	1.06	$/GJ
	Electricity	5.04	cents/kWh

Run Model

- Repopulating forms with previous portfolio data will populate Case 1 to 5 with the input data from last run
- If ‘No’ is selected default values will be used to populate forms

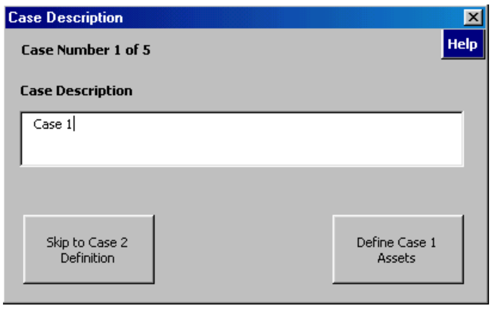


Do you wish to reload previous porfolio model?

Note: Pressing 'No' will repopulate forms with default settings

Case Description

- Up to 5 Cases can be defined
- Enter Case Name and Description
- Previous Case data may be copied to the next case for editing
- Case may be skipped if data is does not need modifying or Case is not required

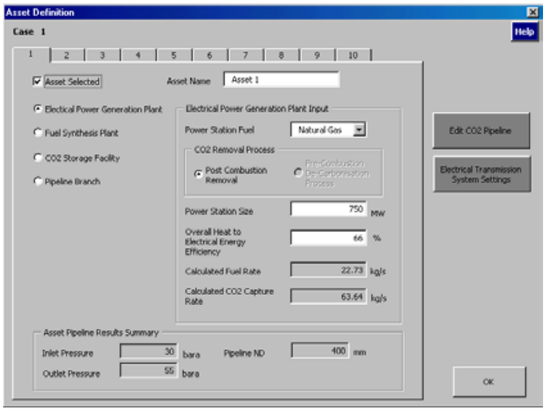


Case Number 1 of 5

Case Description: Case 1

Define Assets

- Enter data for each Asset
- Up to 10 Assets can be defined in each Case
- 4 different Asset types are available
  - Electrical Power Generation
  - Fuel Synthesis Plant
  - CO_2 Storage Facilities
  - Pipeline Branch
- When Asset Definition is complete pipeline and power transmission buttons will turn dark grey



Case 1

☑ Asset Selected

Asset Name: Asset 1

● Electical Power Generation Plant
○ Fuel Synthesis Plant
○ CO2 Storage Facility
○ Pipeline Branch

Electrical Power Generation Plant Input

Power Station Fuel: Natural Gas

CO2 Removal Process: ● Post Combustion Removal ○ Pre-Combustion De-Carbonisation Process

Power Station Size: 750 MW

Overall Heat to Electrical Energy Efficiency: 66 %

Calculated Fuel Rate: 22.73 kg/s

Calculated CO2 Capture Rate: 63.64 kg/s

Asset Pipeline Results Summary

Inlet Pressure: 30 bara

Outlet Pressure: 55 bara

Pipeline ND: 400 mm

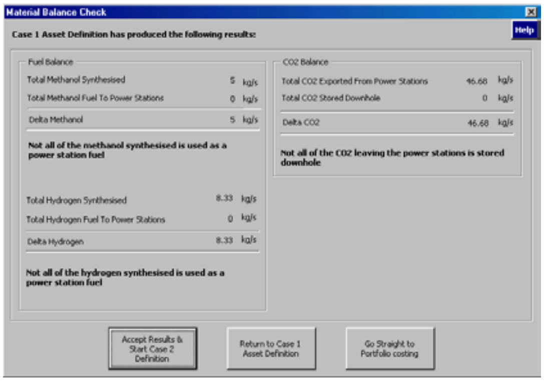
Material Balance Check

Model performs simple material balance to check on:

- quantity of synthesised product Vs. synthesised feed to power stations
- quantity of CO_2 produced from power stations Vs. quantity of CO_2 stored downhole

User has the option to:

- accept results and proceed to next Case
- return to Asset Definition to make amendments
- go directly to the portfolio costing skipping all remaining cases. Note that if the user selected to reload the forms with the previous portfolio data this will remain in the 'skipped' cases and still appear in the results.



Case 1 Asset Definition has produced the following results:

Fuel Balance

Total Methanol Synthesised	5	kg/s
Total Methanol Fuel To Power Stations	0	kg/s
Delta Methanol	5	kg/s

Not all of the methanol synthesised is used as a power station fuel

Total Hydrogen Synthesised	8.33	kg/s
Total Hydrogen Fuel To Power Stations	0	kg/s
Delta Hydrogen	8.33	kg/s

Not all of the hydrogen synthesised is used as a power station fuel

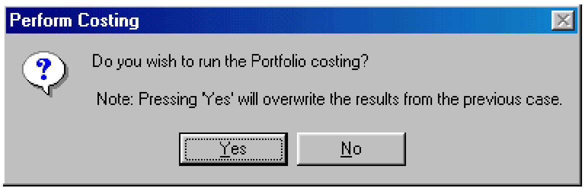
CO2 Balance

Total CO2 Exported From Power Stations	46.68	kg/s
Total CO2 Stored Downhole	0	kg/s
Delta CO2	46.68	kg/s

Not all of the CO2 leaving the power stations is stored downhole

Run Portfolio Costing

- Pressing ‘No’ will stop the run and all data entered will be lost
- Previous portfolio case will not be affected



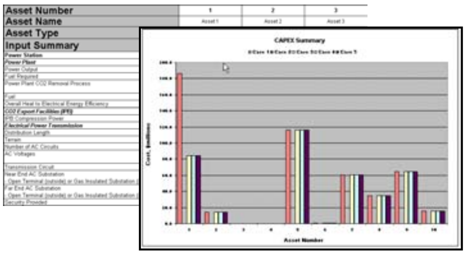
Do you wish to run the Portfolio costing?

Note: Pressing 'Yes' will overwrite the results from the previous case.

Portfolio Costing Complete

Review Results

Input data and results summaries may be accessed from the button on the main screen or from the ‘Cost Estimation’ Toolbar



ANNEX 1

Electrical Transmission Cost and Energy Loss Data

IEA Greenhouse Gas R&D Programme
CRE Group Ltd.
Stoke Orchard
Cheltenham
Gloucester GL52 4RZ

Electrical Transmission Cost and Energy Loss Data

6 July 2001

Mott MacDonald
Victory House
Trafalgar Place
Brighton BN1 4FY
United Kingdom

Tel 01273 365000
Fax 01273 365100

Electrical Transmission Cost and Energy Loss Data

Issue and Revision Record

Rev	Date	Originator (Print) (Signature)	Checker (Print) (Signature)	Approver (Print) (Signature)	Description
0	May 2001	IPF	JEB	STS	First Issue
D	May 2001	IPF	JEB	STS	Draft Issue
F	6 July 2001	IPF	JEB	STS	Final Issue

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1 Introduction

IEA Greenhouse Gas R&D Programme commissioned Mott MacDonald to prepare cost and performance data for electricity transmission in the form of an Excel Spreadsheet. The purpose of the spreadsheet is to be able to rapidly evaluate the costs of electrical power transmission when the energy source is remote from load centres.

The principal factor determining the choice of means of transporting electrical energy over long distances is capital cost expenditure, but it is also important to consider operating costs, particularly those arising from the energy losses which are inevitably incurred in long-distance power transmission.

Mott MacDonald undertake feasibility studies and project management for transmission projects of all types, and are well placed to bring this experience and knowledge of the transmission business into a useful reference tool such as the spreadsheet cost model that accompanies this Report. However it must be noted that major transmission projects are usually unique in their own way, whether for technical, commercial or even political reasons, or a combination of these factors. Hence, it is found in practice that there is a wide variability in tendered prices for transmission projects, and caution should be expressed in using these cost estimates. It is recommended that, at best, the cost estimates should be taken in the order of ±30% accuracy, and this should apply to comparative figures, e.g. when comparing AC and DC transmission options, as well as to absolute prices.

The Terms of Reference issued by IEA Greenhouse Gas R&D are reproduced in Appendix A.

2 Summary

An Excel spreadsheet has been developed for costing power transmission circuits, from a knowledge of the amount of power to be transmitted and the distance involved.

The principal results are:

- Capital expenditure estimate, which includes an adjustment for the country and terrain (if overhead lines are to be used)
- Estimation of the amount and value of losses, expressed as both an annual charge and a capitalised value.
- Estimate of annual operating and maintenance costs (excluding losses)

Power transmission can be by AC (alternating current) overhead line, DC (direct current) overhead line (including convertor stations at each end for connection to local AC networks), DC subsea cable (with convertor stations as AC) and subsea AC cables. The user can select which of these four methods of power transmission is to be costed, and is also given a facility to compare the costs of AC and DC transmission for long overland routes.

The base costs are stored in the spreadsheet in a combination of look-up tables and constants to be used in simple formulae. Complete transparency is ensured by storing all constants, which are named appropriately, in a common worksheet. The worksheets are all protected, but constants and variables such as cost breakdowns expressed as percentages are in unprotected cells (signified by a blue background) hence can be amended and updated by the user.

This report explains the use of the spreadsheet, and for the assistance of engineers who do not specialise in power transmission a brief description is included summarising the principal features of AC and DC power transmission and a glossary of the technical terms involved.

Appendices within the report record the data used to build up the capacity tables for lines and cables, which are used as the basis for matching the specified load and distance requirements.

The issue of losses is dealt with by establishing the minimum technical requirements (and hence capital expenditure) in terms of voltage and conductor size for a transmission circuit which is capable of carrying the specified load. The losses associated with this circuit at the specified loading are calculated and displayed as both annual expenditures and equivalent capital cost.

In an actual project, the option to increase either conductor size or voltage (or both) would be considered to demonstrate least-cost in the particular circumstances of that project. In this case however that facility is not present, rather the approach has been to take a reasonably prudent view of line ratings such that the losses are maintained in the order of 5% at full load, although the very long DC lines allow the losses to rise to a higher level up to 10% on the longest lines. It would be possible to test a higher MW load, which would in turn generate a result using larger conductor size and/or voltage and then manually scale the unit cost of losses back by the square of the ratio of the two loads, to ascertain the potential for saving in lifetime costs.

The final section of the report deals with consents and wayleaves, construction, operating and maintenance costs and the lifetime of transmission assets.

3 Electrical Transmission – Basic Issues

A brief summary of the principal issues which influence electrical power transmission are provided within this Section, in order to assist in understanding the inputs and outputs of the costing spreadsheet model. It is primarily aimed at those who are not electrical power engineers, and a Glossary of technical terms (indicated by the † symbol when first used in the text) is provided at the end of the chapter as an aid to understanding.

3.1 Historical Introduction

Public electricity supplies began in the final years of the 19th century, and typically employed DC† at low voltage, typically in the range 100-200 volts, for generators, distribution of energy and utilisation by consumers. The power stations could only serve a limited area, of radius perhaps 1 or 2 km, hence would be sited as close to city centres as practical.

The limitations of DC, in particular the necessity to locate generating stations as close to consumers as possible, very rapidly led to the adoption of AC† for bulk power transmission. The principal advantage of AC is that it enables the use of transformers† to convert a low voltage, high current supply to a high voltage, low current, suitable for transmission over long distances.

Early examples of the use of AC for transmitting large blocks of power are Niagara in the US (Westinghouse and Tesla) and Deptford to central London in the UK (Ferranti). These projects used overhead lines and early power cables† respectively.

Overhead lines, supported on poles or lattice steel towers (“pylons”) are relatively cheap and became the almost universal means of transmitting power over long distances, with the “Grid” being established at 132 kV† in the UK in the 1920s for linking the previously isolated small generating stations, and also providing the means for the supply of electricity to rural areas.

Power cables, with the conductors† insulated with rubber or plastic compounds at low voltage (LV†) or paper impregnated with oil or wax at higher voltages (MV† and HV†) were developed at around the same time to enable power to be transmitted in locations where overhead lines were unsuitable, principally in urban areas.

A variety of voltages and frequencies were used in early power network developments, but by the middle of the 20th century virtually all power networks used 50 Hz† or 60 Hz (the latter in North America and countries with strong links to the USA), three-phase† and a standard range of voltage levels for utilisation, distribution† and transmission.

Limitations in the use of AC for power transmission over exceptionally long distances, over 500 km on overhead lines but much shorter distances, typically 30 km, for power cables led to the development of HVDC† in the mid-20th century as an alternative to AC. Typical applications of HVDC included several schemes in the USA linking central and western areas and transmission by submarine cables over distances too great for AC, such as to Sardinia, or across the English Channel. HVDC was developed using mercury-arc valves†, nowadays thyristor valves are most commonly employed. Transistors are beginning to replace thyristors, particularly at more modest power levels, up to 100 MW†.

The most recent development with a significant impact on transmission is the change from paper insulation in AC power cables to XLPE†. This has, for technical reasons which will be explored later, extended the range of power cables from not much more than 30 km to up to about 100 km, a move of significance in considering offshore energy resources.

3.2 Technical Features of Power Transmission

3.2.1 Voltage selection

Transformers permit AC voltages from generators to be raised to any desired level for onward transmission. The choice of a suitable voltage is primarily economic, but for AC transmission is constrained in practical situations within a range of standard voltages for which equipment is readily available, and which may already exist within the country (or neighbouring countries, since future interconnection is always a possibility.)

Transmission losses are principally a function of the current flowing through the conductors (“the I^2R losses”†), and since for a given power level, the higher the voltage the lower the current, this would appear to favour the highest possible voltage even for modest power flows. However the provision of insulation to withstand high voltages costs money in the construction of high voltage overhead lines where the higher the voltage the taller and stronger the support must become. Similarly with power cables, the higher the voltage the thicker the insulation and the greater the cost. Figure 3-4 shows the outlines, to scale, of transmission towers for a range of voltages for both AC and DC.

3.2.2 Minimum conductor size

The electric field at the surface of the conductor is a function of the operating voltage and inversely proportional to the conductor diameter. If the electric field is too high it will lead to discharges into the atmosphere (referred to as “Corona”†) and strong radio interference. For this reason a minimum conductor size must be used at any given voltage, and at the highest voltages multiple conductors are employed which act like a single much larger conductor in this respect. Minimising corona is a factor in the design of both AC and DC lines.

A comparable limitation exists in power cables, with the thickness of insulation determined by the need to limit the voltage stress at the conductor surface. This results in the need to adopt a minimum conductor size for a given voltage rating for an economic design.

3.2.3 Interconnection to existing AC networks

The transmission circuit, whether AC or DC, needs to be connected to the existing AC networks, or possibly to a new power station at the remote end. This connection will be made at a substation†, which will comprise circuit breakers†, usually connected via busbars† in various configurations, and optionally may also include transformers and compensation equipment†.

Circuit breakers and busbars are designated as “open-terminal†” when installed outdoors with connections being made by conductors or the busbars supported on insulators in the open, with air as the primary insulation. This arrangement is low-cost but has the disadvantage that the substation is subjected to corrosive or salty air, or severe weather effects, which can cause a problem with maintenance and reliability in some environments such as close to the coast with exposure to salt-laden spray.

The alternative form of construction for substations in such areas is to place all the live† conductors in enclosures filled with an insulating fluid, and modern practice is to use sulphur hexafluoride gas or SF_6, which has excellent insulating and arc-extinguishing properties. These substations are referred to as GIS† or gas-insulated substations, and are usually constructed within a building to provide complete protection against external influences, enhanced security and a safer environment for operation and maintenance. They also have the advantage of requiring a far smaller amount of land than an open-terminal substation, which favours their use in urban areas with high land costs or where difficulties are encountered in obtaining consents for obtrusive open-terminal substations.

3.2.4 DC Transmission

For DC transmission there are two principal requirements to be met:

- The current must be within the (thermal) rating† of the conductors, and
- The losses and volt drop† (numerically the same if expressed as percentages on rated power and nominal voltage† respectively) must be contained within economic and technical limits.

For short lines the conductor rating will determine the line capacity, but over longer lengths a least-cost approach is necessary to optimise the line voltage and conductor size. In practical terms peak load losses as high as 10% may be acceptable for the very longest lines, since these projects will generally be associated with cheap energy supplies. 10% voltage regulation is also the maximum acceptable on technical grounds for correct and efficient functioning of the voltage convertor stations.

Typically DC transmission schemes with overhead lines are economic only over distances of many hundreds of km in order to recover the additional cost of convertor stations through savings in lower line costs.

3.2.5 AC Transmission

AC transmission is more complex than DC. Capacitance† of the lines requires that current is supplied to the line at all times ("charging current"), and although there is no direct net energy loss in capacitance current, the additional current through the conductors increases the I^2R losses. Similarly any conductor possesses inductance†, which causes an additional voltage-drop when current flows. Again there is no net energy loss directly caused by inductance, but as volt drop decreases the voltage at the end of the line, more current is required to deliver a given power load, and the increased current results in additional energy loss.

The effects of capacitance and inductance, current and power are combined by considering apparent power MVA†, the product of current and voltage, real power in MW and reactive ("watt-less") power in Mvar†. Mvar can be a positive or negative quantity and is numerically equal to voltage times charging current ("capacitive Mvar") and line current squared times inductive reactance (inductive Mvar). The simple relationship $MVA^2=MW^2+Mvar^2$ links these quantities.

Load served by a transmission circuit will usually have a power factor† less than unity, showing that the load has a reactive current element. In practice this results from a variety of causes, including reactive losses in the distribution systems and final loads, with motors and discharge lighting having low power factors. Typical values are between 0.8 and 0.9 (lagging).

For AC transmission circuits, similar requirements as for DC must be met, namely maintaining maximum currents within the rating of the conductors and limiting volt drop to some acceptable value (usually 10%). However the simple relationship between load, volt drop and losses which pertains in DC transmission can no longer be applied and it is usually necessary to resort to computer models of the line in order to establish its overall performance.

3.3 Transmission Capacity

The fundamentals determining the transmission capacity and the merits of AC and DC transmission are discussed as follows.

3.3.1 AC Power Transmission by Overhead Line

AC power transmission uses three conductors per circuit, all insulated for the working voltage between the other conductors and to earth and all three phases must be healthy for continuous operation.

The principal insulation for overhead lines is air, with porcelain, glass or epoxy resin insulators at supports. The conductor is usually aluminium reinforced with a steel core (ACSR) or aluminium alloy (AAAC).

Figure 3-1 shows a schematic diagram of a single circuit HV AC overhead line (OHL) transmission system. Note that in a practical situation there may be a requirement for a second circuit to provide security† in the event of an outage on the first circuit, and this could be constructed using a single tower carrying both circuits. At voltages of 500 kV and above this results in a tower of massive dimensions and it may well be economic and certainly more visually acceptable to construct two separate single-circuit lines.

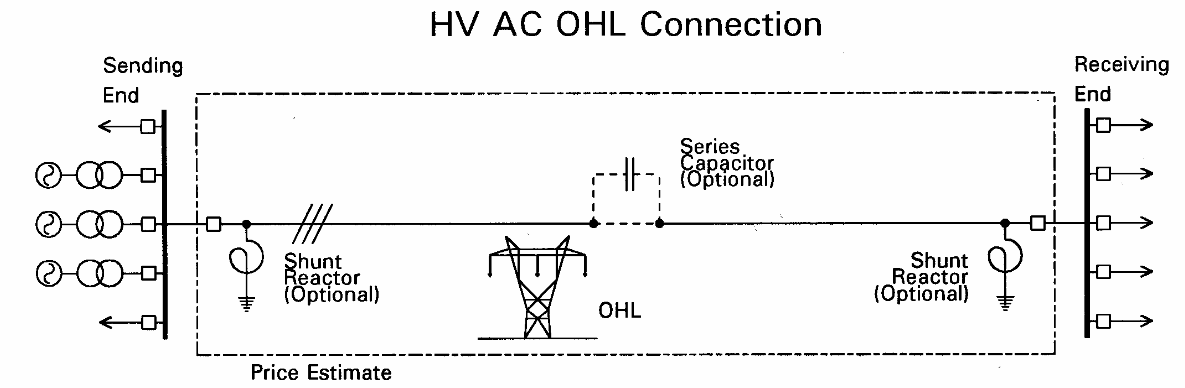


Figure 3-1 – AC OHL one-line Diagram

Note the following features of Figure 3-1

- In accordance with normal practice, a single line is used to denote all three conductors. To clarify this, the three dashes are added on the left-hand side.

- The small box signifies a circuit-breaker. The line needs a circuit breaker at each end, and this will usually be part of a new or existing substation as shown.
- The long line may need shunt or series compensation, as discussed below.
- The dotted box shows the components included within the price estimates for an OHL connection. The terminal substations can be priced separately if required (generators and transformers are excluded).

The performance of an AC OHL is complex and the receiving end voltage can reduce or increase depending upon the length of the line and the load it is delivering. It is further complicated by the capacity of the receiving end system to support the voltage.

At distances up to approximately 100 km and loaded at unity p.f., the AC line follows a satisfactory behaviour and the receiving end voltage regulation is usually within acceptable values.

Above this distance the voltage at both the ends of the line can increase particularly on low loads due to the reactive power produced by the capacitance of the line. This can be corrected by adding shunt reactors at both ends of the line. Low voltages can occur on long overhead lines which are heavily loaded and this can be improved by a series capacitor located approximately half way along the line.

There has recently been transmission equipment developed that quickly and automatically switches capacitor† and reactor† components to maintain the voltages at both ends to within acceptable levels for all values of load. This can also control the load through a transmission system thus giving increasing flexibility. The additional correction plant is often known FACTS (Flexible AC Transmission System) equipment but can considerably increase the cost of the AC transmission system.

Stability† considerations must be taken into account with long AC transmission lines. Generator instability can occur when a disturbance leads to a risk of the generators at each end of the circuit swinging apart in an uncontrolled fashion and falling out of step. This would result in dangerous voltage and current excursions and a risk of generator damage, and must be rapidly controlled by separating the two systems. As the line impedance increases the voltage phase angle between the sending end and receiving end generators increases which increases the risk of instability and a value not exceeding 30 degrees is usually taken as the limiting value.

Voltage instability can also occur when a relatively small load change results in a disproportionate change in voltage, which in turn results in increased currents and yet greater voltage drops leading to a collapse of the voltage to an unsustainable level.

The full specification of the compensation equipment and the calculation of generator stability can only be established by numerous computer load flow and stability studies on the transmission connection and the sending and receiving end systems.

3.3.2 DC Power Transmission by Overhead Line

DC power transmission requires two conductors although one of these could utilise the ground return with an earth electrode† at both ends of the link. On sea crossings the earth electrode system can cause unacceptable ship's compass deflections and earth currents can cause corrosion of adjacent metalwork and the emission of chlorine which can affect marine life.

The OHL conductors are the same materials as for AC systems although the supporting towers for DC are generally lower for the same voltage rating because less insulation is required for a given DC voltage than the same AC voltage.

In general the choice of voltage of a DC system can be optimised to suit the application. The most economic arrangement is generally a bipole installation using two series convertors as shown in Figure 3-2 and no current flows through the centre leg under normal conditions. One conductor would be at positive potential and the other at negative potential with respect to earth potential. Typical voltages would be in the range of ±100 kV to ±800 kV in steps of 50 kV for overhead lines while for cables the present maximum limit would be ±600 kV.

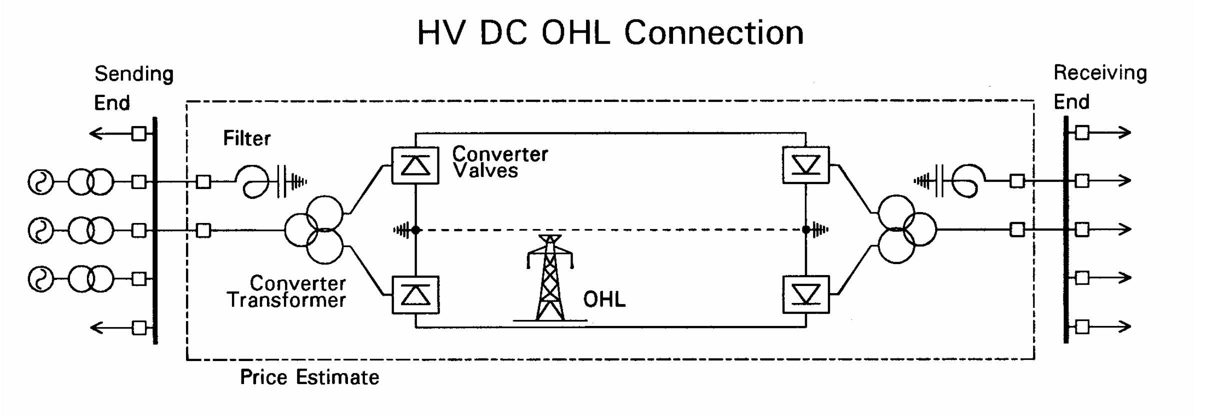


Figure 3-2 – DC OHL one-line Diagram

One major difference of the DC bipole scheme compared with the AC scheme is in its performance upon loss of one conductor. With the load initially at 100 % it is automatically reduced to 50 % and the return current is through the centre leg. Thus the inherent security of the DC link shown is 50 %.

There are no stability problems between generators at the ends of a DC transmission system.

3.3.3 DC Power Transmission by Submarine Cable

On subsea installations the cable connections are single core with a copper conductor and insulated by oil impregnated paper. Waterproof materials and armouring suitable for the subsea conditions are fitted to the cable.

Otherwise, as shown in Figure 3-3 the scheme is essentially the same as for HVDC transmission by overhead line. In this Figure, earth return via sea electrodes is shown to cater for the situation when one pole is lost, but should this be unacceptable because of the disturbance to ships' compasses, a lightly-insulated return conductor would have to be installed alongside the main cables.

Buried cables should generally be employed for sea-bed depths up to 100 m, but interference and damage from fishing activities has been reported below this depth, so advice should be taken on the most appropriate means of protecting the cables if the sea bed profile exceeds this depth.

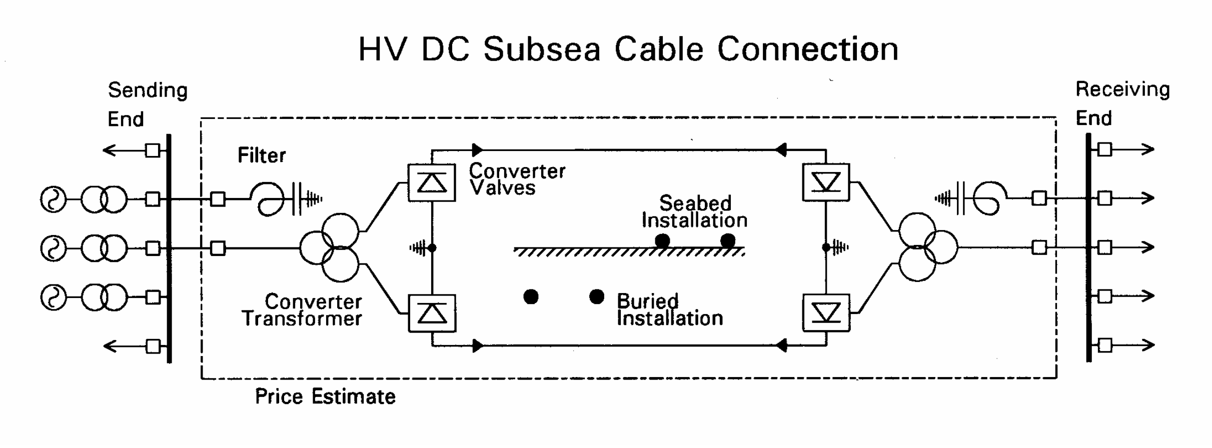


Figure 3-3 – DC Cable one-line Diagram

3.3.4 AC Power Transmission by Submarine Cable

AC power transmission by cable on land is reserved for those situations where it is impossible to use overhead lines because of environmental objections (the visual impact can be obtrusive, particularly at the higher voltages) or simply lack of land availability to locate the supports. With underground circuits costing in the order of 5 to 25 times as much as the equivalent capacity overhead circuits, there is a huge incentive to minimise the use of power cables, and generally these are only employed in heavily-populated urban areas, and are of modest length, in the order of 20 km maximum length.

There are certain applications where cables must be used for AC power transmission, particularly when crossing bodies of water of extent 2 km or more, since this distance represents a realistic maximum for the span length of an overhead line, even with very higher towers and taking full advantage of geographical features.

High Voltage electric cables suffer from several limitations, the main one being the longer the cable the greater the “charging “ current caused by capacitance, and at some point this will equal the cable current rating, leaving no scope to carry useful load current. With traditional paper insulated cable, this occurred at distance in the order of 30-40 km, with XLPE insulated cable this distance can be extended to around 100 km.

Hence, there are now opportunities for transmission interconnections at AC over large distances under water.

3.3.5 Power Transmission by DC Voltage-Source Convertors

Voltage Source Convertors (VSC) are being promoted as devices with new possibilities in Transmission technology, particularly by ABB using their “Light” brand name.

VSCs employ fast switching transistors rather than the thyristors used in conventional HVDC convertors. These can be used in a rectifying mode to generate a controlled DC voltage, and in inverting mode this DC voltage is used as the source to synthesize an AC voltage by rapid switching (at a frequency much higher than mains frequency). They are usually designed in a modular form, which facilitates high voltage, large power applications, but practical experience is limited above 100 MW

VSCs, unlike thyristor convertors, do not need external generation to ensure their correct functioning and can supply both real and reactive power (MW and Mvar). They can therefore be employed as the sole source of power for load centres too distance to use conventional AC technology. This usually means islands and comparable loads over 100 km from a power source, but land applications might be considered particularly where conventional overhead conductors are impractical in urban areas or regions of outstanding natural beauty.

The price for convertors contained in the Spreadsheet is based on ABB Light technology at 100 MW, above that power level the price is for conventional thyristor HVDC valves.

3.4 Glossary of Terms

AC	AC, short for Alternating Current. The polarity of electric current flow reverses rapidly, at 50 or 60 times per second in typical power systems. The alternating current frequency is measured in cycles per second, abbreviation Hz (for Herz).
Busbars	Large, heavy current conductors employed in substations (q.v.) to interconnect various electrical circuits via circuit breakers (q.v.)
Cable	A cylindrical assembly of conductors insulated by solid materials such as paper or a plastic/rubber material such as XLPE (q.v.), twisted together with some form of overall enclosure, typically including steel wires for strength and mechanical protection and an overall plastic covering for corrosion protection. Can be installed buried in the ground or in buried pipes.
Capacitance	The ability of a conductor to hold charge (surplus or deficit of electrons) relative to the earth or other conductors. If energised with AC voltage, current must flow to supply or remove these electrons every cycle.
Capacitors	Assemblies of metal foils separated by insulating sheets with the property of high capacitance (q.v.), which come in two forms; 1. "Shunt" Capacitors are energised by line voltage, and are used to compensate for loads with poor power factor (q.v.). 2. "Series" Capacitors are energised by line current, and are employed to compensate for circuit inductance (q.v.).
Circuit breaker	A circuit breaker is an electric switch which is capable of interrupting load or short-circuit (arising from faults q.v.) currents, which might be in the order of 20 times greater than load currents.
Compensation equipment	Devices used improve the power carrying capacity or technical performance of AC power transmission circuits, typically including reactors (q.v.) and capacitors (q.v.). These passive devices may also be associated with electronic devices to provide active controls, the most common being the SVC or Static Var Compensator.
Conductors	Metals such as copper or aluminium drawn into wires which are then twisted together in sufficient number to obtain the desired electric current carrying capacity. For overhead lines, the wires are heat treated, alloyed or combined with other metals (e.g. steel) to obtain the requisite mechanical strength.
Corona	Electric discharges into the atmosphere, like miniature lightning discharges. Causes a distinctive blue glow with little flashes, and generates strong radio noise. Energy loss through corona can be significant at EHV in bad weather.

DC	DC, short for Direct Current. Electricity flows in one direction only from a positive to a negative terminal from the source, which could be a battery or DC generator. (Note abbreviation "DC" is also sometimes used in the context of overhead lines, short for "Double Circuit", and in the same context "SC" may be found, short for "Single Circuit".)
Distribution	The process of distributing electrical energy to final consumers from central points, typically large HV substations, sometimes power stations. Mostly, distribution utilises MV and LV.
Earth electrode	The earth is a conductor of electricity and a connection to it is via an "earth electrode" which comprises rods or plates of selected materials buried in sufficient number to provided a sufficiently low resistance.
Fault	A defect on a power circuit caused by (in most instances) a failure of the electrical insulation on one or more conductors, permitting excessive currents to flow. The disturbance is detected by protection (q.v.) which disconnects the affected circuit automatically. Some faults are "transient" in nature, such as those caused by lightning, and the circuit can be re-connected very quickly, manually or automatically.
GIS	Short for gas-insulated substation (or gas-insulated switchgear), where busbars and switching devices are all within enclosures filled with pressurised SF_6 gas to provide insulation. Usually GIS equipment is installed within a building.
HV/ EHV	HV and EHV, short for High Voltage and Extra High Voltage respectively, covering voltages above 36 kV, principally used for bulk power transmission. (HV up to 245 kV, EHV above 245 kV). Note the terms "high" or "higher" voltage are sometimes used generically, simply to indicate an absolute voltage above 1 kV or a relatively greater voltage value (which might still be below 1 kV).
HVDC	HVDC, short for High Voltage DC. Typically, AC power is converted to DC at a high voltage, transmitted to another Convertor Station where the DC current is converted back to AC. DC is advantageous to AC over very long distances or in long power cables. HVDC can also be employed to interconnect systems with different frequencies or where stability (q.v.) considerations rule out AC interconnection.
Hz	See AC
I^2R losses	Power developed by the passage of an electric current "I" through conductor resistance (q.v.) "R", which is lost as heat.

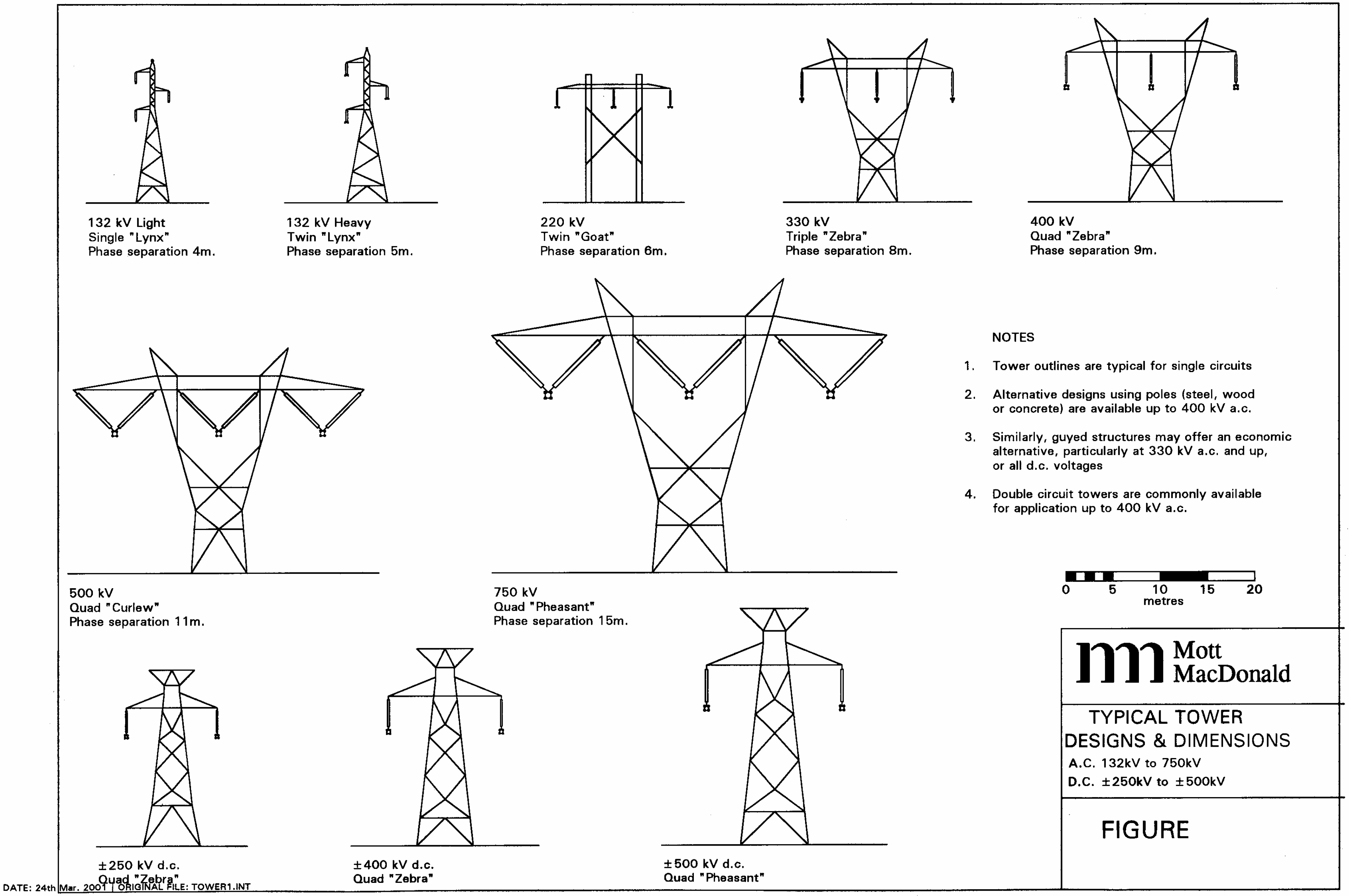
Inductance or reactance	Current passing through a conductor sets up a surrounding magnetic field, which requires energy to establish, which is then released as the current falls to zero. The changing current when energised with AC results in an additional voltage drop. Note the term "reactance" is also used to describe the effect of inductance, this is a measure of the volt drop at a given frequency analogous to the effect caused by resistance and is measured in ohms, the same unit as used for resistance.
kV (also kA, kVA etc.)	A thousand volts (or amps or VA etc.) Note that unless qualified otherwise an AC voltage is the root-mean-square (rms) value measured between any two lines or phases. A DC voltage described as ±100 kV is 200 kV between the two lines or poles.
Live	Used to denote a conductor which can be energised by connection to a supply of electricity (and hence must be protected by adequate insulation, clearances and barriers from human contact)
Loss of Synchronism	When a generator (or a group of generators) is unable to remain "locked" to other generators via transmission interconnections and runs at a different speed or frequency.
LV	LV, short for Low Voltage. Generally defined as voltages less than 1000 V Note the terms "low" or "lower" voltage are sometimes used generically, simply to indicate an absolute voltage below 1 kV or a relatively lower voltage value (which might still be above 1 kV).
M (also k, G etc.)	M, standard abbreviation for Mega or one million. Similarly k for kilo or one thousand, G for Giga or one billion (10^9)
MV	MV, short for Medium Voltage. Generally defined as voltages greater than 1000 up to 36,000 V (or 36 kV). Employed for power distribution in most cases, but could be used for transmission of modest levels of power (say 1-30 MW) over distances of up to 10 km.
MVA	Apparent power, the product of current and voltage (and $\sqrt{3}$ for three phase systems), with current in kA and voltage in kV (line-line). Related to MW by power factor (q.v.).
Mvar	A million "var", the SI unit for reactive power, derived from its old abbreviation of VAr or "volt-amperes-reactive". See text for the basis of the Mvar and its relationship to MVA and MW.
MW	A million watts, the watt being the basic SI unit for power (or the rate of delivering energy)

Nominal (voltage)	The voltage used to designate a power transmission network, circuit or component, typically a voltage in the middle of the range of expected voltage variations from light to heavy loads. For extra clarity, this range can be specifically stated, e.g. "220 kV ±10%". Note that the terms "rated" and "nominal" voltage are not interchangeable, rated voltages have very specific meanings as stated elsewhere, and will not be numerically equal to nominal voltages in many cases.
OHL	Overhead Line (Conductors insulated by air, supported on insulators attached to poles or lattice steel structures).
Open terminal	Generally applied to switchgear (circuit breakers etc.) installed outdoors with live conductors in air, supported on suitable insulators. Equivalent to "Air insulated Substations".
Pole-slipping	A consequence of "Loss of Synchronism" (q.v.) when the interconnection through the transmission system to other generators is too weak to permit the generator to lock its speed/frequency to the other generators on the network, this results in excessive voltage and current flows and compels disconnection of the affected generators.
Power factor or p.f.	The relationship between power and MVA (q.v.) numerically equal to MW÷MVA. It is equal to or less than 1. Sometimes referred to as "Cos ϕ". Qualified by "lead" or "lag" when it is required to distinguish between capacitive or inductive current respectively, since power factor must have a value between 0 and 1.
Protection	A term used in power transmission technology to denote the devices which monitor electric currents, voltages and other quantities to determine whether the transmission circuit is healthy or otherwise, and will act via circuit breakers to isolate a fault (q.v.) should it occur.

Rating	1. As applied to electric current, that current which can be carried continuously in specified ambient conditions without the temperatures of the conductors or adjacent components exceeding prescribed limits. 2 As applied to rated voltages, generally the maximum permitted continuous operating voltage, for clarity qualified as "Um" when applied to components such as insulators and switchgear. For components with iron-cored magnetic circuits such as generators, transformers and motors, rated voltage "U" is the quantity at which the component is rated for maximum operating temperature, in association with rated current "I". Since "U" is typically permitted to fluctuate over a range of ±5% in normal operation, whereas "Um" should never be exceeded save for transient events, rated voltages for generators etc. are typically chosen 5% or 10% below Um. 3 For transformers, the above applies but it should be noted that rated voltages relate to no-load conditions. To secure the correct on-load performance, the rated voltages on transformers, on either or both sides, may differ from "nominal" (q.v.) system voltages. Care and specialist assistance is essential in choosing transformer rated voltages. 4 The product of rated voltage and rated current, VA or volt-amperes for single phase equipment. The same definition applies to DC, but because VA and W (watts) are then identical, DC ratings are expressed in watts (usually MW) rather than VA. , For three phase equipment multiply line to line rated voltage by rated current by $\sqrt{3}$ to get VA or MVA (q.v.)
Reactance	See Inductance
Reactors	Coils with the property of a high inductance (q.v.) which come in two forms: 1. "Shunt" Reactors" are energised by line voltage, and are used to compensate for circuit capacitance (q.v.). 2. "Series" Reactors" are energised by line current, and are usually employed to reduce fault currents.
Regulation (Voltage)	See Volt drop
Resistance	Resistance is a property of all conventional conductors (e.g. copper or aluminium) caused by imperfections or thermal agitation hindering electron flow at an atomic level. The unit of resistance R is the ohm (Ω), related to voltage V and current I by the expression $R=V\div I$ (Ohm's Law). (Superconductors with effectively zero resistance at low temperatures are unlikely to be contenders for power transmission for decades to come save for some very special applications.)

Security	“Security” is used in the context of the ability to provide a continuous supply of electricity or transmission connection which is tolerant of faults or outages. The shorthand means of describing what provision has been made for security are: 1*100% Only one circuit is provided, rated at 100% of the desired capacity. (In this case there is no provision for security). 2*50% Two circuits are provided, each of which is rated at only 50% of the desired capacity. Useful for managing planned outages when the temporary reduction in capacity is probably acceptable for limited periods. Causes a problem in forced outages, because the remaining circuit is overloaded until the load can be reduced. 2*100% Two circuits provided, each being capable of carrying full load. The normal level of security provided to significant loads, say over 10 MW. This is not to rule out a single circuit for a power station connection or interconnector between power systems when loss of the circuit could be tolerated by the systems as a whole without significant risk of loss of supplies to consumers. 3*50% Three circuits provided, any two being capable of carrying full load. It is necessary that the circuits are broadly equivalent in terms of length and electrical characteristics, to ensure sharing.
Stability	“Stability” is a generic term covering the requirement for all generators on an interconnected AC system to operate at the same frequency and at a constant phase angle. Disturbances such as load/generation change or loss of a circuit should be accommodated with minor phase-angle changes but retention of the same frequency at all generators. Loss of stability requires individual or groups of generators to be disconnected, which in turn can lead to a collapse of the system and widespread loss of load. See also “Loss of synchronism” and “pole-slipping”.
Substations	A location containing equipment such as circuit breakers for controlling the flow of electricity, may also contain transformers or other specialist equipment for this purpose.
SVC	See Compensation Equipment
Three-phase	Virtually all AC generators generate three voltages, the second and third of which are delayed in time by 1/3 and 2/3 of a cycle from the first. Power transmission from the generator into and through the high voltage transmission system requires three wires insulated from each other (and from the ground) to carry these three voltages. Single phase, with only two wires, is not used save in domestic premises and specialist applications such as railway traction.
Transformers	Essentially two insulated copper coils wound onto a common iron core. By making one coil with a smaller wire size but many turns and the other coil with larger wire but fewer turns, an AC voltage applied to one coil is “transformed” to a higher or lower voltage. The transformer is highly efficient, with losses typically less than 1% even at maximum load.

Um	Max. continuous operating voltage, see also “Rating (2)”
Valves	A device which can rapidly switch an electric current on or off, and is employed in convertors to rectify (convert AC to DC) or invert (convert DC to AC) as required. Early valves were of the mercury-arc type with the ability to trigger the arc, most HVDC schemes use the semiconductor equivalents formed by a number of thyristors in series and parallel. Transistor valves permit the current to be switched on or off on demand, at higher frequencies than power frequency, giving much greater flexibility in operation.
Volt drop	Volt drop, also referred to as voltage regulation, is the reduction in voltage from one end of a transmission circuit to the other, usually expressed as a percentage of the nominal voltage.
XLPE	XLPE, abbreviation for cross-linked polyethylene, a thermo-plastic material with excellent electrical insulating properties, with principal application in HV AC power cables, where it is taking over from the oil pressure paper-insulated cable at even the highest voltages (400 kV and up). The cross-linking process imparts thermal stability, permitting continuous operating temperatures to 90°C.



NOTES

1. Tower outlines are typical for single circuits
2. Alternative designs using poles (steel, wood or concrete) are available up to 400 kV a.c.
3. Similarly, guyed structures may offer an economic alternative, particularly at 330 kV a.c. and up, or all d.c. voltages
4. Double circuit towers are commonly available for application up to 400 kV a.c.

Figure 3-4 – Typical OHL Tower Outlines

4 Using the Cost Model

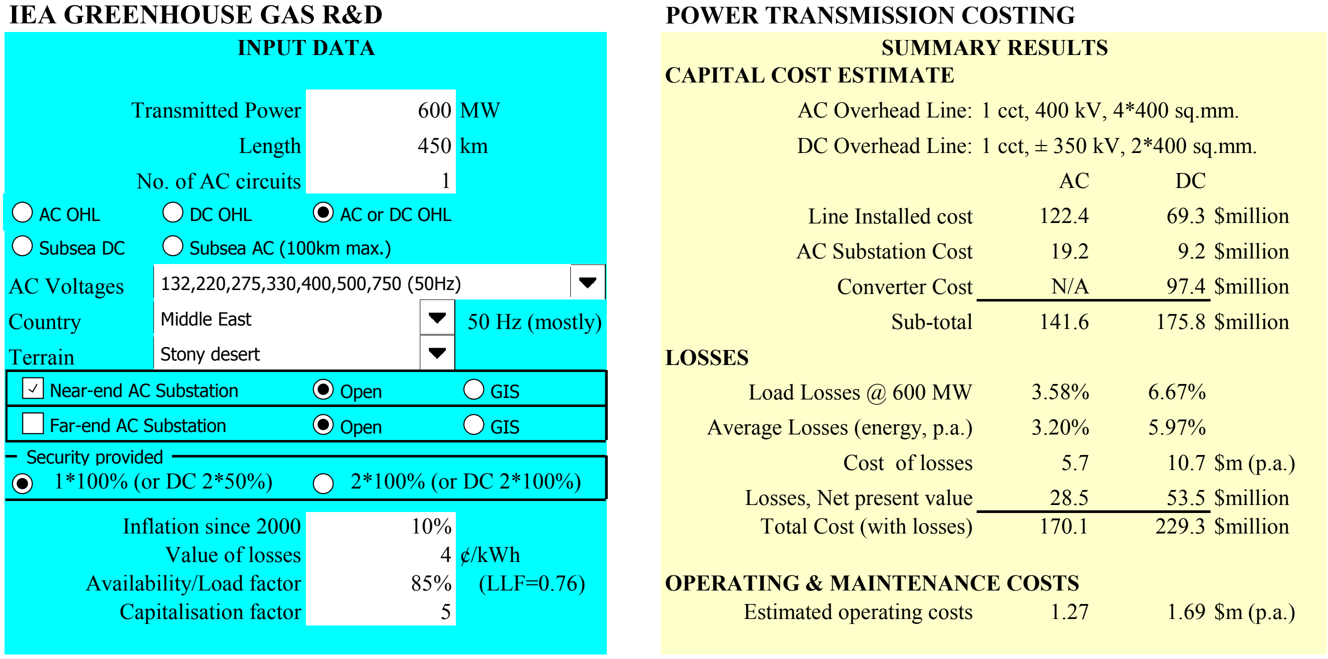
4.1 The Spreadsheet

The costing of transmission circuits has been prepared in the form of a spreadsheet which fulfils the following functions:

- Permits user entry of the principal variables affecting the cost of a transmission connection
- Summarises the results in the form of a capital cost estimate (including construction and the direct costs of right-of-way acquisition), the expected value of losses and the net present value of these losses added to the capital cost
- User selection of AC or DC overhead lines (OHL) or both, for a display of comparative costs, or DC or AC subsea cables.
- Ability to examine separate work sheets for the chosen transmission option (or options) giving a more detailed cost breakdown and technical information such as the voltage, rating and type of the minimum transmission circuit required.

The choice of a circuit is based solely on the provision of sufficient capacity to meet the specified load, over the required distance. It does not take into account the cost of losses, nor attempt to optimise the voltage selection, conductor size or any variable. The circuit parameters are chosen to be representative of typical practices which will yield losses which are broadly acceptable. Optimisation of a given project for minimum lifetime cost is a more complex undertaking than provided for in this spreadsheet.

A general worksheet where all cost data can be viewed and amended, together with other common factors is shown below, and forms the main Input sheet:



IEA GREENHOUSE GAS R&D

INPUT DATA

Transmitted Power	600	MW
Length	450	km
No. of AC circuits	1	

○ AC OHL ○ DC OHL ● AC or DC OHL
○ Subsea DC ○ Subsea AC (100km max.)

AC Voltages: 132,220,275,330,400,500,750 (50Hz)
Country: Middle East — 50 Hz (mostly)
Terrain: Stony desert

☑ Near-end AC Substation ● Open ○ GIS
☐ Far-end AC Substation ● Open ○ GIS

Security provided
● 1*100% (or DC 2*50%) ○ 2*100% (or DC 2*100%)

Inflation since 2000	10%	
Value of losses	4	¢/kWh
Availability/Load factor	85%	(LLF=0.76)
Capitalisation factor	5	

POWER TRANSMISSION COSTING

SUMMARY RESULTS

CAPITAL COST ESTIMATE

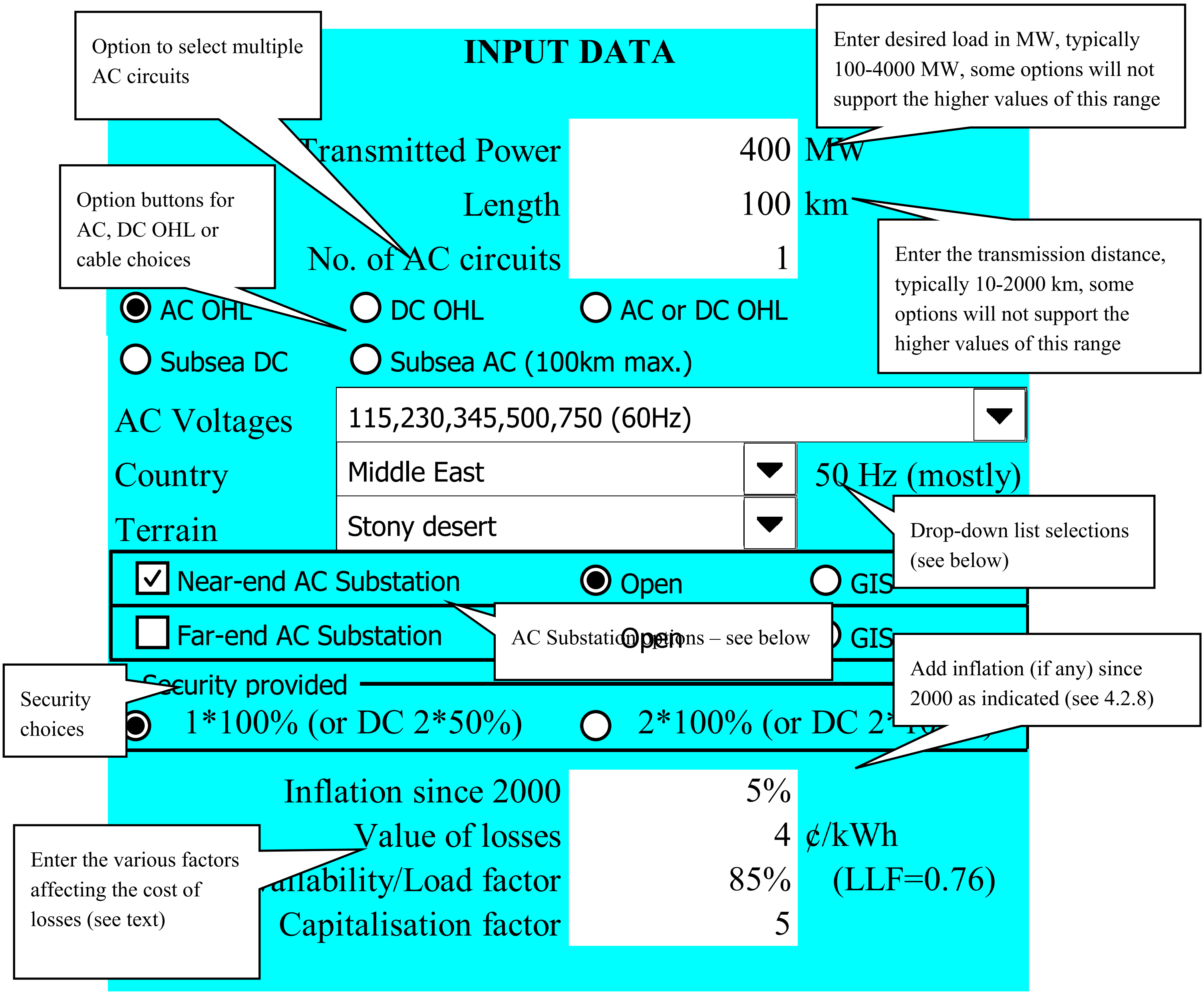
AC Overhead Line: 1 cct, 400 kV, 4*400 sq.mm.
DC Overhead Line: 1 cct, ± 350 kV, 2*400 sq.mm.

	AC	DC	
Line Installed cost	122.4	69.3	$million
AC Substation Cost	19.2	9.2	$million
Converter Cost	N/A	97.4	$million
Sub-total	141.6	175.8	$million
LOSSES			
Load Losses @ 600 MW	3.58%	6.67%	
Average Losses (energy, p.a.)	3.20%	5.97%	
Cost of losses	5.7	10.7	$m (p.a.)
Losses, Net present value	28.5	53.5	$million
Total Cost (with losses)	170.1	229.3	$million
OPERATING & MAINTENANCE COSTS			
Estimated operating costs	1.27	1.69	$m (p.a.)

User data entry is on the form headed “Input Data” (the white boxes, drop-down lists, check boxes etc.) and the right-hand side shows the estimated capital and O&M costs of the chosen option or options, losses and the cost of losses expressed as a per-annum or capitalised cost.

4.2 Input Data

The basis for estimating power transmission costs is user entry of the desired capacity in MW and the distance in km. The remaining data requiring keyboard entry pertains to inflation and an estimate of the cost of losses. Remaining entries are selected with option buttons, check boxes and drop-down lists, as indicated in the overview shown below. Note the work sheet is Protected, so other cells cannot be changed.



INPUT DATA

Transmitted Power 400 MW
Length 100 km
No. of AC circuits 1

● AC OHL ○ DC OHL ○ AC or DC OHL
○ Subsea DC ○ Subsea AC (100km max.)

AC Voltages: 115,230,345,500,750 (60Hz)
Country: Middle East — 50 Hz (mostly)
Terrain: Stony desert

☑ Near-end AC Substation ● Open ○ GIS
☐ Far-end AC Substation Open ○ GIS

Security provided
● 1*100% (or DC 2*50%) ○ 2*100% (or DC 2*

Inflation since 2000 5%
Value of losses 4 ¢/kWh
ailability/Load factor 85% (LLF=0.76)
Capitalisation factor 5

Option to select multiple AC circuits

Enter desired load in MW, typically 100-4000 MW, some options will not support the higher values of this range

Option buttons for AC, DC OHL or cable choices

Enter the transmission distance, typically 10-2000 km, some options will not support the higher values of this range

Drop-down list selections (see below)

AC Substation options – see below

Security choices

Add inflation (if any) since 2000 as indicated (see 4.2.8)

Enter the various factors affecting the cost of losses (see text)

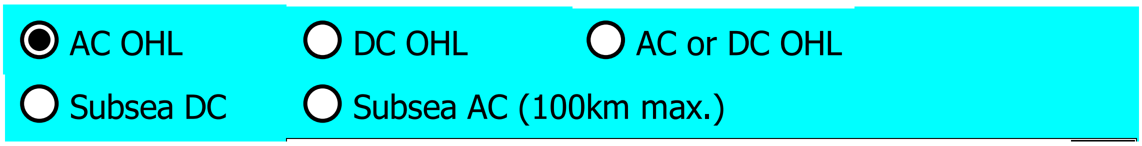
4.2.1 Multiple AC Circuit Option

The power which can be transmitted over an AC circuit over a long distance is heavily reduced compared to short-line capacity, also it may be desirable to use multiple circuits at a lower voltage than a single circuit at the highest voltages of 500 kV and above. The security of multiple AC circuits in inherently better than that of the single circuit.

The option to specify multiple circuits, for AC overhead lines (or AC cables) permits tests of one AC option against another, or comparisons with DC costs up to the MW limits which can be handled by DC.

4.2.2 Choice of Transmission Circuit

Option buttons are provided for the four types of power transmission circuit, as shown below:



● AC OHL ○ DC OHL ○ AC or DC OHL
○ Subsea DC ○ Subsea AC (100km max.)

AC overhead lines cover a wide range of line sizes, from 110 kV up to 750 kV at 50 Hz and 60 Hz, for distances up to 1000 km (800 km for 60 Hz). Lines over 200 km in length have shunt compensation, and over 500 km have series compensation also. The costs of this compensation are included in the tabulated substation cost, in addition to the provision for line-end switchgear.

Note that the distance limits for AC overhead lines are not fixed at the above values, in that technical measures such as the installation of SVCs (static var compensators) or increased series compensation could permit transmission over greater distances. To reflect this, the spreadsheet simulates a progressive reduction in capacity between 1000 and 1200 km (800 and 1000 km at 60 Hz) rather than a sharp cut-off.

Nevertheless there are fundamental problems with AC transmission over very long distances without intervening connections to load or generation, and any projects involving such connections should be subject to design studies on an individual basis.

The capacity of AC overhead lines has been assessed using computer program POW4 which tests thermal current rating, voltage regulation and stability for a user-defined series of distances. The maximum permitted line voltage variation is taken as ±10% on nominal voltage. The receiving end power factor is defined as 1.0 in all cases (i.e. the transmission circuit transfers MW only, with any net Mvar being supplied at the supply end, which is maintained at 100% nominal voltage. This is a compromise position since capacity could be enhanced with a large source of active generation at each end of a transmission circuit, conversely if either system is weak, capacity is reduced. Further information on the means of assessing the capacity of AC transmission circuits is provided in Appendix C.

DC overhead lines data is included for lines up to 3500km in length and with capacity 100 MW up to over 5000 MW. The capacity of the long lines is assessed on the basis of permitting losses to increase over the range 5% to 10% as line length increases from 300 km to 2000 km, presuming the line thermal limit is not attained. Further information on the means of assessing the capacity of DC transmission circuits is provided in Appendix D.

The option for both AC and DC overhead lines simply outputs the results of both tests to be shown together on the "Summary Results" screen, permitting comparisons to be made.

DC cable data is included for subsea cables up to 2500km in length and with capacity 100 MW up to over 3000 MW. The capacity of the circuits is assessed on a similar basis as DC overhead lines, namely permitting losses to increase over the range 5% to 10% as the route length increases from 300 km to 2000 km, presuming the cable thermal limit is not attained.

The subsea AC cable option is limited to cables up to 100 km in length, operated at nominal voltages 66 kV to 220 kV 50 Hz only at power levels 60 MW to 280 MW. This represents, or goes somewhat above, the present range of options and the results should be regarded as indicative at best, particularly at the higher distances and power levels. AC cable lengths are limited by the need to supply charging current from each end, and the point of diminishing returns is attained when charging current reaches the same magnitude as load current. For this reason, the spreadsheet will not generate any result above 100 km, this being typically representative of the maximum feeding distance, although longer distances might be possible in individual cases.

4.2.3 AC Voltages

The following five voltage-range options are presented in the drop-down list entitled "AC Voltages":

1	132,220,275,330,400,500,750 (50Hz)
2	115,230,345,500,750 (60Hz)
3	110,220,380/400 (Europe)
4	132,275,400 (UK)
5	132,230,400 (Some 60Hz)

Table 4-1 – AC Voltage Ranges

Voltages are chosen from the appropriate group for AC overhead lines, and also the AC switchgear rated voltages for connections to DC schemes.

The AC overhead line tables include a number of 60 Hz lines which are only accessible in place of the range of 50 Hz lines when one of the two 60 Hz options is chosen here.

Note that if one of the options is chosen which excludes 500 kV and 750 kV, lower limits will be reached on high MW and/or long distances and the spreadsheet will flag this by printing "OUT OF RANGE" in place of details on the chosen line type and voltage.

As previously noted, data for 60 Hz lines terminates at 800 km (over this distance at 60 Hz, the midpoint voltage on a series-compensated line exceeds the assigned limits of ±10% at maximum load, a limit not reached until 1000 km at 50 Hz). At low loads, the spreadsheet may still yield a notional capacity at distances above 800 km, because it interpolates between a value at 800 km and zero at 1000 km. A similar effect may be found on 50 Hz lines above 1000 km.

The choice of standard nominal voltages as tabulated also yields a corresponding list of standard switchgear rated voltages (Um basis), which are generally applicable at both 50 Hz and 60 Hz.

4.2.4 Country

The drop-down list headed "Country" is based on the "Countries" column of the following table, and each country or group of countries is associated with a "Country Factor" as shown, and information on the typical power frequency voltage used in the region, qualified if some countries use other frequencies (e.g. in the Middle East, most countries are 50 Hz, but Saudi Arabia uses 60 Hz.

Countries	Factor	Hz
Europe	1	50 Hz
UK	1.2	50 Hz
USA/Canada	1	60 Hz
S. America	0.8	60 Hz (mostly)
N. Africa	0.8	50 Hz
Equatorial Africa	0.9	50 Hz
S. Africa	0.7	50 Hz
Russia	0.7	50 Hz
Middle East	0.9	50 Hz (mostly)
Indian Sub-cont.	0.7	50 Hz
SE Asia (exc. Japan)	0.8	50 Hz (mostly)
Japan	1	50 or 60 Hz
China/C. Asia	0.7	50 Hz
Australia/NZ	1	50 Hz

Table 4-2 – Typical Country Factors

The "Country Factor" (which may change from the above as it is user-changeable) is intended to act as a guide to local costs as affected by:

- Indigenous sources of labour and/or overhead line materials which may be significantly cheaper than international prices.
- The difficulty in working in the territory, e.g. the need to use a significant imported or ex-patriate labour force for engineering and construction, a slow and unwieldy bureaucracy, problems in wayleave procurement etc., which will all tend to increase costs.
- Remoteness and/or lack of local infrastructure (e.g. roads) which will increase construction costs.
- Adverse ambient conditions, such as high ambient temperatures, heavy insulator pollution or being subject to tropical storms, which will need a higher design standard than used in Europe/North America.
- Labour laws and regulations, safety legislation, restricted access etc., which puts up costs in densely-populated regions in developed countries.

Some of these factors co-exist, and the net result may be to leave prices relatively unchanged,

The frequency information under "Hz" is displayed on the main input screen as a guide in selecting the correct voltage ranges.

Country factors are applied to overhead line rates only. Substations and cabled connections are deemed to be based on International prices wherever installed.

4.2.5 Topography

The drop-down list headed "Terrain" is based on the following drop-down list, which influences overhead-line prices only:

Topography	Factor
Cultivated land	1.1
Grassland	1
Wooded	1.05
Jungle	1.1
Stony desert	1.1
<20% Mountainous	1.3
>50% Mountainous	1.5

Table 4-3 – Typical Terrain Factors

The base price is for open grassland in reasonably flat or rolling countryside, altitude 1000 m or less, with relatively easy vehicular access and route selection which permits the maximum number of straight-line suspension towers, and minimal problems in obtaining wayleaves or tower siting.

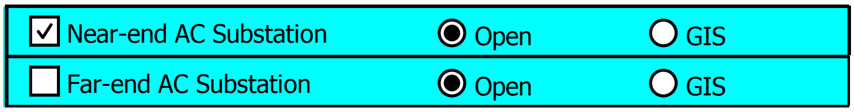
Other topographies attract greater premiums reflecting:

Cultivated land	Greater difficulties in obtaining routes and wayleaves and access to sites for construction because of crops.
Wooded	Tree clearance and constructing access roads
Jungle	Jungle clearance, constructing access roads, higher towers
Stony desert	Access problems, harsh environment, longer insulators
<20% Mountainous	Access, needing much greater air/helicopter use, unusual towers, foundations and possibly conductors over a portion of the route.
>50% Mountainous	As above, but a much greater proportion of the route.

The various factors are user selectable, and can be updated based on experience.

4.2.6 AC Substation Costs

Two sections are provided for allowing for substation costs, whether the link is AC or DC, overhead line or cable, if no suitable substation already exists. (Note the cost of circuit-breakers at each end of the circuit is already allowed for in the pricing.) The choice of a substation or otherwise and the type of circuit breakers required, at either or both ends of the circuit(s) is specified in the following portion of the input data screen:



☑ Near-end AC Substation ● Open ○ GIS
☐ Far-end AC Substation ● Open ○ GIS

The tick box labelled Near/Far-end Substation, if selected, adds in a pre-determined number of circuit breakers (currently 6, the value is in the Common Factors section of the COMMON worksheet), based on an allowance for bus-section and bus-coupler bays and outgoing circuits. (The terns Near/Far can be considered synonymous with Sending/Receiving whenever used in this document.)

Option buttons "Open" and "GIS" permit the selection of open-terminal (outdoor) or a SF_6 gas-insulated substation respectively. This choice will also affect the circuit breaker costs allowed for within the line or cable cost, regardless of whether an existing or new substation is selected.

The price of transformation to another voltage level is excluded.

4.2.7 Security

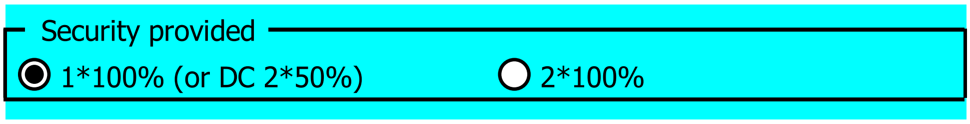
As described in Section 3, it is possible for there to be a need for an additional transmission circuit to provide security in the event of planned or forced outages. This requirement depends on circumstances, in particular whether the loss of the transmission circuit (or one of them, if more than one) is likely to result in a disturbance at one end or the other which in turn is likely to result in a substantial loss of consumer load. Such an assessment will probably require a full computer study of the power system.

Two possibilities exist which may make the omission of a redundant circuit tolerable:

- Use of a DC interconnection, which can offer 2*50% security by use of ground return in the event of loss of one pole

- Use of single-phase auto-reclose(1) on AC overhead lines, which may permit the clearance of transient faults (which will form the great majority of all faults) without loss of generation.

The level of security to be provided is selected by the appropriate option button in the Input screen, as shown(2):



Security provided

● 1*100% (or DC 2*50%)　○ 2*100%

Note that if the "2*100%" option is chosen:

- It may be possible to use double-circuit towers, and even if two single circuits are installed over the same route there will be significant economies in the cost of overhead lines. The price of a single circuit is multiplied by a factor less than two, currently 1.65, which can be amended if necessary in the Common Factors section of the COMMON worksheet

- The costs of line-end switchgear, convertors and compensation, and cable connections are simply doubled. If additional near or far end switchgear is included in the estimate to form a new substation, the price of this item only is unaffected.

Note 1 – Single phase auto-reclose

The majority of faults on AC transmission lines (but not cables) are transient in nature, caused by external factors such as lightning strikes, and it is common practice to arrange to re-close the circuit breakers at each end of the circuit automatically, after a short interval measured in seconds or fractions of a second. Furthermore, the majority of these transient faults involve one phase only and since some power can still be transmitted via two out of three conductors and earth, there is a benefit in arranging that the circuit breaker trips only one phase at each end and re-closes after the fault is cleared.

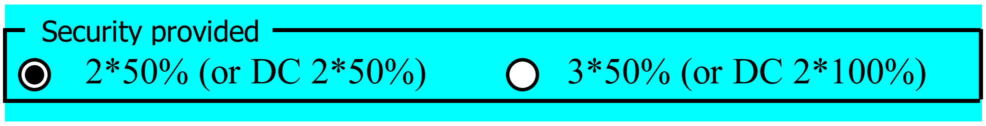
If the interconnector links generation at both ends, sufficient “synchronising power” can be exchanged during the fault up to the time of reclosure to maintain synchronism.

There is a modest extra cost associated with having circuit breakers with three independent mechanisms to facilitate single-pole operation and on long lines precautions have to be taken to ensure that the capacitive coupling between healthy and faulted conductors does not result in a sustained arc even after the circuit breakers have opened.

Single-phase auto reclose is not usually adopted where a double-circuit line is installed or alternative routes exist via other transmission circuits. Detailed technical studies are necessary to justify the use of single phase auto reclose in all possible applications, to confirm that it will achieve the necessary objective of maintaining stability on the system.

Note 2 – Multiple AC Circuits

If multiple (two or more) AC circuits are specified, the Security option works in the same way, but the display is modified as shown below to reflect the provision of the additional circuit and the resulting security provision (100% is total specified load).



Security provided

● 2*50% (or DC 2*50%)
○ 3*50% (or DC 2*100%)

Note that in the cost calculations, the provision of a second circuit permits economies to be made by multiplying the cost of the first circuit by either “double circuit” or “two_cables”. For overhead lines, a total of three circuits (or five etc.) requires one to be double-circuit construction, the other to be single circuit construction, so the resulting economy is reduced by an algorithm which takes this into account.

4.2.8 Price Inflation

Enter the percentage price inflation, if there has been significant movement in prices since 2000. This percentage is applied to all capital cost elements.

Historically, a combination of technical advances and increased competition has led to a situation where the inflation in transmission costs has remained low or even negative in comparison to general inflation factors. Conversely, the modern tendency for disengagement by governments in the provision of utilities in favour of the private sector, has resulted in the “intangibles” such as getting consents for new transmission circuits getting more difficult, which adds to costs and incurs delays.

On balance, international prices have actually fallen over the last 10 years, but total costs in some countries (Europe and North America in particular) have risen as a result of more stringent safety requirements affecting both design and construction,. The present situation is reflected in the “Country” factors.

An allowance for inflation at 2-3% p.a. is probably quite adequate. It should be noted that this is in the context where internationally tendered prices may well vary over a ±25% band depending on market conditions at the time.

4.2.9 Cost of Losses

The losses in the transmission system are calculated as part of the line selection process, and the result summarised in the Summary Results screen. Note:

- Losses are based on the nominated maximum load, not the line capacity
- DC circuits have a fixed quantity, currently 2% (which can be amended in the COMMON worksheet), added to the line/cable losses to account for losses in the convertor stations at both ends.
- If the “2*100” security option is chosen, the total line or cable losses are halved, reflecting normal load of 50% maximum on each circuit.
- If the AC multiple circuits option is chosen, the reduction of losses obtained by installing an additional circuit for security purposes is adjusted according to the new total number of circuits.

The user must supply the cost of losses in a value per kWh figure, an Availability/Load factor (LF) estimate and a Capitalisation factor. Since losses are proportional to the square of load current, a factor called the Loss Load Factor (LLF) is calculated using the empirical relationship $LLF=K*LF+(1-K)*LF^2$, where constant K is currently 0.3, but can be amended in the COMMON worksheet. This formula is based on typical load profiles.

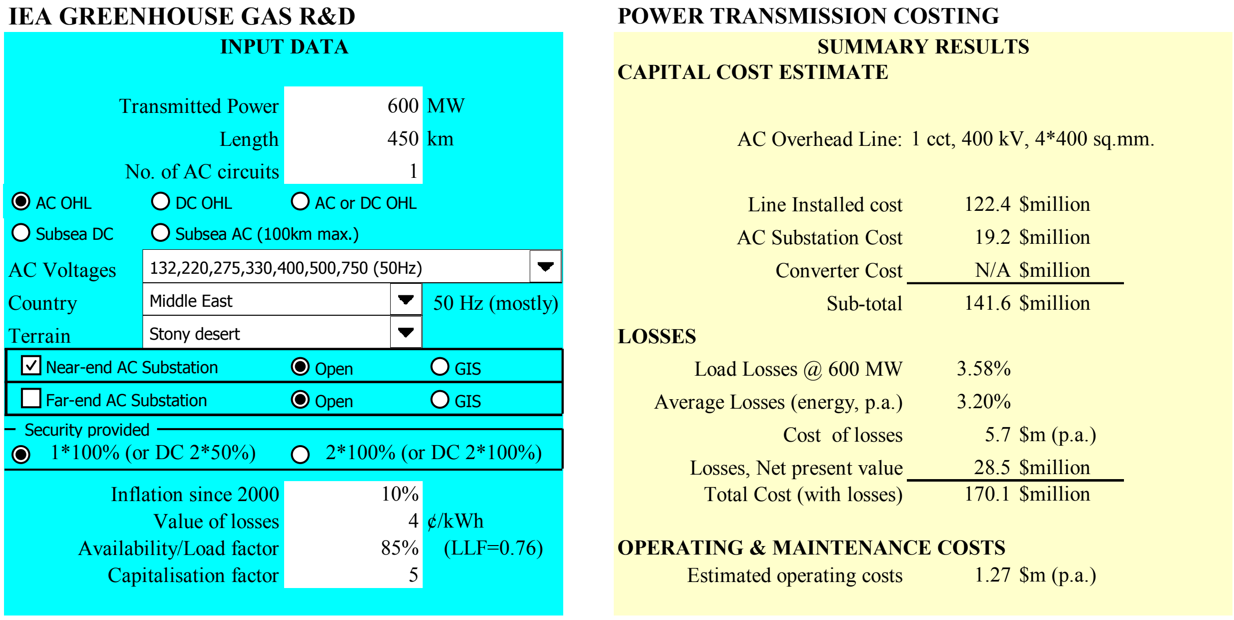
The Capitalisation factor used is a matter of judgement, based on an appropriate rate of return on the project and the period over which the cost of losses should be recovered. The value of years in a simple Payback calculation might also be an appropriate means of assessing a suitable value to use.

The overall cost of losses is calculated by multiplying the load by the cost of losses, LLF and 8760 hours/annum to get a per-annum figure, and then by the Capitalisation factor to get an overall cost for comparison with estimated capital cost.

Although outside the scope of the facilities provided within the spreadsheet, it should be noted that the installation of a major transmission circuit may result in a net reduction in overall losses within a given power transmission network. Further study is recommended on the impact of losses on a particular transmission project.

4.3 Summary Results Display

The Summary Results screen is shown below, together with the associated input data screen:



IEA GREENHOUSE GAS R&D

INPUT DATA

Transmitted Power	600	MW
Length	450	km
No. of AC circuits	1	

● AC OHL ○ DC OHL ○ AC or DC OHL
○ Subsea DC ○ Subsea AC (100km max.)

AC Voltages: 132,220,275,330,400,500,750 (50Hz)
Country: Middle East — 50 Hz (mostly)
Terrain: Stony desert

☑ Near-end AC Substation ● Open ○ GIS
☐ Far-end AC Substation ● Open ○ GIS

Security provided
● 1*100% (or DC 2*50%) ○ 2*100% (or DC 2*100%)

Inflation since 2000	10%	
Value of losses	4	¢/kWh
Availability/Load factor	85%	(LLF=0.76)
Capitalisation factor	5	

POWER TRANSMISSION COSTING

SUMMARY RESULTS

CAPITAL COST ESTIMATE

AC Overhead Line: 1 cct, 400 kV, 4*400 sq.mm.

Line Installed cost	122.4	$million
AC Substation Cost	19.2	$million
Converter Cost	N/A	$million
Sub-total	141.6	$million
LOSSES		
Load Losses @ 600 MW	3.58%	
Average Losses (energy, p.a.)	3.20%	
Cost of losses	5.7	$m (p.a.)
Losses, Net present value	28.5	$million
Total Cost (with losses)	170.1	$million
OPERATING & MAINTENANCE COSTS		
Estimated operating costs	1.27	$m (p.a.)

In this case an AC overhead line has been chosen, to carry a peak load of 600 MW over a distance of 450 km. Other input data is as shown above, note that a Near-end substation (with open-terminal switchgear) has been chosen and a single circuit selected, giving 1*100% security.

4.3.1 Capital Cost Estimate

The minimum requirement to carry the specified load over 450 km has been estimated as an overhead line operating at 400 kV nominal voltage, with four 400 sq.mm. aluminium (or equivalent) conductors. This information is provided at the top of the screen.

Following it, the estimated capital cost of the overhead line, is given as $122.4 million, this price will include materials, construction, country and terrain factors and inflation.

The AC substation cost includes:

- One circuit breaker at each end of the line
- An extra 6 circuit breakers for the new near-end substation
- Shunt compensation (which will be physically located at both ends of the line)
- Series compensation, situated at the line mid-point.

Substation and compensation estimates are not affected by the choice of country and terrain factors, presuming international procurement.

For further information on the capital and operating cost breakdowns, click the tab on the worksheet titled AC_OHL. A brief summary of the tables in this sheet and the others covering DC lines and cables, and AC cables is provided as follows:

Worksheet Tab	**Clause**	**Heading**
AC_OHL	4.4	Cost Breakdowns – AC Overhead lines
DC_OHL	4.5	Cost Breakdowns – DC Overhead lines
DC_CABLE	4.6	Cost Breakdowns – DC Subsea Cables
AC_CABLE	4.7	Cost Breakdowns – AC Subsea Cables

4.3.2 Cost of Losses

Quoted losses as a percentage are peak load losses based on the conductor resistances. DC schemes have a fixed amount added to account for convertor losses. Average losses, that is losses as a percentage of the total energy transmitted over the circuit in a year, are also displayed.

The cost of losses is presented as a per-annum and capitalised costs, with the latter added to the estimated Capital expenditure.

The method by which these costs are calculated is set out in Clause 4.2.9.

4.4 Cost Breakdowns – AC Overhead lines

4.4.1 Overhead line details and costs

To obtain further details on costs, select the appropriate worksheet, in this case AC_OHL, and place the cursor in the top left if not already there. The program displays the requested load and distance, and below that the following details appear:

OVERHEAD LINE DETAILS AND COSTS

(line capacity 667 MW at 1.0 p.f. over 450 km)	
Description	1 cct, 400 kV, 4*400 sq.mm.
Nominal Voltage kV	400
Peak Load Losses	0.035775 p.u.

This displays the minimum line size calculated to meet the specified load, and its estimated capacity over the specified distance (calculated by interpolation of the given data at predetermined distances. This information is followed by a table showing a cost breakdown based on percentages which can be amended by the user (indicated by cells shaded light blue).

SUMMARY COSTS	**$million**
Installed Cost over 450 km	112.4
Add Inflation	11.2 (10%)
Add Country Factor	-12.4 (Middle East, -10%)
Add Terrain Factor	11.1 (Stony desert, 10%)
Cost of second circuit	0.0
Total cost	**122.4**

BREAKDOWN	**$million**	**Based on**
Materials FOB	66.76	60.0%
Insurance & Freight (CIF)	6.68	6.0%
Engineering/Project Management	3.34	3.0%
Sub-total	**76.78**	
Survey/ROW acquisition	4.41	3.0%
Local Transport	4.41	3.0%
Construction	36.79	25.0%
(Total)	**122.40**	
		(100%)

Percentages are all against Total Cost, hence all should add to 100%.
Costs are adjusted by Terrain Factor to allocate the appropriate amount to Local costs

General Notes

FOB (Free on Board) - Assumes International procurement

Survey/ROW (Right of Way) and site acquisition costs can vary enormously, take local advice

Local Transport - Gets materials to line material storage areas/substation sites only

Construction (Lines) - includes transport of materials to tower positions, erection and commissioning

Construction (Substations/compensation equipment) - excludes GIS building cost, take local advice

Note in particular that the material and engineering costs estimate is based on a percentage of total installed costs with the Terrain factor taken out. The balance of costs is allocated to the construction-related element, reflecting the higher costs of survey, transport of materials and construction in difficult territories. The materials costs are however affected by Country factors, reflecting the benefits of local procurement.

4.4.2 Substation and Compensation details and costs

The AC substation and Compensation cost estimates are presented alongside the overhead line data. The first portion of the display is a technical summary as follows:

SUBSTATION AND COMPENSATION EQUIPMENT

	Near end	Far end
No. of Circuit Breakers (Lines)	1	1
No. of Circuit Breakers (Substations)	6	0
Circuit breaker type	Open	Open
Circuit breaker Rated Voltage (Um)	420	
Shunt compensation (Mvar/cct.)	114	114
Series Compensation (nom. Mvar/cct.)	114	

The first row of data shows the number of circuit breakers at each end of the line, which will be one near end, one far end unless two lines are costed for security, in which case there will be two at each end. The next line schedules the circuit breakers allocated to a new substation, if specified. In this case a new near-end substation is required.

The next two lines confirm the type and rated voltage of the circuit breakers.

In this case, shunt and series compensation is required, and the requirements are listed in the final two lines. Shunt compensation is required at each end. The notional Mvar figure for series compensation is simply based on the required reactance value and load current, the actual Mvar rating of the series capacitors would be higher to allow for overloads and faults. This is taken into account in the higher costing allowed for series compensation. In this particular example, the fact that the notional Mvar for both series and shunt compensation is the same is coincidental.

The summary cost table shown below is derived simply from the quantity, voltage rating and price of circuit breakers (open-terminal or GIS as nominated) and shunt and series Mvar as per the data stored in the COMMON worksheet. The "substation" figure is for all the circuit breakers, shunt and series compensation is in the "Compensation" figure, although in practice the shunt reactors would be installed in the substation also.

SUMMARY COSTS	**$million**
Substation Installed Cost	11.4
Compensation Installed Cost	6.1
Add Inflation	1.7
Total cost	**19.2**

BREAKDOWN	**$million**	**Based on**	**Of (cost basis)**
Materials FOB	14.43	75.0%	
Insurance & Freight (CIF)	1.44	7.5%	Percentages are all
Site acquisition	0.48	2.5%	against Total Cost,
Local Transport	0.29	1.5%	hence all should add
Construction	1.64	8.5%	to 100%
Engineering/Project Management	0.96	5.0%	
(Total)	**19.24**		
		(100%)	

In contrast to the cost breakdown for overhead lines, substation costs are not adjusted by country or terrain factors. Particularly at the higher voltage levels, switchgear, reactors etc. are likely to be procured internationally and erected with a high proportion of skilled labour brought in by the Contractor. The FOB+CIF cost element of the total installed cost is likely to be much greater than for overhead lines.

4.4.3 Operating and Maintenance Costs

Estimated Operating and Maintenance (O&M) Costs are shown under the capital costs element in a small table as follows:

OPERATING & MAINTENANCE COSTS	
	$million p.a.
Estimated O&M cost for line	1.224
Estimated O&M cost for cable	N/A
Est. O&M cost for convertors	N/A
Est. O&M cost for substations	0.048
Total	**1.272**

The individual components of this table are derived by multiplying the total installed costs of lines, cables etc. by the factors "Op_cost_OHL", "Op_cost_cable" etc. stored in the COMMON worksheet.

Refer to Appendix B for a description of the remainder of this worksheet under "Calculations Section".

4.5 Cost Breakdowns – DC Overhead lines

4.5.1 Overhead line details and costs

To obtain further details on costs, select the appropriate worksheet, in this case DC_OHL, and place the cursor in the top left if not already there. The program displays the requested load and distance, and below that the following details appear:

OVERHEAD LINE DETAILS AND COSTS

(line capacity 679 MW at 1.0 p.f. over 450 km)

Description	1 cct, ± 350 kV, 2*400 sq.mm.
Nominal Voltage kV	350
Peak Load Losses	0.0667265 p.u.

This displays the minimum line size calculated to meet the specified load, and its estimated capacity over the specified distance (calculated by interpolation of the given data at predetermined distances. This information is followed by a table showing a cost breakdown based on percentages which can be amended by the user (indicated by cells shaded light blue).

SUMMARY COSTS	**$million**	
Installed Cost over 450 km	63.6	
Add Inflation	6.4	(10%)
Add Country Factor	-7.0	(Middle East, -10%)
Add Terrain Factor	6.3	(Stony desert, 10%)
Cost of second circuit	0.0	
Total cost	**69.3**	

BREAKDOWN	**$million**	**Based on**
Materials FOB	37.77	60.0%
Insurance & Freight (CIF)	3.78	6.0%
Engineering/Project Management	1.89	3.0%
Sub-total	**43.44**	
Survey/ROW acquisition	2.50	3.0%
Local Transport	2.50	3.0%
Construction	20.82	25.0%
(Total)	**69.25**	
		(100%)

Percentages are all against Total Cost, hence all should add to 100%. Costs are adjusted by Terrain Factor to allocate the appropriate amount to Local costs

General Notes

FOB (Free on Board) - Assumes International procurement

Survey/ROW (Right of Way) and site acquisition costs can vary enormously, take local advice

Local Transport - Gets materials to line material storage areas/substation sites only

Construction (Lines) - includes transport of materials to tower positions, erection and commissioning

Construction (Substations/compensation equipment) - excludes GIS building cost, take local advice

Note in particular, as for AC overhead lines, that the material and engineering costs estimate is based on a percentage of total installed costs with the Terrain factor taken out. The balance of costs is allocated to the construction-related element, reflecting the higher costs of survey, transport of materials and construction in difficult territories. The materials costs is however affected by Country factors, reflecting the benefits of local procurement.

4.5.2 Substation and Compensation details and costs

The AC substation estimates are presented alongside the overhead line data. The first portion of the display is a technical summary as follows:

SUBSTATION AND COMPENSATION EQUIPMENT	Near end	Far end
No. of Circuit Breakers (Lines)	2	2
No. of Circuit Breakers (Substations)	6	0
Circuit breaker type	Open	Open
Circuit breaker Rated Voltage (Um)	245	

The first row of data shows the number of AC circuit breakers serving the convertor stations at each end of the line, which will be two near end, two far end unless two lines are costed for security, in which case there will be four at each end. The next line schedules the circuit breakers allocated to a new substation, if specified. In this case a new near-end substation is required.

The next two lines confirm the type and rated voltage of the circuit breakers. In the case of DC lines/cables, the appropriate AC voltage is simply based on a look-up table based on the interconnector MW rating.

The summary cost table shown below is derived simply from the quantity, voltage rating and price of circuit breakers (open-terminal or GIS as nominated) and convertor equipment as per the data stored in the COMMON worksheet. The "substation" figure is for all the AC circuit breakers, the Convertors price includes associated AC and DC filters, and DC terminal equipment, as well as the convertors themselves at each end of the line.

SUMMARY COSTS	**$million**
AC Substation Installed Cost	8.3
Add Inflation	0.8
Substations Total cost	**9.2**
Convertors Installed Cost	88.5
Add Inflation	8.9
Convertors Total cost	**97.4**
Grand Total	**106.5**

BREAKDOWN	**$million**	**Based on**	**Of (cost basis)**
Materials FOB	79.88	75.0%	
Insurance & Freight (CIF)	7.99	7.5%	Percentages are all
Site acquisition	2.66	2.5%	against Total Cost,
Local Transport	1.60	1.5%	hence all should add
Construction	9.05	8.5%	to 100%
Engineering/Project Management	5.33	5.0%	
(Total)	**106.51**		
		(100%)	

In contrast to the cost breakdown for overhead lines, substation and convertor costs are not adjusted by country or terrain factors. Particularly at the higher voltage levels, this specialist equipment is likely to be procured internationally and erected with a high proportion of skilled labour brought in by the Contractor. The FOB+CIF cost element of the total installed cost is likely to be much greater than for overhead lines.

4.5.3 Operating and Maintenance Costs

Estimated Operating and Maintenance (O&M) Costs are shown under the capital costs element in a small table as follows:

OPERATING & MAINTENANCE COSTS	
	$million p.a.
Estimated O&M cost for line	0.693
Estimated O&M cost for cable	N/A
Est. O&M cost for convertors	0.974
Est. O&M cost for substations	0.023
Total	**1.689**

The individual components of this table are derived by multiplying the total installed costs of lines, cables etc. by the factors “Op_cost_OHL”, “Op_cost_cable” etc. stored in the COMMON worksheet.

Refer to Appendix B for a description of the remainder of this worksheet under “Calculations Section”.

4.6 Cost Breakdowns – DC Subsea Cables

4.6.1 Cable details and costs

To obtain further details on costs, select the appropriate worksheet, in this case DC_CABLE, and place the cursor in the top left if not already there. The program displays the requested load and distance, and below that the following details appear:

SUBSEA CABLE DETAILS AND COSTS

(Circuit capacity 638 MW at 1.0 p.f. over 450 km)

Description	1 cct, ± 200 kV, 1*1600 sq.mm.
Nominal Voltage kV	200
Peak Load Losses	0.06185 p.u.

This displays the minimum line size calculated to meet the specified load, and its estimated capacity over the specified distance (calculated by interpolation of the given data at predetermined distances. This information is followed by a table showing a cost breakdown based on percentages which can be amended by the user (indicated by cells shaded light blue).

SUMMARY COSTS	**$million**
Installed Cost over 450 km	381.3
Add Inflation	38.1
Add Country Factor	N/A
Add Terrain Factor	N/A
Cost of second circuit	0.0
Total cost	**419.4**

BREAKDOWN	**$million**	**Based on**	**Of (cost basis)**
Materials FOB	239.06	57%	
Initial Survey	12.58	3%	
Installation (including burial of shallow portion and protection of deep portion	155.18	37%	Percentages are all against Total Cost, hence all should add to 100%
Engineering/Project Management	12.58	3%	
(Total)	**419.41**	(100%)	

General Notes

FOB (Free on Board) - Assumes International procurement
Survey costs can vary enormously, take local advice
Local Transport - Gets materials to line material storage areas/substation sites only
Construction (Substations/compensation equipment) - excludes GIS building cost, take local advice

No adjustment is made to subsea cabling or convertor costs by Country or Terrain factors, since it is presumed that the great majority of the costs are independent of location, and the Terrain factor is of course inapplicable.

4.6.2 Substation and Compensation details and costs

The AC substation estimates are presented alongside the cable data. The first portion of the display is a technical summary as follows:

SUBSTATION AND COMPENSATION EQUIPMENT	Near end	Far end
No. of Circuit Breakers (Lines)	2	2
No. of Circuit Breakers (Substations)	6	0
Circuit breaker type	Open	Open
Circuit breaker Rated Voltage (Um)	245	

The first row of data shows the number of AC circuit breakers serving the convertor stations at each end of the line, which will be one near end, one far end unless two lines are costed for security, in which case there will be two at each end. The next line schedules the circuit breakers allocated to a new substation, if specified. In this case a new near-end substation is required.

The next two lines confirm the type and rated voltage of the circuit breakers. In the case of DC lines/cables, the appropriate AC voltage is simply based on a look-up table based on the interconnector MW rating.

The summary cost table shown below is derived simply from the quantity, voltage rating and price of circuit breakers (open-terminal or GIS as nominated) and convertor equipment as per the data stored in the COMMON worksheet. The "substation" figure is for all the AC circuit breakers, the Convertors price includes associated AC and DC filters, and DC terminal equipment, as well as the convertors themselves at each end of the cable.

SUMMARY COSTS	**$million**
AC Substation Installed Cost	8.3
Add Inflation	0.8
Substations Total cost	**9.2**
Convertors Installed Cost	88.5
Add Inflation	8.9
Convertors Total cost	**97.4**
Grand Total	**106.5**

BREAKDOWN	**$million**	**Based on**	**Of (cost basis)**
Materials FOB	79.88	75.0%	
Insurance & Freight (CIF)	7.99	7.5%	Percentages are all
Site acquisition	2.66	2.5%	against Total Cost,
Local Transport	1.60	1.5%	hence all should add
Construction	9.05	8.5%	to 100%
Engineering/Project Management	5.33	5.0%	
(Total)	**106.51**		
		(100%)	

In contrast to the cost breakdown for overhead lines, substation and convertor costs are not adjusted by country or terrain factors. Particularly at the higher voltage levels, this specialist equipment is likely to be procured internationally and erected with a high proportion of skilled labour brought in by the Contractor. The FOB+CIF cost element of the total installed cost is likely to be much greater than for overhead lines.

4.6.3 Operating and Maintenance Costs

Estimated Operating and Maintenance (O&M) Costs are shown under the capital costs element in a small table as follows:

OPERATING & MAINTENANCE COSTS	
	$million p.a.
Estimated O&M cost for line	N/A
Estimated O&M cost for cable	2.097
Est. O&M cost for convertors	0.974
Est. O&M cost for substations	0.023
Total	**3.093**

The individual components of this table are derived by multiplying the total installed costs of lines, cables etc. by the factors "Op_cost_OHL", "Op_cost_cable" etc. stored in the COMMON worksheet.

Refer to Appendix B for a description of the remainder of this worksheet under "Calculations Section".

4.7 Cost Breakdowns – AC Subsea Cables

4.7.1 Cable details and costs

To obtain further details on costs, select the appropriate worksheet, in this case AC_CABLE, and place the cursor in the top left if not already there. The program displays the requested load and distance, and below that the following details appear:

CABLE DETAILS AND COSTS

(line capacity 115 MW at 1.0 p.f. over 50 km)

Description	90 kV, 1*1000 sq.mm.
Nominal Voltage kV	90
Peak Load Losses	0.0166667 p.u.

This displays the minimum cable size and voltage calculated to meet the specified load, and its estimated capacity over the specified distance (calculated by interpolation of the given data at predetermined distances. This information is followed by a table showing a cost breakdown based on percentages which can be amended by the user (indicated by cells shaded light blue).

SUMMARY COSTS	**$million**
Installed Cost over 50 km	47.7
Add Inflation	2.4
Add Country Factor	N/A
Add Terrain Factor	N/A
Cost of second circuit	0.0
Total cost	**50.1**

BREAKDOWN	**$million**	**Based on**	**Of (cost basis)**
Materials FOB	28.55	57%	
Initial Survey	1.50	3%	
Installation (including burial of shallow portion and protection of deep portion	18.53	37%	Percentages are all against Total Cost, hence all should add to 100%
Engineering/Project Management	1.50	3%	
(Total)	**50.09**	(100%)	

General Notes

FOB (Free on Board) - Assumes International procurement

Survey costs can vary enormously, take local advice

Local Transport - Gets materials to line material storage areas/substation sites only

Construction (Substations/compensation equipment) - excludes GIS building cost, take local advice

4.7.2 Substation and Compensation details and costs

The AC substation and Compensation cost estimates are presented alongside the cable data. The first portion of the display is a technical summary as follows:

SUBSTATION AND COMPENSATION EQUIPMENT

	Near end	Far end
No. of Circuit Breakers (Lines)	1	1
No. of Circuit Breakers (Substations)	6	0
Circuit breaker type	Open	Open
Circuit breaker Rated Voltage (Um)	123	
Shunt compensation (Mvar/cct.)	21	21

The first row of data shows the number of circuit breakers at each end of the line, which will be one near end, one far end unless two lines are costed for security, in which case there will be two at each end. The next line schedules the circuit breakers allocated to a new substation, if specified. In this case a new near-end substation is required.

The next two lines confirm the type and rated voltage of the circuit breakers. Note although the cable is selected as 90 kV, the next highest standard voltage rating is selected.

In this case, shunt compensation is required, and the requirements are listed in the final line. Shunt compensation is required at each end.

The summary cost table shown below is derived simply from the quantity, voltage rating and price of circuit breakers (open-terminal or GIS as nominated) and shunt Mvar as per the data stored in the COMMON worksheet. The "substation" figure is for all the circuit breakers, shunt compensation is in the "Compensation" figure, although in practice the shunt reactors would be installed in the substation also.

SUMMARY COSTS	**$million**
Substation Installed Cost	3.3
Compensation Installed Cost	0.6
Add Inflation	0.2
Total cost	**4.2**

BREAKDOWN	**$million**	**Based on**	**Of (cost basis)**
Materials FOB	3.13	75.0%	
Insurance & Freight (CIF)	0.31	7.5%	Percentages are all against Total Cost, hence all should add to 100%
Site acquisition	0.10	2.5%	
Local Transport	0.06	1.5%	
Construction	0.35	8.5%	
Engineering/Project Management	0.21	5.0%	
(Total)	**4.17**		
		(100%)	

In contrast to the cost breakdown for overhead lines, substation costs are not adjusted by country or terrain factors. Particularly at the higher voltage levels, switchgear, reactors etc. are likely to be procured internationally and erected with a high proportion of skilled labour brought in by the Contractor. The FOB+CIF cost element of the total installed cost is likely to be much greater than for overhead lines.

4.7.3 Operating and Maintenance Costs

Estimated Operating and Maintenance (O&M) Costs are shown under the capital costs element in a small table as follows:

OPERATING & MAINTENANCE COSTS	
	$million p.a.
Estimated O&M cost for line	N/A
Estimated O&M cost for cable	0.250
Est. O&M cost for convertors	N/A
Est. O&M cost for substations	0.010
Total	**0.261**

The individual components of this table are derived by multiplying the total installed costs of lines, cables etc. by the factors "Op_cost_OHL", "Op_cost_cable" etc. stored in the COMMON worksheet.

Refer to Appendix B for a description of the remainder of this worksheet under "Calculations Section".

5 Construction, Operation and Maintenance

In this section a number of issues raised by long-distance power transmission will be explored, including their cost impacts.

Each long distance power transmission project, whether overland by AC or DC or by subsea cable, is to some extent unique since there will be local factors which will influence the project feasibility and the costs of construction and operation quite heavily. An attempt has been made within the spreadsheet to address these factors as they affect capital costs by identifying "order-of-magnitude" factors which should be applied to a particular country or region, and a typical topography, but it would be unfair to assign any great accuracy to these factors. With operational and construction issues an even greater variability will be found. For this reason, most of this section deals with these issues in a qualitative rather than a quantitative way, and any suggested costs are at best indicative.

5.1 Modifications to Existing Grids

Existing power Grids will comprise a number of power transmission circuits at high voltage (generally at 220 kV nominal or above) which are usually run fully interconnected and their primary function is to connect generation and load over the whole country.

Connecting new generation (or load) into an existing Grid will be at such a voltage level and geographical location that can handle the maximum power flow of the new connection without overloading, loss of security or unacceptable technical disturbances (voltage deviations and excessive fault levels being the usual problems.). Because of the complex nature of power flows in interconnected networks it will usually be necessary to undertake a series of "loadflow", "short circuit" and "stability" studies using specialist power systems analysis software. However it is possible to generalise, based on typical power system characteristics, the minimum voltage levels which should be considered to accept a given MW load. This approach is used in the spreadsheet to decide the minimum voltage level at which DC Interconnectors are connected, and the relevant table is reproduced below for guidance:

Load range (MW)	Um (kV)	Nominal voltage range (kV)
0-59	36	30-34.5
60-119	72.5	60-69
120-149	123	90-115
150-199	145	120-138
200-399	170	150
400-799	245	220-230
800-1499	300	275
1500-1999	363	330-345
2000-2999	420	380-400
3000-3999	525	500
4000 and up	765	750

In most countries, only a sub-set of these voltages is available. Introducing a new voltage level has many implications and is potentially very costly, so should only be considered as a last resort. (Subsea AC cabling may be an exception to this rule).

A major practical problem arises when the nearest point on the network at the appropriate voltage level is geographically remote, or may itself be relatively weak. In this case the Utility may seek to reinforce their own network to carry the intended load, at the cost of the Project. A similar situation can arise where existing circuits are already heavily loaded and the new connection adds to those loads, necessitating reinforcement.

Occasionally a new generation connection (sometimes a new load connection) will subtract from existing load flows and relieve existing circuits. In such cases the Utility benefits and may be prepared to support some of the costs of connecting the new circuit at its own expense.

Provision is included within the spreadsheet to allow for the cost of a new substation at either or both ends of the proposed transmission circuit. A new substation (the alternative is simply to extend an existing substation) will be required typically in the following circumstances:

- HV/EHV lines pass close to the intended terminal point of the new transmission circuit, but there is no existing substation within a considerable distance.
- The Utility wishes to establish a new substation which can fulfil a dual role as a suitable terminal point for the new transmission circuit and as a means of connecting to or reinforcing its existing lower voltage network and loads.
- A new power generating facility is being constructed at the end of the transmission circuit. Terminal points for power plants are often selected as being at the HV bushings of generator step-up transformers, and the substation is considered as an obligation for the Transmission side of the utility to be responsible for. (This is not always the case, but it is typical of IPP (Independent Power Producer) projects.)

As can be seen from the above summary of issues, the impact of connecting into an existing grid is complex and will usually entail detailed technical and commercial negotiations.

5.2 Survey, Consents and Wayleaves

5.2.1 Survey Requirements and Costs

A new overhead transmission circuit will require a survey of the possible route or routes prior to submitting applications for consents or entering negotiations on wayleaves. This initial survey can be based on maps, aerial photography, helicopter flights along the intended routes and a limited amount of work on the ground with four-wheel drive vehicles. The objective of the initial survey is to obtain a ground profile, preliminary tower spotting, existing land use and the crossing details of roads, railways, other power and communication circuits etc. It will also be necessary to identify vegetation and buildings within the right-of way (ROW), a strip of land under the proposed line route of width 50 to 100 m.

For any proposed sub-sea cable route a marine survey is required which has similar objectives to the land survey listed above. This survey, which will probably entail the use of specialist scanning equipment and possibly an ROV (remotely operated vehicle) will of course be significantly more expensive then the equivalent land survey. If the cable is to be buried (this is usually recommended in shallow waters), core sampling will be required in addition to bottom samples.

A value of 3% of the project value is suggested for marine survey costs. Actual costs will include a fixed element for mobilisation of the survey vessel, crew and equipment, and a variable cost depending on the length and difficulty of the route, so the answer given by a fixed percentage of installed cost may underestimate survey costs for a short route and overestimate them for a long route. The important point is that survey costs are quite significant, but a thorough survey may easily be repaid by savings in reduced delays and faster progress when the cable is installed.

5.2.2 Planning Consents and Wayleaves

The procedure for application for Consents will vary according to the country, but minimum requirements are likely to be the survey, an environmental impact assessment and details of the conductors and towers sufficient to ascertain the visual impact. Potential subsea cable routes, at least over continental shelf routes, will probably require application to the relevant governments or government bodies, taking into account the interests of international maritime and fishing organisations, military (Naval) bodies and oil and gas companies involved in offshore exploration and production.

Wayleaves are required to obtain land-owners permission to construct towers or poles and to erect conductors over the land. Financial arrangements, are based typically on long leases including means to compensate for loss of use of the land for agriculture and procedures to allow for access for maintenance and repairs.

Overhead lines are ideally erected in straight lines, since this permits maximum use of suspension towers or their equivalent for pole lines. Suspension towers are far cheaper than the tension towers required whenever the line changes direction by more than a fractional amount (maybe 3°, depending on the design of the structures). This introduces considerable constraints on the choice of route and severely limits the flexibility of land agents or equivalents to negotiate wayleaves. In general, towers or poles can be moved along the route of the line, perhaps by ±50m from the ideal position, without undue expense, but lateral movement of support positions is comparatively very expensive.

The legislative framework for “compulsory purchase” or enforcing fair compensation terms varies widely between countries, and in countries with less developed legal systems obtaining wayleaves can be protracted and expensive, with payments bearing no relationship to the actual costs incurred by the land owners. As a counter to this situation, which can verge on blackmail in some instances, a pro-active approach with political support at all levels from central and regional government down to mayor/village headman level can be fruitful, with community benefits such as a new or improved road, support to local medical or educational institutions, improving water supplies etc paid for by the developer.

The spreadsheet proposes that the costs of undertaking surveys and obtaining the necessary wayleaves for the ROW at 3% of the total cost of an overhead line. Clearly this may underestimate the costs of a long planning enquiry, such as might be necessary in the UK, and overestimate the costs in a country with the line routed over largely uninhabited territory. This estimate is intended as provision for the direct costs incurred in negotiating the appropriate consents and wayleaves only. The way the Terrain Factor is applied in the costs table (it is used solely to adjust local costs) compensates to some extent for this.

5.3 Construction

5.3.1 Overhead Lines

Overhead lines can be carried on various types of supports, and a particular circuit may employ more than one of construction methods outlined in the following table:

Type of Support	Description	Application
Pole	Poles may be of wood, steel or concrete Single poles or pair of poles may be used at each support	Generally up to 220 kV, though it is possible to use at up to 400 kV. Economic up to 132 kV with small conductors, but more expensive than lattice steel towers at higher voltages or with larger conductors. Usually single circuit, but it is possible to construct double-circuit. Relatively short spans and small "footprint", may be an advantage if routing difficulties experienced. Generally held to be the most visually acceptable type.
Lattice steel tower	The traditional electricity "pylon", assembled on site by bolting together pre-cut and drilled angle-iron members Placed on a buried or piled concrete foundation, in most cases individual foundation blocks for each leg suffice.	The most common form of construction from 132 kV and up. Site assembly eases transportation problems. Spans typically in the order of 300 m, though can be far longer in mountainous regions. Can be single or double circuit construction up to 500 kV, but the towers at these highest voltage are quite massive and visually obtrusive

Type of Support	Description	Application
Guyed Structures	Support comprises light girders fabricated from lattice steel, typically on a single foundation with guys each side to resist overturning moments.	Can be a cheaper and quicker alternative to single-circuit lattice steel towers, particularly on long straight runs over level or lightly undulating ground. Integrity of construction requires secure ground anchors for guys which may cause problems in poor ground conditions and arguably the line is more vulnerable to severe storms. Needs a larger right-of-way for the guys. Less visually obtrusive than lattice steel towers.

Table 5-1 Types of Overhead Line Support

Prior to construction, the Contractor will need to do a final survey to identify each tower location, its details such as height, type of foundation and type of tower, which are usually categorised as Suspension, Terminal and various types of angle tower, the greater the angle the stronger the tower.

Route clearance and cutting of vegetation is required as an initial step, and depending an ease of access for construction and subsequent maintenance, rough roads may need to be built.

Typically, two or more construction teams will be working simultaneously, in order to meet the construction program. In some territories, e.g. those subjected to monsoons perhaps with seasonal flooding, there may be a relatively short “window” for the majority of the construction period. In any case, save for the longest lines, the construction period will typically be in the order of 12 months.

5.3.2 Subsea Cables

Subsea cables are manufactured in factories with access for cable ships, and the cables are manufactured in long lengths and loaded directly onto the ships. The length of cable which can be loaded depends on its dimensions and weight, but a large cable ship can carry many thousands of tons of cable, sufficient for distances of hundreds of km of single-core cable.

If the cable is to be buried, a plough may be employed, or the cable jetted into the sea bed. Where the bottom is rocky, external protection will be laid over the cable. In general, experience with the reliability of buried cables is good, but cables laid on the surface of the sea-bed are often damaged by fishing or ships anchors, even in relatively deep waters.

The manufacture of a long subsea cable may take a considerable time, longer than the time to lay it. The laying time may be constrained by the need for good weather and sea conditions, and the availability of suitable ships (there are only a few in the world), but a time for installation measured in weeks or months would be the aim.

5.4 Maintenance and Operational Issues and Estimated Costs

Maintenance and operational (O&M) issues are grouped under four headings, lines, cables, convertor stations and substations, since each type of installation raises different issues.

5.4.1 O&M – Overhead Lines (AC or DC)

Maintenance of overhead lines includes activities such as:

- Inspection and repair of damaged conductors, insulators or fittings.
- Repair of defective coatings, e.g. paint and galvanising on support structures.
- (Wood poles only) Treatment of timber and replacement of rotten poles
- Clearance of vegetation in the right-of-way
- Insulator cleaning (desert areas)

Inspection and location of faulty equipment is increasingly being performed by helicopter patrols. Repairs can be done without shutting down the circuit by using “live-line” working techniques, but it is prudent to allow for an outage of short duration, in the order of a day, each year.

A notional value of 1% of the installed cost of the overhead line is allowed for in the spreadsheet for annual operating and maintenance costs. (variable Op_cost_OHL in the COMMON worksheet)

5.4.2 O&M – Subsea Cables (AC or DC)

Power cables are essentially maintenance-free, but subsea cable routes should be inspected regularly to check for signs of possible external damage and loss of cover for buried cables.

If a subsea cable is punctured it will have to be cut, lifted to the surface, cut back until all signs of water penetration have disappeared and a new length jointed in. The complete cable will then be lowered back to the sea bed and re-buried if required. This is expensive (a cost in the order of perhaps $1 million) but infrequent. The estimate for O&M costs includes provision for this.

A notional value of 0.5% of the installed cost of the cable is allowed for in the spreadsheet for annual operating and maintenance costs. (variable Op_cost_cable in the COMMON worksheet)

5.4.3 O&M – Convertor Stations (DC)

A convertor station uses solid-state valves, transformers and filters, and cooling circuits. Maintenance requirements are minimal, but individual thyristors will fail periodically and need replacement.

The convertor station may be manned, for security reasons rather than for supervision of the equipment which can be done remotely. In any case, there will be a large amount of sophisticated control and supervisory equipment which will need regular testing and component replacement. The thyristor valves are intensively cooled using mineral oil or demineralised water and will also require supervision and repair to keep them in perfect condition.

A notional value of 1% of the installed cost of the convertor station is allowed for in the spreadsheet for annual operating and maintenance costs. (variable Op_cost_convertor in the COMMON worksheet)

5.4.4 O&M – Substations (AC)

Modern switchgear and protection is virtually maintenance-free, and typically may need internal inspections at long intervals only (perhaps 5 years or more, especially if fault-switching operations are rare). Outdoor switchyards will need periodic inspection, replacement of damaged insulators or fittings, and (especially in coastal areas) insulator cleaning. GIS substations will need SF_6 gas pressures to be monitored and topped up if necessary, though leakage rates should be extremely low.

Substations are usually unmanned, although in some countries manning may be provided as a security measure only. Periodic visits will be required to check the integrity of the equipment, building and fences, and auxiliaries such as batteries will need maintenance.

The substation may contain other equipment such as power transformers which will need routine maintenance to oil systems, tap-changers, fans and pumps.

A notional value of 0.25% of the installed cost of the substation is allowed for in the spreadsheet for annual operating and maintenance costs. (variable Op_cost_substation in the COMMON worksheet)

5.5 Transmission Equipment Lifetime and Decommissioning

Power transmission equipment is designed for a long life, typically 40 years. The only exception to this is transmission lines supported on wood poles, where a shorter life may assigned of perhaps 20-30 years to take account of the deterioration of the poles.

In practice, the life of transmission assets can be and is extended by refurbishment, particularly noting that the most valuable element of a substation or transmission line is the land, consents and wayleaves. Another consideration of great importance is that a modern society relies almost totally on an adequate and reliable supply of electricity, and there is often no alternative but to continue this process of refurbishment, replacement and upgrading to ensure this position is maintained.

As a result, decommissioning of a transmission circuit is a rare occurrence, but of course individual components are disposed of as they reach the ends of their lives.

The following table summarises some of the factors affecting life and eventual disposal of the principal components of transmission circuits:

Transmission Case	Component Lifetimes	Disposal Issues
Overhead lines (AC or DC)	Wood poles, life varies between 15 and 40 years depending on the type of timber, its treatment and the environment	Biodegradable, but presence of poisonous preservatives needs attention
	Steel and concrete poles – lifetime is 40 years+	Steel is recycled, concrete into landfill
	Lattice steel towers, if adequately galvanised and maintained can be expected to last 80 years	Steel can be recycled
	Conductors – lifetime typically more than 40 years, but aluminium will corrode, particularly in salty atmospheres and if a composite conductor with steel core, perhaps halving this life.	Metals can be recovered and recycled
	Insulators will gradually deteriorate through pitting and glaze damage from corona and corrosion of the metallic components, but a life of 40 years attainable in most cases.	Principal materials are porcelain, glass epoxy resin and artificial rubbers, with steel fittings. Generally inert and disposed of by burial
Power cables (AC or DC)	Power cables are designed for a notional life of 40 years, but will last much longer if operated well below design temperatures. Principal failure mechanisms are lead embrittlement and cracking and aluminium corrosion. XLPE insulated cables will fail eventually from water-tree growth, but this mechanism is far better controlled than in the early days of XLPE use.	At the end of the life of a power cable, it is an economic decision as to whether it is abandoned in the ground (or under the sea) or recovered. In the latter case, most EHV cables use copper conductors which are recycled, as is the lead sheath. Other metals, principally steel in armouring and the alternative aluminium conductors may also be recycled if it is economic to do so. It is possible that future environmental legislation may enforce the recovery of cables.

Transmission Case	Component Lifetimes	Disposal Issues
Substation equipment including convertors	Switchgear – Notional life 40 years, older designs may suffer deterioration in solid insulation systems. Switchgear is often replaced for other reasons, such as needing to increase fault ratings or to reduce the maintenance requirements by substituting more modern designs	Copper content is recovered, oil in older designs is recycled, other materials disposed of in the most economic fashion.
	Convertors – Major components apart from valves will have a notional 40 year life. Valves will have periodic thyristor failures, and when reliability deteriorates to an unacceptable level, the whole valve or valves will be replaced. Because of continuing technical improvements in semi-conductor technology it is difficult to assess valve life, but 20-25 years is a prudent estimate.	The quantities of valuable metals probably too low for economic recovery
	Transformers and Reactors – Life around 20-25 years when operated at full load at all times, for longer life either design for a less onerous loading regime or reduce permitted temperature rises	Most of the materials in transformers and reactors can economically be recovered and recycled
	Series Capacitors – Life should be around 40 years	The quantities of valuable metals probably too low for economic recovery.

Appendix A Terms of Reference

(IEA Greenhouse Gas R&D Programme Technical Specification IEA/CON/01/65 is reproduced below:)

ELECTRICITY TRANSMISSION

1 INTRODUCTION

The IEA Greenhouse Gas R&D Programme (IEA GHG) was established in 1991 to evaluate technologies that can be used to abate greenhouse gas emissions from the use of fossil fuels and identify targets for useful R&D. It is an international organisation, supported by sixteen countries world-wide, the European Commission and several industrial organisations[1]. IEA GHG has carried out studies on a wide range of techniques for reducing emissions of greenhouse gases, including capturing and storing CO_2 from fossil fuels, renewable energy sources such as wind and biomass and various techniques for reducing emissions of non-CO_2 greenhouse gases.

The need to avoid emissions of greenhouse gases has implications for energy transmission. For example, electricity from renewable energy may have to be transmitted long distances from where the energy resource (e.g. wind and solar energy) is plentiful to where the energy is consumed. Similarly, fossil fuel energy may be converted to energy carriers, such as hydrogen or electricity, close to places where the resulting CO_2 can be stored underground or in the deep ocean.

The aim of this task is to provide cost and performance data for electricity transmission. Separate studies will be carried out to provide data on other energy and CO_2 transmission techniques and to produce computer software to enable a variety of energy supply and transmission options to be compared. The software will be suitable for use by energy planners and researchers in IEA GHG's member countries.

2 SCOPE OF WORK

Costs and energy loss data for new electricity transmission systems will be provided. Particular emphasis will be given to large onshore high voltage DC and AC (400 kV+) transmission lines. Data will also be provided for underground and offshore transmission lines.

The cost data will consist of the following:

- Capital cost
- Cost of wayleaves
- Annual maintenance and other operating costs
- Typical construction time
- Equipment lifetime

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[1] The members of IEA GHG are currently Australia, Belgium, Canada, Denmark, Finland, Japan, Korea, The Netherlands, New Zealand, Norway, Poland, Sweden, Switzerland, UK, USA, Venezuela, The European Commission, BP, EPRI, Exxon-Mobil, EniTecnologie, RWE and Shell.

- Decommissioning costs

The energy loss data will consist of the following:

- Transmission line energy losses
- Transformer, inverter and other energy losses

The sensitivities of costs and energy losses to the following factors will be provided:

- Type (AC or DC)
- Length of transmission line
- Capacity
- Voltage
- Topography

The cost and performance data will be provided in graphical form. It will also be provided in a mathematical form, such as equations, look-up tables or other method suitable for simple incorporation into a computer programme for analysis of energy transmission options. The most convenient format for providing the data would be as an Excel spreadsheet.

Costs will be presented in US$ for typical transmission systems installed in the USA or Europe. Factors will be provided to enable capital and operating costs to be derived for other parts of the world, i.e. other developed countries, including Japan and Australia, and less developed countries including China and India.

Modifications that would typically need to be made to existing grids if a large proportion of the electricity input was provided via long distance transmission lines will be described and typical costs of these modifications will be provided.

Limitations on siting large transmission lines and timescales for obtaining permits will be discussed in general.

A report containing the results of the task will be prepared.

3 DELIVERABLES

The deliverables are the following reports:

- A draft final report
- The final report, taking into account IEA GHG's comments
- The cost and performance data in electronic form

An unbound copy of the draft report will be produced by the date specified in the Instructions to Tenderers. The IEA Greenhouse Gas R&D Programme will provide comments on the draft report within a month. The contractor will then make the necessary changes and deliver the final report within one month of receiving the comments.

Two copies of the final report will be supplied on paper (one unbound), together with an electronic copy in Microsoft Word format on a PC 3.5" diskette, Iomega 100 Megabyte ZIP disk or PC CD-ROM. All diagrams, pictures and illustrations must also be supplied as TIFF or CGM files, unless they have been created in Corel Draw, PowerPoint or Excel, in which case copies in the original format are acceptable. Photocopies of photographs and illustrations are not acceptable. The cost and performance data will be provided electronically in a format compatible with Microsoft Excel.

The final report (and any material supplied with it, and including this specification) are the property of the IEA Greenhouse Gas R&D Programme and its contents must not be reported or published in any form, written or electronic, without the permission of the IEA Greenhouse Gas R&D Programme. The IEA Greenhouse Gas R&D Programme will copy and distribute the final report to its members.

4 PROGRESS REVIEWS

Allowance should be made for up to two meetings, if required, at the offices of the contractor:

- .A project launch meeting.
- .An interim progress meeting or a meeting to review the final report.

IEA GHG will be responsible for the costs of its representative attending the meetings. These meetings may not be necessary given good progress and agreement of the various issues by fax, e-mail or other means.

5 FORM OF PROPOSAL

A fixed cost in UK Pounds will be quoted for completion of the task as described in this specification. A schedule of daily rates will also be given (holding for six months after completion of the task) which would be used in the event of identifying useful supplementary activities.

The proposal will set out the names and relevant experience of the persons involved, nominating a project manager responsible for the timely and competent completion of the work. Sources of cost information on transmission systems that will be used by the contractor will be specified.

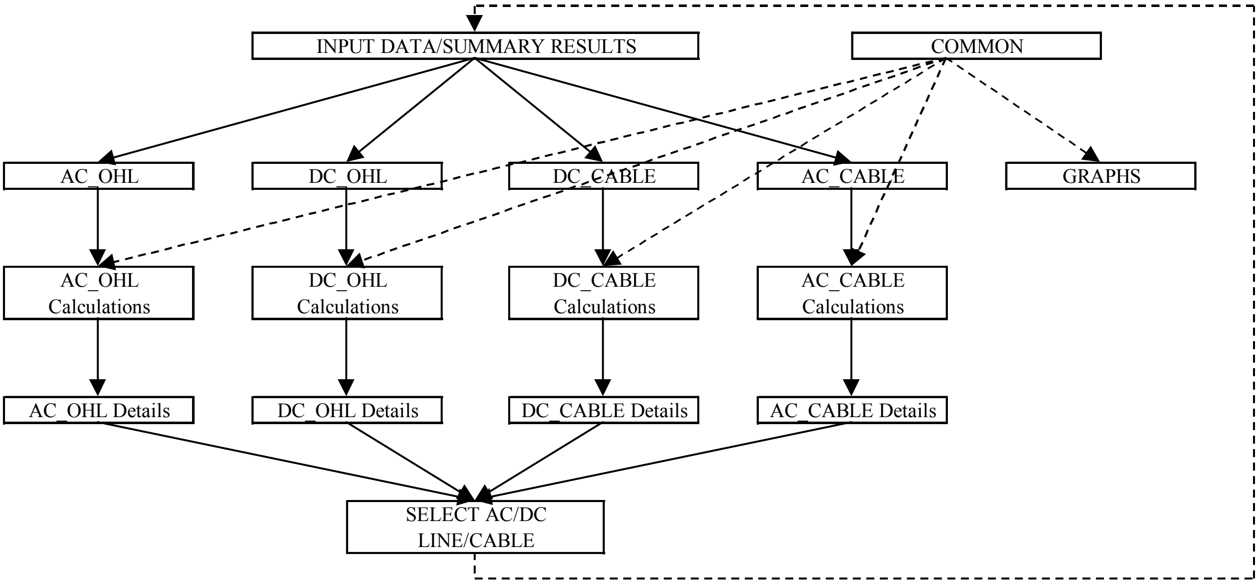
A preliminary workplan based on the scope of work and the deliverables will be included. The date for delivery of the draft report is given in the attached covering letter.

Appendix B Spreadsheet Structure and Algorithms

B.1 Spreadsheet Structure

The costing spreadsheet is structured as shown in outline in the following diagram:

COSTING SPREADSHEET STRUCTURE



Data and option selections are made by the user in the worksheet “INPUT”, which is shown above as the box “INPUT DATA/SUMMARY RESULTS”. This data is then made available to each of the four sheets, “AC_OHL”, “DC_OHL”, “DC_CABLE” and “AC_CABLE”, which have two main sections each “Calculations” and “Details”.

The Calculations section takes input data (primarily the circuit load and length, supported by selections on voltage/frequency, country and terrain and substation quantities and types) and common data from worksheet “COMMON”. A choice of a suitable circuit is made, and this information is displayed in the Details section, together with the costs of the circuit and associated substation, convertor and compensation equipment as appropriate.

The total cost estimates are presented in the INPUT screen in “Summary Results” according to the choice of AC or DC, overhead line or cable.

The GRAPHS worksheet takes information from COMMON (also from the data held in AC_OHL) primarily for the purposes of preparing presentations. It plays no part in the calculations.

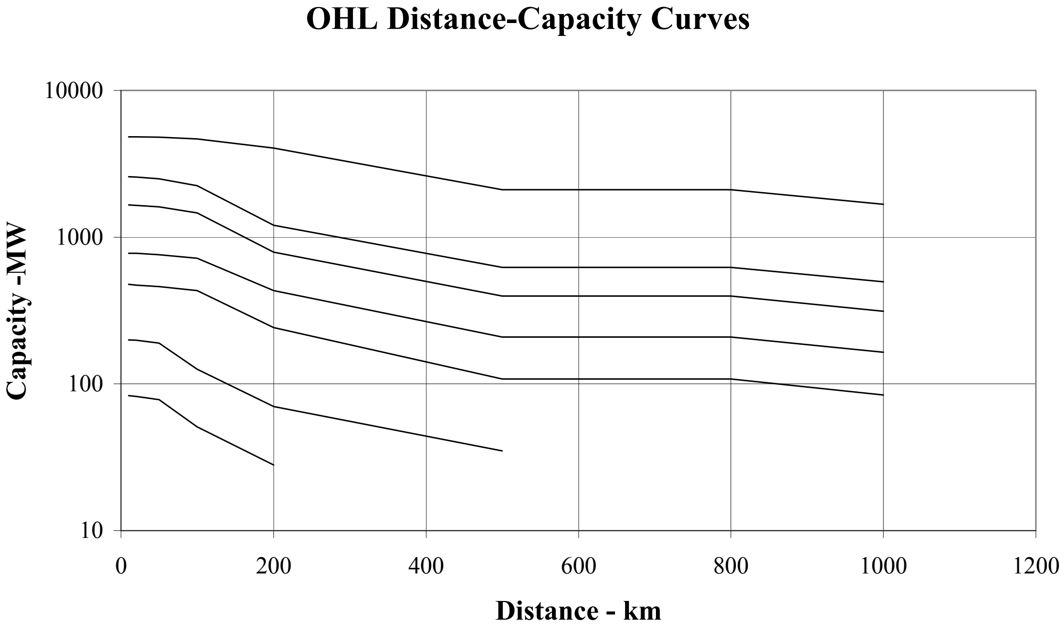
Cells and ranges referenced from one worksheet within another are (in most cases) named, for easier understanding of the cell formulae. To assist in understanding the algorithms, named ranges are boxed and named in a text box (red-coloured titles).

The graphs are based on the Spreadsheet data at the time of drafting this Appendix, and may have changed subsequently. Always refer to the spreadsheet model for the current values of prices.

B.2 Transmission Circuit Selection

The key to understanding the operation of the spreadsheet is the basic principle that the capacity-distance characteristic of a number of circuits is stored within each of the four sheets, "AC_OHL", "DC_OHL", "DC_CABLE" and "AC_CABLE". In the case of AC overhead lines, data is stored for 50 Hz and 60 Hz lines separately.

Typically, the longer a circuit, the less its capacity, or in the case of DC the losses become excessive which has the same effect. If the data for a number of overhead lines is plotted, the typical characteristics are as shown below:



In this example, a selection of AC overhead lines is plotted, ranging from 110 kV to 750 kV, with the range of the first two limited to 200 km and 500 km respectively, the remainder at 220 kV and up being capable of transmitting power at up to 1000 km with the assistance of series and shunt compensation. The curves for DC lines and cables are similar, but can extend to longer distances, for AC cables the range is limited to 100 km.

Details of the means of calculating these distance-capacity values are summarised in Appendix C for AC circuits and in Appendix D for DC circuits.

For the specified distance, the capacity of each line is calculated by interpolation between data points stored at predetermined intervals. This is then compared to the specified load, and the first line which has sufficient capacity to meet it is chosen by means of a HLOOKUP function.

Each line or cable has associated with it technical data describing its voltage, number of conductors, conductor cross-sectional area and conductor resistance. Its fully-installed cost per km is also stored, which is used as the basis for the cost estimates. The resistance value is used to compute its losses at the specified load level.

Principal cell and range names are:

Name	Description
Dist_Table (Distance table)	Table of distances (km) at which capacity data points are stored.
Cap_Table (Capacity table)	Table of capacities for each line/cable at each distance entry
Line_Selector_Table	List of capacities at the specified distance (calculated by interpolation between the capacities at the distances less and greater than the specified distance
Line_Base_Data	Stores voltage, conductor details and cost/km
Line_No	Calculated by a Hlookup function on the Line Selector Table
Length_No	Calculated by a Vlookup function on the Distance Table

B.3 AC Lines/cables – Shunt and Series Compensation

AC lines and cables may have shunt reactance to compensate for circuit capacitance, also the long AC lines will need series capacitance to enhance their capacity.

Tables Line_Shunt_Data and Line_Series_Data (AC_OHL only) hold the data identifying what shunt and series reactances, in Mvar, are required at varying line/cable lengths. A similar interpolation routine is used as for the capacity table to identify the compensation requirements at the specified distance, and an INDEX function selects the appropriate values in Shunt_Selector_Table or Series_Selector_Table as appropriate. Note that dummy values are inserted at 1200 km of 1.2 times the 1000 km values for shunt reactance, the same value for series capacitors, this ensures the interpolation routine produces a correct result for lines over 1000 km.

The values of series and shunt compensation, in Mvar, are presented in the table headed "SUBSTATION AND COMPENSATION EQUIPMENT".

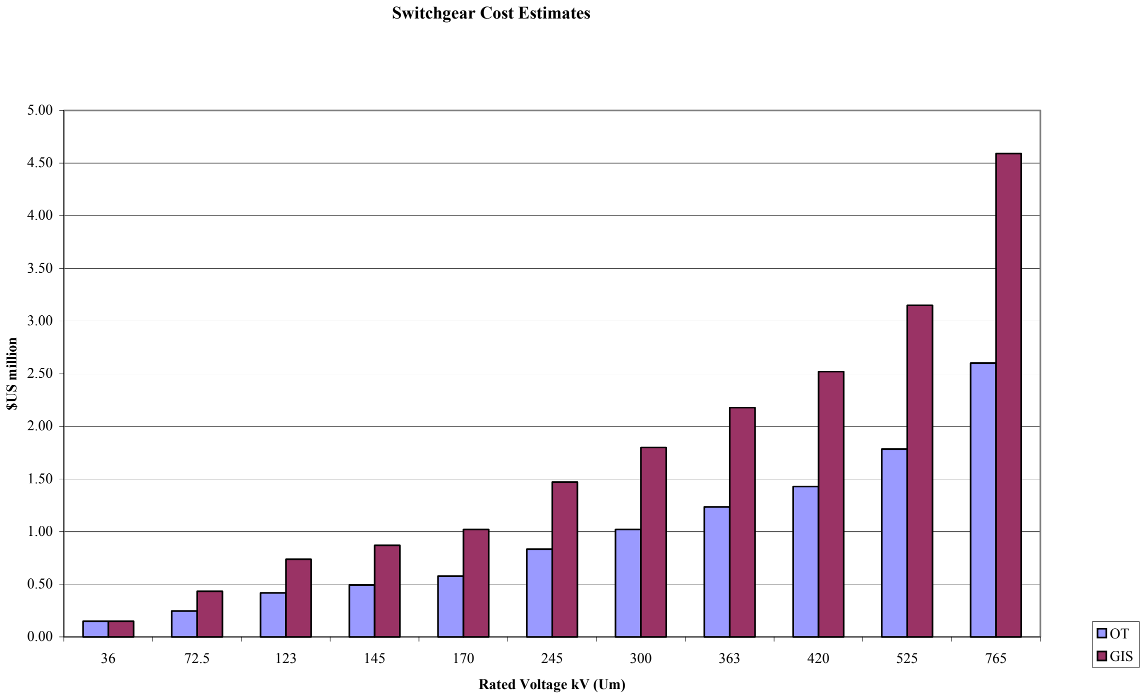
B.4 Substation Pricing

B.4.1 AC Switchgear

Substation costs include circuit breakers, whether the interconnector is AC or DC, and for AC only compensation may be required, whereas for DC convertor costs, including associated filters, need to be included.

For AC interconnectors, the switchgear rated voltage (which is a Um value applicable to 50 Hz or 60 Hz) is established using a VLOOKUP function on table "Swg_OT_cost" located in COMMON, using a value 1.15 times the nominal voltage (this factor ensures selection of the correct value of Um). The method of choosing Um for DC interconnectors is described in B.4.3.

The switchgear price depends on whether Open Terminal or GIS has been chosen in the INPUT section by the appropriate option buttons. The price is chosen by looking up the appropriate value using Um. Present stored values are shown in the following graph:



B.4.2 AC Shunt and Series Compensation

Shunt and series compensation prices are held in COMMON as tables of prices per Mvar, adjusted according to the rated AC voltage (Um basis). The price falls progressively as the voltage increases, reflecting the larger sizes of units that will be used at higher voltages.

It is assumed that shunt reactors are directly connected to the line or cable without additional switchgear, whereas the price for series capacitive compensation is deemed to allow for:

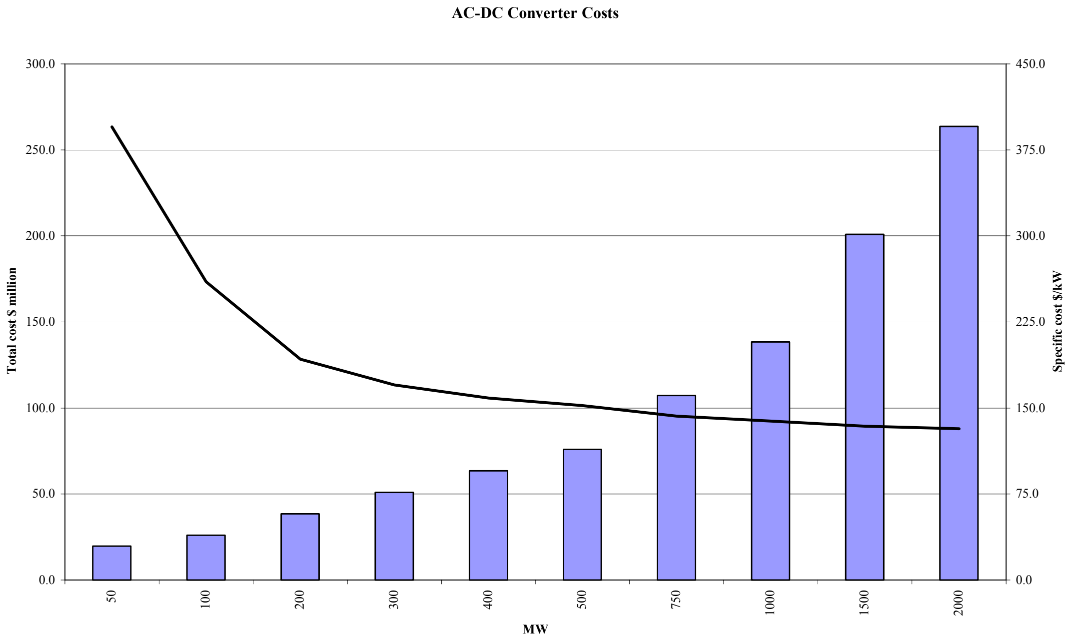
- Capacitor Mvar rating greater than the tabulated value by a suitable factor to allow for overloads, short-circuits etc.
- The site, the insulated platform supporting the capacitors, together with line terminal structures and all the ground-mounted equipment for control and supervision
- Bypass and protection equipment for the capacitors

Costing for series capacitor compensation will be a detailed process involving a complex optimisation process on the suitable rating and means of integrating into the network. The prices generated by this program should be regarded as indicative rather than definitive.

Refer to tables “Shunt_cost” and “Series_cost” in COMMON for shunt and series compensation prices/Mvar respectively. In both cases these prices are deemed to be indicative rather than of the same accuracy as line/cable costs.

B.4.3 DC Lines/cables – Convertor and AC substation costs

Convertor costs for DC connections are based on a function of the MW load with a simple relationship cost/MW = K/MW+C, where constants K and C are stored in COMMON as Convertor_Cost_Var and Convertor_Cost_Fixed respectively. The resulting cost profile is shown in the following graph:



Note the fall in the specific cost per MW with increasing rating. The overall cost of the convertors covers both ends of the circuit, and is not subject to the application of country or terrain factors.

DC interconnectors need to be connected to AC systems at each end, and there will be a cost in switchgear, and optionally, new AC substations. Unlike the AC transmission cases where the voltage of the substation is determined by the line voltage required, DC connections can be made at an existing voltage level that is capable of handling the rating of the interconnector.

The procedure for deciding which AC voltage to be used is based on the MW rating and a lookup table in COMMON named DC_Link_AC_Volts. This table estimates a suitable voltage level based on MW rating, and selected from the available voltages, selected out of the drop-down list “Volt_range” and stored as the value “Volts” (an integer between 1 and 5).

The returned voltage is a Um value, which can be used for 50 Hz or 60 Hz and is then used to select the appropriate circuit breaker cost.

B.5 COMMON – Common Factors

Common factors are used within one or more individual worksheets are defined in the COMMON worksheet. Names, current values, (which may differ from those adopted in the Release version) and a brief description are given in the following table – which has been taken directly from COMMON:

Short name (=Name)	Value	Description
LLF	0.3	Constant used to define Loss Load Factor (e.g. LLF=0.3*LF+0.7*LF², where LF=Load Factor)
Double_circuit	65%	Approximate price increase for Double-circuit over Single Circuit OHL
Two_cables	75%	Approximate price increase for 2 cables per phase/pole over one cable per phase/pole subsea AC or DC
SS_CB_No	6	Additional No. of circuit breakers required for a new substation, inc. bus-section & coupler bays
LCF_V	0.667	LCF=AC Line cost function. V=power to which Voltage is raised
LCF_A	0.6	LCF=AC Line cost function. A=power to which total c.s.a. is raised
LCF_Mult	0.045	LCF=AC Line cost function. Constant multiplying the voltage and c.s.a. factors
LCF_Fixed	45	LCF=AC Line cost function. Fixed cost added to variable cost elements
DC_AC_Cond_No	0.66	For costing DC lines, Ratio 2/3 reflecting fewer conductors on DC

Cost function for AC overhead lines is:

$$(\text{Line voltage}^{LCF\_V})*(\text{c.s.a.}*\text{No. of conds})^{LCF\_A}*LCF\_Mult+LCF\_Fixed$$

Where multiple AC overhead line circuits are specified, the cost of the single circuit is multiplied by a function which takes into account the economies achieved by using double-circuit construction. Actual multipliers are generated by an algorithm which generates the following results for a value of "double_circuit" of 0.65

No. of circuits	Multiplier of single-circuit cost
1	1
2	1.65
3	2.65
4	3.3

A similar algorithm is used to compute the cost of the additional line if required for security.

Cost function for DC overhead lines is:

$$(\text{Pole voltage}^{LCF\_V})*(\text{c.s.a.}*\text{No. of conds}*DC\_AC\_Cond\_No)^{LCF\_A}*LCF\_Mult+LCF\_Fixed$$

Short name (=Name)	Value	Description
Convertor_losses	0.02	Convertor losses (both ends) p.u.
Convertor_cost_fixed	125	Convertor base cost $/kW
Convertor_cost_var	13500	Convertor cost increase for reducing rating, $/kW per 1/MW
CCF_V	0.5	CCF=DC Cable cost function. Power to which voltage is raised
CCF_A	0.33	CCF=DC Cable cost function. Power to which conductor csa is raised
CCF_K	5.25	CCF=DC Cable cost function. Constant to give $k/km

Cost function for DC cables is:

$$(\text{Pole voltage}^{CCF\_V})*(\text{c.s.a.}^{CCF\_A})*CCF\_K$$

(and if the number of conductors “No. of conds” is greater than 1,
the price is multiplied by “*No. of conds”-1*”Two_cables”)

Short name (=Name)	Value	Description
CCF_V_AC	0.667	CCF_()_AC=AC Cable cost function. Power to which voltage is raised
CCF_A_AC	0.5	CCF_()_AC=AC Cable cost function. Power to which conductor csa is raised
CCF_K_AC	1.5	CCF_()_AC=ACable cost function. Constant to give $k/km

Cost function for AC subsea cables is:

(Line voltage$^{\mathrm{CCF\_V\_AC}}$)*(c.s.a.$^{\mathrm{CCF\_A\_AC}}$)*CCF_K_AC* No. of conds

Additional cables, whether specified as multiple circuits or added for security reasons are costed at “two_cables” times the cost of a single circuit.

Short name (=Name)	Value	Description
SWG_OT_F	0.0034	Switchgear cost function. Constant multiplying Um to give bay cost (installed) for Open Terminal
SWG_GIS_F	0.006	Switchgear cost function. Constant multiplying Um to give bay cost (installed) for GIS
Op_cost_OHL	1.00%	Operating and maintenance costs as a percentage of capital cost, per annum for overhead lines
Op_cost_cable	0.50%	Operating and maintenance costs as a percentage of capital cost, per annum for cables
Op_cost_convertor	1.00%	Operating and maintenance costs as a percentage of capital cost, per annum for convertors
Op_cost_substation	0.25%	Operating and maintenance costs as a percentage of capital cost, per annum for substations

Appendix C AC Transmission Capacity

An AC transmission line (which could be an overhead line or cable) can transmit power up to a limit which is set by:

- The thermal current rating of the conductors, which in turn is limited by a maximum permitted temperature which should not be exceeded without risking excessive sag or conductor deterioration (on overhead lines) or damage to the insulation (power cables).
- Maximum and minimum voltage on the circuit, the former limited by the rated insulation strength of the insulators and terminal equipment (switchgear, transformers etc.), the latter by the ability of tap-changing equipment on transformers and generation to restore utilisation voltages to the desired values.
- Stability considerations, which are less easy to define without a case-by-case study, but the desired result is that the transmission circuit should be able to carry its rated load without prejudice to the stability of voltage or generation when the network sustains disturbances such as a change of load or a fault cleared by protection.

C.1 POW4 Transmission Line Capability Program

C.1.1 POW4 – Characteristic Curves

A computer program "POW4" can simulate loading a transmission circuit at pre-determined power factors. This gives a set of characteristic curves as shown in the example shown in Figure C-1 which has taken the typical data for a 500 kV line employing four 500 sq.mm. conductors, codeword "Curlew" per phase.

The program will function in the same manner for AC cable circuits, since it uses the "long-line" formulae for transmission lines, which is important in the case of cables with much higher capacitance and lower inductance. Modelling of shunt compensation follows the same practice as used for overhead lines, for cables series compensation is not generally applicable (the lengths being much shorter).

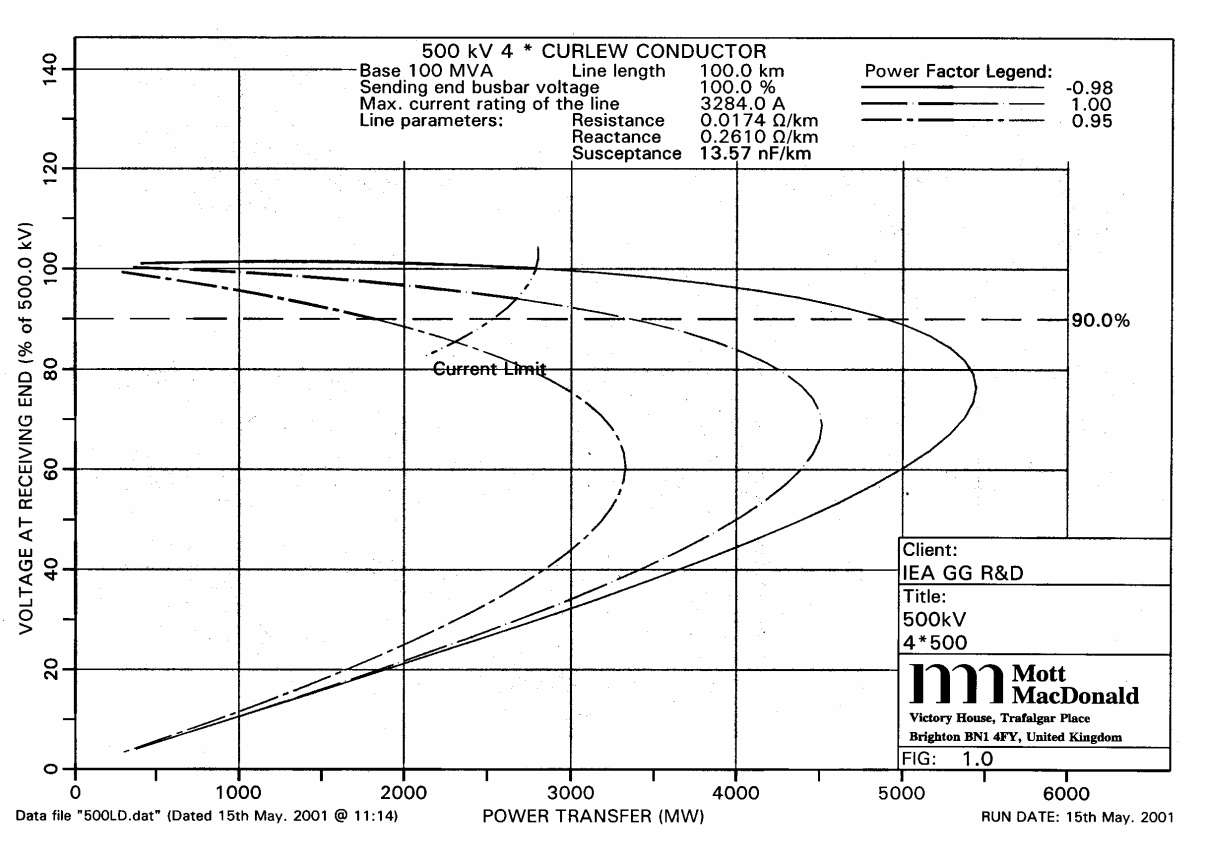


Figure C-1 – 500 kV Line 100 km. Load-voltage curves

The figure shows a 100 km 500 kV line loaded at –0.98, 1.0 and 0.95 p.f. (The negative power factor value indicates that generation at the receiving end is delivering lagging Mvar into the line, positive values represent the usual case of supplying a load which also draws lagging Mvar).

In this case, the maximum power that can be transmitted is limited to around 2700 MW by the current rating of the line for power factors –0.98 and 1.0. At 0.95 p.f., the receiving end voltage limit of 90% restricts the transmitted power level to 1820 MW.

Figure C-2 shows the same line, but its length is now 1000 km. Over this length of line, shunt compensation is essential to prevent the voltage rising to unacceptably high values at light loads, and a good case can be made for adding series compensation to increase the line capacity. Values for series compensation vary in practice from 30% to 70% of the line reactance, the choice of 50% is simply taken as a mean value. The actual choice of a suitable series compensation value requires careful study on both technical and economic issues, and heavily-compensated lines have been known to interact unfavourable with generators, setting up torsional oscillations.

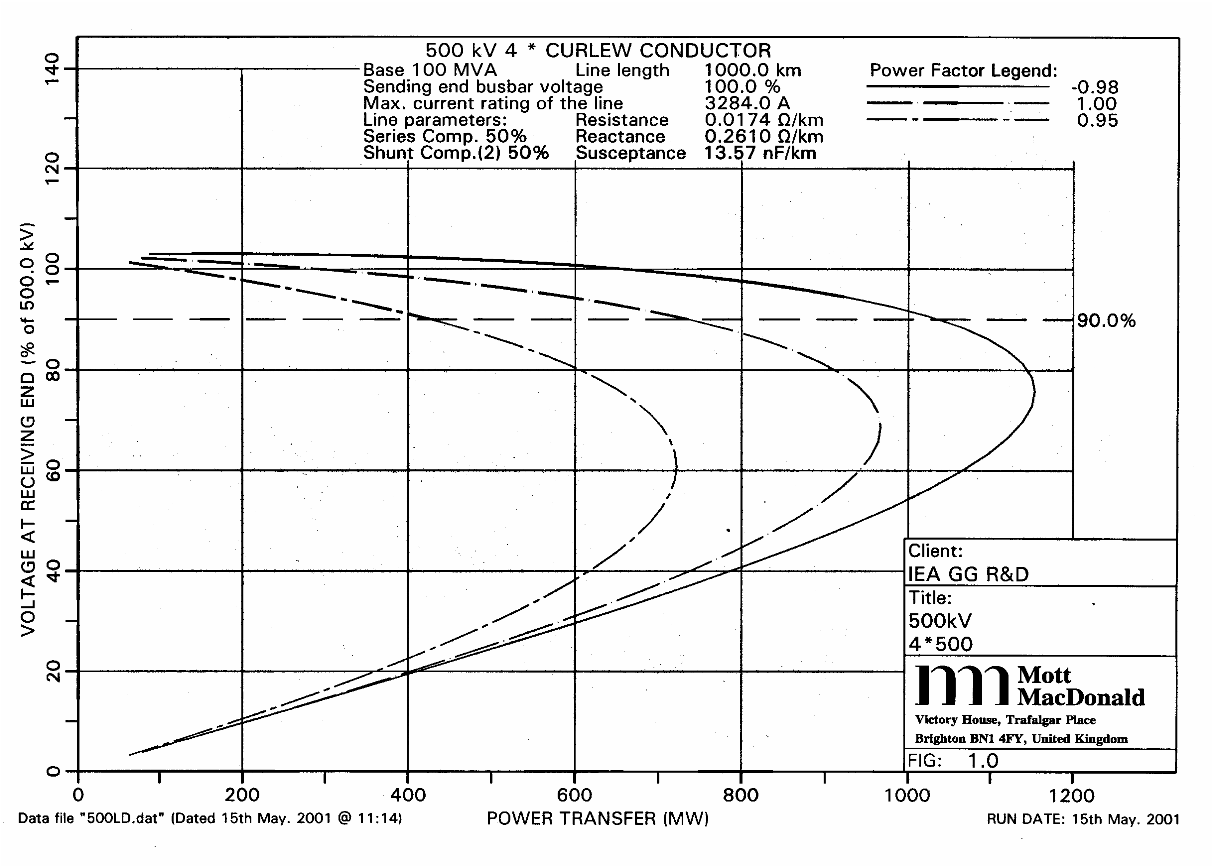


Figure C-2 – 500 kV Line 1000 km. Load-voltage curves

The general appearance and shape of the curves is similar to the 100 km example, but now there is no current limit shown since the line capacity is limited by other factors. At 1.0 and 0.95 p.f. voltage regulation limits the power flow. At the leading power factor of 0.98, the program limits the capacity to 920 MW, this representing 80% of the theoretical maximum of 1150 MW, even though the voltage is above the 90% limit. (The curve moves from a thick to a thin line). This limit is introduced to avoid operation in the region close to the “knee” of the characteristic, when voltage stability would occur (also, almost certainly, generator instability).

C.1.2 Pow4 – Characteristic Data

Table C-1 lists the results from POW4 for the 500 kV line of length 100 km. Of particular note are the losses, which range from 1.7 to 2.1% at the design load (the middle line, terminated by an asterisk, in each block of results) and the line angle “Delta”, which at 17° or less is well within the region where stability is generally satisfactory.

```
PROGRAM POW4; VERSION 1.55 - 27 Mar. 2001 - transmission line characteristics
RUN DATE: 15th May. 2001
POW4 DATA FILE "500LD.dat"
(LAST UPDATE 15th May. 2001 @ 11:14)

LINE AND SYSTEM DATA
--------------------
500 kV 4 * CURLEW CONDUCTOR
IMPEDANCE DATA FOR LINE OF LENGTH 100.0 km
BASE            = 100 MVA, SOURCE VOLTAGE = 100.0 %
NOMINAL VOLTAGE = 500.0 kV, FREQUENCY = 50 Hz
RESISTANCE   = 0.0007 %/km or 0.0174 ohms/km
REACTANCE    = 0.0104 %/km or 0.2610 ohms/km
SUSCEPTANCE  = 1.0658 %/km or 13.57 nF/km

RECEIVING END VOLTAGE LIMIT = 90.0 %
RECEIVING END CURRENT LIMIT = 3284 Amps
POWER STABILITY LIMIT = 80 % of maximum theoretical limit

RECEIVING END POWER FACTOR = -0.98
    Pr(MW)     Vr(%)     Ir(A)    Ps(MW)  Qs(Mvar)     Is(A)  Loss (%)   Delta
      0.00    100.56      0.00      0.03   -106.98    123.52         -     0.0
   2789.35    100.08   3284.00   2845.89    176.31   3292.45       2.0    17.1*
   5442.53     76.37   8396.87   5810.05   4333.41   8369.40       6.3    48.8

RECEIVING END POWER FACTOR = 1.00
    Pr(MW)     Vr(%)     Ir(A)    Ps(MW)  Qs(Mvar)     Is(A)  Loss (%)   Delta
      0.00    100.56      0.00      0.03   -106.98    123.52         -     0.0
   2674.73     94.05   3284.00   2730.84    742.63   3267.82       2.1    17.3*
   4512.98     68.84   7569.41   4810.97   4399.52   7527.83       6.2    43.1

RECEIVING END POWER FACTOR = 0.95
    Pr(MW)     Vr(%)     Ir(A)    Ps(MW)  Qs(Mvar)     Is(A)  Loss (%)   Delta
      0.00    100.56      0.00      0.03   -106.98    123.52         -     0.0
   1822.47     90.00   2461.30   1853.56    969.52   2415.41       1.7    11.9*
   3326.29     60.64   6667.27   3556.67   4482.51   6607.35       6.5    34.0
```

Table C-1 – 500 kV Line 100 km. Load-voltage data

In Table C-2 following, the data is listed for the 1000 km case. The 500 kV line has both series and shunt compensation, and the results need to be considered with some care.

```
PROGRAM POW4; VERSION 1.55 - 27 Mar. 2001 - transmission line characteristics
RUN DATE: 15th May. 2001
POW4 DATA FILE "500LD.dat"
(LAST UPDATE 15th May. 2001 @ 11:14)

LINE AND SYSTEM DATA
--------------------
500 kV 4 * CURLEW CONDUCTOR
IMPEDANCE DATA FOR LINE OF LENGTH 1000.0 km
BASE             = 100 MVA, SOURCE VOLTAGE = 100.0 %
NOMINAL VOLTAGE = 500.0 kV, FREQUENCY = 50 Hz
RESISTANCE   = 0.0007 %/km or 0.0174 ohms/km
REACTANCE    = 0.0104 %/km or 0.2610 ohms/km
SUSCEPTANCE  = 1.0658 %/km or 13.57 nF/km

COMPENSATION PROVISION
MID-LINE SERIES COMPENSATION = 50.0 %
RECEIVING END SHUNT REACTOR = 50.0 % (or 532.9 Mvar)

RECEIVING END VOLTAGE LIMIT = 90.0 %
RECEIVING END CURRENT LIMIT = 3284 Amps
POWER STABILITY LIMIT = 80 % of maximum theoretical limit

RECEIVING END POWER FACTOR = -0.98
    Pr(MW)     Vr(%)     Ir(A)    Ps(MW)  Qs(Mvar)     Is(A)  Loss (%)   Delta  Vm1(%)  Vm2(%)
      0.00    102.67      0.00      8.75   -645.50    745.42         -     0.3  118.55  115.98
    922.59     94.49   1150.39    985.62   -342.29   1204.77       6.4    28.4* 111.80  111.10
   1153.24     75.75   1793.79   1291.76    301.94   1531.80      10.7    47.6   91.84  106.92

RECEIVING END POWER FACTOR = 1.00
    Pr(MW)     Vr(%)     Ir(A)    Ps(MW)  Qs(Mvar)     Is(A)  Loss (%)   Delta  Vm1(%)  Vm2(%)
     -0.00    102.67      0.00      8.75   -645.50    745.42         -     0.3  118.55  115.98
    736.09     90.00    944.40    780.13   -313.73    970.93       5.6    23.0* 106.93  111.67
    966.38     68.65   1625.54   1079.74    325.04   1302.04      10.5    41.9   84.58  107.55

RECEIVING END POWER FACTOR = 0.95
    Pr(MW)     Vr(%)     Ir(A)    Ps(MW)  Qs(Mvar)     Is(A)  Loss (%)   Delta  Vm1(%)  Vm2(%)
     -0.00    102.67      0.00      8.75   -645.50    745.42         -     0.3  118.55  115.98
    426.35     90.00    575.80    446.78   -380.49    677.63       4.6    12.7* 106.38  113.16
    721.78     60.87   1441.34    810.36    354.38   1021.29      10.9    32.8   76.51  108.36
```

Table C-2 – 500 kV Line 1000 km. Load-voltage data

At zero load (the first line of each block of results), the receiving end voltage Vr is 102.7%, with sending end voltage 100%. This is quite acceptable, and was the basis of the choice of 50% shunt compensation. At low levels of compensation the voltage rise would have been well over 10% and unacceptable. As a further check, note Qs, the sending end reactive load of 645 Mvar will be supplied in the main by the 533 Mvar of shunt reactor at that end, leaving only 112 Mvar entering the 500 kV network, which should be acceptable at that voltage level.

The two voltages Vm1 and Vm2 are the mid-point voltages each side of the series capacitor. At zero load these are quite high at 118.6% and 116%, and might necessitate a slightly higher insulation level in the mid-portion of the line, or dropping the 500 kV voltage level at the sending end to bring these voltages back within an acceptable limit.

The middle line of data for each power-factor level shows the effective capacity of the line limited by stability considerations or receiving-end voltage regulation. Note in particular:

- Net Mvar generated by the line has fallen to the band 314-380 Mvar, and the deficit net of the shunt compensation of 219-153 Mvar must be supplied by the 500 kV network, which should be well within its capability.

- The line capacity is heavily dependent on the receiving end power factor, ranging from 426 MW to 923 MW, a ratio over 2:1. The assumption that the receiving end draws power at unity power factor comes in on the upper end of this range, so it remains a prudent choice and may be considered accurate to ±25% in practical situations.

- Losses range from 4.6% to 6.4%, which are acceptable over such a long circuit, the value at unity power factor of 5.6% is probably approaching the economic limit and tends to support this choice of rating rather than the higher value when losses reach 6.4%

- The mid-point voltages of 111% to 113% probably represent the maximum acceptable working voltages on load. It should be noted that this parameter starts rising rapidly when line lengths exceed 1000 km (800 km at 60 Hz) hence no ratings were assigned to AC lines above these lengths.

- Line angles “Delta” range from 13° to 28°, and noting that 30° is proposed as a limiting value, the preferred rating at unity power factor at 23° is comfortably within and the +25% capacity value of 922 MW just approaches it.

C.2 AC Line and Cable Impedances

The performance of an AC transmission circuit over long lengths is primarily determined by its characteristic impedances, namely resistance, reactance and capacitance (leakage currents over insulators are very small and usually neglected).

Resistance is a property of the conductor and is a function of its material, cross-sectional area and operating temperature. The effective resistance of AC conductors is slightly higher than their DC resistance because of a tendency for the current to flow in the outer layers as a result of magnetic effects ("Skin-effect"). These properties are evaluated in the current rating program, see C.3.

The characteristics of AC cables are calculated by a spreadsheet based on the following:

Characteristic	**Assumption**
Conductor material	Copper (AC resistance taken from manufacturer’s catalogues)
Maximum conductor temperature	90°C
Insulation	XLPE
Sheath	Lead
Oversheath	PE
Insulation thickness	Adjusted to give working stress 6 kV/mm at conductor surface (7 kV/mm for 220 kV)
Installation	Trefoil or flat touching (mean spacing approx. 1.5* cable diameter)
Ground temperature	15°C
Depth	1 m
Soil resistivity	1.2 W/m.K

The soil conditions, hence the current rating, are typical for temperate countries. Subsea cables would have better conditions, but the most critical region for rating purposes are the shore ends.

Reactances and capacitances of an overhead line are calculated by a program OHLINES which calculates these parameters from input data describing the conductor dimensions and spacings, relative to each other and the ground. A typical result, relating to the same 500 kV line with four 500 sq.mm. conductors is shown in the following table:

```
                  *****      OHLINEOUT      *****

PROJECT TITLE:_ 500kV QUAD CURLEW
NUMBER OF CONDUCTORS:_ 5
CONDUCTOR CONFIGURATION IN MATRIX FORM:
X(1) =     -11.000                Y(1) =      15.000
X(2) =       0.000                Y(2) =      15.000
X(3) =      11.000                Y(3) =      15.000
X(E) =      -5.500                Y(E) =      20.500
X(E) =       5.500                Y(E) =      20.500

AVERAGE HEIGHT OF PHASE CONDUCTORS:   15.000 metres
NOMINAL FREQUENCY:                    50 Hz
PHASE CONDUCTOR DC RESISTANCE:        0.0696 Ohms/km
GEOM. MEAN RADIUS OF THE CONDUCTOR:   12.8 millimetre
DIAMETER OF PHASE CONDUCTOR:          31.7 millimetre
NUMBER OF CONDUCTOR/PHASE:            4
SPACING BETWEEN THE CONDUCTORS:       500 millimetre
RESISTIVITY OF EARTH:                 100 Ohms/metre cube
NUMBER OF EARTH WIRES:                2
EARTH WIRE DC RESISTANCE:             0.0674 Ohms/km
GEOM. MEAN RADIUS OF EARTH WIRE:      11.6 millimetre
DIAMETER OF EARTH WIRE:               28.6 millimetre

  Calculated parameters:
  ~~~~~~~~~~~~~~~~~~~~~
  Pos./Neg. seq. resistance ...........= 0.01740 ohms/km
  Pos./Neg. seq. induc. reactance ......= 0.261 ohms/km
  Pos./Neg. seq. capac. reactance ......= 0.235 Mohms-km
  Pos./Neg. seq. capacitance ..........= 13.57 nF/km
```

Table C-3 – Typical OHL Impedance Characteristics

These calculations are based on 50 Hz. For 60 Hz the reactance as expressed in ohms/km is multiplied by 1.2 for input into POW4. The resistance value is taken as the same at either frequency (it will be very slightly higher in practice at 60 Hz, but the difference is not significant) and since POW4 expects a capacitance value in nF (nano-Farad or $F*10^{-9}$), the conversion into the appropriate susceptance value is performed within POW4.

C.3 Current Rating and Resistance

The tables use a limited number of conductor sizes, and all are assigned a thermal rating based on the following site conditions:

```
PROGRAM LINES - CURRENT RATING AND SAG-TENSION CALCULATIONS
-----------------------------------------------------------

CONDUCTOR CODEWORD               CURLEW
                                (ACSR)
ALUMINIUM AREA                    523.7 SQ.MM.
(NUMBER OF STRANDS                54 )
STEEL AREA                       (NOT SPECIFIED)
OVERALL DIAMETER                  31.68 MM.
D.C. RESISTANCE AT 20 DEG. C      .0548 OHMS/KM.
A.C. RESISTANCE AT 75 DEG. C      .0696 OHMS/KM.
MAXIMUM CONDUCTOR TEMP.           75 DEG. C
AMBIENT TEMPERATURE               40 DEG. C
MINIMUM WIND SPEED                .5 METRES/SEC
SOLAR RADIATION                   .9 KILOWATTS/SQ.M.
EMISSIVITY FACTOR                 .8
ABSORPTIVITY FACTOR               .8

                 CURRENT RATING = 820.8 AMPS
```

Table C-4 – Typical Current Rating Calculation

Note the assumed ambient conditions pertain to European/US temperate climates with a maximum ambient of 40°C. The most important parameter affecting current rating is the permitted temperature rise, in this case 35 K. In general aluminium or aluminium alloy conductors, with or without steel reinforcement, are quite suitable for operation at 75°C, and can operate up to 80°C without excessive long-term creep, particularly if the maximum rating of the conductor is only reached under abnormal conditions, e.g. if worst-case ambient conditions are coincident with a line outage.

Another reason for adopting a reasonably conservative assumption on maximum conductor temperature is that higher current ratings generate greater losses. Whereas a circuit serving load which has typical seasonal and daily fluctuations, and 2*100% redundancy provided has low losses, a circuit connecting base-load generation to a system will have higher losses, possibly warranting a choice of conductor larger than warranted by thermal rating considerations alone.

“High-temperature” conductors are being offered, principally by Japanese manufacturers, which can operate at above 80°C. In general, applications for such conductors are limited to short lengths in circumstances where exceptionally high loadings may be experienced in unusual conditions, otherwise the cost of losses is prohibitively high. In any case such conductors may require either higher towers or shorter spans (=more towers) because of the greater design sag compared to conventional conductors.

Appendix D DC Transmission Capacity

A DC transmission line (which could be an overhead line or cable) can transmit power up to a limit which is set by:

- The thermal current rating of the conductors, which is based on the use of the same conductors, current ratings and resistances as in the AC modelling for overhead lines and separate calculations for DC cables.
- Maximum and minimum voltage on the circuit, the former limited by the rated insulation strength of the insulators and terminal equipment (switchgear, transformers etc.), the latter by the ability of the convertors to operate at rating.
- Maintaining losses (NB numerically equivalent to voltage regulation) to an economic level. What this level is should be decided on a case by case basis, the assumed values are stated below

D.1 DC Overhead Lines

Conductors for DC overhead lines are chosen from a similar range as used for AC transmission lines, with the following characteristics:

Al. Equ. c.s.a. sq.mm.	**Codeword**	**Rating Amp**	**Resistance ohms/km**
175	Lynx	445	0.192
300	Goat	625	0.109
400	Zebra	725	0.0846
500	Curlew	820	0.0696
630	Pheasant	930	0.0566

A spreadsheet is then devised for a range of DC voltages, ±250, ±350, ±450, ±600 and ±800 kV with a selection of the above conductors. Each combination is tested over a range of distances from 200 to 3500 km, to ascertain the capacity as limited by:

- The thermal rating of the conductors
- Transmission losses, with a limiting value that rises pro-rata to the length of the circuit, from 5% at 300 km to 10% at 3000 km

The choice of this profile for losses is arbitrary and is based on an expectation that the longest (and most expensive) DC transmission schemes will only be justified when high-cost local generation can be displaced by remote power sources with much lower energy costs, hence loss capitalisation will be based on progressively lower energy costs and by inference lower costs of losses.

DC schemes tend to be very individual and there is considerable scope to optimise the choice of voltage, conductor size etc. to get lowest overall costs on a Capex basis or taking into account lifetime costs.

A typical profile for a ±350kV, 2*630 sq.mm. line appears as shown:.

Distance km	Load current kilo-Amp	Capacity MW	Losses MW	Losses (percent)
200	1.860	1,302	39.2	3.01%
300	1.860	1,302	58.7	4.51%
450	1.451	1,015	53.6	5.28%
650	1.075	752	42.5	5.65%
1000	0.779	545	34.3	6.30%
1500	0.595	417	30.1	7.22%
2000	0.504	353	28.7	8.15%
3000	0.412	289	28.9	10.00%
3500	0.386	270	29.5	10.93%

Note up to 300 km in this example, line capacity is limited by the conductor rating, thereafter the loss profile limits its capacity.

D.2 DC Cables

DC cables are dealt with in the same way as DC overhead lines, selecting a number of conductor sizes and voltages and then assessing capacity according to current rating or losses, whichever are limiting.

Unlike overhead line conductors, the current ratings of DC cables are a function of voltage, since the higher voltage cables need more insulation. The current ratings were calculated by using a model single-core cable with solid paper insulation, selecting a suitable working stress to determine insulation thickness and calculating the resulting rating. Burial conditions were the same as employed for AC cables.

Calculated ratings were as follows:

Size (Cu.)	Resistance	Rating in Amps at stated voltage rating							
Sq.mm.	Ohms/km	±100	±150	±200	±250	±300	±400	±500	±600
500	0.0395	849	814	785	761	742	710	686	N/A
630	0.0317	967	929	899	873	851	817	790	N/A
1000	0.019	1309	1266	1229	1199	1173	1130	1097	1071
1600	0.0124	1686	1637	1595	1560	1529	1480	1441	1409

The limiting conditions for DC cables were slightly different from DC overhead lines, with the losses set as a function of distance varying from 5% at 100 km to 10% at 2000 km. In practice, particularly at the higher voltages, the current rating was the limiting factor at all but the very greatest distances.

A typical example of the results of this calculation are shown below for a ±200 kV, 1000 sq.mm. cable.

Distance **km**	**Load current** **kilo-Amp**	**Capacity** **MW**	**Losses** **MW**	**Losses** **(percent)**
20	1.229	492	1.1	0.23%
50	1.229	492	2.9	0.58%
100	1.229	492	5.7	1.17%
200	1.229	492	11.5	2.34%
500	1.229	492	28.7	5.84%
1000	0.776	310	22.9	7.37%
1500	0.609	244	21.2	8.68%
2000	0.526	211	21.1	10.00%
2500	0.476	191	21.6	11.32%

In this case the current rating limits capacity up to 500 km, thereafter the loading is reduced in order to keep the losses within the prescribed limits.