AN EVALUATION OF THE PROSPECTS FOR INTERCONNECTIONS AMONG THE BORNEO AND MINDANAO POWER SYSTEMS

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Final Report

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Contents

Abbreviations

ADB	Asian Development Bank
AIMS	ASEAN Interconnection Master Plan Study – AIMS II is the most recent study
APG	ASEAN Power Grid
ASEAN	Association of South Eastern Asian Nations
APEC	Asian Pacific Economic Cooperation
ASCOPE-TAGP	ASEAN Council on Petroleum - Trans ASEAN Gas Pipeline Project
BIG	Baden Informasi Geospatial (Indonesian GIS data base centre)
BPS	Baden Pusat Statistic
BIMP-EAGA	Brunei Darussalam-Indonesia-Malaysia-Philippines East ASEAN Growth Area
CSP	Concentrating Solar Power Plant
DES/BPC	Dept of Electrical Services & Berakas Power Company Private Limited, Brunei
DOE –DDP	Department of Energy (Philippines) – Distribution Development Plan
GTZ	German Agency for Technical Co-operation
HAPUA	Heads of ASEAN Power Utilities/Authorities
IAEA	International Atomic Energy Agency
IPP	Independent Power Producer
JICA	Japan International Cooperative Agency
Kalbar	Indonesian Province of Kalimantan Barat (West Kalimantan)
Kaltim	Indonesian Province of Kalimantan Timur (East Kalimantan)
Kalut	Indonesian Province of Kalimantan Utara (North Kalimantan)
Kalsel	Indonesian Province of Kalimantan Selatan (South Kalimantan)
Kalteng	Indonesian Province of Kalimantan Tengah (Central Kalimantan)
MEC	Malaysia Energy Commission (Regulator for TNLB and SESB)
NGCP	National Grid Corporation of The Philippines
OECD	Organization for Economic Cooperation and Development
PDP	Power Development Plan
PLN	PT Perusahaan Listrik Negara (Persero - Indonesian state electricity company)
Pusat	Head office (Indonesian), e.g. “PLN Pusat,” BPS etc.
PPA	Power Purchase Agreement or PEA Power Exchange Agreement
RUKN	Annual Energy Plan of the Indonesian Government (*Rencana Umum Ketenagalistrikan* Nasional)
RUPTL	PLN’s Annual Power Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SCORE	Sarawak Corridor of Renewable Energy
SESCO	Sarawak Energy Berhad
SESB	Sabah Electricity Sdn. Berhad

SCADA	System Control and Data Acquisition(facilities used to manage power system operation)
SPC	Special Purpose Company (established to manage Joint Venture Operation)
Sulut	Indonesian Provinces of North Sulawesi, Gorontalo and part of Central Sulwesi
TNB	Tenaga Nasional Berhad – Peninsular Malaysia Power Utility
TOR	Terms of Reference
WASP	Wien Automatic System Planning. IAEA software freely available to utilities
Wilayah	PLN Branch Office (e.g. PLN Kalbar)

Common Technical and Financial Acronyms used in this Report

bay	A substation switch-bay comprising circuit breakers, protection equipment and steelworks
CBM	Coal Bed Methane
GHG	Greenhouse Gases
CO_2	Carbon Dioxide
SO_2	Sulfur Dioxide
NO_x	Nitric Oxides
MV	Medium Voltage – PLN 20kV; Malaysia 11kV
HV	High Voltage – PLN 70kV or 150kV; Malaysia 132kV and 275kV
EIRR	Economic Internal Rate of Return
d/c	Double circuit (as opposed to s/c single circuit)
EHV	Extra High Voltage – 500kV
EFB	Empty fruit bunch – measurement of waste suitable for biomass production
FACTS	Flexible Alternating Current Transmission System
FIRR	Financial Internal Rate of Return
GIS	Geographic Information System
HVDC	High Voltage Direct Current (VSC [Voltage Source Converter])
kV	Thousand Volts
LRMC	Long Run Marginal Cost
OHTL	Overhead Transmission Line
O&M	Operations and Maintenance
FIRR	Financial Internal Rate of Return
NPV	Net Present Value (used to bring future cash flows to a value today)
POME	Palm Oil Mill Effluent (used for biomass energy production)
SIL	Surge Impedance Loading (characteristic of transmission line design)
WACC	Weighted Average Cost of Capital

Currency

US$k	United States Dollar (k thousands) or US$m (million)
MYR	Malaysian Ringgit (assumed 3 MYR to 1 US$)
Rp	Indonesia Rupiah (assumed 11,000 Rp to 1 US$)

Physical Measurement Units and their Application

\$/kW	Measure of capital cost of power plant
\$/km	Average cost of a km of transmission line or submarine cable
\$/bay	Average of a substation bay
c/kWh	Cost in U.S. cents for a kWh of electrical energy
\$/bbl	Cost per barrel of fuel oil
\$/tonne	Cost per tonne of Coal
\$/GJ	Cost per unit of energy produced in Giga Joules
Cal/gm	Calories per gram (used herein to compare heat content of coal)
g/kWh	Grams per kWh (measure of CO_2 emission factor)
km	Kilometers; km^2 unit of area
kWh/m^2	Used to measure insolation – i.e. daily average solar radiation
Hz	Power frequency in Hertz (cycles per second)
MT/yr	Millions of Tonnes per Year
kW	Kilowatts
MW	Megawatt – also MWe electricity and MWth for Heat
GWh	Giga Watt (GW) hours
MVA	Mega Volt Amps – measurement of both active (MW) and reactive power (MVAr)
mtpa	Metric Tonnes per Anum

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Report Summary and Recommendations

Background

By 2030, an ambitious concept implicitly supported by the Heads of ASEAN Power Utilities & Authorities ("HAPUA") envisions the island of Borneo[1] as a major energy resource center within a regionally interconnected power grid. Following the successful completion of transmission interconnections in other regional power systems of the ASEAN region, it is timely to examine how Borneo's respective power systems[2,3] could be interconnected to enable interisland power trading between utilities in Malaysia, Indonesia, and Brunei, as well as offshore power trading with power system utilities in neighboring island grids. These would include Peninsular Malaysia, Mindanao and Luzon in the Philippines, and North Sulawesi and Java in Indonesia if deemed appropriate by Indonesia's main utility PT PLN.

This report examines current power development plans within Borneo to recommend ways in which various utility transmission network plans might be adapted to increase power trading, while also mutually benefitting the country, state or province through which the lines will pass. The report is a high level overview that includes general recommendations for addressing existing technical and commercial arrangements for the development of optimum power trading platforms. It also identifies priority transmission interconnection projects that can be considered for IFI financing.

This study has drawn on information and technical papers that are publically available, largely on the internet, together with more limited information received during onsite discussions with the respective utilities and regulatory authorities[4]. It has also drawn on reports prepared by HAPUA subcommittees relating to the harmonization of standards, interconnection priorities and commercial considerations. Building on the work done under the AIMS II studies[5] , this study identifies potential interconnection plans and recommends the scope for further investigation, including more detailed studies of potential subprojects. It is hoped that these projects may be considered for future funding by the Asian Development Bank (ADB) or other international financial institutions (IFIs) in support of ASEAN's wider goals.

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1 Borneo comprises two Malaysian states (Sarawak and Sabah), Brunei Darussalam, and the Indonesian territory of Kalimantan.

2 These systems are each operated separately by power companies in the Malaysian States of Sarawak (SESCO) and Sabah (SESB), the nation of Brunei (EPS), and by the branch offices of Indonesia's state-owned power company (PLN) located in each of the five Indonesian provinces of Kalimantan/Borneo.

3 To allow PLN's respective regional systems to be easily identified, this report uses the Indonesian acronym KAL (for Kalimantan), followed by the region's regional ID, i.e.: BAR (Barat = West); SEL (Selatan = South); TENG (Tengah = Central); TIM (Timur=East); UT (Utara=North). Thus the main PLN supply areas are Kalbar (West Kalimantan), Kalsel (South Kalimantan), Kalteng (Central Kalimantan), Kaltim (East Kalimantan), and Kalut (North Kalimantan). Following interconnection, the aggregated areas are identified as Kalselteng; Kalseltengtim, etc.

4 In addition to site visits during July 2014, preliminary findings were discussed by the ADB with BIMP/EAGA officials in Pelawan on 6/8/14, and the Draft Report was discussed by the Team Leader in a Workshop in Kuching on 3/11/14

5 The AIMs II Reports, completed in 2010 provide a comprehensive analysis of various ASEAN interconnection projects including some valuable insights into the possibilities of interconnectsions between Borneo and its neighbouring countries.

XI

Resource Use and Potential in Borneo

Politically divided among Indonesia, Malaysia, and Brunei, Borneo is ASEAN's largest single island and contains significant resources for electricity production, primarily hydropower (mostly Sarawak in Malaysia and North Kalimantan in Indonesia) and coal and gas (mostly East Kalimantan, Brunei and Sabah in Malaysia). These resources could eventually be complimented by the island's considerable renewable resource potential in terms of biomass, geothermal and solar (especially in Sabah), wind and possibly marine energy from the Makassar Strait.

Due largely to the long distances between resources, major urban demand centers and rural communities on Borneo, many of the island's existing power generation sources particulary in remote areas utilize diesel power generation facilities. Utilities on Borneo thus face conflicting priorities in trying to expand their transmission and distribution networks, per their mandate to help meet government targets for rural electrification, while also seeking to reduce their dependency on imported diesel fuel or small inefficient coal fired plants. In this context, building transmission interconnections would enable inter-Borneo regional power markets to grow while facilitating the construction of larger, more efficient generation facilities that can be designed to modern and environmentally acceptable standards.

Unlike hydropower, any decision to build large coal- and gas-fired power plants in Borneo must be proven economically competitive with the alternative of transporting fossil fuel to large power plants in offshore markets. In this respect, power markets in the Philippines, Java and Peninsular Malaysia all incorporate large efficient thermal generation plants that run on imported coal (much of which comes from Kalimantan) or gas that may well be supplied through a parallel network of ASEAN gas pipelines.

In principle, a mine-mouth coal fired power station[6] in Borneo, located where there is a substantial indigenous coal resource, should be competitive with plants built off shore and importing coal. A mine-mouth plant should be able to obtain its fuel for substantially less than the international price of imported coal. A mine-mouth plant would also tend to have better access to the land and often the cooling water it needs. On the other hand, a sophisticated high temperature/pressure coal-fired power station built in Borneo (i.e. with unit sizes greater than 250MW) would require skilled operational staff who may be difficult to recruit in remote locations. Furthermore, to ensure power system security and reliability, larger generator unit sizes would need to supply into a diverse power system with significant generation reserve capacity to minimize any disruptions from transmission faults or rapid changes in demand.

Coordinated by the ASEAN Council on Petroleum (ASCOPE), a plan exists to develop an ASEAN regional gas grid by 2020 by linking the existing and planned gas pipeline networks of ASEAN's member states. This proposed co-development of an ASEAN interconnected gas pipeline system also poses a challenge for potential electricity exporters hoping to use combined-cycle plants supplied from domestic gas fields. The ASCOPE-TAGP (Trans ASEAN Gas Pipeline) Masterplan, updated in 2012, involves the construction of 4,500 km of pipelines worth $7 billion. If these projects go ahead, the pipelines would be located mainly underseas, with some passing overland through Borneo.

Besides the potential to exploit well-established renewable resources including biomass, wind and geothermal, it is also important to recognize the significant technological developments occuring for other benign sources of renewable energy. For example, solar power is an important source of energy that is rapidly becoming cost competitive with hydro and coal.[7] In Borneo's situation, where there is a desire to conserve gas for exports, opportunities may arise in the development of grid-scale solar PV or Concentrating Solar Plant (CSP) power stations. These can generate power from sunlight during the day and use the same boiler-turbine facilities by burning gas or coal at night. Other emerging opportunities also exist to take advantage of the enormous tidal flows that exist in the Strait of Makassar, to generate marine-powered energy.[8]

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[6] A mine-mouth plant is a coal burning electric-generating plant that is built near a coal mine.

[7] See http://www.solarnovus.com/record-breaking-growth-in-global-solar-industry_N8001.html#atop

[8] See http://www.minesto.com/deepgreentechnology/

Current Power Development Planning

Each power utility in Borneo has a Power Development Plan (PDP) for its own particular supply area. They generally do not prioritize export or import opportunities outside of their borders. The most detailed PDPs are provided by PLN in its annually updated ten-year development plan, the *Rencana Usaha Penyediaan Tenaga Listrik* (RUPTL). PLN also makes available various other studies about hydro, coal and gas resources in Kalimantan. Reference information for these is given in the main body of the report and in Annex 2.

PDPs and associated technical reports from Sarawak and Sabah, the two Malaysian states on Borneo, are not so readily available – perhaps because they are used in commercial negotiations with industrial developers. Data can, however, be pieced together from the *Statistical Data and Electricity Supply Industries Energy Outlook* published by Malaysia's Energy Commission. It has also been possible to obtain a limited amount of supplementary information for Sarawak from onsite discussions and from recent technical papers that have analyzed various options for developing generation and transmission systems. Likewise, resource planning issues for Sabah were described in a recent study of renewable energy potential as well as in various technical papers. Plans to interconnect the two states through Brunei were provided to the ADB at a recent HAPUA conference in Palawan, Philippines.

Like the Malaysian states, plans for Brunei are difficult to obtain. This is a general problem that should be addressed by the respective national regulators in the interest of promoting greater transparency by these large monopoly power utilities. On the other hand, power plans for the Philippines, where the power market is well regulated and transparent, are quite detailed – both in the form of the Transmission Development Plan (that includes details of generation plans) released by the National Grid Corporation of the Philippines (NGCP) and the Department of Energy's separate Distribution Development Plan.

Environmental and Social Considerations

Several significant issues will need to be addressed in developing Borneo's resources and building power evacuation facilities in environmentally sustainable ways. The northern regions of Borneo in particular are rugged and mountainous with pristine native forests, and contain a diverse population of indigenous peoples living in remote areas plus an enormous variety of wildlife. Proposals to exploit natural resources must thus carefully consider the impact of any development on Borneo's unique social and environmental conditions.

Although Sarawak has developed hydropower projects in Bakun and Murum, these have taken many years to implement and suffered cost overruns, delays and international criticism. Likewise, Sabah has also recently faced criticism in attempting to develop coal-fired generation. As a consequence, the Sabah utility company SESB had to forestall plans for coal development and focus its efforts on other resources such as gas, solar power, biomass and geothermal power.

Mining and IPP developers in Kalimantan may also face similar issues in attempting to build large mine-mouth coal stations and associated transmission lines that cut through the island's pristine forests. They could make PLN vulnerable to delays and cost overruns for its transmission lines, particularly if its plans involve financing from IFIs which usually require strict adherence to rigorous environmental and safeguard standards. To mitigate such risks, the deployment of advanced, commercially-available coal-fired generation technologies should be considered hand-in-hand with innovations in clean coal technologies. Not only should these larger and more efficient plants be more acceptable to the international community, but also their development should result in lower overall cost generation expansion plans.

Likewise, building new transmission lines – particularly through densely forested areas – will not be without their associated problems. In many cases, no roads exist where the lines are routed and access to tower sites could prove very difficult during both construction and operation. Temporary access roads are inevitably used to provide access to illegal loggers, and tree clearing for large transmission wayleaves could be detrimental to indigenous species.

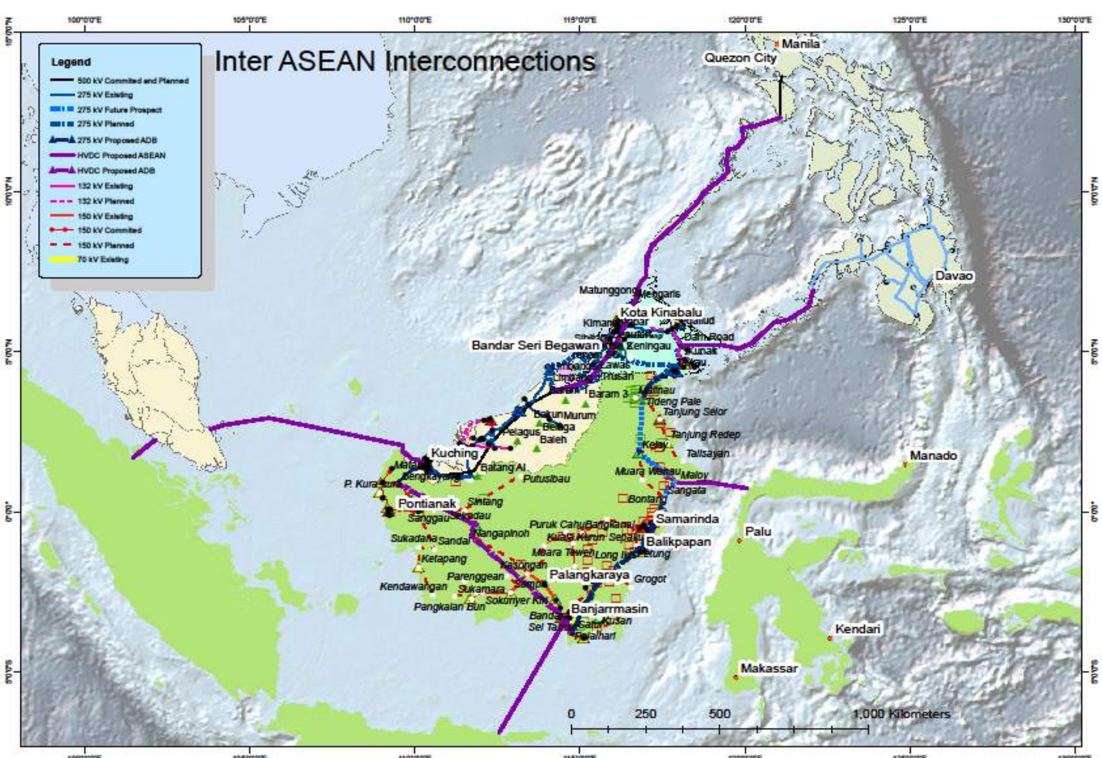
Developing an Inter-Borneo Grid

Under an ongoing construction project funded by ADB, PLN Kalbar and Sarawak's power utility SESCO are building a 275kV power system interconnection for service by 2015. The project is based on a Power Exchange Agreement (PEA) designed with legally enforceable technical and commercial conditions, one benefit of which is the protection of both parties from political interference. The PEA has been designed to help build trust between both parties and to enable more flexible terms to be reached at the end of the first five-year period. In this way, the PLN Kalbar-SESCO project is expected to catalyze further interconnections among Borneo's power utilities and eventually lead to a fully interconnected transmission grid for Borneo Island. To this end, PLN is indeed planning to interconnect its five provincial 150kV power systems into one Kalimantan grid. There are also ongoing discussions between Sarawak, Brunei and Sabah, and between PLN Kalut and Sabah, to explore ways in which their HV transmission systems can also be interconnected.

A key priority for the utilities in Borneo is to design individual transmission investments so that they can eventually be upgraded at minimum cost and integrated into an HV grid transmission network. This will allow generating capacity to be aggregated in the utilities' service areas, as required for a least cost generation expansion plan, and enable the respective utilities to better position themselves for export when the time is right. In this context, it is not possible for PLN's current plans for 150kV interconnections among regions of Kalimantan to be appropriate for power aggregation and trading with neighboring countries. It is also unlikely that the concept of building many small generation plants is indeed the least cost power system development for the region.

This study has identified twelve possible interconnection links (shown in Figure 1), together with budget costs and indicative minimum wheeling charges based on a preliminary assessment. The feasibility of such connections would need to be investigated in more detail before they can be included in a future strategy for Borneo development. Seven possible links are by Overhead Transmission Lines (OHTL) within Borneo and five are by submarine cables to neighboring island grids. Although the proposed inter-Borneo links could each be conceived as part of a future backbone grid, a decision to proceed with any one link would require much more detailed investigation. Moreover

Figure 1 Potential Interconnections within Borneo and Offshore



in each situation there would need to be a driver, usually in the form of a plan to build a new power plant or a commitment to buy bulk power, before an interconnection would proceed to an investment stgae. Notably in this instance the two cross-border interconnection projects in Borneo (Sarawak-Kalbar and Sarawak-Brunei-Sabh) have emerged from the availability of surplus hydropower in Sarawak. It should also be easier to proceed with inter-Borneo power system interconnections because they are less costly (typically $300,000 per kilometer) than off-shore submarine interconnections (typically US$1-3 million per kilometer), and good relationships exist between neighboring states.

Technical Issues

Some of the proposed internal transmission interconnections, such as between PLN Kalbar and PLN Kalsel, would be extremely long (850 km) and thus impractical using PLN's standard 150kV transmission service. This is because the capacity of any long HVAC transmission line is limited by its natural "surge impedance" – a characteristic of transmission line design determined primarily by voltage, conductor spacing and height. In order to function effectively, long HVAC lines will thus generally need to use higher voltages (e.g. 275kV or 500kV) and may include additional investments in flexible alternating current transmission systems (FACTS) equipment or other devices. For the PLN's Kalbar-Kalsel interconnection mentioned above, it may be preferable to change the transmission technology by replacing (or supplementing) PLN's planned 150kV interconnection proposals with an HVDC-VSC monopole link.

The proposal herein to build a 275kV HVAC backbone grid (initially operated at 150kV) along the east coastal region of Kalimantan will facilitate the use of a larger, more efficient generating plant. As such it would be an integral step of the least cost development plan for the coastal region of Kalimantan. An example of this staged approach is Sarawak's planned 500kV backbone line, which will initially be operated at 275kV to forestall the costs of having to build the necessary 500/275kV substations before these are needed.

In any case, the introduction of HVDC technology will be an important component of the various proposals for long interconnections. HVDC d/c OHTLs require only two conductors and are generally about 60% cheaper to build than the equivalent HVAC d/c OLTC lines (which have six conductors). Accordingly HVDC lines have a smaller right-of-way requirement compared with HVAC lines, a factor of considerable importance in traversing Borneo's protected forest areas. HVDC transmission do require more expensive terminal converter equipment, but for transmission distances greater than 400km, HVDC lines plus their associated converter terminals are still generally cheaper to build. HVDC also offers many other advantages: it can be used to stabiliize parallel or separate HVAC systems, as well as to facilitate the interconnection of unsynchronized HVAC systems (such as exist between the Mindanao 60Hz system and the Borneo 50Hz systems). HVDC systems can also be designed with more flexibility than HVAC systems so they can be upgraded over time from monopolar to bipolar systems as power transfer requirements increase.

Submarine cable interconnections for route lengths over 50 kilometers also require the use of HVDC because of the natural limitations of HVAC cables. However submarine links are often risky because cables are hard to inspect and are prone to damage by fishing equipment. Thus for situations where a utility is dependent on a submarine link that has not been properly installed on the sea bed, prolonged repairs to faulty cables can cause serious operating constraints. To mitigate these risks, such links are usually installed with spare cables, and cable routes are designed to use overland sections wherever possible.

Economic and Financial Issues

It is not possible within the scope of this study to perform detailed analysis of Economic Internal Rate of Return (EIRR) and Financial Internal Rate of Return (FIRR) for any of the suggested transmission interconnections. There are too many variables relating to possible complementary generation and transmission investments in the short term, any of which could change such a study's basis for justification over time. Moreover, during the lifetime of a transmission line (typically 45-60 years), its function in the power system is likely to change. For example, the Sarawak-Kalbar 275kV will initially transport lower cost hydro power from north to south, but power flow may well travel in the reverse direction when PLN has surplus coal-fired power. Besides transporting bulk power, the economic benefits of transmission interconnections usually include other less easily quantifiable aspects of power systems operations – for example, reducing generation reserve capacity and losses, or mitigating operational problems (e.g. increasing stability and avoiding voltage collapse).

A major step on the road towards regional power trade will be achieved by addressing the commercial issues (often highly politicized) of power trading between two utilities, even more so when power is wheeled through a third party's transmission network. This issue will need to be addressed if PLN Kalteng wishes to trade power with Sabah utility company SESB using SESCO's 500kV network, or if SESCO and PLN Kaltim wish to trade with Mindanao through SESB's 275kV network. Plans for power trade with Mindanao or Luzon also need to consider the way in which the Philippines' power market is operated, wherein it may be difficult to arrange financing for the construction of a transmission link without a long-term Power Purchase Agreement (PPA).

Deciding to proceed with cross-border power transfer is also complicated by the allocation of costs for an interconnection project. The responsibility for project costs normally lies within national boundaries and, in the case of proposed connections with the Philippines, most of these costs will be allocated to either to Mindanao or Luzon authorities. In such situations, a Special Purpose Company (SPC) may need to be established to manage cross-border interconnection construction and operations.

Sequencing Transmission Investments

It is also unrealistic to define an optimum sequence for building each of the proposed projects, largely because of the many conflicting national interests which lie outside of the control of the respective power system owners and operators. Most importantly, each country normally desires energy self-sufficiency regardless of the economic consequences for others in the region—a situation illustrated by the Malaysian government's desire to build the 3,000 MW, 1,500 km Sarawak-Peninsular Malaysia HVDC interconnection. This major national infrastructure project, incorporating what would be the world's longest submarine cable (800 km) with all its attendant technical and operational risks, has proceeded haltingly for twenty years. It has undergone various design reviews and was even made ready for tendering in 2006 before being cancelled in 2010. If a final decision is made to proceed with the interconnection with Peninsular Malaysia, it would impact the availability and cost of sales to Sarawak's huge industrial corridor development and the viability of power exports to other inter-Borneo states. An analogous situation would be if the Indonesian government decided to build a large coal-fired power plant but use it for export only to Java or North Sulawesi.

Other complicating factors will also affect decisions to invest in interconnections. For example, the Philippines' competitive power market may be perceived as too difficult by a potential IPP investor wishing to finance and build a power plant in Borneo along with expensive submarine cable interconnections. Given the risks of power delivery using long lines, the IPP would surely be more comforted by a sovereign or equivalent guarantee of recovering its money over the life of the station. Moreover, to further complicate the IPP's contractual arrangements, a dedicated IPP in Kalimantan and Sarawak designed just to supply the Philippine market would also need transmission rights through Sabah.

Most of the proposed interconnection links are conditional on other significant investments being made, either for new generation or other extensions to existing transmission networks. This was the case for the Sarawak-Kalbar interconnection which was proposed because of the availability of surplus power in Sarawak. Likewise, the early implementation of the proposed 275kV interconnections between Sarawak, Brunei and Sabah would later improve the prospects for future Kaltim and Kalut interconnections.

In terms of investment sequencing, the relatively short ADB-funded Sarawak-Kalbar 275kV interconnection can now be conceived as an integral part of a future inter-Borneo grid. Given that the existing PEA with Sarawak has provisions for Kalbar to import up to 600 MW, PLN has an opportunity to expand the link's service area by interconnecting Kalbar to Kalsel. This would supply sufficient power to Kalsel, giving more time to PLN to plan and build a suitably large (4 x 250 MW) mine-mouth coal-fired generating capability near Banjarmasin that would be able to supply into a larger market. Moreover, the generation supply area would expand even further if PLN simultaneously built a 275kV line from Banjarmasin in Kalsel to Bontang in Kaltim (instead of the proposed 150kV connections built section by section). This would enable PLN to develop a second or third even larger mine-mouth station near Balikpapan in Kaltim using the latest clean coal technologies to improve efficiency and minimize environmental impact.

Proposed Interconnection of Borneo with Mindanao

As required by the TOR, this report gives particular attention to the prospect of supplying Borneo's energy resources to the Philippines, in particular to the island of Mindanao which is currently experiencing serious supply shortfalls to its population of 21 million. In various HAPUA documents, two Borneo-Philippines transmission routes have been suggested: (i) an HVDC 800km line to Luzon via Palawan; and (ii) an HVDC 400km line directly to Zamboanga in Mindanao. A third connection could possibly be made from Manado (North Sulawesi) 400km to Mindanao. However, this would require PLN to build another 400km HVDC line from Kalimantan across the Sulawesi Sea and through the northern provinces of Sulawesi to reach Manado – a daunting project to consider at this stage of PLN's development of the Sulut power systems.

Although the power system in Mindanao is currently isolated from the Philippines' main electricity demand centers in Visayas and Luzon, there is a plan (in abeyance for at least 20 years) to interconnect Mindanao with the Philippines HVDC/HVAC grid at Leyte to enable the transfer of baseload geothermal power into the Mindanao network. This would naturally reduce geothermal offtake to the Visayas and Luzon region, where power shortages are also a problem. It would thus be logical to supply Mindanao directly from Borneo, in effect displacing the power that would otherwise be drawn from the larger Philippine grid.

However, it is also recognized that Mindanao has a competitive generation market and has already received applications from prospective IPPs to build about 2,000 MW of coal-fired generation over the next five years.[9] Considering the risks involved for prospective offshore power generation developers in Sarawak or Kalimantan, they would need long term commitments to fund both generation and transmission facilities along with marine cable and OHTL transmission in Mindanao. Developers would also require special dispensation from their respective Governments to mitigate their market risks if they were to consider making such investments.

Projects for Consideration by ADB and International Financing Institutions

One outcome of this study is to identify projects within the framework of promoting the highest priority inter-Borneo power system interconnections that might be suitable for financing by ADB or other international financing institutions (IFIs). In this context it is expected that the cross-border interconnections between Sarawak-Brunei-Sabah are likely to proceed within the next 1–2 years and be financed by the parties involved. Thus to maintain the momentum of Borneo power system integration, it would be appropriate to firstly assign the next three priority interconnection projects within Kalimantan, and thereafter to determine what other lines should be prioritized later on.

[9] San Miguel Corp. has started the construction of 150 MW x 2 to be commissioned by 2016 and plans additional 300 MW x 1 by 2018 and 300 MW x 2 by 2020

Two of the projects proposed for Kalimantan are designed to reduce the cost of PLN's generation expansion plan achieved by aggregating demand in Kalimantan and enabling the construction of larger, more efficient coal-fired power stations. These two projects can be shown to reduce the long-run marginal cost of generation by about 5c/kWh (Annex 9) and described as follows:

The **PLN-SESCO Extension Project** would introduce the use of HVDC technology to utilize more of the power generation available through the new 275kV line from Sarawak. This would support PLN's growth in Kalbar and Kalsel until a large coal-fired power station can be built near Banjarmasin in Kalsel. The **275kV Backbone Transmission Project** is also designed to support the development of more efficient mine-mouth coal generation. It would do so by facilitating larger load transfers between Banjarmasin and Bontang, thereby aggregating demand growth in the four main load centers, including Balikpapan and Samarinda. Prelimary analysis herein shows that based on current planning using a large number of small generating units, the LRMC would be about 16c/kWh for Kalbar and about 17c/kWh for Kalseltengtimut. However by building a sufficiently strong HV transmission backbone system to enable PLN to use a larger, more efficient coal-fired plant, the LRMC for the combined power system would fall to about 13c/kWh. These two projects would require PLN to identify optimal coal resource locations for a mine-mouth development program with minimal environmental impact.

A third **PLN Kalut-Sabah Interconnection project** would be designed to support PLN's ongoing discussions with Sabah to develop either a coal-fired or hydropower IPP in Kalut to supply the East Sabah industrial region. The project design takes into account Sabah utility SESB's plans to build a base-load geothermal plant (potential up to 100 MW) near the border with Kalut, as well as a run-of-river plant in central Sabah. The project would support the concept of Sabah and Kaltimut co-developing a generation expansion plan to benefit both Malaysia and Indonesia. In Sabah's case, clear economic incentive exists to reduce diesel costs and the 50% gas subsidy; while in PLN's case, an opportunity exists to reduce the cost of diesel generation by building larger and more efficient coal-fired or hydro plants to serve a larger combined load center. Completion of this project would subsequently justify extending the 275kV line from Bontang to the Kalut IPP.

Conclusions and Recommendations for Further Investigations

It is apparent that interconnections with Borneo's off-shore neighbours should not proceed until plans for Borneo's internal transmission interconnections are well established. Borneo power utilities need time to devise a coordinated transmission network expansion strategy and gain invaluable experience in operational and commercial power exchange. In this respect Sarawak's intiatives to build hydropower have been strong drivers for expanding the other regional transmission networks and providing the momentum for further the integration of the Borneo power systems. In particular it is evident that the extension of the new ADB-funded 275kV line from Sarawak to Kalbar provides a unique opportunity for PLN to link the larger Sarawak-Kalbar power system to the potentially large East Kalimantan networks. This would give PLN an opportunity to finalize a Masterplan for the optimum development of its coal and gas resources in such a way they could complement the hydro developments in Sarawak.

An objective of this report has been to define the scope of further studies needed to formulate and plan strategy for greater Borneo interconnection. The following studies have emerged as reasonable next steps to take.

Study 1: Power Development Master-Plan for Kalimantan. To strengthen its case for funding from ADB or other IFIs, PLN needs to review its strategy for Kalimantan and determine the least cost expansion plan for the island in terms of generation, transmission and distribution. This should be done by comparing two approaches based on: (i) the concept of using high capacity HVDC and 275kV transmission interconnections to aggregate demand, and (ii) incremental expansion as detailed in the RUPTL document. In this instance, the RUPTL plan proposes the gradual expansion of the 150kV system using small distributed generating stations and 150/20kV substations scattered throughout the network. An alternative plan based on aggregating demand with backbone interconnections could minimize cost and environmental impact. This would be achieved by developing fewer but larger-scale, more efficient mine-mouth coal generation plants (supported by appropriate gas-fired peaking and hydropower plants where possible). By comparing an alternative plan based on load aggregation with the base case plan (i.e. RUPTL 2013-22), it should be possible to determine the optimal way forward.

Such a study would also need to review load growth in the regions between Kaltim, Kalteng and Kalbar to verify whether so many intermediate 150/20kV substations are really required to meet PLN's targets for rural electrification. The WASP-type[10] generation expansion study required to study generation alternatives would also need to include technical power system studies (load flow, fault and stability analysis) to determine the optimum generation unit sizes and reserve requirements. The latter work would be required to ensure system stability after a major disturbance when various combinations of generation sources (and transmission links) are in operation. The study should also review options to increase the proportion of non-hydro renewables in the electricity generation system, particularly solar power generation within major load centers or at other locations where large solar-powered farms may be appropriate (e.g. in cleared areas that have not been particularly productive).

Study 2: Enclave Project for Kalut Exports to Sabah. The proposal for PLN to invest in a large hydro or coal fired station in Kalut designed primarily for export to West Sabah needs to be examined more closely, particularly in terms of available alternatives for Sabah and environmental impact in Kalut. For Sabah, the project should be compared with the option to develop various renewable resources including geothermal, biomass and solar power, as identified in a 2010 study by the University of California, Berkeley.[11]

It is assumed that an IPP developer would be invited to investigate options to enable financing for the development of the recommended 300-600 MW hydro or coal-fired generation project on the basis of a long-term PPA with Sabah. The preferred 275KV interconnection arrangement would be designed to ensure that the transmission line eventually becomes part of a greater Borneo grid, in similar arrangement to that reached between Sarawak and Kalbar. In other words, PLN would build and operate the 275kV interconnection to the border, and likewise SESB would undertake responsibility for 275kV interconnections in West Sabah.

Study 3: PLN exports power to North Sulawesi and East Java. The export of mine-mouth, coal-fired power from Kalimantan to Java would avoid the need to locate a suitable site near Surabaya for building another large thermal power station to serve the growing demand in this highly populated industrial load center. This approach would also enable Kalimantan to export power to North Sulawesi to minimize the need for small coal-fired generation near Manado, and to supplement geothermal power planned for North Sulawesi. However, while the economics of displaced generation is relatively straightforward, it will be necessary to assess the technical feasibility of interconnection using long submarine cables. Accordingly, this study should include preliminary investigations of potential cable routes to determine potential problems, particularly with regard to high current flows through the Strait of Makassar and long distances across the Java Sea. This study should also investigate the potential for exploiting marine power in the Strait of Makassar.

Study 4: Options for Developing a Coordinated Borneo Export Strategy. The export of electricity to offshore demand centers will require a coordinated strategy by all the Borneo utilities to develop the regional electricity trading designed to compete with the export of coal and gas in the same markets. The circumstances for export to Mindanao and/or Luzon will need to address complex institutional and financing issues to enable the participation of imports into the competitive Philippine power market, as well as to protect project financiers over the life of the project.

The export of up to 600 MW to Mindanao is likely to be initially sourced in Sarawak or Kalut but wheeled through Sabah 275kV systems. Exporting power from Sarawak to Luzon is expected on a much larger scale (i.e no more than 10% of demand in Luzon or about 2,000 MW) to justify the high cost of interconnection. The study will need to consider the possibility of having sufficient generation to cater for major exports to Peninsular Malaysia. Such a decision is likely to be politically driven, but if the project proceeds, there may be important effects on the viability of power for other power trading opportunities.

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[10] WASP = Wien Automatic System Planning. Standard software freely available to utilities by the International Atomic Energy Agency. See: http://www.energyplan.eu/wasp/ Although WASP studies assume a common bus for all generators it is possible to model interconnections by forcing the use of power plants into planned sequences of generation expansion.

[11] "Clean Energy Options for Sabah: an analysis of resource availability and cost," D Kammen et al, University of California, Berkeley, Renewable and Appropriate Energy Laboratory, School of Law, Energy Resources group, Berkeley Goldman School of Public Policy and Harvard College (2010).

Notably, the high cost of an HVDC submarine connection and onward overland HVDC line to the main Philippine load centers will lie mostly in Philippine territory. It is also assumed that the interconnection assets will be owned and operated by the National Grid Corporation of the Philippines (NGCP). Initially the power will be sourced in Sarawak and transmitted through a dedicated HVDC line traversing through Sabah with an intermediate HVDC converter terminal supplying the Kota Kinabalu load center. At a later stage, power exports from Kaltim or Kalut could be developed to complement the Sarawak supplies. As for Mindanao, it is expected that the high cost of HVDC submarine connections and overland HVDC lines through Pelawan/Mindoro to Luzon would be borne by the NGCP.

1 Overview and Study Objectives

This report provides an overview of the potential for electricity power trading within the island of Borneo and with the island's offshore neighbors. It also identifies priority transmission links and proposes a strategy for investment sequencing.

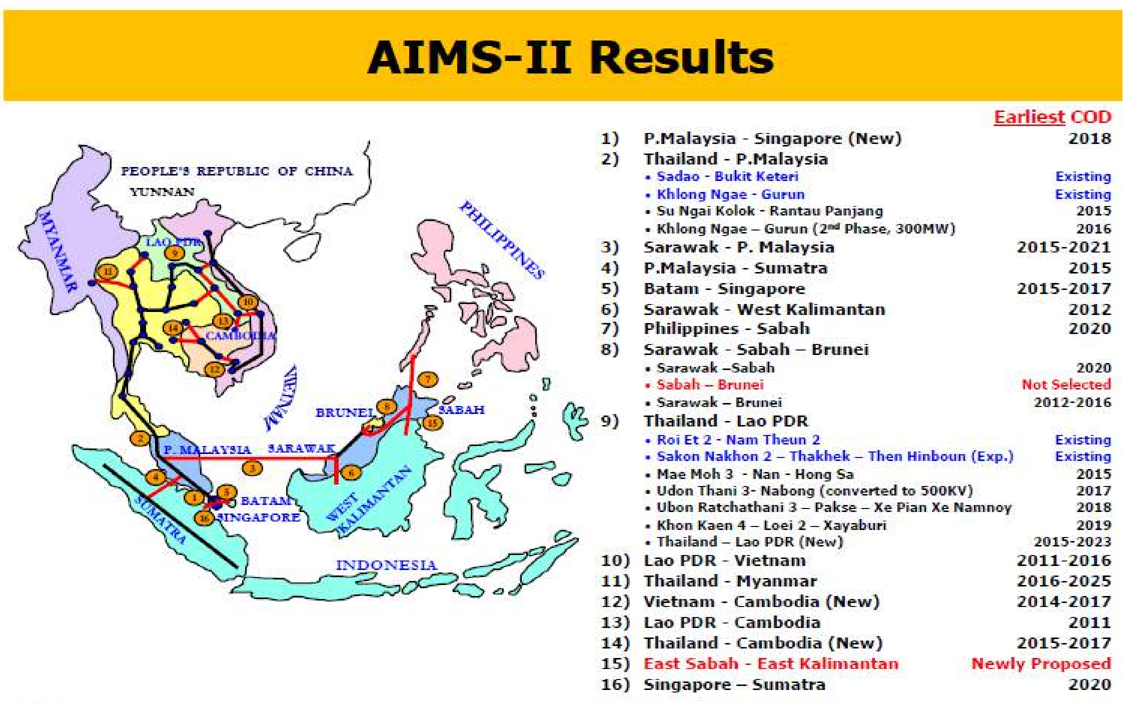
As required by the Terms of Reference provided by the Asian Development Bank (ADB) for this study (Annex 1), this report will: (i) evaluate prospects for electricity interconnections among Borneo's provinces in Malaysia (Sarawak and Sabah), Indonesia (provinces in Kalimantan), and the Nation of Brunei, as well as prospects for interconnecting these areas to prospective offshore power markets in the Philippines (Mindanao and Palawan), Indonesia (Java and Sulawesi), and Peninsular Malaysia; and (ii) provide a preliminary analysis of the potential for interconnecting power systems within Borneo that could inform lending operations from the ADB or other international financing institutions (IFIs).

2 Eastern ASEAN Grid Development Planning

2.1 Overview of ASEA Region Power Development Plans

The nations of Southeast Asia have been seeking to build a regionally integrated power network ever since international power trade commenced between Thailand and Laos in 1961. An association of the Heads of ASEAN Power Utilities and Authorities ("HAPUA") was established in 1981 to promote regional power interconnections, and the ASEAN Power Grid program (APG) was identified and initiated through stakeholder consultations of HAPUA activities in 1997. The original ASEAN Interconnection Master Plan Study (AIMS) was completed in 2003 to serve as the basis of interconnection plans, which was recently revised and published as AIMS-II in 2010. AIMS-II identifies sixteen interconnection systems for a regionally integrated power system, as listed below:

Figure 2 Interconnection Systems for a Regionally Integrated ASEAN Power System



Source: AIMS II and III Publication

In its 2012 meeting to discuss these projects, HAPUA prioritized certain interconnections in the order reflected in Table 1 below. This table, adapted for this report from HAPUA's summary, shows the indicative costs of wheeling power through the proposed interconnection projects based on an assumed long-term average load factor (LF) and financial assumptions (shown in red).

Table 1 HAPUA 2012 Investment Cost Estimates of APG Projects

	Wheeling Rate PWF	9.82	Interest	8%	20		years LF=	60%
No.	**Interconnection Projects**	**Type & Size**		**Voltage**	**Dist**	**US$**	**Invest**	**Wheeling**
		Size	**MW**	**(KV)**	**(km)**	**/kW**	**(MUSD)**	**c/KWh**
1	Thailand - Lao PDR	HVAC	600			55.09	45	0.15
	Nong Khai - Khoksa-at			230	35			
	Thoeng - Bo Keo			115	72			
2	Thailand - Cambodia	HVAC	300	230	300	337	134	0.87
3	Peninsular Malaysia - Sumatra	HVDC	600	275	272	589	335	1.08
4	Singapore - Peninsular malaysia	HVDC	600	250	42	1170	436	1.41
5	Singapore - Sumatra	HVDC	600	250	270	1831	682	2.20
6	Singapore - Batam	HVDC	600	230	32	1401	376	1.22
7	Thailand - Peninsular Malaysia	HVDC	600	300	110	210	63	0.20
8	Sabah - Philippines	HVDC	500	500	800	1852	523	2.03
9	Sarawak - West Kalimantan	HVAC	200	275	128	420	133	1.29
10	Sarawak - Brunei	HVAC	300	275	13	667	269	1.74
11	Sarawak - Peninsular Malaysia	HVDC	800	500	1,650	NA	1500	3.63

Source: AIMS II Report Exec Summary 2010. Note that the apparently low wheeling rates shown above are determined using a relatively high utilization load factor and long life of the line. As noted in Section 3.11, wheeling rates can be significantly higher if a line is to be designated and justified only for peaking duty over a shorter term.

Table 1 shows that while the upfront costs of interconnection are significant, the incremental cost of generating power at either end of the line is higher than that of wheeling power through cross-border interconnections. Typically generation costs amount to 8-20c/kWh depending on the time of day and generation source. Therefore, as long as the sending-end generation cost plus wheeling charge is lower than the cost of generation at the receiving end, then power exchange should occur for at least the duration of the cost difference. However, such bulk power exchanges for limited economic reasons represent just one possible benefit of interconnection. Other important benefits include the aggregation of supply and demand to facilitate the building of more efficient generation plant, and reinforced system stability that enables both parties to hold lower reserve capability. The later benefits occur regardless of whether bulk power exchange is occurring, since bothe systems will be continuously interconnected.

That so few of these ASEAN interconnection projects have been realized indicates that other issues may be dominating the decision-making process. Indeed, stakeholder concerns include the risk of overdependence on long lines or undersea cables, whether partly owned by or under the control of others, in addition to the political imperative of energy security and the more common financial and contractual risks associated with large cross-border projects. There is also a "chicken and egg" conundrum to the decision-making process in that the economic justification of an interconnection in one country often depends on a complementary investment being made in another country. In this respect, the initiative by Malaysia to build the Bakun hydro project (2,400 MW), followed by Sarawak's building the nearby project Murum (1,000 MW), and more recently Sarawak's decision to build an associated 500kV backbone system, have all helped to break the impasse. In effect, these projects became the figurative "eggs" that will give rise to the future interconnection (the "chicken").

The first of these interconnections is the ADB-funded interconnection between Sarawak in Malaysia and West Kalimantan ("Kalbar") in Indonesia[12], which in turn is likely to inspire new opportunities for Indonesian utility PLN to extend export power surpluses into Kalimantan's southern and eastern regions. The success of this first cross-border interconnection project will give PLN more latitude in developing its domestic generation projects to support a future export market. It is also likely that the large generation and 500kV transmission investments being made in Sarawak will inspire similar transmission interconnections with both Brunei and Sabah.

2.2 Energy Security within the ASEAN Power Market

The desire to create a greater ASEAN grid is driven partly by the need of each member country to have alternative sources of power and minimize their dependence on imported fuels such as oil, gas and coal. In this respect, an electricity grid offers considerable flexibility in energy transportation and should therefore play a key role in regional energy planning. On the other hand, one-way electricity trade usually implies that one country would invest in, for example, coal or gas generation resources to export to another; whereas the importing country may prefer the security benefits of investing in its own generation capacity using imported fuel.

Most participants in ASEAN's electricity market wish to ensure that power exchange occurs neutrally, with each country responsible for ensuring that its own generation resources are capable of meeting domestic growth in electricity demand. There are concerns that depending too much on electricity imports, no matter how cheap to deliver, may place a country at a disadvantage in difficult political situations. Avoiding this often means that a given country would need to turn to sophisticated technologies such as nuclear power or renewable sources to reach energy independence.

Although ASEAN member access to Borneo's unexploited energy resources is attractive, an enormous investment in the island's power system infrastructure is required before an electricity export market can be created. However, Borneo's respective Borneo power utilities (see 2.3 below) are charged with first meeting their own domestic needs. Unless they receive significant investment support, the utilities are unlikely to seriously prioritize major power export business. The utilities are just now beginning to come to terms with the institutional and operational issues of interconnecting with each other. While these issues must be addressed, there are also complex territorial issues that need to be resolved to before investing in major submarine cable interconnections between Borneo and its neighboring states.

2.3 Grouping of ASEAN and BIMP/EAGA sub-regional power systems

The integration of ASEAN's power system has been divided by HAPUA into three key systems: **System A** covers the upper west system, comprising Cambodia, Laos PDR, Myanmar, Thailand and Vietnam. **System B** covers ASEAN's lower west system, namely Indonesia, Malaysia and Thailand. Systems A and B are relatively large networks serving densely populated regions where cross-border overland transmission interconnections are generally feasible. With the exception of interconnections with Laos, System A and B interconnections are mostly designed to provide net power transfer capability to provide backstop generation support in both directions. In this way, the planned HVDC submarine connection between Peninsular Malaysia and Sumatra, Indonesia, will be an important precedent in expanding ASEAN systems across marine boundaries.

System C, the subject of this report, covers the eastern sub-region of ASEAN including the Philippine power system along with the Malaysian, Indonesian and Brunei power systems on the island of Borneo. In contrast to the HVAC power exchange interconnections of Systems A and B, the proposed Borneo interconnection requires the use of HVDC submarine cable links to evacuate power by overhead lines and submarine cables over long distances, mostly from relatively unpopulated major energy resource areas to highly populated electricity markets.

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12 See Project Documents for ADB Loan 3015-INO "Strengthening West Kalimantan Power Grid Project," dated 20th October 2013.

As a whole, Borneo is considered to have significant untapped energy generation resources in terms of hydro, coal, oil and gas, as well as other largely untapped renewable energy resources including wind, geothermal and solar power. In contrast to the much larger and mostly interconnected power system of the Philippine archipelago, Borneo's aggregate MW peak is a combination of relatively low demands from small cities, towns and scattered rural communities that are separated by difficult and mountainous terrain.

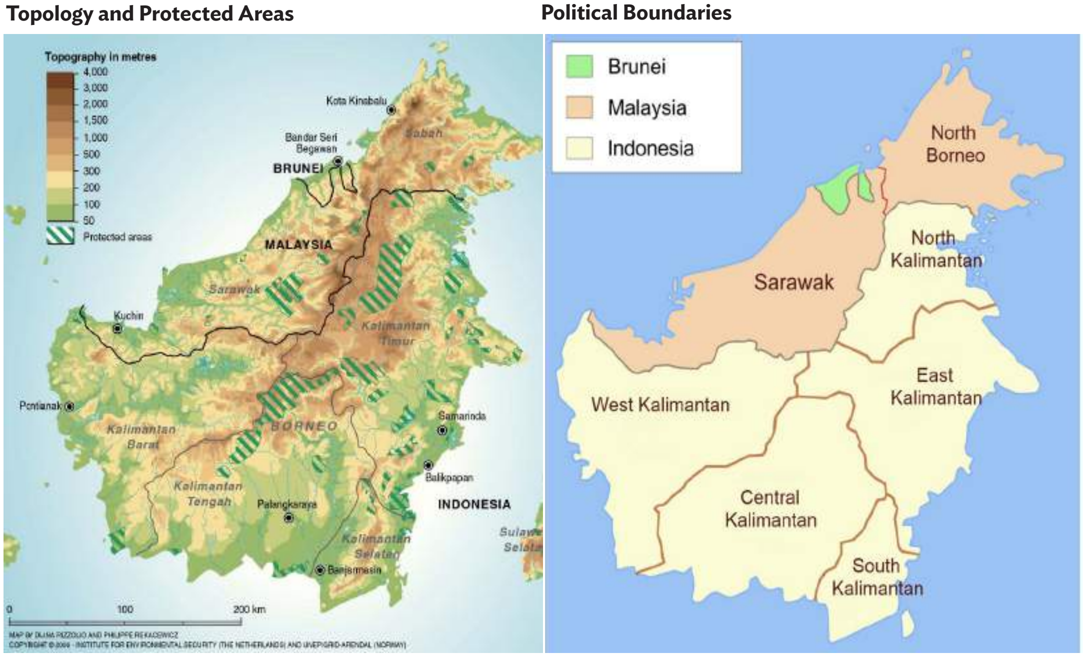
Northern Borneo's power systems included in the BIMP-EAGA sub-region[13] are administered by Brunei's power company (Berakas Power Company, or BPC) and the Malaysian utilities in Sabah (SESB) and Sarawak (Sarawak Energy Berhad, or SEB).[14] In the Indonesian portion of Borneo, which is referred to by its Indonesian name "Kalimantan," the power systems of Kalimantan's five political provinces are each administered by a separate branch offices (*wilayah*) of state-owned power company PLN.[15] This includes two interconnected power systems: the East (Kaltim) and North (Kalut) provinces, and the South (Kalsel) and Central (Kalteng) provinces.[16] The now-isolated system in the West (Kalbar) will be interconnected with Sarawak by 2015 under the ADB-funded loan referenced above. Drawings showing the extent of the existing and planned power systems are included in Annex 3.

2.4 Eastern ASEAN Economic, Social and Environmental Issues

ASEAN's eastern region, i.e. the BIMP-EAGA sub-region, is broadly composed of wealthy Brunei (population: 415,717), the larger and relatively mature economy of the Philippines (population: 100 million), and the less developed Malaysian states and Indonesian provinces that occupy the island of Borneo (aggregate population: 20 million). Only Brunei is a member of OECD/APEC, while Brunei, the Philippines, Indonesia, and Malaysia are all

Figure 3 Overview of Borneo topology and Political Boundaries

Topology and Protected Areas **Political Boundaries**



Old Map showing Sabah as North Borneo

[13] See: http://aric.adb.org/initiative/brunei-darussalam-indonesia-malaysia-philippines-east-asean-growth-area

[14] SESCO = 100% State Owned Sarawak Energy http://www.sarawakenergy.com.my/; SESB = Sabah Electricity Sdn. Bhd. is an 80% owned subsidiary of Tenaga Nasional Berhad (TNB) and 20% by the State Government of Sabah http://www.sesb.com.my/

[15] The power systems are run by PLN Wilayahs identified by their respective provincial acronyms: Kalbar (west); Kaltim (east), Kalsul (south); Kalsel (central) and Kalut (north). See http://www.pln.co.id/

[16] To allow PLN's respective regional systems to be easily identified, this reports uses the Indonesian acronym KAL (for Kalimantan), followed by the region's regional ID, i.e.: BAR (Barat = West); SEL (Selatan = South); TENG (Tengah = Central); TIM (Timur = East); UT (Utara = North). Thus the main PLN supply areas are Kalbar (West Kalimantan), Kalsel (South Kalimantan), Kalteng (Central Kalimantan), Kaltim (East Kalimantan), and Kalut (North Kalimantan). Following interconnection, the aggregated areas are identified as Kalselteng; Kalseltengtim, etc.

members of ASEAN. Borneo is centrally located in this region and thus well positioned to provide power system interconnections with its neighboring countries.

2.5 Borneo Ecology and Demographics

With an area of 743,330 km^2, Borneo is the largest single island in Asia and third-largest island in the world. Its largest river system is the Kapuas in West Kalimantan (length: 1,143 km) with other major rivers including the Mahakam in East Kalimantan (980 km), the Barito in South Kalimantan (880 km) and Rajang in Sarawak (562.5 km). Most of Borneo's population lives in coastal cities, although the central areas also have small towns and villages along the rivers. About six million people live in Borneo's twenty larger coastal cities whose populations regularly exceed 100,000. Of these, the largest include Samarinda (730,000), Banjarmasin (650,000), Balikpapan (557,000) and Pontianak (554,000) in Kalimantan along with Kuching (617,000) and Kota Kinabalu (462,000) in Malaysia.

Table 2 Overview of Existing Borneo-Mindanao National or Provincial Power Systems

	Units	Kalimantan		Sarawak	Sabah	Brunei	Mindanao
Capital		Pontianac	Balikpapan - Bontang	Kuching	Kota Kinabalu	Banda Seri	Davao
Population Census 2010	million	4.39	9.90	2.42	3.12	0.41	21.00
Regional Office		PLN	PLN	SESCO	SESB	DES/BIA	NGCP
Area	km2	146,760	472,422	124,450	73,619	5,770	104,630
Pop/km2		30	21	19	42	70	201
Electricity Consumers	000	834	2064	549	415	100	2715
Electrification Ratio	%	76%	83%	91%	90%	99.70%	71%
Peak Demand 2014	MW	234	847	1251	1051	620	1,428
Energy Sold 2014	GWh	1371	5154	6575	6353	3259	7,506
kWh/cap	kWh	312	520	2717	2036	8022	357

Sources: PLN RUPTL data for East and West KalimantaniInterconnected systems and Annual Reports for Sabah, Brunei & Sarawak. NB Sabah is currently experinceing generation shortfalls and was not able to meet its forecast paek in 2014.

Table 2 provides comparative population densities and electricity usage for each of the electricity supply areas of Borneo. It quantifies the significant differences between states which could further indicate their prospects for growth and development. With a large and growing population, Borneo will inevitably become a major component of the ASEAN grid concept, particularly once domestic electricity usage rises to levels seen in other parts of Asia.

The prospect of power system development in Borneo comes with daunting social and environmental considerations. In 2010, the World Wide Fund for Nature classified the island into seven distinct ecoregions, including lowland rainforests of 427,500 km^2 covering most of the island; peat swamp forests; the Kerangas heath forests; the Southwest Borneo freshwater swamp forests; the Sunda Shelf mangroves; and the montane rain forests in the central highlands of the island (above 1,000 m elevation). Borneo's rainforest is one of the oldest in the world[17] and an important refuge for many endemic forest animal and plant species,[18] placing Borneo at the center of evolution and distribution for many endemic species of plants and animals. Borneo's highest elevations are also home to the Kinabalu mountain alpine meadow, an alpine shrubland notable for its numerous endemic species, including many

[17] A series of photographs of various aspects of Borneo Ecology can be seen at: http://ngm.nationalgeographic.com/2008/11/borneo/klum-photography

[18] Borneo is reputed have about 15,000 species of flowering plants, 3,000 species of trees, 221 species of terrestrial mammals, 420 species of resident birds, and 440 freshwater fish species (about the same as Sumatra and Java combined).

orchids. Unfortunately, the island's historically extensive rainforest cover has already been drastically reduced by heavy logging for the Malaysian and Indonesian plywood industries, with half of the world's annual tropical timber acquisition now coming from Borneo. Proliferating palm oil plantations are also rapidly encroaching on the island's last remnants of primary rainforest.

The most widely practiced religion in Kalimantan is Islam, reinforced in numbers by Indonesian programs promoting Javanese transmigration in the 1990s. Ethnic Chinese descended from immigrants primarily from southeastern China make up 29% of the population of Sarawak and 17% of the total population in West Kalimantan. Other groups include the Dayak population (700,000) who practice Christianity and a small Hindu minority in Central Kalimantan. Borneo's interior hosts the Penan, some of whom still live as nomadic hunter-gatherers, while some of Borneo's coastal areas have marginal settlements of the Bajau people known for their sea-oriented, boat-dwelling, nomadic culture.

2.6 Geography, Resources and Economic Development in Borneo

Central Kalimantan (Kalteng) (area: 153,800 km^2) is a mountainous and densely forested province about 1.5 times the size of Java. Eighty percent of Kalteng is covered in dense forest, peatland swamps, mangroves, rivers, and traditional agriculture land, while its mountains in the northeast tend to be remote and not easily accessible. The center of the province is covered with tropical forest, which produces valuable timber products. Kalteng's Sabangau National Park is a protected area known internationally for sheltering endangered orangutans. The province is a wet-weather equatorial zone with an eight-month rainy season and a four-month dry season, averaging 145 rainy days annually.

East Kalimantan (Kaltim) (area: 139,462 km^2) is the second least densely populated province in Kalimantan. Kaltim borders Sarawak and other provinces in Kalimantan, and shares a long maritime border in the east with West and North Sulawesi, just over the faunal boundary "Wallace Line"[19] and 120 km across the Makassar Strait. Due to illegal logging, less than a half of Kaltim's original forest remains, which is mostly concentrated in national parks such as Kayan Mentarang and Kutai. Besides agriculture and tourism, the Kaltim/Kalut economies depend heavily on earth resources such as oilfield exploration, natural gas, coal and gold. Balikpapan hosts an oil refinery plant and a number of oil fields have been discovered in the Mahakam River Delta.[20] Lack of transportation infrastructure has long held back economic development in Kaltim since traditional boats are largely used to connect coastal cities and areas along the Mahakam River. However, Russia's state railway firm reached an agreement with the governor of Kaltim in 2012 to initiate a two-phase railway development project to transport coal and other freight. The first stage, costing $1.8 billion, will connect port city Balikpapan to West Kutai (183 km) by 2017 with capacity to transport 20 million tons of coal annually, while a later phase will connect to Murung Raya in Central Kalimantan (60 km).

South Kalimantan (Kalsel) (area: 38,744 km^2) is divided by the Meratus Mountains into two largely flat halves, much lying under sea level with expanses of swampland. Its annual rainfall intensity is high (2,000-3,700 mm). Its main Barito River is used as a transportation route through northern Kalsel to Kalteng, with other smaller rivers running from the central mountains. Kalsel's primary natural resources include forest and coal, with coal deposits found throughout the province which are exploited commercially in some places. Other minor resources include oil, gold, gem stones, quartz sand, phosphate and granite.

West Kalimantan (Kalbar) (area: 147,307 km^2) has a population of 4,393,239 comprised of ethnic groups including the Dayak, Malay, Chinese, Javanese, Bugis, and Madurese. Kalbar's borders roughly trace the mountain ranges surrounding the watershed of the Kapuas River, which drains most of the province.

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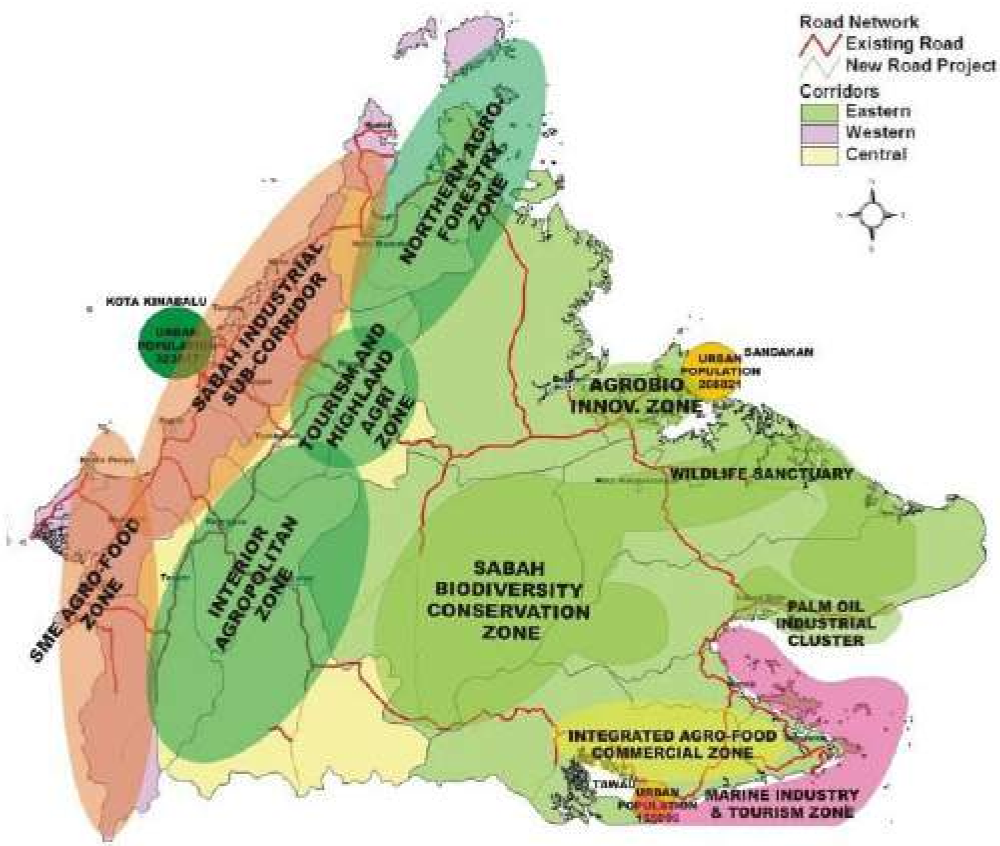
[19] The Wallace line is a transitional zone between Asia and Australasia plates with high marine current flows from the Philippines, as shown in this animation: http://www.minesto.com/oceanenergy/index.html.

[20] These oil fields include: Attaka, Badak (1971), Semberah, Nilam, Sanga Sanga, Bekapai (1972), Handil (1974), Samboja, Jakin and Sepinggan.

Sabah (area: 73,631 km^2) has a western mountainous area that contains Malaysia's three highest mountains, including Mt. Kinabalu in the Crocker Mountain Range. The jungles of Sabah are classified as tropical rainforests and a number of Sabah's protected wildlife regions are designated as national parks, wildlife reserves, virgin jungle reserves, or protection forest reserve, with Kinabalu National Park inscribed as a World Heritage Site since 2000. Sabah's mountains and hills are traversed by an extensive network of river valleys and are mostly covered by dense rainforest. The forests surrounding the Kinabatangah River Valley also contain an array of wildlife habitats, and constitute the largest forest-covered floodplain in Malaysia. Sabah's economy relies on agriculture, tourism and

Figure 4 Sabah's Development Zone



Source: University of California Renewables Study, 2010.

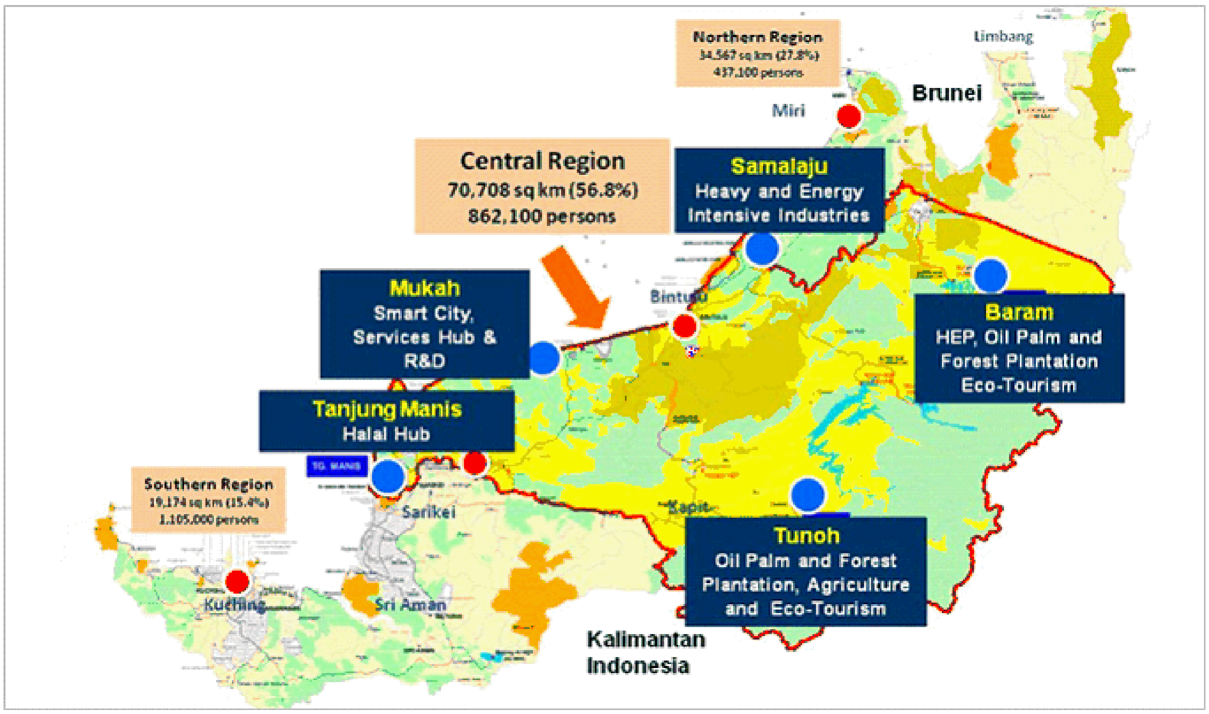
manufacturing. Petroleum and palm oil, along with rubber and cocoa, are the most exported commodities, while Sabah imports mainly automobiles and machinery, petroleum products and fertilizers, food, and manufactured goods. Palm oil has become the largest agricultural source for Sabah despite this crop's destruction of natural habitats for the Borneo pygmy elephant, proboscis monkey, orangutans and rhinoceros.

Tourism, particularly eco-tourism, is a major contributor to Sabah's economy. Annual tourists have surpassed two million and numbers will continue to rise thanks to vigorous promotional activities by the state and national tourism boards. Sabah contains several ports[21] and hosts hundreds of small and medium enterprises (SMEs) and industries (SMIs). The Sabah government is seriously pursuing industrialization with the **Sabah Development Corridor Plan**, particularly in the Sepanggar area where KKIP Industrial Park and Sepanggar Container Port Terminal are located.

[21] Sabah's ports include: Kota Kinabalu Port, Sepanggar Bay Container Port, Sandakan Port, Tawau Port, Kudat Port, Kunak Port, and Lahad Datu Port.

Sarawak (area: 124,450 km2) makes up 37.5% of Malaysia's land area. Sarawak is separated from Kalimantan by Borneo's central mountain ranges. Its major rivers flowing from the south to the north include the main Sarawak River (2,459 km2) which bypasses the state's capital, Kuching. Sarawak can be divided into three natural regions: (i) a low-lying, flat coastal region widespread swamps; (ii) a hilly region hosting the most easily inhabited land and most of Sarawak's larger cities and towns, including the ports of Kuching and Sibu; and, (iii) a mountainous region along the border with highlands in the north. Sarawak's large tracts of both lowland and highland rainforest habitats, home to a number of endangered animals, have been severely encroached upon by heavy logging since the 1950s and the expansion of monoculture tree plantations and oil palm plantations. Sarawak's large land area, low population density, high rainfall, and mountain ranges make the state ideal for hydroelectricity production; the state has already built three dams, with two fully running and nine more in planning stages.

Figure 5 Sarawak Corridor of Renewable Energy



Source: SCORE Publication.

The Sarawak Corridor of Renewable Energy (SCORE) in central Sarawak is a targeted program to develop a vast area extending 320 kilometres up Sarawak's coast. The area stretches from Tanjung Manis to Samalaju and into the state's extensive and remote hinterlands, where two rural growth nodes (Baram and Tunoh) will also be developed.

The SCORE program has grown remarkably since it was launched in 2008. SCORE is focused on ten key industries (tourism, oil, aluminium, metals, glass, fishing, aquaculture, livestock, forestry, ship building and palm oil) in five major growth nodes (Tanjung Manis, Samalaju, Mukah, Baram and Tunoh). New roads are being built to connect centrally located urban centers with the rest of Sarawak and facilitate access to goods, resources, and human capital. Overseas investment, so far totaling over $30 billion but continuing to grow thanks to Chinese and Arab investors, has been key to SCORE's development key.

Sarawak's supposedly rich energy resources, claimed to top 28,000 MW[22], have also proven attractive to investors.

[22] This potential includes hydropower (20,000 MW), coal-fired plants (5,000 MW), and 3,000 MW of other energy sources, including biofuel.

This has allowed Sarawak to price its energy competitively and encourage investments in power generation and energy-intensive industries that will further stimulate strong industrial development in the corridor. For the purposes of this report, although Bakun Dam is yet to operate at full generation capacity and Murum Dam should be online in 2015, Sarawak utility SESCO claims to have the entire electricity output of both hydro projects contracted under long-term agreements with SCORE investors. There are, however, concerns about dry years which may offer opportunities for Indonesian PLN to supply coal-fired generation in the future.

Brunei Darussalam (area: 5,765 km^2), located on the northwest coast of Borneo, has a long coastline and land covered by primary forest (75%) including hilly lowlands, mountains, and a swampy tidal plain along the coast. Its equatorial climate boasts heavy annual rainfall (2,500-7,500 mm). Brunei's population is concentrated in the capital (Bandar Seri Begawan) and the western oil refining area of Seria, with the rest of Brunei sparsely populated and largely undisturbed. Brunei's economy encompasses agriculture, forestry, fishing, aquaculture, and banking, but its prosperity is mostly due to its oil and gas sector which accounted for 67.7% of GDP and 95.6% of total exports in 2011. Brunei is the fourth-largest oil producer in Southeast Asia and the ninth-largest exporter of liquefied natural gas (LNG) in the world (BEDB, 2011). Its existing and potential oil and gas reserves lie within the country's northern landmass and extend offshore to the outer limits of its exclusive economic zone (EEZ). As of 1 January 2012, Brunei's proven oil reserves stood at 1.1 billion barrels and its gas reserves were estimated at 13.8 trillion cubic feet (Tcf) (390 billion cubic meter (bcm)), enough to last 25 years and 40 years, respectively. New recovery technologies as well as potential onshore and deepwater fields are expected to add to the lifespan of these reserves.

Brunei is rapidly becoming aware that its natural resources are waning and it needs to diversify its economy away from dependence on upstream oil and gas production. A key initiative under the government's long-term development plan, "Vision Brunei 2035," is to designate cluster-specific industrial sites with supporting infrastructure and facilities to promote industrial investment. The first site (Sungai Liang Industrial Park, or SPARK), launched in 2007, was designed specifically for downstream petrochemical processing activities. Additionally, 1 Tcf (28.3 billion cubic meter (bcm)) of natural gas has been allocated for domestic downstream activities over a 20-year span.

3 Power Development Options for Borneo

3.1 Sources of Information and GIS Data Base Management

Each Borneo power utility has its own plan for development within its particular electricity supply areas. PLN provides the most detailed of these through its RUPTL[23] document available on PLN's web-based portal, while also making available various other studies of hydro, coal and gas resources in Kalimantan through the internet or directly from PLN.

Power Development Plans (PDPs) by the two Malaysian states are not so readily available, perhaps due to sensitivity in their commercial dealings with industrial developers, but data can be pieced together from the Malaysian Energy Commission's statistical data and its *Electricity Supply Industries Energy Outlook*. This study has also obtained supplementary information relating to Sarawak from onsite discussions and recent technical papers on development options for generation and transmission systems. Resource planning for Sabah is likewise described in a recent study of renewable energy potential[24] as well as in various technical papers.

This study has used ArcGIS mapping facilities to provide an overview of aspects such as population, demand, resources, and environmental considerations in identifying key issues for power system planning. GIS facilities can be used both as drawing tools for overall master-planning purposes or to burrow down into the detail, as a planning and contraction tool for implementation. GIS layers have been used to facilitate project identification and assessment (e.g. topography, land cover, road, electricity transmission, distribution sub stations and administration boundaries) and to build a GIS-linked database of power generator inventory.

Basic demographic and geographic information available from Government sources such as Bukosurtanal[25] must exist in the Malaysian states but was not available at the time of writing this report.

3.2 Overview of Power Markets

An overview of the respective ten-year energy demand (MW) forecasts that underlie power development planning in each of the Borneo subsystems is given below. This table, derived from various published sources, represents just one of several scenarios under consideration by the responsible power utilities. The table indicates that a 2,500 MW power market in Mindanao by 2022 will be comparable in size with each of the three main markets in Borneo (Sarawak, Sabah and aggregate demand in Kalimantan), but significantly smaller than the 16,000 MW Philippines power market concentrated mainly in the northern regions of Luzon and Visayas.

The demand forecasts provide an indication of the amount of power that can be contributed by an interconnection link to ensure that the market receiving transmiited power can survive a sudden loss of supply in an emergency

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23 RUPTL = *Rencana Usaha Penyediaan Tenaga Listrik,* PLN PT Pesero 2013-2022. This defines PLN's detailed plans for implementation under the direction of the Ministry of Energy and Mineral Resources – Director General of Electricity General Plan for Electricity (RUKN) 2012–2031 Jakarta (7 February 2013).

24 "Clean Energy Options for Sabah - an analysis of resource availability and cost," University of California March 2010.

25 See: www.bakosurtanal.go.id/global-mapping-indonesia/

situation. Typically the capacity of the interconnector should therefore not exceed the size of the largest generating unit, or any more than the approximate reserve capacity which might be about 10–20% of peak load.

Table 3 Comparison of Forecast Peak MW Demands in Power Markets in East ASEAN Systems

Eastern Subsystem	Demand	Av Inc	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
West Kalimantan	MW	7.6%	234	280	319	413	506	575	636	703	776	856
Central-North-East	MW	7.3%	847	1036	1286	1391	1511	1690	1819	1956	2095	2252
Total Kalimantan	MW	7.4%	1081	1316	1605	1804	2017	2265	2455	2659	2871	3108
Sarawak (Domestic)	MW	4.1%	1251	1326	1406	1490	1580	1674	1775	1800	1912	1996
Sarawak SCORE	MW	10.8%	2217	2817	2817	3417	3417	3417	3500	3500	3500	3500
Sabah	MW	5.0%	1051	1137	1220	1321	1428	1543	1666	1800	1876	1993
Brunei	MW	5.5%	620	654	690	728	768	810	855	902	952	1004
Total Borneo	MW	7.0%	6220	7250	7738	8760	9210	9709	10251	10661	11110	11601
North Sulawesi	MW	3.7%	311	349	379	445	487	535	587	645	708	777
Mindanao	MW	2.6%	1,428	1,502	1,574	1,645	1,729	1,813	1,902	1,990	2,095	2,199
Philippines	MW	2.9%	11,305	11,918	12,433	12,959	13,509	14,065	14,639	15,228	15,849	16,486
Borneo-Mindanao	MW	6.3%	7648	8752	9312	10405	10939	11522	12153	12651	13205	13800

Source: Own estimates based on information from various sources. NB they do not include MW demands in isolated rural areas that are shown in Table 9.

Intra-Borneo Interconnections. Outside the main urban centers, the growth of provincial power systems has largely been dependent on the use of scattered, diesel-powered, isolated, medium voltage (MV) power distribution systems serving coastal towns and larger villages with river or road access. Many of these diesel power plants are still in operation, which is likely to continue until the towns are interconnected with their respective state and provincial grids. This is particularly the case for Kalimantan and Sabah with the high costs involved in supplying diesel fuel along poor road networks.

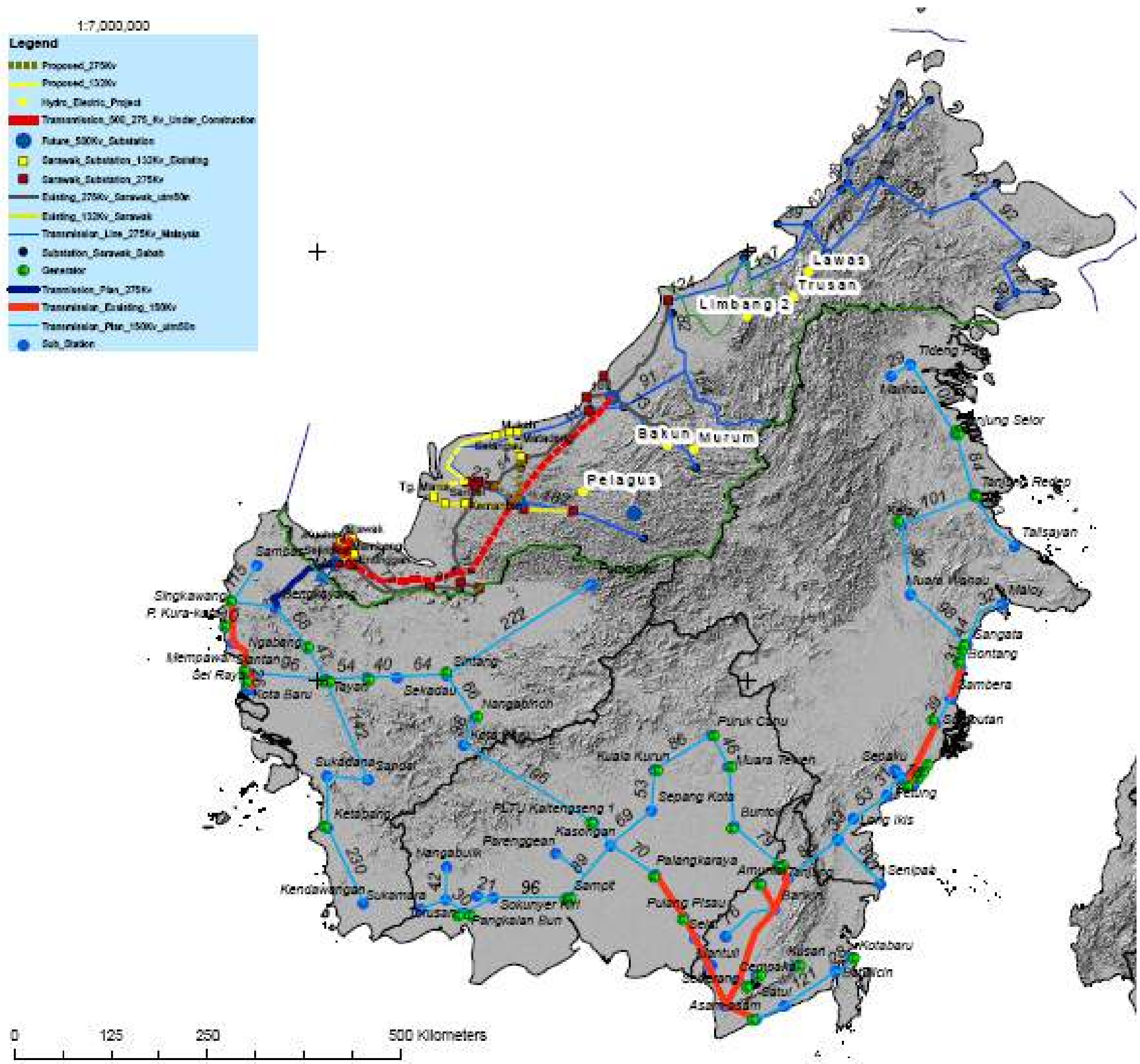
Accordingly, as the MV distribution systems have expanded, the respective utilities have extended their MV into rural areas, usually along main roads where consumers are willing to pay for the high cost of electricity services. To maintain satisfactory voltages on longer MV lines, the utilities have also built high voltage (HV) subtransmission lines (66-132KV in Malaysia/70-150kV in Kalimantan) and interconnected them with each other where feasible. Figure 6 shows the existing and current plans for transmission network expansion in Borneo based on the information shown in Annex 3.

Notably none of the utilities has incorporated provision for future crossborder interconnections in their plans. In particular PLN's concept of development of Kalimantan electricity networks follows an incremental growth pattern designed to meet targets for connections based on building many small (often costly and inefficient) generating plants near load centers. This takes into account the limitations of transmitting large amounts of power on long distances using conventional 150kV networks. A more strategic approach would be to centralize generation as much as possible and build new lines on major routes suitable for upgrading to a higher voltage (e.g. 275kV) later when the higher loads justify the additional investment.

Power Generation Planning. In each of the respective plans, generator unit sizes have generally been designed to ensure they do not represent much more than about 10% of the demand in the individual grids.[26] Thus, as transmission interconnections expand the networks, the capacity of the generator units can also be increased, enabling the utilities to build larger and less costly generator units that run more efficiently and reduce fuel requirements. For example, the first coal-fired generating plants in PLN Kalimantan were built in very small units (e.g. 3 x 7 MW) which are costly and operate inefficiently (typically 23%). As demand has increased, unit sizes have also grown to 50 MW but these are still inefficient (30%); unit size should be at least 250 MW (efficiency 40%)

[26] The hydro generator unit sizes in Sarawak are an exception in that the Bakun and Murum projects were originally designed for export to the larger power market in Peninsular Malaysia.

Figure 6 Existing and Planned Power Networks in Borneo



Source: RUPTL and Publically available information shown in Annex 3

to get the most value out of the available fuel. In this respect, investing in the interconnection of power systems within Borneo should be prioritized in terms of meeting national objectives for expanding rural electrification and to efficiently utilize natural and preferably renewable resources.

Off-Shore Interconnections. Proposals for cross-border interconnections with the Philippines or peninsular Malaysia are not yet prioritized by any of Borneo's power companies or neighbors. Such interconnections are still considered a national responsibility and only pursued on a case-by-case basis based on their political or economic merit. Geographically the nearest major ASEAN energy market is in the Philippines, which could potentially absorb as much power as Borneo can produce.

3.3 Current Power Development Plans within Borneo

Within Borneo, the two Malaysian states are quite advanced in formulating their respective programs for generation and transmission development to support domestic industrial growth. However, the politics of power trading among the Borneo jurisdictions are complex; each state is apparently very protective of its sovereignty. For example, even though Sabah is currently suffering power shortages, and Bakun in Sarawak is operating beneath its maximum capacity, SESB in Sabah is reluctant to extend the grid to enable it take any more than peaking capacity from Sarawak to minimize its blackouts. Likewise, Brunei has been unwilling to commit to receiving cheaper renewable power supplies from Sarawak. This is partly because Brunei recently upgraded its conventional gas turbines to combined-cycle gas turbines and now has sufficient power generating capacity to meet its needs.

In total, SESCO in Sarawak claims to have a portfolio of twenty hydro, gas-fired and coal-fired generation projects at various stages of development, and would accelerate implementation if it could secure satisfactory contracting arrangements. To support its development, SESCO is proceeding with the construction of a 500KV backbone system (initially operating at 275kV) which is primarily designed to aggregate generation capacity in order to expand services to the SCORE corridor. This 500kV line would also provide SESCO with the opportunity to extend north to Sabah and east to Kaltim to transmit power from its other hydro resources. During this study's site visit, SESCO suggested informally that, in fact, Kalsel could use the 500kV backbone to sell power to the SCORE region through the existing 275kV line from a possible mine-mouth coal plant near the border between both countries.

The supply situation in Sabah is more critical where blackouts are continuing to hold back the state's development. SESB is highly dependent on gas-fired generation with few options for generating from its other indigenous resources. A recent study[27] by the University of California found that Sabah has considerable potential to develop its renewable energy potential, including solar power (particularly in Kota Kinabalu), biomass, and geothermal power (in East Sabah), along with some run-of-river hydro power stations that have yet to be investigated. A hydro mapping study completed in 2010 indicated that Sabah has a total of 1,900 MW hydro potential, of which 782 MW of potential from twelve sites has been identified as economically viable for development.

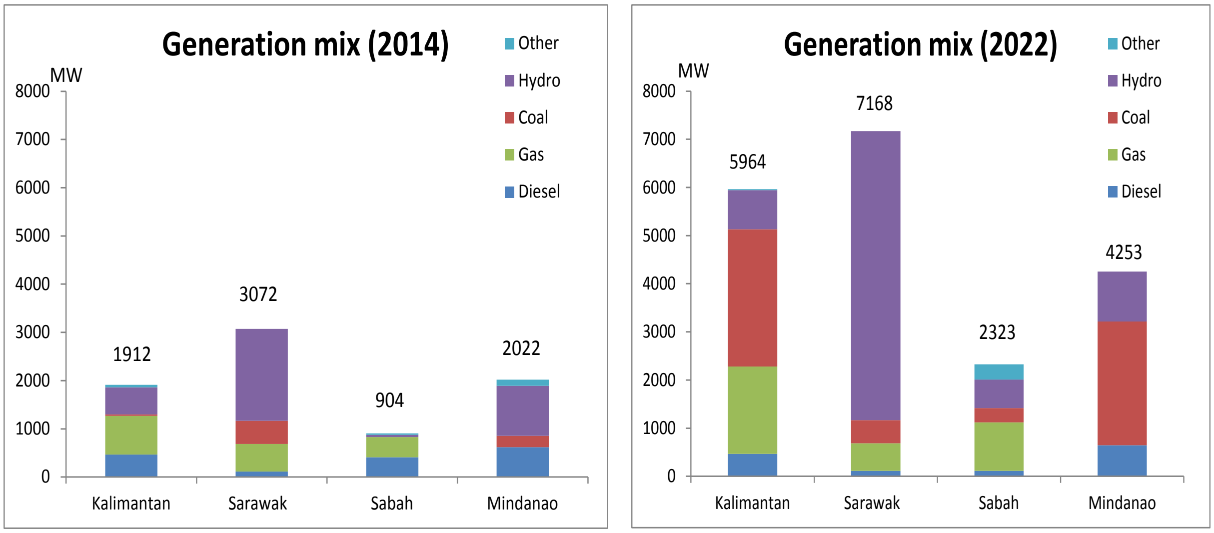
The supply situation in Kalimantan is detailed in PLN's RUPTL planning documents. These show that the plan to expand generation in Kalbar is expected to include about 900 MW of coal-fired power, 100 MW of gas turbine, and 128 MW of hydro power to be built over next ten years. The other four provinces in Kalimantan are also planning the strategic interconnection of their respective provincial grids: the south and central system is planned to connect to the eastern system by 2016 and the northern system by 2018. Interconnection between these four provinces is designed to enable the PLN's combined regional power system to develop 1,925 MW of coal-fired power, 912 MW of gas turbine and 120 MW of hydro power to be built over the next 10 years.

The two charts in Figure 7 illustrate how each of utility's energy mix is expected to gradually change as demand increase in Kalimantan and Mindanao becomes more dependent on coal, and likewise in Sabah becomes more dependent on gas.

With respect to inter-Borneo power trading opportunities, the new ADB-funded 275kV interconnection from Sarawak to West Kalimantan will become the area's first export project. The interconnection will provide PLN's branch office (*Wilayah*) in Kalbar with both peaking and base load power to support its domestic electricity growth. This will enable Kalbar to plan the development of a largely thermal-powered generation expansion plan using mainly local coal supplies. This interconnection also provides the chance to establish economic and technical protocols that will help in designing other links. If indeed the Indonesian, Malaysian and Brunei governments decide to embark on a coordinated Borneo export program involving some power wheeling through their respective territories, there should be adequate energy resource capacity within Borneo to be able to export power even after supplying local demand. This would be the case even if East Kalimantan decided to export to the northern provinces of Sulawesi (Gorontalo and North Sulawesi) using a 120km submarine cable.

[27] "Clean Energy Options for Sabah: an analysis of resource availability and cost," Prof el Kammen et al, University of California, Berkeley, Renewable and Appropriate Energy Laboratory, School of Law, Energy Resources group, Berkeley Goldman School of Public Policy and Harvard College (2010).

Figure 7 Change in Generation Mix 2014–2022 – Current Planning



Source: PLN RUPTL - own estimates.

3.4 Future Generation Options

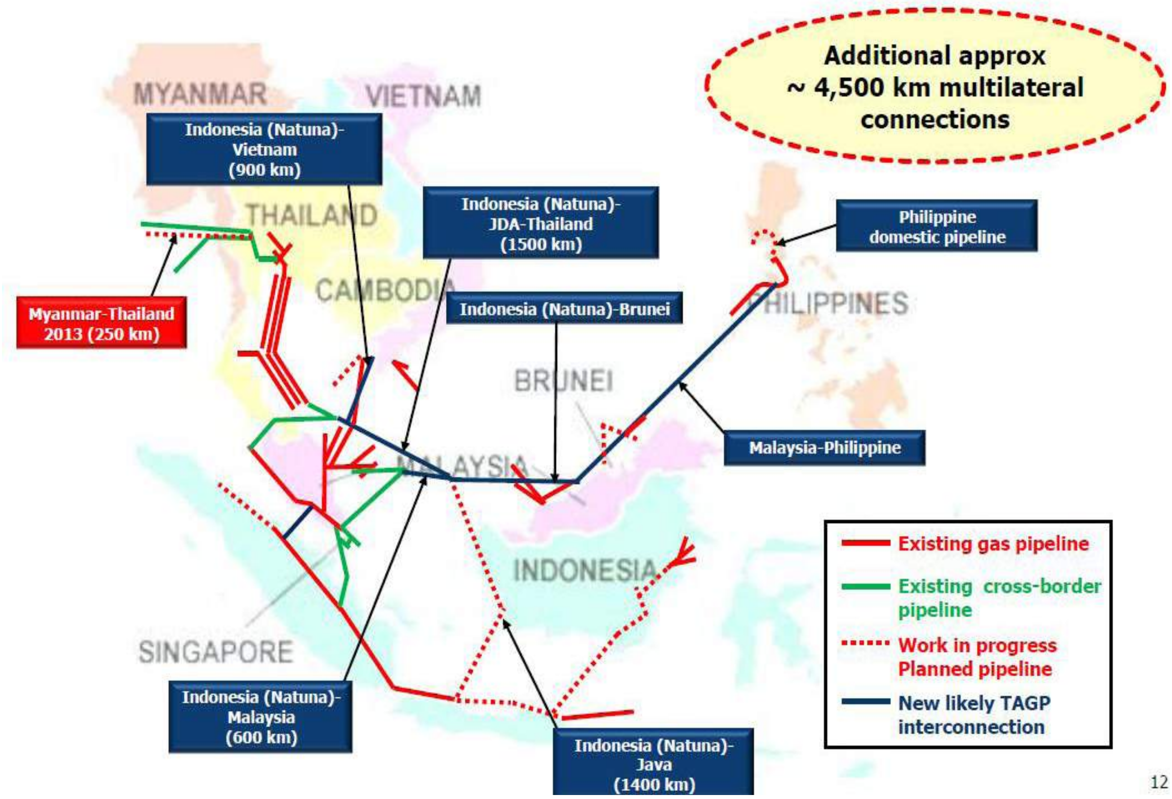
The following are general comments on the applicability of the various power generation technologies to Borneo.

Gas. Compared to coal and hydropower plants, natural gas open cycle plants are relatively cheap and quick to build, typically costing about $600/kW with emissions of 400 g CO_2/kWh. They can also be turned on and shut down quickly, making them suitable for use as "peaker" plants that come online at midday to serve peak electricity loads. More efficient gas generation plants based on the use of combined cycle designs can be built for about $1,200/kW. Gas can also be used in Concentrating Solar Power (CSP) plants[28] using the same boiler equipment to generate power when the sun is not shining. This is a system of power plant operation that may well offer Borneo electricity exporters a competitive advantage over locally sited gas-fired power generation using imported gas.

As shown in Figure 8, gas is likely to be readily available from a network of gas pipelines to many of the larger ASEAN load centres. The pipelines give local gas producers access to alternative markets and hence the opportunity to price their resources competitively. Figure 8 shows that gas in Kalsel is likely to be exported direct to Java, and likewise gas in Brunei, Sarawak and Sabah may similarly be exported direct to Malaysia or the Philippines.

[28] See "IEA Technology Roadmap 2010: Concentrating Solar Power" (http://www.iea.org/publications/freepublications/publication/csp_roadmap.pdf)

Figure 8 Concept Plan for Trans ASEA Gas Pipeline



Source Briefing on Trans ASEAN Gas Pipeline Plan PTT Public Company Limited 2013

Coal-fired power plants. Coal-fired power plants emit about 1,000 g CO_2/kWh, twice as much as natural gas and significantly more than diesel. Coal mining is a major source of ecosystem destruction and soils and water pollution. Sulphur dioxide released by burning coal causes acid rain. Heat exchange requires the discharge of large quantities of heated water outside the plant and disposal of coal ash presents a major hazardous waste problem.

As for a gas power plant, a decision to build new large coal-fired power projects in Borneo has to be shown to be economically competitive with the alternative of transporting fuel to large power plants in offshore markets. In particular the power markets of Philippines, Java and Peninsular Malaysia all incorporate large generally efficient generation plant that run on imported coal (much of which comes from Kalimantan).

In principle, a mine-mouth coal fired power station in Borneo, which has substantial indigenous coal resources, should be able to obtain its coal fuel for as low as 50% of the current international price of imported coal[29]. Such a plant would also tend to have better access to the land and cooling water it needs. On the other hand, a sophisticated high temperature/pressure coal-fired power station built in Borneo (i.e. with unit sizes greater than 250 MW) would require skilled operational staff who may not wish to live in the plant's remote location. Furthermore, to ensure power system security and reliability, larger generator unit sizes would need to supply into a diverse power system with significant generation reserve capacity to minimize any disruptions from transmission faults or rapid changes in demand.

[29] The cost of minemouth coal of course varies considerably from place to place as do shipping costs. In Indonesia costs are also governed by formula set by the Government to assist in meeting policy goals relating to royalties and local industrial development. See: http://www.bakermckenzie.com/alindonesiacoalpricingregimejun14/

The levelized cost of coal-fired generation is sensitive to the price of coal, such that increases in coal price make coal-fired capacity less competitive with other resources. In 2007, the coal price was over $120/tonne with some analysts expecting it to rise to $175/tonne. The economic crisis of 2008 and 2009 brought world prices down, but recent reports show prices rising again. At prices over about $100/tonne, coal loses its cost advantage over many of the renewable options discussed in this report.

Hydro Generation. Borneo's topography lends itself to the possibility of developing a significant hydropower resource. In this respect, Sarawak has led the way by developing the Bakun and Murum power plants – and appears likely to continue developing hydro resources in support of its ambitious industrial corridor developments. Other regions of Borneo also claim to have significant hydro resources,[30] but these can be difficult to access and may face significant access and environmental issues. Although hydropower does not directly release any greenhouse gases, significant indirect emissions can result from forest clearing, cement use, and the anaerobic decomposition of submerged vegetation. Moreover, the effect of dams on river ecosystems is objectionable on other environmental and economic grounds: they decrease fish populations, lead to destructive erosion, displace human populations, and can deprive downstream users of access to river water. All hydroelectric projects, and especially large hydroelectric projects in Borneo, will be characterized by large up-front capital costs for constructing infrastructure but very low ongoing operating costs. In many regions, low precipitation during certain seasons may mean that hydro power is only available during certain months of the year.

Biomass. The study by the University of California has shown that biomass has considerable potential, particularly in Sabah. Because the palm oil waste produced by Sabah's many mills contains more energy than the mill needs, the mills are typically designed to generate sufficient power cheaply rather than maximize the energy produced per tonne of biomass waste. Therefore, upgrades to mills' electricity generation infrastructure—usually meaning higher pressure boilers and more efficient steam turbines—combined with fuller utilization of mill waste streams can allow them to generate more electricity than they need for their in-house processing requirements. Even accounting for mill process steam and electricity requirements, full utilization of both biomass waste and POME-derived methane could conceivably allow a mill to produce 160 kWh of electricity energy per tonne of processed waste product.

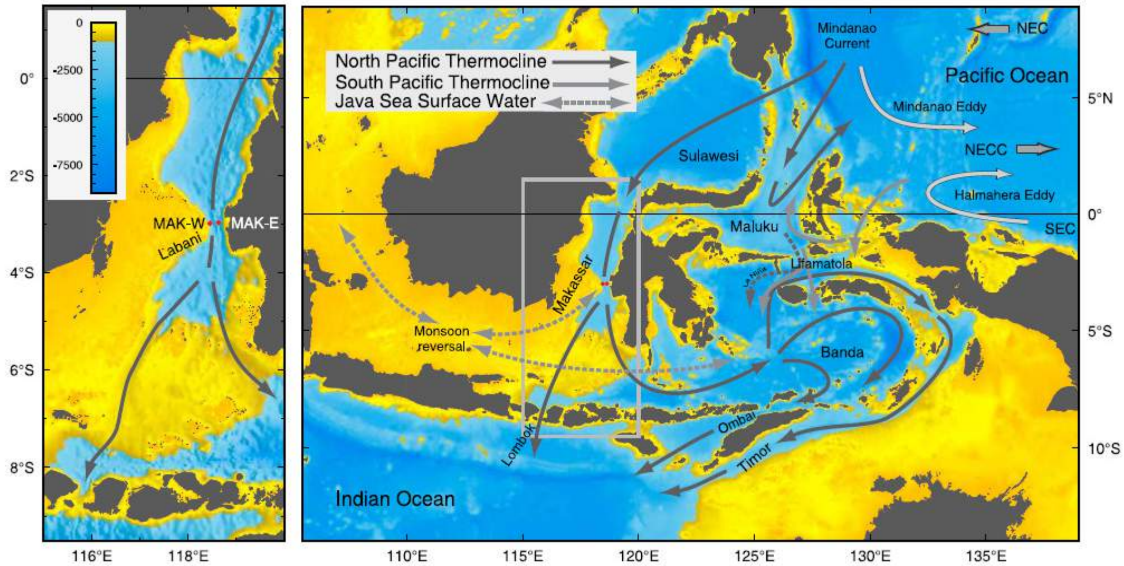
Solar Power. Borneo receives an average daily solar radiation ("insolation") of 4-6 kWh/m^2, making most of the island suitable for solar power generation. Averaging 5 kWh/m^2 per day, or approximately 1825 kWh/m^2 per year, Sabah in particular receives one of the highest insolation levels in Malaysia, with the area around Kota Kinabalu identified as especially productive. In theory this energy would be sufficient to meet Sabah's entire electricity demand if it could be used in conjuction with large hydro storage schemes such as exist in Sarawak.

It is important to appreciate that solar power is increasingly being used globally to augment supplies to domestic and commercial users, particularly those with high air conditioning or cooling loads. Solar PV is now price-competitive without subsidies in fifteen countries, with costs having fallen from about $3,000/kW in 2005 to under $1,000/kW today – very competitive with fossil fuels especially when it can be used to mitigate daytime peaks due to air condioning and cooling loads. As a result, solar power is more and more likely to be used in Borneo's larger demand centers, and could well become a disruptive force in the management of Bornean distribution operations.

As noted above, Concentrating Solar Power (CSP) technology uses sunlight to produce steam which is then used to generate electricity. The possibility of integrated thermal storage is an important feature of CSP plants, and virtually all of them have fuel-power backup capacity. CSP thus offers firm, flexible electrical production capacity to utilities and grid operators while also enabling the effective management of a greater share of variable energy from other renewable sources (e.g. solar PV and wind power). Hybrid systems couple traditional fossil fuel-powered plants with CSP technology to improve the efficiency and performance of both systems and marry baseload power with new, cost-effective capacity.

[30] Hydro power could take the form of large, traditional hydropower projects wherein a dam is used to gain elevation and create a reservoir that evens out water flow between rainy and dry seasons. In contrast, smaller "run-of-river" installations do not rely on a dam, but rather harvest the river's natural kinetic energy by diverting water into a pipe running alongside the river, passing it through a turbine, and then returning it back to the river channel. Production from the latter is difficult to manage and can be severely disrupted during drought.

Figure 9 Potential For Marine Energy in Makassar Strait



(Left) Expanded view of the Makassar Strait region. The solid grey lines mark the approximate pathway of the Makassar throughflow. (Right) Schematic of the Indonesian throughflow pattern. The grey box delineates the expanded view shown on the left.

Source: Makassar Strait through flow 2004 to 2006 GEOPHYSICAL RESEARCH LETTERS, VOL. 35, L24605, doi:10.1029/2008GL036372, 2008

Marine Power. Borneo's significant coastline also offers the possiblity to develop both wind and marine energy. In particular, the Strait of Makassar has very high seasonal tidal flows which could possibly be exploited using techniques such as that proposed by Minesto.[31] While Marine power has yet to make a significant impact in the world's renewables market, experts considered this will be a major source of power in the next 5-10 years.[32]

3.6 Harmonization of Power Systems in Borneo

The ASEAN Final Technical Harmonization Report[33] covered a number of major principles relevant to the planning, development, operation and maintenance of an ASEAN Power Grid, including the requirement for the respective systems to be designed so as to: (i) maintain supply and unrestricted flow of electricity at all times; (ii) balance supply and demand over each Control Area; (iii) ensure the transmission of power, including maintaining adequate reactive power levels and providing adequate reactive power when needed; (iv) respond to system faults and disturbances in a coordinated manner; and (v) provide communication to ensure that Transmission System Operators in each Control Block / Control Area know what is happening.

Borneo utilities all use conventional 50Hz high voltage alternating current (HVAC) mainly as overhead transmission lines (OHTL) based on Malaysian (formerly U.K.) or Indonesian (formally European) standards. As explained below, these HVAC facilities will need to be augmented with new HVDC technologies to transmit power over long distances or via submarine links.

[31] See: http://www.minesto.com/deepgreentechnology/

[32] See conference papers for "The 8th International Tidal Energy Summit" 24-26 November 2014 London: http://www.tidaltoday.com/tidal-conference/

[33] See ADB's TA-7893 REG: "Support to Achieve the ASEAN Economic Community and Accelerate the Narrowing of Development Gaps by 2015 - Harmonization Study for ASEAN Power Grid" (45075-001) Sept 30 2013

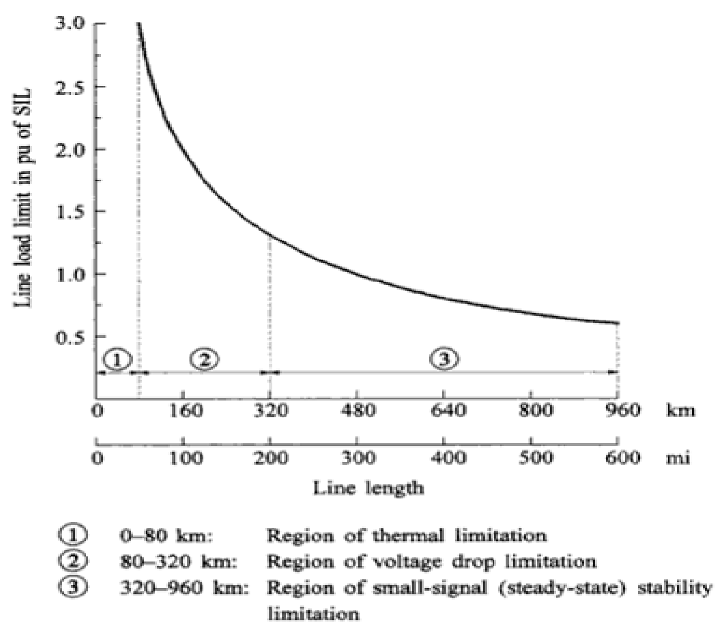
Most of the power system interconnections within Kalimantan have been based on the extension of PLN's standard 150kV sub-transmission grid that has been used extensively in the more densely populated regions of Java and Sumatra. However, since distances between load centres in Borneo are quite long,[34] it is questionable whether 150kV is an appropriate voltage to use for inter-provincial transmission lines, especially as the lines become more heavily loaded in future. While interconnections between Kalimantan and Sabah or Sarawak are likely to continue using the 275kV standard, which is common in Malaysia[35] and deployed throughout Sumatra, future interconnections to transfer bulk power in excess of 1,000 MW over longer distances would need to use the 500kV overhead design.

At this stage of planning, it can be concluded that no significant harmonization issues would need to be addressed with regard to interconnecting Borneo systems. There will naturally be technical issues arising from the interconnection of long transmission lines, and voltage and stability issues will need to be properly addressed by technical studies. It is also unlikely that there will be any significant harmonization issues relating to HVDC interconnections between Borneo and offshore island systems (including the Philippines, which operates at 60Hz). In these cases, HVDC will effectively be a buffer between systems, isolating one from the other and enabling each to operate independently.

3.7 Transmission Line Loadability

HVAC transmission lines are limited in their ability to transfer large amounts of power over long distances due to the complex interrelationship of their natural electro-magnetic characteristics. The limitations are normally expressed in terms of: (i) transmission line "inductance," a current-induced reactive function of conductor size and spacing, and (ii) "capacitance," a voltage-induced reactive function of tower height and spacing. The limiting affect on transmission capcity caused by induced reactive power flows during periods of high and low loadings must be mitigated periodically by the installation of capacitors or inductors at intermediate substations.[36]

Figure 10 Loadability of Transmission Lines as a function of SIL and Line Length



Source: IEEE Transactions on Power Apparatus and Systems, Vol.PAS-98, No.2 March/April 1979

When such transmission lines are interconnected with each other, the resulting power system flows must be analyzed carefully to ensure that interactions between active and reactive power flows are stable. Such analysis would require: (i) load flow studies to verify adequate voltage conditions, (ii) fault studies to ensure that faults are safe and detectable to protection relays, and (iii) stability studies to ensure that connected generation and loads do not

[34] PLN RUPTL 2013 proposes to extend the 150kV line about 800km from Kalbar to Kasel by 2020. This would be far too long to transfer Sarawak hydro power to Kalsel or cola fired power from Kalsel to Kalbar without building intermediate substations fitted with adequate reactive capacity to maintain voltage and stability levels.

[35] 275kV has also been used to evacuate power from the Asahan hydro scheme in North Sumatra and can be considered a relevant PLN standard for areas such as Kalimantan where 150kV transmission is inadequate.

[36] Other more sophisticated techniques are increasingly being used to improve the performance of HCAC lines. These are generally termed "FACTS" (flexible alternating current transmission) devices.

oscillate out of control under normal or fault conditions. Accordingly, transmission line "loadability" is a function of a number of factors that are characterized by its Surge Impedance Loading (SIL), a design parameter that is used to compute the permissible loading for lines of various lengths. The interrelationships between parameters are shown in Figure 10 derived from the original St. Clair curve.[37]

For a typical PLN double 150kV circuit tower configuration, with 240 mm^2 ACSR conductor, the SIL is about 85 MW. Thus for a length of about 200km, a 150kV line can be loaded to roughly 1.7 times the line's SIL, or about 180 MVA. On the same basis, the loadability of a single circuit 275kV line would be about 300 MVA. Other options to increase loadability could include the use of bundled twin conductors that are normally used to manage corona and radio interference effects on HV transmission lines 220kV and above. The reactance of a twin conductor is 20% more than a double circuit of the equivalent cross-sectional area. This means that a double circuit has a higher loadability than an equivalent bundled conductor design along with extra reliability and higher stability limit.

3.8 Cost Estimates for HVAC Lines and Substations

Transmission lines have a typical life of 40-60 years. Accordingly, it is prudent to reduce up-front costs as much as possible by making provisions that will allow for upgrading at a later date. It is common practice to build tower-insulator clearances suited to a higher voltage standard (e.g. build a line for eventual 275kV operation) but use the line initially at a lower voltage (e.g. 150kV). This enables the utility to delay having to install the requisite 275/150kV transformers and associated substation equipment. It is also common practice to initially install only one circuit of a double circuit line; this allows transmission line to be upgraded by adding a second circuit as the need arises, either to increase capacity or to improve reliability.

Selecting the conductor rating is a key variable in estimating cost. The conductor rating determines the cost of the line, the power that can be transmitted, and the losses incurred in transmission. The physical characteristics of conductors also determine the structural strength and therefore the weight and construction cost of the steel towers. Conductor cost is determined by its aluminium and steel raw material content, the prices of which can vary significantly.

For a given conductor's size and environmental conditions (since wind speed and temperature conditions largely determine tower heights and loadings), transmission line capacity is a function of voltage (affecting tower heights) and distances between substations (as limited by the transmission line SIL). Another important cost factor is reliability, as determined by the ability of the lines to maintain a given level of service (e.g. n, n-1 etc.). Cost is also influenced by whether a route is high-altitude, since low air density affects insulation characteristics and thus tower and conductor design costs. Finally, construction costs can vary based on a particular route's terrain and accessibility.

The contracts signed recently to build lines from Sarawak to West Kalimantan have provided a basis for estimating the construction costs of 150kV and 275kV lines. These lines are being built over typical Borneo terrain and require supply and delivery logistics that would be similar to other remote areas of Borneo. The analysis shows that a typical PLN double circuit 150kV line would cost about $160,000 per kilometer, compared to about $300,000 per kilometer for 275kV lines. Likewise, component substation bay costs can be shown to be about $1.1 million per bay (150kV) or $6 million per bay (275kV), plus other associated costs for busbars, communications facilities and civil works. While these costs would need to be adapted in the case of more difficult terrain, they can be taken to adequately represent today's cost of transmission development for the purposes of this study.

As shown in Annex 4, these unit costs have also been used as the basis for determining the cost of HVDC lines (which are usually expressed as a percentage of the equivalent capacity HVAC line). In this case, it has been assumed that a typical bipolar HVDC ±250kV line should cost about 60% of the equivalent capacity 275KV double circuit line.

[37] R. D. Dunlop, R. Gutman, and P. P. Marachenko, "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines", IEEE Transactions on Power Apparatus and Systems, Vol, PAS-98, No. 2, March/April 1979, pp. 606–617.

Based on PLN standards, a staged transmission upgrade plan might thus include the following steps:

Table 4 Typical Stages of Development of MV and HV AC Transmission Interconnections

Step No.	MVA	Rel[a]	Dist km	Operatn (AC)	Construction Type & Stage	Cost
I	10-20	n	20	11-20kV	Usually built along roads for easy access	$25k/km
II	50	n	100	70KV	Usually built to small remote loads with little growth	$80k/km
III	150	n	100	150kV	Build a single or double circuit line for 150kV operation	$100/kmsc $180/kmdc
IV	150	n	200	150kV	Build a double circuit line for eventual operation at 275kV	$300k/kmdc
V	150	n-1	200	150kV	Add second circuit on existing towers	+$30k/km
VI	300	n-1	200	275kV	Add 150/275kV transformers at terminations of existing line	+$20k*500
VII	2,000	n-1	500	500kV	Build 500kV d/c line	$600k/km

[a] The n-1 reliability criterion expresses the ability of the transmission system to lose a linkage without causing an overload failure elsewhere. Likewise the n-2 criterion is a higher level of system security for special supply zones, where the system can withstand any two linkages going down. Additional criteria may include a requirement for load shedding - disconnecting certain large power consumers to maintain supplies for the rest of the network, and rescheduling of generation to bring on generation units at short notice that normally would not be used.

Source: Own estimates

3.9 HVDC Transmission

For point-to-point distances over 500 kilometers, HVDC transmission links would normally be built at a lower overall cost than conventional HVAC lines. Although HVDC lines can be constructed at about 50% of the cost of an equivalent HVAC line, the cost of the necessary HVDC/HVAC converter stations are about $120/kW, compared with $20/kW for a conventional HVAC/HVAC substation.

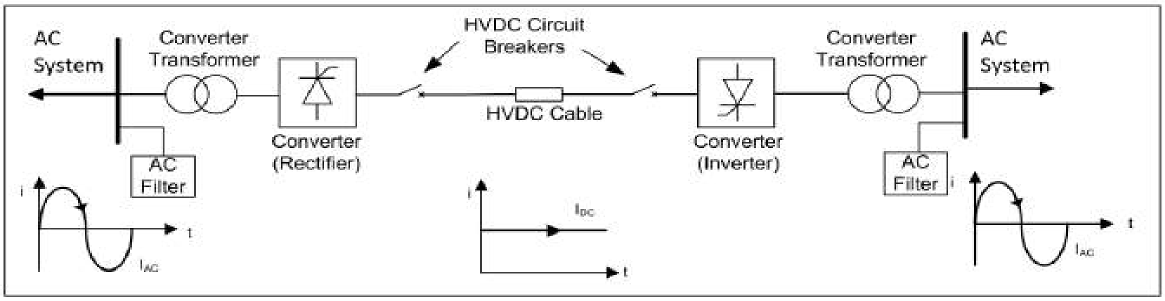
Although HVDC technology has had many years of operational experience,[38] new control systems have been developed recently which reduce cost and improve flexibility and performance. This is based on modern, newly developed voltage source converters (VSC[39]) with series-connected insulated gate bi-polar transistor (IGBT) valves controlled with pulse width modulation (PWM) that have already reached levels of 1,200 MW and ±500 kV. There are a number of such projects already in operation, and applying this concept initially at ±250 kV seems ideally suited to Borneo's situation with very long lines and relatively low loads en route.

Notably, HVDC can also be built in stages to increase loading, as required. This can be done by first building the line for monopole operation, then later uprating to bipole operation—and, if necessary, uprating again using a higher operating voltage. Given that the line is designed for its ultimate operating configuration (at little extra cost), the cost lies primarily in uprating the HVDC/HVAC terminals at each end of the line.

[38] HVDC was originally developed to supply large volumes of power over long distances. The first large-scale commercial project was installed in 1965 in New Zealand where a 600 MW HVDC line was built to carry power from the South Island 600 km to the North Island. This has operated very reliably for over 45 years and was recently upgraded to 1,400 MW. Over 200 HVDC systems have been built over the years. The longest HVDC link in the world is currently the 2,071 km ±800 kV, 6,400 MW link connecting Xiangjiaba Dam to Shanghai in the People's Republic of China.

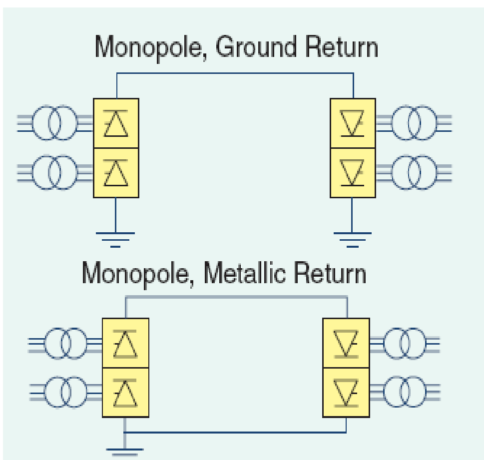
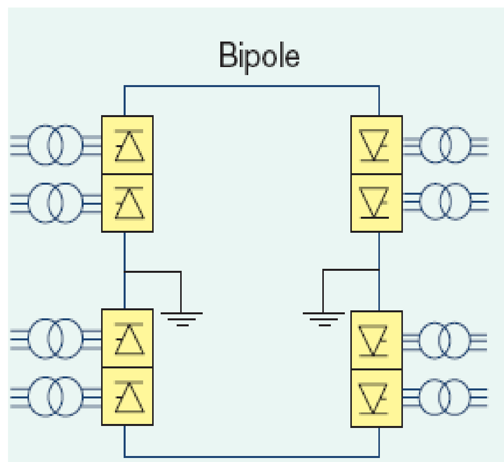
[39] e.g., ABB's HVDC Light, Siemens HVDC Plus, Alstom's HVDC Maxsine.

Figure 11 Typical HVDC Interconnection Arrangements



Source *IEEE power & energy magazine*, March 2007.

Figure 12 Uprating HVDC Interconnection From Monopole to Bipole Configuration

HVDC Monopole Configurations	Monopole Uprated to Bipole Configuration
	

Source: IEEE power & energy magazine, March 2007.

HVDC is also required to interconnect unsynchronized large power systems, like those between Borneo and any of its potential offshore interconnections. An HVDC interconnection for this purpose is sometimes effected with an HVDC back-to-back facility, thereby enabling both power systems to maintain their own system frequencies independently of the other.[40] HVDC effectively enables two power systems to be interconnected without having to re-synchronize at every forced or planned disconnection. However, in considering a HVDC back-to-back facility, it is prudent to consider building an HVDC interconnection instead to achieve the same objective at much lower cost.

[40] The ability to synchronize all types of electricity generation plant within an integrated alternating current (AC) power system is key to ensuring the most economic operation of a country's generation plant is used to provide reliable supplies to consumers. For a small AC system it is relatively easy to lock one of more generators together by carefully controlling their respective speeds until they are identical and then quickly connecting them together. For a larger power system interconnection must be made according to an established Grid Code for the network to ensure failure of any unit or line does not adversely impact other units in the system. Once interconnected however the respective generators can be readily coordinated by observing common market rules to serve an aggregated regional demand according to their economic or technical advantages.

HVDC is also used in many countries, in parallel with HVAC systems, to improve system stability at both ends of the HVDC line. In effect, HVDC can be designed to act as a very fast FACTS operating device designed to inject power into the HVAC system and counteract inherent instability problems.

3.10 Submarine Transmission

Offshore interconnections that require submarine cables of more than 50 km would normally require point-to-point HVDC links with operating voltages determined by the capacity that they are expected to provide. While it will be possible to supply at least one local load en route, there are currently very few such multi-terminal HVDC links in the world. Notably, it is not technically feasible to use HVAC submarine cables for long distances because the high capacitive loading in cable networks restricts loading capacity. It is also important to note that for extra-high voltage (EHV) overhead lines in excess of about 500 km, it is usually more economical to use HVDC.

The use of long undersea cables is also fraught with technical issues, which have been well summarized in a recent UNDP report.[41] While there is much international experience in undersea cable laying, it has not always been positive, especially on seabeds subject to intense volcanic and earthquake activity (such exist in the Sulu Sea southwest of the Philippines). Nevertheless, there is considerable hard-won regional operating experience already within PLN with its Java-Bali 150kV submarine cables[42] and in the Philippines with the ±500kV Leyte-Luzon HVDC cables.

Any future links with North Sulawesi, Mindanao or even Java would need to use HVDC bipolar cables, probably rated to operate between ±250kV and ±500kV depending on the agreed transfer capacity. PLN may prove to prioritize exports to North Sulawesi or Java over cross-border exports, which are subject to international agreements and fraught with political constraints.

Because of the considerable distances involved in sending power from Borneo to Manila, as well as the problems of long undersea cables, any future link with Leyte is also likely to use HVDC for most of the route – with perhaps one take-off in Palawan to support local development. It could be possible to convert back to HVAC in Palawan en route, but local demand would need to exceed about 1,000 MW to justify multiple HVDC/HVAC conversions.

3.11 Comparative Costs of HVDC and HVAC Transmission Facilities

The chart[43] below shows the cost relationship between HVAC and HVDC for different loading levels, taking into account their various components. The key difference is the cost of overhead lines, wherein HVDC lines cost 60% of the price of HVAC lines, the costs of which in turn vary according to voltage. HVDC lines are much simpler in construction and have less impact on the environment, plus AC lines require shunt capacitors every 100-200 km, costing about $20/kW. The cost of terminal converter equipment is typically about 120–150$/kW, depending on the chosen configuration. Notably, the cost of HVDC line commutated convertor (LCC) facilities have been relatively constant for the past decade. The cost of new designs using voltage source converter (VSC) technology have been up to 25% higher, though that difference has reduced in the last two years.

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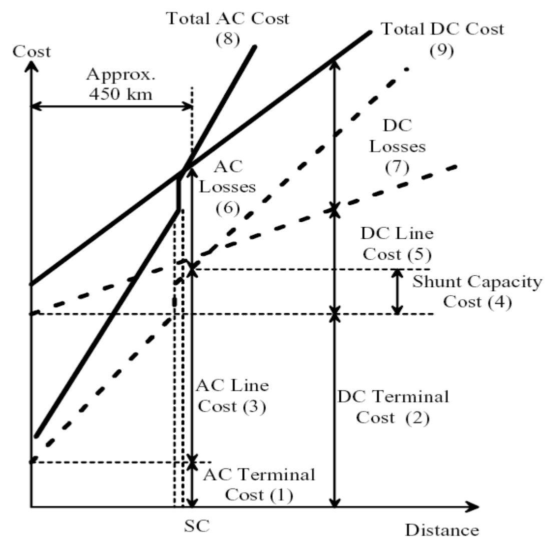
[41] See: 2009 UNEP WCMC Report by The International Cable Protection Committee Ltd (ICPC), "Submarine cables and the oceans: connecting the world ,"ISBN: 978-0-9563387-2-3.

[42] Seven out of nine 150kV cables between Java and Bali have failed over the past 20 years.

[43] The chart is taken from the book HVDC Transmission Chapter 1 Fig 1.3 of 2009 publication "Development of HVDC technology" by Cha-ki Kim et al: published by John Wiley & Sons.

Figure 13 Component Breakdown of HVDC and HVDC Costs over Distance



3.12 Economic Evaluation of Interconnection Options

The interconnection of adjacent HV networks generally offers the following economic and technical advantages which, over the long-term life of a transmission facility (typically 40-60 years), would be incorporated into the least cost development plans for the respective power systems of Borneo.

Table 5 Main Factors to be Considered in Evaluating Transmission Alternatives

1	Possibility of using larger and more economical power generation plants
2	Reduction of the necessary generation reserve capacity in each power system;
3	Earlier utilization of the most favorable regional energy resources;
4	Flexibility of building new power plants at favorable locations;
5	Increased reliability in the power systems; and,
6	Loss reduction.

The financial and economic evaluation of a specific transmission proposal is often concerned with a short-term outlook, often only considering the planned operational and commercial usage of the link for 5-10 years. This could include one or more of the following scenarios: (i) a firm energy purchase over a specific time period, which is usually associated with a dedicated power plant supplying a separate power market; (ii) an economic exchange of power or energy in either direction between two independently operated powers systems; or (iii) reserve or emergency power for short-term transactions. However, over the life of the transmission line, some of these restrictions on power exchange rules can change significantly as each interconnection is seen as an integrated element of the power system.

A key factor in determining the long-term viability of a transmission interconnection is its nominal wheeling rate for power trading operations. There are naturally other (sometimes more important) quantifiable costs and benefits of interconnection, including the ability to: (i) aggregate supply and demand and thereby reduce generation reserve requirements, (ii) provide stabilizing reactive power (particularly in the case of HVDC interconnections), and (iii) facilitate short-term energy supplies while a new plant is being built.

The nominal wheeling rate is determined by computing the present value of energy volumes carried by the interconnection and transferred over the specified period. It is largely affected by the Load Factor (LF), the WACC, and the period concerned. For interconnections that are used for peak lopping purposes, the LF is quite small (10-20%), for bulk one-way energy transfers, the LF may be quite large (50-60%). Table 6 indicates how much a nominal wheeling rate might vary (i.e. from .31c/kWh to 2.64c/kWh) according to changes in these key assumptions (shown in red).

Table 6 Variation of Nominal Wheeling Charges by LF, WACC and Yrs

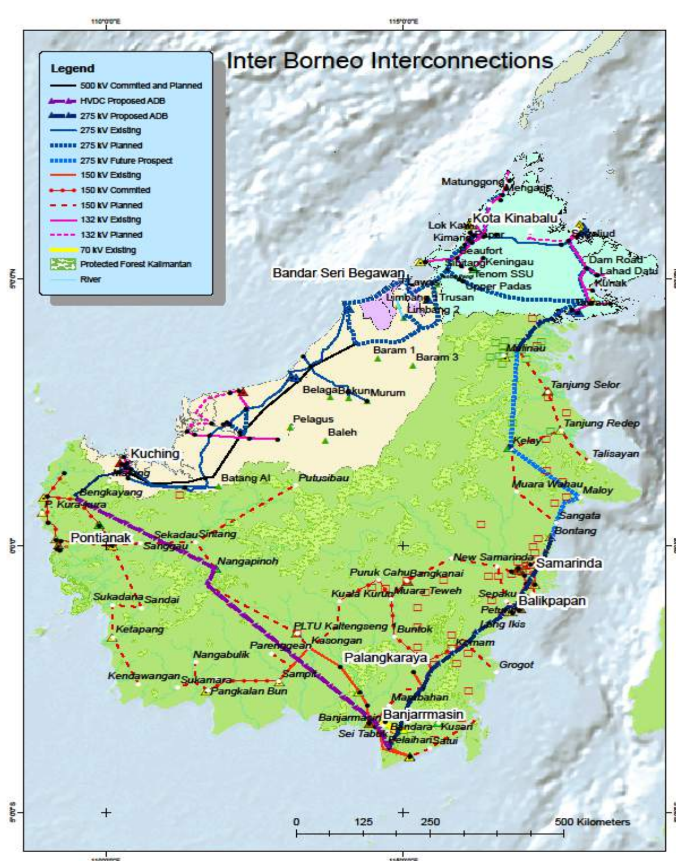
Variation of Wheeling Rates According to LF, WACC and Duration								
Interconnection Capacity and Cost				MVA	300	US$m	60	
PVF parameters			WACC	5%		Period (yrs)		20
Interconnection Duty		LF	Period	PVF	c/kWh	WACC	PWF	c/kWh
Peak Sharing		20%	5	4.33	2.64	5%	12.46	0.92
Net Power Exchnage		40%	5	4.33	1.32	5%	12.46	0.46
Bulk Exports		60%	5	4.33	0.88	5%	12.46	0.31
Peak Sharing		20%	20	12.46	0.92	10%	8.51	1.34
Net Power Exchnage		40%	20	12.46	0.46	10%	8.51	0.67
Bulk Exports		60%	20	12.46	0.31	10%	8.51	0.45

The examples below indicate how different types of interconnection projects shown in Figure 14 have been or may be justified in terms of short-term planning:

Financial Justification of Sarawak-Kalbar Link. The interconnection of Sarawak and Kalbar is an example of how a long-term transmission asset was justified based on short-term benefits. Over the next decade, the new line (capable of carrying up to 300MVA/cicuit) will enable PLN to import up to 230 MW of power generation to the West Kalimantan grid. This will enhance PLN's least-cost generation plan by combining power imports from Sarawak with other Indonesian base-load generation from oil or coal; PLN will thereby avoid the high expense of generating power by burning oil.

The base scenario assumes that only 50 MW will be take-and-pay for off-peak time for the first five years, and only 50 MW will be purchased at a 25% higher tariff as base-load after the first five years of contract. The high-case scenario assumes that 100 MW will be taken for the first five years, and the same capacity will be purchased by PLN for 15% higher. It has

Figure 14 Potential Interconnections within Borneo and with Neighboring Power Systems



been proposed that power imports to Kalbar may further reduce future costs as Sarawak plans to reduce its average power generation cost to below $0.10/kWh. However, it can also be assumed that PLN will use the opportunity to build its own base of competitive generation, and may over time be in a position to supply to Sarawak.

Justification of the Sarawak-Brunei-Sabah Interconnection. It is currently understood that: (a) Sabah is urgently in need of peaking capacity; (b) power supplies in Brunei from its newly uprated combined-cycle plants are adequate to meet domestic demand; and (c) Sarawak still has some uncommitted hydropower surplus. In this case, it is assumed that the financial and economic justification of a 275kV interconnection between Sarawak, Sabah, and Brunei will have many mutual benefits, particularly based on scenarios (b) and (c) above.

One initial benefit of interconnection will be export from Sarawak to Sabah (on a similar basis to the Sarawak-Kalbar link), and by transferring power through Brunei (at a beneficial wheeling rate), the supply of all three utilities will be better secured. The financial and economic benefits of the power exchange component will most likely be defined by a PEA which sets out power transfer prices and wheeling charges agreed in a power trading formula. The financial and economic benefits of the increased security would be determined through independent “with-link” and “without-link” power system stability studies. Each utility would compute how much benefit they would receive from the interconnection based on what they would save in reducing their reserve requirements. For Brunei, the link would provide access to independent power sources in its east and west. For Sabah and Sarawak, the link would provide access to fast-acting gas turbine spinning reserve in Brunei.

Aggregation of Kalbar-Kaltim Demand Centers. In the short term, the main economic benefit of both the proposed Kalbar-Kalsel HVDC and Kalsel-to-Kaltim 275kV backbone lines would be the aggregation of electricity demand in these regions to enable the building of larger, more efficient coal-fired power plants. In this instance, the aggregated system demand would increase from about 2,000 MW to about 5,000 MW, justifying the early use of larger generating unit sizes. Assuming they would be no more than 10% of demand, the unit sizes could typically range from 250-500 MW. The optimum unit size for a coal-fired plant would need to be determined through detailed system stability studies that account for the impact of the loss of a generator (or for that matter, the loss of a transmission interconnection). These can cause large power imbalances and, consequently, significant frequency excursions. In the longer term the HVDC line could offer other benefits when its capacity is increased to bipolar operation in accordance with load growth. In particular it would provide a means of stabilizing the two HVAC systems at both ends of the line as well as eliminating circulting currents when the 275kV ring around Borneo is completed.

Enclave project. The proposal to build an IPP coal-fired plant in Kalut mainly to supply the load in eastern Sabah would probably be treated as an enclave project for the first few years of operation, or at least until a 275kV interconnection between Kalut and Kaltim is built. The power exchange would most likely be contracted on the basis of a take-or-pay PPA for 5-10 years to enable the IPP operator to secure financing. The PPA would also require PLN and SESB to build the interconnecting transmission network and include terms to pay a fixed wheeling rate to cover the costs of building the 275kV and substations.

Export to Mindanao. This project would need to be strongly supported by the Philippine government in terms of financing the bulk of the costs for the submarine interconnection and enabling access to the Mindanao power market, probably through some form of agreed minimum takeoff arrangement.

Export to Large Markets (Java, Peninsular Malaysia, and Luzon). These are major projects that will probably be more related to concerns over energy security, and justified accordingly. While the Java interconnection is not currently included in PLN’s long term plans, it may well be considered further, particularly if the situation in Java becomes more critical.

4 Kalimantan Electricity Development Planning (PLN)

4.1 Indonesian Power Planning Responsibilities

Two national power development plans are used in Indonesia: the *Rencana Umum Ketenagalistrikan* Nasional (National Electricity Plan, or RUKN) and the *Rencana Usaha Penyediaan Tenaga Listrik* (Electricity Supply Business Plan, or RUPTL). RUKN is a government document prepared by the Director General of Electricity within Indonesia's Ministry of Energy and Mineral Resources (MEMR),[44] providing a twenty-year masterplan of primary energy potential and demand forecast that is updated and published every year. RUPTL[45] is a business plan prepared by PT PLN (Persero) as a ten-year plan for generation, transmission and distribution expansion which is primarily used for PLN's budgeting purposes. RUKN provides PLN with the basis of its planning to reach the government's target to extend electricity access to 99% of the population by 2030. This target is used by PLN to derive its demand forecasts. Electrification consumer targets for Kalimantan derived from the RUPTL are summarized in Table 7.

Table 7 RUKN Electrification Targets: Consumer Numbers

Summary of Consumers Required to be Connected in Kalimantan							Annual
Year	Kalbar	Kalsel	Kalteng	Kalim	Kalut	Total Kalim'tn	Kwh/C
2013	834,147	960,354	430,458	626,073	47,176	2,898,208	2538
2014	874,156	997,400	483,612	674,347	50,814	3,080,329	2752
2015	918,602	1,036,362	539,382	724,317	54,579	3,273,242	2882
2016	964,400	1,071,786	592,785	776,003	58,474	3,463,448	2985
2017	1,022,070	1,108,007	647,995	829,243	62,486	3,669,801	3087
2018	1,061,362	1,145,043	677,765	884,211	66,628	3,835,009	3236
2019	1,112,432	1,182,915	706,011	940,538	70,872	4,012,768	3389
2020	1,165,896	1,221,644	734,794	998,595	75,247	4,196,176	3543
2021	1,221,551	1,253,667	761,541	1,058,397	79,753	4,374,909	3708
2022	1,279,864	1,282,084	788,340	1,119,748	84,376	4,554,412	3888

Source: PLN RUPTL 2013–2022

4.2 Energy Resources in Kalimantan

Kalimantan is thought to be endowed with considerable, but in many cases unexplored, natural resources of hydro, coal, and gas; these are complimented by yet-unquantified renewables such as wind, solar, biomass and marine energy. The basis for the estimates of each resource is summarized as follows:

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[44] See http://www.djlpe.esdm.go.id/

[45] See: http://www.pln.co.id/dataweb/RUPTL/RUPTL%202013-2022.pdf

Hydro Development Opportunities. Estimates of Kalimantan's hydro potential vary widely. One report indicated a potential of 21,000 MW in 171 sites, but evidence for this assertion is lacking. A desk study in 2005 based on a preliminary reconnaissance by a local consultant (PT Wiratman) indicated there may be 5,572 MW in 15 schemes located in northeastern Kaltim/Kalut. Of these, Kayan 2 is listed as 2,070 MW, and the cascade of eight stations along the Sesayah river aggregated to about 2,000 MW.

The scope for hydro development throughout Indonesia was evaluated more realistically in 2011 by the Japanese International Cooperation Agency (JICA).[46] This study, a comprehensive update of previous hydro development masterplans, was designed to develop a list of prospective projects throughout Indonesia that had passed previous screening processes and for which detailed design, feasibility study and pre-feasibility studies had been finished. For Kalimantan, the projects listed below are the only ones that have been studied in any detail. Notably they are all characterized by large reservoirs, mostly because of the gentle topography, which is likely to make development difficult. Most other rivers are generally quite short with steep slopes and not well suited for hydro development.

Table 8 Summary of Kalimantan Hydropower Schemes in their Various Stage of Development

Extract from JICA Table 4.5.1 List of Planned Hydro Schemes with Current Status								
No.	Name	Province	Type	Installed Capacity (MW)	Annual Energy (GWh)	Status in HPPS2 (1999)	Current Status (2010)	RUPTL 2013-22 I/S year
36	Riam Kiwa	South Kalimantan	RES	42	152	DD	DD	
37	Pade Kembay	West Kalimantan	RES	30	235	FS	FS	
38	Kusan-3	South Kalimanatan	RES	68	101	FS	DD	2015
39	Amandit-2	South Kalimantan	RES	2.5	20	Pre FS	Pre FS	
40	Kelai-2	East Kalimantan	RES	168	1,103	Pre FS	FS	2019
41	Kayan-2	East Kalimantan	RES	500	3,833	Pre FS	Pre FS	
42	Pinoh	West Kalimantan	RES	198	1,375	Pre FS	Pre FS	2018
43	Silat	West Kalimanatan	RES	29	130	Pre FS	Pre FS	

Source: JICA Project for the Master Plan Study of Hydropower Development in Indonesia 2011

Developing hydro power in Kalimantan faces many challenges. For example, the feasibility study of the Kusan 3 Hydropower was completed from 1988 to 1990. According to the design, the installed capacity was originally 130 MW supported by the 100-meter high dam and the 40 km^2 widespread reservoir. Because of the large area submerged by the reservoir, some 670 inhabitants were required to be resettled and the project was stopped. In 2008, JICA reviewed the project and re-planned it on a much smaller scale. The revised plan features 65 MW of capacity with the 69-meter high dam and 8 km^2 of reservoir with no resettlement requirements. Although considerable attention was paid to preserving social and natural environments, the project was not able to progress. This was largely because the long-nosed proboscis monkey, registered as an endangered species by the International Union for Conservation of Nature (IUCN), was found within the project area and no mitigation measures for coexistence with the project could be framed.

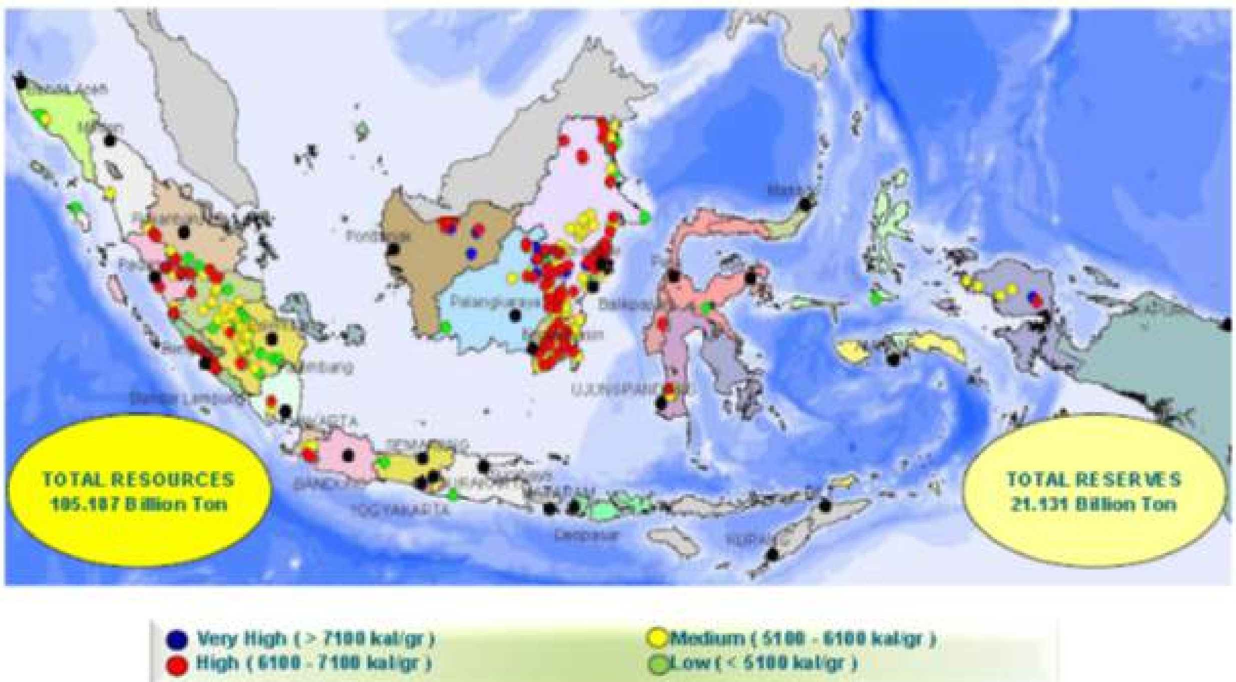
Gas Resources. The Bontang LNG plant in Kaltim has eight processing trains and a capacity of 22.2 million metric tons per annum (mtpa) of LNG. It is supplied with gas from offshore Mahakam, Sanga-Sanga, Makassar, Attaka and East Kalimantan. From a peak production level in 2001 of just over 21 mtpa, LNG exports fell to 10.5 mtpa in 2010 due to declining supply from 80% of Bontang's natural gas sourced from Total's fields in the Mahakam PSC area. Term contracts with several Japanese customers were not renewed in 2010 and 2011, enabling Bontang LNG to divert some LNG production to the domestic market.

[46] See: "Project for the Master Plan Study of Hydropower Development in Indonesia FINAL REPORT," JAPAN INTERNATIONAL COOPERATION AGENCY by NIPPON KOEI CO., LTD (August 2011).

Indonesia planned to begin coalbed methane (CBM) production with an eye on a growing domestic gas market for power generation and the possibility of export.

Coal Resources. According to the BP's Statistical Energy Survey (2010), Indonesia had coal reserves of 4,328 million tons (0.52% of the world total). Forty-nine percent (49%) of Indonesia's coal resources were classified as being low-quality (<5,100 calories/gram), 26% as medium-quality (5,100 - 6,100 cal/gr), and 24% as high-quality (6,100 - 7,100 cal/gr). Government estimates total 12,466 million tonnes of measured reserves, 20,533 of indicated reserves and 24,314 million tonnes of inferred reserves. Kalimantan was cited as the country's leading coal-producing region; Kalteng itself held reserves of 1,400 Mt of high-quality metallurgical coal and produced 1.5 Mt/yr of high-grade coal from fifteen coal mining companies.

Figure 15 Distribution of Indonesian Coal



Source Ministry of Energy and Mineral Resources.

Most of these coal resources are being developed by a number of small and large developers for export. The largest, BHP Billiton, plans to develop the 774-Mt Maruwai deposit in Kaltim and Kalteng to produce 6 million metric tons (Mt) per year of combined thermal and coking coal and to expand output to between 15 and 20 Mt/yr. Minerals Energy Commodities Holdings (MEC) of the United Arab Emirates had expected a coal railway to start operating by the end of 2017 when its coal mine in Kaltim was to begin producing a limited amount (1 Mt/yr) of coal; the company planned to begin exporting 14 Mt of coal to Chinese and Indian power producers beginning in 2013. Kangaroo Resources Ltd. of Australia acquired Indonesian coal conglomerate PT Bayan Resources Tbk, including 99% of the Pakar thermal coal project in Kaltim, for $277 million. The Pakar project hosted a total coal resource of 3,800 Mt, including a total coal reserve of 116 Mt, and was ready for production in 2011. Kangaroo Resources' other Indonesian coal assets included the 100%-owned Mamahak coking coal project, the Tanur Jaya thermal coal project, and the GPK thermal coal project (Mineweb.com, 2010a).

Other Renewables. The potential for biomass, solar and marine power have not been investigated in Kalimantan but should indeed be capable of making important contributions to the Kalimantan economy. The conclusions presented in the University of California, Berkeley report on Sabah (see Section 5.3) are probably just as applicable to many other parts of Kalimantan/Borneo, particularly given the large areas that may be suitable for CSP plants combining solar power and gas to achieve low cost base power generation.

4.3 PLN RUPTL Electricity Planning Assumptions (2013–2022)

PLN's RUPTL covers the three main power supply regions of Sumatra, Java-Bali, and East Indonesia – the latter region aggregating power supply data for the larger islands of Kalimantan, Nusa Teggara, Sulawesi, and Papua, and the many hundreds of smaller islands between them. The main RUPTL report (550 pages) details the existing situation and annual planned increments for new generation, transmission lines, HV substations, MV and LV lines, consumer numbers and estimated costs for expansion. The plans are based on the knowledge and views of the local staff with regard to a priority sequence of generation development and anticipated distribution expansion in order to meet the government's targets for new connections. These publications include:

- System planning assumptions and planning criteria
- The existing condition and statistics for generation, transmission and distribution system
- Demand forecast for the next 10 years
- Generation expansion plan
- Transmission expansion plan
- Substation expansion and augmentation plan
- Distribution expansion plan by MV, LV distribution transformers & customer connections
- System load flow studies
- Investment plan
- Key indicator targets.

4.4 Generation Planning

To meet its obligations, PLN has a generation expansion plan designed to supply a growing aggregate peak load (summarized in Table 9). Because of Kalimantan's proximity to Sulawesi, the table also includes details for prospective demand growth in the two northern provinces of Sulawesi (Sulut and Gorontolo).

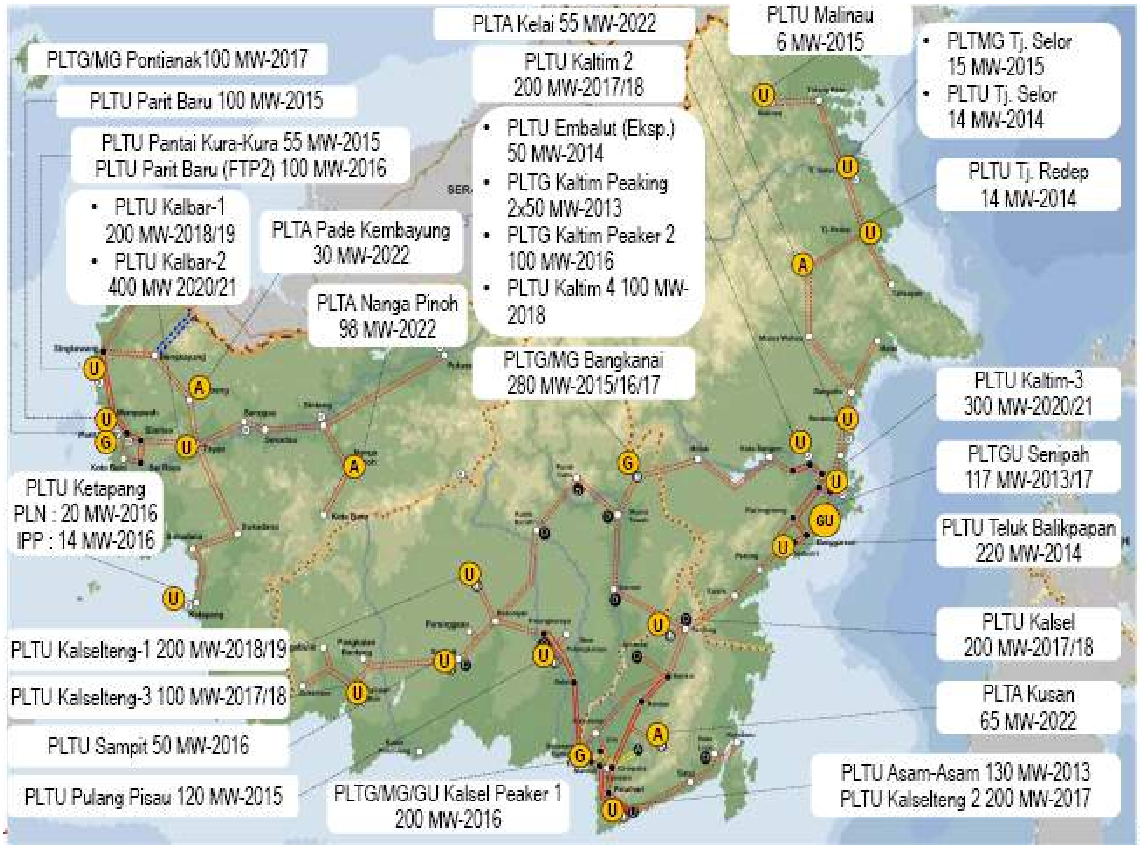
Table 9 PLN RUPTL Forecast of Electricity Demand

Summary of Peak Demand Growth MW in Kalimantan & North Sulawesi for Interconnected & Isolated Systems									
Year	Kalbar	Kalsel	Kalteng	Kalim	Kalut	Total Kalim'tn	Goront .1 Teng	Sulut	Total Nth Sulwesi
2013	371	406	177	467	26	1447	86	262	348
2014	402	447	198	555	30	1632	96	293	389
2015	457	476	240	636	36	1845	108	316	424
2016	512	499	281	697	39	2028	120	343	463
2017	569	537	299	765	44	2214	135	372	507
2018	632	580	320	840	48	2420	151	405	556
2019	701	615	343	925	53	2637	169	440	609
2020	777	654	363	1018	58	2870	190	479	669
2021	860	688	381	1122	64	3115	215	519	734
2022	951	729	402	1238	71	3391	241	563	804

Source: RUPTL Wilayah Reports. NB these include the MW contribution in isolated systems (not included in Table 3)

To meet this demand, PLN is proposing to develop a large number of mostly small generation plants, scattered throughout the provinces (as shown in the Figure 16). Most of the nominated 52 generation plants (Kalbar 16, Kalsel 8, Kalteng 8, Kaltim 15, Kalut 5) are not considered particularly efficient. They mainly include gas turbines or

Figure 16 Summary of PLN Generation Expansion Plan for Kalimantan to 2022



small package coal-fired plants based on standard designs from China. The RUPTL plan includes ten stations with one or two 100 MW units, which will operate at slightly increased efficiency (about 25%) over the other fifteen stations with unit sizes ranging from 3 – 25 MW (typically about 20%). The plan also shows that larger units will be used, but not until 2020 or after.

The table below shows how this plan will shift dependence from diesel generating units to coal-fired units by 2022.

Table 10 PLN RUPTL Generation Expansion Plan Plant Change in Plant Mix (MW)

	Existing Plant Mix MW 2014/15						Exist & Planned Generation MW in 2022					
Region	Diesel	Gas GT	Coal	Hydro	Other	Subtot	Diesel	Gas CC	Coal	Hydro	Other	Total
West Kalimantan (with Imports)	135	259		5	50	449	5	365	932	132.9	151	1586
Central-North-East	331	541	35	556		1463	331	1447	1924	676	0	4378
Total Kalimantan	466	800	35	561	50	1912	466	1812	2856	809	21	5964
Fuel Mix in Kalimantan	24%	42%	2%	29%	3%	100%	8%	30%	48%	14%	0%	100%

Based on the generation cost data given in Table 11, simplistic evaluations of the ten-year Long-Run Marginal Cost of Generation (LRMC) for both Kalbar and the interconnected Kalsel-teng-tim-ut (South/Central/East/North Kalimantan) systems are given in Annex 9-1 and 9-2, respectively. This analysis uses PLN's RUPTL data for the commissioning of new power and does not take into account the cost of extending the 150kV lines. It assumes a standard four-year construction period for the power plants and a weighted average cost of capital (WACC) or discount rate at 8%.

Table 11 Summary of Generation Cost and Availability Data Used to Compute LRMC

Generation Cost Table for Standard Generation Types							
	Typical	Fuel Prices		Effy	Energy	Capacity	Available
Generation Type in RUPTL	Unit Size	US$	Unit	%	c/kWh	$/kW	%
Diesel Generation Units	<20MW	120	$/bbl	38%	25	1000	70%
PLTU - Coal imports	<20MW	120	$/tonne	25%	15	3000	60%
PLTU - Coal Import at Port	20-100MW	100	$/tonne	32%	10	2000	70%
PLTU - Coal Minemouth	100-250MW	60	$/tonne	35%	6.5	1500	80%
PLTU - Coal (supercitical)	> 250MW	60	$/tonne	40%	6	1500	90%
PLTG/MG - Gas engines	<20MW	8	$/GJ	38%	10	1500	90%
PLTG GT - Gas Turbines	<50MW	8	$/GJ	33%	10	800	40%
PLTG - Combined Cycles	>100MW	8	$/GJ	45%	9	1500	90%
PLTA - Small Hydro ROR	<30MW				8	5000	40%
PLTA Large Hydro	>50MW				5	3000	60%

Source: Own estimates.

The computations presented in Annex 9-1, 9-2 and 9-3 show that, based on current planning using a large number of small generating units, the LRMC totals about 16c/kWh for Kalbar and about 17c/kWh for Kalseltengtimut. However, the analysis also shows that by building a sufficiently strong HV transmission backbone system to enable PLN to use a larger, more efficient coal-fired plant, the LRMC for the combined power system would fall to about 13c/kWh. While this is not intended as a thorough analysis of the LRMC for Kalimantan, preliminary analysis does suggest that PLN needs to aggregate demand as quickly as possible to enable larger, more efficient power plants to be built.

4.5 HV Transmission and Substations

The RUPTL's planning documents for PLN's *wilayah* level begin with two forecasted demand scenarios, a normal-growth scenario and a high-growth scenario, to achieve the government's target for 100% electrification by 2030. Demand is broken down and allocated to all major substations for the purpose of determining voltage performance with power flow during both normal load flow situations and contingency situations. If the model shows that system performance is outside the required parameters, new or upgraded transmission circuits are added. In this manner, a plan is developed to upgrade and reinforce the network on a yearly basis.

PLN's strategy in Kalimantan is to gradually interconnect all existing grids with 150kV lines by 2020. The network is characterized by very long double circuit 150kV lines with many intermediate substations that would be required both to evacuate power to the rural areas and provide reactive injections to maintain system voltages. As noted above the Kalimantan systems incorporate a number of small generating stations that are inherently likely to be more costly than a larger centralised station located closer to a natural resource.

Transmission and major HV-MV Substation planning is usually performed by PLN at its national level ("PLN Pusat"), though incorporates input from PLN's local *wilayah* branches. The plans are updated annually, so if demand does not develop as anticipated, plans can be readily changed to re-prioritize the transmission expansion plan. MV and LV planning is usually done at *wilayah* and subdistrict (*kabupaten*) levels. These local PLN organizations maintain lists of electrified and un-electrified villages, together with information relating to the village's distance from the existing 20 kV grid, the total number of households in the village, and the number of electrified households in the village. They prepare single line diagrams, drawn to scale, which detail the conductor size used and the distribution transformer capacity. Using this information, the least-cost method of supplying an un-electrified village can be established based on the key variables of distance to the 20 kV grid and number of households per village.

Although PLN's planning is supported by load flows for various intermediate years, it is questionable whether the extensive 150kV network will be stable or whether in fact it represents the least cost development. It is thus recommended that PLN conduct further studies in the form of a comprehensive masterplan to verify that RUPTL plans are indeed least-cost and meet adequate reliability standards. In this respect, PLN needs to consider alternate development plans that: (i) provide for the eventual use of a higher voltage backbone – possibly built for 275kV operation but operating initially at 150kV; (ii) consider the use of HVDC lines for longer routes (e.g. from Kalbar to Kalsel which would link the 275kV backbone); (iii) minimize the use of double circuit 150kV lines serving small load centres by providing instead for looped single circuit lines linked through the higher voltage backbone system; and (iv) eliminate the use of remote small generation facilities where these are not economically justified by making best use of power from interconnections with Sarawak and Sabah, and building large minemouth coal-fired plants at strategic locations in the backbone network.

4.6 North Sulawesi

JICA prepared a power development plan (PDP) for Sulawesi in 2008,[47] which has been used as a basis for PLN's RUPTL plans. This report presented the comprehensive proposal, including a PDP considering the characteristics of potential primary energy in Sulawesi, and the associated transmission development plan including an interconnection of small isolated systems to secure a stable power supply. The JICA report also considered alternatives for interconnecting North and South Sulawesi, concluding that the distance involved would probably require the use of a HVDC back-to-back link.

Figure 17 PLN RUPTL Transmission Planning for Northern Sulawesi Region

Because of its remote geography, the three PLN supply areas to northern Sulawesi include the northern part of Central Sulawesi ("Sulteng"), Gorontalo, and Sulawesi Utara ("Sulut"). The map below of the northern region of Sulawesi shows the relative distances between the North Sulawesi supply area and the northern-central Sulawesi, compared to the distance from Kalimantan. A full depiction of Sulawesi's North and South supply area is given in Annex 3.

The study concluded that an optimal generation plan through 2027 would treat both North and South Sulawesi separately. For the northern region, the plan consisted of a mixture of small (25 MW) coal-fired units (using coal imported from Kalimantan) and gas-fired units (25-50 MW), plus twelve 20-MW geothermal power plants (280

47 JAPAN INTERNATIONAL COOPERATION AGENCY by CHUBU ELECTRIC POWER CO., INC. NIPPON KOEI CO., LTD., "The Study on Optimal Electric Power Development in Sulawesi in the Republic of Indonesia," final report (2008).

MW). The study proposed that eventually the north and south systems shoud be interconnected by an HVDC back-to-back interconnector to provide the northern region with access to lower cost hydro power from the south and central regions of Sulawesi. It did not, however, investigate the possibility of mine-coal-fired power being produced in Kalimantan and supplied by cable across the Makassar Strait.

4.7 Java

The RUPTL power plans go into considerable detail with regard to meeting very high growth seen in Java. While it is beyond the scope of this particular investigation to study this plan in detail, it is recognized that there are significant constraints to expanding the use of coal-fired generation in East Java.

5 Northern Borneo Transmission Development Plans

5.1 Sarawak PDP[48]

Hydro Development in Sarawak. The first hydropower project built in Sarawak was the Batang Ai dam financed by the ADB. This relatively small dam completed in 1985 produces 104 MW. The operation of the dam was so successful that the Sarawak government decided to build the Bakun and Murum dams, primarily to export power to Peninsular Malaysia. The Bakun project was particularly controversial due to its catchment in a rainforest with some of the highest rates of plant and animal species found nowhere else on Earth. Constructing the dam also required the relocation of more than 9,000 native residents of indigenous peoples (mainly Kayan/Kenyah) who lived in the area to be flooded.

The Bakun Dam is an embankment dam located in Sarawak on the Balui River, a tributary of the Rajang River and some 60 km west of Belaga. It is the second tallest (height: 205m, length: 748m) concrete-faced rockfill dam in the world, built to generate 2,400 MW of electricity or 15,500 GWh annually. The project, which came online on 6 August 2011, was reputed to have cost $2.4 billion (i.e. about $1,000/kW capable of producing power with a high capacity factor). The original Bakun export scheme envisioned 730 km of overhead HVDC transmission lines in East Malaysia, 670 km of undersea HVDC cable, and 300 km of HVDC transmission lines in Peninsular Malaysia. From a technical and financial viewpoint, this transmission interconnection would have been an extremely challenging project and, if built, would have been the longest such submarine HVDC link in the world. The Malaysian Federal Government decided to cancel the HVDC link in 2010, but there seems to be some possibility that it could be revived in the near future.

The nearby Murum project has a 141m-high dam, with a reservoir area of 245 km^2 and storage capability of 12 billion m^3. It is fitted with 4 x 236 MW generators capable of producing a firm 5,680 GWh annually. Concerns have been raised about the displacement of the Dayak people and the rainforest destruction due to the dam's construction. Construction began in 2008 and the dam's reservoir began to fill in July 2013. The first generator should be operational in 2014 with all generators operational in early 2015. The dam site is located on the Murum River, which is in the uppermost part of the Rajang River basin, about 200 km from Bintulu. Upstream Rajang River includes four cascade plants (Pelagus, Bakun, Murum, and Belaga). Located 70 km from the Bakun Hydroelectric Project downstream, the Murum Hydroelectric Project is the second Step-Hydroelectric Project of the cascade to be constructed.

Sarawak's other hydro resources were confirmed in 1981 by the masterplan for Sarawak power system development created by SAMA Consortium, under technical aid granted to Malaysia by the German government through the German Agency for Technical Co-operation (GTZ). This study identified 155 possible dam sites with installed capacity of more than 50 MW each, with an overall combined identified capacity of approximately 80,000 MW. However, many of the dam sites are located very near to each other within one short river section. As such, these dam sites are not mutually exclusive, i.e. the development of one site will flood some others. Thus only 51 of the 155 identified dam sites can be independently developed.

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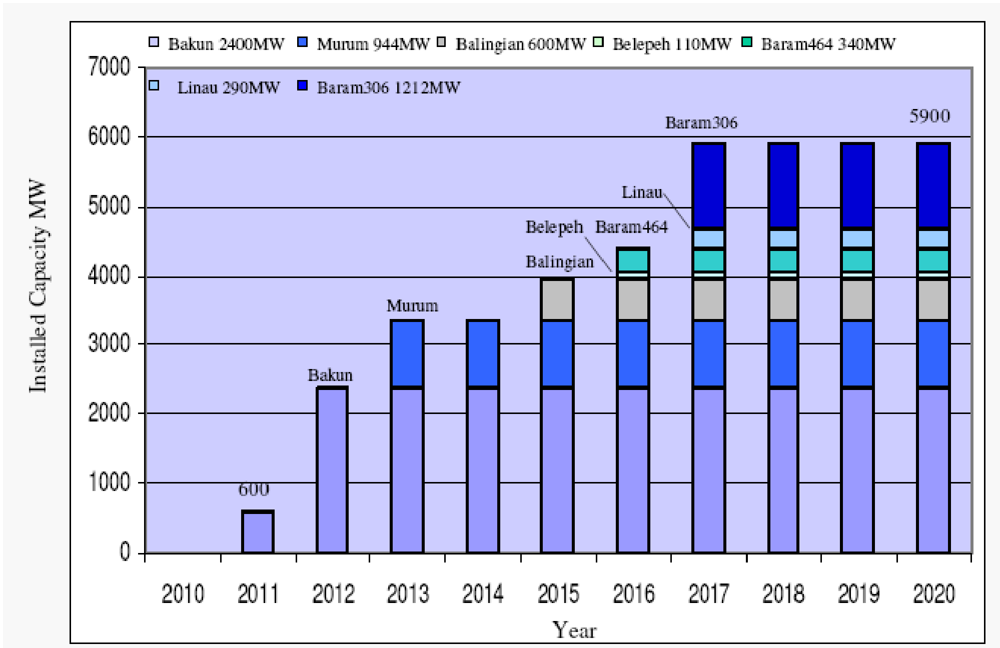
[48] The information for Sarawak's Power Development has largely been obtained from three published papers available on the internet: (a) *Electric Power Grid Optimisation for the State Of Sarawak* by Prashobh Karunakaran 2014 IJEETC; (b) *Long-Term Hydropower Development in Sarawak* from the British Hydropower Association Annual Conference (2010); and (c) *Integration of Solar and Wind Power to a Borneo-Wide Power Grid*, Salim S Maji et al in *International Journal of Environmental Science and Development, Vol. 4, No. 6, December 2013.*

Figure 18 SESCO Long-Term Generation Development Plan: (Potential New Hydro Capacity Additions)

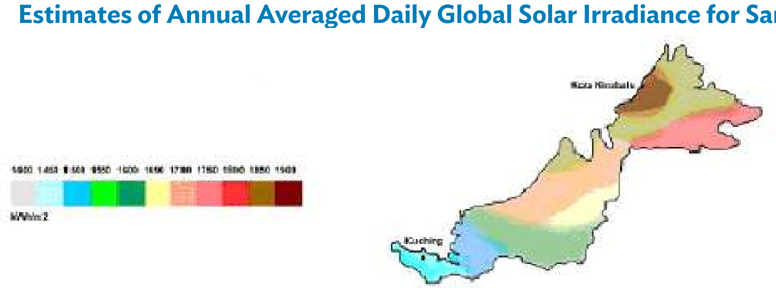


Their combined installed capacity amounted to 20,000 MW capable of producing 87,000 GWh with 90% of the output being considered firm. Clearly the development of all these projects would be capital intensive, requiring big investments within short period of time. Multiple projects would need to be financed concurrently, and skilled manpower would be required for project construction, management, operation and maintenance. It would be difficult to justify such an ambitious program without some certainty of an off-taker under strictly enforced PPAs.

SESCO is currently planning to build additional hydro capacity, primarily to serve the needs of the SCORE industrial program, on the basis of the following:

Other Renewables. Wind is unlikely to be a significant resource in this part of Asia, which was formerly known to sailors as "the doldrums." As shown below, compared with Sabah, solar power in Sarawak may also be problematic because the sunlight is quite often blocked by the heavy cloud cover, typical of equatorial areas[49]. Fungus also reportedly grows very fast in equatorial climates and can consume the minerals within the solar panels, rendering them opaque to the flow of sunlight to the photovoltaic cells.

Figure 19 Estimates of Annual Averaged Daily Global Solar Irradiance for Sarawak



Source: Daniel Ruoss, 2008

[49] http://www.sarawakenergy.com.my/index.php/r-d/solar-energy

Electricity Demand. Over the next two to three decades, power demand in Sarawak is expected to grow rapidly due to higher living standards, more economic activities, and increased scale and pace of industrialization. Medium-term power growth for Sarawak is depicted in Table 12 below. The table shows that four power demand sectors identified to grow rapidly are: (i) normal (organic) load in Sarawak; (ii) energy-intensive industries in Sarawak (SCORE); (iii) power export to Peninsular Malaysia; and (iv) power export to BIMP-EAGA countries.

Table 12 Indicative Power Demand Growth in Sarawak

Power Demand Growth in Sarawak												
Demand Center		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Domestic Demand	MW	991	1050	1113	1180	1251	1326	1406	1490	1580	1674	1775
SCORE & Exports	MW	90	307	807	1637	2217	2817	2817	3417	3417	3417	3417
Total	MW	1081	1357	1920	2817	3468	4143	4223	4907	4997	5091	5192
% Sarawak		92%	77%	58%	42%	36%	32%	33%	30%	32%	33%	34%
Installed	MW	1260	1850	3762	4570	4570	5170	5170	5720	6024	7024	7294
% reserve		14%	27%	49%	38%	24%	20%	18%	14%	17%	28%	29%
Demand GWh @ LF	69%	5990	6347	6727	7132	7562	8015	8498	9006	9550	10118	10729

Source: http://www.ijeetc.com/ijeetcadmin/upload/IJEETC_534f2dfe09da0.pdf: ELECTRIC POWER GRID OPTIMIZATION FOR THE STATE OF SARAWAK AS AN EXAMPLE FOR DEVELOPING COUNTRIES

Electricity Demand in SCORE. The SCORE program in particular is designed to provide sustainable income by creating business opportunities, new growth nodes or townships based on the development of the hydropower program. Usage of the generated capacity was first proposed in 2003 for an aluminium smelting plant in Samalaju, near Bintulu, located approximately 180 km from the Bakun dam. This plant, expected to consume 50% of the power generated, never materialized. Later in August 2007, Rio Tinto announced that they had signed a deal with a Malaysian conglomerate to build an aluminium smelter. Slated to start at the end of 2010, aluminum production would reach 550,000 tonnes initially with possible expansion to 1.5 million tonnes. However, due partly to delays in dam construction and partly due to a slump in the world aluminium market, the latter plans for the smelter have since been stalled. As of July 2014, five companies have started or completed the construction of facilities at Samalaju. The total committed investment is 11.32 billion ringgits (about $3.5 billion).

Table 13 List of SCORE Major Industrial Consumers (July 2014)

Company	**MYR b**	**Product**	**Production commencement**	**PPA with SEB (MW)**
Press Metal	2.00	Aluminium ingots & billets	Q4 2012	480
Tokuyama Corp.	6.60	Polycrystalline silicon	Q3 2013	380
Pertama Asia Minerals Ltd.	0.49	Silicone manganese	Q4 2012	270
OM Holdings Ltd.	1.50	Silicone manganese	Q2 2013	500
Asia Advanced Materials	0.72	Metallic silicon	Q4 2013	55*
Total	**11.32**			1,685

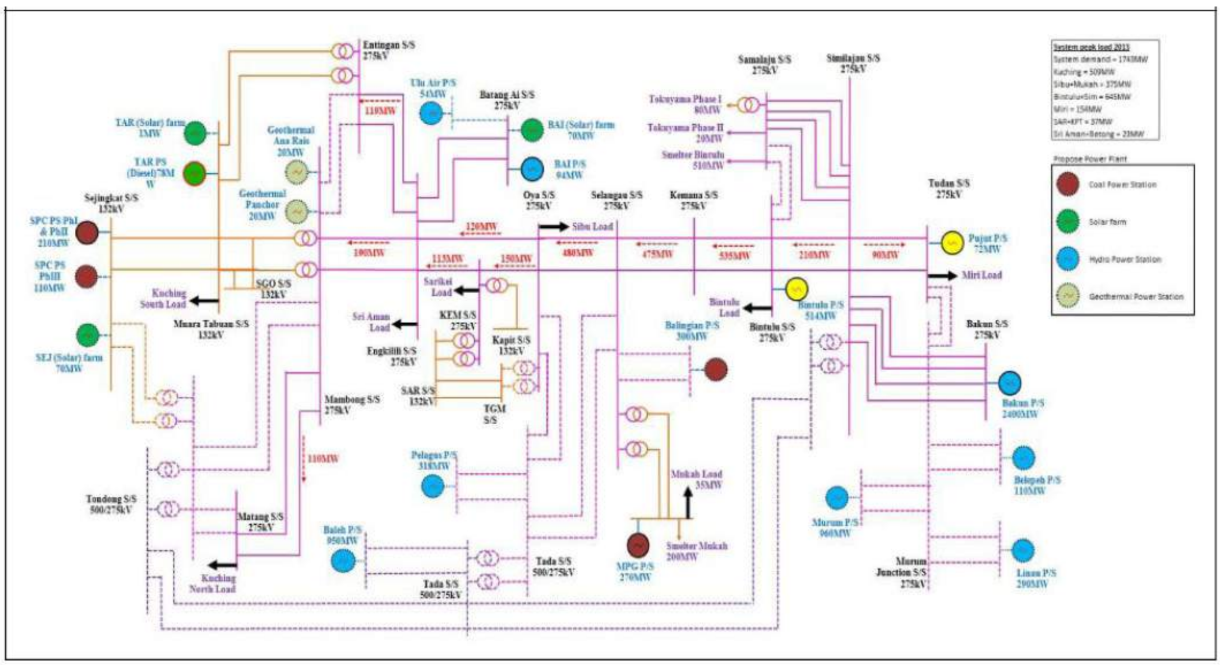
Source: RECODA Annual Report 2012, Pg.25

These companies have secured electricity supply from SEB. According to RECODA, SEB has signed PPAs for a total of 1,800 MW and term sheet agreements for an additional 600 MW as of 2013. SEB has committed to the sales of the entire firm output of Bakun (1,771 MW) and Murum (635 MW) to the customers in the Samalaju Industrial Park by 2012.[50] For the entire SCORE initiative, there are 18 approved projects with a total investment amount of 29.43 billion ringgit, of which 14 are located in the Samalaju Industrial Park with investment value of 24.17 billion ringgit as of March 2014.[51]

These industrial developments will be the major drivers of SESCO's power system development plan, and consequently the basis for developing its 30-year strategic development plan.

Electricity Planning. The schematic diagram in Figure 20 shows how the coordinated development of transmission infrastructure is expected to proceed in tandem with hydropower project development.

Figure 20 Schematic of SESCO's Planned Transmission Interconnections



5.2 Sabah PDP

Electricity demand in Sabah is reportedly growing at over 7% per year, but much of SESB's existing generating capacity is in the form of aging, expensive, and increasingly unreliable diesel plants. Unplanned outages lead to costly service interruptions throughout Sabah, especially on the east coast which is almost wholly dependent on diesel plants.

Sabah has at least 17 major grid-connected power plants. Major plants are located near Kota Kinabalu, Labuan, Sandakan, and Tawau, with smaller plants scattered across the state. Since the completion of a transmission line connecting the East and West coasts in July 2007, all of these plants have been connected to a single integrated

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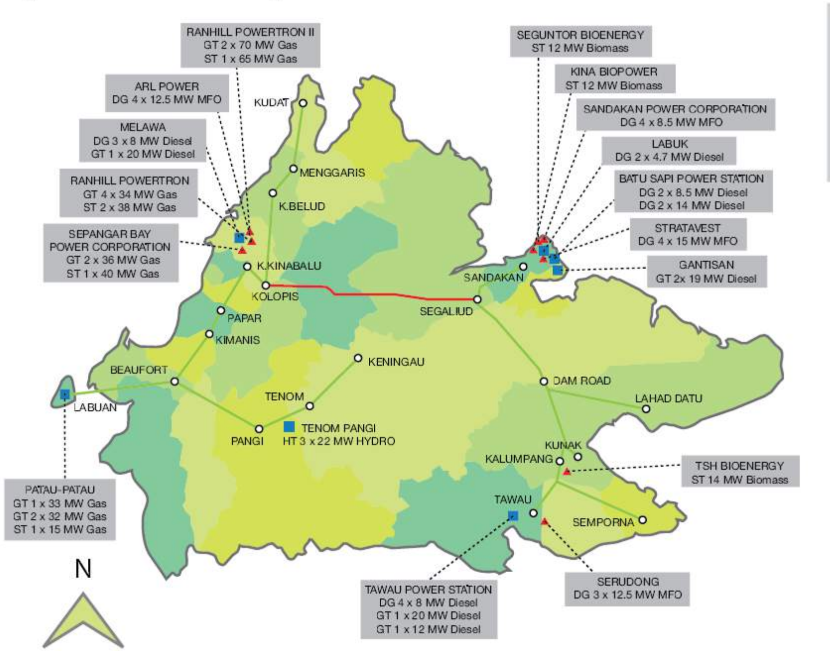
[50] Pg. 36, RECODA Annual Report 2012

[51] See: http://www.theborneopost.com/2014/03/14/18-projects-worth-rm29-43-bln-in-score-nansian/

Figure 21 Locations of Power Generation Facilities in Sabah

Major Power Stations and Grid System in Sabah



power transmission grid that allows power produced anywhere in Sabah to be consumed at any other grid-connected location in the state. This transmission grid, however, is not connected to the Sarawak or Kalimantan grids, meaning it is currently impossible to import or export power between those states.

Fossil fuel-fired power plants account for 90% of Sabah's current installed capacity. All of these plants burn either natural gas or diesel/fuel oil. Several additional natural gas-fired plants are under development, as well as a proposed coal-fired plant that would be the first of its kind in Sabah. In the meantime, SESB plans to add significant generation capacity to its grid over the next decade, both to meet electricity demand (which is forecasted to grow at 7% a year) and to allow for the decommissioning of some of the diesel plants. New capacity is slated to come primarily from three 100 - 300 MW natural gas plants, and three 100 - 200 MW hydropower plants.

An earlier plan to build a coal plant in East Sabah, however, was controversial. The first two locations proposed for the plant were abandoned, due primarily to community resistance to ash ponds, high-temperature water discharges, acid rain-causing sulphur dioxide, hazardous arsenic contamination, and other local environmental effects expected from the plant.

In 2010, the University of California, Berkeley completed a study of the electricity sector in Sabah[52] which concluded that the Government should focus its efforts on developing the country's renewable resources including solar power, geothermal, run-of-river hydro and biomass. The report proposed that this should be done by phasing out fossil fuel (i.e. gas and oil) subsidies in order to recognize clean energy's status as a "premium product," which would bring significant external benefits to Sabah and Malaysia as a whole.

Energy Resources. As of 2009, ten run-of-river hydroelectric plants were operational in Sabah. The older of these plants is located on the Padas River near Tenom, and has an installed capacity of 66 MW. It was producing approximately 8% of Sabah's electricity as of 2012. Additionally, one small (2 MW) hydroelectric project was completed by ESAJADI Sdn Bhd under the Small Renewable Energy Power (SREP) programme in 2009. This project's two sister projects (2.5 MW and 4 MW) are scheduled for completion by the same company in 2010.

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[52] Prof el Kammen et al (2010).

No large dam projects have been built in Sabah but several plans are under development. The 150 MW Upper Padas dam, upriver of the Tenom Pangi run-of-river project is planned for 2020. A comprehensive 1984 study[53] identified hydropower as one of Sabah's most attractive electricity generation resources. The study identified 68 sites that were feasible for hydroelectric projects. Based on stream flow statistics and geographical information, the study's authors estimated that these sites have the potential to generate 1,900 MW of capacity. A later hydro identification study completed in 2010 indicated that 782 MW of hydro potential from twelve sites would be economically viable for development. Pre-Feasibility and Feasibility Studies are currently underway to ascertain this potential.

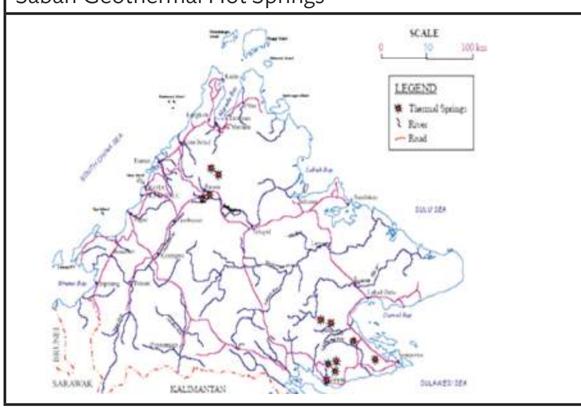
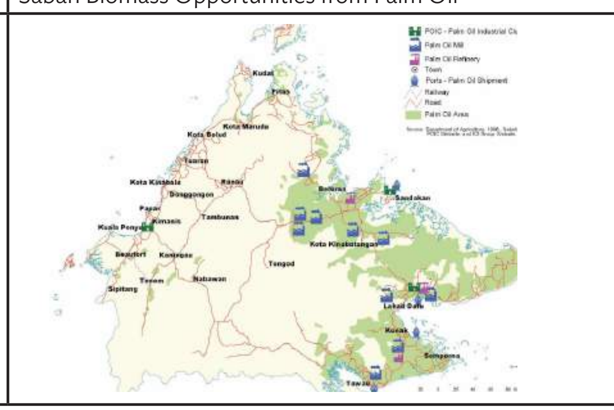
Sabah's palm oil industry is the single largest industry in the state, accounting for 23% of the state's gross domestic product and 30% of Malaysia's national production, the highest yields of any Malaysian state. Sabah's 117 palm oil mills operate year-round. While the mills tend to crush at just 80% of their rated capacity between October and May, they may operate above capacity between June and September. Over 2008's full calendar year, Sabah's palm oil mills crushed over 27 million tonnes of palm oil fresh-fruit bunch (FFB), about 93% of their collective rated capacity (29.3 million tonnes). By coupling our per-tonne electricity export estimate to these production statistics and growth estimates, it is estimated that nearly 500 MW of baseload generation capacity is theoretically available. Most of this potential (over 85%) is located in East Sabah.

Sabah receives one of the highest solar insolation levels in Malaysia, and the area around Kota Kinabalu has been identified as especially productive. The state receives an average of 5 kWh/m^2 per day, or approximately 1,825 kWh/m^2 per year. In theory, this energy would be sufficient to meet Sabah's entire electricity demand: with an average horizontal solar radiation of 5 kWh/m^2 per day and a typical conversion efficiency of 10%, Sabah's reported 2007 electricity demand of 3,312 GWh could have been met with a solar collection area of 1,815 hectares (182 km^2).

It is highly likely that some areas of the country are suitable for geothermal energy. Indeed, as shown in Figure 22, preliminary geothermal prospecting has revealed several locations that may have geothermal potential in Sabah. For instance, hot springs – a common indicia of geothermal activity – are abundant in Poring-Ranau and the Semporna Peninsula in Sabah. Further invesetigation is thus warranted.

A 1994 study by the Universiti Kebangsaan Malaysia measured wind speeds and calculated wind power densities for Kota Kinabalu, Tawau, and Labuan. None of these locations had wind speeds greater than 3 m/s or wind power densities above 50 W/m. As a result, the study classified Sabah's wind potential as "3" on NREL's scale of 1 to 7, corresponding to a judgment that wind investment was not likely to be feasible.

Figure 22 Potential Renewable Development Opportunities in Sabah

Sabah Geothermal Hot Springs	Sabah Biomass Opportunities from Palm Oil
	

Source: Clean Energy Options for Sabah: an analysis of resource availability and cost," Prof el Kammen et al, University of California, Berkeley, Renewable and Appropriate Energy Laboratory, School of Law, Energy Resources group, Berkeley Goldman School of Public Policy and Harvard College (2010)

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[53] Tenaga Ewbank Perunding (M) Sdn Bhd, Sabah Power Development Master Plan Study, Draft Final Report Volume One, p. 3–7.

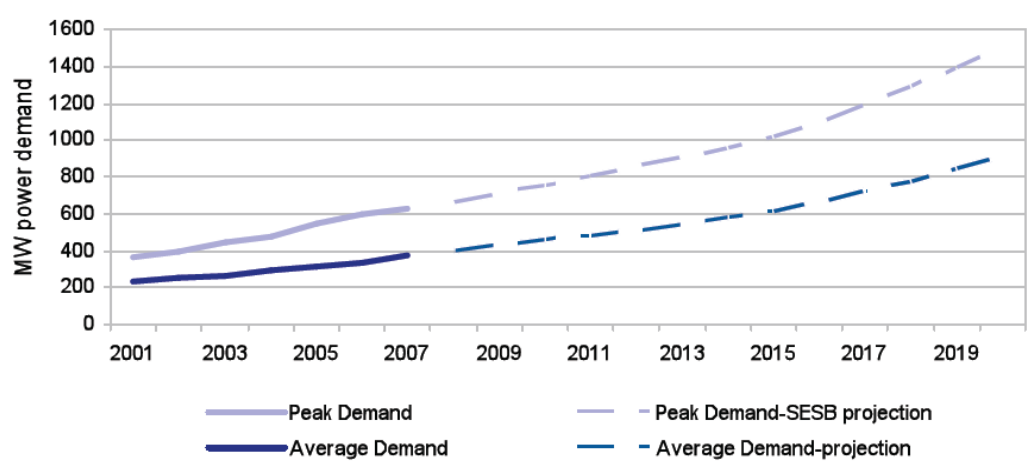
In July 2009, the Mineral and Geoscience Department concluded that a 67 MW geothermal power plant would be feasible at the site shown in East Sabah in Figure 22. If the site can be developed at the average capital costs, O&M costs, and capacity factories reported for similar projects in the literature, it might be economically feasible at a levelized cost of RM 0.172 per kWh. If it receives carbon offset revenues in proportion to its emissions reductions, our estimate would fall to RM 0.157, making geothermal's levelized cost comparable to that of hydro, cheaper than natural gas, and only slightly more expensive than that of coal.

The University of California, Berkeley's detailed investigations of Sabah's power supply options concluded the following main points regarding the state's power development plan:

- Palm oil mill waste projects can feasibly replace the planned 300 MW coal-fired plant for the East Coast of Sabah. These projects present a very attractive electricity supply option, and should continue to be supported by utilities and the government.
- Geothermal and small hydropower investments can also be feasible clean replacements for the proposed coal plant, though at slightly higher cost.
- Solar is an attractive long-term option in Sabah, and the government should continue to support programs that aim at reducing solar PV capital costs.
- Integrating solar "peaker" plants into a larger portfolio of renewables is highly recommended, perhaps by using waste biomass as a backup fuel for steam turbines at solar thermal plants.

Electricity Demand. It has not been possible to obtain a definitive demand forecast for Sabah aside from information gleaned from a bid document for the Upper Padas Project (August 2008). It is understood that Sabah is suffering power shortages and has only recently resorted to contracting with an IPP (gas-fired Combined Cycle) to meet its current commitments. A more recent indicative forecast was provided in the 2010 University of California, Berkeley report as in Figure 23:

Figure 23 Indicative Power Demand Growth in Sabah



Source: University of California, Berkeley, 2010

Electricity Planning. Generation Capacity Planning in Sabah lies under the purview of the Electricity Supply and Tariff Planning and Implementation Committee (JPPPET) which is chaired by YB Minister of Energy, Green Technology with the Water and Energy Commission acting as the Secretariat. SESB and its IPPs plan to build at least ten major power plants in Sabah over the next decade. The current ongoing project consists of development of 2 Combined Cycle Gas Fired Power Plant in West Coast with total capacity of 385MW. This project is expected to be fully operational by 4th quarter of 2014. Most of the planned capacity additioiniplens are located on Sabah's West Coast. Three new natural gas plants with an aggregate capacity of about 600 MW are slated for construction on the West Coast over the next few years. Later in the decade, SESB plans several new hydro projects with an additional 300 - 500 MW of capacity. These projects will also be connected to the West Coast grid.

According to SESB statistics, Sabah's East Coast currently has an installed capacity of 316 MW against a maximum peak demand of 192 MW. However, because the East Coast is heavily reliant on ageing diesel plants, its reliable installed capacity may be significantly lower. SESB reports that power transfers of over 50 MW between West and East Sabah occur on a daily basis over the 255-km, 132-kV East-West transmission line, suggesting that the East Coast plants actually generate less than 150 MW during peak periods. Transfers over the line will likely increase as demand grows and SESB decommissions aging plants, but required transfers should remain below the link's total capacity of 332 MW through 2020.

5.3 Brunei Power Development

Brunei consumes a disproportionate amount of energy relative to its small population. Its energy used for transportation and electricity consumption per capita both rank among the highest in Asia. According to figures from Brunei's Department of Statistics, the country had electricity coverage of 99.7% in 2008, with the remaining 0.3% accounted for by remote communities, most of which have their own generators. The recorded average usage of electricity for the past five years has shown that 48% is consumed by the domestic sector, 25% by the commercial sector, 17% by the government sector, and 10% by the Oil and Gas Sector.

Electricity is supplied by the Department of Electrical Services (DES) and the Berakas Power Management Company Sdn Bhd (BPMC). The BPMC is in effect owned by the Brunei Investment Agency (BIA), but operates as a private limited company. BPMC owns four power stations including Berakas 1, Berakas 2, Gadong and Jerudong, and supplies 40% of the national electricity requirement through three main grids (only recently interconnected). Brunei's demand is expected to grow about 3-4% annually, and taking into account planned plant retirements at Gadong, an additional 300 MW of combined cycle capacity is expected to be added at Gadung and Bukit Panggal by 2017.

The country's current reliance on oil and gas as the sole sources of energy, for both generating income and providing a ready surplus of energy for the citizens of Brunei, is not considered sustainable in the long term without proper energy efficiency and conservation measures. The Bukit Panggal Power Plant has a designed thermal efficiency of 47%, whereas the efficiency of existing generators using the 'Simple Cycle' is just 28%. The Bukit Panggal Power Station is based on a 140 hectare piece of land, where 75 hectares have been developed for Phase 1 of its long-term planning with a capacity of 500 MW.

Brunei Darussalam has set an economy-wide target to reduce its energy intensity by 45% by 2035, using 2005 as the base year. To ensure that this target is met, Brunei has identified a number of action plans for five sectors – generation, residential, industry, government and transportation – to be implemented between 2010 and 2030. Some of the action plans identified include: restructuring the residential electricity tariff structure; improving the efficiency of new and existing power plants; formulating an economy-wide standard and labelling for air conditioning and lighting systems; initiating energy management programmes in government and industrial buildings; and introducing energy efficient vehicles like hybrid and electric vehicles into Brunei.

Mostly 66/11kV electricity networks extend throughout the Sultanate, providing power to almost the entire population. Brunei plans to build a 275kV link from East-West to serve as a transmission network backbone and to facilitate interconnection with Sabah and Sarawak. The upgrade will include six new 275/66kV switchyards at the existing Kuala Belait, Sg Bera, Spark, Pasir Puteh, Bukit Panggal and Tungku substations.

Renewable Resources. Although Brunei may have some hydropower potential, its running river water does not have a sufficient head to utilize for power without first building a storage dam. However, because of the small size of the country, it is difficult to find a location to build a dam. Measurements taken by the Department of Electrical Services indicate that the Temburong Basin has an estimated hydro-electric potential of 300 GWh per year, equivalent to 70 - 80 MW of installed hydropower capacity. However, the negative environmental impacts in the construction of hydropower installations are blocking the further study of this resource.

Measurements taken by the Department of Physics at the University of Brunei Darussalam indicate annual average wind speeds of 5 m/s in coastal regions, suggesting the potential for power generation from wind energy in the country. The first wind turbine to be installed in the country will be at the Ministry of Development, and further studies are being conducted in order to ascertain the potential for further wind energy utilization. Based on offshore wind data, theoretical offshore wind power could total about 372 MW annually.

Brunei has considerable potential for solar energy, and photovoltaics/solar thermal technologies have been the most investigated renewable energy application in the country. Average daily insolation ranges from 400 to 500 W/m^2, with peaks of over 1,000 W/m^2. A solar diesel hybrid electric power system with a 2.4kW solar array and an 80kVA diesel generator was installed in 2000 at Ulu Belalong National Park in the Temburong district, representing an initial trial of solar technology. In August 2008, Mitsubishi Corporation constructed a 1.2 MW solar PV power generation demonstration project, Tenaga Suria Brunei, to evaluate the performance of six types of photovoltaic panels. The plant first connected to the power grid of the Department of Electrical Services in May 2010, and is now operating at full capacity.

Oil and gas market. Brunei Shell Petroleum (BSP) dominates the production of natural gas and crude oil from both onshore and offshore fields, and owns the Brunei Refinery. BSP produces 90% of its oil and all its commercial gas from seven offshore fields. LNG activities are carried out by Brunei LNG (BLNG), a joint venture between the government of Brunei (50%), Mitsubishi (25%), and Shell (25%). BLNG receives most of its natural gas supplies from BSP, although it began receiving small amounts of natural gas from Total's offshore production facilities in 1999. The Brunei National Petroleum Company (PetroleumBRUNEI) is the state-owned utility in the field of oil exploration and production, as well as mining.

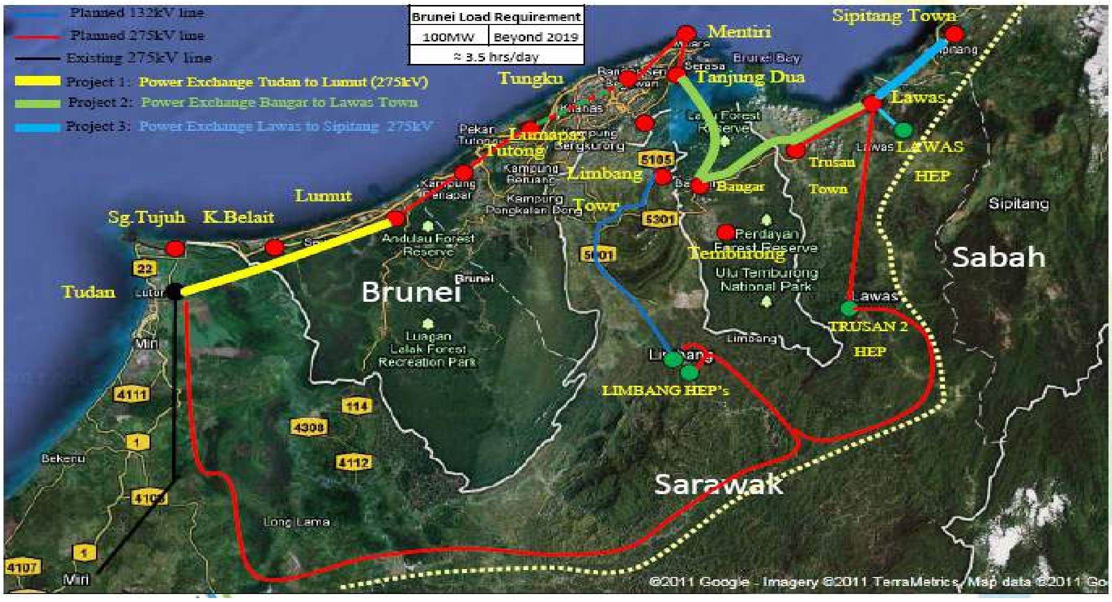
5.4 Interconnection of Sarawak-Brunei-Sabah

The three utilities of Sarawak, Brunei and Sabah are currently negotiating a proposed 275kV interconnection scheme that will integrate the adjacent power systems with secure alternative transmission circuits, both through and around Brunei, as shown in Figure 24.

The interconnection appears to have many merits including the reinforcement of the Brunei network, transferring power from Sarawak to Sabah, and simultaneously exploiting a potential of about 500 MW of new hydro capacity in Northern Sarawak at Limbang and Trusan. The 275kV loop design will circumvent potential territorial issues and provide Brunei with access to the proposed hydro plant at Limbang. It also enables Sabah to access the two reliable connections to the Sarawak power system, which will provide secure supplies to the main loads in Kota Kinabalu.

The new transmission capacity will also provide Sabah with more time to examine ways of importing more power from Sarawak, both for domestic use and for onward wheeling to the Philippines. While it has been proposed to extend SESCO's 500kV backbone directly to Kota Kinabalu (i.e. bypassing Brunei), it appears better to use HVDC line for this purpose (as proposed in the following section of this report). In this respect, an HVDC line could be used to transmit a large amount of power (i.e. 2,000–3,000 MW) from the termination of the 500kV busbars in Sarawak, passing directly through Sabah and onwards via Palawan to the Philippine market (with an intermediate terminal in Kota Kinabalu).

Figure 24 Proposed Interconnection of Sarawak-Brunei-Sabah



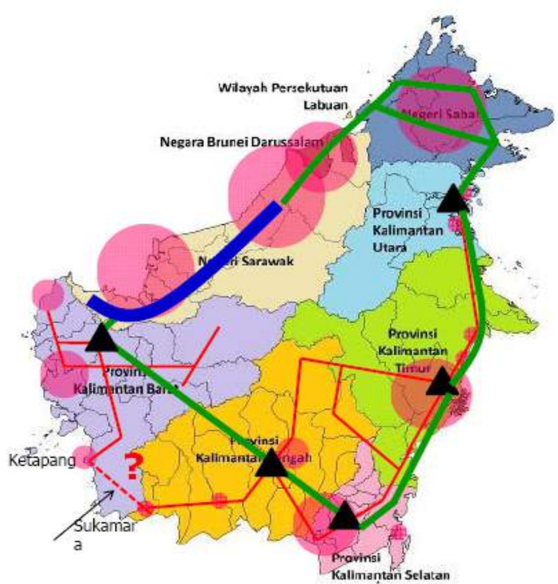
6 Proposed Borneo Interconnection Strategy

6.1 Concept of Borneo Grid Planning

Following the successful development of the Sarawak-to-Kalimantan 275kV interconnection, PLN is currently exploring the possibility of another bilateral interconnection, this time with Sabah with the aim of accelerating resource development in the sparesly populated Kalut province. In 2012 PLN signed an MOU with SESB setting out an agreement to explore various ways of developing Indonesian resources that would be mutually beneficial to both parties.

PLN's proposals have also been concieved as an incremental step towards the eventual interconnection of all the Borneo power networks, a concept which is represented in Figure 25.[54] Notably the PLN concept incorporates the 500KV Sarawak (in blue) connected to a 275kV ring around Kalimantan (in green), superimposed over PLN's 150kV lines. A logical outcome of such a plan would be the construction of PLN's new transmission lines along the proposed routes using a 275kV design. To save having to build the nessary 275/150kV substation upgrades earlier than necessary, the line should be operated initially at 150kV.

Figure 25 PLN's Proposed Concept for an Inter-Borneo Interconnection Strategy



Source: PLN proposal to Sabah March 2014.

[54] The proposed concept for Borneo interconnections was developed by Djoko Prasetijo, the former Head of System Planning Division of PLN, and discussed with SESB planners in March 2014. The map was reproduced in a submission by Sabah to the project team.

6.2 Interconnection of Sarawak-Sabah-Luzon

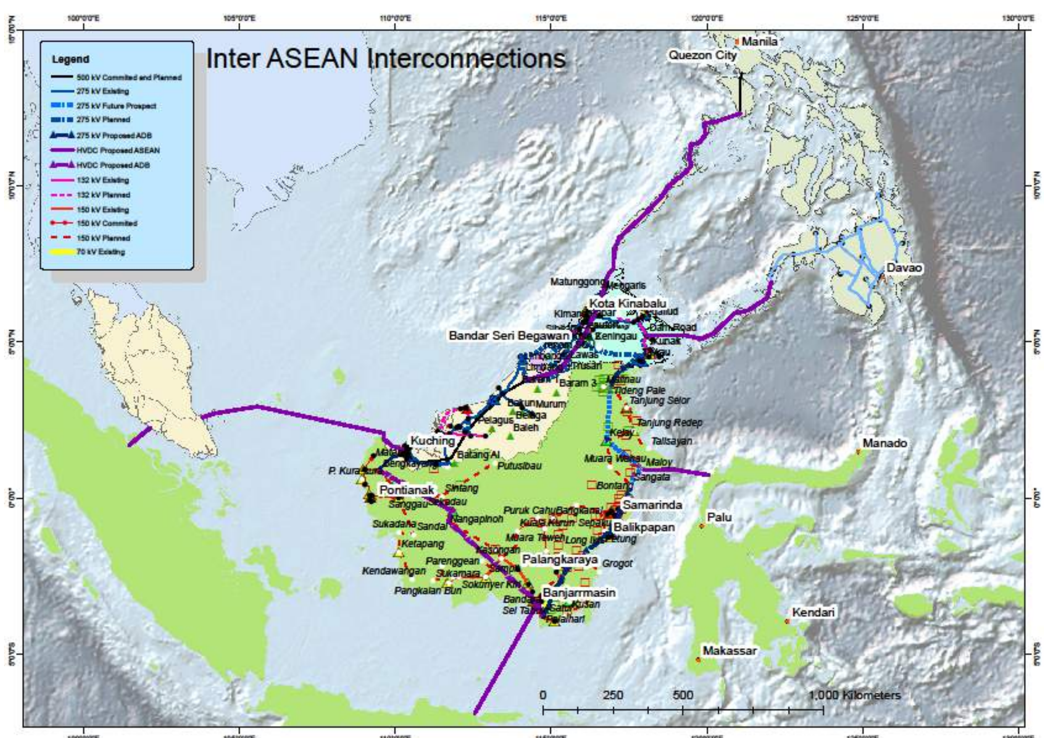
As noted in section 5.4, the three utilities in Sarawak, Brunei and Sabah are also in negotiations to extend Sarawak's existing 275kV line from Tudan Substation through Brunei to connect to the Sabah 275kV network. Once completed, the interconnection will provide Brunei and Sabah with peaking capacity from Sarawak to complement their existing thermal generation sources. This appears to be an excellent demonstration of the mutual benefits of interconnection. Its early implementation will enable the three utilities to develop a cooperative operational regime that could become the basis for other future interconnections. It is also consistent with PLN's conceptual proposals shown in Figure 25.

However, prospects exist for even larger power transfers between Sarawak and Sabah which could be achieved by extending 500kV line from Similajau Substation to Bunut, and then on-connect directly into the load center at Kota Kinabalu. Although this is not likely to be feasible in the short-term, it may well become a serious option if the Philippines decides to import power from Sarawak. In the meantime, all participants would be prudent to compare the 500kV option with a HVDC connection emanating from the 500kV terminal at Bunut, connecting directly to Kota Kinabalu. If a suitable contract to supply Luzon was subsequently feasible, the HVDC line could be continued all the way through Palawan to Manila.

6.3 Future Transmission Interconnection Options

It has been established that interconnection can offer many benefits to participating countries and their utilities. However, there is a "chicken and egg" conundrum to the sequencing processes in that the logic and economics of one interconnection often depends on either a prior interconnection or investing in a major generation source. In figure below shows the extent to which interconnections with ASEAN could be developed over time:

Figure 26 Possible ASEAN Interconnections



Some interconnections (e.g., with Java or North Sulawesi) could be made as enclave projects without depending on prior investments in other parts of the grid. Table 14, shown also in schematic form in Figure 26, lists ten interconnections by possible in-service date; this list indicates the order of magnitude of the costs involved and the minimum wheeling charge that would be required to repay the cost of the interconnection over a specified time period, based on the rated power capacity of the interconnector.

A logical outcome of inter-Borneo power trading would be for each of the respective power companies to continue building their networks for ready upgrade in the future, thus facilitating future integrated grid power trading as shown in the figure, table and schematic drawing that follow. In effect, SESCO is doing just this by building a new 500kV backbone line (operated initially at 275kV) to aggregate its hydro power development in one bus.

Figure 27 Inter-Borneo Interconnections

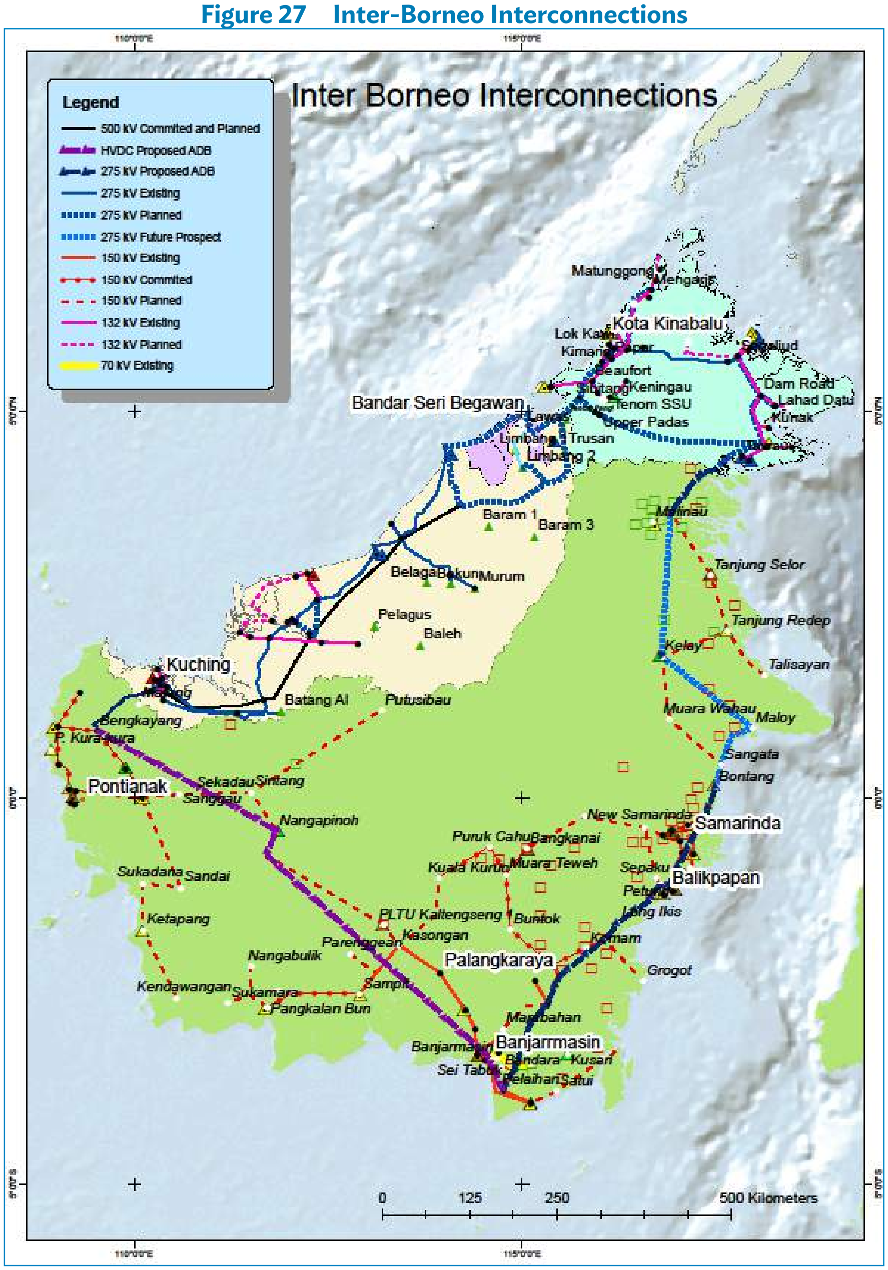
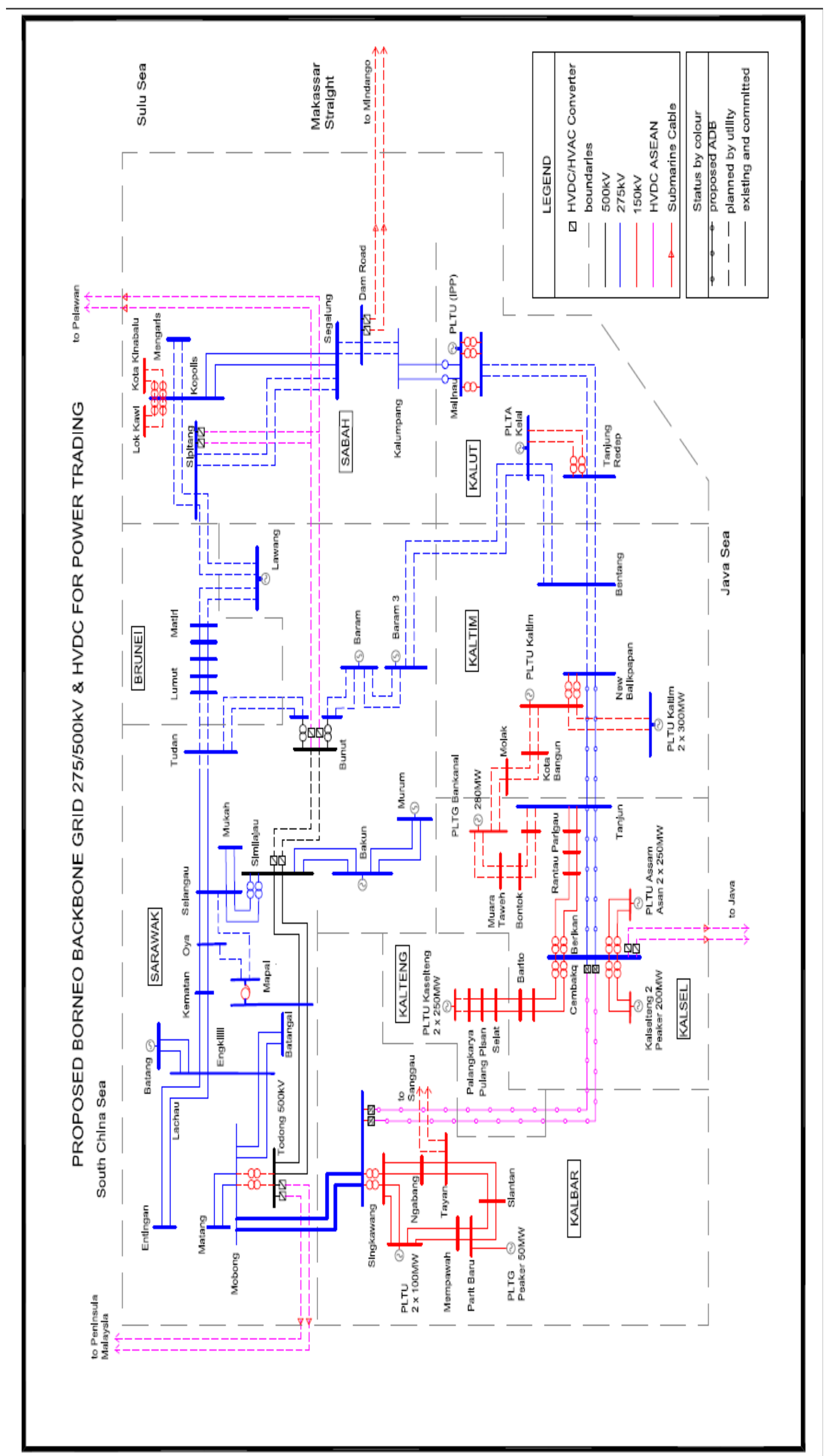


Table 14 Optional Transmission Interconnections—Base Costs in US$ and Long Term Average Wheeling Rate
(i.e excludes power system reinforcement)

					PWF 9.82		WACC 8%		for		20 years		
	Interconnection Proposal	Year	MW n-1	Sale Price c/kWh	OHTL km	HVDC Cable km	Trans Cost M$	Terms Cost M$	Peak/Base LF	Tot Cost $/kW	Wheel rate c/kWh	Rationale and Conditionality	Benefits/Risks
1	275kV Sarawak- Kalbar (under construction with ADB financing (COD 2015))	2015	300	10	83	0	$31	$32	20%	209	1.22	Sarawak surplus power 5year PPA renewable at 15% increase	Pilot Project = Lower cost power unitil PLN build HVDC and/or develops coal and gas generation at lower cost
2	275kV Sarawak- Brunie -Sabah Extend Sarawak 275kV from Tudan via Brunei to supply two branches of Sabah planned 275kV system	2016	300	10	265		$89	$20	50%	363	0.84	Under discussion by SESCO-SESB-EBS to extend 275kV 330 km from Limanjau through Brunei to Kotakinabalu	Sabah obtains low cost power from Sarawak and CCGT gas power from Burnei. Strong 275kV links avoids need to extend 500kV through to KK.
3	HVDC ±250kV Monopole Kalbar-Kalteng 2nd stage PLN Kalimantan Backbone from Benkayang to exiting SS Pelaihari 150kV	2018	300	11.5	860	0	$189	$60.00	60%	830	1.61	Project will Increase supply from Sarawak for 5yrs at PEA price +15% through Kalbar to Kalsel. Enables PLN To build more efficient minemouth Coal fired power stations to serve larger aggregate demad.	Reduces LRMC of PLN generation. Two way exchange hydro power im[ports to Kaltim coal power exports to Kalbar/Sarawak. HVDC provides increased stability at both ends of the line. Upgradeable to bipole in future
5	Extend 275kV Coastal Grid from Kaltim to Kalut	2018	600	6	550		$185	$88	60%	454	0.88	Build 275kV lines in place of planned 150kV lines with at least 4 intermediate 275/150kV SS for reactive correction and local supplies	Enables power exchange between PLN regions using Larger Minemouth power stations to serve larger aggregated demand
4	275kV Kalut -Sabah Enclave minemouth coal project to be incorporated in large PLN 275kV Grid	2020	600	6	150		$50	$29	60%	132	0.26	PLN/SESB already have MOU for IPP Coal fired power station dedicated to supply Sabah - with small offtake to Kalut. Probablysuited to an IPP enclave development.	Sabah recives coal fired generation and avoids environmental impacts in pristine coastal area and enables development geothermal and run-of-rver hydro projects. Facilitates PLN extension of 275kV grid along NE Kalimantan.
6	500kV HVDC bipolar Sarawak – Peninsular Malaysia (500kV overland in Sarawak to HVDC terminal at Yong Peng in Johor, Pen. Malaysia)	2020	2000	5	600	600	$1,778	$480	70%	1129	1.88	Poltical decision by Malaysian State - price of Bakun decided by FED Govt	Assume lower Bakun cost to TNB/High cost/risk of world's longest HVDC cable
7	HVDC Kalsel- Northern Sulawesi regions HVDC terminals in north Sulteng and Kaltim	2025	300	6	105	130	$191	$72	60%	875	1.70	PLN Kaltim supplies northern Sulteng/Gorontalo/Manado and norther part of Sulteng	Kaltim power supplement Sulut geothermal and diesel. Possible cable problems with deep channel. Opportunities for marine energy in channnel
8	HVDC Sabah-west Mindanao HVDC terminations in Sabah and Zamboanga	2025	600	8	150	262	$396	$144	60%	899	1.74	Sabah wheels power from PLN's coal fired plant in Kalutalong with surplus power from Sarawak	Cheaper Hydro/Coal for Mindanao and wheeling charges for Sabah. JV SPC to own HVDC cable link. Most cable and overland investment by Mindanao
9	HVDC Kalsel-Java HVDC link from Coal Fired Station on Kaltim to East Java	2025	2000	6	50	420	$560.62	$480	60%	520	1.01	PLN build 2000MW combined cycle gas or minemouth coal plant in Kalsel	Avoids having to build 2000MW plant in East Java/may need duplicate cables to mitigate outages
10	HVDC Sarawak-Sabah Build 250kV monopole HVDC terminals in Limanjau, Sarawak for supply to KK (Stage 1 of Bipolar link to Luzon)	2025	300	6	300		$116	$72	60%	626	1.21	First Stage of interconnection between Sarawak and Sabah with provision for upgrading to 500kV onward supply to Palawan/Luzon (Project 12)	Cheaper and more relaible interconnection than 500kV extension with significant stabilising benefits
11	HVDC Sabah-Luzon Upgrade to 500kV bipolar terminal in KK to Luzon (Stage 2 of HVDC link to Luzon)	2030	2000	6	734	216	$562	$480	60%	521	1.01	NGCP has long term contract with Borneo power companies to sell into Luzon Power market	PLN and Sabah could also feed supplies into KK for onward tranmission to Manila

Figure 28 Schematic Diagram of Borneo's Existing planned and Proposed HV Interconnections



PLN could thus also designate a future north-east 275kV backbone route to enable greater power transfers between its provinces, and thereby facilitate the later construction of larger, more efficient coal-fired power plants. In PLN's case, the backbone lines would be expected to follow the planned routes for 150kV lines and could initially be operated at 150kV (to save the cost of installing 275kV substations until such time as they are needed).

Before embarking on the extra investment to extending the 275kV system, PLN could also consider supplying North Sulawesi to help justify the additional loads on the Kalimantan system. PLN could also consider building a large mine-mouth coal-fired station in Kalsel to supply Java through an HVDC line, which could avoid having to either extend existing coal-fired stations or find new locations in Java's highly populated landscape. PLN could separately promote the opportunity to export coal-fired or hydropower generation to Sabah with a view towards expanding supply to Mindanao as well. This could be done as a joint development with Sabah and Sarawak, perhaps by forming a Special Purpose Company to operate an HVDC cable link to Mindanao.

An outcome of this report is to identify projects within the framework of inter-Borneo connectivity that might be suitable for financing by ADB or other IFIs. Given that the proposed cross-border interconnections between Sarawak-Brunei-Sabah can probably be financed by the parties involved without international involvement, the next priority interconnection projects within Kalimantan are illustrated below and described in section 6.4 for possible IFI consideration.

6.4 PLN-SESCO Extension Project

It is proposed that an (initially) 300MVA, 850 km HVDC line and terminal facilities should be built between PLN Kalbar and PLN Kalsel at an estimated total cost of $340 million. This line would replace PLN's current proposals to build 150kV lines between the two grids, to be fed en route by various small distributed generation facilities (mostly small coal-fired stations). It is recognized that PLN's current proposals envisage supplying about a dozen small 150/20kV substations located between the two largest load centers at Pontianak and Banjarmasin. Since the forecast loads in the intermediate 150/20kV substations are rather low (consistent with the region's low population density), it would be feasible if necessary to install an intermediate HVDC converter terminal at some central location which could feed out to lightly loaded 150kV single circuits.

The main purpose of the proposed HVDC interconnection would be to enable PLN to increase offtake from SESCO up to the existing PEA's full allocation (600 MVA), giving itself time to rationalize its plans to build coal-fired plants in accordance with a least cost generation expansion plan. Once the HVDC line is in place (by perhaps 2018), this would enable the aggregation of about 2,000 MW of demand in the two load centers of Banjarmasin and Pontianak, to be fed by a 600 MW link from Sarawak plus existing coal- and gas-fired generation in Kalsel/Kalteng. More importantly, larger regional load centers would enable PLN to simultaneously build a 2,000 MW mine-mouth coal-fired plant near Banjarmasin. Such a facility would enable PLN to send lower cost power back to Pontianak and Kuching. It could also serve as a generation center for developing an even larger plant for future export to Java.

The HVDC line should be built for about the same cost as a 150kV double-circuit line (or about 60% of the cost of a double circuit 275kV line). Given that most of the terrain in question is flat, low lying, and marshy, it could be built using low-cost V-shape stayed towers (common in parts of Russia). It is likely that co-financing could be secured from a supplier country for the terminals (about $60 million) and that other agencies may be willing to support the financing of the line.

6.5 275kV Backbone Transmission Upgrade

PLN currently plans to extend the 150kV networks up the southeastern coast of Kalimantan and has already built some of the 150kV lines, generally within 50-100 kilometers of the main centers of Banjarmasin, Balikpapan, Samarinda and Bontang. Under its current plans, PLN is proposing to interconnect these systems by about 2020 so that they can be fed en route by about 18 stations, mostly coal-fired and ranging in unit size from 50-200 MW. Notwithstanding the technical, environmental, logistical and financial difficulties of getting all of these relatively small stations built by 2020 as proposed in RUPTL, it appears that a least cost expansion plan based on a stronger backbone 275kV grid would give PLN the opportunity to develop Kalimantan's north-southeastern coastal corridor more efficiently and at lower cost.

Coal resources are scattered along the southeastern region of Kalimantan, some of which appear to be well suited for large mine-mouth plants. It is thus proposed to build a 275kV backbone grid system (similar to the system built in Sarawak), which would be interconnected into PLN's associated 150kV circuits and used largely for supplying outlying distribution systems. The 275kV backbone would enable no more than 3-5 large power stations to be built. These power stations would generally be located where PLN is already planning to build either coal-fired power plants (e.g. PLTU Asam-Asam, PLTU Kalsel, PLTU Kaltim 2/3) or gas-fired stations (e.g. Kalsel Peaker and Bangkenai). Most of the 275kV line would use the planned routes for the 150kV lines they would replace.

Developing this proposal would require PLN to identify the best coal resource locations for a mine-mouth development program with minimal environmental impact. This would require PLN to also undertake a least cost generation expansion plan to evaluate transmission and associated generation expansion options, as required to develop an optimal program for support by an IFI.

6.6 PLN Kalut-Sabah Interconnection

An alternate project would be to support PLN Kalut's proposal to trade power with Sabah. In this case, SESB is very interested in buying hydro or coal power from PLN in Kalut. SESB indicated they would be keen to participate in a joint ADB-sponsored TA to look at generation expansion options that could be enhanced by interconnecting PLN Kalut with Sabah. This would take into account their plans to build a 100 MW base load geothermal plant (although they have yet to start drilling for steam) near the border with Kalut, in addition to a run-of-river hydro site. SESB is definitely not interested in developing their own coal-fired plants. In Sabah's case, there is a clear economic case for reducing diesel costs and gas subsidies. In PLN's case, there is an opportunity to reduce the cost of diesel generation by building larger, more efficient coal-fired or hydro plants to serve a larger combined load center.

SESB recently signed a 21-year, take-or-pay, IPP-base load agreement (with the gas price passed through), and is still considering the possibility of importing significant amounts of power from Sarawak. However, their load is growing at 6-7% per year and will require more base load plants within next five years – about the time it would take to build an interconnection.

6.7 Interconnection of Kalimantan and Other PLN Networks

As noted, there are prospects for Kalimantan to become a major source of energy to both Java and Sulawesi. However, these opportunities need to be studied in more detail, particularly with regard to the difficulties of installing cable routes across the Java Sea and Makassar Strait. Until these investigations are completed, it is not possible to comment seriously on the viability of these options.

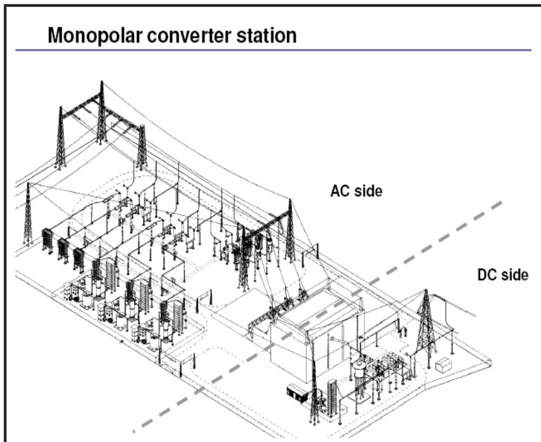
7 Recommended Transmission Project for IFI financing

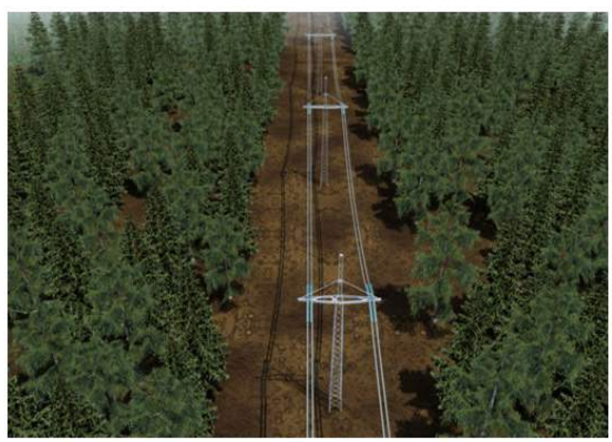
7.1 Scope of Transmission Interconnection Project

Project Concept. It is recommended that the most suitable project for early ADB or IFI financing is the proposed 850 km HVDC interconnection between Pontianak and Banjarmasin. This would follow logically from the ongoing ADB-financed Sarawak-to-Kalbar 275kV interconnection, enabling PLN to take advantage of Sarawak's surplus power to avoid resorting to short-term, inefficient measures to meet load growth. The project, estimated to cost about $327 million, will provide PLN with vital experience in the design, construction, management and operation of an unfamiliar technology (HVDC) which will play an important role in future interconnection plans.[55]

The transmission line and its associated converter facilities should be designed to meet current demand but also capable of upgrading as demand grows. In this respect, a detailed technical study is needed to specify key parameters such as voltage and capacity staging, ground return arrangements, control system capability and transmission line design characteristics. It is, however, expected that the optimum design for the first stage will likely be a 300 MW HVDC ± 300kV VSC monopole system with the provision for upgrading to a 600 MW bipole system after 5-10 years of operation. The transmission line should be built with two conductors and a ground return capable of carrying 300 MW on each circuit. It is likely that the HVDC transmission line should provide for

Figure 29 Layout of HVDC Converter Station & Wayleaves for HVDC Lines





HVDC conserves forests and saves land

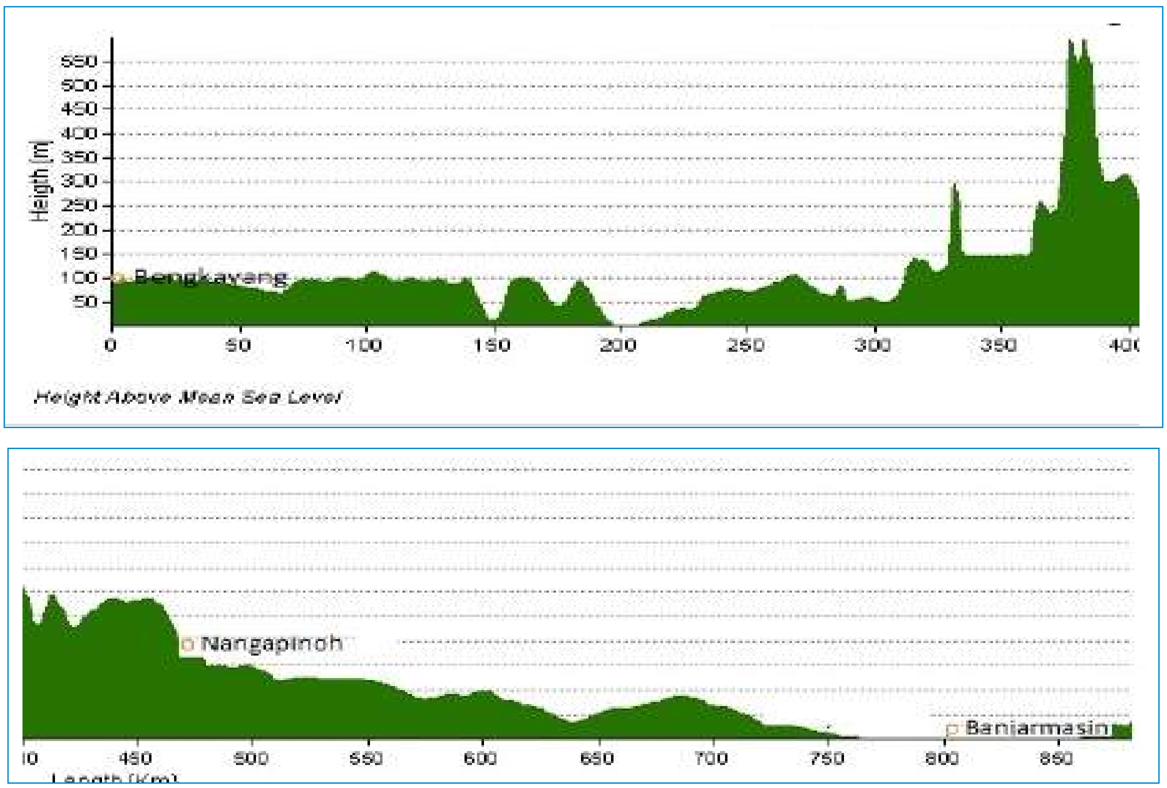
[55] The project concept and scope is remarkably similar in capacity, staging and distance to the recently completed Caprivi project, an 950km 350kV HVDC link between Namibia and Zambesi. Commissioning of the 300 MW monopole phase of the scheme was completed in October 2010. The scheme has been designed for a future bipole extension to 600 MW. The scheme connects two presently very weak AC networks where the fault levels are in the order of the rated power of the converters. The scheme utilizes Voltage Source Converter (VSC) technology and is the first scheme to use VSC technology with overhead lines. The scheme has also been designed for earth return operation. The papers below provide an overview of the scheme, the AC networks that it interconnects and the features of VSC technology that are particularly suited to connecting weak AC networks. The process of selecting sites and the design of the earth electrodes is described. Initial operating experience is also presented. http://millicentmedia.com/2011/12/02/shedding-some-light-on-namibia/ http://www.powerengineeringint.com/articles/print/volume-19/issue-11/features/modern-hvdc-solution-provides-vital-african-link.html

at least one intermediate converter terminal to be installed in the future; this will allow additional hydro capacity to be injected into the network and supplied to PLN's local 150kV networks.

Line Design. The line and associated converter substations should be designed to use low-profile type structures suited for the given terrain, environmental conditions and operational safety. The converter substations shown below should be designed with the provision for additional space for uprating to bipolar operation. The lines should typically be designed with narrow right-of-ways to minimize impact on forest areas, as shown in Figure 29.

Line routing should be as direct as possible to minimize both project costs and associated losses in operation. As noted in Annex 5, the route profile shown below indicates that for most of the way, the transmission line will traverse low-lying land, less than 100 meters above sea level, through the relatively swampy areas around Banjarmasin. A short portion of the route will be through the Schwaner mountains, where the line may reach an elevation of about 500 meters – not a particularly difficult crossing compared to other routes in Borneo.

Figure 30 Topographic Profile of Proposed HVDC Transmission Route from Benkayang Substation to Banjamasin



Project Costs. The project costs will cover the design, manufacture and installation of two HVDC monopolar converter terminals plus approximately 800 km of HVDC transmission line, as shown above. It does not include the cost of the associated 150kV reinforcements at each end of the line which will need to be evaluated during the feasibility study.

The cost of the converter terminals is estimated to be $150/kW, made up of valve groups (21%), converter transformers (20%), DC and AC switchyard filters (16%), control, protection and auxiliaries (11%), civil/mechanical works (14%) and project engineering (17%). The converters are normally built as turnkey projects, often with financing arranged by the exporting country.

The estimated unit cost of the HVDC line is based on 50% of the cost per kilometer of the equivalent capacity double-circuit 275kV line that is currently being built between Sarawak and Kalbar. A contingency amount of 10% has been applied to cover extra costs for the two major river crossings, the use of special foundations in swampy areas, and access difficulties over the Schawner Mountains. Because roughly 60% of the cost of transmission lines is dominated by world aluminum and steel prices, it will be necessary to review cost estimates from time to time until the contract is awarded.

An indication of how the projects costs would be composed for financing purposes is shown in Table 15 below.

Table 15 Indicative Project Cost Estimate US$m - HVDC Interconnection from Kalbar-Kaisel

Monopole HVDC Converter & Transmission Costs	%PC	%FC	FC	LC	Total
Valve Groups	21%	90%	$11.3	$1.3	$12.6
Converter Trafos	20%	90%	$10.8	$1.2	$12.0
DC & AC Switchyard, Filters Control & Protection	27%	90%	$14.6	$1.6	$16.2
Civil Mechnical works	14%	50%	$4.2	$4.2	$8.4
Project Engineering	18%	50%	$5.4	$5.4	$10.8
Subtotal Base Cost HVDC Monopolar Converter			**$46.3**	**$13.7**	**$60.0**
Survey & Engineering Design	5%	50%	$4.7	$4.7	$9.5
Conductors & fittings	35%	90%	$59.6	$6.6	$66.2
Structures	30%	50%	$28.4	$28.4	$56.7
Foundation & Erection	30%	30%	$17.0	$39.7	$56.7
Subtotal Transmision Line			**$109.7**	**$79.4**	**$189.1**
150kV Evacuation Facilities			$20.0	$5.0	$25.0
Subtotal Project Base Cost	FC	LC	**$176.0**	**$98.1**	**$274.1**
Physical Contingencies	10%	15%	$17.6	$14.71	$32.3
Financial Contingencies	5%	12%	$8.8	$11.8	$20.6
Total Project Cost			**$202.4**	**$124.6**	**$326.9**

Financial and Economic Justification. The evaluation of the FIRR and EIRR for building the HVDC line should be based on (i) the use of lower cost power from Sarawak to supplement PLN supplies in Kalut and Kaltim; (ii) the breathing space provided to PLN by the additional power, which will enable PLN to investigate, plan and build an environmentally acceptable mine-mouth coal plant near Banjarmasin (to supply Kalsel and feed back into Kalbar and Kuching); (iii) the provision of the essential HVDC stabilizing support at both ends of the HVDC transmission line that will also facilitate the synchronized interconnection of the RUPTL-planned underlying 150kV systems; and, importantly, (iv) the reduced impact of a much reduced right-of-way on sensitive forest areas.

7.2 Key Environmental Issues

Spatial planning. In the AMDAL[56] approval processes outlined in Annex 6, issues such as alignment with regional spatial planning can significantly delay project preparation and approval. Since transmission line projects often cross regency and/or provincial borders, aligning with the spatial planning of each local government will likely be required. Therefore, identifying feasible routes early in the planning stage, together with close communication and coordination with local governments, will be a key to the success of proposed projects.

[56] Environmental Impact Assessment and Approval Process

Forestry permits. Kalimantan has large areas of protected and conservation forest areas. The use of these forest areas will require permits from Indonesia's Ministry of Forestry, a process which has taken significant amounts of time in past PLN projects. The best solution is to avoid protected or conservation forest areas whenever possible; however, given the length of the proposed routes, it may become necessary to go through such protected areas. Planning ahead and starting any permit processes early will thus be crucial in completing the proposed projects on time.

Biodiversity. With its vast forest areas, Kalimantan is home to many types of fauna and flora, including some endangered species. This may pose challenges not only to the proposed transmission lines, but also to large generation projects used as the basis of larger transmission lines. Again, early planning and careful site selection will become key to successful implementation.

Indigenous peoples. Kalimantan houses many different groups of indigenous peoples. For example, the ADB-financed West Kalimantan Transmission Strengthening Project (ADB Loan-3015) identified a traditional Dayak ethnic group residing in the project area around Bengkayang-Ngabang-Tayan. While this ethnic group is well integrated with the local government and the Indonesian state constitutional legal system, they maintain some of their traditional practices in the management of land ownership. Identifying these ethnic minorities and their customs will also be critical for garnering their support for the implementation of projects and for compliance with the safeguard guidelines typically required by multilateral development banks (MDBs) or other IFIs.

Cross ownership of land. In forest-intensive areas, cases where national forest areas overlap with private land ownership have been seen in many projects financed by MDBs or bilateral agencies. There are also cases in which multiple private owners have claims on the same piece of land. The presence of indigenous people with traditional land management systems further complicates this issue. Early planning and careful route selection to avoid potentially conflicted areas will be the key in the implementation stage.

Compensation for land. Indonesian regulation requires the use of tax object selling value, which is the basis of taxation and is determined by the government. The new land acquisition law requires the use of a third party independent auditor if the government and the land owner cannot agree on the price. However, the current regulations do not provide a mechanism for calculating replacement costs, which reflects the market value of the land including any income losses from activities previously conducted on the acquired land, such as farming. The MDBs, on the other hand, require the use of replacement cost for compensation. This gap has been an issue for past projects, and PLN and MDBs have found resolutions on a project-by-project basis. However, the process requires careful attention to the requirements of both national and MDB guidelines. The preparation of Land Acquisition and Resettlement Action Plans (LARAP) must therefore be started early, in close coordination with financing partners such as ADB.

Other potential issues. Other general potential issues seen in high-voltage transmission line projects are listed in Annex 6. The information is largely taken from ADB's feasibility study for the Sumatra-Peninsular Malaysia HVDC interconnection project.[57]

7.3 Scope of Further Technical Investigations

Need for Further Studies. It will be necessary for PLN to recruit consultants to take the project to the next step in developing its portion of the ASEAN grid. To accelerate implementation, the consultants' work should be in the form of a full feasibility study that uses PLN's RUPTL plan as a baseline for comparing an alternative least cost investment plan to supply the Kaltim and Kalbar demand centers. The plan should also take into consideration that the next phase of expansion should be based on the development of a 275kV backbone line in the north-west coastal region of Kalimantan.

[57] ADB, *Sumatera-Peninsular Malaysia HVDC Interconnection, and Mine Mouth Coal Fired Power Plant and Coal Mine Projects in Sumatera,* November, 2013

This study should compare an approach based on the concept of using high capacity HVDC and 275kV transmission interconnections to aggregate demand, with an approach based on incremental expansion as detailed in the RUPTL documentation. In this instance, the RUPTL plan proposes the gradual expansion of the 150kV system using small distributed generating stations and 150/20kV substations scattered throughout the network. The alternative plan, based on aggregation of demand with backbone interconnections, should be designed to minimize cost and environmental impact. This would be achieved by developing fewer but larger-scale mine-mouth coal generation resources (supported by appropriate gas-fired peaking plants and hydro projects where possible). By comparing the alternative plan based on load aggregation with the base case plan (i.e. RUPTL 2013-22), it should be possible to determine the best way forward.

Implications for the proposed coal-fired generation projects. The benefits of large mine-mouth coal-fired power plants justifies the choice of such plants not only because of the future interconnection potential, but also because of their economic benefits. The management of large mine-mouth coal-fired power plants requires careful attention to structuring and legal issues, but this would be no more difficult than the significant management issues faced by PLN in managing so many small-scale power plants in Kalimantan. As explained in Annex 7, a number of on-going power generation projects are facing significant problems; these require extensive use of PLN's resources for management, and are thus unlikely to meet the original COD targets. The efforts required of PLN for these small-scale projects could be streamlined towards building a smaller number of much larger mine-mouth coal-fired projects.

The study would also need to include a review of load growth in the region between Kaltim, Kalteng and Kalbar to verify whether there is really a need for so many intermediate 150/20kV substations to meet PLN's renewable energy targets. The WASP-type generation expansion study required to study generation alternatives would also need to include technical power system studies (load flow, fault and stability analysis) to determine generation unit sizes and spinning reserve requirements. The latter work is required to ensure system stability after a major disturbance in cases where there are various combinations of generation sources and transmission links in operation.

The study should also review options for increasing the proportion of non-hydro renewables in the electricity generation system, specifically including the use of solar-powered generation within major load centers, or at other locations where large solar-powered farms may be appropriate (e.g. in cleared areas that have not been otherwise productive).

Development of Geo-spatial Mapping Database. PLN's System Planning Department needs to expand the use ArcGIS (or similar software) to enhance their planning database to include all information relevant to power system planning in Kalimantan. This should include: (i) the location of coal, hydro, gas and potential solar sites (i.e. large open areas with good solar attributes, preferably near a gas field); (ii) the location of large population centers and population densities where electricity supplies are required and demands can be forecast; (iii) the identification of suitable routes for long transmission lines that account for terrain, ground (e.g. avoiding swamps) and submarine cable seabed conditions; (iv) links with other databases and making the power planning database available to stakeholders (e.g., other Borneo utilities and resource planners for mining and other energy sources).

Annexes

Annex 1
Terms of Reference for this Study

Objective/Purpose of the Assignment

Since international power trade commenced between Thailand and Lao in 1961, Southeast Asian nations have sought to build an integrated power network within the region. The Heads of ASEAN Power Utilities/Authorities (HAPUA) was established in 1981 to promote regional power interconnections, and the ASEAN Power Grid program (APG) was identified and initiated through stakeholder consultations of HAPUA activities in 1997. The original ASEAN Interconnection Master Plan Study (AIMS), as the basis of interconnection plans, was completed in 2003. It was recently revised and published as AIMS-II in 2010, and identified sixteen interconnection systems for the regional integrated power system (see Appendix A). This integration is divided into three key systems. System A covers the upper west system, consisting of Cambodia, Laos PDR, Myanmar, Thailand and Vietnam. System B is for the lower west system, covering the network for Indonesia, Malaysia and Thailand. System C covers the eastern sub-region with Brunei, Malaysia (Sabah and Sarawak) and Indonesia (Kalimantan), which is also called the BIMP/EAGA sub-region.

Currently, there are five main existing interconnection lines in the region that connect Thailand, Peninsular Malaysia, Lao PDR, Singapore, Cambodia and Vietnam. The sixteen APG projects together aim to integrate the regional systems by 2025, including the currently non-connected areas of the Philippines and the Borneo-Kalimantan areas of Malaysia and Indonesia. Among these, ADB has helped finance the Sarawak-West Kalimantan interconnection, which is scheduled to be completed by 2015. Furthermore, the intra-national connection between Sarawak and Sabah regions of Malaysia is also in a planning stage (see Appendix B). ADB is also in discussion with the Tenaga Nasional Berhad, a major power utility in Malaysia, PLN, Indonesian state-power company, and Bukit Asam, a state-owned coal supplier in Indonesia, on the preparing an investment project that will finance the interconnection between Peninsular Malaysia and Sumatra, Indonesia.

In February 2014, senior officials from the Philippines, Malaysia and Indonesia held a key strategy meeting in Davao, Philippines, and agreed on commencing a pre-feasibility assessment of a further integration of power systems in the three countries. This study, therefore, will provide the pre-assessment of interconnections in the eastern region, or the System C, of the APG program, namely Mindanao (Philippines), Sabah-Sarawak of Malaysia and Kalimantan (Indonesia). A final report with stakeholder reviews is expected to be delivered by November 2014. The senior officials have requested ADB to provide a small team of experts to carry out this assignment. The consultants report will form the basis of the final report to the senior officials' meeting to be held in November 2014.

Brief Introduction to the Power Systems in the Countries

In Mindanao, Philippines, the demand for power is expected to grow at 8.43% annually, and an additional 2,200 MW will be needed by 2030 to meet this demand. The Mindanao system currently relies heavily on its hydro power plants, which makes up 50% of the energy mix in the area, and the supply stability will likely be compromised as water availability becomes more variable owing to climate change. Mindanao already has some coal-fired power plants, which comprise 12% of the energy mix, but the diversification of power sources, especially through interconnection with Borneo, where there is abundant hydro and coal resources, is an important measure of securing power supply capacity.

Sarawak Energy and Sabah Electricity are the key power utilities in the Sabah-Sarawak region of the portion of Borneo that belongs to Malaysia. These two companies offer a total of about 2,100 MW supply capacity. The region, especially Sarawak, has abundant hydro power resources, which offer potentials for low cost electricity to the Kalimantan (Indonesia) side of the island. ADB–financed project (Loan 3045: West Kalimantan Grid Strengthening project) to connect these regions will be key to more stable and lower cost power supply systems.

According to the ten-year power development plan (RUPTL 2012-2021) of the Indonesian state power utility, PLN, the power generation and delivery system in Kalimantan had a total installed capacity of 993 MW in 2011, with a peak demand of 1,083 MW. The system comprises four major regions: West Kalimantan, South Kalimantan, Central Kalimantan and East Kalimantan. All four areas are characterized by small and medium isolated systems with minimal interconnections. Under Loan 1983, ADB financed the construction of a 150 kV transmission line in 2013 which served to extend the sole connection from South to Central Kalimantan onwards to East Kalimantan. However, these connections cover limited areas of the island, and most parts of Kalimantan remain isolated. PLN's plans for additional capacities are set to meet the growing demands, but without the intra and interconnections in the four main regions, isolated standalone systems will pose threats to the stable supply of power. Further, connecting PLN systems in Kalimantan across the border to the Sarawak/Sabah system in Malaysia can help in the import of cleaner and cheaper hydropower into Indonesia, while also conferring additional stability and resource efficiency. Under the APG program, ADB is supporting PLN in its efforts to connect its systems with the Sarawak system in Malaysia, most notably through a recently approved investment program (Loan 3045)) to support the construction of a 275 kV interconnection from West Kalimantan to Sarawak (see Appendix C for more details on the current conditions of the Kalimantan power systems). In particular, the viability of any future cross border connection between Indonesia and Sabah-Sarawak will be strengthened by interconnecting the systems within Kalimantan.

Scope of Work for the Consultants

Given these potential for future regional interconnections, a pre-feasibility assessment of such plans is urgently needed for identifying opportunities for power trade, priority interconnections and their appropriate sequencing to maximize economic and financial return. In return, given ADB's prior support for specific interconnections in Kalimantan, PLN has recently requested ADB to conduct a preliminary assessment of the potential for interconnecting all systems in Kalimantan.

The proposed regional study will therefore: (1) evaluate prospects for interconnections across Sarawak and Sabah in Malaysia, to Kalimantan in Indonesia, and out to Mindanao or Palawan in the Philippines, and (2) provide a preliminary analysis of the potential for interconnecting systems within Kalimantan.

Toward this end, ADB seeks to hire three (3) consultants, namely Transmission Specialist/Team Leader (international), GIS Specialist (national) and Energy Analyst (international), on an intermittent basis during the period April 15, 2014 - August 30, 2014

Detailed Tasks and/or Expected Output

Transmission Engineer/Team Leader

(i) Review and summarize the current power conditions, power demand forecasts, peak operating hours and projected transitions, and transmission network development plans in Borneo (Malaysia), Kalimantan (Indonesia) and Mindanao or Palawan (Philippines). This review should take into consideration the available energy sources and generation expansion plans in each region to devise a plan for optimized resource utilization through power trading from a regional perspective.

(ii) Review and summarize the existing networks and isolated systems in Mindanao/Palawan, Sabah, Sarawak and Kalimantan in detail. Identify potential technical issues for the interconnection.

(iii) Based on the data and analyses from i) and ii) above, propose preliminary routes (in particular explore the pros and cons of a Borneo-Palawan-Leyte versus a Borneo-Mindanao connection), voltage specification of each interconnections, and HVDC interconnection plans, where appropriate.

(iv) Conduct site visits to the Malaysian side and Indonesian side of Borneo, and identify potential issues and countermeasures to reflect on the recommended implementation plans.

(v) Provide preliminary cost estimates of the interconnection projects, including the transmission lines, distribution lines and substation construction.

(vi) Provide recommendation to associated distribution network expansions along the proposed interconnection lines.

Financial Analyst

(i) Collate information on power grid and non-grid systems in the three target regions, namely, Sarawak-Sabah, Mindanao/Palawan and Kalimantan, and analyze the future supply-demand balance, energy mix and optimal timing of interconnections, in collaboration with the Transmission Specialist;

(ii) Develop preliminary financial and economic analysis based on the technical reviews and cost estimates provided by the Transmission Specialist;

(iii) Identify potential options for financing, including export credit, ASEAN Infrastructure Fund, and sovereign and non-sovereign-backed financing from ADB

GIS Specialist

(i) Set up a geospatial mapping platform to analyse load centers, existing T&D infrastructure, major land use zones, areas of biodiversity and reserve forests, key land forms that need to be taken into account while planning interconnections and use this information and in consultation with the Team Leader, prepare alternate high-level renditions of possible alignments for the proposed priority interconnections. The generated maps will be high-level for the international interconnections and more detailed for the interconnections in Kalimantan.

(ii) In particular, the following data need to be represented:

   (a) Geographical information, such as topography and natural features such as rivers and lakes;

   (b) Infrastructure information, such as roads;

   (c) Population data, including the location and size of settlements and load centers;

   (d) Administrative boundaries including spatial planning classes such as different categories of forest;

   (e) Determine the locations of power lines as well as planned or potential substations and power plants, conducting a site visit, as necessary.

(iii) Maintain the geospatial database over the course of the assignment

Annex 2
Reference List – Key Documents Made Available to Consultants

#	Date	Subject	Relevant Information
ADB 1	11 May 2014	ADB Project Data Sheet	Background Scope of Work, timetable etc.
ADB 2	July 2011	Sarawak-West Kalimantan 275 kV Transmission Line: Draft Resettlement and Ethnic Minority Development Plan	General information relating to project area and ADB safeguard requirements
ADB 3	August 2013	Report and Recommendation of the President to the Board of Directors :Proposed Loan and Administration of Loan and Grant Republic of Indonesia: West Kalimantan Power Grid Strengthening Project	ADB loan appraisal and loan documents; File also includes Project Agreement between ADB and PLN
ASEAN and HAPUA		Policies and Action Plans	
ASEAN 1	March 2010	THE 3RD ASEAN INTERCONNECTION MASTER PLAN STUDY AIMS - II MEETING TRANSMISSION SUB-WORKING GROUP 3 - 4 MARCH 2010, BANDUNG, INDONESIA	Progress of various transmission studies
ASEAN 2	18 Feb 2013	Development of ASEAN Energy Sector Power Network Interconnection, Natural Gas Infrastructure, and Promotion of Renewable Energy and Energy Efficiency	ACE Report: Strategy and Status of Asean Grid development
ASEAN 3	2010	AIMS II (2010) ASEAN Interconnection Master Plan Study Also see separate Reports: Master Plan on ASEAN Connectivity;	HAPUA objectives: covers Vision, Goals and Objectives of ASEAN Connectivity; Achievements of, and Challenges and Impediments to ASEAN Connectivity; Key Strategies for Enhanced ASEAN Connectivity; Mobilising Resources for Enhancing Connectivity in ASEAN; and implementation
		http://meih.st.gov.my/documents/10620/8ffd36cd-a3ed-472a-a329-2ec8b42bc02a	Malaysia Regulator Summary report
General Technical Papers		Subject and Authors	Relevance
Gen	2014	GOBITEC AND ASIAN SUPER GRID FOR RENEWABLE ENERGIES IN NORTHEAST ASIA	Technologies and Cost implications
Gen	2013	RENEWABLE ENERGY IN THE ASIA PACIFIC – A legal Overview – DLA Piper	Institutional Issues in various countries
Tech	January 2005	Detailed Feasibility study of Malaysia-Sumatra Interconnection – Shaw-PTI (Vols 1-4 and Executive Summary	Technical analysis of options, Cost estimates etc.
Tech	March 2010	Clean Energy Options for Sabah: an analysis of resource availability and cost – University of California (various authors)	Sabah's Electricity Sector; Electricity Resources: Cost, Availability, and Environmental Quality; Power Supply Simulation Analysis;

continued on next page

Internet References Last Updates		**Webpages**	**Current Topic of Interest**
Int	June 2014	ASEAN: http://www.asean.org/communities/asean-economic-community/item/memorandum-of-understanding-on-the-asean-power-grid	Subset of ASEAN homepage dealing with power sector
Int	Jan 2014	Hapua: http://www.hapuasecretariat.org/	13 th APGCC, 19th HWC and 30th HAPUA Council Meetings will be held on June 3 – 6, 2014 in Manado, North Sulawesi, Indonesia.
Int	2010	ACE: http://www.aseanenergy.org/index.php/pages/links	Web references, data bases, project information
Int		Google Search Images: Asean regional power grid map; maps of Borneo Malaysia; Sarawak power system diagrams; Sarawak power development plan 2014 Wikipedia Searches: National Grid (Malaysia);	A large selection of maps, drawings and pictures including various aspects of the East Asian Power Grids
Int	November 26, 2012	The Asian Supergrid: http://www.japanfocus.org/-John_A_-Mathews/3858	Japanese view of opportunities for investments in ASEAN grid
Int		Sarawak Energy Homepage: http://www.sarawakenergy.com.my/	Details of hydropower potential
Int	Various dates	Nautical maps – Sulu Sea https://www.nauticalchartsonline.com/chart/zoom?chart=92020	Details of seabed soundings

Annex 3
Conceptual Power Plans for Borneo

Figure A3.1 PLN RUPTL KalBar Planned 150kV extensions in West Kalimantan to 2022

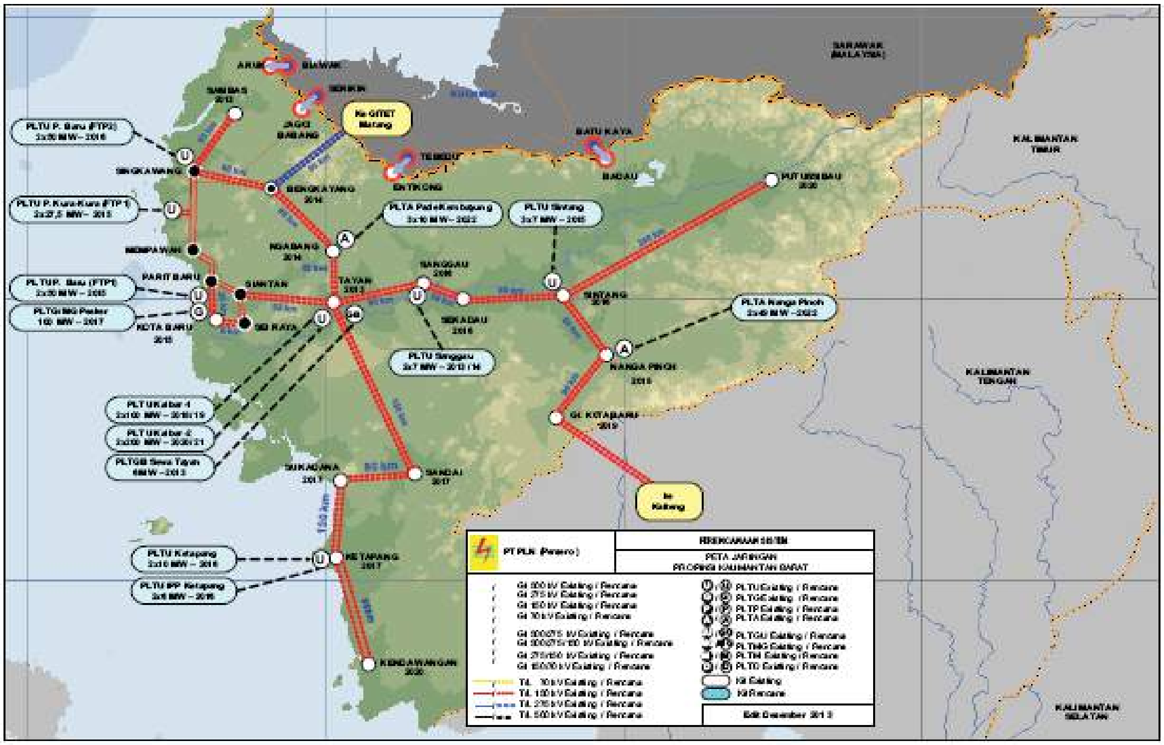


Figure A3.2 PLN RUPTL Kaltimut Planned 150kV extensions in North–East Kalimantan to 2022

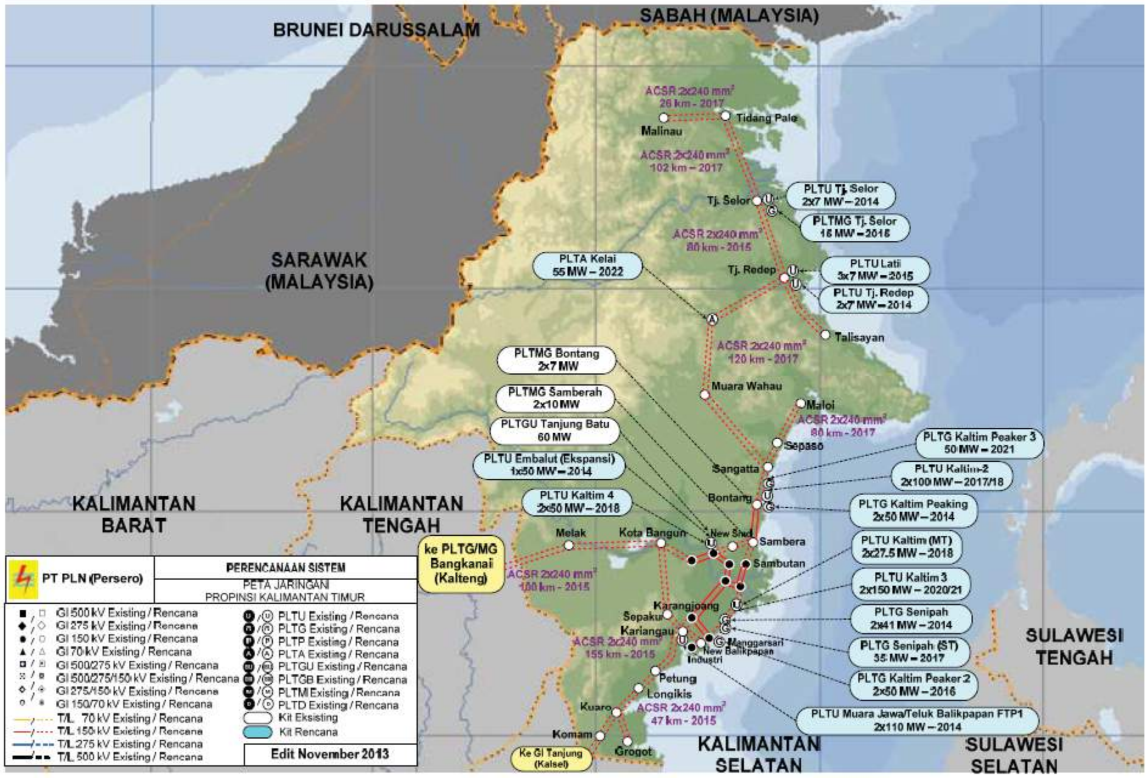


Figure A3.3 PLN RUPTL Kaltselcen Planned 150kV extensions in South Central Kalimantan to 2022

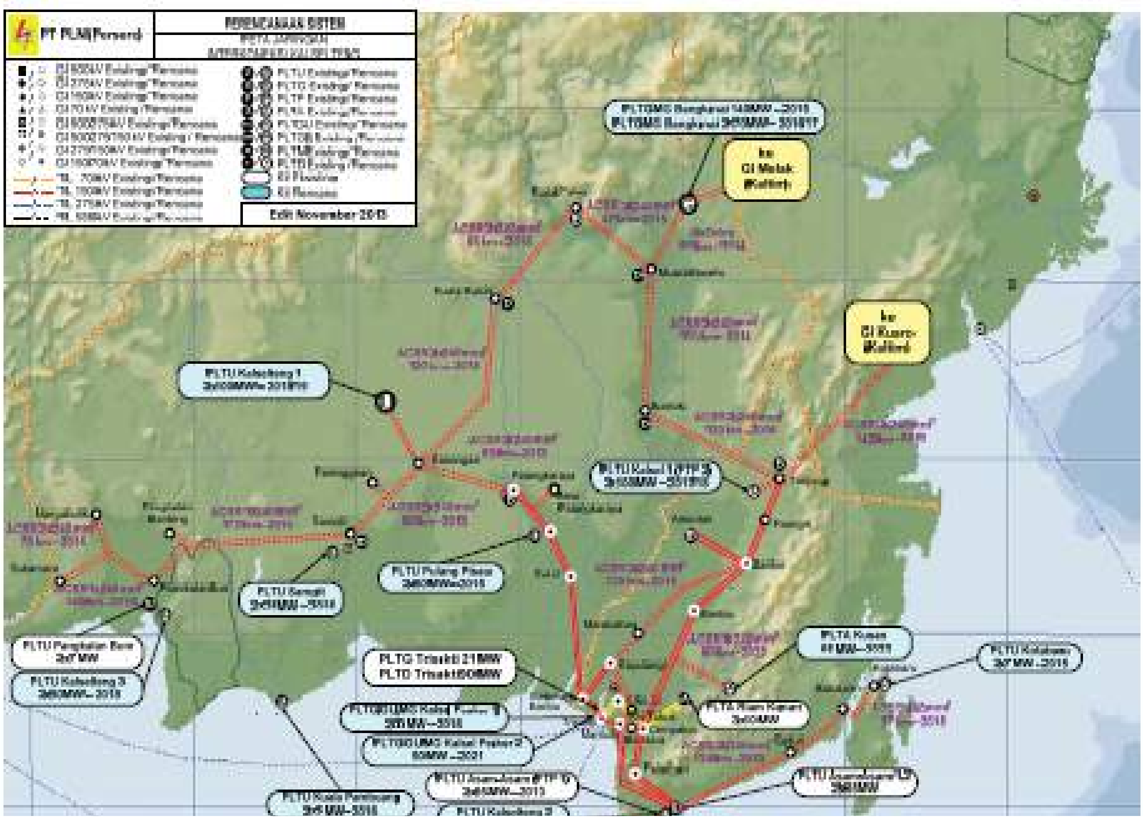


Figure A3.4 Sabah Power Plans for 2023 (source SESB July 2014)

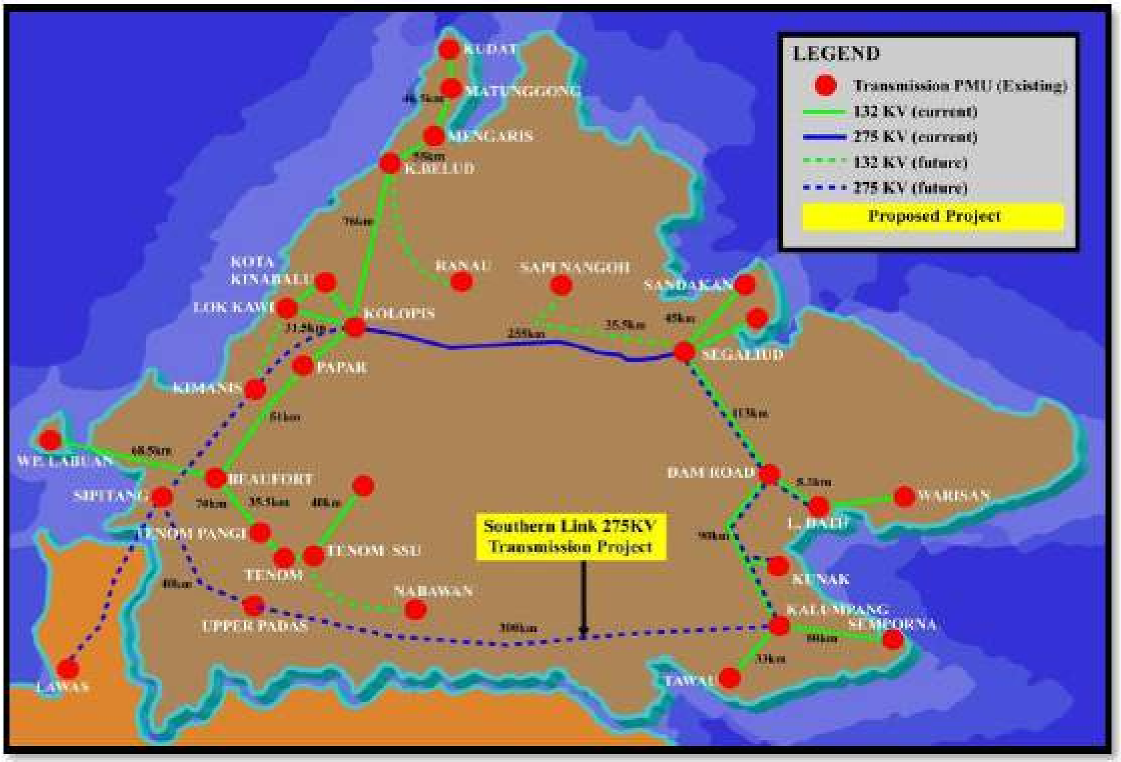


Figure A3.5 Sarawak Conceptual Power Plan to 2022
(source International Journal of Environmental Science and Development, Vol. 4, No. 6, December 2013

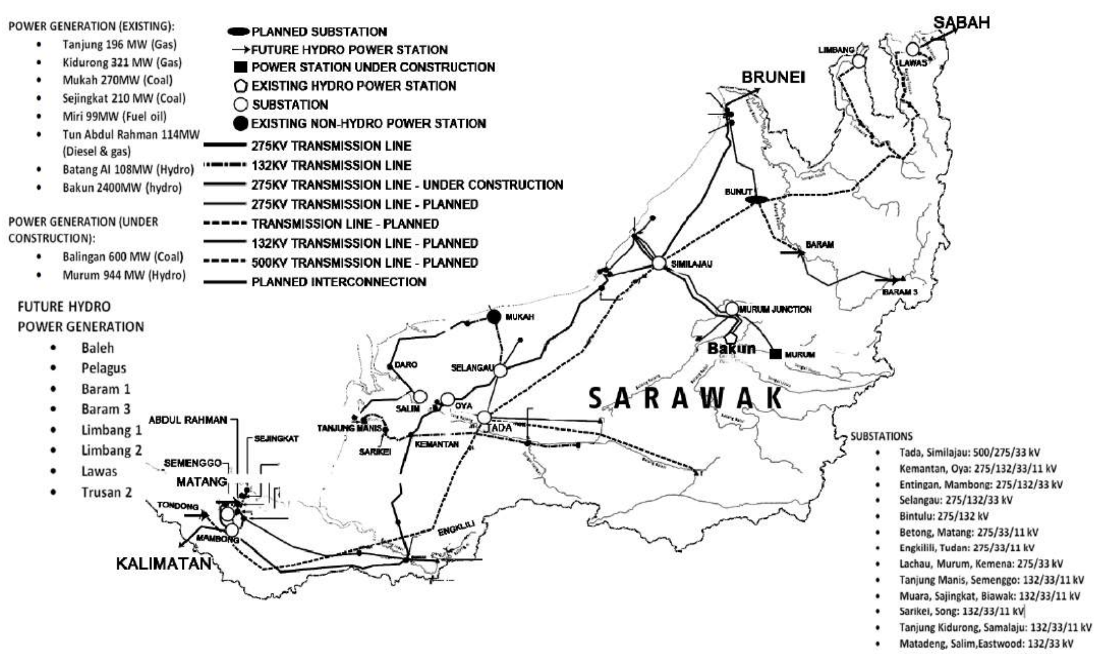


Fig. 1. Sarawak Energy's development plan

Figure A3.6 Sarawak Planned First Stage 500kV Line (source SESCO July 2014)

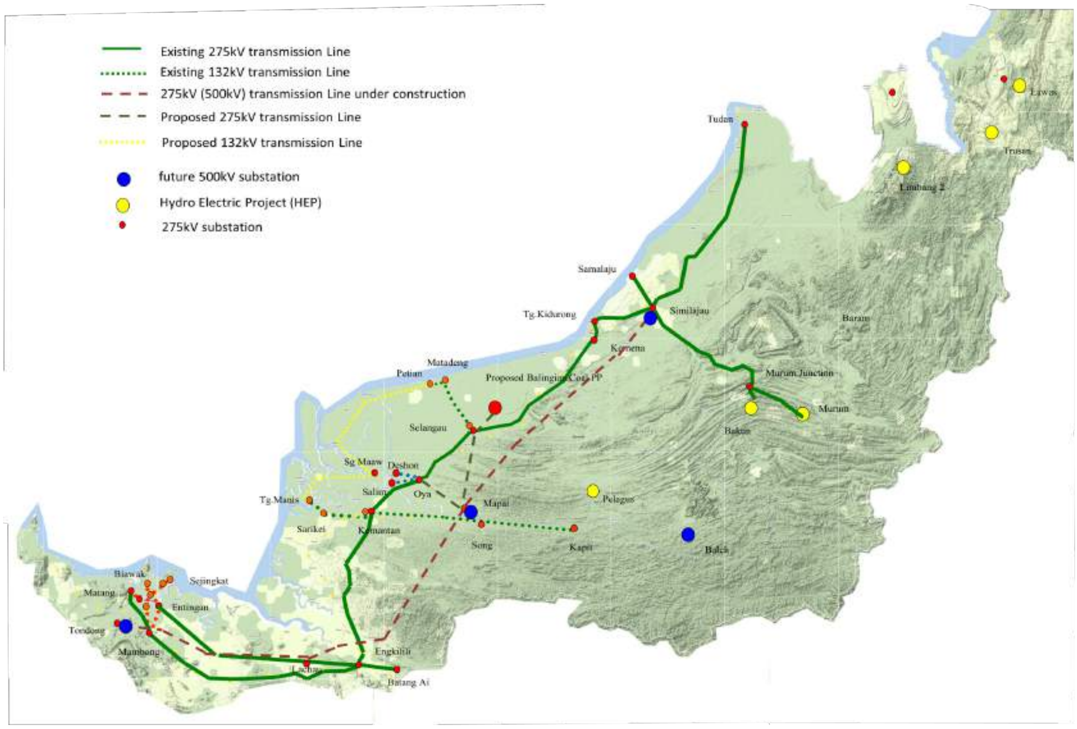


Figure A3.7 Sarawak- Brunei-Sabah Interconnection

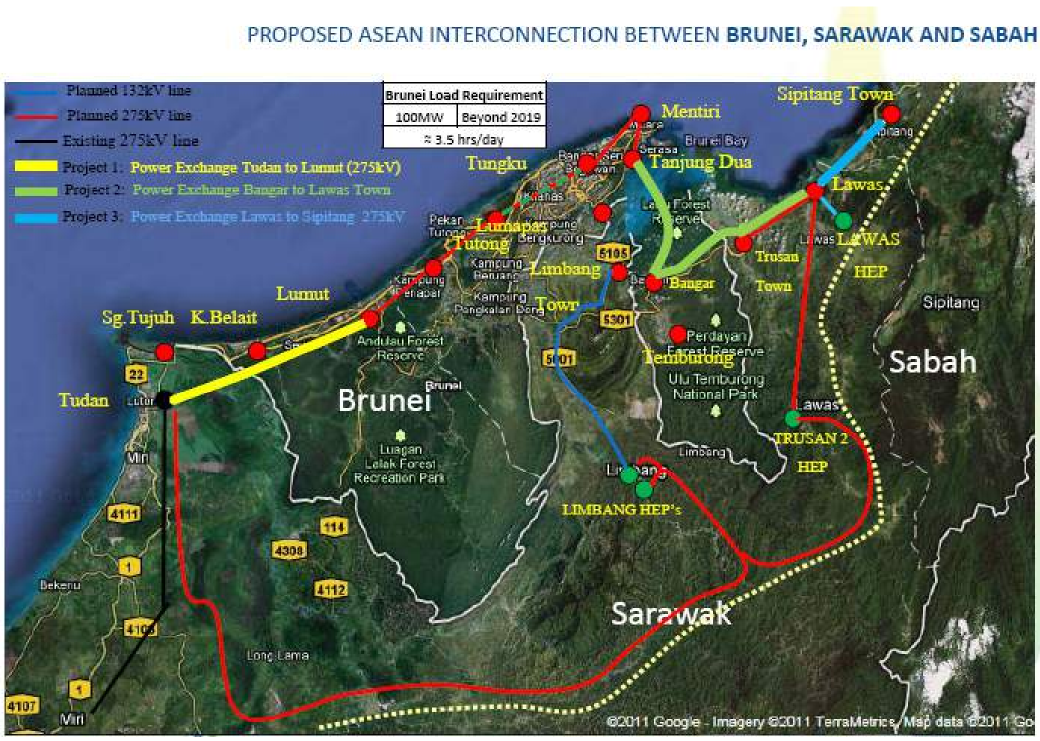


Figure A3.8 Mindanao Grid

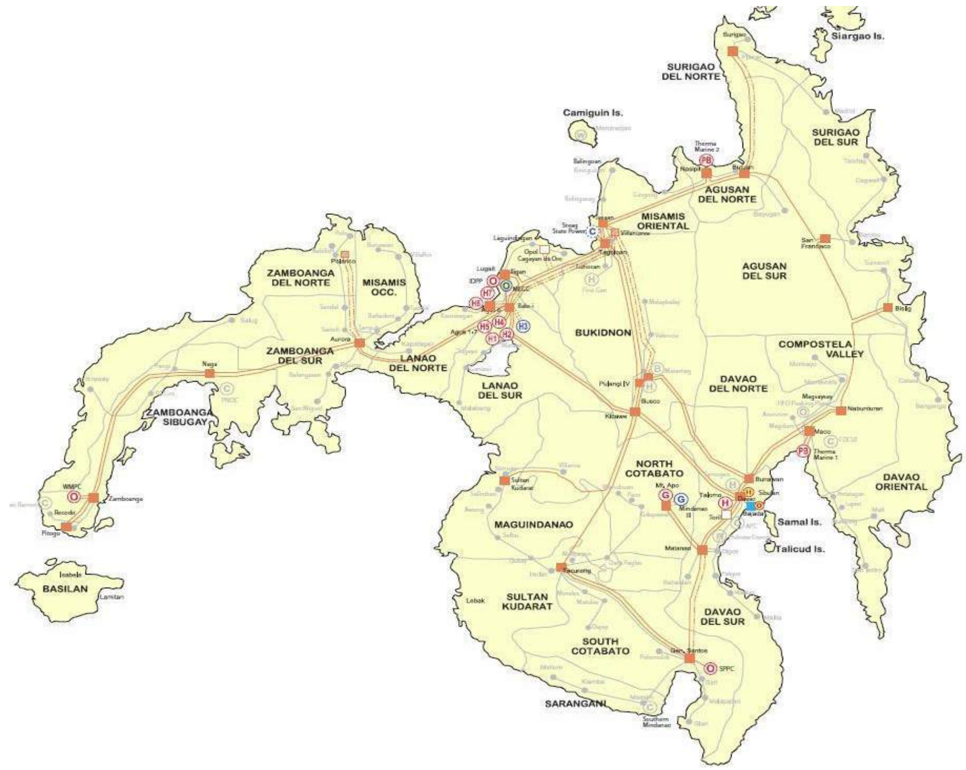
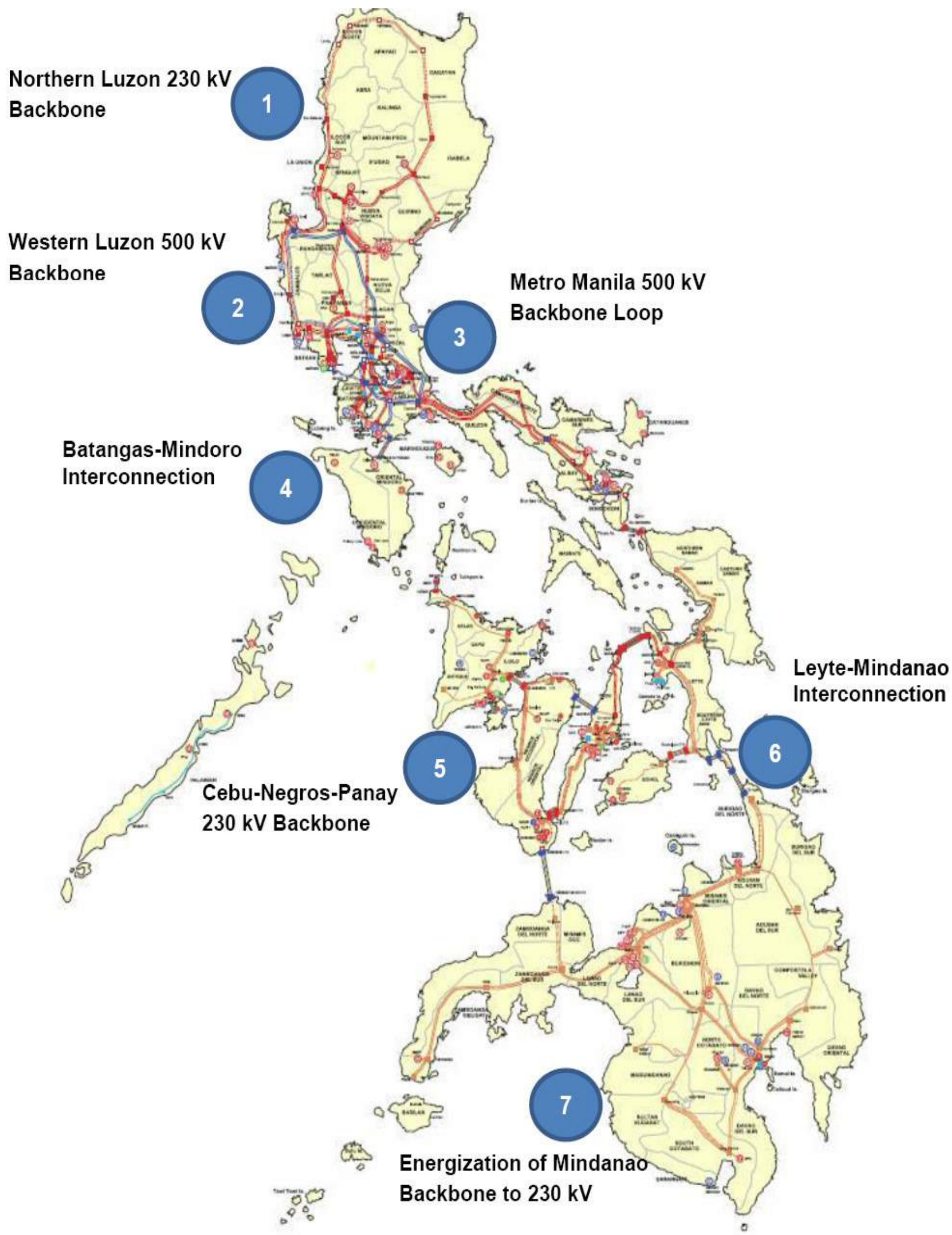


Figure A3.9 Map Showing Relative Distances from North Sulawesi Supply Area to Main Generating Centers in Sulsel and Kaltim

Figure A3.10 Philippines Long Term Transmission Grid Expansion Plan to 2023



Annex 4
Summary of Base Rate Costs Used in the Report

Table A4.1 Transmission and Substation Interconnection Cost Rates

	Transmission Lines	Amp	MW	Base Rate	Unit	Rate Esc	Est'd Rate	Source
1	150kV D/C OHTL - mixed terrian	577	150	149	$/km	1.1	$164	Sarawak-West Kalimantan 2012
2	275kV D/C OHTL - mixed terrian	1260	600	305	$/km	1.1	$336	Ditto
3	500kV D/C OHTL - mixed terrian	2309	2000	594	$/km	1.2	$713	Egypt/India 2013
3	±250kV HVDC - 2 phase-ground return OLTC - monopole	1200	300	183	$/km	1.2	$220	60% of 275kV rate
4	±500kV HVDC - 2 phase-ground return OLTC - bipole	1000	1000	322	$/km	1.2	$386	Afghanistan 2013
5	±500kV HVDC - bipolar Cables (1 spare)	1000	1000	1074	$/km	1.2	$1,289	2006 Shaw Budget updated
	Substations		Units	Rate				
1	150/20kV Substation - 4 Line Bays/1 B/C 1 trafo		5	204	k$/bay	1.05	$1,071	Sarawak-West Kalimantan 2012
	- Transformer capacity (MVA)		60	25	k$/KVA	1.05	$1,576	
	- Auxiliaries and Civil Wks		1	10%	% tot	1.05	$278	
	Standard PLN 150kV Substation Total				LS	1.05	$2.924	k$
2	275/150/20kV Substation - 4 230kV Bays/1 B/C 1 trafo		5	1264	k$/bay	1.05	$6,635	Sarawak-West Kalimantan 2012
	- Transformer capacity (MVA) with spare		300	23	k$/KVA	1.05	$7,166	spare single pahse unit
	- Reactor & auxiliaries		50	16	k$/KVAr	1.05	$841	
	- 150/20kV substation		1				$2,924	
	- Spares		1	10%			$1,757	
	- Auxiliaries and Civil Wks		1	15%	% tot	1.05	$2,635	Land & building not included
	Total 275/150/20kV substation				LS		$21.96	k$
3	500kV/275kV Substation							
	- 6 CB and half 500kV $ incommers		6	2000	k$/bay	1.05	$12,600	
	- Auto Transformer capacity (MVA)		600	15	k$/kVA	1	$9,000	
	- 275kV sitch bay		5	204	k$/bay	1.05	$1,071	
	- Spares		1	10%			$2,267	
	- Auxiliaries and Civil Wks		1	15%	% tot	1.05	$3,401	Land & building not included
	Total 500/275kV Transformer Substation				LS		$28	k$
4	One 500kV/HVDC bipolar1000MW Converter Facility		1000	120	k$/KW	1	$120	k$
5	One 250kV/HVDC monopolar 300MW Converter		300	100	k$/KW	1	$30	k$

Summary of Base Rate Costs Used in the Report

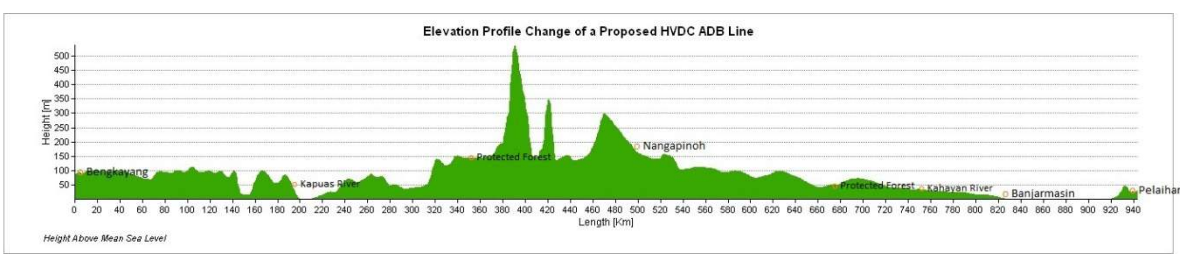
Annex 5
Profiles for Proposed Transmission Line Routes in Kalimantan

Transmission line routing should be as direct as possible to minimize the cost of the project along with the associated losses in operation. It is necessary to consider not only technical issues, but also the impact on natural environment, the influence on local communities, and various regulations. In this Borneo Interconnection study, a GIS-based application[58] was used to determine the most suitable site and shortest path.

There is a need for more detailed desk studies followed by site surveys to find the optimum routing for any transmission line. The studies will need to take into account access for construction, concerns about environmental issues and the growing consciousness of (opportunistic) land owners. Other factors include (i) geotechnical factors such as slope, landslide, earthquake/fault and road/pipeline crossing; (ii) environmental factors such as national parks, archaeological areas, water resources, river crossing, wildlife, and protected forests area; (iii) socioeconomic factors such as agricultural areas, residential areas, cultural assets, temples, shrines, recreation areas, tourism, right of way, and relocation. In GIS terms, each of these factors corresponds to a spatial data set used to resolve complicated spatial problems. A raster data model used for storage and visualisation of spatial data sets provides important advantages especially for line routing over long distances along the least slope, and avoidance of protected forests, wetlands and other ecologically sensitive areas

Figure A5.1 below shows the profile of the proposed HVDC line route shown from Bengkayang to the Banjarmasin – Pelaihari area. The route will cross the Kapuas river to Kaltim traversing through a protected area near the border of Kalbar and Kalteng. In Kalsel, the route is over relatively low lying land (less than 10m above sea level) near Banjarmasin with the areas around Banjarmasin relatively swampy and requiring special foundations. About 50km of the route will be through the Schwaner mountains where the line may reach an elevation of about 500m – not a particularly difficult crossing relative to other routes in Borneo.

Figure A5.1 Elevation profile of a proposed 940km HVDC line from Bengkayang to Banjarmasin—Pelaihari area.



[58] This preliminary TL routing process has been based using the geographical information system incorporated into ArcGIS software

The route profile in Figure A5.2 below shows the proposed 275 kV line from Pelaihari near Banjarmasin in Kalsel to Bontang north Samarinda in Kalbar passaging through high hilly forest. The route will traverse through protected forest area lying in 100m – 300m height above mean sea level. Before Kariangu, the route will be across the Lombok River near the border between Kalsel and Kaltim. From the Balikpapan area to Bontang, the line goes over relatively low-lying land less than 20m in height along the coast line, except near Samarinda, where the line must pass a relatively swampy area and the Mahakam River.

Figure A5.2 Elevation profile of a proposed 275 kV line from Pelaihari, Kalsel to Bontang Kaltim

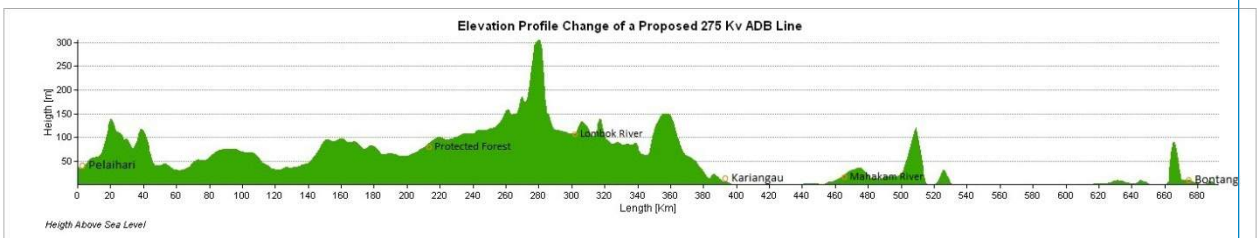


Figure A5.3 shows the elevation profile of the proposed 275 kV line route from Bontang to Kelay in East Kalimantan. From Bontang to Sangata, the route will follow the coast line, through some undulating areas before Sekerau river. From Maloy to Kelay the profile indicates that most of the route will travel over relatively low lying land between 100m to 500 m above sea level. There is a protected forest area where the line may have difficulty in crossing relative to other routes in Kalimantan.

Figure A5.3 Elevation profiles of proposed 275 kV line from Bontang to Kelay in Kaltim

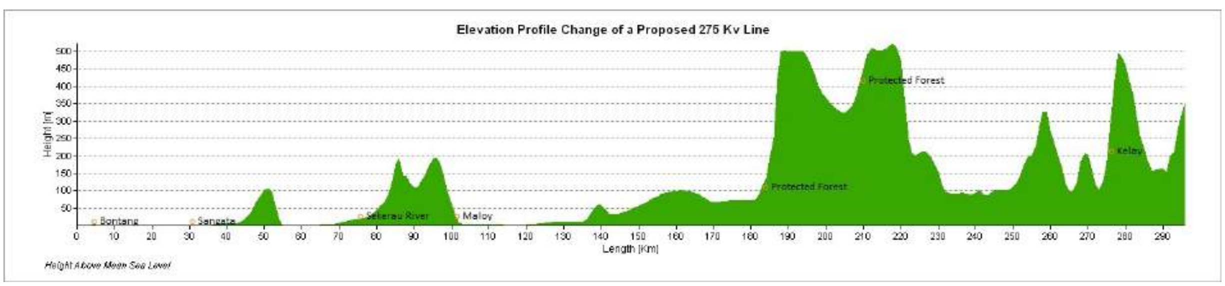


Figure 5.4 shows the elevation profile of the proposed 275 kV line from Kelay in Kaltim to Baram 3 in Sarawak through the border between two countries. The route passes through an area with significant hydropower potential. The route will cross the Kayan river before traversing over an extensive protected area along the Iban mountains country border. In Sarawak the transmission line will traverse relatively undulating and rolling with height about 500m.

Figure A5.4 Elevation profile for proposed 275 kV line from Kelay, Kaltim to Baram 3, Sarawak

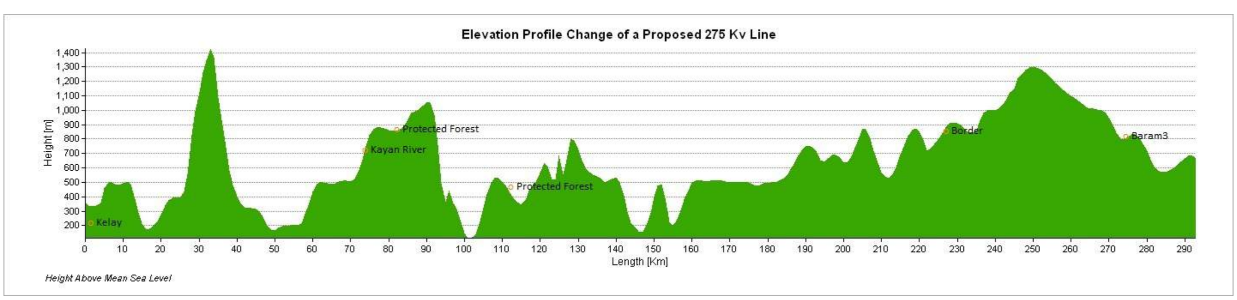
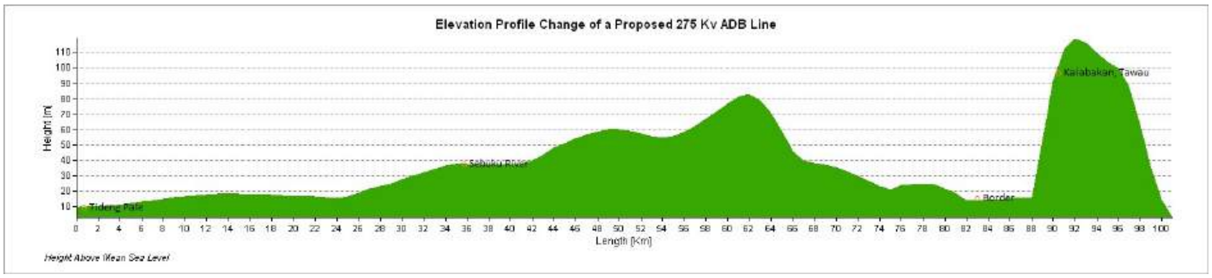


Figure A5.5 shows the elevation profile of the proposed 275 kV line from Tideng Pale, East Kalimantan to Kalabakan, Tawau, Sabah in Malaysia. From Tideng Pale in north part, east Kalimantan to Sebuku river the transmission line lying to go uphill from 10m height above mean sea level until 40m, this route line will travel over relatively high lying land and will declining through the border between two countries. There was no protected area along this route. In Kalabakan, Tawau area route the transmission line will travel over relatively high lying land up to 100m height.

Figure A5.5 Elevation profile change of a proposed 275 kV line from Tideng Pale, East Kalimantan to Kalabakan, Tawau in Sabah Malaysia.



Annex 6
Environmental Impact Assessment (AMDAL) and Approval processes

Official environmental impact assessment documents are called AMDAL in Indonesia. AMDAL consists of three documents: ANDAL (environmental impact assessment), RKL (environmental management plan) and RPL (environmental monitoring plan). The types of projects that require a preparation of AMDAL are listed in the ministerial regulation No. 11/2006 of the Ministry of Environment. Projects that do not fall under the types listed in this regulation are not required to prepare a complete set of AMDAL but required to prepare simplified environmental management and monitoring plans, called UKL and UPL, respectively.

The authority of the approval of AMDAL or UKL/UPL depends on the affected areas and their governing entities. For example, projects with affected areas within only one regency require AMDAL to be approved by the environmental impact management agency (Bappedalda) of the regency government. Projects that spans across two regencies are governed by provincial governments and those span across two provinces are governed by the central government.

The process of AMDAL approval is regulated by the ministerial regulation No.8/2006 and No.11/2006. First, the project owner initiates the process by creating the terms of reference to prepare AMDAL. This TOR is called KA-ANDAL. The project owner needs to submit KA-ANDAL to the respective approval entity. This initiates the formation of the AMDAL evaluation committee. After KA-ANDAL is approved by the committee, the project owner starts the preparation of all required AMDAL documents and submits the draft to the committee. The committee may require revisions, which the project owner needs to revise and reflect in the AMDAL, but the committee has a maximum of 70 days to approve AMDAL. The number of days the project owner spends on revision processes is not counted in this limit. If the committee does not provide specific indications, the AMDAL is deemed approved under the current regulation. However, for the project to proceed and obtain subsequent permits such as location permits for land use and acquisition, AMDAL needs to be accompanied by the approval letter by the head of the governing entity (regency head, provincial governor or the environmental minister). Therefore, explicit approval by the AMDAL evaluation committee is in effect a requirement.

Social impact assessment Land acquisition for public projects is governed by the land acquisition law No. 2 of 2012 and related presidential decree No. 71/2012, regulation of the National Land Agency (BPN) No.5/212 and ministerial decree No. 72/2012 of the Ministry of Home Affairs. The process requires the local office of BPN to lead the land acquisition process, including price setting and negotiations. While the application of these new processes for on-going projects is subject to the conditions stated in the Presidential Decree No. 71/2012 on the progress of projects, projects that will complete land acquisition after 2015 are required to follow the new process under the Law No.2/2012.

Other relevant regulations for land acquisition include the ministerial decree No. 38/2013 of the Ministry of Energy and Mineral Resources. This regulation provides guidance on determining the compensation levels for the right of way (RoW) for high voltage transmission line projects. Other local government regulations on compensations for lost or damaged crops also need to be referenced in the project preparation stage.

Classification of proposed projects A transmission project of capacity above 150kV is required to prepare a complete set of AMDAL and not UKL/UPL. Therefore, the proposed HVDC line between West and Central Kalimantan and the 275kV upgrade on the eastern coasts of Kalimantan will need to prepare AMDAL.

Transmission line projects by PLN are generally considered to be projects of public interest. Therefore, the processes under Law No 2/2012 will be the basis of the land acquisition process for the proposed projects.

Alignment with ADB/MDB safeguard requirements Indonesian environmental and social impact documents, however, do not require the coverage of all safeguard requirements by multilateral development banks such as the ADB. Therefore, projects financed by these agencies often require additional environmental and social impact considerations.

One of the key requirements by MDBs is the land acquisition and resettlement action plans (LARAP). Indonesian regulations do not require the preparation of LARAP, but MDBs require the preparation by the executing agency, or PLN in the case of the proposed projects. In LARAP, the calculation of compensation under the Indonesian regulations differs from the requirements by MDBs and requires careful attention in the preparation. (see below for more details).

Annex 7
Distributed Small-Scale Coal Power Plants

Implications for the proposed projects

PLN has planned a number of distributed small-scale power plants mainly for the concerns of potential wide-area blackouts. Large scale generation and transmission lines are, however, still capable of overcoming these issues. First, on the generation side, larger plants with some backup peakers provide more margin to supply to other load centers. Therefore, as long as there are strong transmission network, load centers can be covered by these plants. Second, on the transmission network side, as long as reserve power plants such as peaking plants are built, the potentially isolated network can still sustain minimal level of power supply while enjoying low cost coal-fired power during regular operations. With planning, the key concerns of PLN can be resolved. However, building distributed small scale CFPPs would come with major disadvantages as described below without effective solutions.

Inefficient use of coal: The limited size of small scale CFPP boilers does not allow them to operate at high pressure or high temperature, leading to low thermal efficiency of the plant. While large scale super critical coal-fired power plants offer thermal efficiency of 40 to 45%, PLN's small scale CFPPs have been reported to operate at about 26% efficiency.[59] The thermal efficiency would decrease further if low grade coal is used at mine mouth power plants. Such inefficient use of coal for Kalimantan as a whole would lead to a much larger amount of coal consumption than building a select number of large scale CFPPs, causing much greater levels of environmental issues such as air and water pollution.

Greater capital expenditures: The larger the plant size, generally the lower the cost of per-kW capital expenditure. PLN's own experience shows that large scale CFPPs are built at about US$ 1,800 per kW whereas small scale CFPPs require about US$ 2,300 per kW, including financing costs. PLN currently plans to add 2,903 MW[60] of CFPPs in Kalimantan by 2022. With the current plans of building a collection of small scale CFPPs, the expected total capital expenditure is US$ 4,506 million [61]. If all of the additional capacity is fulfilled with >250 MW plants, the expected capital expenditure decreases to $3,774 million. While some small scale power plants are needed to meet demand in remote areas and a substantial portion of the addition will be supplied by IPPs, these estimates indicate the potential of maximum capital expenditure savings of about $750 million for CFPPs alone over the next ten years.

Increased management challenges: Currently, many of these power plants are in the planning or procurement stages, and the demand is mostly met by a number of leased diesel generators. However, the progress status as of July 2014 suggests that many of planned power plants are facing implementation challenges such as land acquisition, contractor performance, and determination of financing options. PLN needs to manage these issues

[59] Based on PLN's actual data in East and West Nusa Tenggara according to *"Unlocking Indonesia's Geothermal Sector"* (ADB and WB, forthcoming in 2014)

[60] PLN currently plans to add a total of 922 MW of power plants in West Kalimantan and 1,981 MW of power plants in Central-South-East-North Kalimantan by 2022.

[61] These calculations are based on real value cost assumptions of $2,000/kW for <20 MW, $1,800/kW for 20-100 MW, $1,500 for 100-250 MW, $1300 for >250 MW (without financing costs).

for all of the small scale projects, which creates a further challenge in project management for PLN. The degree of management difficulty does not decrease relative to the scale of generation capacity, but it remains at about the same level for small scale projects compared to larger ones. Given the current level of delays and problems, it is likely that many of them will not meet the COD targets. Project management issues actually prevent power plants from being built, and therefore, create even more serious problem than the inefficiency issues that can be resolved by supplying more funding and coal.

Benefits of large-scale mine mouth CFPPs

The benefits of building larger scale CFPPs is further enhanced by the use of mine mouth plants. CFPPs are often built along the coast, as they require large coal shipping facilities and a large amount of cooling water. Mine mouth coal-fired power plants, on the other hand, are built near coal mines, which are generally inland. The proximity of energy source to power generation facilities provides some advantages to mine mouth plants with some challenges of cost and contractual structuring. Given the large potential of coal resources in Kalimantan, however, an appropriate structure of mine mouth CFPPs can create opportunities for PLN to secure low cost supply of power in the region as well as justifying more efficient and high voltage transmission network.

Reduction of fuel supply risks: Mine mouth CFPPs have associated coal mines as dedicated source of fuel, while conventional CFPPs may require sourcing of coal from multiple developers. With insufficient levels of infrastructure in countries like Indonesia, delivery to demand centers is often a bigger challenge for coal producers than the production of coal[62]. For the same reason of infrastructure deficiency, power producers often struggle to secure coal fuel supplies. Mine mouth CFPPs, therefore, resolve these supply chain issues on both the coal producer and power developer sides.

Reduction of transport infrastructure costs: Since the coal is consumed near the production site, there is minimal requirement for transportation infrastructure for mine mouth CFPPs. This leads to reduction of necessary investment costs, which reduces the cost of coal for power producers and off-takers as well.

Higher efficiency of coal resource use: While CFPPs are generally designed to have some flexibility in the types of coal to be used, they have target specifications of coal that maximizes the efficiency of the boiler in the plant. Therefore, when there is a specific type of coal dedicated for the power plant, as in mine mouth CFPPs, the boiler design can be customized to achieve the highest efficiency for the use of such coal.

Reduction of environmental and social costs: Coal mines are often located inland and far away from areas with high population density. The use of coal near mines therefore minimizes potential hazards and environmental impacts to nearby households. Furthermore, the lack of transportation needs also reduces the potential environmental and social impacts by reduction of fuel for transportation and negative impacts of coal transportation along the way. This is especially the case for lower ranked Indonesian coal, which are susceptible to self-heating during storage and transportation.

Utilization of low-rank coal: Low-rank coal such as those with calorific values less than 3,000kcal/kg and with high water contents is normally not suited for exports or long distance transportation even if transportation infrastructure existed. These types of coal would not be developed unless there is demand near the coal mines. Mine mouth CFPPs are, therefore, ideal options for mines with low quality coal.

Coal price stability (Indonesia): As discussed below, coal sales prices are determined by a cost-plus mechanism in Indonesia for mine mouth CFPPs. This provides fuel cost stability and allows for financial projections with greater certainties. The combination of the advantages in the supply and demand risk issue and the stable pricing mechanism creates greater incentives for mine mouth CFPPs in Indonesia.

[62] http://gbreports.com/2014/04/15/mining-in-indonesia-a-win-win-for-all/

Disadvantages and issues of mine mouth CFPPs

Lack of flexibility in adapting to different types of coal: The use of a dedicated source of coal allows mine mouth CFPPs to achieve high thermal efficiency for the coal. While the high efficiency is an advantage, the dedicated specification can lead to inefficiency when coal sources need to be changed. For example, coal mines may fall short on their productions. Coal mine developers may even decide to sell coal elsewhere and stop the supply to the mine mouth plant. The remote location of mine mouth plants also makes it difficult to transport coal from other locations. To avoid these risks, contractual obligations of the coal developer needs to be determined carefully in the preparation of mine mouth CFPPs.

Remote from load centers: The distance from densely populated areas for coal mines and mine mouth CFPPs provides advantages from the standpoint of environmental and social impacts. However, this also signifies that mine mouth CFPPs are often far away from load centers. This leads to higher cost of transmission lines and also difficulty in determining transmission routes.

Higher capital costs in the case of low rank coal utilization: The use of low grade coal is often the driver of mine mouth CFPPs. However, the high-moisture low grade coal in Indonesia often necessitates the introduction of coal upgrading technology. Regardless of the types of technology, additional facilities require additional costs. Careful attention in the design of mine mouth CFPPs is critical in order to maintain greater economic benefits from advantages of mine mouths plants than additional capital costs from coal upgrading.

Contractual complexities: The ownership structure of coal mines and power plants vary from one project to another. For example, some IPPs may own both the coal mine and the power plant, while others may involve two different owners bound by fuel supply agreements (FSA). If the coal mine needs to be owned by the power producer, it potentially requires the power producers to enter into a different type of business, which may deter participation by some bidders and reduce competition for the project while it reduces the fuel supply risk for the project. If the owners of the coal mine and the power plant are separate entities, the legal structure of FSA to secure the supply of coal becomes critical in realizing the project. Coal pricing for mine mouth CFPPs also plays a significant role. If the market coal prices are higher than purchase price, coal producers may opt to sell their coal in the market rather than to mine mouth power producers. On the other hand, unless the price of coal from the mine is cheaper than the market prices, there is little incentive for power producers to engage in mine mouth power plants. The combination of pricing mechanism and contractual mechanism makes the structuring of mine mouth power plants complex, and some utility companies may not have sufficient experience to properly manage project preparation activities.

Key features of mine mouth CFPP regulations in Indonesia[63]

Production cost plus margin mechanism for coal pricing: MEMR issued a regulation in 2010 to set the coal reference prices (CRP). Indonesian coal must be sold at or above CRP, which is calculated monthly by MEMR based on a basket of multiple coal indices such as the Global Coal Index, the Indonesia Coal Index, the Newcastle Index and the Platts Index. This applies even to long term coal sales agreements by including adjustment clauses based on the fluctuation of CRP. For mine mouth CFPPs, however, MEMR issued the regulation of the Directorate General of Coal and Minerals No.1348/2011 and the ministerial regulation No.10/2014 to set coal prices for mine mouth power plants based on a production cost plus margin mechanism with a margin of 25%. Under the regulation No.1348/2011, the application of the cost-plus mechanism was only for coal with calorific value of less than 3,000kcal/kg. The new regulation No. 10/2014 abolished this requirement of calorific value and applied the

[63] This information relies largely on the following sources from Norton Rose: http://www.nortonrosefulbright.com/knowledge/publications/104630/the-indonesian-government-considers-new-mine-mouth-regulations, and http://www.nortonrosefulbright.com/knowledge/publications/115996/new-regulation-on-mine-mouth-power-projects-in-indonesia

cost-plus margin mechanism to all mine mouth power plants. The production cost needs to be approved by the Directorate General of Coal and Minerals based on the criteria in the regulation No. 10/2014. Whether the DG Coal and Minerals will reference CRP in determining the production cost is not clear.

Domestic Market Obligations: Ministry of Energy and Mineral Resources determines the quantity of domestic market obligations based on the production forecasts for each year. Based on the percentage of DMOs, specific coal producers are named and matched with specific buyers by a ministerial decree of MEMR. In 2014, a total of 85 coal mining permit holders[64] are required to supply 25.9% of their production to the domestic markets. PLN receives the largest share of the total DMO supplies (60.08% in 2014), indicating the government's intention to prioritize the use of coal for power generation. While the mechanism of DMO application to mine mouth power plants is not clear as of August 2014, DMOs have implications to the production levels and profit structures of coal mines, requiring careful attention in preparing mine mouth CFPPs.

Power plant ownership by mine owners: The regulation No. 14/2014 requires coal mine owners to have at least 10% share in the associated mine mouth power plants through affiliates. While the government does not intend mine owners to be in control of mine mouth IPP projects, share of mine owners in the power project would help alleviate the potential issues of securing coal supply for the power plant.

[64] This is a sum of the 34 concession (IUP) holders based on the new mining law (Law No.4/2009) and 50 holders of contract of works based on the previous mining law and one state-owned enterprise.

Annex 8
Comparison of Typical Generation Costs

LEVELISED COSTS, inclusive of FUEL USAGE, EFFICIENCY and EMMISSIONS FOR ALTERNATIVE GENERATING PLANT USED IN RUPTL

Standard Plant Characteristics for all Options

Gross MCR		100	MW @ LF(elec)		80%				
Period		8760	hrs	=	365	d			
Outages		6%	FOR, Maint		10	d/yr			
Availability		91%	Check Idle time		41.7	d/yr			
Gross Genertn	=	701	GWh/yr	=	1920	MWh/d			
WACC Discount Rate		8%	years	@	20			9.82	PWF
CO2 Emmissions		25	$/tonne						

Gas - GT or Combined Cycle

		Value	Units		Value	Units		Value	Units
Gas Price		7.56	$/mCF		304.8	$/TOE eq	=	266.77	$/km^3
	=	191	c/MkCal		7.59	$/MBTU	=	8.00	$/GJ
Usage	=	14503	mCF/d	=	5.29	BCF/yr	=	150.0	Mm^3/yr
Heat Val		0.253	MkCal/mCF	=	1004	BTU/CF	=	29.98	MJ/m^3
Totl Heat	=	1339	GkCal/yr	=	123	kTOE/yr	=	5598	TJ/yr
Elec Effy		45.0%		SFC	7.55	CF/kWhe	=	0.21	m^3/kWh
Waste heat	=	737	Gkcal/yr	=	854	GWh/yr		121.93	MWt
Heat Rate	=	1911	kCal/kWh	=	7583	BTU/kWh	=	7996	kJ/kWh
Fuel Cost	=	40.02	M$/yr	=	72%	Tot M$	=	460	PW M$
Fixed O&M		0.4	$/kW/mth	=	0.48	M$/yr	=	5	PW M$
Varbl O&M		1.5	$/MWh	=	1.05	M$/yr	=	10	PW M$
Auxiliaries		3%	Net El Gen	=	**680**	GWh	Aux =	3	MW
Construct		1500	$/kW	@	3	Yrs	@	8%	IDC
Plant Cost	=	150	m$	*	1.11	IDC	=	166.8	PW M$
Energy @	=	10.65	c/kWhe (incl emmisions cost) Revenu					72.37	$m/yr
Revenue (M$/yr)		72.37	M$/yr						
Tonne CO2	=	0.05	T/GJ gas	=	412	g/kWh	=	1.03	c/kWh
CO2 Emmisions	=	280	ktons CO2	=	7	M$/yr	=	68.71	PW M$

Coal - Steam Turbine Generation

		Value	Units		Value	Units		Value	Units
Coal		60	$/tonne	=	66	$/ton	=	2.95	c/lb
	=	1091	c/MkCal				=	45.60	$/GJ
Usage	=	858	tonne/d	=	313	ktonne/yr		78629	lbs/hr
Heat Val		5500	kCal/kg	=	9920	BTU/lb	=	22990	kJ/kg
Totl Heat	=	1722	GkCal/yr	=	159	kTOE/yr	=	7198	TJ/yr
Elec Effy		35%		SFC	447	g/kWhe	=	983	lb/kwh
Waste heat	=	1119	Gkcal/yr	=	1298	GWh/yr		185.27	MWt
Heat Rate	=	2457	kCal/kWh	=	9750	BTU/kWh	=	10271	kJ/kWh
Fuel Cost	=	18.79	M$/yr	=	56%	Tot M$	=	238	PW M$
Fixed O&M		0.4	$/kW/mth	=	0.48	M$/yr	=	5	PW M$
Varbl O&M		1.5	$/MWh	=	1.05	M$/yr	=	10	PW M$
Auxiliaries		7%	Net El Gen	=	**652**	GWh	Aux =	7	MW
Construct		1500	$/kW	@	4	Yrs	@	8%	IDC
Plant Cost	=	150	m$	*	1.14	IDC	=	170.6	PW M$
Energy @	=	9.30	c/kWhe (incl emmisions cost) Revenu					60.62	$m/yr
Revenue (M$/yr)		60.622	M$/yr						
Tonne CO2	=	2.23	/Tonne Coal	=	1071	g/kWh	@	2.68	c/kWh
CO2 Emmisions	=	698.18	ktons CO2	=	17.45	M$/yr	=	171.37	PW M$

Diesel - Medium Speed Diesel

		Value	Units		Value	Units		Value	Units
Diesel (1997)		120	$/Bbl	=	902.26	$/ton fo	=	286	c/US gal
	=	8202	c/MkCal	=	73	c/l	=	342.86	$/GJ
Usage	=	2970	Bbl/d	=	162	ktonne/yr		5198	gal/hr
Heat Val		1.463	MkCal/Bbl	=	0.14	MBTU/gal	=	38	MJ/l
Totl Heat	=	1586	GkCal/yr	=	146	kTOE/yr	=	6630	TJ/yr
Effy		38%	SFC	=	0.065	gal/kWh	=	0.25	l/kWh
Heat Rate	=	2263	kCal/kWh	=	8980	BTU/kWh	=	9469	kJ/kWh
Fuel Cost	=	130	M$/yr	=	94%	Tot M$	=	1620	PW M$
Fixed O&M		0.66	$/kW/mth	=	0.79	M$/yr	=	8	PW M$
Varbl O&M		4.05	$/MWh	=	2.84	M$/yr	=	28	PW M$
Auxiliaries		4%	Net El Gen	=	**673**	GWh Aux	=	4	MW
Construct		1000	$/kW	@	2	Yrs	@	8%	IDC
Plant Cost	=	100	m$	*	1.08	IDC	=	107.6	PW M$
Energy @	=	28.6	c/kWhe (incl emmisions) Revenue				=	192.492	M$/yr
Tonne CO2	=	3.19	Tonne Diesel		765.91	g/kWh	@	1.9	c/kWh
CO2 Emmision	=	515.3	ktons CO2	=	12.882	M$/yr	=	126.48	PW M$

Geothermal Power Station

		Value	Units		Value	Units		Value	Units
Geoth HR		6.89	kg/kWh	=	224.96	BTU/lb	=	689	t/hr
Reservoir		1	m$/yr	@	11.26	PWF	=	11	PW M$
Lifetime		30	Years			Royalty		0.05	c/kWh
Water/Steam	=	0.35	M$/yr	@	11.26	PWF	=	4	PW M$
Fixed O&M		0.35	$/kW/mth	=	0.42	M$/yr	=	4.12	PW M$
Varbl O&M		0	$/MWh	=	0.00	M$/yr	=	0.00	PW M$
Auxiliaries		7%	Net Gen	=	**652**	GWh Aux	=	7	MW
Construct		3000	$/kW	@	3	Yrs	@	7.5%	IDC
Plant Cost	=	300	m$	*	1.11	IDC	=	331.7	PW M$
Energy @	=	4.8	c/kWhe			Revenue	=	31.184	M$/yr
Avoided CO2		1071	coal - g/kWh		412	gas g/kWh		766	oil g/kWh
Credit @ $/t 25		17.5	M$/yr		6.71	M$/yr		12.48	M$/yr
Carbon Credits		56%			22%			40%	

Hydro Power Generation

		Value	Units		Value	Units		Value	Units
Maintain Reservoi		1	m$/yr	@	11.26	PWF	=	11	PW M$
Lifetime		30	Years			Royalty		0.1	c/kWh
Royalty	=	0.70	M$/yr	@	11.26	PWF	=	8	PW M$
Fixed O&M		0.35	$/kW/mth	=	0.42	M$/yr	=	4.12	PW M$
Varbl O&M		0	$/MWh	=	0.00	M$/yr	=	0.00	PW M$
Auxiliaries		7%	Net Gen	=	**652**	GWh Aux	=	7	MW
Construct		3000	$/kW	@	3	Yrs	@	7.5%	IDC
Plant Cost	=	300	m$	*	1.11	IDC	=	331.7	PW M$
Energy @	=	4.84	c/kWhe			Revenue	=	31.534	M$/yr
Avoided CO2		1071	coal - g/kWh		412	gas g/kWh		766	oil g/kWh
Credit @ $/t 25		17.5	M$/yr		6.71	M$/yr		12.48	M$/yr
Carbon Credits		56%			22%			40%	

Annex 9-1 Long Run Marginal Cost of PLN RUPTL Generation Expansion Plan for West Kalimantan

Calculation of Long Run Marginal Cost of PLN RUPTL Generation Expansion Plan - Kalbar									PW capex	WACC 8%		4 yr const period		Chk Total
(excluding cost of T&D)									80%	10%	20%	40%	30%	100%
				Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Kalbar Peak Demand			30787	MW	234	280	319	413	506	575	636	703	776	856
Annual Generation 2013-2022 GWh		Equiv PV	18905	GWh	1371	1632	1855	2373	2907	3302	3675	4088	4544	5040
Existing & Retiring Generation Avail Capacity		Gen Cost		MW	335	434	136	79	131	139	139	139	139	139
Planned New Generation facilities		c/kWh	$/kW	Avail F										
Pantai Kura-Kura (FTP1)	PLTU	13	1800	70%			55	55	55	55	55	55	55	55
Parit Baru (FTP1)	PLTU	13	1800	70%			100	100	100	100	100	100	100	100
Parit Baru (FTP2)	PLTU	13	1800	70%				100	100	100	100	100	100	100
Kalbar - 1	PLTU	6.5	1500	80%					100	200	200	200	200	200
Kalbar - 2 (usulan baru)	PLTU	6.5	1500	80%								200	400	400
Peaker	PLTG/MG	11	800	70%					100	100	100	100	100	100
Nanga Pinoh*)	PLTA	8	5000	40%										98
Pade Kembayung	PLTA	5	3000	60%										30
Power Purchase dgn SESCo Peaking	275 KV	10		60%			50	85	85	85	150	150	150	150
Total generation MW					335	434	341	419	671	779	844	1044	1244	1372
Reserve MW					101	154	22	6	165	204	208	341	468	516
% reserve					30%	35%	6%	1%	25%	26%	25%	33%	38%	38%
Capex in NPV at Start of Project	US$m	PVF	80%	$951	$0	$0	$224	$144	$184	$120	$0	$241	$241	$465
GWh Required from Existing Generation					1371	1632	642	363	-417	-723	-692	-1680	-2626	-2631
NPV Opex Cost Existing Generation	US$m	c/KWh	25	$861	$343	$408	$160	$91	$0	$0	$0	$0	$0	$0
New Generation at Available Cost	US$m high cst	MW	455		$0	$0	$150	$248	$361	$407	$441	$532	$623	$658
NPV New Gen Opex = Avail Cost - Gen Reserve @ av		c/Kwh	10	$1,198	$0	$0	$0	$0	$319	$333	$370	$361	$357	$391
Total NPV Generation Capex + Opex gives	LRMC in	c/kWh	**16**	$3,010	$343	$408	$384	$235	$503	$453	$370	$602	$597	$857

Annex 9-2 Long Run Marginal Cost of PLN RUPTL Generation Expansion Plan for Southern, Central and North-Eastern Kalimantan

Calculation of Long Run Marginal Cost of PLN RUPTL Generation Expansion Plan - Kalseltengtimut														
(excluding cost of T&D)				Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Kalseltengtimut Peak Demand				MW	847	1036	1286	1391	1511	1690	1819	1956	2095	2252
Annual Generation 2013-2022 GWh		Equiv PV	62039	GWh	5154	6304	7744	8495	9376	10545	11390	12277	13178	14190
Existing & Retiring Generation Avail Capacity		Gen Cost		MW	815	814	708	527	299	354	354	354	354	354
Planned New Generation facilities		c/kWh	$/kW	Avail F										
Pulang Pisau (FTP1)	PLTU (60MW)	18	2000	60%			120	120	120	120	120	120	120	120
Asam Asam (FTP1)	PLTU (65MW)	18	2000	60%	130	130	130	130	130	130	130	130	130	130
Bangkanai (FTP2)	PLTG/MG/GU	18	2000	60%			155	225	295	295	295	295	295	295
Kaltim Peaking (APBN)	PLTG	11	800	40%	100	100	100	100	100	100	100	100	100	100
Muara Jawa/Teluk Balikpapan (FTP1)	PLTU	6.5	1500	80%		220	220	220	220	220	220	220	220	220
Sampit	PLTU	18	2000	60%				50	50	50	50	50	50	50
IPP On Going & Committed														
Senipah	PLTG	11	800	40%	82	82	82	82	82	82	82	82	82	82
Embalut (Ekspansi)	PLTU	18	2000	60%		50	50	50	50	50	50	50	50	50
Senipah (ST)	PLTGU	18	2000	60%					35	35	35	35	35	35
Future Planned Generation RUPTL														
Kalsel Peaker 1	PLTG/MG/GU	13	1800	70%				200	200	200	200	200	200	200
Kalsel Peaker 2	PLTG/MG/GU	13	1800	70%									50	50
Kaltim Peaker 2	PLTG/MG/GU	13	1800	70%				100	100	100	100	100	100	100
Kaltim Peaker 3	PLTG/MG/GU	13	1800	70%									50	50
Kelai	PLTA	8	5000	40%										55
Kusan	PLTA	8	5000	40%										65
Kalsel (FTP2)	PLTU	13	1800	70%					100	200	200	200	200	200
Kalselteng 1	PLTU	13	1800	70%						100	200	200	200	200
Kalselteng 2	PLTU	6.5	1500	80%					200	200	200	200	200	200
Kalselteng 3	PLTU	18	2000	60%					50	100	100	100	100	100
Kaltim (FTP2)	PLTU	13	1800	70%					100	200	200	200	200	200
Kaltim (MT)	PLTU	18	2000	60%						55	55	55	55	55
Kaltim 3	PLTU	13	1800	70%								150	300	300
Kaltim 4	PLTU	13	1800	70%						100	100	100	100	100
Total generation MW					1127	1396	1565	1804	2131	2691	2791	2941	3191	3311
Reserve MW					280	360	279	413	620	1001	972	985	1096	1059
Percent Reserve					25%	26%	18%	23%	29%	37%	35%	33%	34%	32%
Capex in NPV at Start of Project	US$m	PVF	80%	$3,102	$325	$345	$441	$626	$778	$890	$144	$217	$361	$481
GWh Required from Existing & Committed					3833	3178	3173	1454	-1108	-2944	-2712	-2745	-3377	-2785
NPV Opex Cost Existing + Committed	US$m	c/KWh	25	$2,465	$958	$795	$793	$363	$0	$0	$0	$0	$0	$0
New Generation at Available Cost	US$m high cst	MW	505		$193	$341	$601	$954	$1,351	$1,769	$1,849	$1,968	$2,167	$2,201
NPV New Gen Opex = Avail Cost - Gen Reserve @ av		c/Kwh	15	$5,013	$0	$0	$0	$0	$1,189	$1,338	$1,452	$1,567	$1,673	$1,794
Total NPV Generation Capex + Opex gives	LRMC in	c/kWh	**17**	$10,581	$1,284	$1,140	$1,234	$989	$1,967	$2,228	$1,596	$1,783	$2,034	$2,275

Annex 9-3
Long Run Marginal Cost of PLN RUPTL Generation Expansion Plan for Kalimantan Integrated Power System

Calculation of Long Run Marginal Cost of Generation Expansion Plan With Backbone inerconnections														
(excluding cost of T&D)				Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Kalseltengtimut Peak Demand				MW	1081	1316	1605	1804	2017	2265	2455	2659	2871	3108
Annual Generation 2013-2022 GWh		Equiv PV	80944	GWh	6525	7936	9599	10868	12283	13847	15065	16365	17722	19230
Existing & Retiring Generation Avail Capacity		Gen Cost		MW	1150	1248	844	606	430	493	493	493	493	493
Kalbar Proposed large generation														
Kalbar - 2 (usulan baru)	PLTU	6.5	1500	80%								200	400	400
Peaker	PLTG/MG	11	800	70%					100	100	100	100	100	100
Nanga Pinoh*)	PLTA	8	5000	40%										98
Pade Kembayung	PLTA	5	3000	60%										30
Power Purchase dgn SESCo Peaking	275 KV	10		60%			150	150	150	150	300	300	300	300
Kalseltentimut Large gerneration														
Pulang Pisau (FTP1)	PLTU (60MW)	18	2000	60%			120	120	120	120	120	120	120	120
Asam Asam (FTP1)	PLTU (65MW)	18	2000	60%	130	130	130	130	130	130	130	130	130	130
Bangkanai (FTP2)	PLTG/MG/GU	18	2000	60%			295	295	295	295	295	295	295	295
Kaltim Peaking (APBN)	PLTG	11	800	40%	100	100	100	100	100	100	100	100	100	100
Muara Jawa/Teluk Balikpapan (FTP1)	PLTU	6	1300	90%		250	500	500	500	500	500	500	500	500
IPP On Going & Committed														
Senipah	PLTG	11	800	40%	82	82	82	82	82	82	82	82	82	82
Embalut (Ekspansi)	PLTU	18	2000	60%		50	50	50	50	50	50	50	50	50
Senipah (ST)	PLTGU	18	2000	60%					35	35	35	35	35	35
Kalsel Peaker 1	PLTG/MG/GU	13	1800	70%				200	200	200	200	200	200	200
Kelai	PLTA	8	5000	40%										55
Kusan	PLTA	8	5000	40%										65
Kalsel (FTP2)	PLTU	6	1300	90%				250	500	500	500	500	500	500
Kalselteng 1	PLTU	6	1300	90%						250	500	500	500	500
Kaltim (FTP2)	PLTU	13	1800	70%					100	200	200	200	200	200
Kaltim 4	PLTU	13	1800	70%						100	100	100	100	100
Total generation MW					1462	1860	2271	2483	2792	3305	3705	3905	4105	4353
Reserve MW					381	544	666	679	775	1040	1250	1246	1234	1245
% Reserve					26%	29%	29%	27%	28%	31%	34%	32%	30%	29%
Capex in NPV at Start of Project	US$m	PVF	80%	$2,414	$325	$341	$455	$262	$525	$549	$261	$289	$64	$481
Capex to build HVDC & 275kV Backbone Transmision Interconnections				$515			$200	$200	$200					
GWh Required from Existing & Committed					4516	3432	-68	-2515	-5015	-7043	-8958	-9472	-9973	-9725
NPV Opex Cost Existing + Committed	US$m	c/KWh	30	$2,137	$1,355	$1,030	$0	$0	$0	$0	$0	$0	$0	$0
New Generation at Available Cost	US$m high cst	MW	700		$70	$236	$825	$1,103	$1,402	$1,679	$1,876	$1,968	$2,059	$2,120
NPV New Gen Opex = Avail Cost - Gen Reserve @ av		c/Kwh	8	$5,324	$0	$0	$820	$906	$1,008	$1,126	$1,173	$1,224	$1,275	$1,356
Total NPV Generation Capex + Opex gives	LRMC in	c/kWh	13	$10,317	$1,680	$1,371	$1,475	$1,368	$1,733	$1,676	$1,434	$1,512	$1,340	$1,837

Annex 10
Environmental and Social Impact Issues for HV Transmission Line Projects in Kalimantan

Project Stage / Environmental Aspect	Environmental Component Likely to be Affected	Potential Impact	Mitigation Measures
A. Pre-construction Phase			
Design of overhead transmission line and converter station	People	• Exposure to electric and magnetic field (EMF) at or near converter stations (HVDC) • Loss of endangered species of fauna and flora	• Ensure compliance with relevant national regulations, company Standard Operating Procedures for worker exposure to EMF and the limits set by International Commission on Non-Ionizing Radiation Protection (ICNRP) of 4.17 kV/m for electric field and 833 mG for magnetic field • Avoid transmission line routes that require the loss of endangered species
	Land and Water	• Contamination of soil and water from oil use at converter stations (HVDC)	• Include oil leakage catchment and containment including an oil-water separator at converter stations
B. Construction Phase			
Site clearing	Land and People	• Vegetation clearing at the tower site and ROW including the land area for converter stations • Temporary displacement/disturbance of wildlife species associated with cleared vegetation	• Compensate affected owners for damaged crops, plants and trees cleared. • Limit disturbance of wildlife species through proper planning to • Avoid breeding season to limit disturbance

continued on next page

Table *continued*

Project Stage / Environmental Aspect	Environmental Component Likely to be Affected	Potential Impact	Mitigation Measures
Excavation and stockpiling of construction materials	Land and water	• Land disturbance • Runoff erosion and sedimentation	• Only stockpile the exact amount of construction materials at the substation and tower sites • Implement erosion control such as silt traps
Drilling, hammering and boring activities	Air and People	• Noise, dust and vibration during tower erection and construction of converter stations	• Keep impacts temporary and for short duration only • Only conduct noise-generating activities during daytime • Spray water to opened areas, as needed.
Movement of people, construction equipment and materials	People	• Localized traffic and nuisance to affected residents	• Schedule major work during off-peak hours • Assign designated staff to manage traffic • Provide clear traffic signals and danger signs.
Recruitment and presence of construction workers	People	• Employment opportunities • Increased demand for services such as food and housing	• (These are beneficial impacts)
Workers health and safety	People	• Exposure of workers to changes in weather may cause respiratory problems • Exposure to excessive noise may cause hearing impairment • Risks of accidents due to handling and transport of overhead transmission line parts and working at elevated position	• Provide appropriate raingear and protective clothing • Provide earmuffs and appropriate gadgets and protective device • Provide training on health and safety practices • Employ trained workers for the job
C. Operation Phase			
Presence of power transmission lines	Land	• Depreciation of land property values adjacent to sub-stations and power transmission towers	• Identify benefits of regional economic development through the availability of stable and reliable power
	People	• Potential exposure to electric and magnetic fields (EMF)	• Keep EMF levels below the limits set by ICNRP, which is 4.17 kV/m for electric field and 833 mG for magnetic field • Conduct spot measurements of EMF • Build fences around sub-stations and assign security staff to prevent unauthorized public access • Conduct information and education campaign for local people to create awareness on safety practices
		• Accident working in elevated position	• Implement safety plans to reduce risks • Provide safety belts and other working gears for protection

Table *continued*

Project Stage / Environmental Aspect	**Environmental Component Likely to be Affected**	**Potential Impact**	**Mitigation Measures**
		• Hazards such as electrocution, lightning strike, etc. due to accidental failure of power transmission lines	• Provide security and inspection personnel to avoid pilferage and vandalism of equipment and lines • Conduct appropriate grounding and deactivation of live power lines during maintenance work • Build in the design a protection system that shuts off during power overload or similar emergencies • Maintain and comply with electrical standards • Insulate or cover distribution lines entering and leaving the sub-stations to minimize impacts • Monitor and conduct maintenance regularly to ensure safety and integrity of power lines and sub-stations • Conduct information and education campaign for local people to enhance awareness on safety practices of living near sub-stations

[a] The n-1 reliability criterion expresses the ability of the transmission system to lose a linkage without causing an overload failure elsewhere. Likewise the n-2 criterion is a higher level of system security for special supply zones, where the system can withstand any two linkages going down. Additional criteria may include a requirement for load shedding - disconnecting certain large power consumers to maintain supplies for the rest of the network, and rescheduling of generation to bring on generation units at short notice that normally would not be used