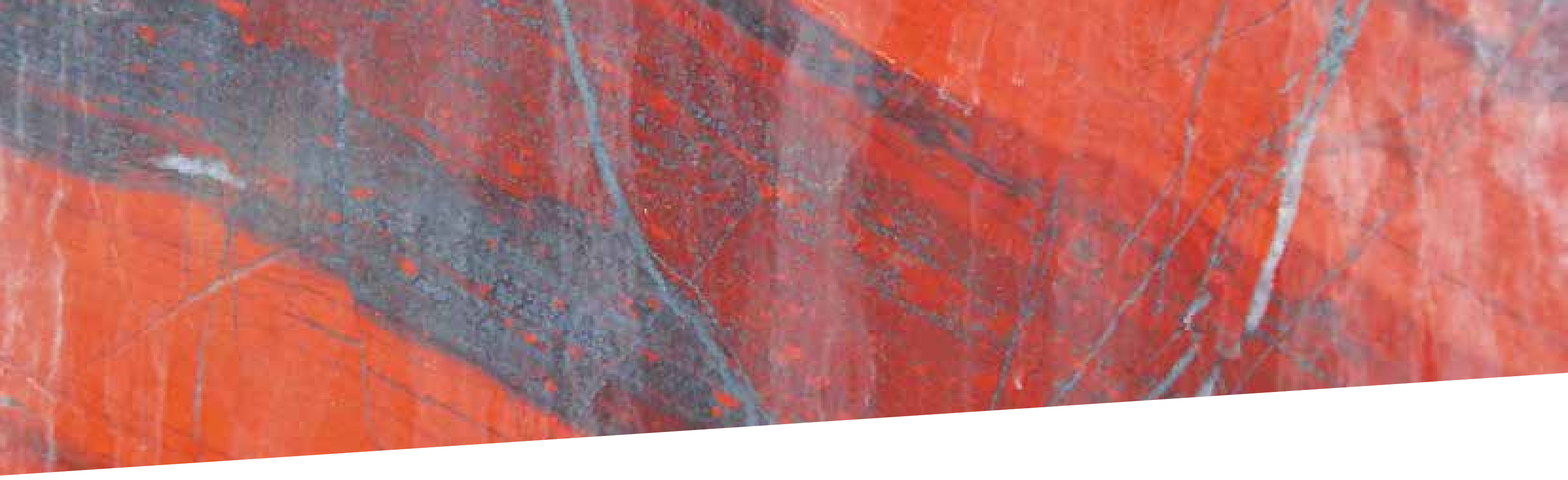
PRE-FEASIBILITY STUDY

2017

Evaluating the potential to export Pilbara solar resources to the proposed ASEAN grid via a subsea high voltage direct current interconnector

Samantha Mella Geoff James Kylie Chalmers



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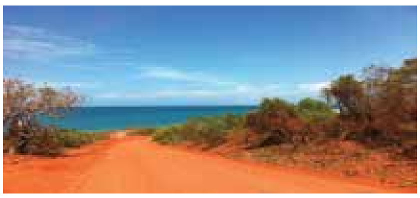
Contents



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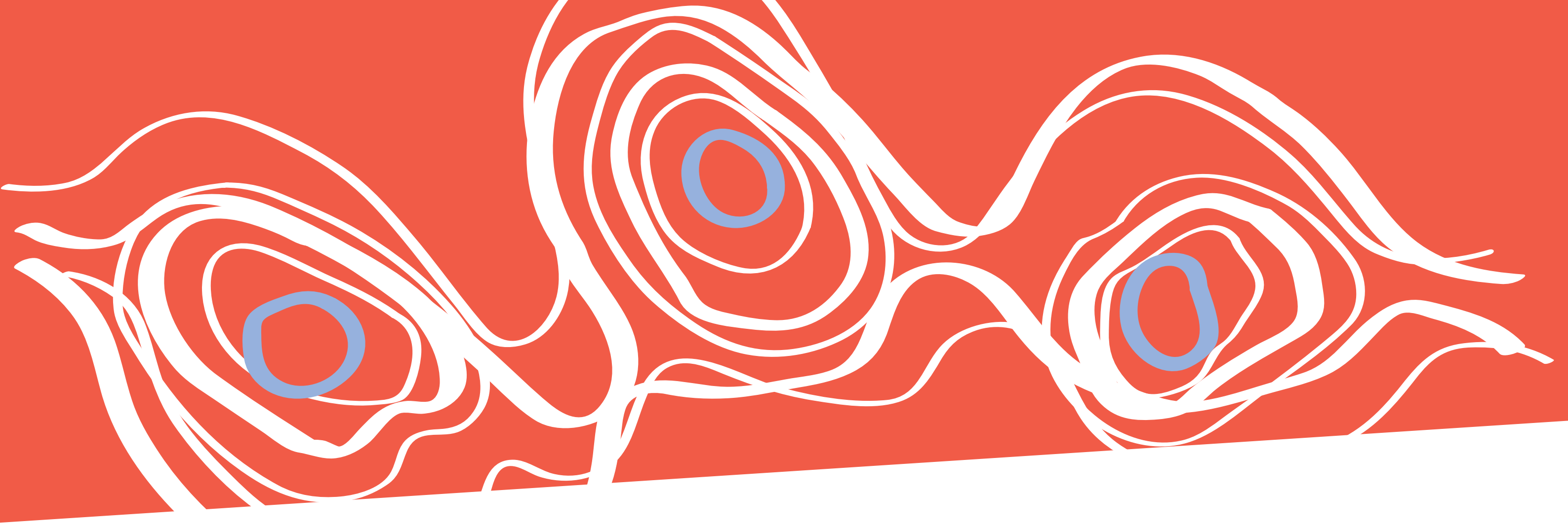
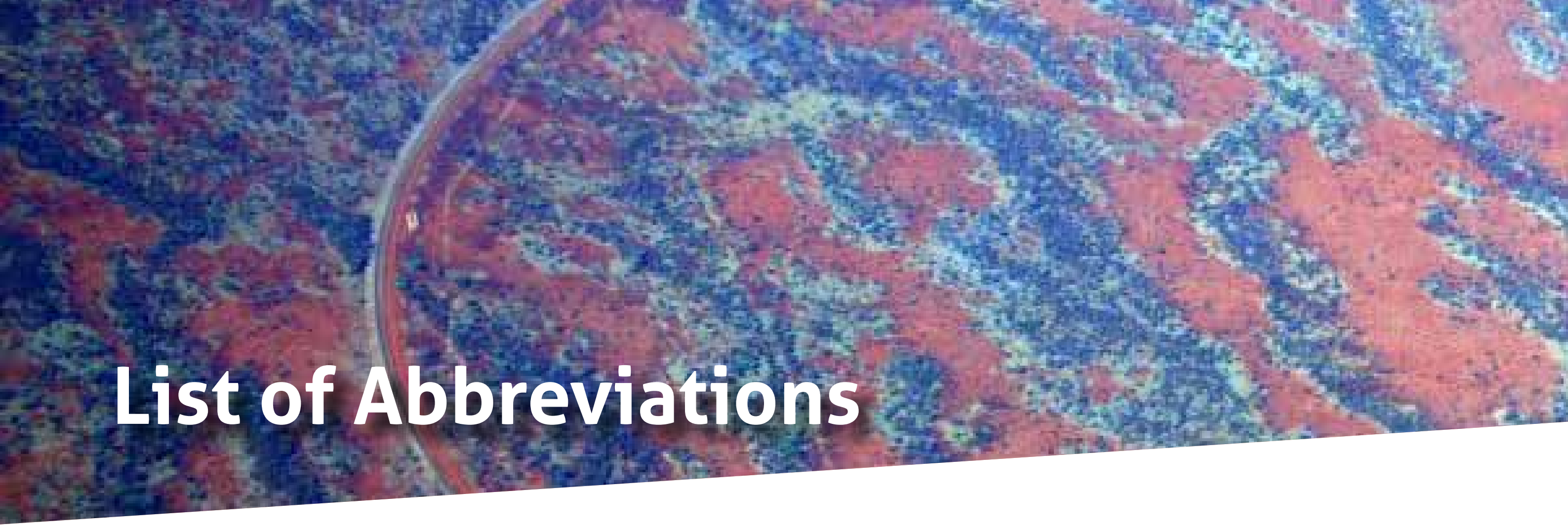


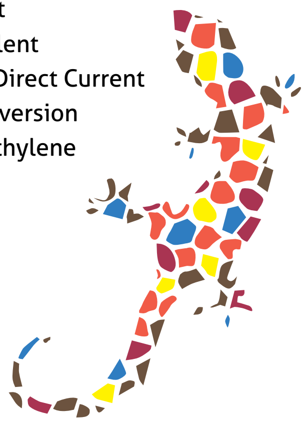
07 Economic Impact Assessment for a Potential Solar Export Industry 80

08 Partnering with Traditional Owners.91



List of Abbreviations

ACEC	African Clean Energy Corridor
ACE	ASEAN Centre for Energy
AHA	Aboriginal Heritage Act
AIMS	ASEAN Integration Masterplan Studies
APG	ASEAN Power Grid
APGCC	ASEAN Power Grid Consultative Committee
APAEC	ASEAN Plan of Action on Energy
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
ASG	Asia Super Grid
ARENA	Australian Renewable Energy Agency
CAPEX	Capital Expenditure
CSR	Corporate Social Responsibility
CST	Concentrating Solar Thermal
DEN	Indonesian National Energy Council
DAA	Department of Aboriginal Affairs
DJK	Indonesian Directorate General of Electricity
FIFO	Fly-in Fly-out worker
FPIC	Free, Prior and Informed Consent
GEIDCO	Global Energy Interconnection Development and Cooperation Organization
GHG	Greenhouse Gas
GMS	Greater Mekong Sub Region
GW	Gigawatt
IUPTL	Indonesian Electric Power Supply Business Permit
JAMALI	Java, Madura, Bali
HAPUA	The Heads of ASEAN Power Utilities/ Authorities Council
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IGBT	Insulated-gate bipolar transistors
INDC	Intended Nationally Determined Contributions
IPP	Independent Power Providers
IRENA	International Renewable Energy Agency
KEPCO	Korea Electric Power Corporation
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hours
LAA	Land Administration Act 1997 WA
LCOE	Levelised cost of energy
LCC	Line Current Commutation (LCC)
LVRT	Low-voltage ride through
MEMR	Indonesian Ministry of Energy and Mineral Resources
MI	Mass Impregnated
MW	Megawatt
MWh	Megawatt hours
NTA	Native Title Act
NWIS	North West Interconnected System
OPEX	Operating expenditure
RPJMN	Indonesian Medium Term National Development Plan
PBC	Prescribed Body Corporate
PPA	Power Purchase Agreement
PT PLN	Perusahaan Listrik Negara, Indonesian State Electricity Company
PV	Photovoltaic
RTN	Right to Negotiate
RUPTL	PLN Electricity Business Plan
RUEN	Indonesian National Master Plan of Energy Development
SAPP	South African Power Pool
SEIPAC	Central American Interconnected System
SICA	Central American Integration System
SEM	Single Electricity Market
SCF	Standard Cubic Feet
TOE	Tonne of oil equivalent
UHVDC	Ultra High Voltage Direct Current
VSC	Voltage Source Conversion
XLPE	Cross-Linked Polyethylene



01

Executive Summary

This prefeasibility study evaluates the potential to export Pilbara photovoltaic (PV) solar electrical generation to the proposed ASEAN Grid via a subsea high voltage direct current (HVDC) interconnector. The intention of this study is to draw attention to economic diversification opportunities in the Pilbara, and to determine whether more research is warranted for the development of this export-scale renewable energy project.

It is technically feasible to build gigawatt scale PV solar generation in the Pilbara and deploy High Voltage Direct Current (HVDC) transmission, both subsea and overland, to deliver the electricity generated to Indonesia. This study analyses a 3 gigawatt (GW) Pilot Project with a single bipole HVDC link, using the latest existing technology, and enough utility-scale solar PV generation to justify capacity. It found that Pilbara solar generation has the potential to be competitive in the Indonesian market in the near future. The present solar feed-in tariff in Java is 19.3 c/kWh.

Solar, storage and HVDC prices are heading downward. The decline in the solar PV price is most dramatic (see Figure 1). Solar PV is tipped to be the lowest cost generation technology by 2030 and supply 15% of the world's electricity by 2040 (Bloomberg, 2016). In Australia, PV costs fell so quickly that the Australian Renewable Energy Agency (ARENA) was able to support 480 megawatts (MW) of utility-scale PV installations from funding intended for just 200 MW (ARENA, 2016). If present trends continue the commercial case for connection to Indonesia will be well established within 5-10 years.

This study found that at today's prices, delivering Pilbara solar energy to Java will cost 18-25 c/kWh (Australian) over its lifecycle. This is called its levelised cost of energy (LCOE) and includes full replacement of all equipment at end of life. The range of uncertainty

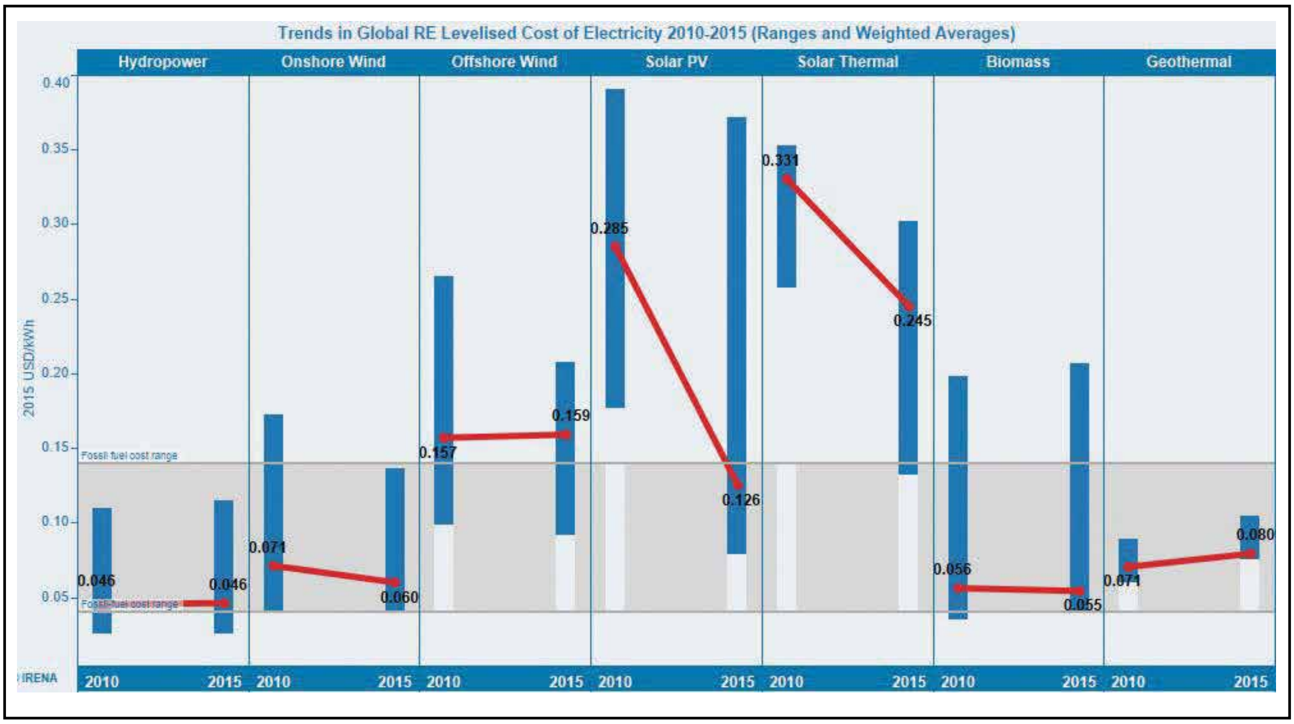


Figure 1: Global Trends in LCOE 2010-2015

Source: International Renewable Energy Agency in the calculations is influenced by the cost of finance, the cost and economic life of the subsea HVDC cable, the costs of large-scale solar generation and the losses in the cable and converter stations. This analysis also includes 40% remote mark-up on the initial construction cost to account for the lack of a local solar supply chain and expertise in the Pilbara. This mark-up declines over time as the supply chain is established.

The analysis also revealed that energy storage can dramatically increase the utilisation of the subsea cable, and therefore its effectiveness as an investment. Integrating GW-scale energy storage decreases the overall cost of delivered solar energy.

The Pilbara region has more than 1,400 GW of installed capacity of gas and diesel off-grid for the mining industry (Green, 2014). In this study, the ability of the first 200 MW to earn income from Renewable Energy Certificates and Power Purchase Agreements (PPAs) during construction of the full 3 GW made a significant impact on the LCOE. The industrial load gives the Pilbara an advantage over locations further north, despite their closer proximity to Indonesia and roughly equivalent solar resources.

South East Asia is rapidly developing and experiencing considerable expansion of electricity demand. By 2040, the International Energy Agency has projected ASEAN nations will require an additional 400 GW of electricity infrastructure (IEA, 2015a). Indonesia is at the forefront of this electrification and has a target of 80.5 GW of new installed capacity by 2025 including 14.4 GW of renewable energy.

This study finds that it is an appropriate time to initiate a dialogue and seek Indonesian perspectives on diversifying its energy mix to include solar feed-in from Australia. There is potential for Indonesian electricity generators to fully or partially own solar generation assets in the Pilbara. This may stimulate local investment and ensure a secure supply for Indonesia. There are several ownership models of the HVDC transmission infrastructure to consider.

The economic analysis in this study found the 3 GW solar pilot project would create 2,019 jobs in the Pilbara for the solar operations alone, a 4.4% increase in employment. The construction phase would create an additional 766 jobs in the Pilbara. Across Western Australia there would be a total over 12,210 jobs created (both construction and operations). Indonesia could enjoy significant economic benefits from a 3 GW pilot as well, with key responsibilities for the subsea cable production and its maintenance, and strategic options to become the infrastructure hub.

This study recommends that a local solar transition in the Pilbara is an essential step to create the solar supply chain and industry to deliver utility scale solar designed for the local conditions. A local solar transition has the potential to bring many benefits to the region, even if cross-border trade does not eventuate. The precedent of the solar hybrid model has been set with the DeGrussa Copper Mine, located north of Meekatharra, just south of the Pilbara, which reduces the mine's diesel consumption by 5 million litres each year.

In December 2016, the Australian Institute of Mining and Metallurgy published an article that included a business case for solar at remote sites:

When including the federal government's $0.40/L fuel tax credit, long-term contracting and the buying power of a large mining company, most large mine sites are likely to be paying ...$210-$260/MWh for diesel for larger mines and up to $450/MWh for communities and smaller industrial loads (depending upon the efficiency of the diesel unit). In contrast, the levelised cost of energy (LCOE) of a medium-sized solar PV plant in a remote location such as the Pilbara is approximately $160-$200/MWh (without grants or rebates). In addition, the project is able to generate large-scale generation certificates (LGCs), which currently have a market value of over $80/MWh. (Bearsley, 2016.)

This study also examined Native Title in the context of an emerging solar industry. Land access is key to solar development. There are currently 19 Native Title claims and determinations in the Pilbara that cover most of the land in the region. This study found that partnership with Traditional Owners in building a solar industry could have excellent social and commercial benefits in the Pilbara.

Traditional Owners in the Pilbara have already expressed interest in solar development. Aboriginal ownership of solar generation assets has the potential to enable Traditional Owners to secure income from Country in a sustainable, non-invasive way. Power Purchase Agreements negotiated with local industry could enable Traditional Owners greater economic participation in the region, and to receive a share of the wealth being generated in the Pilbara.

Partnership with Traditional Owners may assist to secure tenure for solar farms where other forms of tenure already exist. Following a Best Practice model of engagement with Traditional Owners will assist the Pilbara solar industry to obtain (and retain over time) a high Corporate Social Responsibility (CSR) profile. This is likely to guarantee good outcomes for Traditional Owners and maintain all funding and investment options into the future for the potential expansion to cross-border electricity trade.

Obtaining a high CSR profile will support investor diversification. Both investor and economic diversification will promote a more vibrant regional economy, and will ultimately support the aspirations set out in the Pilbara Regional Investment Blueprint and the Pilbara Cities Vision.

This report articulates a bold and ambitious vision. The proposed interconnector would be the longest and deepest to date and would traverse complex subsea terrain. The GW-scale solar farms would be larger than any presently existing. It is a shared vision; similar ambitions are unfolding in North Asia, China, South America, Europe, Africa and Iceland.

Western Australia has shown vision and determined leadership before. In 1895, an engineer named Charles O'Connor developed the concept of a pipeline to pump water over 500 km from coastal reservoirs and uphill to create a reliable supply of water for the Goldfields. It was a bold project for its time, criticized as "madness." The Western Australian Premier, Sir John Forrest, stood firmly behind the pipeline and the Goldfields Water Supply Scheme opened in 1903. The project was a success and the reliable water supply in Coolgardie and Kalgoorlie transformed the Goldfields. It is still operational today.

With similar leadership and vision, the Pilbara too can achieve economic diversification with HVDC and solar PV.

Cable Beach in Broome is named after the subsea telegraph cable laid in 1889 that connected Broome and Java.

Selena Brown. *Marble Bar, My Country,* 35.5 x 76cm, acrylic on canvas, 2016

02

Introduction

In 2015, renewable energy accounted for 70% of the new electricity infrastructure investment around the world, valued at US $288 billion

(International Energy Agency, 2016)

The 2015 Paris Agreement provided a clear turning point in the transition towards a decarbonised global economy. The shifts in global energy investment are in motion. In 2015, renewable energy accounted for 70% of the new electricity infrastructure investment around the world, valued at US $288 billion (International Energy Agency, 2016). Between now and 2035 it is expected that US $28 trillion will be invested in renewable energy and energy efficiency. This creates significant opportunities in those regions with abundant renewable energy resources, however the window for this transition investment is time limited (Drew, 2015).

The Pilbara region of Australia has an immense and inexhaustible supply of solar energy. The International Energy Agency's Task 8 Committee examined potential sites for very large-scale solar photovoltaic (PV) installations. Their study estimated that up to 30 terawatts (TW) or 30,000,000 megawatts (MW) of very large-scale solar PV deployed in north-west Western Australia could produce 49,000 terawatt hours (TWh) of electricity each year (Keiichi, 2015), 194 times the total electricity production within the Australian National Electricity Market (NEM) (252 TWh for 2015-16) (Department of Industry, 2016).

High Voltage Direct Current (HVDC) electricity transmission can now provide bulk transit of electricity over very long distances with low transmission loss. Cross-border electricity trade is on the rise. Europe is now a fully interconnected Single Electricity Market (SEM), and the trend to integration is worldwide. While China dominates overland HVDC implementation, in Europe, there are many subsea interconnectors.

In Southeast Asia, the ASEAN region is forecast to be the epicentre of new electricity infrastructure, with demand for 400 GW projected by 2040 (International Energy Agency, 2015). At the time of writing, ASEAN countries are planning an interconnected electricity grid and Indonesia has a 35 GW electrification drive in progress.

This pre-feasibility study is intended as a 'first pass' of commercially oriented research to stimulate discussion and determine whether further research is warranted.

This pre-feasibility study is based on the immense solar potential in the Pilbara and the alignment of:

- The shift to a decarbonised economy
- A transitional window of very large renewable energy investment
- Falling prices of solar generation and breakthroughs in HVDC technology
- The forecast increased electricity demand and grid integration in ASEAN.

This pre-feasibility study is the first step toward establishing whether there is a commercial case for mobilising Pilbara solar resources to high demand centres in Southeast Asia. Given that the 35 GW electrification drive is underway, and Java is the closest significant load, the pre-feasibility study examines a 'pilot' project, to provide 3 GW of Pilbara-generated solar to the Java grid.

The pre-feasibility study examines:

- Trends in cross-border electricity trade
- The potential market impact of solar energy and regional trading
- The value to Southeast Asia
- Preliminary engineering and costing of GW scale solar farms and HVDC transmission
- Economic impacts in the Pilbara region
- Best practice and partnership models for Traditional Owners of land in the Pilbara.

This pre-feasibility study was intended as a 'first pass' of commercially oriented research to stimulate discussion and determine whether further research is warranted.

03

HVDC and trends in cross-border electricity trade

3.1 Key findings

- HVDC technology is driving grid interconnection, cross-border electricity trade, and long-haul transmission.
- HVDC enables remotely located renewable energy resources to be accessed by load centres thousands of kilometres away, with minimal transmission loss.
- Interconnection of electricity grids and electricity trade is occurring worldwide. Renewable energy is a key feature of this integration.
- The endpoint of this trend towards interconnection is a global electricity market, which is being advocated by the special purpose Chinese organisation, Global Energy Interconnection Development and Cooperation (GEIDCO.)
- Plans for increased electricity trade is occurring in the ASEAN region. ASEAN is forecast to become a 'centre of gravity' of world economic activity, with rapidly expanding electricity demand.
- The ASEAN Power Grid is progressing slowly.
- Preconditions for fostering successful cross-border electricity trade in other parts of the world include:

    • Shared culture, identity, and trust
    • Safe regulatory environment with clear rules
    • Leadership and Key Actors and Project Champions
    • Pre-existing economic agreements.

3.2 HVDC - An introduction

High Voltage Direct Current (HVDC) technology is one of the catalysts driving transformation in electricity markets. Alternating Current (AC) is the technology of choice for distribution networks where electricity is dispatched for consumption at many points. One feature of HVDC is that it can connect two non-synchronous AC networks (Ardelean 2015). HVDC interconnectors link AC networks, for example, the Basslink interconnector connects the Tasmanian electricity network with the National Electricity Market (NEM). Electricity is traded both ways between those two networks. Basslink is an unregulated interconnector, in that it has unregulated income. Income is derived via arbitrage, trading of spot 'prices' between markets or contracted service/volume arrangements with retailers or generators.

HVDC is also the long-haul bulk carrier of electricity. Higher voltages for both AC and DC have less transmission loss. DC can go far greater distances with very low transmission loss. DC also requires fewer materials and is more compact, so it has less environmental impact and lower costs for land-based transmission (ibid, 2015). These long-haul interconnectors that transport electricity from point A to point B are regulated interconnectors. They are usually internal to a network and have a regulated income derived from a set of jurisdictional rules or laws.

Hydro electric generation has been a major driver of long-haul overland HVDC transmission. In Brazil, for example, the San Antonio and Jirau hydro generation sites are more than 2,300 km away from the load centres in east Brazil. HVDC has been used across many continents to link hydro generation to loads. It is very heavily used in China, in projects such as Three Gorges-Changzhou (890km) and Xiangjiaba-Shanghai (1,907 km).

China has 22 operational HVDC interconnectors and seven under construction (Jun, 2015). These interconnectors also link other types of generation, such as thermal power and renewable energy. For example, once completed, the Ultra High Voltage Direct Current (UHVDC) ± 800 kV Jiuquan-Hunan project (2,383 km) will carry 8000 MW of wind energy (State Grid Corporation, 2016).

HVDC transmission and interconnection play a significant role in the high level of integration in the European Single Electricity Market, and underpins the proposed Asia Super Grid. For Mongolia, HVDC is the critical technology on the pathway to becoming a renewable energy superpower. President Elbegdorj Tsakhia is a powerful advocate for the development of the Gobitec project, which would transform Mongolia into North East Asia's energy hub. Gobitec aims to connect to the electricity grids of Russia, China, Japan and South Korea via HVDC and export 100 gigawatts of Mongolian wind and solar energy (Mano, 2014).

HVDC and AC transmission can also be implemented subsea. Currently, Europe is a hotbed of existing and proposed subsea HVDC projects. This includes regulated and unregulated interconnectors with network-to-network transmission, as well as transmission from generation sites including offshore wind farms. As noted in Figure 2, an offshore HVDC grid is currently under discussion.

It is important to note that land-based HVDC transmission capacities are significantly higher than subsea HVDC transmission, however increasingly ambitious subsea projects are being considered. The European Union and the North Atlantic Energy Network are currently undertaking preliminary research projects to understand the technical and geopolitical challenges of a transcontinental interconnection between North America and Europe – the Offshore Transnational grid (OTG) (Ardelean, 2015) (North Atlantic Energy Network, 2016).

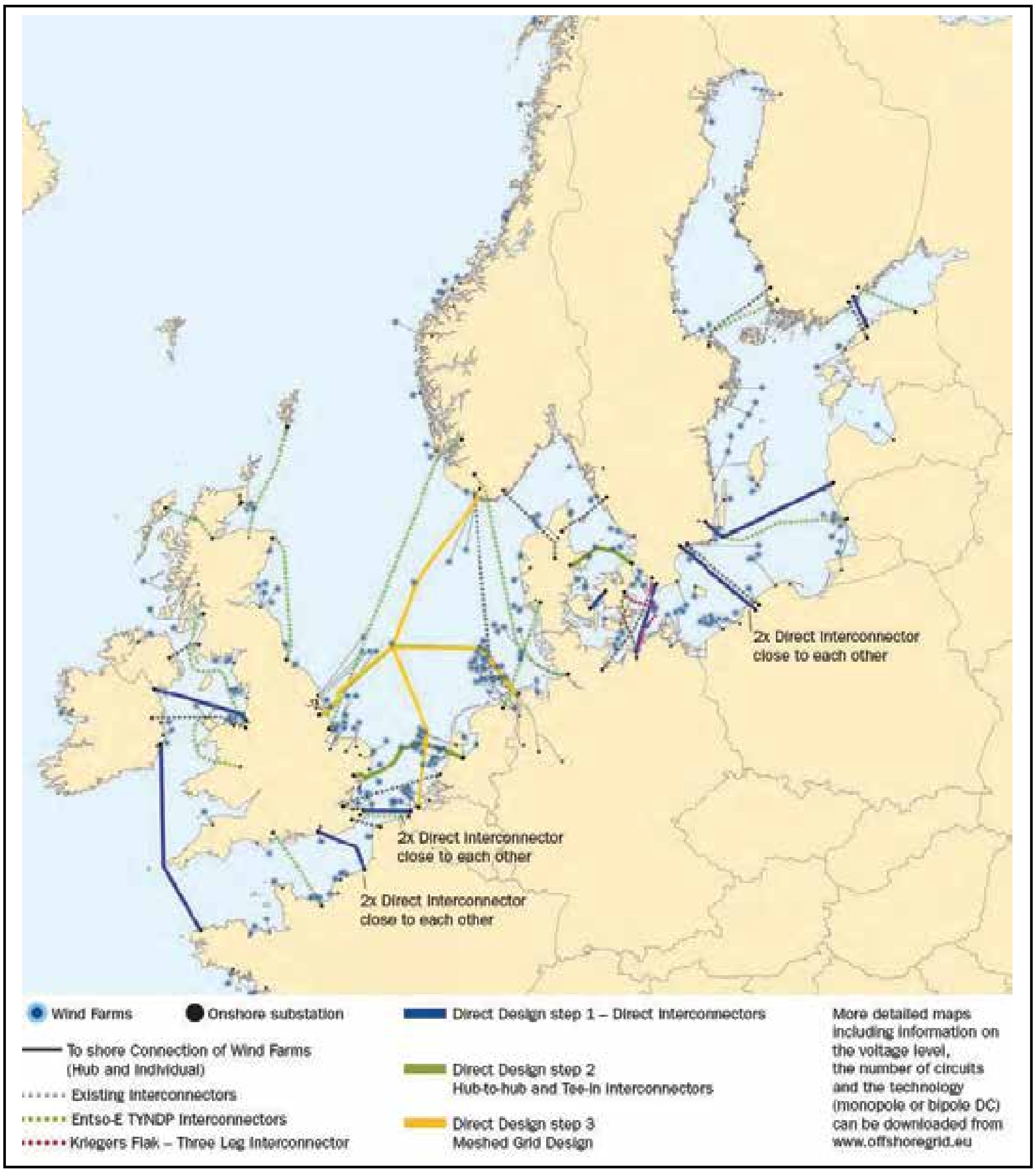


Figure 2: Proposed and existing European Application of subsea interconnection *Source: DNVGL*

3.3 Profiles of HVDC Projects

The following section profiles some key HVDC projects. It is important to note that these profiles represent only a small number of existing projects. The projects outlined below were selected because they have some instructive elements to a potential link between the Pilbara and ASEAN countries. (For future reference, an HVDC link can have a single electrical circuit called a ***monopole***, or a pair of electrical circuits called a ***bipole***, with a bipole having twice the power capacity of a monopole.)

3.3.1 Madeira

Capacity: 7,100 MW
Length: 2,375 km
Voltage: 600 kV bipole x 2
Cost: N/A
Ownership: Multiple

The full scope of the 'Madeira Complex' consists of two hydro-electric generation power stations – San Antonio and Jirau – and two transmissions systems – the two local AC transmission systems and two long-haul HVDC bipoles. It is described visually in Figure 3. These two bipoles combined have the capacity to transfer 7.1 GW of electricity from the dams in western Brazil to the major demand centres in the east. At 2,375 km in length, the Madeira Complex is the longest HVDC transmission system in the world.

An interesting and distinctly Brazilian feature of the Madeira Complex is that different components are owned by different entities, which are responsible for their own construction and operation, yet are integrated into one system. This 'Lots' system is common in Brazil to ensure a competitive outcome (Graham, 2012). Table 1 shows the ownership structure of the whole Madeira Complex.

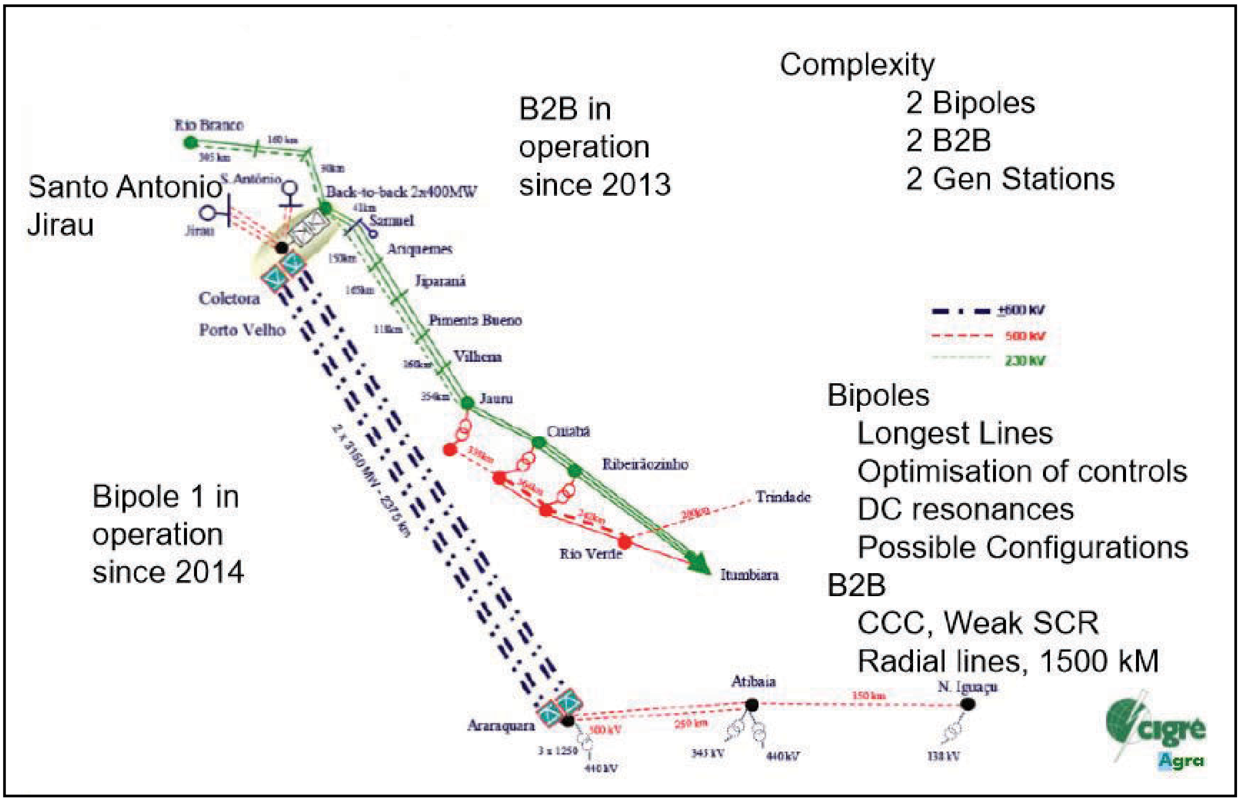


Figure 3: The Madeira Complex

Source: CIGRE SC B4 Colloquium on HVDC and Power Electronics (Toledo, 2015)

Component	Specifications	Owner
Bipole One: 2 Poles/Porto Velho Substation	600kVDC, 1,575MW each pole	Eletronorte
Bipole One: 2 Poles/Araraquara Substation	600kVDC, 1,575MW each pole	Eletronorte
Bipole One: 1 Bipolar Transmission Line Porto Velho - Araraquara	2,375km	Interligação Elétrica do Madeira (IE Madeira)
Bipole Two: 2 Poles at Porto Velho Substation	600kVDC, 1,575MW each pole	Interligação Elétrica d Madeira (IE Madeira)
Bipole Two: 2 Poles at Araraquara Substation	600kVDC, 1,575MW each pole	Interligação Elétrica do Madeira (IE Madeira)
Bipole Two: 1 Bipolar Transmission Line Porto Velho - Araraquara	2,375 km	Norte Brasil Transmissora de Energia (NBTE)
Back-to-back local energy systems x 2	400MW each pole	Eletronorte
Jirau Power Plant	3.75 MW	Energia Sustentável do Brasil
Santo Antônio Power Plant	Not available	Santo Antônio Energia

Table 1: Components and ownership structures of the Madeira Group

The Madeira Complex structure of different owners and manufacturers for the two bipoles created significant challenges. Respecting separate intellectual property, the differing philosophies and strategies of each manufacturer, and complexities with the joint commercial operations and the technical integration of AC and DC systems were all issues. In addition, Bipole 2 was delayed in commissioning due to a fault.

The Madeira Complex HVDC transmission lines – Bipoles One and Two – also faced enormous environmental and social challenges. The DC overhead lines navigated diverse terrain – swamps, savannahs and the World Heritage-listed Amazon Rainforest as shown in Figure 4 – in compliance with strict environmental requirements. The overhead lines passed through five states, 82 municipalities and rainforest areas populated by Indigenous people. Where possible, the transmission lines avoided areas populated by Indigenous groups. Fundação Nacional do Índio, a federal government agency tasked with protection of Indigenous groups, mediated negotiations where the transmission lines did traverse their land. More than 3,000 land use agreements were signed to enable the lines to be constructed. IE Madeira also undertook environmental and social mitigation programs, including in the Indigenous areas (Morais, 2015).

Source: Interligação Elétrica do Madeira

Figure 4: Bipole One passes over the top of the rainforest to minimise environment impact

3.3.2 Neptune

Capacity: 660 MW
Length: 105 km total, 82 km submarine
Voltage: 500 kV
Cost: US$600 M
Ownership: Private consortium

"In selecting Neptune, LIPA determined that importing power via the Neptune cable was more economical than building new power plants on Long Island. Neptune provides access to one of the most diverse and competitively priced power markets in the United States, called PJM, which controls electricity flows in all or parts of 13 states and contains more than 160,000 MW of diversified and relatively low-cost power generation."

(Neptune RTS, 2016)

The Neptune Project was commissioned in 2007. It links the PSEG Long Island network (previously LIPA) in New York State to the much larger PMJ network through New Jersey, as shown in Figure 5. The link imports 660 MW– or 20% – of Long Island's electricity. LIPA stated that in its first 100 days of operation, Neptune had saved US$20 million, and that over 20 years, it was expected to save US$1 billion (Hocker, 2007).

The Neptune Project is managed by Powerbridge. It is privately owned by Neptune Regional Transmission System (RPT), which is made up of a group of equity investors.
The original investors that launched Neptune were Atlantic Energy Partners, Energy Investment Fund and Starwood Energy Group Global. The current principal equity investors are:

- California Public Employees Retirement System – the largest pension fund in the USA
- NM Neptune LLC – a company that sits within the Northwestern Mutual Life Insurance Company
- Ullico – a family of financial services companies
- Ridgewood Private Equity Partners
- Atlantic Energy Partners – a consortium of private companies with expertise in the development of energy projects, construction, investment: Anbaric Holdings; Cianbro Development Corporation; CTSBM Investments LLC – an investment entity owned by individuals; Standard Energy Development Inc; Boundless Energy LLC.

Neptune is a separate entity from PSEG Long Island and PMJ. PSEG Long Island is the 'client' and has a long-term agreement with Neptune for the transmission service from the PMJ network – therefore it is a regulated interconnector. The cable used for Neptune was custom-designed and manufactured by Prysmian. The Neptune Project was delivered on time and on budget (ibid, 2007).

Figure 5: The Neptune route map *Source: Neptune Regional Transmission System*

3.3.3 NorNed

Capacity: 700 MW
Length: 580 km submarine 20 km overland
Voltage: 450 kV Monopole
Cost: €600 M
Ownership: Joint Venture Statnett and TenneT

NorNed connects the Dutch and Norwegian grids and, for the moment, is the longest submarine interconnector in the world (See Figures 2 and 10). The Netherlands imports Norwegian hydroelectricity during the day and Norway imports Dutch gas-fired energy at night. NorNed is a 50-50 joint venture between state-owned transmission system operators Statnett (Norway) and TenneT (Netherlands).

NorNed was a natural evolution from the positive experience with Skagerrak and other submarine links between the Scandinavian and Baltic states. Skagerrak is the Norwegian-Danish joint venture that began in 1977 and which has evolved into a two bipole (four poles) 1,700 MW transmission system linking the two countries. Building from this experience, NorNed underwent a 10-year planning process and three years of engineering and construction.

The interconnector has different cable designs for different depths of the route, as it runs across a busy shipping lane. In the shallow section of the route, the cable requires protection from anchors, but was also required to minimise its magnetic field to reduce the risk of interference with shipping navigation equipment. In the deeper part of the route, these risks are reduced. The cables were designed and manufactured by Nexans and ABB (Skog, 2010).

Given the difficult North Sea environment, the rapid construction of NorNed was a significant feat. While there were some setbacks from cable failures in the initial stages, NorNed's operations have since been stable, with no significant interruptions (Skog, 2010). NorNed is known for being a profitable interconnector with annual revenues of €50M (Ardelean, 2015).

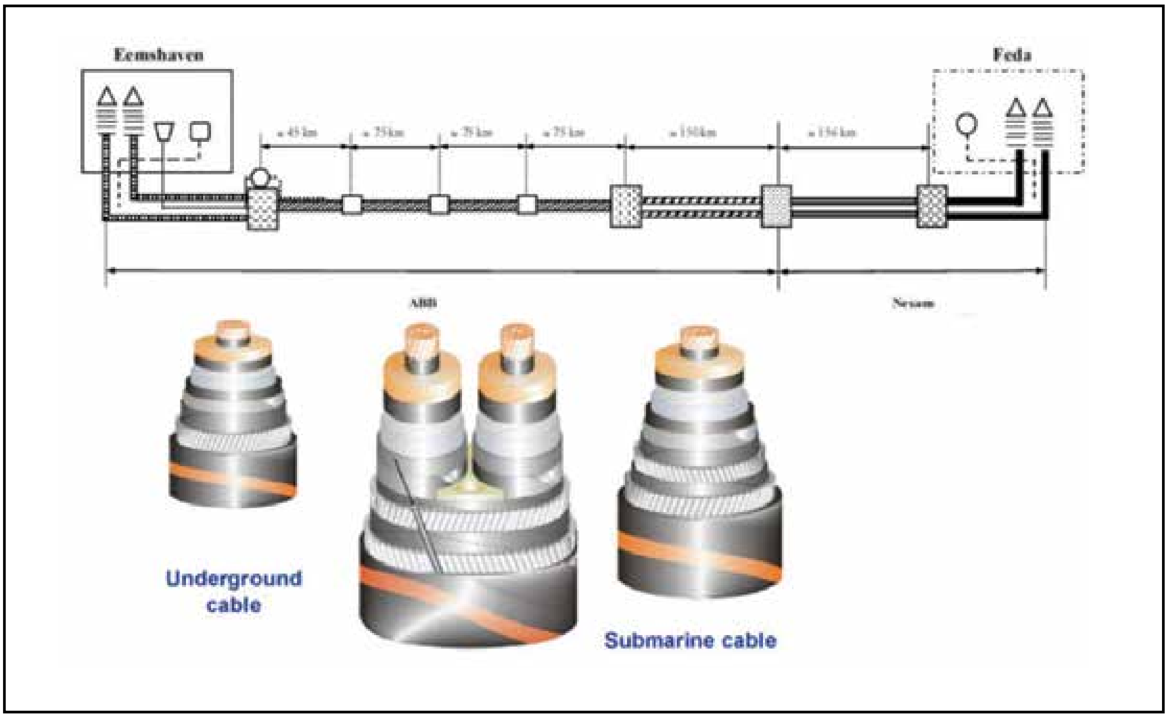


Figure 5a: Cable types used for the NorNed subsea HVDC project
Also see Figure 40.

Source: Skog, 2010

3.3.4 Basslink

Capacity: 500-630 MW
Length: 366 km total, 290 km submarine
Voltage: 400 kV monopole
Cost: AU$874 million
Ownership: Keppel Infrastructure Trust, Singapore.

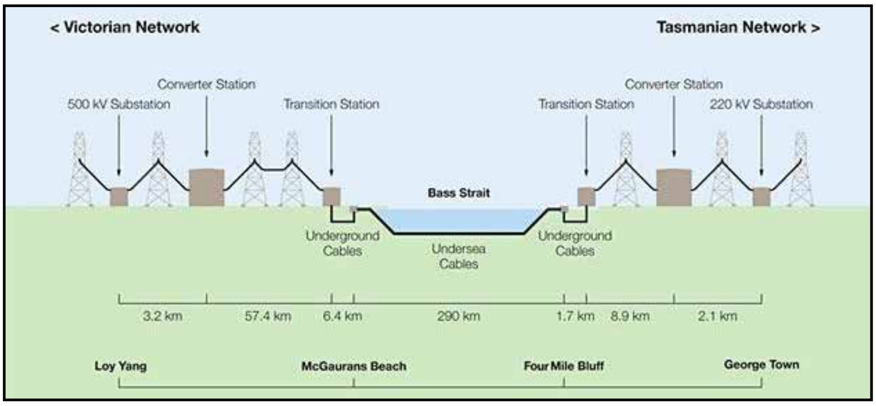


Figure 6: Components of the Basslink interconnector

Source: Basslink

Basslink connects Tasmania to the National Electricity Market (NEM) through the Loy Yang brown coal power station in the LaTrobe Valley. The interconnector enables Tasmania to sell its hydroelectric resources into the NEM and to import power from the mainland as required. Fibre optic telecom cable is embedded in the interconnector and telecoms services provide an additional – although small – revenue stream. Basslink is the only alternative telecommunications provider to Telstra in Tasmania.

The Basslink vision was conceived in the 1960s, however the Tasmanian government did not commit to the project until 1997. National Grid, a British transmission network company, won the tender to design, build, own and operate Basslink. When it was built, Basslink was the longest subsea interconnector in the world. In 2007, Basslink was sold for $1.2 billion to the Singaporean investment company CitySpring Infrastructure Trust (ABC, 2007). Keppel Infrastructure Trust now owns Basslink.

Basslink was a "project of State significance" (Electricity Supply Expert Industry Panel, 2012) and one part of major package of electricity reforms in Tasmania. It underpinned the following strategic objectives:

- To improve energy security during drought
- To allow Tasmania access to competitively priced electricity in the NEM
- To enable Tasmania to export electricity to the NEM
- Ensure returns from the state-owned electricity businesses were maximised

Basslink's business case evolved considerably during the development phase, between 1999 and 2002. The developers considered it financially unviable for Basslink to be funded solely by transmission charges to customers. The revenue streams in the final 2002 business case included revenue from arbitrage, value in added yield from improved water storage management, creation and sale of Renewable Energy Certificates, and more net export to Victoria. (Electricity Supply Expert Industry Panel, 2012).

It is still relatively early in Basslink's 40-year lifecycle. The key risks to Basslink were identified as hydrological issues. Low rainfall did impact on Basslink during its first five years of operation, limiting Hydro Tasmania's ability to practice arbitrage, export electricity and benefit from Renewable Energy Certificates. However, Basslink's ability to import from the NEM protected Hydro Tasmania from the potential consequences, averting the need to build additional power stations. It's estimated that during the period of low rainfall (2005-2011) more than $300 million in power station construction costs were avoided due to Basslink.

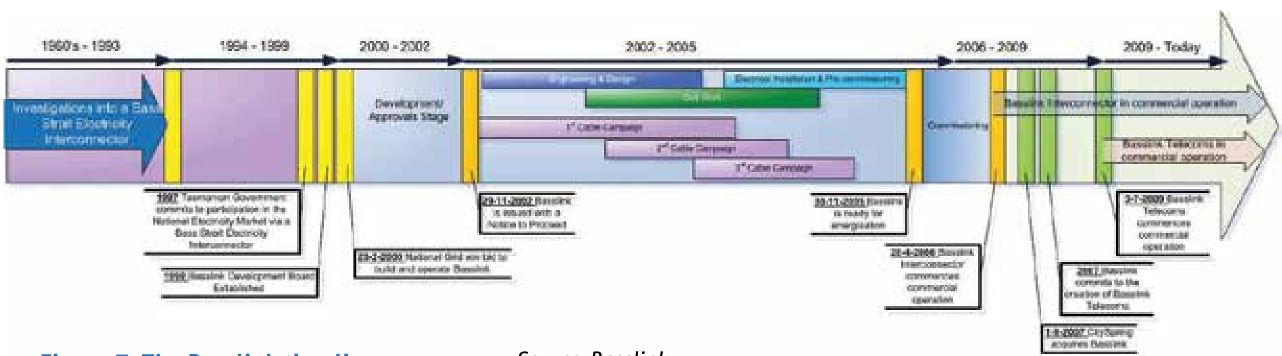


Figure 7: The Basslink timeline

Source: Basslink

3.3.5 SAPEI

Capacity: 1,000 MW
Length: 435 km total, 420 km submarine
Voltage: +/- 500 kV Bipole
Depth: 1,650 m
Cost: €740 M
Ownership: Terna (Italian Transmission systems operator

The SAPEI interconnector runs between the Italian mainland and Sardinia, crossing a stretch of deep water with complex subsea topography. SAPEI uses a copper conductor in the shallow water, and an aluminium conductor, which is lighter, in the deep water (Kauffman, 2015). The precedent of SAPEI was the SACOI, a long-lived submarine interconnector that had linked Sardinia, Corsica and mainland Italy since 1967 (Terna, 2014).

The rationale for building SAPEI was an upgrade from SACOI. It was designed to guarantee security of supply of load in Sardinia and better utilisation of peak load. SAPEI also enables export and there is now significant pipeline of wind generation underway. SAPEI is owned and operated by the Italian transmission system operator, Terna, and began operating in 2012.

Reaching a depth of 1,650 m (Figure 8), the SAPEI interconnector is the deepest in the world and this makes it an important precedent project for a transmission line between Australia and Indonesia.

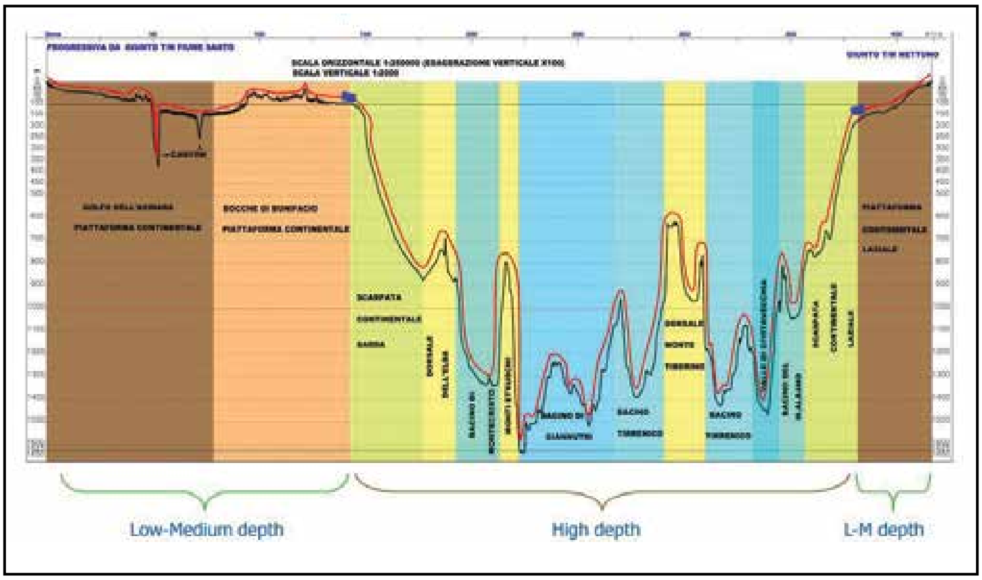


Figure 8: SAPEI subsea cable profile

Source: Terna Presentation of SAPEI Project Cigre Seerc meeting

3.3.6 Icelink (proposal)

Iceland has abundant hydro and geothermal resources. It has become a base for data centres and aluminium smelters that require cheap electricity. Iceland has long considered a subsea link to Europe, however with increased demand for renewable energy and the breakthroughs in HVDC technology, it seems that Icelink is increasingly economically viable. A recent analysis demonstrated that a 1,200 km 1,000 MW interconnector from East Iceland to Northern Great Britain could be delivered for €2.8 billion (Askja Energy, 2016).

It is interesting to note that imported Icelandic geothermal and hydro appears to be more competitively priced than domestically generated offshore wind for Great Britain (Askja Energy, 2016). A 'contract for difference' and solid support from Great Britain is essential for this project to go ahead. The estimated connection date is 2025.

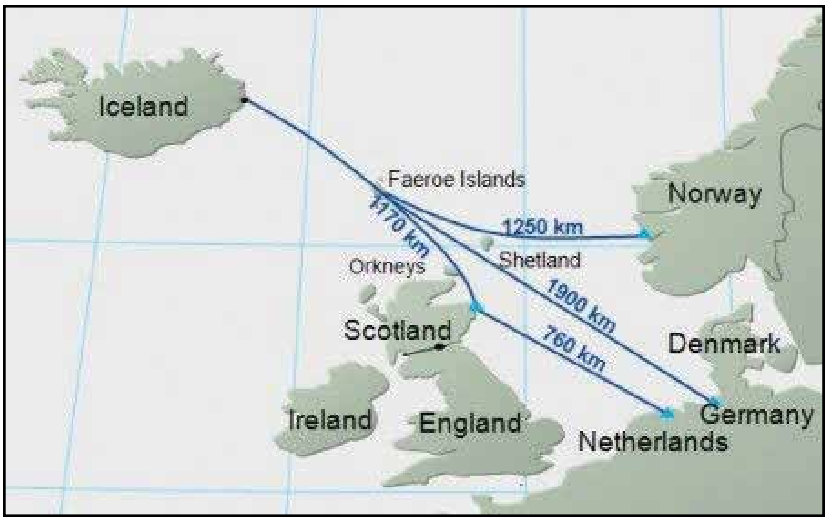


Figure 9: Submarine routes *Source: Askja Energy Partners Ltd.*

3.4 HVDC Project Risks

There are engineering risks to any major infrastructure and energy project, including HVDC projects. Outages can occur for a variety of reasons and can be mitigated via competent design methodologies and circumstances, however it must be assumed they will occur. The extent and significance of impacts is linked to the duration and regularity of events.

With regards to submarine cable interconnectors, repairs can be complex and can take many months (Eccles, 2014). NorNed experienced two cable failures in the first months of operation (Skog, 2010). In 2015, Basslink experienced a fault some 100 km offshore. While these are unfortunate for the respective owners, these events are rare (CIGRE Working Group B1.10, 2009).

Significant outages are not limited to subsea cabled interconnectors. The Madeira Complex Bipole Two faulted immediately after construction and was offline for many months. At the time of writing, Bipole Two was in trial operations and preparing to resume full operation. There is a general phenomenon in engineering called the 'bathtub effect' where, all being equal, equipment failures are more likely to occur at the beginning or end of design life. Hence when failure rates are plotted, a bathtub shape occurs.

There are a number of design and operational strategies employed to mitigate the severity of major outages. The Madeira Complex design of bipoles versus monopoles, plus a duplicate transmission system, reduces the potential of severe electricity supply restrictions if faults occur. The Submarine Cables: the Handbook of Law and

Policy notes that "restoration of services by other oceanic power cables is not available in the case of monopole HVDC and AC cables" (Eccles, 2014). This is because these are single cable systems connecting standard terrestrial AC networks that have no other form of interconnection. In such situations, redundancy provided elsewhere in the power system will mitigate the impact and severity of outages if and when they occur, as will best-practice operational planning and maintenance.

Risks do need to be viewed in context and are not limited to significant electricity infrastructure projects. For example, in 2009 the Montara oil and gas spill leaked oil and gas for 10 weeks and covered 90,000 square kilometres of the Timor Sea (White, 2011).

In Brazil, the 2015 BHP Fundão Dam collapse killed 19 people, and the associated contamination is still having ongoing economic and social impacts (Knight, 2016). Subsea HVDC cable failures are unlikely to have such devastating consequences, however may cause economic losses.

The risks of all HVDC projects – both overland and subsea – need to be thoroughly assessed and viewed with the benefits, within the full lifecycle of the project. Prudent owners and operators of major infrastructure will plan significant impacting events, putting in place measures to mitigate severity, including design revisions and operational strategies. This doesn't mean that major outages are inevitable, it is just good practice.

3.5 Emerging trends in cross-border electricity trade

Historically, electricity has been generated and distributed by vertically structured state-owned entities within nations or states, that has favoured the development of monopolies. This has been gradually changing. In the United States, deregulation of electricity markets began in the 1970s and many other countries have since followed suit. Deregulation usually decouples generation and transmission. It creates a market-based trading platform and opens the transmission system to many generators, which increases competition and brings prices down. The process of electricity market deregulation began in Australia in the 1990s.

In some parts of the world, such as Scandinavia and Europe, cross-border electricity trade is commonplace. Electricity is traded in commodity markets with spot and futures trading. In North and South East Asia, there is a push for integrated electricity markets and cross-border trade. This is being driven by a number of factors: to ensure security of supply; to create efficiencies and reduce duplication; to create more competitive energy markets; and to accommodate the need to integrate renewable energy.

Samantha Mella Geoff James Kylie Chalmers

Figure 10: The Nordic power system

Source: Svenska Kraftnat (Swedish Transmission System Operator)

3.6 Cooperation and collaboration

Cooperation and collaboration between electrical utilities has occurred in many regions that share boundaries and common interests. The first power pool began in 1927 in the US with the three utilities serving New Jersey and Pennsylvania pooling resources and cooperating to save costs. This collaboration has evolved over time into PJM Interconnection – a Regional Transmission Organisation (RTO) that manages a high-voltage transmission grid across 13 states, ensuring supply of electricity to 61 million people. It operates a wholesale market and provides long-term grid planning. PJM is a not-for-profit organisation operating within strict guidelines to ensure an open and transparent energy market. It is one of the most competitively priced markets in the United States. PJM is cross-jurisdictional as opposed to cross-border (Oseni, 2014).

The Nordic countries have a long history of cooperation in many areas, underpinned by strong cultural ties. The high level of integration in the power market in Scandinavia today was driven by the power sector. The first cross-border interconnection was built in 1915 between Denmark and Sweden (Joergensen, 2016). In the 1960s, a collaborative research organisation, Nordel, was created by the transmission system operators of Iceland, Norway, Sweden, Denmark and Finland (Bredesen, 2016). Nordel became a valuable research and advisory body that contributed to cooperation and forged links across the region. It was retired in 2009 due to the emergence of the European Agency for Energy Transmission System Operators (Bredesen, 2016).

Nord Pool is a wholesale regional electricity market that evolved after the successful collaboration of Nordel. Again, it is an initiative of the transmission system operators themselves. It is regulated by common principles rather than rules (Andrews-Speed, 2016). Nord Pool began operations in 1996 when deregulation enabled a Norwegian and Swedish power exchange. Finland and Denmark soon joined. Nord Pool is now owned by transmission system operators from Norway, Sweden, Finland, Denmark, Lithuania, Estonia and Latvia, and is linked to the European market (NordPool, 2016). At the time of writing, 320 companies from 20 countries were using Nord Pool's trading platform.

3.7 Single European Electicity Market

The Single Electricity Market (SEM) was mandated by a distinct policy push by the European Union, as opposed to Nord Pool and PJM that evolved from voluntary collaboration. The need for a single electricity market was identified in 1988 as part of a comprehensive set of economic reforms (Andrews-Speed, 2016). Directives to open electricity markets were delivered in 1996, 2003 and 2009 as part of the Single European Market Project, which aimed to remove trade barriers across Europe. National governments were obliged to pass legislation that facilitated cross-border electricity trading and apply a consistent set of rules across national markets (Oseni & Pollitt, 2014).

Energy should flow freely across the EU – without any technical or regulatory barriers. Only then can energy providers freely compete and provide the best energy prices, and can Europe fully achieve its renewable energy potential.

European Union

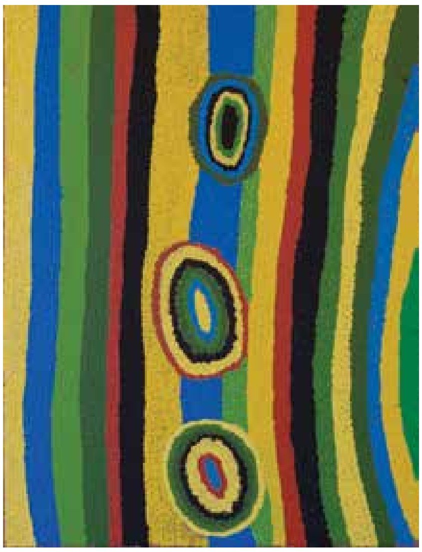
The EU Single Market reports on eight regional wholesale electricity markets:

- Central Western Europe (Austria, Germany, France, the Netherlands, Switzerland)
- British Isles (UK, Ireland)
- Northern Europe (Denmark, Estonia, Latvia, Lithuania, Finland, Norway, Sweden)
- Apennine Peninsula (Italy)
- Iberian Peninsula (Spain, Portugal)
- Central Eastern Europe (Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia)
- Southeast Europe (Greece, Bulgaria) (European Commission, 2016)

European countries also have a long history of deep cultural and economic engagement – as well as conflict. The top-down approach of the EU has meant a slow evolution of the Single Electricity Market (SEM). Some countries have not been eager to implement the EU directives, putting the interests of national utilities ahead of the development of the single market. The EU directives are legally binding and nations can be taken to court if they are deliberately obstructive.

3.8 The Southern African Power Pool

The **Southern African Power Pool (SAPP)** grew out of the Southern African Development Community in 1995 and with 12 members, is the most mature power pool in Africa. The foundations for the SAPP existed previously in prevailing bilateral and multilateral agreements. The SAPP enables vertically integrated state-owned utilities to trade with one another. The energy mix is almost three quarters coal, largely generated in South Africa. The 20% of energy generated from hydro comes from Zambia, Zimbabwe, Mozambique, Malawi, the Democratic Republic of Congo, Angola, Namibia and Tanzania. The implementation of the power pool has been effective in attracting investment and encouraging bilateral trade between states, which has helped with security of supply, however it has not yet been able to meet fluctuating demand. A 'day ahead market' has been introduced to address this (Oseni, 2014).



Beryl Ponce, *Make Soak Water to Drink*, 45 x 61cm, acrylic on canvas, 2016

3.9 The African Clean Energy Corridor

The African Clean Energy Corridor (ACEC) is a joint venture of the Eastern and Southern African Power Pools. The 2014 agreement aims to accelerate the development of Africa's vast renewable energy resources by propagating more regional renewable development and promoting cross-border trade. The ACEC vision is an interconnected trading corridor stretching from Egypt to South Africa, 50% of which will be powered from locally produced renewable energy by 2030. Partners include 21 countries in Africa, five outside Africa and three African regional bodies. The African Development Bank and the Agence Française de Développement are the partnering financial institutions and other international partners include the United Nations and IRENA as well as some commercial partners (United Nations, 2014).

3.10 Central American Electrical Interconnected System

The Central American Electrical Interconnected System (SEIPAC) was created to build economies of scale with greater generation capacity, as each of the six Central American states struggled to deliver affordable electricity supply with small-scale production. The centrepiece of the system is a single circuit transmission line linking all the Central American nations. The Central American Regional Electricity Market (MER) overlays the six national electricity markets and enables international transactions. Traded electricity accounts for around 5% of regional consumption and power exchanges, and typically takes the form of medium to long-term bilateral agreements, however there is also small spot market (Oseni, 2014). The Central American Integrated System (SICA) is also working with IRENA towards a Clean Energy Corridor (IRENA, 2015).

3.11 Gobitec and the Asia Super Grid

> *Somewhere on earth, the sun is always shining, the wind is always blowing, water is always flowing.*
>
> Masayoshi Son,
> CEO SoftBank

North Asia has complex geopolitical relationships and does not have a regional association of nations. Despite this, there are key actors in North Asia driving interconnection and the transition to renewable energy. Cooperation began with research collaboration. The 2014 Gobitec Report bought together researchers from Korea, Mongolia, Russia, Japan and Germany, as well as the Energy Charter Treaty. (The Energy Charter Treaty provides the legal and regulatory framework for the safe transit of energy across and between states.)

The Gobitec study examined the potential for a massive 100 GW rollout of wind and solar in Mongolia with interconnection between Korea, Mongolia, Russia, Japan and China. While the findings highlight some complexities, mutual benefits include economic diversification, skills transfer, job creation, access to low-cost renewable energy, improved infrastructure, and reduced pollution and emissions (Mano, 2014). One interesting finding is that the capacity-saving benefits of interconnection are very significant – equal to three quarters of the current generating capacity of the Republic of Korea (Voropai, 2014).

Finally, it was recommended that dispatchable technologies such as hydrogeneration be combined with wind and solar (Mano, 2014). The concept future interconnected system is shown in Figure 11.

Masayoshi Son – a wealthy and influential Japanese businessman - is one high-profile proponent of the vision of North Asian interconnection. The combination of climate change and the nuclear devastation of Fukushima led him to set himself the task of building a renewable energy society. Son has established the 'Renewable Energy Institute' in Japan to undertake research and advocate for the ASG. He started a renewable energy arm within his IT company Softbank, secured a 100-year land lease for 7GW of wind projects in Mongolia, and started construction on a 350 MW solar farm in India. At the 2016 International Symposium in Japan – Bringing Vast Renewables to Global Interconnection – Son stated that his research has found that renewable energy can deliver electricity cheaper than fossil fuels despite transmission costs (Son, 2016).

Mongolia is a key actor, aspiring to become North Asia's clean energy hub. President Elbegdorj Tsakhi's message is that Mongolia is open for business, and seeking partners and foreign investment to expand its renewable energy industry. Mongolia has passed a number of laws and tax incentives to create a stable, attractive investment environment for renewable energy investors. It has removed protectionism and streamlined processes to create a 'one-stop-shop' for investors wishing to enter the Mongolian market (Javakhlanbaatar, 2014).

Korea Electric Power Organization (KEPCO) is another major supporter of a North Asian renewable energy grid. KEPCO is a heavy consumer of fossil fuels and plans to increase its consumption (Kepco, 2014). CEO Hwan Eik Cho has described the impact of climate change on KEPCO, and how it has struggled to cope with demand during the extreme heatwaves in Korea. Cho describes the proposed interconnected system as "One Asia" and the transition to renewable energy as the "zeitgeist" (Cho, 2016). These are significant statements coming from the CEO of a company so heavily entrenched in fossil fuels.

Figure 11: One interpretation of the Gobitec Vision

Source: The Energy Charter Secretariat

3.12 China's Vision – Global Energy Interconnection (GEI)

Liu Zhenya, former Chairman of China's State Grid Corporation, shared his concept of Global Energy Interconnection (GEI) in his 2015 book. GEI is China's response to the triple threats of climate change, pollution, and resource constraints and was proposed in 2015 at the UN Sustainable Development Summit by President Xi Jinping.

In 2016, the **Global Energy Interconnection Development and Cooperation Organization (GEIDCO)** was launched, dedicated to creating an interconnected global electricity grid. Liu Zhenya is the Chairman. GEIDCO has 14 member countries from five continents. GEI is defined as transmission connecting grids with a capacity above 10GW across regions, nations and continents. GEI aims to:

- Decarbonise electricity systems
- Provide enough transmission capacity to bring renewable energy into the grids
- Drive electrification in other energy sectors, for example, transport.

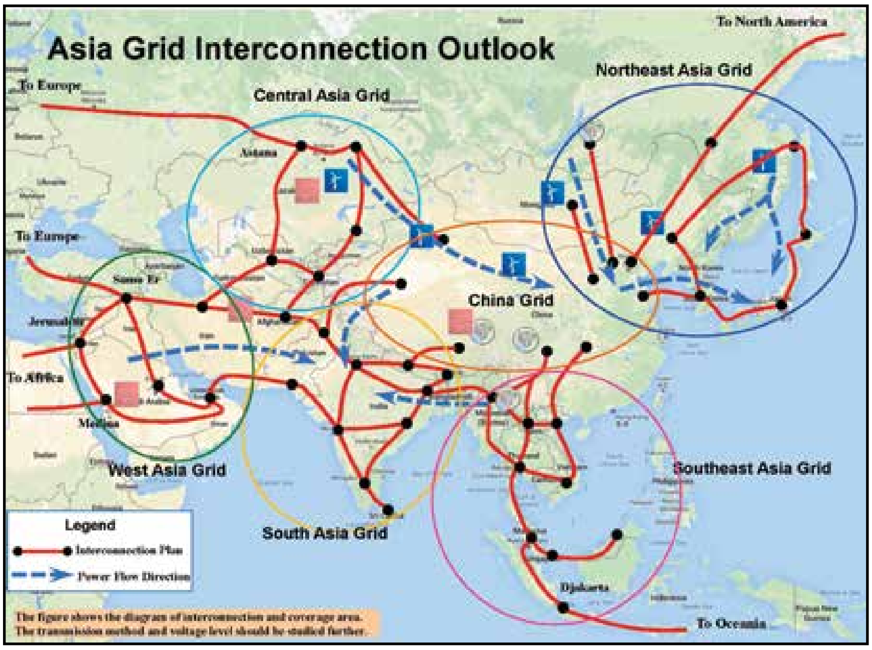


Figure 12: GEIDCO's '1+5' *Source: GEIDCO*

Liu Zhenya states that GEI is technically feasible and the preconditions for global interconnection were laid down in the Paris Climate agreement. GEI has the support of the United Nations and the International Energy Agency (Liu, 2016).

GEIDCO's most urgent priority for interconnection and renewable energy implementation is Asia. Asia is the fastest-growing region with the largest economic potential and the most energy demand. GEIDCO's goal includes 1.6 TW and 15 TW of installed renewable energy capacity across Asia by 2030 and 2050 respectively. This is an ambitious target.

GEIDCO's vision of Asian interconnection is '1+5' – the Chinese national grid linked by HVDC interconnectors with five Asian regional grids in North, Central, West, South and Southeast Asia (Liu, 2016) as shown in Figure 12. GEIDCO has signed an MOU with UN ESCAP to undertake research and planning on Asian Grid Interconnection, and pre-feasibility studies on the Sino-Mongolia and China-Japan-Korea HVDC projects are in progress.

The State Grid Corporation of China, previously chaired by Liu, has prioritised research, development, and implementation of bulk long-haul electricity transmission - High Voltage Direct Current (HVDC). Across China, there are 22 HVDC and Ultra HVDC (UHVDC) transmissions lines and seven under construction (Jun, 2015). China's capability is demonstrated in State Grid's existing UHVDC projects, which are truly massive both in length and transmission capability. They include:

- Jinping-Sunan 7.2 GW 2,059 km
- Xiangjiaba-Shanghai 6.4 GW 1,907 km
- Hami-Zhengzhou 8 GW 2,210 km

There are three other 8 GW projects in progress, including the Jiuquan-Yunnan 800 kV transmission line, which is 2,383 km long (Jun, 2015). China is therefore very well placed to advocate for the rollout on global electricity interconnection with HVDC and UHVDC – though without subsea experience.

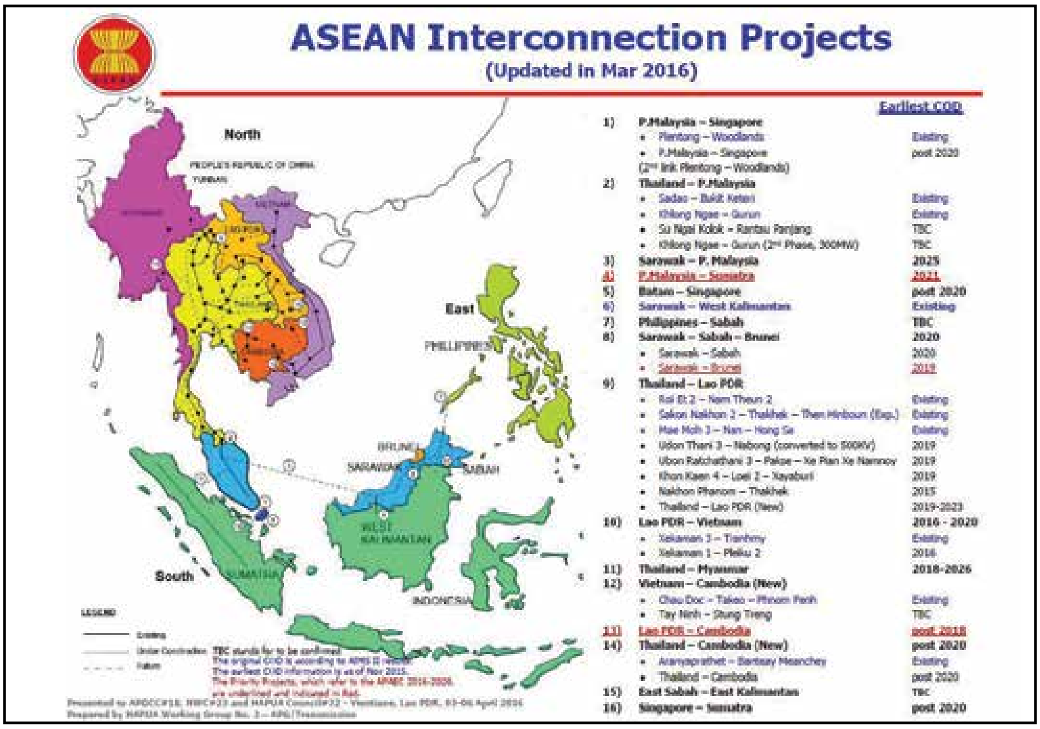


Figure 13: ASEAN interconnection – proposed and existing *Source: HAPUA Secretariat*

3.13 ASEAN Power Grid

While ASEAN countries are not as closely culturally tied as the Nordic nations, the region is not as geopolitically complex as North East Asia. ASEAN countries do share history and culture, and the experience of being small countries with a large and powerful neighbour. The ASEAN Power Grid (APG) has emerged from the region's desire for an ASEAN Economic Community (AEC) – a single market for goods, services and capital. The APG was mandated in 1997 as part of AEC Vision 2020. The goal of a single ASEAN network include increasing energy security and efficiency, providing more flexibility of supply, and increasing access to renewable energy. Full integration enabling multilateral trade is a long-term goal (Andrews-Speed, 2016).

The Heads of ASEAN Power Utilities/Authorities Council (HAPUA) and the ASEAN Power Grid Consultative Committee (APGCC) are the responsible agencies. There have been two ASEAN Integration Masterplan Studies (AIMS) in 2003 and 2010 (Syaiful, 2016). The second AIMS study found interconnection is economically viable, identifying savings in both investment for new projects and operating costs. As outlined in Figure 13, at present, the ASEAN Power Grid is a series of bilateral interconnectors that traded a total of 3,489 MW in 2015 (Syaiful, 2016).

It has been acknowledged that the APG will not be completed by 2020 as planned. HAPUA has updated its priority project list to reflect that (Syaiful, 2016). The reasons the APG is behind schedule are understood to be lack of capital, differences in energy system management, a lack of a common regulatory framework, and governments prioritising national self-sufficiency over regional integration (Andrews-Speed, 2016).

Three sub regions have been identified to provide indigenous power: North – hydrogeneration; East – hydro, geothermal and fossil generation; and South – fossil and geothermal generation (Syaiful, 2016). The Northern system is the most developed and active, with Thailand exporting to Cambodia and importing from Laos.

The Greater Mekong Sub Region (GMS) is an economic development project of the Asian Development Bank. It has brought capital and support to build infrastructure, connectivity and economic development in a region that has been severely impacted by conflict (ADB, 2016). The GMS includes Cambodia, Laos, Viêt Nam, Myanmar and Thailand, plus the Chinese Provinces of Yunnan and Guangxi. GMS has helped boost the development of hydroelectric projects in the Mekong region.

Southeast Asia is moving to the centre of the global energy arena, a trend that is underpinned by economic and demographic drivers, and that is set to continue for the foreseeable future.

(IEA, 2015)

The International Energy Agency (IEA) has forecast that electricity demand for Southeast Asia will almost triple by 2040. To meet the increase in demand, an additional 400 GW of power generation capacity is required across the region within the next 25 years (International Energy Agency, 2015). Given the projected rapid expansion of demand, HAPUA aims to accelerate the APG with both bilateral and sub-regional trade.

The Laos-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) is a pilot project to expand electricity trade beyond bilateral arrangements. LTMS-PIP will be an important indicator of progress. Technically, it is relatively simple for Laos to sell electricity to Singapore via Thailand and Malaysia, as the connections exist. However, the commercial, legal and regulatory barriers are yet to be resolved. Laos is eager to sell its hydro, yet Singapore will not commit to a power purchase agreement and Thailand and Malaysia have yet to reveal if their transmission tariffs will be competitive (Andrews-Speed, 2016).

Another complexity for the APG is that most of the projects in the GMS have 25-year power purchase agreements, which exclude third party access to the interconnectors. While these agreements provide security for investors, they can represent a barrier to a competitive open market (Andrews-Speed, 2016).

While ASEAN aspires to have a single integrated energy market, only a small proportion of electricity is currently traded bilaterally. Many of the nations are focused on internal domestic electrification projects rather than interconnection. ASEAN does not have the legal authority of the EU to mandate legislative changes. To help create a common framework, HAPUA is considering the implementation of the APG Transmission System Operator Institution (ATSO) and the APG Generation and Transmission System Planning Group Institution (AGTP), as recommended by the Asian Development Bank (Syaiful, 2016).

3.14 The Indonesian 35GW electrification drive

Indonesia sees its electricity shortage as a major barrier to its development goals, and therefore President Joko Widodo has made electrification a high priority. The Indonesian 35,000 MW electrification drive program was announced in June 2015 and is scheduled to conclude by 2019.

The electrification is largely directed at coal-fired infrastructure using Indonesia's coal resources. There are allocations for renewable and imported energy. Indonesia understands that its target is ambitious and faces constraints, for example, land use conflicts. Indonesia is considering new ideas for electrification from both national and foreign enterprises. (See Sections 4.2.1 and 5.6).

04

Market impact of solar energy and regional trading

4.1 Key findings

- The business case to deliver Pilbara solar energy via interconnection to Indonesia can be expressed simply: how much will it cost, and how much will it earn?
- This study finds that it will cost 18-25 c/kWh over the long term and it will earn 19-20 c/kWh from the solar feed-in tariff applicable in Java. There are technology and supply chain uncertainties on the cost side, and the need for a negotiated outcome recognising strategic benefits on the revenue side.
- The economic case for connection to Indonesia has potential, and the falling costs of solar and storage may confirm this in the near future.
- A higher feed-in tariff in Indonesia means that the business case for connecting to Indonesia is more favourable than connecting to the NEM.
- An experienced solar industry in the Pilbara with a proven ability to deliver cost-effective utility scale solar, potentially with storage, would significantly improve the economic case.
- The speed and geographic distribution of the solar build have an important influence on the resulting levelised cost of energy (LCOE) over the project lifetime.
- Battery energy storage can be integrated without increasing LCOE due to improving the HVDC capacity factor and makes the solar generation fully dispatchable, increasing its value to the local and international markets.

4.2 Introduction

The business case to deliver Pilbara solar energy via interconnection to Indonesia can be expressed simply: how much will it cost, and how much will it earn? This is not to ignore the complex risk-and-opportunity analysis that will support a commercial decision to proceed. However, unless the outlined economic case is credible with our present level of knowledge, it is unlikely that there will be any commercial interest.

This study finds that the levelised cost of energy (LCOE) from solar PV generation in the Pilbara delivered to Java is 18-25 c/kWh. This energy will earn 19-20 c/kWh from the solar feed-in tariff presently applicable in Java. But these simple answers ignore the technology and supply chain uncertainties on the cost side, and the need for a negotiated outcome recognising strategic benefits on the value side. The uncertainties are significant in both directions, with cost and performance assumptions tending to be conservative, so it is quite credible that the LCOE could be less than the applicable solar feed-in tariff. The business case has potential for success given the right conditions and preparation.

This section documents a set of economic assumptions, referring to technology assumptions in the engineering analysis later in the report, and develops a 40-year cash flow analysis for a Pilot Project with a 3 GW subsea HVDC transmission line and a compatible solar PV generation capacity. Several key input assumptions are examined through a sensitivity analysis. Integrating battery energy storage with solar PV generation to improve the utilisation (capacity factor) of the subsea cable is considered, and found to be an attractive option. Pumped hydro storage would have a similiar benefit.

For comparison, the market value of Pilbara solar energy delivered overland to the east coast of Australia is also shown. Due to the time difference, afternoon solar energy in the Pilbara would supply into the evening peak demand on the east coast, and would correspondingly have a high value in the National Electricity Market (NEM). Delivering to the NEM, in addition to Indonesia, would also mitigate the risk of depending on a single market.

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Parameter	Value	Unit	Source
Applicable feed-in tariff in Java	14.5	US c/kWh	Presently with a capacity cap (Sullivan, 2016) that would require negotiation
Exchange rate with US dollar	0.75	$/US$	Approximate present exchange rate (recently lower and trending upwards)
Wholesale electricity price in the NEM	(time series)	$/MWh	Historical half-hourly market data from AEMO for the year 2010
Typical PPA value for solar energy in remote WA	200	$/MWh	Personal communication with a mining industry representative
REC price assumed constant until expiry in 2030	57.0	$/MWh	ASX REC Futures forecast for January 2021 (as of 16/10/2016)
European forward carbon price	4.94	Euro/tCO_2	EUA Futures (as of 14/08/2016)
Emissions intensity of electricity displaced by solar	0.8	tCO_2/MWh	Estimate (likely to be lower in the NEM and higher in Indonesia)
Exchange rate with Euro	1.44	$/Euro	Present exchange rate (as of 16/10/2016)
European carbon price used from 2031	5.69	$/MWh	Calculated from previous 3 parameters
Discount rate	7%		Typical for energy industry studies
Inflation rate	0%		This is a constant-dollar analysis

Table 2: Economic input assumptions for the cash-flow analysis of the 3 GW Pilot Project

4.3 Input assumptions

The general economic assumptions behind this LCOE analysis are shown in Table 2 which notes some data sources used for the cash flow analysis. Where up-to-date data are not available from our project partners, data have been obtained from generic and reputable sources, and conservative estimates are made when there is uncertainty.

For example, electricity prices are assumed to be constant apart from inflation, although this has not been the case in Australia during the past decade, where prices have risen at a rate higher than inflation.

In addition to these general assumptions, there are technology-specific assumptions for each of the major components and these are shown in Table 13, Table 14 and Table 17.

The major areas of uncertainty on the expenditure side are costs of finance (represented here by the discount rate), costs of the HVDC infrastructure, costs of solar power plant development in remote regions with potentially difficult conditions, and the rapidly declining costs of battery energy storage. Engineering challenges are discussed in Chapter 6. The major uncertainties on the revenue side are the valuation of Pilbara solar energy to the Java grid, including the grid support services provided at the HVDC connection point, and the strategic benefits of this project in positioning Indonesia as the epicentre of a new energy infrastructure and trade.

Before discussing the cash-flow analysis, the two potential receiving markets considered in this study will be examined.

4.3.1 Indonesian market for solar energy

On the revenue side, the major uncertainty is the applicable feed-in tariff in Java and the potential for network services payments based on the contribution of the proposed HVDC converter stations and transmission line to operating the Java grid.

The market for solar energy in Indonesia is discussed by Sullivan (2016). The National Energy Policy of 2014 anticipates that new and renewable energy will account for 23% of total energy by 2025. Total energy includes not only energy delivered as electricity, but also transport fuels, residential heating and cooking, and industrial heating processes. The target is extremely ambitious because achieving it will require significant transformation of the energy industry.

However, the policy environment in Indonesia is complex and subject to continuing debate. The 23% target has recently been reduced to 19.6%, and other policies are not necessarily consistent with this. For example, only 2.9 GW (8.1%) of the 35 GW target for new electricity generation is anticipated to be from new and renewable energy sources. Solar development has been held back by this uncertain and changing regulatory framework and also by a lack of attractive feed-in tariffs for solar energy.

The regulatory system that has been established in Indonesia is beginning to provide sufficient certainty to attract investment in solar generation. A 2013 regulation related to the purchase of solar energy was struck down by the Supreme Court because local solar panel manufacturers believed it did not sufficiently encourage local content. The Ministry of Energy and Mineral Resources recently issued Regulation No. 19 of 2016 (MoEMRR 19/2016) to provide regulatory certainty and a tariff structure to encourage the private sector to develop solar power projects and sell the generated electricity to PLN.

The new regulation appoints PLN to purchase the output of solar power plants developed and managed by private sector developers. It includes regional capacity quotas that account for electricity network constraints and assume a minimum aggregate capacity of 5 GW across all regions. The Indonesian Directorate of New and Renewable Energy will offer the quotas in stages, as part of a rolling program to achieve Indonesia's optimal energy mix. Developers are required to submit a Capacity Quota Application within two months of a quota announcement. If approved, they are required to sign a Power Purchase Agreement (PPA) with PLN within one month, and financial closure should take place within six months of signing a PPA.

The first-stage capacity quota for Java is 150 MW and the solar feed-in tariff applicable is US 14.5c/kWh. This is inclusive of network connection costs, non-negotiable, and payable in Indonesian rupiah. PPAs are valid for 20 years. Estimating the returns from solar energy imported to the Javanese grid is difficult for several reasons:

- There are measures to prevent one single solar developer from dominating any stage of the solar development program in any region. Even in regions with the largest quotas, where the aggregate planned quota exceeds 100 MW, a developer may only submit a Capacity Quota Application for up to 20 MW.
- The Ministry of Energy and Mineral Resources, and the Directorate of New and Renewable Energy within it, anticipate solar development on Indonesian territory. An HVDC connection point is a different thing, even if the solar generators in Australia are partly owned by Indonesia. Potentially, non-solar generators could also feed the HVDC transmission line.
- Segments of the Javanese transmission network are not commonly outsourced to non-Indonesian, non-PLN enterprises. Establishing a commercial model for this and for transmission network services (such as frequency regulation and system restart after a blackout) would be significant precedents.

The proposed GW-scale project would require a negotiated position to be reached and it is not possible to anticipate this outcome with any certainty. In the meantime, US 14.5c/kWh is used as the PPA tariff, and estimating network services payments is avoided by not including the HVDC transmission line overland to Jakarta from its landing point in east Java, and ignoring potential network support services provided by the HVDC converter station.

4.3.2 Solar energy in the Australian NEM

Most of Australia has a competitive wholesale market for electricity generation. Returns on energy sales for a market generator can be estimated from historical price information. A selected whole year of wholesale electricity price data (2010) were used to estimate market returns from solar energy delivered to the east-coast NEM. Hourly estimates of solar power output were multiplied by wholesale prices averaged per hour to calculate what a solar generator would have earned in each year. By allowing for the time difference between the time series for west-coast solar output and east-coast electricity prices, the premium value of solar energy delivered into the east coast early evening is accurately represented.

The Indonesian feed-in tariff for solar energy is generous compared to average Australian wholesale electricity prices. US 14.5 c/kWh corresponds to 193 $/MWh assuming an exchange rate of 0.75, compared to the average NEM wholesale price in 2015-16 of 64 $/MWh in Queensland and 54 $/MWh in NSW (Australian Energy Regulator, 2016). This difference is reflected in estimated annual revenues from 3.4 GW of solar PV generation of the kind discussed in Section 6.4:

- $1,622 million based on the solar feed-in tariff allocated to Java,
- $284 million based on NEM NSW wholesale prices in 2010.

A useful comparative calculation is what a solar generator would have earned if it had sufficient energy storage to sell its output only at the highest market prices achieved:

- $419 million based on only the highest NEM NSW prices in 2010.

This is an upper bound on earnings, on the assumption that the energy storage system does not change the maximum output power of solar generator – so this calculation shows the impact of wholesale market variability. It is a significant but not overwhelming impact, and is still far below the potential earnings in Java, even though the losses are assumed to be 10% to the NEM compared to 15% to Java.

This calculation does not show how the HVDC transmission line could be used more efficiently through the integration of energy storage. This is discussed in the sensitivity analysis below. It does show that the market returns are so much lower in the NEM that interconnection with the east-coast market is unlikely to be commercially viable as a stand-alone proposition. When there are multiple factors encouraging the interconnection of markets then, this project may happen.

Introducing a significant new kind of generator into either market may have an impact on local conditions by changing the competitive balance among suppliers. In the NEM, this will be directly reflected in the wholesale market outcomes. Indonesia has a system of defined feed-in tariffs, so the market impact will be indirect, changing the policy-making environment in which tariffs are established. The cash flow analysis is a static calculation representing a snapshot of present market conditions and not accounting for potential market impacts. These impacts may be significant should the Pilot Project be a successful precursor of further high-capacity interconnection projects in the region. This impact will include economic return to multiple nations trading energy on the backbone grid created by the HVDC interconnectors. The promise of such an outcome is crucial to building regional support and co-investment.

4.4 Cash flow analysis

4.4.1 Base scenario with one solar precinct and accelerated build

A discounted cash flow analysis based on the assumptions shows the timeframe of the Pilot Project build and its geographical spread to be important influences on the levelised cost of energy (LCOE) delivered to Java. Due to the considerable cost of AC transmission to aggregate output from multiple sites, two alternative scenarios for the build were considered: 1 GW of solar generation located at each of the three solar precincts shown in Figure 30, and 3 GW of solar generation located at the De Grey solar precinct only. Another considerable cost is an extended build time frame, which leaves some solar PV and AC transmission assets waiting non-productively for several years while the remaining capacity is built and the HVDC transmission line is completed. This has the effect of increasing the LCOE due to lack of revenue during this time. Therefore, both a ten-year and a five-year build time frame are considered, the latter placing more strain on the supply chain.

Table 3 shows the estimated LCOE over 40 years for each build scenario. Also shown is the impact of local electricity sales from the first 200 MW of solar PV generation, which is presumed to serve local loads until being aggregated for dispatch to Java, and revenues from the Renewable Energy Target until 2030 and a supposed international carbon market thereafter.

The build time frame, geographical concentration, and local revenues are all seen to be significant influences on the LCOE, which can be brought close to the solar feed-in tariff of 19.3 c/kWh in Java (i.e., 193 $/MWh as discussed). The influence of build time frame and geographical spread are also graphed in Figure 14 to show the convergence of LCOE; the ten-year build concludes in 2030, and the five-year build concludes in 2025 and therefore generates revenues from 2026 for energy delivered to Java. The growth of solar PV generation corresponding to these build scenarios can be seen in Table 12 and the AC aggregation network configurations are listed with estimated costs in Table 14.

Considering the importance of these factors, a five-year build concentrated at the De Grey solar precinct is considered to be the base case for the sensitivity analysis to follow.

The 40-year investment time frame used for the cash-flow analysis is compatible with other electricity network projects. In Australia, electricity network 'poles and wires' are usually planned with a lifetime of 40 years and favourable finance is available to network businesses. With low interest rates worldwide, infrastructure is a popular form of investment, and international investors may be willing to offer finance over a suitable time frame for this project.

The cash flow is fully amortised with replacement: repayments for each component of the project build are calculated at the assumed discount rate for the term of the estimated component lifetime. By continuing these repayments indefinitely, the cost of replacement at end-of-life is included throughout the 40-year analysis time frame. For example, solar PV panels, mounts, and inverters are replaced after 25 years, AC infrastructure is assumed to last 40 years, HVDC power electronics 25 years, HVDC control and protection systems 15 years, while the HVDC cable itself is assumed to have a design lifetime of 60 years.

Build scenario	Ten-year build	Five-year build
Three solar precincts with 1 GW each	27.0 c/kWh	24.7 c/kWh
De Grey precinct only with 3 GW	25.5 c/kWh	23.3 c/kWh
Include local sales and carbon revenues	22.3 c/kWh	21.9 c/kWh

Table 3: Levelised cost of energy (LCOE) for a 3 GW Pilot Project according to build time and geographic spread

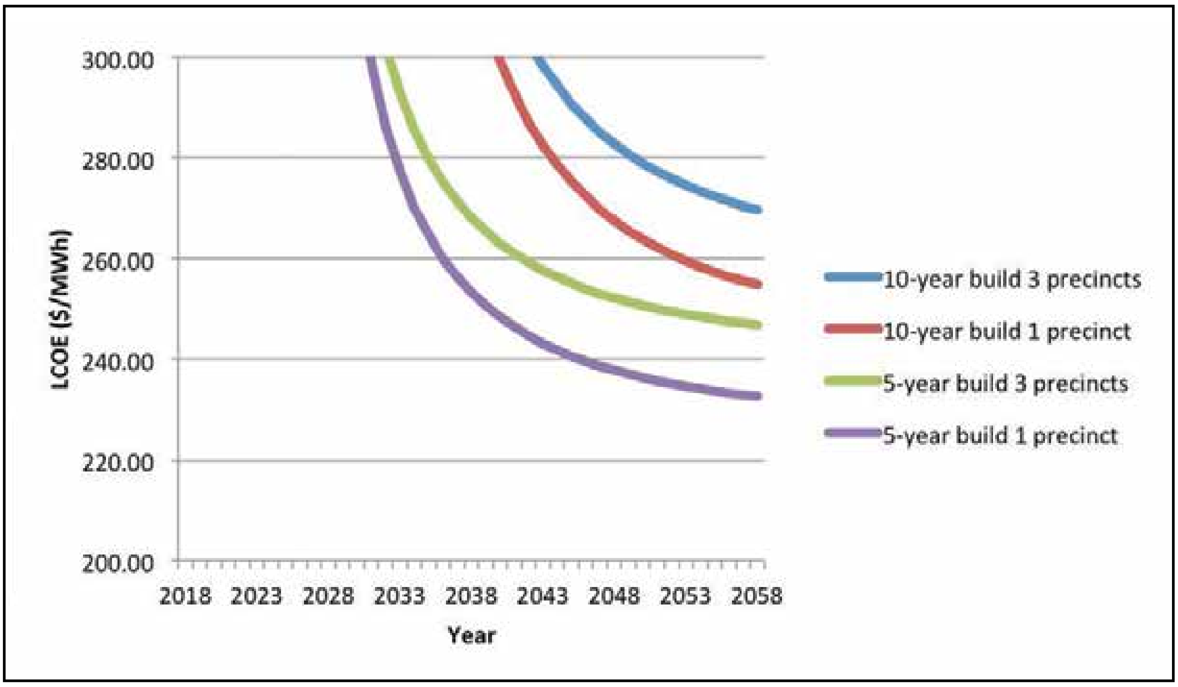


Figure 14:
Levelised cost of energy (LCOE) for a 3 GW Pilot Project according to build time and geographic spread

4.4.2 Sensitivity analysis of the LCOE

Any analysis is only as useful as its inputs are reliable. This analysis is based on many estimates that have been tabulated in this report. Table 4 gives an indication of the impact of some key assumptions on the estimated LCOE which for the base case scenario (five-year build at a single solar precinct) is 21.9 c/kWh when local electricity sales and carbon revenues are included.
The inputs considered are:

- The discount rate which is the key economic assumption indicating the availability of finance at favourable terms.

- The operating expenditure on the AC aggregation network. This is difficult to estimate and has a noticeable impact even for the limited network within a single solar precinct.

- Local electricity sales early in the project, even though they are assumed to conclude when exports begin, are very helpful to the commercial case.

- The assumed 60-year cable life which is longer than most asset lifetimes; reducing this investment time frame has a noticeable but not large impact on the LCOE.

- The cost of procuring and laying the subsea cable which requires deeper investigation, and until then a 20% uncertainty can be ascribed to the capital cost.

- HVDC system losses of 15%. This may be a conservative estimate and assuming 10% has a significant and helpful impact.

Considering these input uncertainties and allowing for others, it is reasonable to assume a 15% uncertainty in the resulting LCOE, which is therefore 18-25 c/kWh. This range includes the solar feed-in tariff of 19.3 c/kWh that is presently available in Java.

The opportunity to integrate energy storage at HVDC conversion stations or solar farms is very promising. By storing daytime solar generation output for delivery at night or either end of the day, storage can make better use of the HVDC transmission infrastructure, which improves its economic efficiency. This analysis suggests that the improved capacity factor of the HVDC asset balances the capital expenditure on battery energy storage – so that in effect the storage is free. This presents an interesting opportunity to deliver dispatchable renewable energy to any market. Further investigation with technical experts will help to quantify the costs and techniques for integrating batteries at solar PV generators or potentially at the HVDC converter station.

Table 4 includes the result that battery energy storage ***decreases*** the cost of energy due to its impact on the capacity factor. This is due to having a delivery mechanism that contributes a large proportion of the total project cost, and also to the historically low prices of battery cells, in this case lithium ion technology. Table 5 shows the cost and performance assumptions related to battery energy storage. Figure 15 shows the reduction in LCOE due to concentrating the solar PV generation at a single precinct, local energy sales and carbon market revenues, and finally due to integrating a large amount energy storage to level the solar output.

To provide some perspective of the contributions to the total project cost, Figure 16 shows a pie chart of the net present cost (NPC) of solar PV generation, AC aggregation (at a single solar precinct), and HVDC transmission to east Java.

*Battery energy storage **decreases HVDC** the cost of energy due to its impact on the capacity factor.*

Figure 17 shows the same including sufficient battery energy storage to provide approximately constant output through 24 hours. The HVDC cost is the same in both cases, but the solar PV generation and associated AC aggregation network must be scaled up dramatically (by 216%) to provide additional energy to fill the subsea cable through the night. The overall balance is similar if the HVDC transmission and battery energy storage are considered together as delivery infrastructure.

A discounted cash flow analysis based on the assumptions in this chapter, and the data tables in Chapter 6, show that delivering Pilbara solar energy via HVDC to Java has potential in commercial terms, with sufficient uncertainty in the inputs to be worth further detailed examination. As several input costs are on a downwards trend, notably for solar PV generation and energy storage, and allowing for efficiencies that may be found through careful engineering design, the commercial case for developing the 3 GW Pilot Project is likely to be favourable during the coming 5-10 years.

Input	Base case	Low	LCOE	High	LCOE
Discount rate	7%	6%	**19.5**	8%	**24.4**
AC opex	$3/MWh	$2/MWh	**21.8**	$5/MWh	**22.1**
Local PPA	$200/MWh	$180/MWh	**22.0**	$220/MWh	**21.8**
Cable cost	$6 billion	$4.8 billion	**20.4**	$7.2 billion	**23.4**
Cable life	60 years	40 years	**22.3**		
HVDC losses	15%	10%	**20.7**		
Batteries	Nil			7.45 GWh	**21.4**

Table 4: Sensitivity study of impact of some key inputs on the LCOE (c/kWh compared to base case of 21.9)

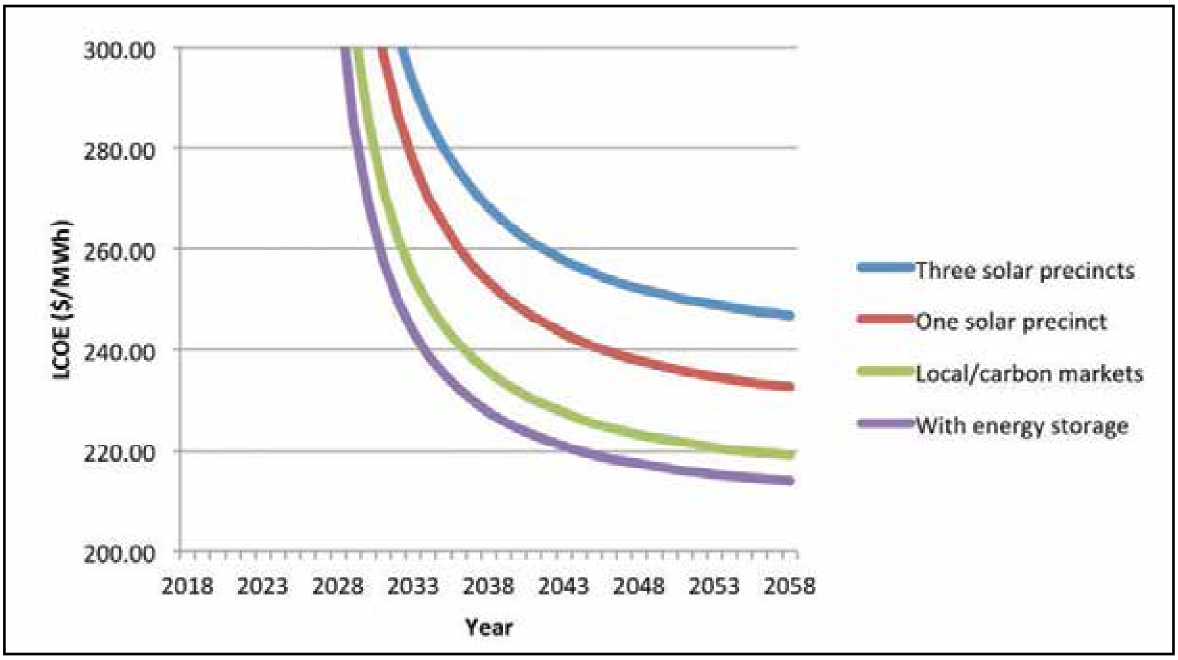


Figure 15: Levelised Cost of Energy (LCOE) for a 3 GW Pilot Project with local revenues and energy storage

Samantha Mella Geoff James Kylie Chalmers

Parameter	Value	Unit	Source
Capacity of solar farms (GW) - no storage	3.43	GW	Calculated from solar output traces (single-axis PV)
Capacity of solar farms (GW) - with storage	7.41	GW	Calculated from solar output traces (single-axis PV)
Capacity factor for solar PV in NW Australia	27.93%		Calculated from solar output traces (single-axis PV)
Capacity of storage integrated at converter stations	7.45	GWh	Calculated from solar output profile
Fully installed cost of lithium ion batteries in 2017	699	$/kWh	(Rutovitz, 2017)
Balance of plant for storage system with battery cost	40%		Estimate
Lifetime of battery cells	15	years	(Rutovitz, 2017)
Lifetime of balance of plant	25	years	Assumed the same as solar inverters
O&M (fixed) for storage	9.8	$/kW/year	(Rutovitz, 2017)
O&M (variable) for storage	3.0	$/MWh/year	(Rutovitz, 2017)
Round-trip AC efficiency of storage	93%		(Rutovitz, 2017)
Available capacity of storage wrt nameplate	90%		Average over lifetime degradation to 80%
Fraction of delivered energy passing through storage	50%		Estimate for simple daily average dispatch

Table 5: Battery (lithium ion) energy storage assumptions for the cash-flow analysis of the 3 GW Pilot Project

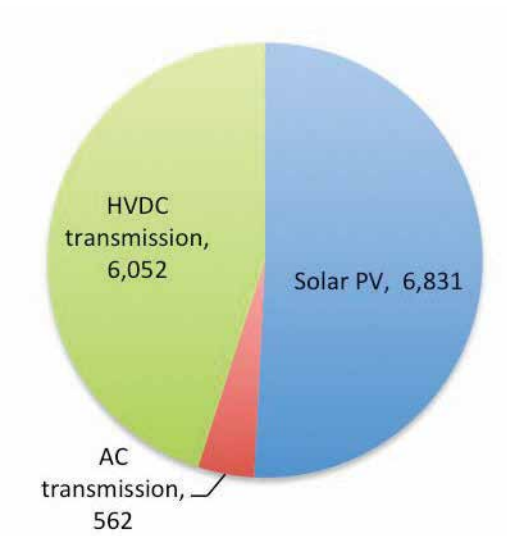


Figure 16:
Net present cost (NPC) of components of a 3 GW Pilot Project ($ millions)

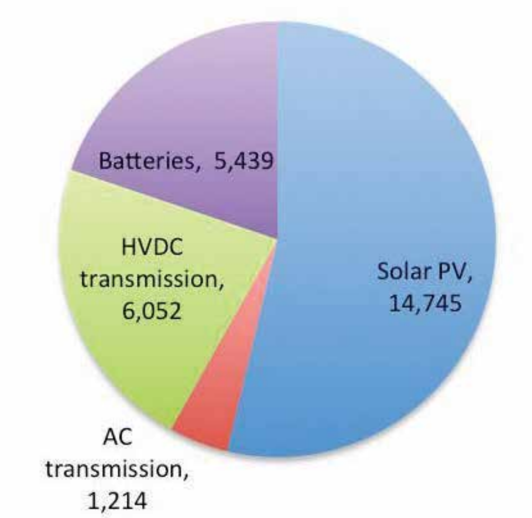


Figure 17:
Net present cost (NPC) of components of a 3 GW Pilot Project with energy storage ($ millions)

05

The Asian value proposition

5.1 Key findings

- Energy use is growing rapidly in Southeast Asia. The projected growth in new electricity infrastructure by 2040 is 400GW of new capacity, which will almost triple current capacity. Under present policy settings, this is forecast to be coal.
- The ASEAN region's energy-related emissions have more than tripled since 1990 and are expected to almost triple again by 2040. This is due to low cost of coal combined with a lack of incentives for CO_2 emission reductions.
- The energy self-sufficiency ratio will steadily decline among ASEAN countries.
- OECD and ADB modelling (OECD, 2014) indicates a disproportionately large impact on GDP from the effects of climate change in the ASEAN region.
- Climate change is important ideologically, however economic development and access to modern energy supply take priority in Southeast Asia. Climate change alone will be unlikely to give renewables a big advantage over fossil fuel alternatives.
- Both to assure energy security and to address climate change, ASEAN countries need to find a different solution to their future energy requirements.
- The proposed Pilbara solar feed-in project would shift the emphasis of the ASEAN Power Grid south and may bring leverage to Indonesia, Malaysia and Singapore, as potential hubs for international electricity trade.
- An agreed ASEAN vision supports regional electricity trade, however a clear regulatory framework would be required for effective clean energy trade, including Pilbara solar.
- Indonesia is focused on accelerating electrification with the 35 GW Fast Track program due for completion in 2019. Indonesia's total target is 114 GW installed capacity by 2025 – which includes a total of 80.5 GW of new capacity (older infrastructure will be retired).
- Indonesia has already significantly reduced fossil fuel subsidies.
- The policy environment in Indonesia is complex and changing. Indonesia has strong renewable energy targets but low implementation. Policy may be subject to unexpected shifts through the usual workings of a democratic government.
- Indonesia has strict policy regulations around cross-border electricity trade and a special negotiated position would be required to enable 3 GW of solar import, accounting for strategic benefits.
- Indonesia is currently focused on energy independence and rolling out the 35 GW Fast Track Program. There is existing electricity trade with Malaysia, but no plans for interconnection or electricity trade with Australia at this time.
- To supply Indonesia with solar generation, careful preparation and relationship building would be required from Australia. An HVDC interconnector and solar generation **must be price competitive** with attractive benefits for Indonesia to consider the HVDC-enabled solar feed-in proposition.

5.2 ASEAN electricity demand and access

Between 1990 and 2011, the primary energy demand of the ASEAN region increased by 150%, or a factor of 2.5, and it is projected to increase by 80% between 2011 and 2040 (IEA, 2015a). This is according to the IEA's "new policies scenario" that considers existing policies and measures affecting energy markets as of mid-2015, and policy proposals that have not yet been fully developed or implemented.

An estimated tripling of the regional economy, a 25% growth in population, and a steady increase in access to electricity will drive energy use. Southeast Asia's energy use per capita was just half of the global average in 2011 (IEA, 2015a) and this was highly differentiated between countries. Energy use per capita in Brunei Darussalam and Singapore was above 7 tonnes of oil equivalent (toe) per year while Malaysia and Thailand were above 2 toe/year. Energy use per capita for other countries was below 1 toe/year. The differences in energy use correspond roughly to the development gap between the richest and poorest.

Electricity demand is expected to triple by 2040 in tandem with economic growth. Different rates of total energy and electricity demand are due to a trend of greater electrification and energy efficiency of both industrial and residential consumption. Parts of ASEAN have a low rate of access to energy and low energy use per capita. As of 2013, the total number of ASEAN population without electricity is about 120 million out of a total population of 616 million (Table 6). The population without access to electricity is mainly from Indonesia (49 million), Myanmar (36 million), the Philippines (21 million) and Cambodia (10 million). Only four countries, Brunei Darussalam, Malaysia, Singapore, and Thailand, have national and urban electrification rates of about 100%.

Cambodia has the lowest electricity consumption per capita in ASEAN while Brunei and Singapore have the highest (Figure 18). Considering the minimal need for a modern society to be 2000 kWh per capita per year (AGECC, 2010), only Brunei Darussalam, Singapore, and Malaysia had achieved this level in 2010. Even Thailand, which is relatively advanced in terms of economic development, still falls short of the level suggested by the UN report. The lack of electricity

Region	Population without electricity (millions)	National electrification rate (%)	Urban electrification rate (%)	Rural electrification rate (%)	Population relying on traditional use of biomass (millions)	Percentage of population relying on traditional use of biomass (%)
ASEAN	**120**	**81%**	**94%**	**69%**	**276**	**45%**
Brunei	*0*	*100%*	*100%*	*99%*	*0*	*0%*
Cambodia	*10*	*34%*	*97%*	*18%*	*13*	*88%*
Indonesia	*49*	*81%*	*94%*	*66%*	*98*	*39%*
Laos	*1*	*87%*	*97%*	*82%*	*4*	*65%*
Malaysia	*0*	*100%*	*100%*	*99%*	*0*	*0%*
Myanmar	*36*	*32%*	*60%*	*18%*	*49*	*93%*
Philippines	*21*	*79%*	*94%*	*67%*	*53*	*54%*
Singapore	*0*	*100%*	*100%*	*100%*	*0*	*0%*
Thailand	*1*	*99%*	*100%*	*98%*	*15*	*23%*
Viêt Nam	*3*	*97%*	*99%*	*96%*	*42*	*47%*
China	**1**	**100%**	**100%**	**100%**	**450**	**33%**

Table 6: Access to modern energy services in ASEAN and China in 2013

Source: IEA, 2015c

access is more prevalent in rural populations. Lack of access to modern energy services for cooking can occur in urban as well as rural populations: the total ASEAN population relying on traditional use of biomass for cooking was 276 million or 45% in 2013 of which 98 million were in Indonesia.

Given the substantial lack of access to electricity and the low energy consumption per capita, energy and electricity demand in many ASEAN countries are likely to grow dramatically from present levels, as the development gap narrows. As demonstrated in the literature by (Yoo, 2006) and (Bakhtyar, 2013) there is a positive relationship between economic growth and energy demand in the ASEAN region.

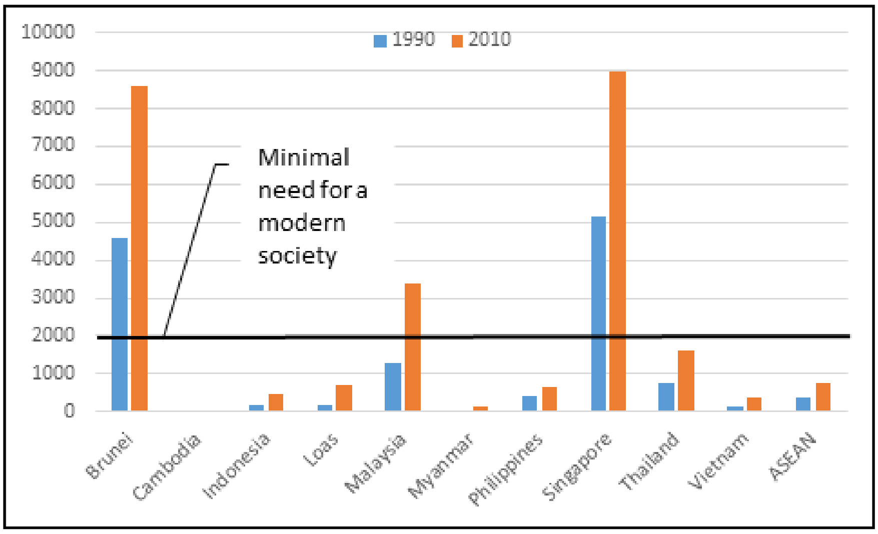


Figure 18: Electricity consumption in ASEAN countries (kWh per capita)

Source: Kimura, 2013

5.3 ASEAN electricity supply

5.3.1 Business as usual: coal, gas and oil

In the present policy environment, energy demand is expected to continue to increase rapidly, and this will result in the continued dominance of fossil fuels in the region's energy mix. From 2013 until 2035, as a share of primary energy supply, gas is projected to decline slightly from 22% to 21%, oil to decline more strongly from 36% to 29%, and coal to jump from 15% to 29% (IEA, 2015a). Having experienced double-digit annual growth rates since 1990, total demand for coal the ASEAN region is predicted to increase by a factor of 3.7 from 66 Mtoe in 2013 to 244 Mtoe in 2040, accounting for nearly 30% of global growth.

This is due to the relative abundance and low cost of coal in the region combined with a lack of incentives for CO_2 emission reductions. The ASEAN region has abundant oil, natural gas and coal. Oil and natural gas are largely concentrated in Indonesia, Malaysia, Viêt Nam and Brunei Darussalam. Indonesia has the most recoverable coal in the ASEAN region (IEA, 2015a).

A study shows that most ASEAN countries, except Indonesia, show a declining reserve-to-consumption ratio over the past three decades (Koyama, 2012). The trend is especially clear in the case of oil and gas, which means an increasing proportion of oil and gas must be imported. This creates new risks for security of supply and affordability.

A forward study (APERC, 2013) shows that only Brunei Darussalam and Indonesia will remain energy independent by 2030, and even for these two countries, the self-sufficiency ratio is steadily declining. (Statistics for Cambodia, the Lao PDR and Myanmar are not readily available.) Indonesia will remain a major coal net exporter in 2030 while Malaysia, the Philippines, Singapore, Thailand and Viêt Nam will remain net importers of coal. All ASEAN member countries except Brunei Darussalam are expected to become oil net importers by 2030. Through 2030:

- Brunei Darussalam and Malaysia will remain net exporters of natural gas
- Indonesia and Viêt Nam are expected to change their status from exporters to net importers of gas
- Singapore and Thailand will likely remain natural gas importers.

5.3.2 Electricity

According to IEA projections, 400 GW of power generation capacity will be added across the ASEAN region between 2013 and 2040, and 40% of this new capacity will be coal-fired under the IEA New Policies scenario. Southeast Asia is the only region in the world where coal-fired generation is projected to increase. Natural gas will decline from 44% to 26%. Renewable sources will increase by a factor of 3.5 by 2040, due to the steady rise in hydropower and the rapid growth of wind and solar generation as their costs fall (IEA, 2015a).

Securing the region's entire energy needs under this scenario requires investment of approximately US$100 billion each year to 2040: a total of US$2.5 trillion. More than half of this is required for the power sector, with US$420 billion included to improve energy efficiency (ibid).

Alternative projected figures are available from the Institute for Energy Economics (IEEJ, 2013) shown by fuel type in Table 7 (along with historical decades), and the ASEAN Centre for Energy (ACE, 2014) shown in Figure 19. While they are different in detail due to somewhat different assumptions and methodologies, the general outcomes are the same. Most of the electricity is expected to be generated from thermal energy, however with slightly decreasing share. Renewable generation will become increasingly important in the ASEAN electricity mix, however, the overall increase in fossil-fuel generation is not consistent with the global action required to mitigate the effects of climate change.

Electricity source	1980	1990	2000	2010	2020	2030	2035	AAGR(*)
Coal	3.0	28	79	185	404	716	926	6.7
Oil	47	66	72	59	84	97	100	2.1
Natural gas	0.7	26	154	335	580	856	1,012	4.5
Nuclear	-	-	-	-	-	45	74	-
Hydro	9.8	27	47	70	137	212	235	5.0
Geothermal	2.1	6.6	16	19	38	59	69	5.2
Other renewable	-	0.6	1.0	6.1	13	23	33	7.0
Total	**62**	**154**	**370**	**674**	**1,256**	**2,007**	**2,449**	**5.3**

(*) Average annual growth rate during 2010-2050

Source: IEEJ, 2013

Table 7: Changing electricity generation (in TWh) in ASEAN

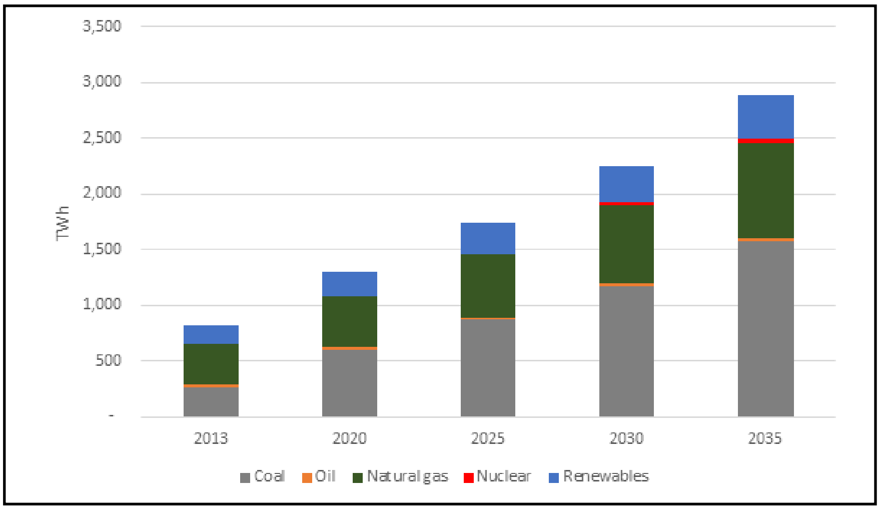


Figure 19: Projected annual ASEAN electricity generation by fuel *Source: ACE, 2014*

ASEAN's energy-related CO_2 emissions have more than tripled since 1990 and are expected to almost triple again between 2013 and 2040.

The projections shown here can be considered business-as-usual scenarios incorporating modest policy changes. Such an increased use of fossil fuels, particularly coal, will lead to considerably higher CO_2 emissions with today's technologies. ASEAN's energy-related CO_2 emissions have more than tripled since 1990 and are expected to almost triple again between 2013 and 2040.

The rapid growth in primary energy supply and increasing dominance of fossil fuels in electricity supply will result in a corresponding 2.7% annual growth in CO_2 emissions from 1,175 million tonnes ($MtCO_2e$) in 2013 to 2,394 $MtCO_2e$ in 2040 (IEA, 2015a). Such growth in regional CO_2 emissions would create long-term threats to the region's living standards and economic vitality, particularly as Southeast Asia is very vulnerable to the effects of climate change, compared to other regions (Majid, 2010). This is covered in greater detail in Section 5.4.

Both to assure energy security and to address climate change, ASEAN countries need to find a dramatically different solution to their future energy requirements.

5.3.3 Renewable energy potential

ASEAN possesses vast renewable energy resources. The potential of a renewable resource is in principle limitless. Wind, solar and geothermal energy are therefore expressed as potential power capacity that could be efficiently obtained. Fossil fuel reserves are expressed as energy potential in tonnes of coal or oil equivalent. Hydropower energy resources depend on rainfall and are usually expressed as annual electrical energy potential in TWh.

A paper (Bakhtyar, 2013) suggested that Indonesia, Malaysia, the Philippines, Singapore and Thailand combined have the capacity to produce 234 GW of hydropower and 20 GW of geothermal electricity generation. Hydropower projects from Cambodia, Laos and Myanmar may provide 18.9 (GW) of power for China, 7.7 GW for Thailand, and 5.1 GW for Viêt Nam in 2025 (Piseth, 2014). The sustainability of large hydropower projects can be questioned, however the Nam Theun 2 Hydroelectric Project in Laos passed World Bank's strict sustainability assessment (Porter, 2007) suggesting that a high standard can be achieved. Indonesia and the Philippines have significant installed geothermal capacity. Indonesia has the largest known geothermal resource in the world, estimated at over 27.5 GW or about 40% of the world total.

Table 8 shows the renewable energy potential for hydropower and geothermal and illustrates the varied distribution of energy resources the ASEAN region. Only 1.6% of potential hydropower resources had been developed by 2009 (Kimura, 2011) and only 5% of the potential geothermal resources had been developed by 2014 (Geothermal Energy Association, 2014). Given the expected increasing demand of electricity, development of ASEAN's hydropower and geothermal potential could replace many planned coal-fired power plants without increasing generation costs over the lifetime of these plants. However, there is little relationship between the potential of renewable energy and the installed generation capacity. In some countries, the share of renewable energy in the total energy mix has declined (Bakhtyar, 2013).

Southeast Asia, including Singapore, is also highly suited to solar photovoltaic (PV) generation and bioenergy. The region is not suitable for concentrating solar power because this depends on direct solar radiation.

The annual insolation levels range from 1,460 to 1,892 kWh/m2/year (Ismail, 2015) and are illustrated on the left-hand side of Figure 20. This compares with insolation levels in the vicinity of 2,300 kWh/m2/year in the Pilbara. On the right-hand side of Figure 20, the ASEAN average wind speed map indicates good wind power potential along some coastal areas but generally poor wind resources elsewhere. Cyclones are frequent, so any infrastructure, including wind and solar generation and the transmission lines that connect it to the grid, must be built to withstand the weather events during its lifetime.

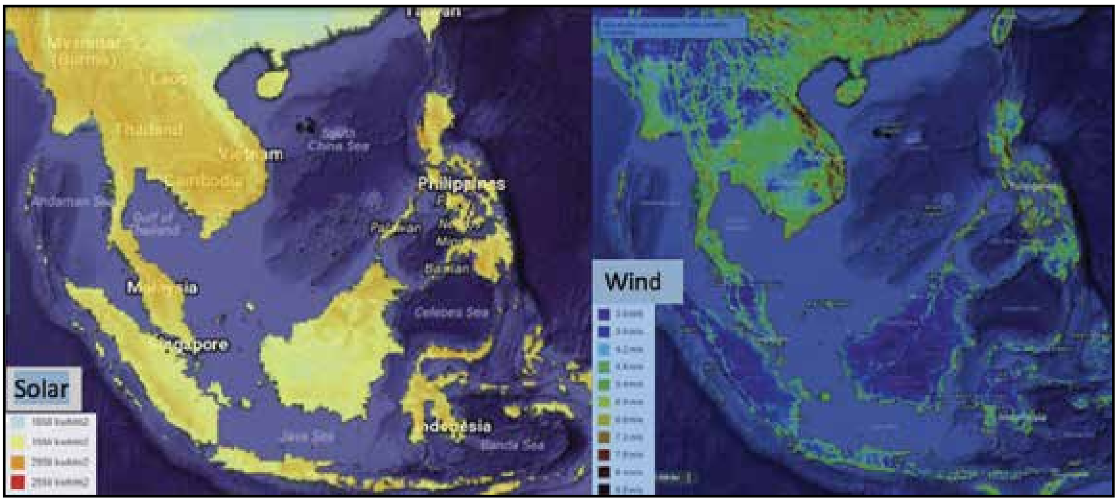


Figure 20: Solar and wind resource map from IRENA's Global Analysis

Source: IRENA, 2016

Country	Hydropower Potential (TWh/year)	Geothermal Potential (GWe)
Brunei Darussalam	-	-
Cambodia	34	-
Indonesia	402	27.7
Lao PDR	63	-
Malaysia	123	-
Myanmar	139	-
Philippines	20	4.3
Singapore	-	-
Thailand	16	-
Viêt Nam	123	0.3

Table 8: Hydropower and geothermal energy potential in ASEAN

Source: WEC, 2010

Wind, geothermal and solar PV represent 11% of total installed capacity in 2040 in the IEA New Policies Scenario. Continued policy and fiscal support and the removal of some fossil fuel subsidies may contribute to their expansion. Together they are expected to add around 63 GW of gross capacity. Under the New Policies Scenario, installed renewables capacity from wind and solar PV increases from 2 GW in 2014 to 54 GW in 2040 (IEA, 2015a).

Bioenergy can to be used for power and heat production or as a transport fuel and has large potential in the ASEAN region. Indonesia, Malaysia, and Thailand are the world's largest producers and exporters of palm oil, a key source of biodiesel (Obidzinski, 2012). Developing modern, sustainable forms of bioenergy will be important to increase renewable energy use in the electricity and transport industries (IRENA & ACE, 2016). As some power systems reach high penetrations of intermittent renewable generation, bioenergy has a potentially important role as dispatchable renewable generation with multiple roles:

- balancing supply and demand as the wind and solar resource and the demand vary
- filling in during extended periods of low wind output
- providing traditional inertia control through its turbines to help keep the grid frequency stable.

Presently the level of wind and solar generation in ASEAN countries is too low for any of these services to be important. This is likely to change over time and using bioenergy is one of several strategies to provide these services without contributing additional CO_2 emissions.

5.3.4 Barriers to renewable energy

Despite this potential, there are several issues that limit the development of low-carbon energy resources.

First, renewable energy sources are unevenly distributed. Countries are usually focused on their own national energy security, rather than thinking in regional terms, and this limits the scope for cooperation. For example, the potential for hydropower from Laos, Cambodia, and Myanmar is large and sufficient for export but this potential is slow to be realised. Similarly, the Sabah-Brunei transmission line was planned to deliver hydropower to Brunei, where it would have reduced generation costs and CO_2 emissions, but it has been dropped from the current APG plan shown in Figure 13 due to concerns about security of supply. As ASEAN countries follow discrete national energy security agendas, the potential to share costs and benefits and deploy renewable energy projects on a regional scale is reduced. (Shi, 2016) (Chang, 2012).

Secondly, renewable energy development is limited by human geography. Areas of Southeast Asia with high energy demand are also crowded, and land-use conflicts restrict the development of large-scale solar generation. Theft of solar panels is a significant problem. It can be addressed by security measures, however these will increase the cost (Lawson, 2012). Opportunities for rooftop solar are limited by a number of factors, not least that residential electricity tariffs have not been high enough to encourage investment. Wind resources, as noted above, are limited and there are frequent destructive cyclones.

Thirdly, the sustainability of bioenergy is sometimes questioned. For example, sourcing of palm oil to make biodiesel is a controversial issue. The European Union Renewable Energy Directive has assigned a much lower default GHG emissions savings value (19%) to palm oil because it is assumed to be produced from land that has been cleared of rainforest (Exiron, 2009) (European Commission, 2010).

The climate targets are generally supported, however, gestures of support have little real impact. Climate change is not a top priority on the region's overall policy agenda because of the urgent need for further economic development and access to modern energy supplies (Shi, 2016). Climate change is important ideologically, but unlikely to give renewables a big advantage over fossil fuel alternatives.

Finally, renewable energy must provide cost-competitive electricity to be accepted in Southeast Asia

Xunpeng Shi, 2016

5.4 Climate change policies

In the ASEAN Vision 2020, the ASEAN leaders envision "a clean and green ASEAN with fully established mechanisms for sustainable development to ensure the protection of the region's environment, the sustainability of its natural resources, and the high quality of life of its people" (ASEAN, 1997). The ASEAN member states have declared their support for action on climate change and ASEAN itself has been actively engaged in related international negotiations (Letchumanan, 2010).

The stakes are high for Southeast Asia, where OECD modelling (OECD, 2014) indicates a disproportionately large impact on GDP from a variety of effects of climate change, as shown in Figure 21.

However, environmental priorities are notably absent from regional energy policy as documented in the ASEAN Plan of Action on Energy (APAEC) 2010–2015. In Southeast Asia and elsewhere, statements of good intentions and actions may be widely separated (Majid, 2010). In Southeast Asia, economic development and access to modern energy supplies are much higher priority items on the region's overall energy policy agenda. Clean energy targets lack attention from the governments, particularly those having low per capita use of energy. The potential for renewable forms of energy to reduce CO_2 emissions without reducing energy usage has not been realised in practice (Lidula, 2007).

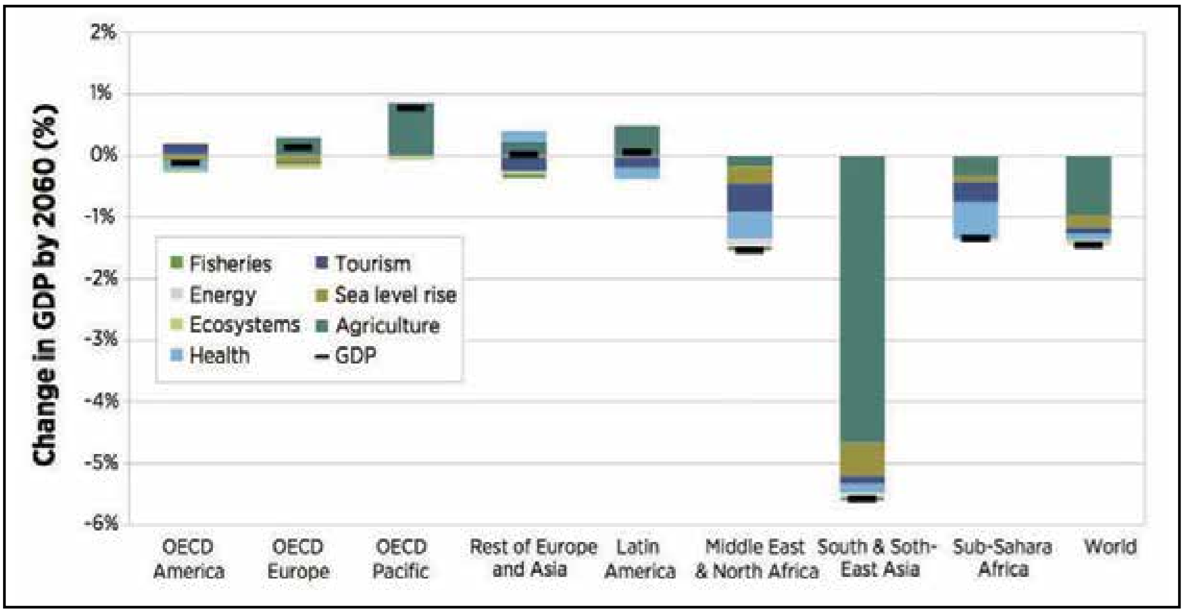


Figure 21: Potential worldwide economic impacts of climate change with 4.5-6°C warming *Source: (OECD, 2014)*

Lack of environmental priorities in energy policies of ASEAN member countries allow the regional energy mix to move unchecked toward a more coal-dominant one. This indicates that CO_2 emissions from the energy sector have not been appropriately checked.

International drivers and incentives may hold the key to progress on clean energy. The Copenhagen Accord of 2009 required a review of global emission targets in 2015. It suggested strengthening the target to 1.5 degrees of warming or 350 ppm (UNFCCC, 2009). Asian countries that supported the 350 ppm target in Copenhagen include Singapore, Cambodia, Myanmar, Viêt Nam and Malaysia. In the approach to the COP21 meeting in Paris in 2016, most ASEAN countries indicated some Intended Nationally Determined Contributions, with different levels of commitment, as shown in Table 9. These are in the process of confirmation and development into policy.

Given ASEAN's energy mix is not bound by any reduction on CO_2 emissions at a regional level, a key driver for regional power trading is missing.

5.5 Electricity trade

ASEAN demand for renewable electricity trade could be boosted by the regional block's new target of renewable electricity share. Although the growth in fossil-fuel generation of electricity seems to be unbounded, member countries intend to increase the component of renewable energy in the ASEAN energy mix, excluding traditional biomass, from 17% in 2013 to 23% by 2025 (ACE, 2015). Given the uneven distribution of RE resources and the heavy dependence on hydro, electricity trade is a natural consequence, though it may not occur without clear regional policy.

Parameter	Source
Brunei	• Energy sector: to reduce total energy consumption by 63% by 2035 compared to a business-as-usual (BAU) scenario; and to increase the share of renewables so 10% of the total power generation is sourced from renewable energy by 2035. • Land Transport sector: to reduce carbon dioxide emissions from morning peak hour vehicle use by 40% by 2035. Forestry sector: to increase the total gazetted forest reserves to 55% of total land area, compared to the current levels of 41%.
Cambodia	• Undertake unconditional actions in various sectors, the impact of which is expected to be a maximum reduction of 3,100 Gg CO_2eq compared to baseline emissions of 11,600 Gg CO_2eq by 2030. • Undertake voluntary and conditional actions to achieve the target of increasing forest cover to 60% of national land area by 2030.
Laos PDR	• A list of reforestation, renewable energy, rural electrification, transportation and hydroelectricity plans and actions to be implemented, subject to the provision of international support.
Indonesia	• Unconditional reduction of 29% of GHGs against a BAU scenario by 2030. • An additional 12% reduction is conditional on technology transfer, capacity building results for payment, and access to finance.
Malaysia	• Reduce its greenhouse gas (GHG) emissions intensity of GDP by 45% by 2030 relative to the emissions intensity of GDP in 2005. This includes 35% on an unconditional basis. • A further 10% is condition upon receipt of climate finance, technology transfer and capacity building from developed countries.
Myanmar	• Provided a list of policy actions in the energy and forestry sectors. • The information required to estimate GHG emissions was collected and an estimate produced. However, given the deadline and the current available data, it was decided not to include the estimate in the INDC, as it was deemed not sufficiently reliable. • Further analysis to quantify the GHG emission will be conducted as a result of the actions and strategies.
Philippines	• Undertake GHG (CO_2e) emissions reduction of about 70% by 2030 relative to its BAU scenario of 2000-2030, conditional on the extent of financial resources, including technology development and capacity building, that will be made available to the Philippines.
Singapore	• Reduce emissions intensity by 36% from 2005 levels by 2030, and stabilise emissions with the aim of peaking around 2030. • Singapore intends to achieve the mitigation objectives under its INDC through domestic efforts, but will continue to study the potential of international market mechanisms.
Thailand	• Thailand intends to reduce its emissions by 20 percent from the projected level by 2030. • The level of contribution could increase up to 25 percent, subject to adequate and enhanced access to technology development and transfer, financial resources and capacity building support.
Viêt Nam	• Not submitted

Table 9: Intended Nationally Determined Contributions (INDCs) by ASEAN countries

Source: C2ES, 2016

5.5.1 Trade potenial

The Asia Pacific Energy Research Centre (APERC, 2013) has projected the import and export of coal, oil, gas and electricity for seven of the ten ASEAN member countries (Piseth, 2014). Table 10 lists the projected net import values for all energy and electricity of up to 2030. Considering total energy trade, including primary energy sources, all ASEAN member countries are expected to become net importers by 2030, with the exception of Brunei Darussalam and Indonesia. Thailand and Việt Nam are projected to maintain their status as net importers of electricity through the projection period. Malaysia, on the other hand, will be a net exporter of electricity, albeit at a very low value.

The future need of electricity trade could be underestimated, because electricity imports could replace some coal and gas imports. The demand for electricity trade would be even higher if there is low carbon electricity, such as solar PV, available at a competitive price. Regional electricity trading would benefit ASEAN members in several ways:

1. Increased energy security and power system reliability, economic advantages, opportunities for integrating higher share of renewables (IEA, 2015a).
2. An integrated electricity market will allow surplus hydropower to be developed, replacing coal. For developing countries, hydro's cost competitiveness creates the potential for new revenues through trade.
3. Energy market integration can increase access to electricity through stimulation of investment in the respective grids of participating countries.
4. The pooling of resources from national grids offers additional security of supply for each country. In an integrated market, countries with limited renewable energy options, such as Singapore, will provide additional market demand for renewables from resource rich countries without necessarily requiring them to invest in additional capacity.
5. Electricity trading could help to meet peak demand as an alternative to investing in local generating capacity that would operate only part of the time.
6. An integrated regional power market can also reduce vulnerability to variability of renewables. In a large geographical area, peak demand and production of various renewable sources may have different patterns, and can complement one another.
7. Market integration can enable more diversified supply by sharing new technologies reduce disadvantage. (Hamid, 2011).

More open electricity trading encourages the development of renewable sources with a substantial cost reduction, even if it is only partial integration where cross-border electricity trading meets some fraction of the energy demand. Table 11 is a simplified trading model that shows the cost savings that may be achieved by ASEAN electricity market integration. The model considers three scenarios (no trade, 20% trade and 50% trade in energy) and four electricity generation technologies (Chang, 2012).Other studies have confirmed that electricity trading would allow more renewable energy to be integrated with a lower total cost of meeting energy demand, whether bilateral (Watcharejyothin, 2009) or multi-lateral (Wu, 2012) trade is considered.

	Coal Net Import			Oil Net Import			Gas Net Import			Electricity Net Import		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Brunei	0	0	0	-7.54	-6.66	-5.09	-7.99	-7.14	-5.58	0	0	0
Indonesia	-141.6	-195.9	-278.7	19.3	53.6	98.7	-27.1	-6.54	36.15	0	0	0
Malaysia	9.37	14.05	11.99	-7.7	11.5	25.2	-21.8	-35.9	-32.2	-0.01	-0.02	-0.02
Philippines	2.87	7.74	18.59	13.7	17.1	25.1	0	0	0	0	0	0
Singapore	0.12	0.63	0.49	56.8	72.2	85.1	7.82	8.91	9.5	0	0	0
Thailand	10.02	14.95	17.56	34.5	49.3	69.7	4.16	11.17	19.34	0.49	2.63	3.85
Viêt Nam	-7.7	-4.03	7.45	-2.96	6.48	23.1	0.22	-1.71	9.34	0.48	0.69	0.69

Table 10: ASEAN net energy imports (exports are negative) (Mtoe)

Source: APERC, 2013

Scenario	Total Cost Savings	Development of Additional Capacity
No Trade	N.A.	Gas, coal, hydro and geothermal
20% of demand met by trade	3.0% (20.9 billion USD)	Gas, coal, hydro and geothermal
50% of demand met by trade	3.9% (29.0 billion USD)	Gas, coal, hydro and geothermal

Table 11: Key Findings from different scenarios of electricity trade

Source: Chang & Li, 2012

The Economic Research Institute for ASEAN and East Asia (ERIA) study on investment in grid interconnections (ERIA, 2014) highlights many benefits if the APG projects planned and in progress are realised. The current centre of the ASEAN Power Grid is Thailand, located between the Greater Mekong Subregion hydropower producers and the southern ASEAN power consumers.

The proposed Pilbara solar transmission project would shift the emphasis of the APG south, and bring more political and economic leverage to Indonesia, Malaysia and Singapore.

A large feed-in of Australian solar power will land in Indonesia, within credible reach of Singapore and Kuala Lumpur. This could establish Indonesia and Malaysia as major corridors for power transmission. Indonesia, Malaysia and Singapore will receive power imports from both south and north and thus have the potential to develop regional power trade hubs, to their significant economic and political advantage.

5.5.2 Barriers to trade

There is a goal to create an integrated ASEAN Power Grid, however to date, there is no ASEAN regional energy market and no single regional electricity network. The existing cross-border transmission lines are pre-established bilateral purchase agreements. Most future trans-boundary power grid connections under the APG plan are also bilateral (Shi, 2013). By 2020, there are likely to be only a few interconnected national power grids in the ASEAN region and these will offer bilateral exchanges of electricity and emergency backups.

Thus, if all projects in Figure 13 are completed, significant electricity trade will occur but a regional power grid will still be far away. The Heads of ASEAN Power Utilities/ Authorities (HAPUA) have yet to decide whether the APG should be an integrated and harmonised single grid, or a few heterogeneous national grids that are linked by an ASEAN-wide backbone power grid (ACE, KEEI, 2013) (Shi, 2013). The latter outcome would make it impossible to trade electricity effectively across the region and this would mean the renewable resources that are geographically mismatched with demand centres would be likely to be unexploited. Clear leadership by a representative body may be needed to establish effective trade.

A major threat is the prevailing subsidy to fossil fuels, which limits ASEAN's ability to develop renewable energy sources, firstly by making them less cost-competitive, and secondly by using funds that could be redirected towards establishing renewable energy industries.

Subsidies among ASEAN countries is estimated at $51 billion in 2011 (IEA, 2015a). The world average of financial energy subsidies is 8.1% of government budgets (IMF, 2013). The low oil price at the end of 2014 made it possible for Indonesia (The Jakarta Post, 2015) and Malaysia (Bloomberg, 2014) to overhaul or remove fossil fuel subsidies. This is a promising sign, although subsidies may return as the underlying policy has not changed (The Jakarta Post, 2015).

Different levels of subsidies in neighbouring countries can cause a country with higher subsidies to strengthen the fence to prevent leaking of its subsidies. For example, the Malaysian government banned the sale of fuel to foreign cars in the areas bordering Singapore and Thailand. The Singaporean government then required anyone leaving Singapore in a Singapore-registered motor vehicle to have more than three-quarters of a tank full of fuel. This kind of border closure policy can be a barrier to regional integration of energy markets (Shi, 2014).

The prerequisites for effective regional trade in clean electricity, including Pilbara solar, are:

- interconnecting transmission infrastructure
- an agreed regional vision
- a policy framework supportive of electricity trade
- the removal, or at least harmonisation, of fossil-fuel subsidies.

5.6 Indonesia

The Republic of Indonesia is the largest archipelago in the world, consisting of approximately 17,000 islands with a total population of around 260 million (UN, 2017). Most of Indonesia's population, almost 80%, lives in the Western part of Indonesia, on the islands of Java and Sumatra (Figure 22). In 2014, around 60% of the population was living in Java.

1.9 million km² land area; 7.9 million km² maritime area 54,700 km coast line
33 provinces, 497 cities/regencies

Figure 22: Map of Indonesia with basic statistics

Indonesia land territory is around 2 million km². The country has nearly 0.2 million km² of arable land, of which about 40% is wetland (e.g. rice paddies), 40% is dry land, and 15% is shifting cultivation.

Indonesia is the world's fourth most populous country. During the past four decades, Indonesia's population has continuously increased, and its population is projected to exceed 300 million by 2030. About one-half of the Indonesian population lives in urban areas.

5.6.1 Energy resources, supply and demand

Indonesia is richly endowed with energy resources. It has proven recoverable resources of 28 billion tonnes of coal, 532 million tonnes of oil and 4 trillion cubic metres of natural gas. Indonesia is also endowed with renewable energy resources, including 75 GW of hydro, 29 GW of geothermal, 50 GW of biomass and solar energy potential of 4.5 kWh/m²/day (BPPT, 2016).

Historically, oil was Indonesia's most important energy resource and the predominant fuel for domestic energy consumption. In their peak in 1981-82, oil and natural gas provided the main export revenue of the country, accounting for 82% of total exports. Since 1987, the share of non-oil and gas in total export has been higher than that of oil and gas. Indonesia is now one of the world's largest thermal coal exporters, primarily exporting to China and India.

Indonesia also has various renewable energy resources, including hydropower, geothermal and biofuel.

Until recently, energy subsidies prevented renewable resources from being a competitive option. The removal of subsidies is expected to encourage more development of the country's renewable energy resources.

In early 2015, the government removed around 80% of energy subsidies and redirected the subsidy budget into social programs such as health and education services, subsistence food aid for the poor and infrastructure investment.

Between 2000 and 2014, primary energy supply grew at a rate of 4.7% per year, from 114 Mtoe to 220 Mtoe. In addition, traditional biomass is still used for cooking in rural areas. Ever since the decline in domestic oil production capacity, the government has attempted to move the country away from oil by promoting energy sources abundantly available in the country, i.e., coal, natural gas and renewable energy. These attempts have resulted in high growth rate in coal supply (12.7% per year), far outstripping the growth of the oil (2.7% per year) and natural gas supply (3.6% per year). The major energy consumers in Indonesia are industry (50.6%) and transport (33.1%). Most final energy consumption (88%) is in the form of fuels (oil, coal, gas, biomass), and the remaining 12% of final energy is provided as electricity.

In the last decade, electricity consumption has been growing at a rate of around 7% per year, from 91 TWh in 2000 to 228 TWh in 2014. Coal, gas, hydropower, geothermal and oil fuels are the main sources in the power generation mix.

As seen in Figure 23, the increase in electricity production over the last decade has come from a steady rise in coal-based power generation, which has experienced a 9.4% annual increase over the period. In 2014, coal, natural gas and oil respectively represent a 53%, 26% and 10% of the generation mix. The remaining 11% is provided by hydropower (6.6%) and geothermal (4.4%).

Gas power plants also grew in the past decade at a rate of 4.6% per year, as a result of improvements in gas infrastructure and government policy to prioritise natural gas production. Despite government efforts to reduce oil consumption, electricity from oil-fueled power plants still grew by 4.6% per year. The oil-fueled power plants are small-to-medium sized diesel generation plants distributed across remote regions of the country, installed to boost rural electrification.

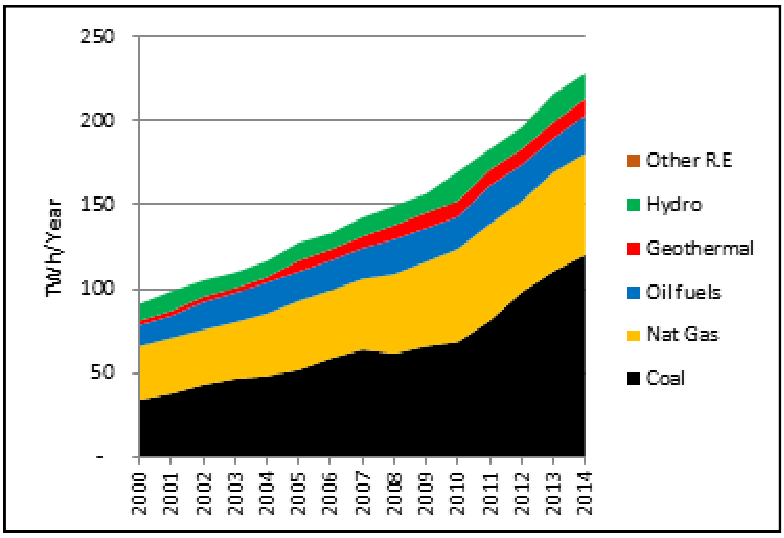


Figure 23:
Growth of electricity generation in Indonesia

Source: (PUSDATIN, 2016)

Geothermal represents less than 5% of the power generation mix, yet it has been experiencing double-digit annual growth over the last decade, highlighting its potential in Indonesia.

Indonesia's electrification rate was around 85% in 2014, with a low per capita annual consumption of 930 kWh/capita. Given that the country is an archipelago with many islands and remote rural communities, many Indonesians do not have access to electricity.

The electricity demand centers located in western part of Indonesia account for around 75% of Indonesia's total electricity consumption. The JAMALI (Java, Madura, Bali) interconnection grid has installed capacity of 33 GW with peak load at 25 GW. The Sumatra system has installed capacity of 7.6 GW with peak load of 4.8 GW. Kalimantan and other eastern Indonesia islands have total installed capacity of 5.65 GW.

Indonesia has a significant middle-income population that is still growing. It is expected that the Indonesian economy will continue to grow at around 5-6% in the coming decade. In line with the economic growth, energy demand will also grow. The business-as-usual (BAU) case of the National Energy Council's *Energy Outlook* projects that Indonesian electricity demand will more than triple between 2013 and 2030, from 210 TWh to 770 TWh. This will require significant additional power generation infrastructure.

5.6.2 Regulatory settings in Indonesia

Indonesia National Power Utility (PT PLN) in principle holds the monopoly of Indonesia's electricity sector. Partial liberalisation of the sector since 2009 has been implemented through the issuance of Electricity Law No.30/2009. The Law stipulates that to increase the country's generation capacity, the private sector can participate in electricity generation. However, the transmission and distribution is still monopolised by PLN.

The Electricity Law provides rules for the development, generation and distribution of electricity. The Ministry of Energy and Mineral Resources (MEMR) is responsible for the development of the power sector by establishing policy, technical and business regulations, technology development/promotion and the sector development plan. The specific division of the Ministry that deals with the electricity sector is the Directorate General of Electricity (DJK).

Indonesia recognises two types of electricity supply business: (i) public use and (ii) own/private use. Both types require government permits. The former requires an Electric Power Supply Business Permit (IUPTL). The supply business for own/private use requires an Operational Permit. Electricity supply businesses include: generation; transmission; distribution; and/or sales to consumers. Electricity business permits should be obtained from the Directorate General of Electricity.

Some of features of electricity business in Indonesia are as follows:

- PLN has the first right for electricity supply in Indonesia.
- PLN functions as system operator for the existing transmission and distribution grid.
- Corporate bodies, cooperatives and self-supporting communities can participate in the supply of electrical power to end-users.
- PLN has the obligation to serve areas where no private interest has been shown.
- PLN is obliged to purchase electricity generated from renewable power plants that are smaller than 10 MW.
- Areas not already served by PLN may be served by private businesses as long as the specific area is not included in PLN's plans for electrification.
- IPPs generating electricity in areas already served by PLN may only sell electricity to PLN (PPA). This is referred to as "captive generation".
- Captive generation may be conducted by government agencies, state-owned companies, private corporate bodies, cooperatives and individuals.
- Private businesses selling electricity to the public should hold a permit (IUPTL) issued by DJK.
- Private business may need to build transmission and distribution grid if supplying directly to end-users.

In addition to the MEMR, the National Energy Council (DEN) also oversees the development of the electricity sector. DEN issues general policy for all energy sector development, including electricity. DEN published a long-term energy outlook (2050), showing the trajectory of the country's energy sector.

5.6.3 The 35 W Fast Track Program

To support and encourage the growing economy, in 2015 Indonesia launched an acceleration (Fast Track) program for power plant expansion, targeting the development of a new 35 GW power plant by 2019, which along with the ongoing 7 GW power plant construction under the previous Fast Track program, it is expected to deliver an additional 42 GW capacity by 2019. The 35 GW expansion plan has been included in Indonesia's Medium Term National Development Plan 2015-2019 (RPJMN) and in the PLN Electricity Business Plan (RUPTL) for 2015-2024.

The 35 GW expansion plan consists of 109 projects. Of this expansion plan, PLN will build 17 GW (35 projects) while IPPs will build the remaining 18 GW (74 projects). Most additions from the 35 GW program will be coal-fired power plants (56% of the total additions), followed by gas (36%), hydropower (4%), geothermal (2%), and other energy sources (2%).

According to the latest RUPTL 2016-2025, the Government has set an even more ambitious target for 2016-2025 that includes additional power plant capacity of up to 80.5 GW. Some of the key features of the latest RUPTL are as follows:

- The planned capacity addition is higher than that in the RUPTL 2015-2024 to achieve the Government power mix target in 2025, i.e., renewable 25% and gas 24%.
- Coal-fired power will dominate the capacity expansion i.e., 34.8 GW (43.2%) followed by gas power plants 23.2 GW (28.8%). Addition of renewable power plants will include hydropower 14.5 GW (18.0% of total capacity addition) followed by geothermal 6.2 GW (7.6%) and other power plants 1.9 GW (2.4%), which include solar PV, wind, diesel, waste-to-power and biomass power plants.
- To meet the renewable target of 25% in the 2025 power mix, an additional 14.4 GW is needed on top of the planned renewables. In the event the renewable target cannot be met, 5 GW of additional gas/LNG will be installed.

Considering the slow progress of the 35 GW project, the (Ministry of Energy) and PLN recently stated that the project might be scaled down to around 20-22 GW in 2019. However, in the January 2017 meeting with the National Energy Council, President Joko Widodo insisted that, despite slow progress, the 35 GW project should continue, and should be viewed not only as a target but a need.

In the draft RUEN (National Master Plan of Energy Development) meeting with President Joko Widodo in January 2017, the Government stated that Indonesia should have installed capacity of 114 GW in 2025. The 35 GW projects are needed to achieve the 114 GW target. Therefore, it appears that the 35 GW project will remain in the electricity development agenda and formal (legislative) program revision is not likely to occur in the near future.

5.6.4 Climate change

In 2012 energy activities emitted around 508 million tonnes CO^2e, which is the second largest after land use, land-use change and forestry (LULUCF) and peat fire which together emitted 698 million tons CO^2e. The energy sector emissions primarily came from electricity generation (34%), industry (27%) and transport (26%). Residential and commercial sectors and fugitive emissions of oil and gas production accounted for the remaining 13%. In the past decade, emissions from energy sector grew at an average of 4.5% per year, higher than the LULUCF emission (2.7%).

To contribute to the global endeavor of limiting 2°C increase of global average temperature, Indonesia has pledged to pursue the country's development in a low-carbon way. In its Intended Nationally Determined Contributions (INDCs), Indonesia pledged to unconditionally reduce its emissions by below 29% by 2030. With international support, the reduction could be increased to 42% (conditional pledge).

As the second largest GHG emitter in the country, the energy sector is expected to significantly contribute to emission reduction. For the unconditional pledge, the energy sector emission target is 17.5% below energy sector baseline emission level in 2030. Under conditional pledge, the reduction could be up to 32.7%.
The magnitude of emission reduction is 253 $MtCO^2e$ (unconditional) and 472 $MtCO^2e$ (conditional).

Indonesia has various energy sector mitigation options to achieve the reduction, namely: efficiency measures, deployment of renewable energy, nuclear power and clean coal technology including carbon capture and storage.

5.6.5 Trade

Multinational networks are regulated under *Cross-Border Electricity Trade* (Articles 37 to 41 of Law No. 30/2009, in the Electricity Law).

The power purchase requirements are listed in Article 39:

a. Local demand is not yet fulfilled.

b. Only to support the fulfilment of local demand.

c. Should not jeopardise/sacrifice national interest in sovereignity, security and economic development.

d. Meant to improve the quality and reliability of local electricity supply.

e. Should not disregard the development of domestic capacity in electricity supply, and

f. Should not lead to dependency to foreign electricity supply.

Cross-border power **sale** requirements are listed in Article 40 :

a. Local demand and its surrounding is already fulfilled.

b. Sale price should not contain government subsidy, and

c. Should not disturb the quality and reliability of local power supply.

Article 41 contains more detailed provisions. Government Regulation associated with grid interconnection policy is Government Regulation No. 42/2012. An important feature of the regulation is Article 14:

a. The price of power purchased should consider the economic value of the electricity.

b. The price of power purchased should be approved by the Minister.

Indonesia is, in principle, supportive of multinational interconnection and supports the establishment of the ASEAN Power Grid, and the government has ratified the MOU.

Indonesia has had experience in cross-border power trade with hydropower from Sarawak Malaysia, providing electricity to West Kalimantan. The cross-border trade between SESCO Malaysia and PLN is enabled by an 82 km, 275 kV interconnector that links PLN's West Kalimantan Terminal (Bengkayang) and SESCO's Terminal (Mambong, Sarawak). The trade is covered by a 25-year Power Exchange Agreement (PEA). SESCO Malaysia will supply 50 MW during non-peak times and 230 MW during peak times. The trade is intended to reduce the electricity deficit in West Kalimantan. In addition, it is also viewed as an effort to improve PLN's fuel mix in West Kalimantan, so the electricity production cost could be reduced from Rp 2700/kWh to Rp 1700/kwh, a saving of 3.5 billion Rp per day. The interconnection is considered part of the ASEAN Power Grid.

Public acceptance of the cross-border trade has been widespread and positive because it reduces the power deficit and also reduces electricity production costs.

Under current law, electricity transmission is monopolised by PLN. As a general provision, PLN has the privilege to build and operate transmission as needed by the electricity supply development plan. However, when PLN cannot build the necessary transmission, the Indonesian private sector is allowed to participate. The tranmission's operation is done through PLN's Center for Load Management (P3B). The transmission owner and the user must negotiate the rent of the transmission. The construction of a new transmission should be related to the RUPTL (expansion master plan).

Traditionally, PLN has insisted that transmission is their exclusive domain. However, PLN's inability to build new transmissions especially related to the 35 GW program has made the public push PLN to allow private participation in the transmission business. There is no precedent of PLN renting transmission built by the private sector.

The construction of transmission for electricity sourced from solar generation in the Pilbara project would need a special legal umbrella, separated from the RUPTL. Currently, PLN is focused on domestic supply-demand systems and may regard a project such as the Pilbara solar generation and the ASEAN grid as a secondary priority.

However, overall as the electricity market grows (domestic as well as regional/ASEAN) and the world begins to enter the climate regime, new schemes such as the transmission of Pilbara solar power and the APG may become interesting for PLN and Indonesia in general. This is especially true when PLN and Indonesia have successfully dealt with domestic supply-demand, or if the Pilbara project could fit in with the existing Indonesian supply-demand projects.

There is a precedent for trans-boundary energy infrastructure for gas (Singapore and Malaysia) and electricity (Serawak/Malaysia) in Indonesia. However, these infrastructures are used to transport Indonesian products (gas) or to bring in products needed by Indonesia. For a scheme, such as sourcing solar energy from the Pilbara, a new legal framework is needed. Stakeholders would not be limited to the energy sector if it involves the use of Indonesian land for trans-boundary transmission of energy. There is also the possibility of the Pilbara project transmission system to supply Indonesian demand and/or to export Indonesian energy.

A shared vision of trans-boundary integrated electricity infrastructure the ASEAN region was adopted in the end of 1997. This vision recognises the potential advantages of having an ASEAN grid to supply the ever-growing electricity demand and to stimulate regional economic growth, development and cooperation among ASEAN members. Progress has been slow.

Although Australia is not part of the ASEAN grid idea, the Pilbara project could stimulate the realisation of the ASEAN grid . Discussion is required with members of ASEAN regarding Pilbara solar generation and transmission.

There is no precedent for costing transmission services paid for by PLN. What PLN maybe willing to pay maybe estimated from the investment cost and an acceptable rate of return over, say, 30 years.

5.7 An Asian solution

The projected and generally accepted future energy mix for ASEAN countries is not consistent with concerns and commitments for action on climate change. It is a classic tragedy of the commons in which inaction brings short-term benefits to individual countries but long-term costs to the group. Is the mood of ASEAN more cooperative or competitive? There is certainly a sense of Asian community and shared identity, but this is not submerging competitive pressures. These are fast-moving times for Asian economies – no one wishes to be left behind.

Progress in the energy sector will depend primarily on the economic performance of renewable generation compared to other sources, and Australian solar energy must compete in the same arena. While subsea HVDC delivery of Australian solar energy certainly contributes greatly to its cost, the quality of the resource gives a cost advantage. There are several secondary motives for using Australian solar energy: accessing a physically and politically secure location, avoiding local land use, avoiding many local planning requirements, and diversifying the energy mix.

The potential to become an innovator and a driving force behind a new ASEAN infrastructure may also be significant political and economic motivation. Indonesia, due to its geographical reach, and Singapore, as an existing commercial hub, both seem to be well positioned for this role.

Samantha Mella Geoff James Kylie Chalmers

06

Engineering GW scale solar farms and HVDC transmission

6.1 Key findings

- There are constraints to developing solar resources in the Pilbara – dunes and hard rock, cyclones, wet season, extreme temperatures, and remote locations.
- It is more expensive to produce solar in the Pilbara than some other parts of the world, including the east coast of Australia – LCOC 11 c/kWh at the time of writing, 9.3 c/kWh in the long term. The lack of a solar industry is a major factor.
- Large-scale solar is becoming mainstream in Australia with rapidly falling costs.
- It is difficult to find accurate costing information for other key technologies, some of which have a limited number of suppliers – every project is different.
- For connection to Indonesia, cost can be bought down by:
    - connection and transmission options in the Java grid
    - a rapid solar build - emulating a mining construction boom
    - a few good locations to minimise the cost of the aggregation network.
- Technology already exists that is capable of the lengths, depths, and capacities required for large-scale electricity trade via subsea HVDC transmission from the Pilbara to Java.

6.2 Introduction

GW-scale solar generation in the Pilbara and HVDC transmission from Australia to Indonesia are technically feasible, but challenging to implement. A significant element of the challenge is that a subsea HVDC transmission project doesn't lend itself to an incremental approach – it produces no return on investment until it is complete and delivering energy. Laying a small cable might save in materials and require a smaller ship, but the project would be just as complex, and many of its costs would be the same and would need to be recovered from a much smaller revenue from delivered energy. Therefore, commercial success is more likely to be achieved by laying the largest possible cable, or cable pair, that is technically achievable at the time. This, together with the solar generation plants and AC network to supply the subsea cable, is referred to as the Pilot Project.

The Pilot Project is examined in detail below and in the economic analysis in Chapter 7.

If it is a commercial success and has good environmental and political outcomes, a subsequent Incremental Build would expand the network according to market conditions. A potential first expansion of capacity beyond the Pilot Project is considered in the outline.

The main engineering challenges and the cost estimates used for economic modelling are outlined below. Siting of solar generators and precincts is considered first.

Samantha Mella Geoff James Kylie Chalmers

Engineering considerations for developing GW-scale solar farms at three selected locations are discussed and their output profiles are estimated – with a focus in this report on solar PV generation, although concentrating solar thermal (CST) generation could also be built at these locations. The AC and HVDC network to aggregate and deliver the solar output to Java is then suggested and costed. Several alternative network designs are possible according to the range of locations where solar generation is to be developed. The location of the HVDC converter station is an important design consideration because it is the single export point to which all solar output should be delivered.

6.3 Siting study for solar generation precincts

An assumption of this study is that it will be uneconomic to aggregate the output of solar generators, of various sizes, distributed widely across the Pilbara. This would require a large aggregation network to be constructed, mirroring the way centrally generated electricity is delivered by a distribution network to residential and commercial customers in a more populated region. Recalling that half of a typical Australian electricity bill is due to network costs, such a network would be a very large additional cost. Instead, solar generators are assumed to be concentrated at solar precincts that are at particularly favourable locations, and a much smaller aggregation network is required within each precinct. The major network expense is then to connect solar precincts to the HVDC export point, and this is discussed in Section 6.5 below.

To enable the quantitative market study in Chapter 4, three indicative solar precincts have been identified by considering physical constraints on establishing large-scale solar generation. The sites identified by this study should not be taken as definitive or restrictive – a more comprehensive analysis would certainly identify a range of other potential sites in the Pilbara and the Kimberley. However, it is important to choose some example sites to estimate the solar generation output and the cost of delivering it to the subsea cable. Three sites allow several configurations to be considered and provide an indication of how diverse the solar resource is across the region.

Samantha Mella Geoff James Kylie Chalmers

6.3.1 Criteria for solar generation sites

A naïve viewpoint would be that the Pilbara is flat and sunny and could accommodate solar PV generation almost anywhere. In fact, there are a range of constraints on suitable solar sites and large areas are most likely unsuitable, because they are not sufficiently flat, are too rocky, too sandy, too close to the coast, or too far from road or rail infrastructure to support construction and operation. On top of such constraints will be the potential for land-use conflicts, which are discussed briefly below. Choosing suitable sites for a solar precinct that might support several GW-scale solar farms in reasonable proximity requires careful analysis.

Detailed geographical and geological data for the Pilbara are available through the ALCES software (ALCES Landscape & Land-Use Ltd., 2013) which has been licensed by the Pilbara Development Commission (PDC) to manage and visualise information about land characteristics and land use in the Pilbara. The ALCES software allows a wide variety of parameters, or 'indicators', to be selectively mapped. With assistance from the PDC, a first-pass selection of sites was done, and the key criteria used were as follows.

Buffer of 50 km from the coastline. This will reduce the maximum wind speed likely to occur through cyclonic activity. Category 2 cyclones have been known to go inland as far as Marble Bar, so infrastructure should survive this wind speed (89-117 km/h sustained, with 125-164 km/h for the strongest gusts). This will also reduce the impact of cloud cover on annual solar generation. Consultation with experts at Solar Choice indicated that designing solar PV farms to survive category 2 cyclones would require significant additional expense, so a wider buffer of 150 km is desirable.

Within 250 km of the coastline. This helps to ensure adequate access to population centres with a workforce available for project build and operation. That said, a training partnership with traditional owners should be encouraged to encourage a local workforce in remote locations. Promising sites exist greater than 250 km from the coastline that should not be excluded from analysis.

Mean slope less than 1%. This is helpful for optical and engineering considerations. Flat land greatly assists low-cost construction.

Coarse rock fragments 0-60 cm less than 10%. The Pilbara abounds in rocky ground in which it is difficult to embed footings for solar PV arrays. Additional expense was required for the Marble Bar power station, for example, to construct concrete footings. This requirement highlighted alluvial plains, where the ground covering is water-borne pebbles, and other flat areas, and identified wide areas of red coarse 'sand' and scrub.

Sand 0-60 cm less than 50%. Sandy deserts are popularly considered rich sources of solar energy, but in fact it is not practicable to build solar arrays on sand dunes that are clearly not flat and may shift over time, so sandy areas should be avoided.
The Pilbara becomes sandier towards the east and the Great Sandy Desert, and large parts contain some sand, so this criterion was difficult to fulfil strictly and had to be weakened. It is difficult to distinguish using the available ALCES criteria between sandy soils that might be suitable and sandy desert that is not.

Proximity to roads and railways less than 50 km. This reduces the cost of transporting materials and people to work sites during construction and operation. Note that proximity to existing transmission infrastructure is not likely to be important for this project, which will require dedicated transmission to be built to achieve the most efficient system design.

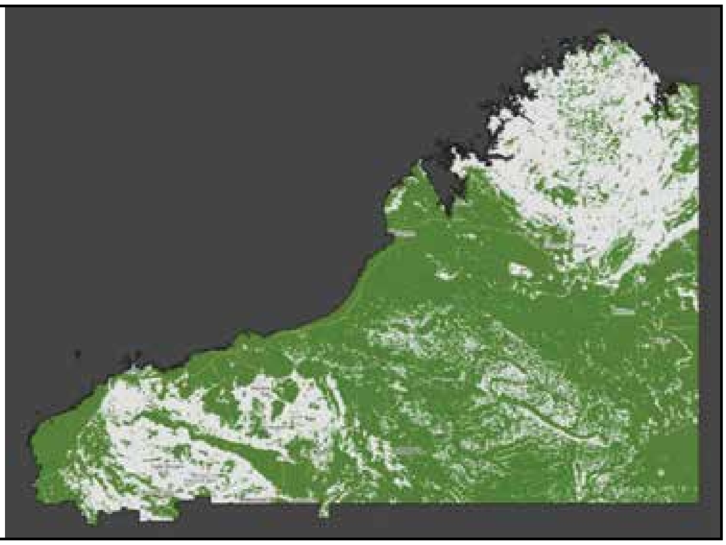


Figure 24: Green = average slope in a square km is less than 1% (Fromm, 2016)

Avoid proximity to habitation, mining sites, national parks and heritage areas. All these and others are likely requirements for a variety of reasons (e.g. mining sites produce dust). Detailed consultation with state and local governments, companies with mining tenements, agricultural leaseholders and traditional owners will be necessary to secure solar sites and transmission corridors.

Avoid land clearing. Protecting native vegetation is an important priority in the western Kimberley, which features large areas of spinifex and small trees. As well as protecting soils and habitats, the vegetation of this region is an important carbon sink and is managed as such by the traditional owners, helping to support local communities (Taylor, 2016).

Figures 24-29 map the separate and combined impacts of these criteria on available land for solar development.

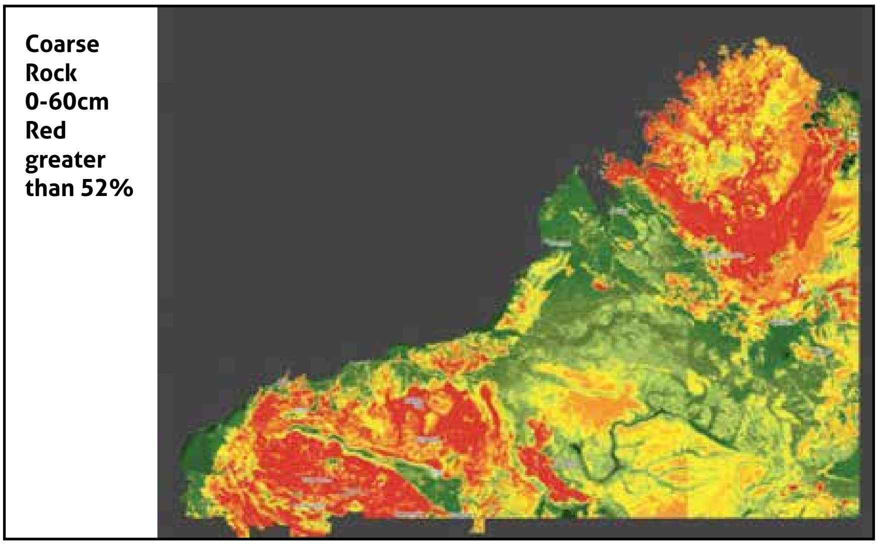


Figure 25: Red = coarse rock greater than 52% (Fromm, 2016)

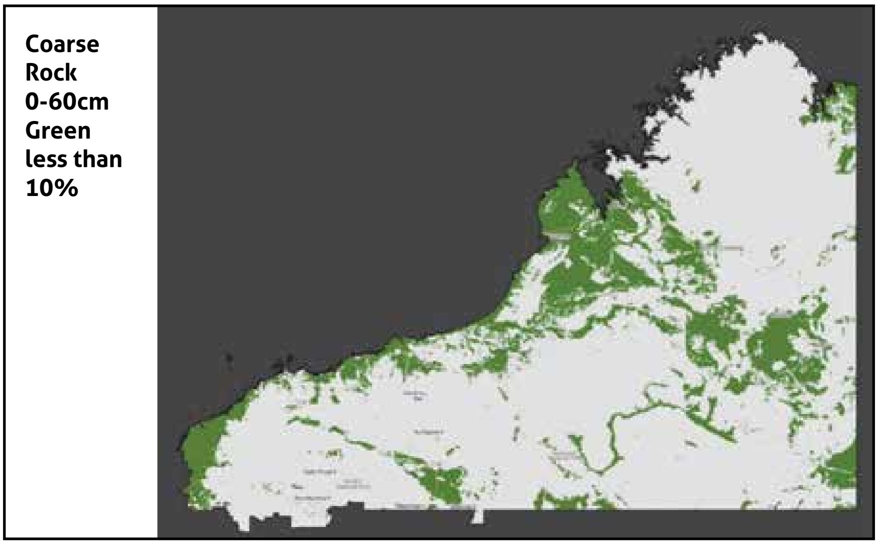


Figure 26: Green = coarse rock less than 10% (Fromm, 2016)

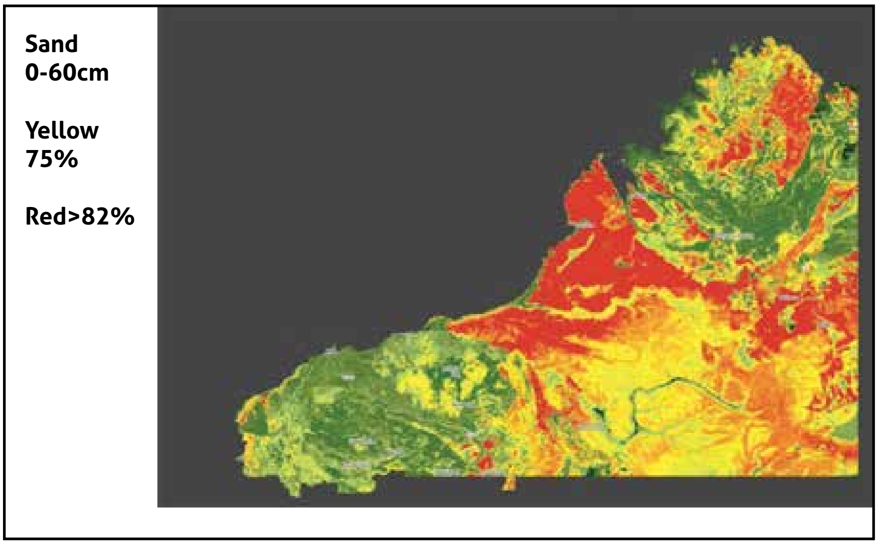


Figure 27: Yellow = sand greater than 75% and red greater than 82% (Fromm, 2016)

Distance from road	Weighting
0-20km	4
20-40km	3
40-60km	2
60-80km	1
80+km	0

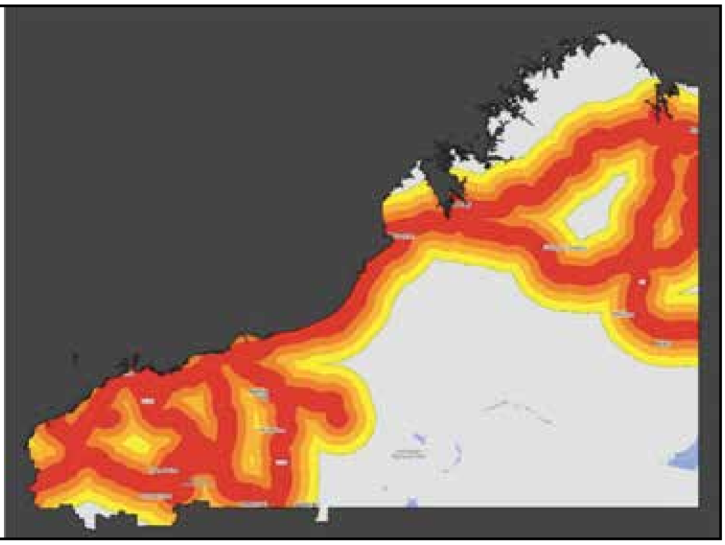


Figure 28: Red = distance from road 0-20 km and yellow = 60-80 km (Fromm, 2016)

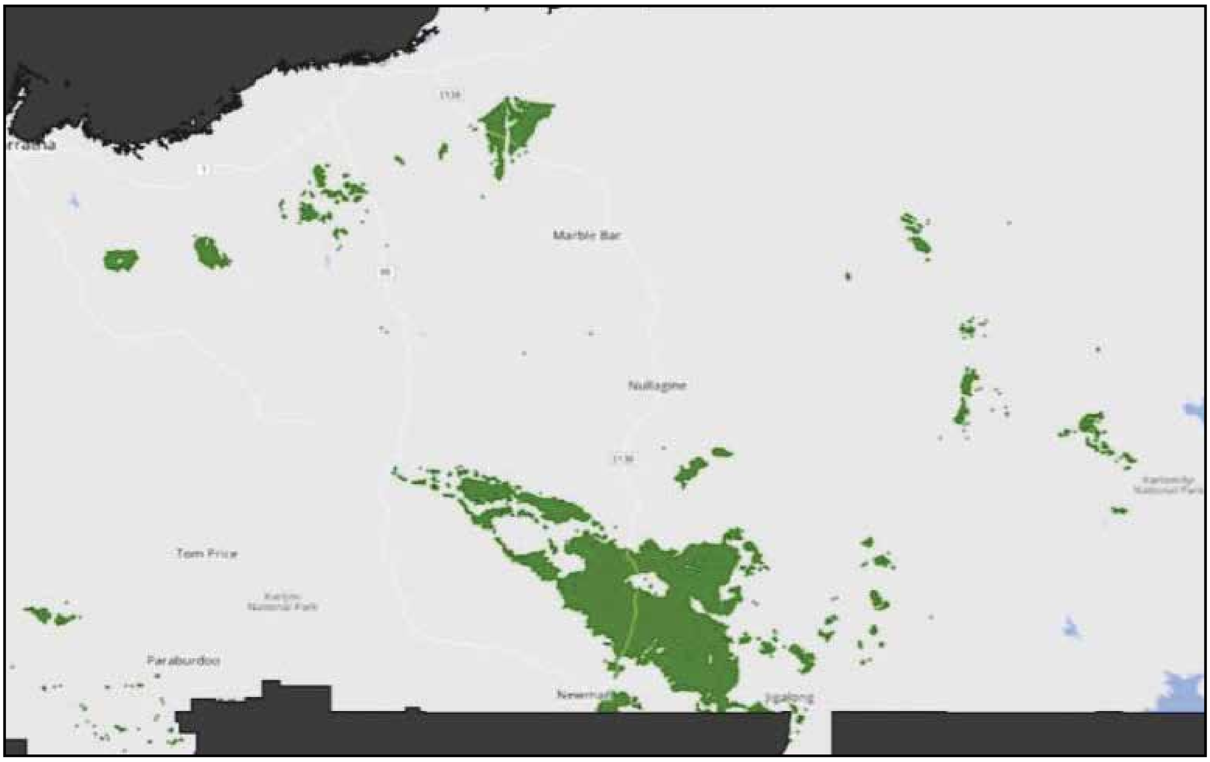


Figure 29: Detail with combined criteria allowing distance from coast > 50 km (Fromm, 2016)

Three locations have been selected as potential solar precincts for analysis in this study, based on the maps above:

- The De Grey River Basin appears to be a suitable location, considering most of the criteria above, except that it is closer to the coast than 150 km and may therefore be subject to occasional cyclones. A location of −20.6 degrees latitude and 119.5 degrees longitude will be a reasonable starting point for solar resource analysis.

- The area north of Newman, surrounded by active and disused iron mines, also appears to be a suitable location, well inland, and located in a broad river valley. It will be necessary to check the frequency of flooding and engineer solar arrays appropriately. A location of −22.7 degrees latitude and 120.1 degrees longitude will be used for solar resource analysis.

- Allowing that the transmission line will traverse the Kimberley, a site southeast of Broome near the likely route has been selected, although it may be more subject to flooding and cyclone risks. The HVDC converter station would be located nearby with an AC network continuing to the Pilbara. A location of −18.3 degrees latitude and 122.8 degrees longitude will be used for solar resource analysis.

The three suggested solar precincts are shown in Figure 30. Indicative transmission line routes and distances between them are also shown.

Another siting study will select a reasonably accessible route for a transmission line to the coast, probably in the region of the Dampier Peninsula. Proximity to road infrastructure would be an advantage. It is not uncommon, though, for transmission lines to be constructed through remote territory. Traversing important wilderness and heritage areas will be an equally important issue. There are successful precedents, for example, the Madeira Complex in Brazil, where environmental and indigenous heritage issues were addressed through design, consultation and mitigation. It is possible that the landing point for the HVDC transmission line will be closer to Broome than the northern end of the Dampier Peninsula for this reason.

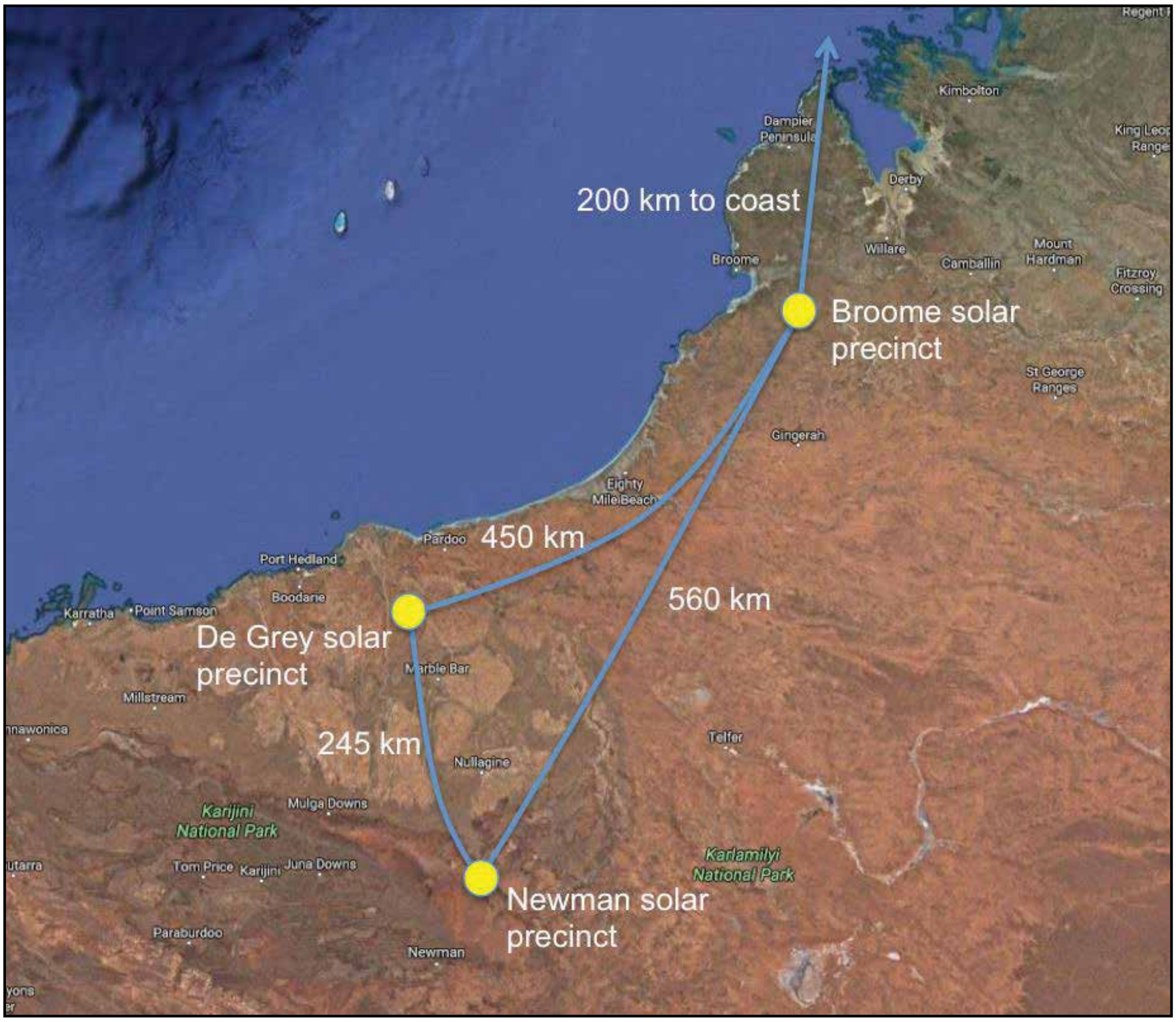


Figure 30: Potential solar precinct sites and transmission line distances between them

6.3.2 Land ownership

The WA government is the owner of almost all the land in the Pilbara, with freehold titles a rarity, and land use is permitted through agricultural leases and mining leases covering the entirety of the Pilbara. Any use of land for solar generation would be in competition with other purposes, as elsewhere in Australia, and the economic and strategic value to Western Australia would need to be justified to negotiate the necessary leases. If the best solar land occurs in relatively few locations across the Pilbara, as this analysis suggests, then it is quite possible that suitable land will acquire a premium value as the solar industry gains momentum. A successful solar export industry may be competitive with agricultural and mining land uses and this could stimulate a strategic shift in WA land management policy.

In parallel with government ownership, the Pilbara is covered by a set of native title claims by traditional owners that in many cases have been upheld in the courts. Consultation with traditional owners is required for the approval of any development in areas subject to native title. Solar farming for export presents opportunities for Aboriginal communities to play an active and potential leadership role. Some opportunities would be local to the sites of solar generation and transmission, while others would be available to any community desiring to participate in a new Aboriginal enterprise. These considerations are discussed at length in Chapter 8.

6.4 Solar resource analysis

The sites selected above for solar precincts allow a preliminary analysis of the technical and economic case for exporting Pilbara solar energy to Asia or to eastern Australia. They are shown as yellow circles on a satellite map in Figure 30. Each circle is about 30 km across and a number of solar generators would be located inside, built over a period of time and interconnected with, most likely, a conventional AC network.

In terms of local loads and distance from cyclonic activity, the solar precincts present more attractive opportunities as the distance from the Dampier Peninsula increases. This study is focused on the Pilbara, however, a site in the Kimberley is included to explore whether it is effective to have the HVDC converter station in the Kimberley and proceed by AC transmission to connect a range of solar developments and, potentially, local loads.

To develop hourly solar output estimates for a typical year of operation of a solar PV generator, project partner Solar Choice (Guo, 2016) designed an example large-scale generator for Pilbara latitudes, and then used the industry-standard software PVSYST (PVSYST, 2012) to calculate its output. The example generator's nominal peak output is 2,880 kW, and its generated output per month and the influence of various losses is shown in Figure 31 for the De Grey precinct, Figure 32 for the Newman precinct, and in Figure 33 for the Broome precinct. Collection losses are larger during the summer months due to the lower efficiency of solar PV cells when operating at high temperatures.

There are significant but not large differences between this solar generator's performance at these sites. At the De Grey site it produces 7,045 MWh in a typical year, which corresponds to a capacity factor of 27.92%. At the Newman site it produces 7,004 MWh in a typical year, which corresponds to a capacity factor of 27.76%. At the Broome site it produces 6,978 MWh in a typical year, which corresponds to a capacity factor of 27.66%. These totals hide an interesting seasonal variation, because although the solar resource is better in the Pilbara due to less cloud cover during the wet season, the collection losses are higher in the very hot summer temperatures experienced there. Higher incident solar energy is partly offset by the lower cell efficiency, resulting in modest variation in annual output between the three sites. The De Grey site seems preferable by a margin that is probably small compared to the inter-annual variation not represented in these graphs.

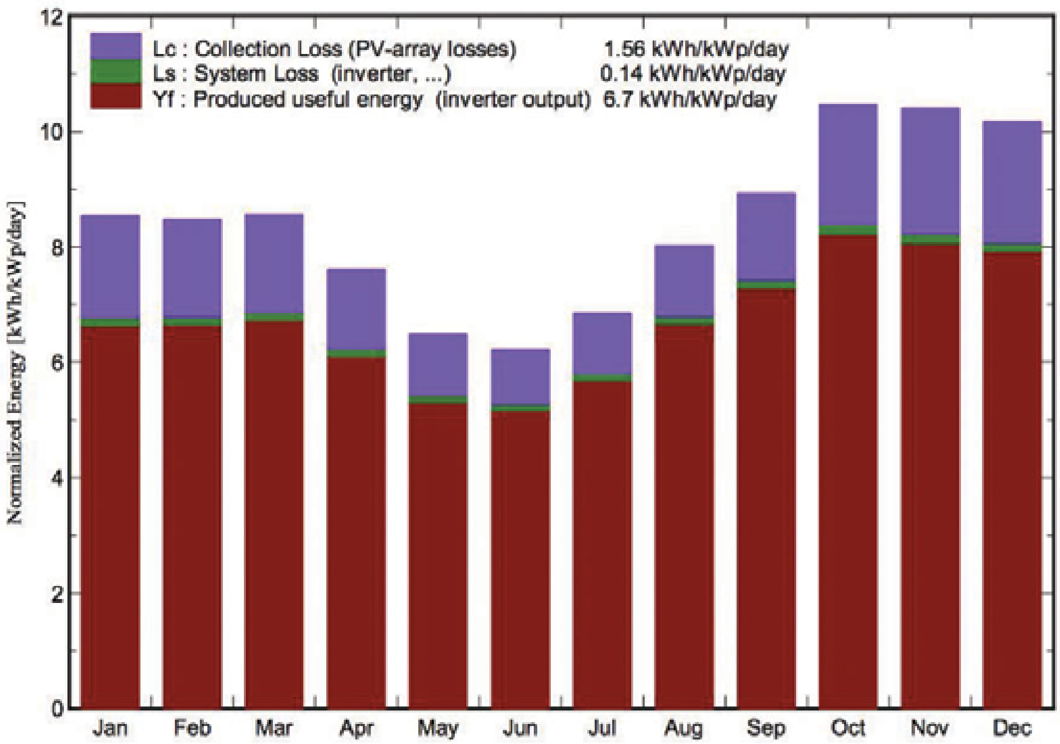


Figure 31: Solar PV generator output per month at the De Grey solar precinct calculated by PVSYST

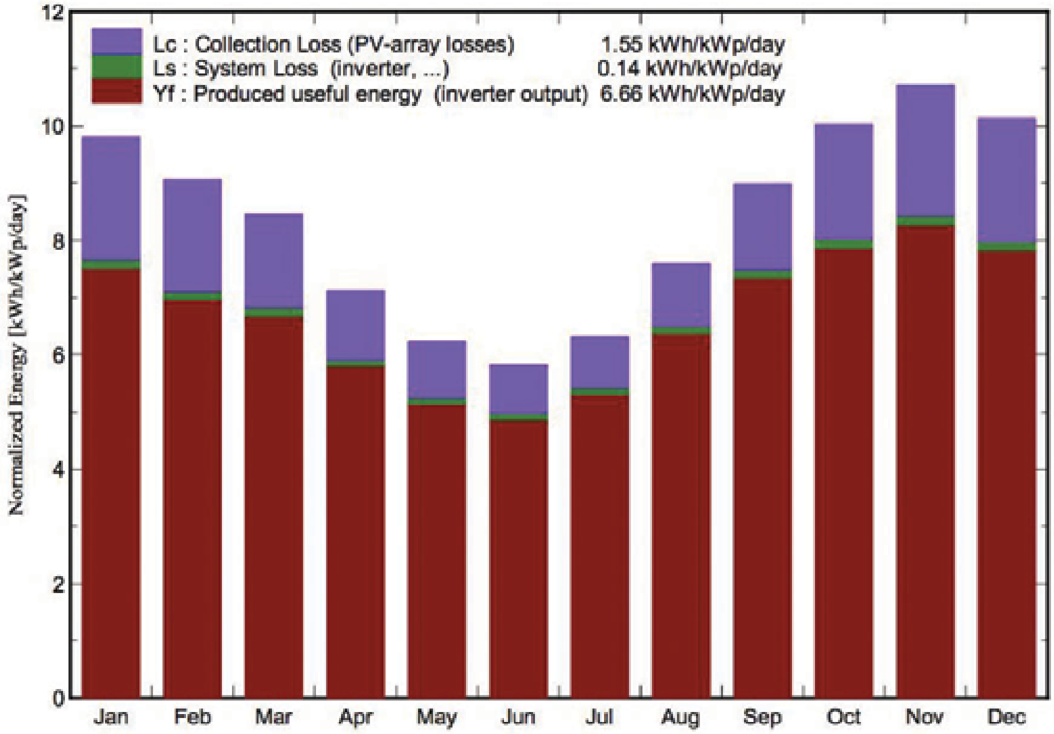


Figure 32: Solar PV generator output per month at the Newman solar precinct calculated by PVSYST

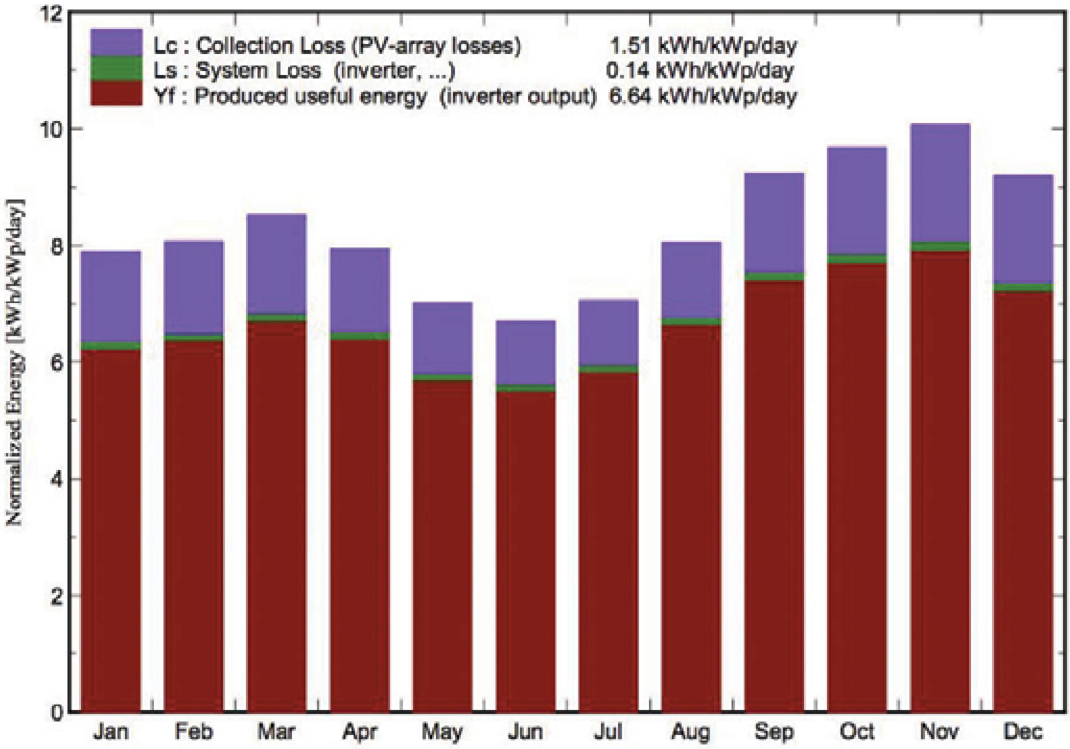


Figure 33: Solar PV generator output per month at the Broome solar precinct calculated by PVSYST

6.5 Solar farm construction and operation

6.5.1 Four stages to develop the local supply chain

Rooftop solar PV generation has been adopted rapidly and effectively by Australian households and businesses reaching a total installed capacity of over 5 GW by 2016, but growth of utility-scale solar generation has been much slower as can be seen in Figure 34. This chart also shows, however, that 2015 was the first year when a significant capacity of utility-scale solar was installed through the Moree, Nyngan and Broken Hill plants. The positive outcomes of the Large-Scale Solar funding round by ARENA in 2016 suggest that utility-scale solar will start to grow rapidly now that the commerciality gap is almost closed – the amount of ARENA funding required by the winning bids was much lower than anticipated. Drivers behind this trend include a more favourable debt market, recognition of the value of the solar through power purchase agreements (PPAs), and system optimisation in several respects (Walden, 2016).

Developing solar generators to supply the HVDC subsea cable will require careful scheduling due to the competing goals of a quick build to minimise dormant plants with no customers connected, and a gradual build to allow an efficient local supply chain to develop. Solar generators can in principle be constructed more quickly than the several years needed to plan and lay the subsea cable, solve new engineering challenges, and integrate new supply into the Java grid. However, doing this would compress a large construction project into a short space of time, which may increase costs and decrease the opportunity for local industries to be established for the wider benefit of the Pilbara economy and community. Managing this issue would allow an accelerated build.

A local solar industry can develop new solutions to challenges specific to the Pilbara and, through good design for manufacture, to reduce costs substantially as the industry grows. East-coast solar developers do not experience challenges such as the following:

- Any infrastructure must be able to survive at least category 2 cyclones (wind speeds gusting to 125-164 km/h) and higher categories near the coast.
- Some inland sites have less cyclone risk but may be inaccessible by road from December to March due to high rainfall. This compresses the build into the remainder of the year and requires extended periods of fully remote management.
- Pilbara soils are often rocky and the common means for establishing footings for arrays of solar PV panels may not be suitable. This is potentially a significant additional cost that may be reduced through experience and large-scale efficiencies.

Solar generation capacity should be built up by small stages at first, to nurture a local supply industry in the Pilbara that can develop projects properly adapted to local conditions.

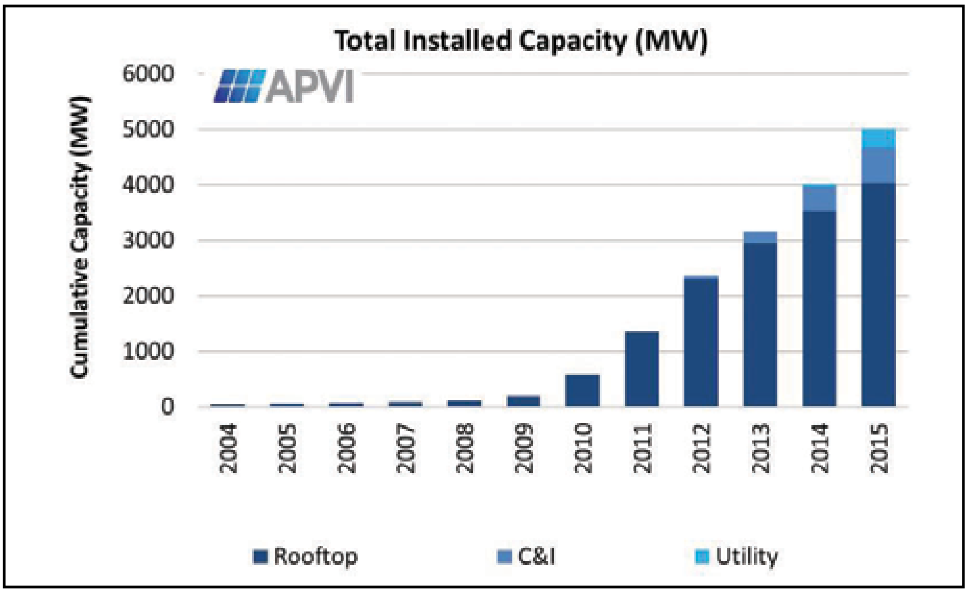


Figure 34: Installed capacity of PV generation by sector in Australia

Source: (Australian PV Institute, 2016)

Financial year(s)	2017-18	2018-19	2019-20	2020-21 to 2024-25	2025-26 to 2029-30	2030-31 to 2034-35
Gradual build stages	**1**	**2a**	**2b**	**3a**	**3b**	**4**
New solar PV capacity	20 MW	60 MW	120 MW	800 MW 160/year	2,500 MW 500/year	7,900 MW 1,600/year
Remote WA markup	40%	40%	40%	20%	0	0
Capital cost in this period	$43 M	$129 M	$259 M	$1,478 M	$3,850 M	$12,166 M
Operating cost in this period	$1 M	$3 M	$8 M	$165 M	$620 M	$2,053 M
Accelerated build stages	**1**	**2a**	**2b**	**3a and 3b**	**4**	**5**
New solar PV capacity	20 MW	60 MW	120 MW	3,300 MW ≤850/year	7,900 MW 1,600/year	Etc.

Table 12: Anticipated growth and costs of solar PV generation in the Pilbara and (potentially) the Kimberley

This creates the difficulty that, during the build, a large installed capacity of solar generation will be dormant, not earning energy revenues, until the HVDC subsea cable is operational. During the early period of the solar build, therefore, an important strategy will be to locate solar generators close to local loads – mining sites, towns and communities, and the existing North-West Interconnected System (NWIS) are all potential customers. These early solar generators would be commercially viable in their own right, and could later be aggregated with others and their capacity augmented for solar export. Alternatively, it may be that some early solar projects remain dedicated to serving local loads, their primary strategic purpose being to build experience and a local supply chain in the Pilbara. To capture the changing purpose of the solar build, four stages of development are defined:

- **Stage 1**: the first utility-scale solar generator with locally manufactured components including mounting systems specifically designed for Pilbara conditions (capacity 20 MW)
- **Stage 2**: expansion of production to several solar generators each serving a load within the Pilbara (new capacity of 180 MW)
- **Stage 3**: accelerated expansion of production to the first stage of exports, involving construction of an AC aggregation network linking the separate generators
  - o **Stage 3a**: first at a single solar precinct (new capacity of 800 MW), and then
  - o **Stage 3b**: any additional precincts concurrent with the laying of the subsea HVDC cable to Java (new capacity of 2,500 MW)
- **Stage 4**: expanded export operations driven by market conditions (indicative new capacity of 7,900 MW).

The capital and operating costs associated with this growth plan are shown in Table 12 for the next three financial years and for five-year periods after that.

The plan includes both a gradual build with 10 years for Stage 3, and an accelerated build compressing Stage 3 into 5 years. The method for deriving these costs is described below and includes a mark-up for projects in remote Western Australia that decreases with the advance of local experience and local manufacture of some components. It's interesting to note that, as the build progresses, operating costs across all existing generators become increasingly significant in comparison to new-build capital costs, rising from 2% in 2017-18 to 17% beyond 2030. This is a good opportunity for developing a local solar management industry in combination with any local supply chain for the build.

This report is focussed on Stages 1-3 concluding with 3 GW of export capacity. Stage 4 corresponds to Figure 45 and indicates how the new industry may grow if the first 3 GW of export capacity is commercially successful.

6.5.2 Features of solar PV generators

Building an electric power generator is a big engineering exercise whatever the technology. The major phases are the feasibility study, financing, contracting, construction, system integration, and commissioning. Critically important contracts are established for Engineering, Procurement, and Construction (EPC) and for a Power Purchase Agreement (PPA); and market registration is also needed if the generator is to sell part or all of its output in a wholesale electricity market. Large solar generators (Gevorkian, 2011) have been constructed since the 1970s and there are many Australian and international companies that are experienced in their development, including project partner Solar Choice based in Sydney.

Solar power generators either concentrate the sun's direct radiation or use flat-plate collectors that can also gather diffuse solar radiation. Concentrating solar generators can be more efficient but require more complex engineering. Their intensified radiation can be used as heat to operate a steam turbine, or converted directly to electrical energy using photovoltaic (PV) cells engineered for high-temperature operation. The most rapidly growing type of solar generator uses arrays of flat PV panels, just like those used on residential rooftops, and the analysis in this report assumes this technology. Nonetheless, concentrating solar generators could be used equally well to supply the subsea HVDC cable, and have some advantages such as the availability of low-cost thermal energy storage integrated with concentrating solar thermal (CST) generators.

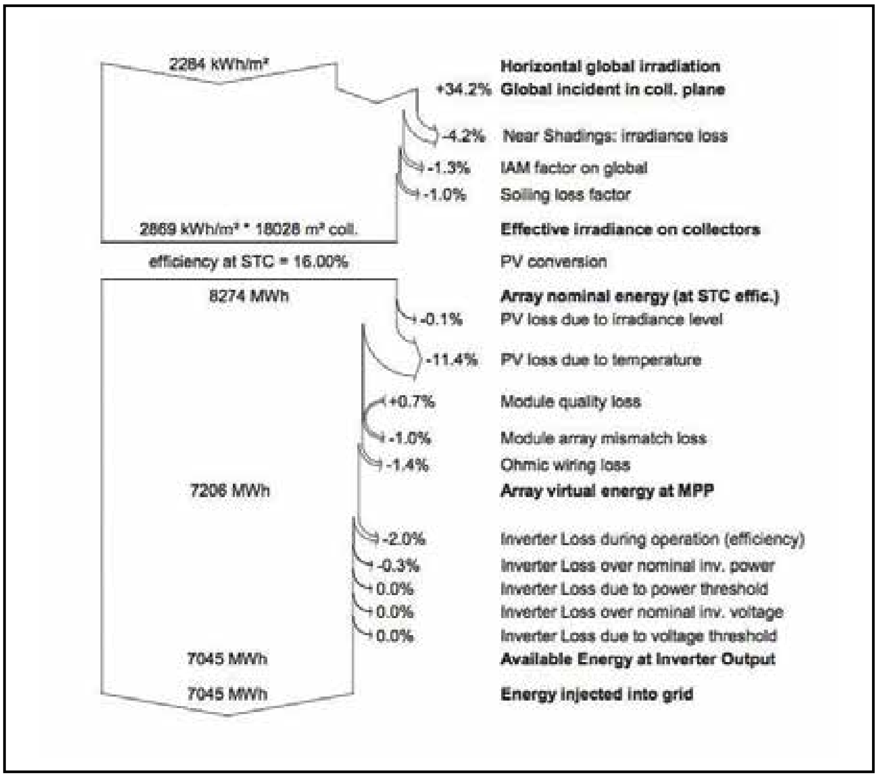


Figure 35: Loss diagram over a whole year at the De Grey solar precinct calculated by PVSYST

Some solar PV arrays have no moving parts, with panels tilted at a fixed angle related to the latitude to get the desired compromise between summer and winter performance. They may be oriented slightly to the east or west to favour production in the morning or afternoon respectively. They may be fully steerable so they can follow the sun precisely and maximise their output at the expense of additional engineering complexity. A compromise design is to have a single axis of tilt to follow the sun's daily path while accepting less than optimal performance in summer and winter.

Presently, this single-axis tilt technology is starting to overtake fixed solar PV arrays in terms of value for money, as the additional energy output can be achieved with a diminishing additional cost. In the recent Large-Scale Solar funding round (Walden, 2016) the EPC costs for both were approaching $1400/kW and this may be taken as the near-future costs of east-coast solar PV generators. Solar Choice confirms that this figure is a suitable estimate for east-coast projects but warns that there will be additional costs when building solar generators on rocky soils in remote WA. The published EOI Application Data (ARENA, 2016) confirmed that capital costs are lowest in NSW, while operating costs are similar across the east coast at about 18 $/MWh but increase to about 23 $/MWh in SA and WA.

This study assumes a base capital cost of 1400 $/kW for EPC with a remote WA mark-up of 40% for the first 200 MW of installed capacity and 20% for the next 800 MW. The base cost is then achieved by efficiencies realised through developing the first 1 GW of projects. An additional 10% on top of EPC costs is assumed to allow for approvals, contracting, and contingencies. Operating costs are assumed to be 23 $/MWh when the generators are delivering energy – and zero during any period that generators are dormant prior to interconnection to the HVDC export point.

Item	Value	Notes
Engineering procurement and construction (EPC) capital cost	1,400 $/kW	Trend for east coast solar developments
EPC capital cost breakdown		
Solar PV panels	40%	Installed using Pilbara labour
Panel mounts and controls	20%	Anticipate establishing a specialised Pilbara manufacturer
Inverters	20%	At least one WA company is expert in this technology
Other electrical	10%	Mostly Pilbara activity
Transport and civil engineering	10%	Mostly Pilbara activity
Additional costs		
Remote WA mark-up	40% 20% 0%	Phases 1-2 Phase 3a Phases 3b-4
Additional for contracting, approvals, and contingency	10%	Mostly Pilbara and Perth labour
Final cost estimates		
Capital costs	2,156 $/kW 1,848 $/kW 1,540 $/kW	Phases 1-2 Phase 3a Phases 3b-4
Operating costs	23 $/MWh	For energy delivered

Table 13: Assumed costing and cost breakdown for single-axis solar PV generation

From the electricity grid's perspective, solar PV generators behave differently to traditional coal, gas, and oil-fuelled generators, and even to solar thermal generators, all of which use 'synchronous' turbines to produce electricity. These turbines rotate at a speed synchronised with the grid frequency of 50 Hz. All synchronous generators on an interconnected grid are locked together by the grid frequency and their spinning masses provide inertia to keep the frequency stable. Solar PV generators are connected to the grid by inverters that use high-power electronics to create AC waveforms from the DC electrical input produced by solar PV panels. Modern inverters for utility-scale (multi-MW-scale) solar PV generators do not provide the same kind of inertia as synchronous generators, but they can provide sophisticated grid services to help keep the grid stable and safe (Williams, 2011):

- Reactive power capability to manage voltage on AC transmission lines;
- Low-voltage ride through (LVRT) to prevent disconnection during grid disturbances;
- Fault current contributions to ensure correct operation of grid protection systems.

Inverters are more efficient if operated with a high DC voltage, so solar PV modules are connected in strings to add their voltages in series to reach a suitable level. Large solar generators have many strings and inverters, and their AC outputs are connected in parallel to feed the total generated power into the grid.

The example solar PV generator design used to estimate output profiles in Section 6.3 comprises 489 strings of 19 PV modules with a nominal peak output of 2,880 kW (DC power). The terrain is assumed to be flat and single-axis tilting modules are spaced appropriately for Pilbara latitudes to avoid shading except in the early morning and late afternoon. Realistic system losses are estimated and the main ones are due to shading, temperature, array mismatch, and conversion losses in the inverters. The calculation of energy inputs and losses for such a generator is interesting and is illustrated in Figure 35. The estimated installed cost and breakdown by major components is shown in Table 13 and these data were used to calculate the capital and operating expenditure projections in Table 12. Output and operating costs assume a linear build of new capacity within each period; newly constructed plant is assumed to operate from the middle of the period in which it is built.

6.6 Aggregation network to an HVDC export point

6.6.1 Single or multiple solar precincts

Depending on the geographical distribution of solar generators, an AC aggregation network to connect them to the HVDC converter station can be a significant part of the solar export infrastructure. Although solar PV generation produces DC electricity from each panel, and aggregation and connection with the HVDC line could in principle be done entirely in DC, this would be a highly novel approach and would carry a significant cost and technology risk. This study presumes that the solar PV generators use standard grid connection technology to produce AC power.

Using an AC aggregation network could encompass supply to local industrial loads, such as mining operations and LNG terminals, and communities. It would also ease interconnection with the existing North West Interconnected System (NWIS) and may help to expand that network to encompass a greater range of industrial loads and generation sites. Serving local load centres, via the NWIS or independently, is likely to be important during the growth phase towards HVDC export. It would provide a business case for solar development before the first export link is constructed, as discussed in Section 6.4.1.

On the other hand, a large amount of AC network expenditure can be avoided by concentrating all the solar generators at a single solar precinct. The growth paths in Table 12 could be accommodated either at one site or at many. Adopting a single solar precinct may offer more limited delivery of output from the solar generators to local loads prior to completion of the subsea HVDC transmission line. This may be acceptable if the solar build is fast and efficient – like the accelerated build shown in Table 12. A single solar precinct requires a minimal aggregation network and is economically the most efficient approach; therefore it is the base scenario for this study, while multiple precincts are also considered as a sensitivity case in Section 4.3.2.

6.6.2 Whether to use HVDC or AC transmission across the Kimberley

From its landing point on the Dampier Peninsula, the transmission line will traverse the Kimberley on its way to the Pilbara. The scale and national significance of this project will focus the attention of many stakeholders and a partnership approach is necessary to motivate the resources necessary for its success. There are several reasons to consider in placing the HVDC converter station in the Kimberley and using AC transmission for the remaining distance to the Pilbara.

Comparison. It will be valuable to quantify the advantages of Pilbara sites compared to other sites and the solar resource data will help to do that. It will also be important to understand the cost and technical implications of converting to AC transmission for part, or all, of the Australian segment.

Investment opportunity. An extended AC transmission segment will allow investment in solar generation over a large area of both the Kimberley and the Pilbara, with perhaps different technologies applicable depending on the available resources – concentrating solar thermal (CST) generation, pumped hydro storage, or tidal generation, for example.

Market diversity. The option to connect and supply towns and private-sector loads over an extended area makes solar investment more attractive, particularly in early stages, by reducing dependence on a single overseas customer and subsea transmission line.

Allowing for these factors, the base scenario of a single solar precinct has the HVDC converter station located near Broome to allow for future expansion of the solar network, and an AC transmission line from the De Grey solar precinct to the Broome converter station. The scenario with three solar precincts has a further AC transmission line from the Newman solar precinct to the De Grey solar precinct. These locations are shown in Figure 30.

6.6.3 Design and costing of AC transmission

A typical Australian transmission network delivers energy from centralised generation to terminal stations that connect major customers and local distribution networks. A solar aggregation network would be different in some important ways. It would be configured like a tree with power flowing from the leaves to the trunk which ultimately connects to the HVDC converter station. Because transmission costs are high and solar PV generation is flexible, the capacity of solar farms could be designed to maximise the capacity factor of transmission lines, leading to an economically efficient solution. Potentially, energy storage integrated with solar PV generation would also play a role in efficient use of the transmission infrastructure, both AC and HVDC; see Section 4.3.2.

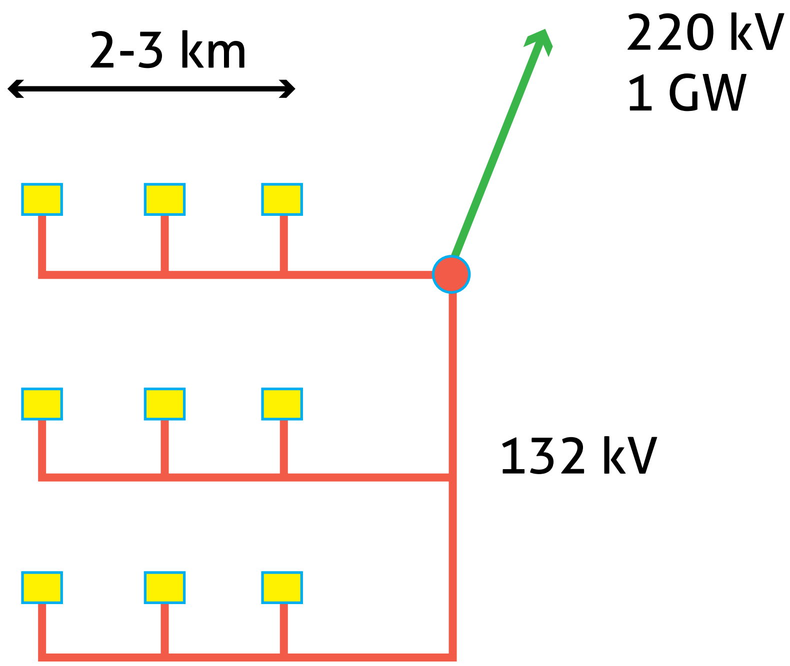


Figure 36: Illustrative AC aggregation network for three clusters of 115 MW (AC) solar PV generators

To explore alternative configurations of an aggregation network, 1 GW of solar PV generation is considered as a unit for building 3 GW at one or several precincts. At the time of writing, there are no precedents in Australia, or indeed anywhere, of a 1 GW solar PV generator. It is supposed that the 1 GW unit is comprised of nine solar farms of about 115 MW each, which is a familiar size for Australian solar developers who have already constructed solar PV generators exceeding this capacity. The output of these generators is aggregated using 132 kV AC transmission lines to a substation, where the voltage is stepped up for a 220 kV AC transmission line to deliver the total 1 GW output, as shown in Figure 36 by a representative line diagram. To transport substantially more than 1 GW, a higher voltage transmission line is required, so another substation is assumed at the De Grey precinct where the voltage is stepped up further for a 330 kV AC transmission line to deliver up to 3 GW output.

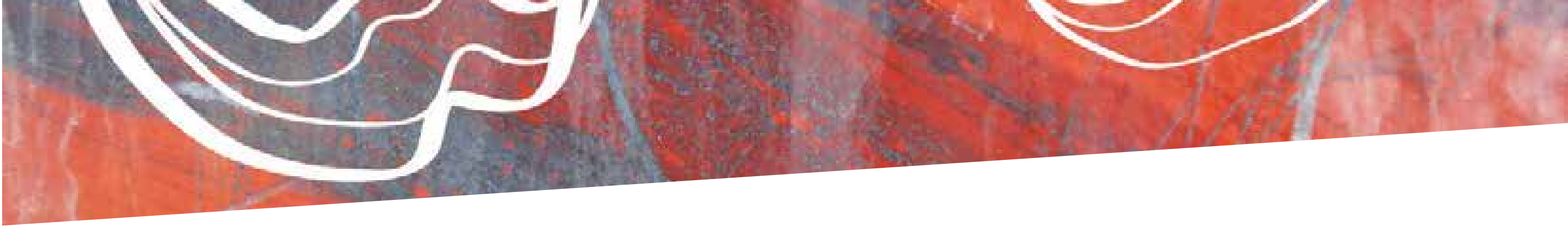
Table 14 shows estimated costs of these major substations and transmission lines, showing both the base scenario of a single 3 GW solar precinct and a more distributed scenario with three 1 GW solar precincts separated by significant distances. These cost estimates are derived from the parameters in Table 15 and are intended to represent costs applicable in remote Pilbara locations. Such costing data are not generally available in the public domain so representative estimates have been made based on expert advice. It is interesting that the cost to construct AC transmission lines does not increase linearly with distance in practice. Based on project experience in WA, it seems that the relationship is close to a square-root function of distance, that is, the exponent in the power-law fit between two cost estimates is close to r=0.5. The same is probably true for overland HVDC transmission although a linear relationship is assumed in Section 6.6.1.

Item	Quantity	Unit cost	Total cost
Local 132 kV interconnection of 1 GW solar precincts (2 km single-circuit and 6 km double-circuit)	3	$23M	$69M
Capital cost of aggregating one 3 GW precinct			**$69M**
Precinct substations 132/220 kV	3	$100M	$300M
Connect De Grey and Broome precincts at 330 kV	450 km	Power law	$259M
Connect Newman and De Grey precincts at 220 kV	245 km	Power law	$160M
Aggregating substation at De Grey 220/330 kV	1	$150M	$150M
Capital cost of aggregating three 1 GW precincts			**$938M**

Table 14: Capital cost estimates for different AC interconnection options

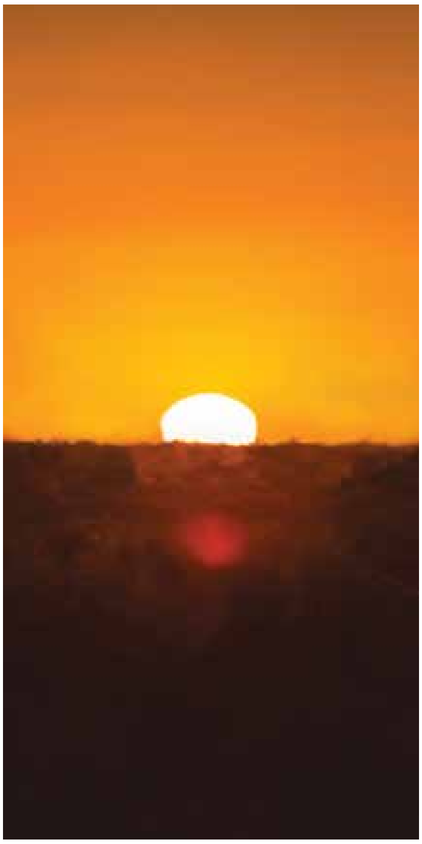
Item	Value	Notes
Remote WA cost of 220 kV single-circuit transmission line (short)	3 $M/km for say 10 km	Expert estimate Capacity about 1,200 MW
Remote WA cost of 220 kV single-circuit transmission line (long)	1 $M/km for say 100 km	Expert estimate
Exponent r of power-law fit between these estimates	0.523	Cost $C = A\,x^r$ for distance x km
Coefficient A of power-law fit between these estimates	$9M	Cost $C = A\,x^r$ for distance x km
Relative cost of 132 kV single-circuit transmission line	66%	Capacity about 150 MW
Relative cost of 132 kV double-circuit transmission line	93%	Capacity about 360 MW
Relative cost of 330 kV single-circuit transmission line	118%	Capacity about 3,100 MW
Cost of connecting a solar PV generator at 132 kV	0	Included in the solar farm costing in Table 13
Cost of aggregating substation 132/220 kV	$100M	Estimate Capacity about 1,200 MW
Cost of aggregating substation 220/330 kV	$150M	Estimate Capacity about 3,100 MW
Lifetime of AC transmission assets	40 years	Typical for this industry
Operating costs of AC transmission assets	10 $/MWh	Estimate

Table 15: Assumed costing for components of an AC aggregation network



6.7 HVDC subsea and overland construction and operation

High Voltage Direct Current (HVDC) power transmission is a mature technology with thousands of kilometres of overland, underground and subsea capacity worldwide. It is the technology of choice for long-haul high-capacity transmission of electricity to connect markets and access remote generation resources. It is the only feasible method for subsea transmission further than 50-100 km. Several state-of-the-art projects and strategic issues have been reviewed in Chapter 3. Here is a brief account of technology for power conversion and cables, interconnection with the receiving grid in Java, and the potential to expand into an ASEAN backbone grid system.



6.7.1 HVDC system design and power conversion

HVDC transmission technology is experiencing a transition from long-established Line Current Commutation (LCC) to newer Voltage Source Conversion (VSC). Presently, LCC transmission lines can reach higher power capacities, while VSC is more flexible and is catching up in terms of capacity. Both products are offered by all the top three HVDC providers, which are ABB, Siemens, and General Electric (since its acquisition of Alstom's energy portfolio in 2015).

An HVDC link has converter stations to connect to the AC grid at each end. They function as a ***rectifier*** (from AC to DC) and an ***inverter*** (from DC to AC) respectively at the source and receiving ends of the link. In most HVDC systems, these roles can be exchanged so the link is bidirectional – although if the link will usually operate in one direction, as when delivering energy from remote resources, cost savings may be achieved by restricting the link to one-way flow or allowing it to be less efficient in the reverse direction. It is at the converter stations that the differences between LCC and VSC technologies are evident (Wikipedia, 2012). First, regarding power flow:

- in LCC systems the current flows in one direction at an almost constant rate, and power flow is controlled by changing the voltage levels and polarities at either end; while
- in VSC systems the voltage is fixed and power flow is controlled by changing the current.

Second, regarding commutation which refers to the timing of three-phase AC power:

- LCC systems are line-commutated because they rely on the AC grid frequency to control switching devices in the converters; while
- VSC systems are self-commutated and can provide network support services to the receiving AC grid.

Some of the important implications of these differences are summarised in Table 16. All of these have important consequences for a transmission line from Western Australia to Java. The power capacity assumed in Chapter 4 is 3 GW which is beyond what has presently been achieved by subsea VSC systems; however, new cables discussed below show promise of exceeding this value in a bipole link. Network services provided to the Java grid by VSC converter stations, including voltage and frequency regulation and black start services, will offer significant value beyond energy delivery. For example, the important role that VSC HVDC can play in managing frequency excursions is discussed by Jiang-Häfner & Lundberg, (2016). Supporting multi-terminal systems is important if Indonesia wishes to host an expanding HVDC network and become a hub for ASEAN energy trading.

Feature	Line Current Commutation	Voltage Source Conversion
Power capacity	Very high voltages and power ratings (for overhead lines)	Power ratings presently lower but are increasing
Overload capability	Significant short-term overload can be accommodated	Power is limited to the rated capacity
Power range	Must maintain minimum power flow which creates a dead-band when changing flow direction	Smooth control of power to zero and smooth flow reversal
Harmonic distortion	AC output is distorted and requires harmonic filtering	Close to ideal AC waveforms can be generated (with MMC)
Space requirement	Extensive converter station yards for harmonic filtering	Significant space saving because harmonic filtering is not required (with MMC)
Reactive power control (for AC voltage regulation)	Reactive power depends on real power flow and requires additional controls	Reactive power can be controlled independent of real power flow
Short-circuit power	No short-circuit current contribution because commutation is interrupted	Short-circuit currents can be provided typically up to designed AC current limit
Black start services	Not possible	Can provide restart services when receiving AC grid fails
Strength of receiving AC grid	Strong AC receiving grid is required for commutation	Can supply weak AC grids and even passive grids with no generation
Multi-terminal systems	Need extra switchgear for voltage polarity reversals	Suitable for extended HVDC grid systems
Converter station losses	Low losses typically less than 1.5% for point-to-point link	Higher losses up to 1.9% half bridge and 2.7% full bridge
Maturity	Decades of experience	Technologies still developing rapidly

Table 16: Points of difference between Line Current Commutation and Voltage Source Conversion

LCC and VSC are also differentiated by the semiconductor components they employ. Modern LCC systems use thyristors as controllable DC switches, which have the feature that they can only be switched on by a control action, hence they rely on the AC grid to which the converter is connected to complete the necessary cycling of currents. The switching method is interesting: each thyristor has a breakdown rating of a few thousand volts (kV), and groups of thyristors are stacked in series to switch HVDC voltages which may be up to ±1,100 kV for overhead lines, so they cannot be connected by conducting wires to the switching controller. Therefore optical switching is used for accurate control.

VSC systems use insulated-gate bipolar transistors (IGBTs) because they can be switched both on and off by a control action. The DC voltage remains quite constant and doesn't change its polarity, hence the term "voltage source", and power flow is controlled using the current. IGBTs are suitable for rapid switching which enables an accurate AC waveform to be generated by the converter station without the necessity for harmonic filters. Filters occupy a lot of space in a switching yard so this allows a significant space saving. Figure 37 shows a thyristor and an IGBT. At the time of writing, the maximum ratings achieved for individual thyristors in service are 8.5 kV and 6.25 kAdc (thousand Amperes DC) while for IGBTs they are 4.5 kV and 1.6 kAdc. There is a performance gap and this is presently a focus of research and development. However, these figures don't translate directly to converter station performance because the semiconductors are arranged in very different ways. Recent VSC projects use Modular Multi-Level Converters (MMCs) to achieve fine control over the AC waveform. Their capabilities are developing rapidly. The major HVDC providers have taken significantly different approaches to MMC design, each with advantages and disadvantages, which are beyond the scope of this summary to discuss.

Several configuration options exist for HVDC transmission lines, all supported by the same principles for power conversion, while differing in their converter station designs. In simple terms, an HVDC link can have a single electrical circuit called a ***monopole***, or a pair of electrical circuits called a ***bipole***, with a bipole having twice the power capacity of a monopole using the same voltage and power conversion technology. The circuits are built using overhead lines on land or cables for underground and subsea transmission lines. Electrical circuits require two conducting paths and there is an option to use the earth or the sea for one or both of them, so that a monopole can be built with a single cable. A bipole presents a special opportunity because it can be arranged like two monopoles with the opposite voltage polarity and therefore the opposite direction of current flow. The return currents from each half of the bipole, which are at low or zero voltage, cancel each other out and the return conductors can be omitted with very little resulting earth or sea return current. A bipole can therefore be implemented with just two overhead lines or cables, and this is preferable to monopole designs due to the redundancy it provides, one half of a bipole continuing to function should one of the cables or converter station elements fail.

Some HVDC configuration options are shown in Figure 38, to which should be added the simplified bipole design that has been used for NorNed and some previous projects. The bipoles in Figure 38 use two sets of AC transformers and two power conversion systems at each end of the transmission line, but a simplified bipole is served by one set of AC transformers with a significant cost saving (Skog, 2010) albeit with less redundancy.

In summary, dynamically controllable HVDC transmission lines can (Ettrich, 2016):

1. Support exploitation of renewable energy sources

2. Provide the capability for inter-regional power exchange, and

3. Improve the stability and reliability of AC grids (for VSC systems particularly).

By the time that the HVDC component of the Pilot Project is financed and ready for contracting, it is likely that VSC systems will regularly match the power carrying capability of LCC systems for subsea projects, and the industry can embark confidently on procurement and construction. Cost estimates for components of an HVDC transmission system from the Pilbara to Jakarta are shown in Table 17. They are derived from an expert estimate that the total cost of the project would be in the vicinity of USD 7 billion.

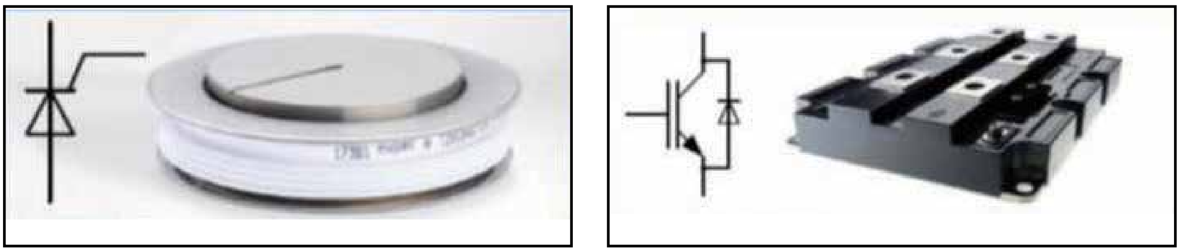


Figure 37: A thyristor (left) and an IGBT (right) with their symbolic representations *Source: Siemens*

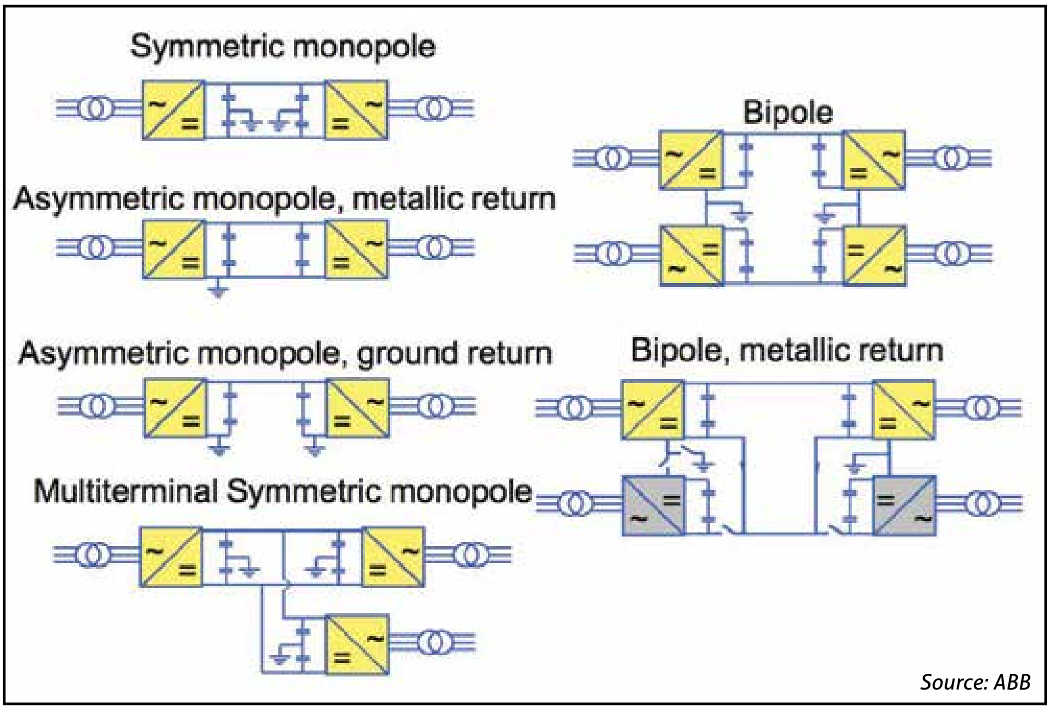


Figure 38: A range of available configurations for HVDC transmission systems (Persson, 2010)

Item	Value	Lifetime	Notes
Cost of overhead HVDC line and construction	1 $M/km	40 years	Based on expert estimate of total project budget
Cost of subsea HVDC cable and cable laying	4 $M/km	60 years	Based on expert estimate of total project budget
Cost of VSC converter station	$500M		Based on expert estimate of total project budget
Converter station cost breakdown			
Power electronics	60%	25 years	Estimate
Transformers and balance of HV hardware	20%	40 years	Estimate
Control and protection	15%	15 years	Estimate
IT systems	5%	5 years	Estimate
Calculation of total project cost			
Additional for contracting, approvals, and contingency	10%		Estimate
Distance from Broome precinct to Dampier Peninsula	200 km		
Distance from Dampier Peninsula to east Java	1,500 km		Via the route shown in Figure 39
Distance along Java	900 km		
Number of HVDC converter stations (2 in Java)	3		Java segment could be managed by Indonesia
Total project cost	**$9,460M**		**Calculated**
Total project cost in USD assuming 0.75 USD/AUD	7,095M		Compared to expert estimate USD 7 billion

Table 17: Assumed costing for components of a HVDC transmission network

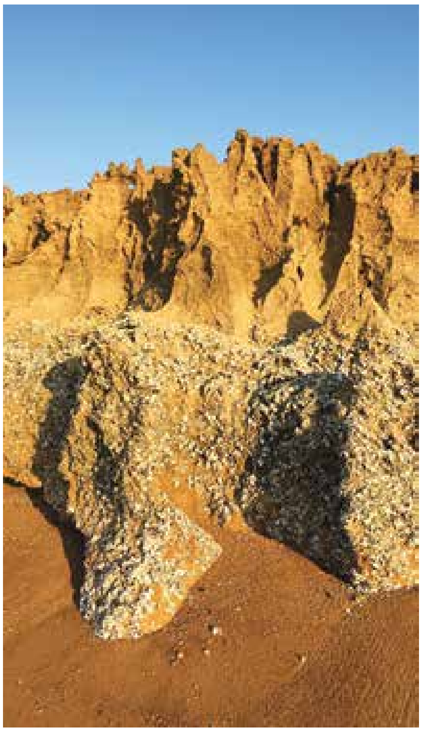
6.7.2 Subsea cable route and design

While subsea HVDC electricity transmission is a mature industry, with diverse examples summarised in Section 3.3, each project presents unique challenges. The route from Western Australia to Java is 50% longer than Icelink, which is the longest project under active consideration. Its depth is in excess of the deepest reaches of the SEPEI link graphed in Figure 8. It traverses an active geological region – Australia is the fastest moving continent on Earth, moving towards Indonesia at around seven centimetres per year – with multiple uses including marine parks, traditional fishing and gas and oil fields.

The Java Trench prevents a direct route to the island and allows only a relatively narrow passage near Rote Island (Pulau Rote) through which a subsea cable could pass without exceeding a depth of 2,000 m. From there, avoiding the gas and oil fields to the east and minimising the distance to the Pilbara, the cable route would probably head south to landfall on the Dampier Peninsula. Towards Java the cable route would head northwest past the island of Sumba and south of Bali according to a detailed subsea survey and the desired landing point in Java. An indicative route and its depth profile are shown in Figure 39.

Planning the cable project involves a combination of engineering and environmental challenges.

Different cable technologies may be needed for different parts of the route according to its depth profile. An example of appropriate selection of cables for a bipole HVDC link is provided by NorNed (Skog, 2010), which had different requirements for deep and shallow parts of the route. A diagram of cable runs and cross-sections is in Figure 40. Shallow parts passed under busy



shipping lanes and it was not possible to pass large DC currents through single cables without causing unacceptable compass deviations. Binding the bipole pair into a specially made flat two-core cable solved the problem of compass deviations because the magnetic effects of the opposite currents cancel. The two-core cable bundle was more cumbersome than a single cable and could only be curved in one plane, but these issues were dealt with, and there were also advantages such as simplified trenching.

Alternatively, multiple separate cables can be laid simultaneously from a cable-laying ship, and laid in a single trench where this is necessary. In shipping lanes and areas subject to high currents, cables should be covered for protection from anchors and movement of materials on the seabed. This can be done either by trenching or by rockdump which must all be performed using underwater machinery. Fortunately, the seabed is usually a stable environment, safe from physical interference, and kept at the reasonably constant ambient temperature of seawater at depth. In principle, very long cable lifetimes can be achieved, with a planning horizon of up to 60 years, compared to investment timeframes of 40 years that are usual for terrestrial power system infrastructure.

There have been concerns about the potential influence of magnetic fields from submarine power cables on marine species that navigate using the Earth's magnetic field. However, a recent peer-reviewed study (Sherwood, 2016) showed that the magnetic field surrounding the Basslink cable when operating is well predicted by theory, diminishes rapidly with distance, and beyond 20 m becomes indistinguishable from the background, naturally occurring field. In other respects, too, ecological studies by divers showed that the submarine cable had minimal, if any, effect on the marine environment two years after it was laid. Where it passed over rock and could not be trenched, its protective casing was colonised by similar species to those occupying nearby areas.

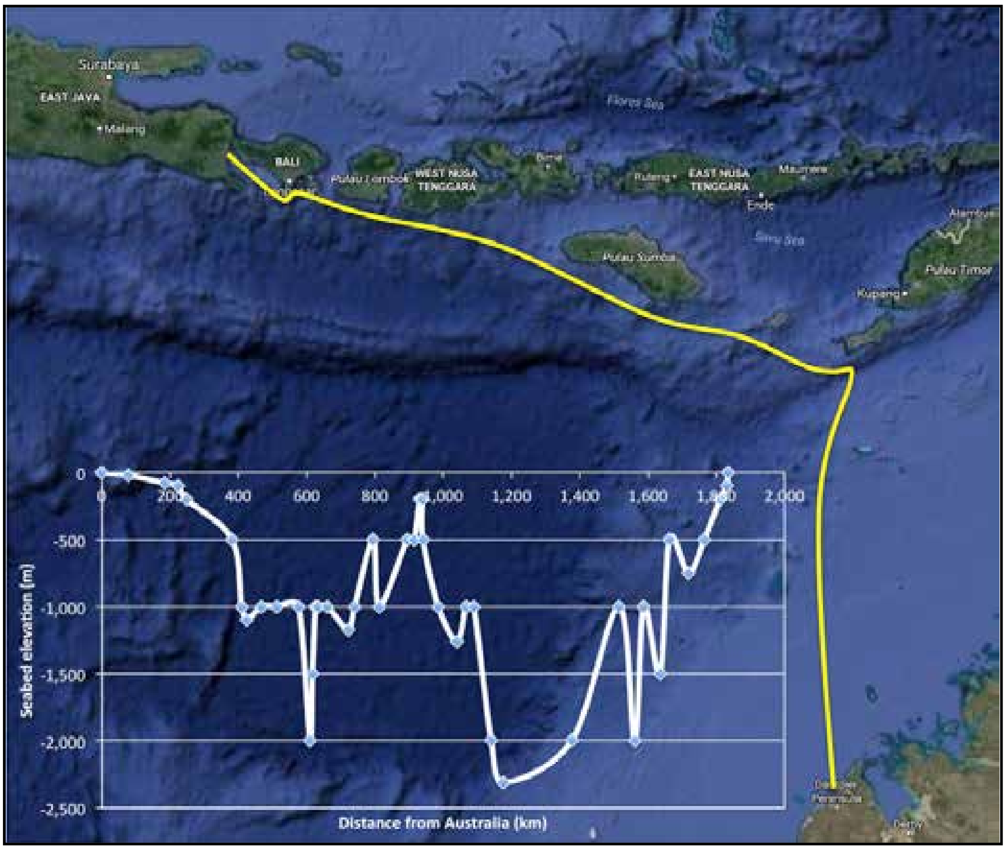


Figure 39: Indicative route and depth profile of a subsea cable between the Dampier Peninsula and east Java

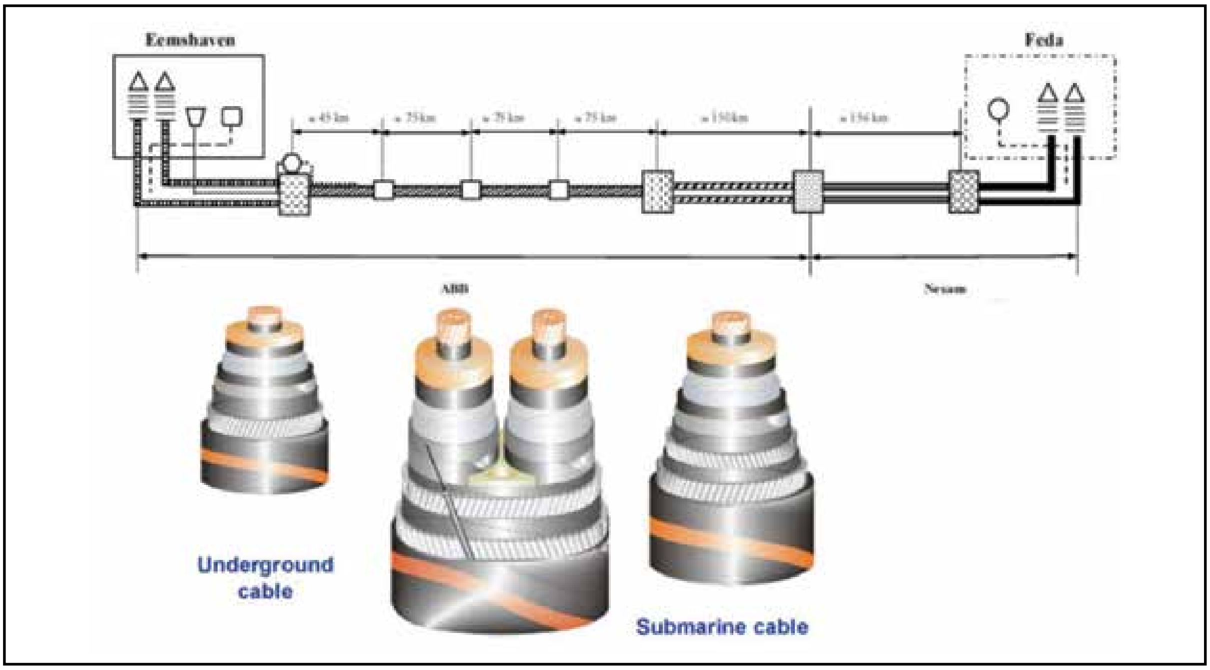


Figure 40: Cable types used for the NorNed subsea HVDC project

Source: Skog, 2010

Sometimes sea returns, while cost effective, have been avoided due to sensitivities about the potential for increased corrosion of nearby submarine infrastructure. This effect can be modelled, estimated, and mitigated effectively during a cable's planning stages (Eccles, 2014). The same issue arises when one cable in a bipole HVDC transmission line fails – as described above in Section 6.6.1, the line can continue to operate at half capacity as a bipole, and the return current goes through the sea. Contingency planning for such failures can include a limited period of monopole operation to mitigate this risk if it is perceived to be significant.

For deep parts of a subsea cable route, handling the cable for repair operations is much more difficult, and single-core cables are preferred for this reason. Other important factors are the enormous pressures that the cable must withstand and the stress that is placed on a cable during laying in deep waters. Specialised ships lay submarine electrical cables, which are much heavier per unit length than telecommunications cables, by unwinding them from a large turntable (Figure 41) and carefully running them along the sea floor. During this process the cable must support its own submerged weight down to the sea floor and this limits the depths that may be achieved. It is a sophisticated operation, as indicated in Figure 42, requiring specialised knowledge and software to ensure reliable laying without undue stress on the cable.

A well-laid subsea power cable can have a design lifetime in excess of 60 years.

New lightweight cable designs are emerging that complement the more flexible VSC power conversion technologies and make deep subsea routes easier to manage. Power transmission cables comprise a conducting core, a layer of insulation usually of comparable thickness, and multiple layers of sheathing to strengthen the cable and protect it from the surrounding environment. Few companies worldwide can undertake the elaborate production process required to produce reliable cables capable of long-term subsea performance: Prysmian, Nexans, ABB, and Sumitomo are the main ones. Progressive advances in the insulation layer have enabled higher voltages and therefore greater transmission capacities. Mass Impregnated (MI) cables use insulation made of high-density paper tapes impregnated with a high-viscosity compound. They have been used since ABB built the first subsea HVDC transmission line in 1954. Demand for efficient manufacture by extrusion methods and risks of environmental contamination by oil leakage led to the use of Cross-Linked Polyethylene (XLPE) cables for subsea HVDC since 1999. These cables are only suitable for VSC transmission systems, because LCC systems experience polarity reversal when the direction of transmission changes, and this can cause premature breakdown of XLPE insulation due to the presence of space charges (Fu, 2008).

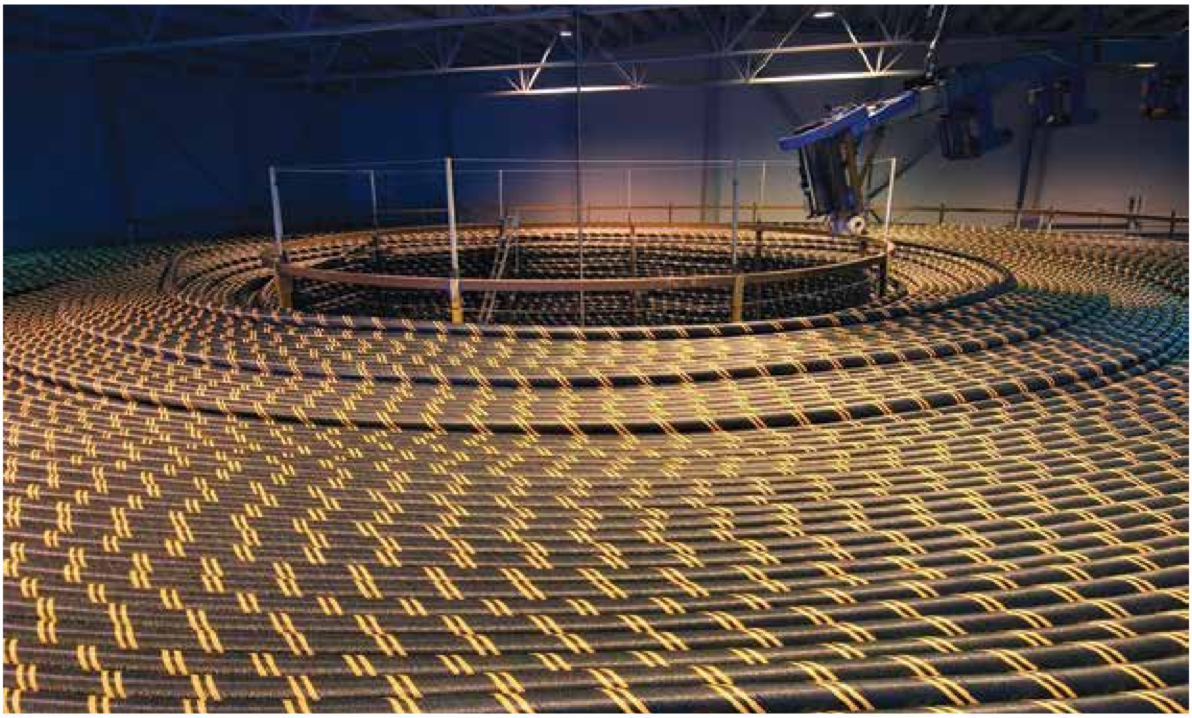


Figure 41: A loaded turntable inside a cable-laying ship *Source: ABB*

There are now many examples of subsea HVDC using both MI and XLPE cables. The achievable voltages are less than for overhead lines: up to ±600 kV for MI cables and up to ±320 kV for XLPE cables are the limits of present projects, compared to ±1,100 kV for overhead lines. These differences are reflected in their relative power capacities. The next generation of insulation technology is High Performance Thermoplastic Elastomer (HPTE) that does not require a chemical reaction during extrusion (Prysmian Group, 2016). This is important for several reasons:

- Chemical by-products that cause space charges in XLPE insulation are avoided
- Production is faster because there is no delay for de-gassing of these by-products
- All the cable materials are fully recyclable.

HPTE cables have recently been tested to ±600 kV suggesting that a capacity of 3.5 GW can be achieved for a bipole HVDC system. "Ongoing developments and tests confirm the feasibility of HV submarine power cables at water depth up to 3,000 m and beyond" (Prysmian Powerlink, 2016). There is no limit in principle to the length of an HVDC transmission line, so it seems that the major assumed parameters to connect Western Australia to Java have been achieved.

Special requirements of such a route, however, remain to be determined in any detail. The distances and depths in Figure 39 are measured from a maritime chart, and subsea surveys have been undertaken through exploration of Northwest Shelf gas and oil basins, but specific surveys would be necessary to plan the cable route thoroughly. The seabed and shallow soils off the west coast of Australia are known to be problematic due to the presence of now submerged aeolian sand dunes, which a cable would need to traverse (Theurich, 2016). Correct burial in the shallow water is imperative due to cyclones, but if the shallow soils are comprised of calcarenite, a form of limestone made from remains of shells, corals, and other carbonate grains, this can cause the trenching costs to be high. Continental plate movement of 7 cm/year is significant and there is a likelihood of earthquake activity during the cable's lifetime. Some innovation and imagination will be required.

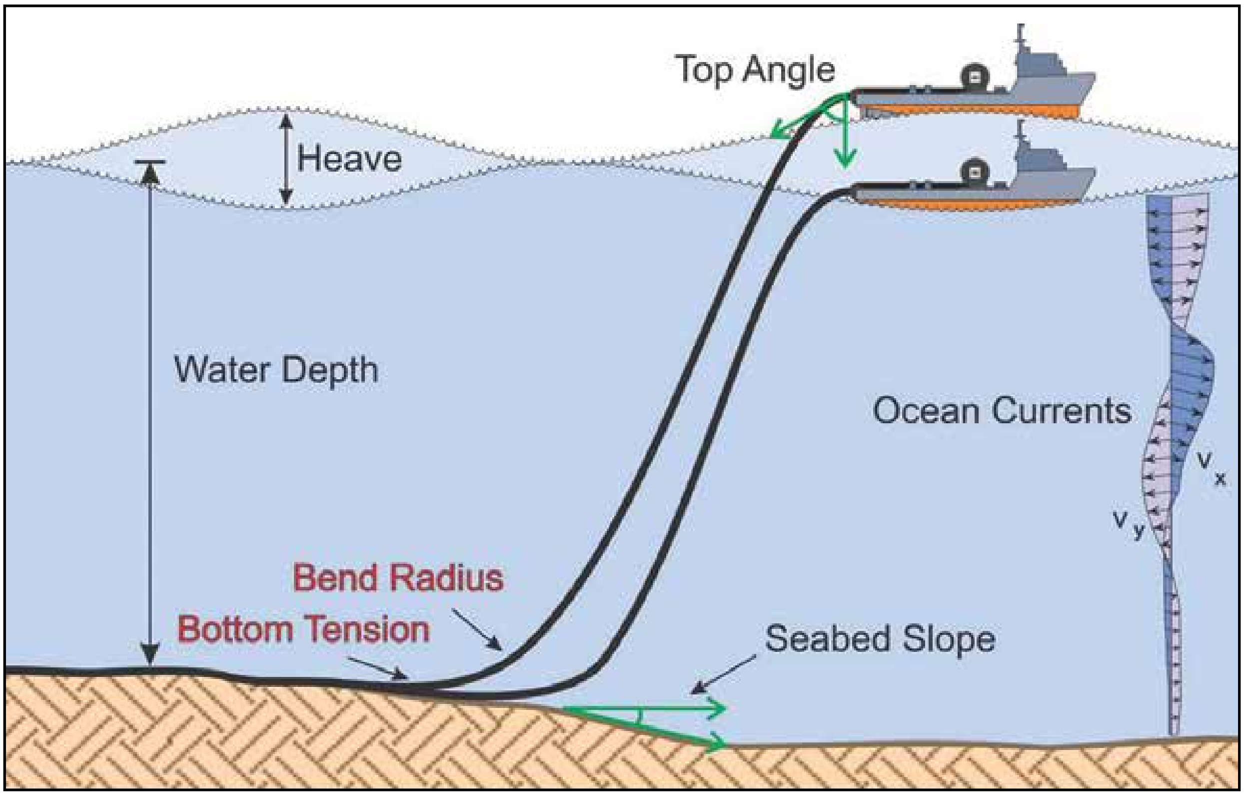


Figure 42: Some factors to account for when laying submarine power cables *Source: Makai Ocean Engineering, Inc.*

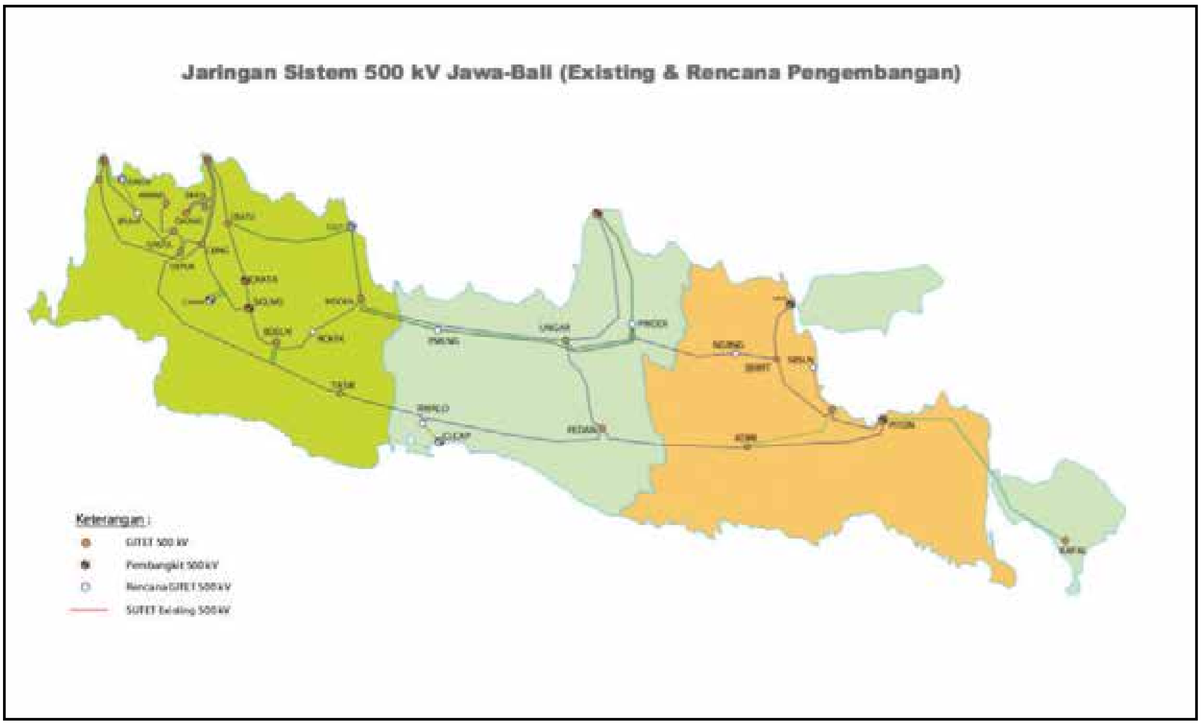


Figure 43: Existing and planned transmission network on Java *Source: PLN*

6.7.3 Integrating with the Java grid

Connection into the Java grid will be subject to detailed negotiations and planning with PLN. Key issues will be the load centres to be supplied and the ability of the existing transmission network to supply new capacity to them. Figure 43 is an indicative map of the existing and planned transmission network in Java.

Connection in the vicinity of Paiton may be a suitable location for an HVDC converter station. This would give the option of supplying local industrial loads, which are substantial in east Java, and sending power to Jakarta via either the northern or the southern transmission corridor shown on the map. However, there are problems with this design. The present priorities for developing the Java grid are (i) connecting east Java to Bali, (ii) strengthening the grid between central Java and Jakarta, and (iii) strengthening the grid in the Jakarta region. Therefore locating an HVDC connection point near Paiton may not allow sufficient capacity to reach Java's main load centre. There is some doubt about plans to develop the southern transmission corridor, so it may provide the impression rather than the actuality of a strongly interconnected power system. But a longer submarine HVDC run to central or west Java, most likely along the northern coast, would be a substantial additional cost.

A better option may be to include in the project an overland transmission line to Jakarta. The latter would effectively be an augmentation of the network owned and operated by PLN and this may be a welcome addition. If the overland segment is HVDC, this would suggest having converter stations in both east Java and Jakarta, to allow 'local traffic' managed by PLN in the context of solar energy import from Australia, and enable highly effective grid support services that HVDC converter stations can provide, including frequency regulation and system restart. The second converter station would add about $500 million to the project cost, however, the revenue streams from PLN for providing the transmission capacity and grid support services may make this a worthwhile investment.

It would also help the project to be seen as a valuable contribution to the Indonesian power system, partly operated by the national power utility, beyond simply providing solar energy. This would tend to increase a sense of Indonesian ownership of the Pilot Project and its future growth.

6.8 Pilot Project and Incremental Build

An advancing international network of HVDC interconnectors is illustrated here to envisage a credible future following the Pilbara-Java Pilot Project. This is not intended as forecasting, because there are too many unknowns to make a credible prediction of individual future projects, but rather an attempt to quantify a potential future – one of many alternatives – and its implications for Asia and the Pilbara. Figures 44-47 show the ASEAN countries north of Australia and a five-yearly advance in subsea interconnectors between major supply and demand centres – or potential centres that would be able to develop on the basis of such infrastructure.

The Pilot Project would most likely be unidirectional for as long as Indonesia's power supply falls short of its growth ambitions, although the potential for Indonesian geothermal energy to contribute to Australia's clean energy transition, perhaps at night, should not be underestimated. This would help to supply NWIS customers and the opportunity could be expanded to a national one by interconnection east and south from the Pilbara to the DKIS, SWIS, and NEM. Once the international HVDC network extends beyond Java, however, it will certainly become a means for international trading and development. Australian solar energy will then compete with Indonesian geothermal, hydropower, and biomass electricity generation, and energy resources of Malaysia, Viêt Nam, and the Philippines, to make an efficient and reliable supply mix.

Figure 44: The Pilot Project connecting the Pilbara with the Javanese grid (completed 2025-2030)

Figure 45: Extension to Singapore and Malaysia with an increase in capacity (completed 2030-2035)

Samantha Mella Geoff James Kylie Chalmers

Figure 46: Multiple extensions through shallow seas and overland (completed 2035-2040

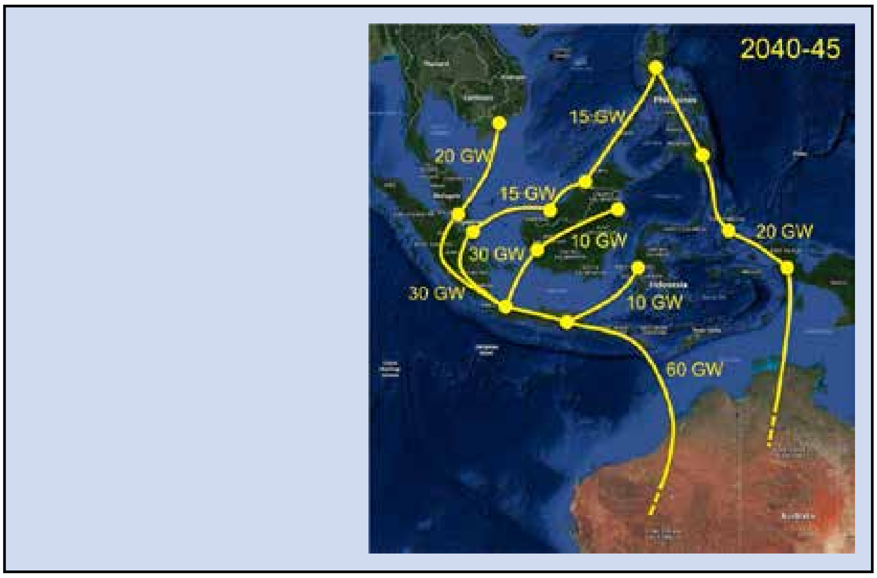


Figure 47: Reaching the Philippines and a second route from Australia (completed 2040-2045)

07

Economic Impact Assessment for a Potential Solar Export Industry

7.1 Key findings

- Initially, building solar industry in the Pilbara has small positive economic impacts. However at gigawatt scale, a solar industry has a substantial positive impact on the local Pilbara economy and the Western Australian economy.

- The 3 GW solar pilot would operate, directly and indirectly:

  o Total Capital Works Jobs in Pilbara – 766 (temporary)
  o Total Operational Jobs in Pilbara – 2,019 (permanent) representing a 4.4% increase in the workforce
  o Statewide – 12,210 jobs (Capex and Opex) would be created.

  There is the potential to develop an Energy Cluster where specialised suppliers and firms in related industries that compete but also collaborate would be attracted to the Pilbara. This could encompass solar generation and supply chain, electricity transmission, hybrid microgrid integration, and local energy trading and consumption, community energy initiatives, lithium mining and processing, battery manufacturing and integration, and other growth areas. The economic impact of these possible developments is not estimated in this report.

7.2 Introduction

The Pilbara Region has been a front-runner in the economic performance of Western Australia, and indeed Australia, over the last 40 years. Output of its mining, oil and gas industries has been stimulated by the emergence of the Asian economic block. China and India have been leaders of world economic growth. At the time of writing there has been concern that this boom may have come to an end. World economic growth has slowed, Western Australian State Final Demand has gone backwards, state unemployment is currently 6%, a number of very large new resource developments have been put on hold, and capital expenditure in the state has fallen sharply. Thus it is fair to say that at the present time, Western Australia, and the Pilbara Region in particular, needs new investment, projects and jobs.

The proposed solar energy export project would involve construction of an extensive area of solar arrays, transformers and commensurate HVDC subsea transmission cables to provide large power inputs to the ASEAN Power Grid (APG). Ultimately, the total investment envisaged - upward of $20 billion - would be comparable to such major national projects as North West Shelf Gas or the National Broadband Network. A significant proportion would be capital expenditure within Australia. The HVDC cables linking to Indonesia and upgrades to the APG would be internationally financed and owned.

In addition to its direct investment and ongoing operations, the proposed solar energy export project could open up new initiatives for development of supply-chain and related industries in the region. Therefore, this economic impact assessment also describes the kinds of support industry development that could occur, subject to planning and full feasibility assessment.

This report documents estimated employment impacts for the Pilbara region, provided by Resource Economic Unit, Perth. There is a small section describing impacts on Western Australia as a whole.

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7.3 Methodology

7.3.1 Application of an Input-Output Model

Economic input-output analysis traces transactions between all sectors of an economy, and their implications for output and employment. Impact ratios are used to estimate the effects of changes in the dollar output of an industry (termed the Direct Effect) on other industries (termed the Indirect effect) through its supply chain demands. Impact ratios are expressed as a ratio of the total economic effect to the initial effect. Two types of effects are typically measured: (i) the inter-industry effects caused by the demands that each industry makes on other industries, plus their subsequent purchases of inputs from further industries ad infinitum; and (ii) the consumption effects when incomes earned from the initial and induced industry outputs are spent. The first of these is termed the Type I effect. Type II is used for the consumption-led effect.

This indicative economic impact assessment reports the results of a 48 x 48 industry input-output analysis of potential impacts on Western Australia and the Pilbara Region. A 33 x 33 industry input-output table was first developed for the Western Australian economy in 2014-15. This was then expanded to a 46 x 46 industry table by splitting 13 industries into a Pilbara versus a Rest of Western Australia component. These 13 industries were selected on the basis that they would possibly have strong supply chain links to the Solar Export Project, and are therefore estimated directly. Estimates of Pilbara Region impacts in the remaining 20 industries were estimated by using regional employment shares.

Finally, the 46 x 46 industry table was expanded to 48 x 48 industries by treating Solar Operating and Solar Capital Works as additional industries (OPEX and CAPEX respectively). The Solar Operating industry purchases inputs from the wider economy and sells its output to Exports. The Solar Capital Works industry likewise purchases inputs from the rest of the economy or imports, and sells its output to the investment component of Final Demand. This treatment of the CAPEX aspects is unconventional. It facilitated the transfer of engineering estimates into the data required for the input-output model. The engineering consultant provided estimates of the costs of inputs to the Solar Export Project for each stage of its development.

7.3.2 Project Stages

Four stages of development were considered:

- **Stage 1:** First solar farm to stimulate local supply chain (capacity 20 MW).
- **Stage 2:** Expansion of production to several farms – each serving individual industries or communities within the Pilbara (capacity 180 MW).
- **Stage 3:** Grow to first stage of exports involving construction of an Aggregation System linking the separate solar farms contemporaneously with the laying of the sub-sea HVDC cable to Indonesia (capacity of 3,300 MW). The construction would be spread over approximately 10 years.
- **Stage 4:** Expanded export operations to meet growing demand (indicative 7,900 MW examined).

Beryl Ponce, *Bush Medicines*, 76 x 40.5cm, acrylic on canvas, 2016

The operating and capital costs (OPEX and CAPEX respectively) at each of the above stages, broken down by supplying industry, were used to make a preliminary assessment of the 'direct' impacts of the project.

Economic multiplier estimates for the Pilbara Region were then developed to assess the potential 'indirect' effects. These comprise (i) inter-industry effects and (ii) consumption-led effects. The latter were limited to industries most likely to be affected by local household expenditure, namely service industries and small-scale manufacturing. The major resource-based industries were assumed to be unaffected by additional household incomes.

7.3.3 Timing

Section 4.3 presents a discounted cash flow analysis of the project, addressing the scheduling of the project.

Economic impacts at each stage of the project are assessed using the 2014-15 input-output model. That is, the 2014-15 technical coefficients for all industries except solar operations and capital works have been applied for all stages. The input coefficients for solar operations and capital works have been varied in the different stages to reflect the engineering assessment of what inputs can be supplied from the Pilbara. In other words, there is a different technical coefficients matrix for each stage. Thus, the proportion of inputs that are directly sourced from the Pilbara varies as the mix of inputs changes. One example is the provision for a factory in the Pilbara supplying panel mounts in Stages 3 and 4.

7.3.4 Data Sources

Published official data for the year 2014-15 were used in estimating the input-output table. This is the latest year for which a comprehensive set of official statistics is available. The impact estimates for each stage are assessed using the 2014-15 input coefficients, as well as the 2014-15 data on industries present in the Pilbara Region and WA as a whole. Data sources consulted included:

- Australian Bureau of Statistics National input-output table for 2014-15;
- Western Australian State Accounts;
- ABS Census Workplace tables for 2006 and 2011;
- ABS industry of employment by place of residence in 2006 and 2011;
- ABS Labour Force survey; and
- Selected individual industry data.

7.3.5 Fly-in Fly-out (FIFO) workers

A significant part of the Pilbara's working force is of a fly-in/fly-out (FIFO) nature. Such workers will not have so much local economic impact as those who are permanent residents. An investment program sustained over many years (for example two decades) would be more likely to attract a permanent resident workforce. Census data for 2011 show the total jobs in each Pilbara Region industry (Census Workplace Tables), and the industries in which Pilbara residents worked. The difference has been taken as an estimate of the proportion of jobs that are held by Pilbara residents and FIFO workers respectively, and has been taken as a constant in each industry over the project stages.

7.4 Direct Project Impacts

Direct project impacts are the sales, operational and capital costs of the project and employment within the project. Economic impact of these depends significantly on the timing of expenditure. Multi-GW installations may take several years to complete. In an impact assessment using an input-output approach, an assumption has to be made about the amount of sales, operating costs and capital expenditure in a particular year, because the input-output table itself records transactions in one year. Suppose, for example, it takes two years to install a 3 GW PV farm and four years to develop the aggregation system. If both project components are under construction in a particular year, the impact assessment could use (0.5*$4,600m) + (0.25*$1,449m) equals $2,962m. This procedure has been followed in converting estimates from the engineering consultant, which were based on varying stage lengths, to representative annual average amounts within each stage.

7.5 Potential Flow-on Effects

Estimated downstream (Type I and Type II) employment impacts from operations and capital works are tabulated in a separate report, available on request. The following sections highlight the key assumptions and results:

	Stage of Project			
	1	2	3b	4
Operations				
Sales value ($m)	3.9	37.3	559.9	2,927.3
Employment	4.7	44.5	1,970.3	6,523.9
Empl/$m	1.19	1.19	3.52	2.23
Capital Works				
Value of Works	46.0	207.0	986.5	2,955.8
Employment	20.2	90.9	360.7	1,139.8
Empl/$m	0.44	0.44	0.37	0.39
Operations Capital Works Combined				
Value ($m)	49.9	244.3	1,546.4	5,883.1
Employment	24.9	135.4	2,331.0	7,663.7
Empl/$m	0.50	0.55	1.51	1.30

Table 18: Projected annual average sales and direct employment within the Pilbara region at various project stages

7.5.1 Capital Works

The employment impacts of capital works are shown in Figure 48. The first stage of the project involves a small farm, with a capacity of 20 MW. It is estimated that construction of this would directly employ some 20 workers. The CAPEX would have a small effect on the Pilbara economy, with an estimated 16 jobs excluding FIFO in the supply chain and a further 2 jobs in Type 2 sectors.

Stage 2 involves an expansion of capacity to 180 MW. The economic impacts in the Pilbara are small, as with Stage 1.

Stage 3 was divided into two sub-stages. Stage 3a is a period when additional capacity is built up, but it is not used for generation until the time comes when that capacity can be linked to the export facility. Stage 3b is a depiction of the solar export project at the point when export operations have begun, following the construction of (i) an aggregation facility that would link up the various solar farms, and (ii) the HVDC cable to Indonesia. To represent economic impacts we present results for Stage 3b. The CAPEX content of Stage 3b represents a major upscaling of generation capacity to 3,300 MW. The capital works program would likely employ some 361 workers. Downstream supply-chain impacts are estimated to employ a further 247 workers.

Stage 4 represents a long-term production level, illustrating how things might expand with exports spreading to wider ASEAN markets. This represents a next step after Stage 3b, but is not necessarily the ultimate production level. Direct employment impacts of the capital works would rise to 1,140 with downstream (Type I and Type II) employment of 880 workers.

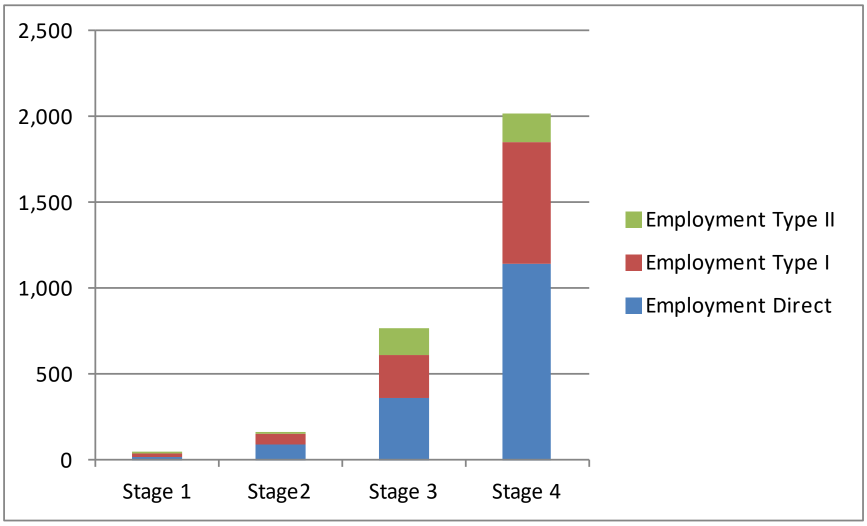


Figure 48: Direct and indirect employment generated by capital works

7.5.2 Operations

The employment impacts of operations, shown in Figure 49, are dominated by direct employment in the solar generating facility at all stages. Table 18 summarises capital and operations employment impacts.

By stage 3b the solar project operations would employ nearly 2,000 workers. Type I downstream employment would remain relatively low, at just 17 workers, but the additional employment of Pilbara residents generates consumption requiring an additional 31 workers, bringing the total Type II employment to 48.

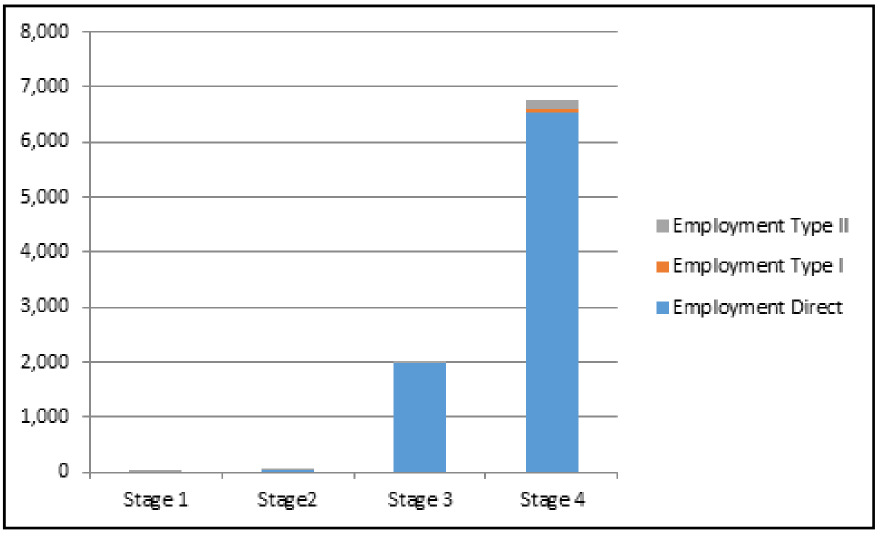


Figure 49: Direct and indirect employment generated by operations

7.5.3 Downstream Industries

To illustrate the industry composition of employment impacts, the results for Stage 3b are shown. A similar pattern of industrial response is found across the stages.

As is seen in Figure 50, the downstream industries most stimulated within the Pilbara by capital works are Road Transport, Civil Engineering and Specialised Machinery and Equipment, including Electrical Equipment. These are mainly Type I impacts, as is to be expected.

The impact and support on employment in the Mining industry is perhaps questionable. The result may occur because the WA electrical industry uses coal, and this affects the technical coefficients for mining inputs. On the other hand, the Mining industry includes Services to Mining, and the professional services of this large industry resident in the Pilbara could plausibly be utilised by the solar export industry. Therefore we have not made any adjustment to the result in this respect.

Compared with capital works, solar operations would have a more significant impact on employment in service industries, including Retail (includes Hotels and Restaurants), and Finance, Government and Business Services, and Other Pilbara Industries, (which includes Education, Health and Personal Services as well as non-Road Transport including air and port operations).

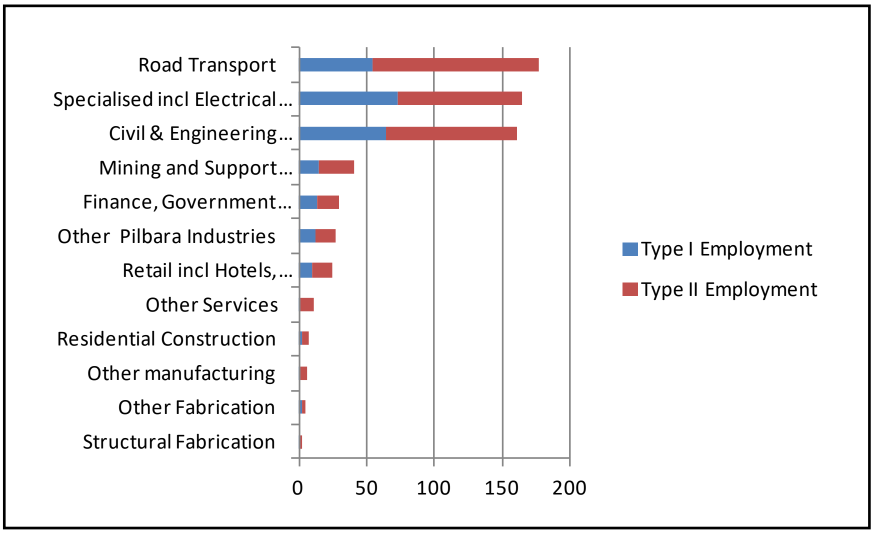


Figure 50: Industry composition of downstream impacts for capital works in Stage 3b

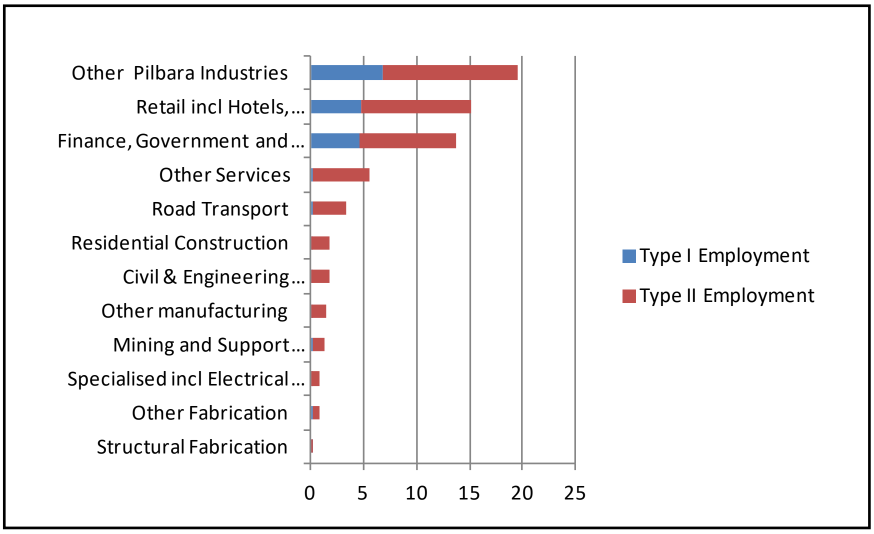


Figure 51: Industry composition of downstream impacts for solar operations in Stage 3b

7.5.4 Fly-in/Fly-out Workers

The estimated proportions of FIFO workers in each stage for capital works and operations are shown in Figures 52-53. Solar operations can be expected to generate a higher ratio of residents to FIFO workers than capital works. This is due to (i) an assumed ratio for solar operatives of 75% resident, and (ii) the fact that the downstream impacts of solar operations have a greater concentration in the service sector, which has higher proportions resident workers.

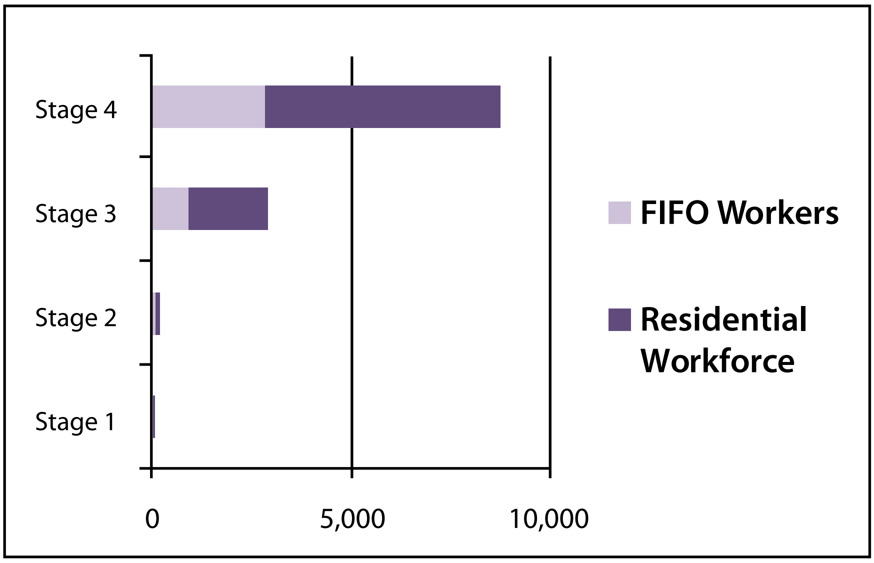


Figure 52: FIFO versus resident workers in solar operations: total effect, in each stage

The situation is much different for capital works. Here, it was assumed that the proportion of FIFO workers would be the same as previously observed in the civil engineering industry (2011 Census): a high 71% FIFO and 29% resident. This significantly lowers the residential workforce estimate.

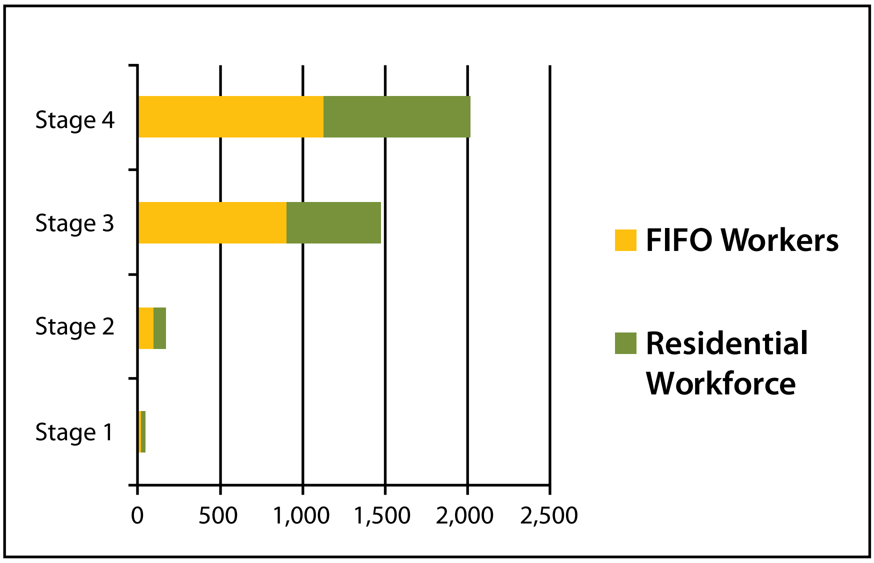


Figure 53: FIFO versus resident workers in capital works: total effect, all stages

7.6 Potential Wider Impacts in the Pilbara

7.6.1 Growth of Towns

The resource towns of the Pilbara have, for the most part, been in existence for less than 50 years. Most started life as operational bases and port facilities for the major mineral resource companies, and, more lately, the oil and gas industry. The State Government's Pilbara Cities initiative is designed to encourage more people to live and settle in the Pilbara by creating modern, higher-density centres, supported by infrastructure and amenity upgrades and improvements. The blueprint includes proposals for major revitalisations of South Hedland, Karratha, Newman, Dampier, Tom Price and Onslow town centres, plus new marinas and improved waterfronts at Port Hedland, Dampier and possibly Onslow. New infrastructure and facilities such as schools, TAFE colleges, medical facilities, leisure and entertainment facilities and retail precincts are also part of the plan. Critical to the success is the attraction of new residents and businesses, creating places where people choose to settle on a permanent basis with access to a high standard of services.

An approximate estimate of the potential impact of the Solar Export Project on the population can be derived from the projected employment impacts and the ratio of population to the employed workforce. The ratio of population to total workforce in the Pilbara is relatively low. The 2011 population of 60,000 compares with 45,000 full-time and part-time jobs, including FIFO workers. By June 2015 the population is estimated to have increased to 65,859 - a growth rate of just under 2% per year (ABS, 2015).

Taking Stage 3b as an indication, the total jobs generated directly and indirectly in the Pilbara Region would be around 2,800. Of these, assuming past rates of FIFO were to continue, some 1,900 jobs would be held by residents. Applying the current ratio of population to jobs of approximately 1.3, the jobs created by the solar export project would support a population of around 2,500 additional residents in the Pilbara Region. This could be considerably higher if a larger proportion of resident workers could be attracted to the capital works program compared with the historic proportion.

7.6.2 Potential Development of an Energy Cluster

Today's economic map of the world is characterised by clusters. A cluster is a geographic concentration of related companies, organisations, and institutions in a particular field that can be present in a region, state or nation. Clusters attract specialised suppliers, firms in related industries, and associated institutions that compete but also collaborate. Clusters arise because they raise a company's productivity, which is influenced by local assets and the presence of like firms, institutions and infrastructure that surround them. Solar energy in the Pilbara could form the basis for such a cluster. If estimated transactional data are forthcoming, the economic impact of a new energy cluster including the solar export industry could be assessed.

The input-output analysis has estimated the transactions and employment effects that could occur directly and indirectly from specific formulations of the Solar Export Project. It does NOT consider situations where *other* (as yet unspecified) projects could have similar requirements, thus enhancing the possibilities for development of common or complementary support activities and infrastructure. For example, another project could have a demand for similar occupations and skills, thus increasing the prospects for feasible development of the regional skill base. Both projects would likely require upgrades to hotels, schools, technical colleges, hospitals and so on. The existence of both projects would increase the feasibility of such infrastructure investment. An example of such a project could be the development of a lithium battery industry using Pilbara-sourced materials. However without specific estimates and probabilities of such a project are not yet available. It is therefore not advisable to build it into the input-output analysis.

7.7 Impacts on Western Australia as a whole

This report has concentrated on economic impacts for the Pilbara Region, as required by the brief. But the input-output analysis also yields results at the state level.

The statewide impacts of the mature Solar Export Project (i.e., following commissioning of the HVDC transmission to Indonesia in Stage 3b) are summarised in Table 19. Statewide, solar export operations in Stage 3b would generate an estimated 4,295 jobs, of which some 1,970 would be directly employed in the project. At that stage, capital works would be continuing and would generate a further 5,692 jobs. The total jobs generated by the project would then be 12,210.

Multipliers are shown in the table. For solar operations, these are broadly consistent with the results of other similar studies. For solar CAPEX, there are very high multipliers. This is because, apart from the project staff involved in planning and commissioning, equipment and works are purchased externally. This means that the direct effect is very small and the multiplier large.

	Output (5m)	Value Added (5m)	Full & Pt Time Employment
Generated by Solar Operations			
Direct Effect	560	476	1,970
Type I Effect	688	584	2,597
Type I & II Effect	1,647	1,163	4,295
Multipliers:			
Type I	*1.23*	*1.23*	*1.32*
Type I & II	*2.94*	*2.44*	*2.18*
Generated by Solar Capital Works			
Direct Effect	986	43	361
Type I Effect	3,064	1,055	4,833
Type I & II Effect	4,370	1,987	5,692
Multipliers:			
Type I	*3.11*	*24.37*	*13.40*
Type I & II	*4.43*	*45.87*	*15.78*
Total impact			
Direct Effect	1,546	519	2,331
Type I Effect	3,752	1,639	7,430
Type I & II Effect	6,017	3,150	12,210
Multipliers:			
Type I	*2.43*	*3.16*	*3.19*
Type I & II	*3.89*	*6.07*	*5.24*

Table 19: Projected annual average sales, value added and employment in Western Australia for Stage 3(b)

7.8 Comparison of Impacts with Past Experience

A simple way of assessing flow-on effects of major new developments in a region is to calculate response elasticities. The elasticity is the percentage change in a 'responding' industry divided by the percentage change in a 'driver' industry. Table 20 shows elasticities for employment responses in the Pilbara economy to growth in its mining, oil and gas industries between 2006 and 2011. During that period, employment in the already large mining industry increased by a phenomenal 17% per year; and in oil and gas by 21.6% per year.

Industries with elasticities greater than 1.0 – which indicates an equal or greater percentage growth rate to that in mining, oil and gas – were as follows. The responding industries have been ranked in order of 2006 employment, with the elasticity shown.

- Construction including civil engineering industries (2,359; 1.4);
- (Retailing (1,379; 1.4);
- Residential construction (521; 1.4);
- Road transport (439; 1.2)
- Metal fabrication (86; 1.9)
- Specialised machinery (62; 1.2)
- Transport equipment (51; 1.0)

These are generally the industries where a similarly strong response could be expected from the proposed Pilbara Solar Export Project. While it is conceivable that some of the employment increases quoted above arose independently of changes in output of the oil, gas and mining industries, and/or related new construction activity, it is highly likely that most of the increases in locally based, private/corporate sector jobs were related directly or indirectly to the major driver industries.

When the labour market is very tight, as it has been in Western Australia and in the Pilbara until quite recently - an increase in the output of one industry may simply detract from output and employment in another, thus reducing or even eliminating any downstream effects. Against this, Table 20 shows that despite its very tight labour market, employment in support industries continued to grow strongly between 2006 and 2011 in response to the very large increases in output and investment by the oil, gas and iron ore industries.

	2006 Place of Work in Pilbara	2011 Place of Work in Pilbara	Annual Average Change %/Yr	Elasticity with respect to Mining	Elasticity with respect to Mining (plus Oil & Gas)
Agriculture, Forestry, Fishing	187	189	0.2	0.0	0.0
Mining	7,995	17,497	17.0		
Oil and Gas	524	1,391	21.6		
Food and Beverages	37	33	-2.3	-0.1	-0.1
Textile, Clothing and Footwear	18	9	-12.9	-0.8	-0.7
Wood and Pulp	7	5	-6.5	-0.4	-0.4
Printing	5	14	22.9	1.3	1.3
Petroleum	18	15	-3.6	-0.2	-0.2
Chemicals	147	262	12.3	0.7	0.7
Non-Metallic Mineral Products	62	126	15.2	0.9	0.9
Basic Metals	219	204	-1.4	-0.1	-0.1
Metal Fabrication	86	347	32.2	1.9	1.9
Transport Equipment	51	108	16.2	1.0	0.9
Specialised Machinery	62	160	20.9	1.2	1.2
Other Manufacturing	6	3	-12.9	-0.8	-0.7
Electricity, Gas and Water					
Services	228	462	15.2	0.9	0.9
Residential Construction	521	1,521	23.9	1.4	1.4
Other Construction	2,359	7,075	24.6	1.4	1.4
Wholesale Trade	440	613	6.9	0.4	0.4
Retail Trade	1,379	3,892	23.1	1.4	1.3
Road Transport	439	1,081	19.7	1.2	1.1
Rail Transport	19	34	12.3	0.7	0.7
Other Transport and Storage	619	1,230	14.7	0.9	0.9
Communications	81	90	2.1	0.1	0.1
Finance, Business and Government	2,974	4,479	8.5	0.5	0.5
Repair and Maintenance	413	839	15.2	0.9	0.9
Other Services	2,876	3,900	6.3	0.4	0.4
	21,772	45,579	15.9		

Table 20: Employment elasticities calculated from changes in employment in the Pilbara region between 2006 and 2011.

08

Partnering with Traditional Owners

8.1 Key findings

- Some Aboriginal groups in the Pilbara have already been discussing the possibility of owning solar farms as income-producing assets, prior to production of this report.
- Corporate Social Responsibility is increasingly important, especially in financing big international projects.
- International standards of Best Practice Models of Consultation with indigenous people are respected benchmarks accepted by international funding bodies.
- There are limitations to the Native Title Act in ensuring free, prior and informed consent of Traditional Owners.
- Legislation protecting Aboriginal Heritage and environmental concerns has limitations from an indigenous perspective.
- Matters of local environmental importance to Traditional Owners should be incorporated into baseline and ongoing environmental surveys.
- There are precedents for management plans that facilitate good outcomes for both Traditional Owners and large electricity transmission projects.
- In developing a solar industry in the Pilbara, a Best Practice Model of Consultation and a regional management plan can help ensure that Traditional Owners can also benefit and participate in emergence of a solar economy in the Pilbara.

8.2 Introduction

Much of land in the Pilbara is subject to native title claims or determinations. The development of solar resources in the Pilbara is an exciting opportunity for real partnership with Traditional Owners.

This Chapter examines the reasons why effective consultation with Traditional Owners will benefit the development of Pilbara solar resources, recommends a 'best practice' method for effective consultation and proposes a model for Aboriginal ownership of solar farms.

Samantha Mella Geoff James Kylie Chalmers

8.3 Native Title and Pilbara Traditional Owners

The 2011 census recorded 12% of the Pilbara population as being of Aboriginal and Torres Straight Island descent (ABS, 2016). Speculatively, this figure may be higher if the census was not completed by members of remote communities, and due to the recent slow down in mining.

There are currently 19 native title claims and determinations in the Pilbara that cover most of the land in the region.

Aboriginal and Torres Strait Islander peoples' connection to land was first accepted into the common law of Australia by the High Court of Australia's decision in Mabo (No 2) in 1992, after which the Australian Parliament enacted the *Native Title Act 1993* (Cth) (NTA) which gives statutory recognition and protection of native title. Native title exists where Aboriginal people have maintained a traditional connection to their land and waters since sovereignty, and where acts of government have not removed it.

In this chapter, the term 'Traditional Owners' refers to the Aboriginal people of the Pilbara who have rights and interests to land and waters under their traditional laws and customs, and which are recognised by the NTA.

In most areas, native title rights co-exist with, or may be subject to, other rights existing in the same area including mining rights, pastoral leases, and other forms of tenure such as those granted under the *Land Administration Act 1997* (WA). (see below for more details). There are generally two classes of native title: 1) Exclusive Possession – the right to use, possess and occupy the land to the exclusion of all others; 2) Non-Exclusive Native Title – no right to control access to the area, but may use the area for a variety of customary purposes, such as to hunt, fish, gather food, or teach Law and Custom on Country.

The NTA describes the process of applying for new forms of tenure on native title areas. The kind of procedural rights afforded to Traditional Owners under the NTA depend on the type, and the proposed purpose, of the tenure being applied for. The procedural rights range from relatively weak rights, such as a right to comment, to the Right to Negotiate (RTN) in relation to certain activities on their land.

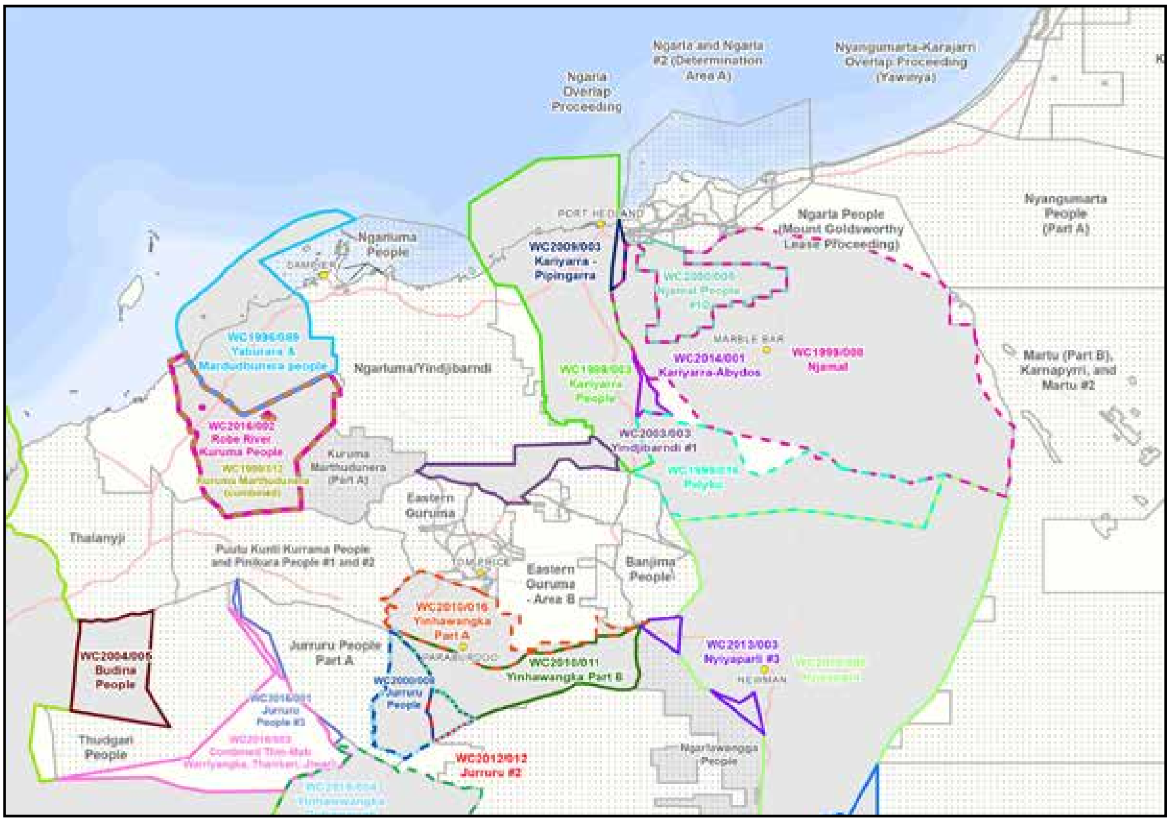


Figure 54: Native title claims in the Pilbara

Source: Native Title Tribunal[1]

[1]Map reproduced with the kind permission of the National Native Title Tribunal. Please note this map has been modified from its original form by cropping a section of the full map. The original version, depicting all WA Native Title Applications and Determination Areas as per Federal Court (31 December 2016), may be viewed at: http://www.nntt.gov.au/Maps/WA_NTDA_Schedule.pdf

8.4 Protection of Aboriginal Heritage

The protection of heritage sites, whether an archaeological site or an area of ethnographic importance, is critical to the maintenance of Aboriginal culture and ability for Traditional Owners to exercise their native title rights and interests; many of which are cultural obligations under traditional law and custom.

In Western Australia, the Department of Aboriginal Affairs (DAA) is responsible for managing the protection of Aboriginal Heritage in accordance with the *Aboriginal Heritage Act 1972* (WA) (AHA). Under the AHA, a person who in any way damages an Aboriginal Site without prior ministerial consent has committed an offence, punishable by fine and/or imprisonment (WA, 1975). Provided a site is determined to meet the definition of an Aboriginal Site under the AHA it is protected, and any land use that does not comply with the provisions of the AHA may be prosecuted. To avoid contravention of the AHA, the DAA recommends land users follow its Due Diligence Guidelines which include undertaking Aboriginal heritage surveys prior to commencing any ground disturbing activities and employing heritage management strategies (Department of Aboriginal Affairs, 2013).

For the purpose of this chapter, 'Aboriginal heritage' refers to places and objects of ethnographic and archaeological significance to Aboriginal people, as well as resources necessary for continued practice of culture, including local plant and animal populations, bush tucker, and water sources.

8.5 Socio-economic Benefits of Engaging with Traditional Owners

As the Pilbara seeks to diversify its economic base and build the Pilbara Cities Vision, the sustainable development of the Pilbara may also benefit from a diversification of investment purpose.

Corporate Social Responsibility (CSR) is becoming increasingly important for mitigation of risk associated with legal compliance and enhancing business reputation to boost investment and profitability. There are many examples of the growing market for CSR-compliant business, including:

- Developing international policies,
- The increasing consumer demand for transparency in manufacturing standards and investment practices,
- The global fossil fuel divestment movement,
- Impact of social media,
- Strengthening multinational compliance standards.

Effective engagement with Pilbara Traditional Owners may satisfy commonly used CSR criteria, for example:

- Diversity, equal opportunity and non-discrimination,
- Indigenous rights and human rights compliant investment,
- Local community impacts,
- Supplier assessment for social impacts,
- Training and education, and
- Public policy (Global Reporting Initiative, 2015).

Economic drivers for voluntarily seeking to be socially responsible include the 'enlightened shareholder approach.' This means corporate decision-makers must consider a range of social and environmental matters if they are to maximise long-term financial returns (Brine, 2007) and ensure the good reputation of the business is retained.

Large-scale solar export may deliver industry diversification in the Pilbara and ensure positive tangible outcomes for Traditional Owners. It may also provide the local community and economic development benefits sought by the government.

For Pilbara solar export to be branded with high CSR standards, the internationally recognised standards must be incorporated from the inception of project planning. While large-scale solar export may deliver industry diversification in the Pilbara, ensuring positive tangible outcomes for Traditional Owners may also provide the local community and economic development benefits sought by the government. In addition, high CSR standards may deliver investor diversification to the region.

8.6 Meeting International Standards – Engagement and Consultation

A 'best practice model' for engagement and consultation with Traditional Owners referenced to international standards is recommended. This will ensure that large-scale solar farms will maintain social licence over the full multi-decadal life cycle of the project, particularly if ethical investment is sought. Another key benefit of meeting internationally recognised CSR standards is that all avenues for investment and funding remain open and uncontroversial.

> *Sustainability begins with a principled approach to doing business.*
>
> UN Global Compact

A best practice model may require a higher standard to be met than the minimum requirements of the NTA. Even if the strongest rights afforded the RTN were to apply, it does not guarantee this process would result in free, prior and informed consent of Traditional Owners.

The RTN under the NTA requires the parties to discuss the effect of the activity on the native title parties' registered rights and interests, and to negotiate in good faith towards reaching an agreement. If negotiations do not result in an agreement after a certain period of time, the proponent may then apply to the National Native Title Tribunal to have the tenement granted. A native title party may object on the basis that the proponent did not negotiate in good faith, or that the tenure should not be granted for other reasons. However, since the NTA was introduced in 1993, there have been few successful objections to a grant of tenure by Traditional Owners in Australia. For instance, it is relatively easy for a developer to prove it has met the base-line requirement of 'negotiating in good faith' and developers have been criticised for treating the requirements under the RTN as window-dressing (Bartlett, 1996) or merely an administrative delay in the development process.

So, while the RTN is a valuable right, the process does not always achieve real recognition or self-determination for Traditional Owners. As it can be difficult for Traditional Owners to oppose development on Country, and as a developer may apply to have the tenement granted anyway even if no agreement is reached, Traditional Owners may decide that it is in their best interest to take something rather than nothing and agree to accept a deal. It is unsurprising that Traditional Owners consider the system to be unfair, patronising and often heart-breaking.

Artist Imelda Charles, with buyer at Spinifex Studios, South Hedland

Samantha Mella Geoff James Kylie Chalmers

8.7 Meeting International Standards – Aboriginal Heritage Protection

Australia adopted the United Nations Declaration on the Rights of Indigenous People (UNDRIP) in 2009. This includes a recognition of the right of indigenous people to access, use and protect sacred sites (United Nations, United Nations Declaration on the Rights of Indigenous Peoples. Article 11 and 12, 2007). The AHA was introduced in 1974 and falls short of meeting this standard. For the emerging solar industry to meet 21st century expectations of CSR, the requisite approach requires consultation and allows Traditional Owners to determine what matters they consider important and in need of protecting on their Country.

The AHA is concerned only with the protection of an 'Aboriginal Site', which is a term that is narrowly construed. Many places of significance to Traditional Owners are not found to meet the definition of an Aboriginal Site, and other matters of cultural significance to Aboriginal people (such as local flora, fauna and resources) are not protected.

No amount of compensation will be able to restore an ancient site to its original condition. It will be permanently changed or lost forever.

Further, for Traditional Owners to take action against a company or person who has disturbed an Aboriginal Site requires resources that are often not available, however and in any event, there is no real recompense for Traditional Owners if a site is impacted. No amount of compensation will be able to restore an ancient site to its original condition and it will be permanently changed or lost forever.

While it is important to protect 'Aboriginal Sites' as defined by the AHA, Aboriginal people also have obligations under traditional law and culture to care for and protect other sites of importance and their traditional lands more generally. Matters of local environmental concern are of high importance to Aboriginal people, such as protection of local water sources, plants, bush tucker and medicines, and maintaining local animal populations such as emu, kangaroo and bush turkey. The ability of Aboriginal people to continue to enjoy their traditional practices is impaired when local flora and fauna populations and resources (such as water) suffer. Traditional Owners also suffer personally from having failed to protect their Country.

Current laws, such as the *Environmental Protection Act 1986* (WA) and the *Environmental Protection and Biodiversity Conservation Act 1999* (Cth), have limited capacity to consider Aboriginal concerns and to protect local populations and resources. Unless populations are already considered under threat nationally or internationally, relevant environmental laws will not assist. Further, the Environmental Impact Assessments required under the *Environmental Protection Act* do not take into account for the cumulative impacts on smaller scale features which are important to Traditional Owners, such as individual fresh water sources, pools, local flora and fauna populations on Country.

Aboriginal people have obligations under traditional law and culture to care for and protect their traditional lands...
Traditional custodians suffer personally from having failed to protect their Country.

Traditional Owners require unique assessments and advice in relation to likely impact of activities specific to their Country. Traditional Owners have expressed their concern, anger and sadness that the AHA and relevant environmental laws do not require consideration of matters of importance to them.

Louise Allen, *Untitled*, 40.5 x 71cm, acrylic on canvas, 2016

8.8 Best Practice Consultation Model

Despite the shortcomings in domestic law, international laws have developed which require good faith, socially appropriate and respectful consultation with indigenous peoples prior to conducting ground-disturbing activities (Butzier, 2014). To ensure that the rollout of the solar industry develops sustainably and can objectively meet a high standard of CSR, international standards need to be adhered to.

If the solar export model is found feasible, one model that may evolve is a series of solar farms located around the Pilbara on the traditional lands of multiple Aboriginal groups. The best practice consultation proposed below may be implemented across the Pilbara through the Incremental Build. Each group of Traditional Owners will have unique requirements for effective consultation, so the process is described in general terms.

An internationally accepted indicator for effective and socially responsible engagement with indigenous peoples is the concept of Free, Prior and Informed Consent (FPIC). This is the principle that a community has the right to give or withhold its consent to proposed projects that may affect the lands they customarily own, occupy or otherwise use.

The International Finance Corporation (IFC), a commercial lending arm of the World Bank, provides a respected international benchmark for identifying and managing environmental and social risk. The IFC recognises that in many cases, indigenous people have limited economic, social and legal status to defend their rights to, and interest in, lands and natural and cultural resources, and may be restricted in their ability to participate in and benefit from development (IFC Performance Standard 7). In 2011, the IFC amended its Policy and Performance Standards on Social and Environmental Sustainability to require that projects financed by the IFC obtain the FPIC of Indigenous peoples (IFC, 2011). Its Performance Standards can be summarised into three tiers:

i. Baseline Consultation – to avoid adverse impacts of projects on communities, consultation should begin early, be based on prior disclosure of information to communities in an accessible format, be free from coercion, and be documented. Concerns of Traditional Owners should be included in baseline surveys. External experts should be engaged to assist in the identification of the project's risks and impacts (IFC Performance Standard 8);

ii. Informed Consultation and Participation – for projects with potentially significant adverse impacts on local communities, the company should use information gathered in consultation to mitigate impacts, tailor implementation, and identify appropriate mechanisms for sharing the project benefits (IFC Performance Standard 7 & 8);

iii. FPIC – a developer is required to seek the consent of Traditional Owners before commencing work. Sufficient time should be provided for Aboriginal decision-making processes, which include being sensitive to the dynamics of communal decision making. FPIC applies to project design, implementation, and expected outcomes related to impacts affecting Aboriginal people. The process followed and the outcomes achieved should be documented. FPIC does not necessarily require unanimity and may be achieved even when individuals or groups within the community explicitly disagree (IFC Performance Standard 7).

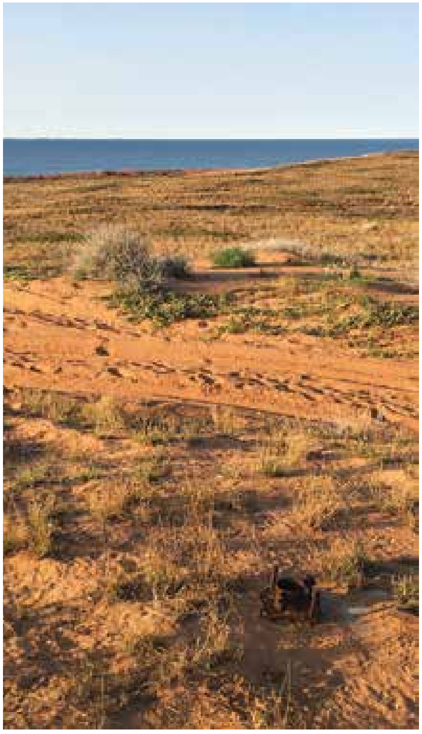
Practically speaking, these performance standards can be fulfilled by structuring the negotiation process as follows:

1. Pre-Consultation Meeting with legal representatives.

2. Consultation Meetings with Aboriginal groups.

3. Undertaking environment and heritage surveys.

4. Post-Planning surveys and subsequent consultation meetings with Aboriginal groups for life of project.



8.8.1 Pre-consultation Meetings

Before meeting with Aboriginal groups, it is advisable to obtain a preliminary understanding of the appropriate process for engaging with each specific group, as this will differ between groups.

Yamatji Marlpa Aboriginal Corporation (YMAC) is the recognised Representative Body for the Pilbara region and represents most Pilbara Native Title Groups in regards to a range of native title-related matters. The group has much experience facilitating consultation with Traditional Owners for large-scale and long-term mining projects. YMAC also has experienced in-house legal and anthropology staff with specific knowledge of the Pilbara Native Title Groups.

For groups represented by YMAC, pre-consultation meetings with relevant YMAC staff members can provide the background to ensure: transparent and appropriate negotiations, compliance with authorised consultation procedures, understanding of and sensitivity to culture and heritage, effective ways of working with specific groups of Traditional Owners. This assists in ensuring that the initial meetings are productive, and lays the groundwork for robust discussion.

Owen Biljabu, *Jaraputal,* 61 x 91.5cm, acrylic on canvas, 2017

8.8.2 Consultation Meetings

The consultation meetings with groups should achieve the following outcomes:

- Present materials to inform groups of the proposed solar export project;
- Provide independent expert advice to the groups in an accessible manner in relation to the footprint and impact of solar farms and transmission lines to enable informed decision (an important factor in FPIC);
- Early consultation will enable Aboriginal heritage and other concerns to be included in early planning stages of the project, with consideration given to the location of solar farms and transmission lines;
- Enable group-specific concerns to be incorporated into baseline environmental surveys, such as local populations of plants and animals (discussed in Section 8.7);
- Discuss what ongoing involvement the groups may wish to have in the project, such as some form of ownership, partnership, employment, training or other (further discussed in Section 8.12.3).

YMAC will arrange meetings with Traditional Owners at appropriate locations. This includes inviting the appropriate attendees, managing logistics, and providing administrative services (including notices, budgets, records, meeting minutes, attendance registers, and processing any travel allowance for attendees).

8.8.3 Conducting Environmental and Aboriginal Heritage Surveys

Once a location is identified for the project, an environmental impact assessment will need to be undertaken in accordance with relevant State and Federal laws. It is recommended that matters of local environmental importance to Traditional Owners should be incorporated into baseline and ongoing environmental assessments and surveys.

Aboriginal Heritage Surveys are also required to assess proposed solar farm sites for Aboriginal Sites and places of significance. A Heritage Survey team is usually made up of an anthropologist, archaeologist, and persons possessing cultural knowledge of the area. Each Traditional Owner group may have a preferred process for nominating attendees and conducting surveys, which can be determined through consultation with the group and with YMAC. Surveys may take a number of days to complete, depending on the size and terrain of the project area being surveyed. Once the area is surveyed, Aboriginal Sites and other areas of importance can be mapped, expert anthropological and archaeological advice can be considered, and management plans can be developed and implemented (Section 8.9).

Caroline Bidu, *Untitled,* 40.5 x 61cm, acrylic on canvas, 2016

Nyaparu William Gardiner, *Nyaparu*, 61 x 76cm, acrylic on canvas, 2016

8.8.4 Follow-Up Consultation Meetings

After heritage and environmental surveys have taken place as agreed, consultation with the relevant groups will be required for:

- development of an acceptable plan for avoidance, minimisation, mitigation or offset of identified impacts on sites or Country;
- the location of solar farm and transmission lines;
- development of management plans for the life of the project should be undertaken in the early planning stage (including site closure/rehabilitation);
- an implementation plan for any desired ongoing involvement or ownership of the project by Traditional Owners.

Traditional Owners usually want to be consulted, involved and receive updates for the life of the project on their land. This will also assist in maintaining a good relationship between the solar developers and the Traditional Owners.

8.9 Management Plan - Immediate and Long Term

Protection of Aboriginal culture and heritage is too often at odds with modern-day economics. Most opportunities in the Pilbara are mining-related, which permanently changes the landscape. In contrast, the Solar Export Project has the potential to provide jobs, education and opportunities to Aboriginal people without the need to trade their land, culture and heritage, as the solar development may require less invasive use of land.

Ideally, management plans are to be developed in consultation with Traditional Owners, to reduce or avoid potential impacts on Aboriginal heritage. Management plans may include exclusion zones, mitigation or salvage of the sites, and offsetting and rehabilitation strategies. Example of management techniques from the Madeira Complex project (see 3.3.1) include:

- very tall structures to preserve vegetation and limit the intrusion onto Indigenous peoples' land, which allowed the project to still be considered environmentally friendly despite inevitable impacts;
- consideration of the territory and the natural resources close to the project;
- the access used by indigenous groups for fishing, hunting, gathering and access to sites with historical and cultural and religious value (burial grounds, sacred areas).

The management plan for specific sites should be incorporated into any agreements entered into for development and administration of the solar farms, to ensure compliance by all stakeholders.

Implementation of a Pilbara-wide management plan is recommended before extensive solar development takes place. This would ensure that cumulative impacts on the environment and heritage can be accounted for and a best practice engagement model can be consistently implemented. Lessons learnt along the way can be incorporated, ensuring that the management plan is implemented with increasing efficiency and effectiveness for each new project.

8.10 Advice on Project Siting regarding impact on Aboriginal heritage

Advice on suitable project siting from an Aboriginal group's perspective can only be achieved through undertaking the Best Practice consultation processes referred to in Section 8.8.

Suitable locations for solar farms and transmission corridors will be wherever a nexus exists between land which meets engineering requirements with the land of Traditional Owners who are ready, willing and able to participate in the solar development.

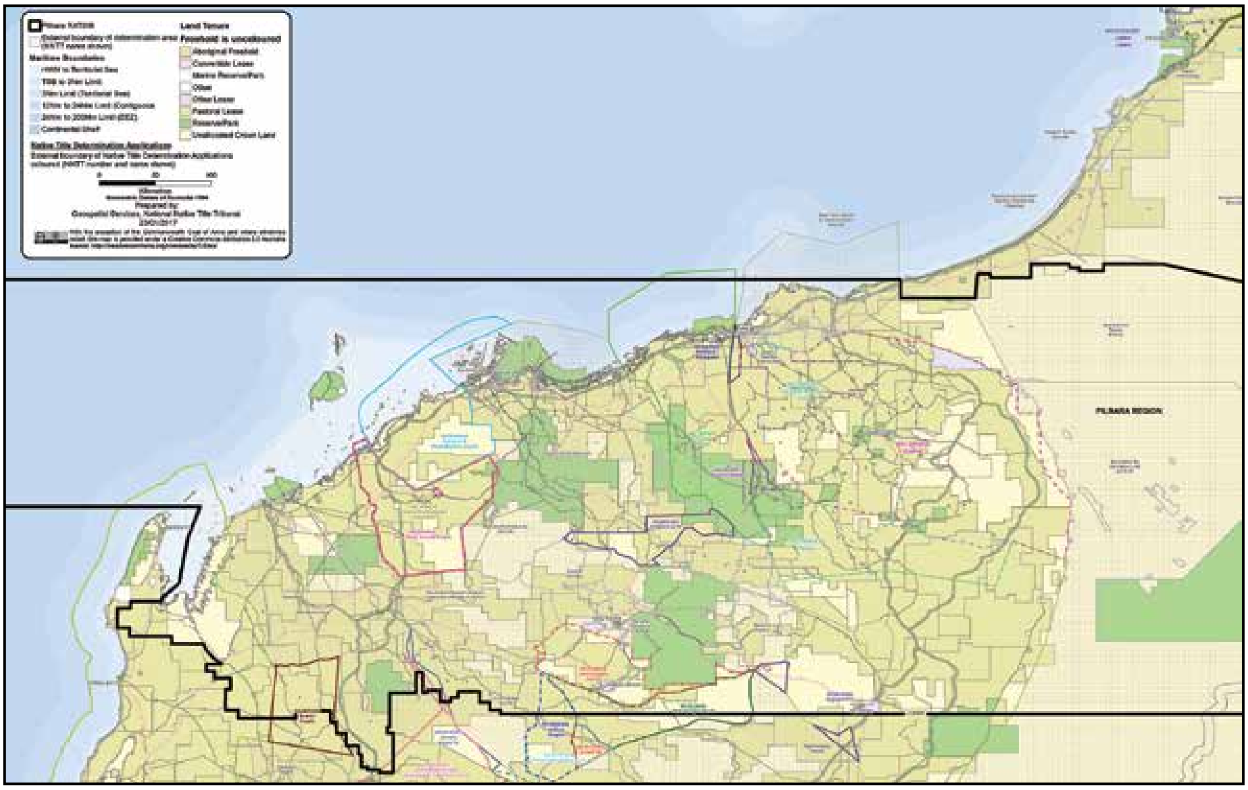


Figure 55: National Native Title Tribunal map illustrating many types of tenure in the Pilbara *Source: Native Title Tribunal[3]*

[3]Map reproduced with the kind permission of the National Native Title Tribunal. Please note this map has been modified from its original form by cropping a section of the full map. The original version, depicting Pilbara Native Title Applications and Determination Areas as per Federal Court (31 December 2016), may be viewed at: http://www.nntt.gov.au/Maps/WA_Pilbara_NTDA_Schedule.pdf

8.11 General Tenure Considerations regarding Project Siting

Navigating the many types of tenure in the Pilbara can be a complex and time-consuming task. The majority of the Pilbara is Crown Land. In addition to native title rights, it is largely covered by some other form of tenure such as pastoral leases, exploration tenements and/or mining leases.

To secure tenure for a solar farm and associated transmission corridors may require an application for tenure in areas where other forms of tenure likely already exist. An application for tenure will require obtaining ministerial consent pursuant to the Land Administration Act 1997 (Cth) (LAA), which may be assisted by reaching an agreement with those who already hold rights in the area (s177 LAA). Different forms of tenure afford various levels of procedural rights to its owner, and when several kinds of such tenure co-exist over the same area of land, the procedural rights of each stakeholder must be met, including where necessary, provision of compensation for the impairment or change to their rights in that area (Part 9 LAA).

Depending on the type of tenure, the type of procedural rights, and the willingness of the tenure holder to relinquish or share those rights (s168 LAA), or the willingness of the Minister to grant tenure in the absence of agreement (165(2) LAA), obtaining the approvals and agreements required for a solar farm (and related transmission infrastructure) could be a lengthy process.

The establishment of power infrastructure (such as solar farms, solar updraft towers, wind farms and biodigesters) to generate surplus power beyond what is required for associated tenure, such as to power a mine site or a pastoral business, can be achieved through a lease pursuant to s.91 LAA or alternative tenure (e.g. s.79 LAA lease). Other tenure options are also available and selecting the best option for the project will require careful consideration.

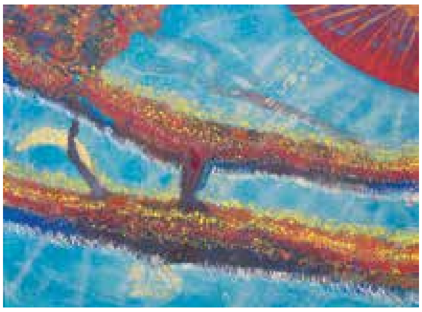
Identification of suitable sites should occur as soon as possible. An application will need to be made to the State detailing the land use proposal, after which it is the responsibility of the applicant to seek all approvals required, and to negotiate any native title agreements required, before the State will consider granting the required tenure.

8.12 Aboriginal Involvement or Ownership Models

The emergence of a solar industry in the Pilbara holds potential to go much further than best practice consultations in delivering positive outcomes for Aboriginal people. A solar industry could accommodate real involvement and partnership with Traditional Owners on a scale never seen before in the Pilbara. Participation in the proposed solar export and also domestic supply could potentially be facilitated through partnerships with Aboriginal Corporations.

Traditional Owners who have achieved native title recognition in the Federal Court must appoint an Aboriginal Corporation which operates as their front-of-house (Commonwealth of Australia, 1993) and this is called a Prescribed Body Corporate (PBC). A PBC acts as either trustee or agent for the native title holders and exist for the benefit of the native title holders of both present and future generations. Groups that have not yet achieved native title recognition may nevertheless have already set up an Aboriginal Corporation which operates to benefit the group.

Aboriginal Corporations are incorporated under the *Corporations (Aboriginal and Torres Strait Islander) Act 2006* (Cth) (CATSI Act) rather than the usual *Corporations Act 2001* (Cth). The CATSI Act includes special measures to meet the specific needs of Aboriginal people, and facilitates the groups' social or economic activities, including contracting and accessing available funding. Aboriginal Corporations are also usually not-for-profit and may only engage in business initiatives to benefit their members.



Teddy Byrne, *Untitled*, 61 x 45.5cm, acrylic on canvas, 2016

Further, some groups in the Pilbara have resources gained through previous land dealings on Country which are managed by trustees on their behalf, and which a group may wish to utilise to establish a solar farm. Funding from various Federal and State resources available for assisting Aboriginal businesses may also be accessed by Aboriginal Corporations for this purpose.

Traditional Owner groups vary in their capacity to participate in economic ventures. Some groups may have a corporation up and running while others do not. Some groups may have greater resources at their disposal than other groups. Therefore a model for Aboriginal involvement requires flexibility to meet the needs, capabilities and aspirations of each group, as well as the ability to assist groups willing and able to participate. It should also be flexible enough to evolve over time with the group (such as allowing groups to take on a greater role as capacity is gained).

Imelda Charles, *Wayarti (turtle)*, 40.5 x 40.5cm, acrylic on canvas, 2016

8.12.1 Land Use Agreement

Land Use Agreements are the most common method employed in the Pilbara in regards to projects occurring on Aboriginal Country. An agreement may be reached between the solar proponents and the Traditional Owners. Agreements may include that Aboriginal people consent to the grant of certain tenure in certain circumstances, in return for financial and non-financial benefits. Benefits provided under agreements are in recognition of, or compensating for, the impact the project will have on Traditional Owners' native title rights.

Some examples of non-financial benefits afforded to indigenous groups during the Madeira Complex project included providing groups on whose land transmission infrastructure was built with school infrastructure, leisure and health facilities. Consultation with the Traditional Owner groups will enable the specific aspirations of the group to be identified and ensure benefits tailored accordingly.

The above provides a very general understanding of what an agreement with Traditional Owners may include. The NTA provides for various agreements options, with differing legal consequences, which will not be considered in greater detail here. Careful consideration as to what kind of agreement is desirable in the circumstances will be required by all parties in due course.

8.12.2 Holders of Tenure

Aboriginal Corporations may apply for and hold tenure on the land which will be used for solar farms or transmission lines.

One advantage is that Aboriginal Corporations have greater options for applying for land tenure, such as under section 83 of the LAA, which provides that the Minister may grant land to an approved Aboriginal Corporation, in "fee simple" or by lease, for the purpose of advancing the interests of any Aboriginal person or persons.

A further advantage is that Aboriginal Corporations may also already have relationships with those who hold land in the area, such as pastoralists, who may be more willing to facilitate the grant of tenure.

Lastly, and purely speculatively, if a change in existing tenure is required to accommodate a licence for the solar farm (which is highly likely), a lease applied for by an Aboriginal Corporation perhaps would add greater support to the position that the project will provide an economic or social benefit on the State, which is required for the Minister to change existing tenure (s165 LAA).

Winnie Sampi, *Salt Flats around Port Hedland*, 30.5 x 40.5cm, acrylic on linen, 2016

8.12.3 Ownership and Management of Solar Farms

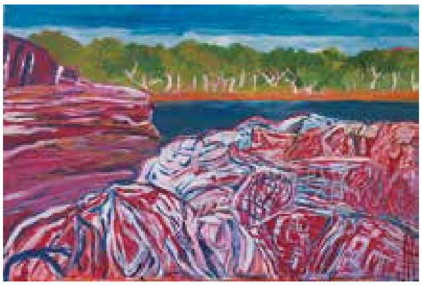
Aboriginal Corporations could own solar farms, which operate in a consortium, like the Sandfire project discussed in Section 8.13 below. One advantage of this is that it may attract higher CSR ratings. There may also be a variety of Federal, State or other funding available for the project and/or Aboriginal Corporation to apply for to support Aboriginal enterprises.

The return on investment for a commercial scale solar farm will vary, given variables such as local conditions, type and cost of panels used, construction costs, the feed-in tariffs, and/or the power purchase agreement. As the solar market evolves, investors are receiving solid returns on solar investments. Ownership of solar assets does provide the potential for an independent income stream for Traditional Owners.

Depending on the capacity of the Aboriginal Corporation, solar farms could also be managed by Aboriginal Corporations, either in whole or in part. Again, there may be funding accessible to assist Aboriginal Corporations to run a business, including training of staff.

8.12.4 Management of the Project

There are various ways in which Traditional Owners could be involved in the management of the solar generation infrastructure. Capacity building is always high on the agenda of any Aboriginal Corporation. A gigawatt scale solar industry could provide excellent opportunities for upskilling, education, and employment of local members of the Aboriginal



Irene Coffin, *Marble Bar*, 51 x 76cm, acrylic on canvas, 2016

community. Further, Aboriginal Corporations are best placed to manage and employ local Aboriginal staff, as cultural considerations and needs are understood and more easily accommodated than they are in the general commercial world.

Further, as solar generation expands, coordination on a regional level could promote collaborative working relationships between Aboriginal Corporations, for example to mentor and assist new groups. Sharing of knowledge, experience and perhaps resources, such as expert staff who could potentially service several solar farms, are examples of the benefits of regional approach.

At a higher level, Aboriginal representatives can sit on the board of the overarching businesses associated with solar export or solar domestic supply. This would assist the solar industry to develop and operate in a culturally consistent manner and in accordance with Best Practice principles and methods.

Any one or a combination of the above options could be employed. Initially a skills assessment would need to be undertaken of an interested Aboriginal Corporation. Agencies such as YMAC can facilitate this process, including by working with groups to prepare them for participation in solar generation, obtaining the necessary expert advice and support they need to structure the business, and providing ongoing support if the Aboriginal Corporation so wishes.

8.13 Building Solar Capacity, Expertise and Supply Chain in the Pilbara

Building capacity of Traditional Owners and Aboriginal Corporations in the region will assist the long-term goal of solar export by increasing expertise, experience, commercial models, engagement models, and local solar supply chains. If found to be feasible, solar export may not commence for some 10 – 15 years. In the meantime, smaller capacity-building projects can enable an understanding of every aspect of the businesses, providing preparation for a large-scale operation. Smaller capacity-building projects could provide the additional benefits of supporting remote Aboriginal communities through employment, training, revenue, and provision of clean energy.

Further, some Traditional Owners may be able to take advantage of relationships and agreements already in place with mining companies to come to power purchase arrangement. Sandfire Resources operates the DeGrussa Copper-Gold Project, 900 km north of Perth and utilises a 10.6 MW solar facility, with 34,080 solar panels (Sandfire, 2016). This project is expected to achieve savings of 5 million litres per year in the consumption of diesel fuel, reducing DeGrussa's CO_2 emissions by an estimated 12,000 tonnes per year.

Sandfire's cash contribution to the project was expected to be less than $1 million, demonstrating that even with a small amount of capital, it may be possible for an Aboriginal Corporation to develop a solar project, provided there is a power purchase offtake agreement in place. The DeGrussa Solar Project cost $40 million and supplies 20% of power requirements of the mine. It was developed as part of an international consortium formed to finance, develop, operate and own the facility.

The consortium stakeholders are:

Sandfire Resources: Customer/ Power Offtaker

JUWI Renewable Energy Pty Ltd: Project developer ECP, O&M – secured PPA

OTC: EPC in joint-venture with Juwi

Neoen: Owner of the facility and provider of equity funding

ARENA: $20.9 million funding support

Clean Energy Finance Corporation: Provider of $15 million debt funding.

Further, if an Aboriginal ownership model is embraced, State, Federal and non-government funding may be available for access by Aboriginal businesses. There is the potential to develop similar projects in the Pilbara, which can assist lower CO_2 emissions, lower the power costs of the mining company, and deliver the capacity-building opportunities the region needs for large-scale solar export projects.

09

Discussion and recommendations

> *"Wind, solar and hydropower are reshaping the electricity system."*
> World Energy Investment Outlook, 2016

For now, fossil fuels still dominate global energy investment, however there is a major restructure in progress driven by market forces and underscored by the Paris Agreement. While investment in renewable energy appears to have been stable since 2011, it is growing because "investment supports an accelerated production expansion due to declining technology costs" (IEA, 2016).

The solar revolution is here and now. As seen in Figure 1, solar PV costs have declined dramatically, and costs are forecast to continue to fall by a further 40-70% by 2040 (IEA, 2016c). Bloomberg's predicts that by 2030 solar PV will be the lowest cost generation technology, and that by 2040, solar PV will supply 15% of the world's electricity (Bloomberg, 2016).

The global electricity market is starting to evolve. The ability of HVDC technology to mobilise bulk electricity over land and sea is already playing a significant role in restructuring energy markets. Cross-border electricity trade and regional grid integration is on the rise. It is creating larger, more diverse and more competitive power pools. With certainty and a clear regulatory framework, the European Single Electricity Market (SEM) demonstrates that high-level regional integration can be achieved. Given the right conditions, as in the Nordic countries, cross-border electricity trade will evolve organically.

Given that Australia is an island continent, international electricity trade has not been an obvious pathway to export energy. However, cross-border trade has evolved among the states since the electricity market was deregulated in 1998.

In the rest of the world, regional and subregional electricity markets are evolving. The endpoint of the Chinese desire to link these regional markets through Global Energy Interconnection is a global electricity market. China has already applied HVDC to bring GW scale renewable inputs into its own electricity system. Asia's transition to a low carbon economy is an urgent priority for GEIDCO, given its rapid economic growth, vulnerability to climate impacts, vast electricity demand and big pollution problems. ASEAN also has the goal of an interconnected regional grid, and the region has a massive need for new power infrastructure.

Assuming that these trends continue, the Pilbara region, and the Western Kimberley are well positioned to participate in an emerging global electricity trade. HVDC subsea technology can open access to the Pilbara's and Western Kimberley's immense solar resources to Indonesia, the ASEAN region and perhaps even beyond.

> *Just as Korean and Chinese companies own coal mines in Australia today, Indonesia and other ASEAN countries could own solar generation assets in Australia.*

HVDC interconnection between Australia and Indonesia, then the ASEAN region, would provide ASEAN countries access to a large high quality solar resource. This has the potential to decouple development from heavy reliance on fossil fuels. Considering that the ASEAN region is the last remaining growth market for coal, investment in HVDC interconnection infrastructure and solar PV instead of fossil fuel infrastructure would have huge benefits for the region and the whole world in terms of reducing emissions and pollution in Southeast Asia.

Southeast Asia is extremely vulnerable to climate change. Asian Development Bank research focussed on Indonesia, the Philippines, Thailand, and Viêt Nam stated that:

"The cost (of climate change) to these countries each year could equal a loss of 6.7% of their combined gross domestic product by 2100, more than twice the world average... As a highly vulnerable region with considerable need for adaptation and great potential for mitigation, Southeast Asia should play an important part in a global solution" (Asian Development Bank, 2009).

Development goals are a priority for ASEAN, and subsea HVDC infrastructure is expensive. More research is required to fully understand the costs, ownership models and potential funding arrangements. It is important to fully understand what funding options are available for infrastructure that enables decarbonised development for developing countries.

This study proposes a 3 GW pilot during Indonesia's electrification drive. It is acknowledged that such a scenario is not under consideration by Indonesia. Both ASEAN's and Indonesia's current plans for future generation are focussed on domestic hydroelectric, geothermal and fossil fuel generation.

The first challenge is to develop an interconnection and electricity supply proposal that is attractive to Indonesia, given that Indonesia has abundant fossil fuel and geothermal resources.

Australia and Indonesia do not have the advantage of shared physical borders nor the close relationships that encourage cross-border trade as seen in the Nordic Countries. Former Australian Foreign Affairs Minister Gareth Evans noted, "We largely differ in language, culture, religion, ethnicity, population size, and in political and legal systems" (Woolcott, 2017). Even in geography, the two countries couldn't be more different - an archipelago of more than 17,000 islands and an island continent.

Diplomatic flashpoints of tension in recent years include:

- 2011 Australian suspension of live cattle export to Indonesia
- 2013 Australian intelligence caught tapping the Indonesian President's mobile phone
- Australia's controversial "turn-back the boats" policy
- 2015 Australian withdrawal of its Ambassador in protest of executions of convicted Australian drug smugglers.

In 2016 Australia military personnel in joint excercises caused offense to Indonesia, and Indonesians were also offended by Australia's patronising attitude regarding the phone tapping of the President (McGrath, 2013).

Despite the diplomatic flashpoints, there is also much successful day-to day engagement between Australia and Indonesia. Millions of Australians visit Bali and Indonesia regularly, and the vast majority are happy events without incident (Lindsey, 2017). In 2016 the first shipment of Australian cattle arrived in South Kalimantan to build up the Indonesian herd. This is part of a food security agreement that includes collaboration on pasture management (ABC, 2016).

There is ongoing collaboration between Australian and Indonesian universities in research in science, health and the arts. This includes a university collaboration that considers Australian-Indonesian HVDC interconnection. There is also ongoing cooperation in business, especially agriculture, mining and tourism. The Australia-Indonesia Comprehensive Economic Partnership Agreement is in progress.

While emphasising that more cultural sensitivity is required, Former Ambassador Richard Woolcott said the relationship with Indonesia was "special" and had many opportunities "if handled with sophistication." As the pendulum of global and economic power swings toward Asia, it presents opportunities. It is up to Australia to act upon them.

"The cost (of climate change) to these countries each year could equal a loss of 6.7% of their combined gross domestic product by 2100, more than twice the world average... As a highly vulnerable region with considerable need for adaptation and great potential for mitigation, Southeast Asia should play an important part in a global solution".

(Asian Development Bank, 2009)

Post-Paris, there has been no leadership on a national level to fulfil Australia's renewable energy potential. This leaves vacuum for States and Regions to fill.

The Pilbara has the advantages of proximity to Asia, successful existing trade relationships and a proven ability to do "big stuff." The foundation is there for the Pilbara and Western Australia to take the leadership, and attract Indonesia's attention in a "sophisticated" way, as suggested by the former Ambassador. **The essential first step is initiating a dialogue about the potential costs and benefits of a clean energy partnership.**

As seen with the evolution of projects like Basslink and NorNed, interconnection projects require sustained effort over many years. A self-reliant economy is important to both Indonesia and President Joko Widodo, and interconnection would require special regulatory arrangements. There must be generous benefits for Indonesia.

The benefits of the proposed 3 GW solar generation and transmission pilot would be immense in Pilbara and Western Australia. It would create a new industry with a 4.4% increase in permanent jobs. Across Western Australia, the combined construction and operations would create 12,000 jobs. It would achieve the regional goals of economic diversification, renewable energy development and deeper engagement with Asia.

Additional economic benefits for Indonesia may include the HVDC subsea cable factory located in Indonesia that would build skills and create employment. There is the opportunity to invest and own solar generation infrastructure in the Pilbara.

The external costs of coal do not have a high profile in Indonesia, however, the BAU scenario in Southeast Asia, particularly Indonesia, may create severe water stress, land use conflicts and health impacts. These impacts will be exacerbated by climate change. Large-scale solar generation sites located in the Pilbara instead of coal-fired power infrastructure in Indonesia could alleviate some land and water use pressures for Indonesia. It would also reduce greenhouse gas emissions and particulate pollution.

Ultimately, cost is the critical factor. The LCOE must be cost-competitive, with the large overhead of the subsea interconnector. The preliminary engineering and costing analysis shows that the 3 GW solar generation Pilot Project with HVDC connection to Java may have commercial potential. It will cost 18-25 c/kWh over the long term and it will earn 19-20 c/kWh. This was a deliberately conservative analysis and there were many uncertainties. **More research is required to get a deeper understanding of the costs involved.**

Despite the superb solar resource, the Pilbara and more broadly Western Australia has an over-capacity of fossil fuel infrastructure. On a government level, focus in WA is on mining. There has been very little ambition to develop WA's immense renewable resources. As seen in Table 21, WA does not have an ambitious renewable energy target.

As a result, there is minimal solar expertise and supply chain in the Pilbara, leading to the 40% markup in the pre-feasbility LCOE analysis. The resulting Pilbara production price of 11 c/kWh is not competitive internationally, but is nevertheless attractive for diesel or gas fuel replacement at remote power stations and such applications are already being implemented.

Some solar infrastructure is emerging in Western Australia with hybrid projects like the 10 MW solar diesel hybrid at the DeGrussa copper mine, the 10 MW Greenough River Solar Farm near Geraldton, and the gas-solar hybrid planned for Onslow. At the time of writing, the Pilbara region's biggest commercial solar farm was the 1 MW at Karratha - the proposed pilot is at least 3,000 times the scale of this.

The Pilbara must first have a local solar industry to be able to offer Indonesia competitive rates on large-scale solar generation. A local industry will build the solar supply chains and become more competitive with experience and scale. Norway's leadership in subsea HVDC transmission and electricity trade is built on a foundation of deep hydroelectric expertise woven with subsea experiences from the north-sea oil platforms. NorNed was built after the three successful Skagerrak interconnectors with Denmark. The Pilbara's own iron ore industry efficiencies come from an industry scaled up over time.

2020	2025	2030	2050
ACT 100%	SA 50%	QLD 50%	NSW 100%
WA 20%	Victoria 40%	NT 50%	

Table 21: State Renewable Energy Targets in Australia

The time to encourage a solar industry is now. A 10 MW Renewable Hydrogen pilot is planned near Karratha for export to Japan. It will use solar energy to desalinate seawater and then extract the hydrogen (Turner, 2015). This project has the potential to expand to GW scale. The Sahara Forest Project will also use solar PV to desalinate seawater for agriculture. This project near Karratha, is supported by the fertiliser company Yara Pilbara Holdings (Yara, 2016).

These projects are a good start, but they alone are not enough to catapult the Pilbara to internationally competitive solar PV generation. The Pilbara has over 1,400 MW installed capacity of gas and diesel ***off grid*** (Green, 2014). A successful model for the solar diesel hybrid has been demonstrated in WA with the DeGrussa Mine, owned by Sandfire resources, and is discussed in Chapter 8.

The opportunity to scale up with solar diesel hybrids has the potential to bring many benefits to all stakeholders, regardless of whether an agreement is reached with Indonesia. These benefits would include:

For the Region:

- Economic diversification
- Building up the solar supply chain and expertise
- Local employment and training opportunities
- Opportunities for Traditional Owners to participate in the Pilbara economy with a non-invasive use of Country.

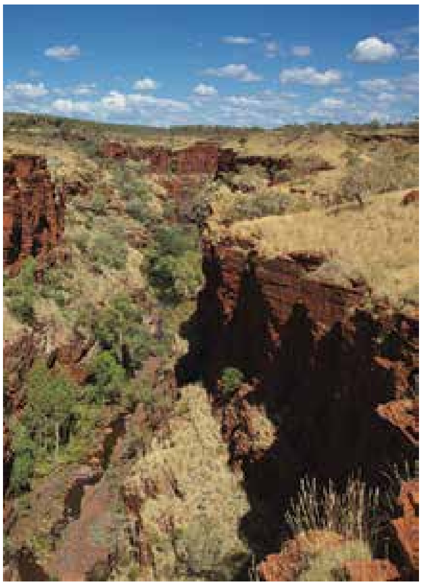
For Mining Companies:

- Reduced generation costs
- Reduced GHG emissions
- Reduced particulate pollution exposure
- Improved Corporate Solar Responsibility profile.

For the Commonweath:

- Reductions in the diesel subsidy
- Reduction in Australian GHG emissions.

Land and land access will be a key issue for a solar industry. Chapter 4 highlighted that not all areas of the Pilbara are suitable for solar PV installation. Chapter 8 discussed the complexity in the many types of land tenure that can be layered over Crown Land - native title rights, pastoral leases, exploration tenements and/or mining leases.



It is important to recognise that there are currently 19 native title claims and determinations in the Pilbara that cover most of the land in the region. Building trust and establishing a positive, respectful and cooperative relationship with Traditional Owners from the outset will bring benefits to both the solar industry and the Traditional Owners of the Pilbara.

Chapter 8 discusses Best Practice Consultation, Free and Prior Informed Consent, and Corporate Social Responsibility. Such practices may be prerequiste for financing of the HVDC interconnector.

Perhaps the most exciting aspect of a solar industry for the Aboriginal communities is that it could lay the foundation for a sustainable, non-invasive use of Country, which does not require the destruction of the environment and cultural heritage.

Traditional Owners in the Pilbara and Kimberley are already expressing commercial interest in the solar industry.

Partnership with Traditional Owners may assist to secure tenure for a solar farm where other forms of tenure already exist. Aboriginal Corporations may apply for and hold tenure on their land to be used for solar farms or transmission lines. Aboriginal Corporations have greater options for applying for tenure to advance the interests of any Aboriginal person or persons. A further advantage is that Aboriginal Corporations may already have relationships with those who hold land in the area, such as pastoralists. If a change in existing tenure is required, a lease applied for by an Aboriginal Corporation may add greater support to the position that the project will provide an economic or social benefit on the State, which is required for the Minister to change existing tenure.

Aboriginal ownership of solar generation assets has the potential to enable Traditional Owners to secure income from their land in a sustainable way. Power purchase agreements negotiated with local industry could enable Traditional Owners greater economic participation in the Pilbara economy. Engaging with Aboriginal people from the outset may bring many benefits to the solar industry, Traditional Owners and the Pilbara at large.

Recommendation One:

Build a locally adapted solar industry

An experienced and competitive solar industry is essential to demonstrate that the Pilbara has the expertise and supply chain to deliver cost-effective, large-scale solar.

Recommended Steps:

1.1 Support Indigenous enterprise through at least two local supply projects with Traditional Owners.

- One mine supply – DeGrussa model.
- One peer trading model – Consumers can purchase directly from Traditional Owners using emerging technologies.

1.2 Work in partnership with Traditional Owners in accordance with best practice processes to develop a draft regional management plan.

1.3 Apply the international best practice consultation model, and develop and apply management plans as an industry protocol.

1.4 Promote other local supply projects at every opportunity across the region – towns, mines, communities.

1.5 Support fast-tracking the diesel solar hybrid transition with local industry.

Adina Newman, *Boab Tree,* 61 x 122cm, glitter on canvas, 2017

Recommendation Two:

Deeper understanding through more research

Due to the wide ranging and complex nature of this subject, additional study is required:

2.1 Land Study - Identify the Land Corridor.

A deeper understanding of land restraints, mining and pastoral tenements, local load, investors suppliers, potential partners, land clearing and native title is required.

2.2 Additional Engineering Study to elaborate key challenges and develop robust costings.

Recommendations Three:

Developing a clean energy partnership with Indonesia

3.1 Consolidate Australian Partnerships: Identify key Australian stakeholders.

3.2 Start and sustain a research dialogue with the relevant actors in Indonesia.

3.3 Support Indonesian research to better understand Indonesian perspectives on the potential interconnection.

3.4 Share knowledge developed from remote solar-diesel hybrid projects and assist Indonesia's efforts towards in the remote electrification of eastern Islands.

10

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11

About the Authors and Contributors

Authors:

Samantha Mella
Project Leader

Samantha Mella has a Bachelor of Communications with High Honours from Clark University in Massachusetts, USA. In 1998, she was invited to join the prestigious Phi Beta Kappa Society, which promotes excellence in the Arts and Sciences in the United States.

Since returning to Australia, Samantha has focussed on communications in science and technology. While working for over seven years in Public Health, Samantha produced several significant bodies of work, and was instrumental in early research on the health impacts of climate change and heatwaves, and developing the first Heatwave Plan for NSW.

Since 2011, Samantha has been tracking High Voltage Direct Current (HVDC) implementation around the world and examining its application in mobilising renewable energy on a large scale. She was the only Australian to attend the Asia Super Grid Forum in Ulaanbaatar, in Mongolia in 2014, and the Asia Super Grid Planning Session at the HVDC 2015 Conference, in Seoul, Republic of Korea.

Samantha's strengths on relationship-building and communication allows her to develop collaborative teams from diverse domains, which is a prerequisite to addressing the major challenges that inspire her to action.

Dr Geoff James
Project Manager

Dr Geoff James is a consultant in clean energy and is respected as a thought leader with over 25 years of multidisciplinary research with government and private-sector clients. His research and consulting interests include integrating renewable energy in power systems, distribution network evolution, international transmission planning, Asian energy market development, and energy storage technology and applications.

Geoff received his PhD in Physics in 1991 contributing to technology for radioastronomy at the University of Tasmania. He then joined CSIRO and until 2002 worked on research and commercial projects in radio antenna engineering. Following a period working on distributed systems with embedded intelligence, Geoff began to apply these ideas to distributed energy.

In 2013 Geoff joined Reposit Power to help commercialise residential energy storage in the Australian market. Since 2015 he has been consulting privately and in 2016 he joined the Institute for Sustainable Futures as a Research Principal. His goal is to speed up regional progress towards clean electrification through a balanced mix of local energy systems and international clean energy trading.

Kylie Chalmers

Native Title - Chapter 8

Kylie Chalmers is a native title lawyer living in the Pilbara. Kylie has worked with Yamatji Marlpa Aboriginal Corporation (YMAC) since 2013 to assist Aboriginal people achieve native title recognition, negotiate agreements, set up appropriate corporate structures and achieve development aspirations.

Previously, Kylie was working in the National Native Title Unit at the Federal Court of Australia, managing the Victorian native title claims and providing advice on native title policy development.

Kylie has experience living and working with indigenous communities in the Pilbara, Canberra, and in Papua New Guinea where she was advising the Department of Justice and Attorney General on national legislative and policy development and practical implementation procedures.

Kylie completed her Bachelor of Laws (LLB) and Bachelor of Science (B.Sc.) in 2008 with the Australian National University (ANU). Kylie was admitted to practice in 2009 in the ACT Supreme Court, and joined the Register of Practitioners in the High Court of Australia in 2011. In June 2017, she will achieve her Masters of Laws (LLM) with ANU.

Contributors:

Jonathan F. Thomas
Regional Economic Impact - Chapter 7

Jonathan Thomas holds Bachelor's and Masters' degrees in Economics and Statistics from Oxford University. After many years of service in CSIRO Divisions of Land and Water Management, he became Senior Principal Research Scientist and Assistant Chief of Division. He established the Resource Economics Unit in 1997.

His specialities include regional economic modelling, benefit-cost analysis and natural resources. He has authored a total of 138 publications, including 3 books, 15 refereed journal papers, 32 conference papers and 88 consultancy reports.

Dr Xunpeng Shi
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Dr Xunpeng (Roc) Shi is a Principal Research Fellow at the Australia-China Relations Institute, University of Technology Sydney and an Adjunct Senior Research Fellow at the Energy Studies Institute (ESI), National University of Singapore. His areas of expertise include energy market integration and connectivity and other energy economics and policy issues with a regional focus of ASEAN, and Northeast Asia, and the Chinese economy.

Dr Ucok Siagian
Indonesian Report - Chapter 5

Dr Ucok Siagian is a Professor at the Centre for Research on Energy Policy, Institut Teknologi Bandung (ITB), one of Indonesia's top two universities. Ucok is an alumnus of the Chemical Engineering Department of ITB, and received his PhD in Petroleum and Chemical Engineering from the New Mexico Institute of Mining and Technology in 2001. He is well-known in Australia having been part of several collaborative teams researching regional energy issues, particularly those relating to decarbonisation.

Dr Retno Gumilang Dewi
Indonesian Report - Chapter 5

Dr Retno Gumilang (Gelang) Dewi is Chairman of the Center for Research on Energy Policy, Institut Teknologi Bandung, and received her PhD in Chemical Engineering from there in 2004. She also received a Masters' in Environmental Engineering Science from the University of New South Wales. She is a key researcher in the Australia Indonesia Centre. She co-authored a significant case study of pathways for decarbonising Indonesia's electricity sector whilst simultaneously addressing widespread energy access with Keith Baldwin (ANU). They are now preparing Indonesian energy technology and resource assessments.