Energy Planning and Development in Malaysian Borneo: Assessing the Benefits of Distributed Technologies versus Large Scale Energy Mega-projects

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Abstract

Malaysian Borneo is the currently the subject of contentious state-led development plans that involve a series of mega-dams to stimulate industrial demand. There is little quantitative analysis of energy options or cost and benefit trade-offs in the literature or the public discussion. We use the commercial energy market software PLEXOS to prepare a long term capacity expansion model for the state of Sarawak which includes existing generation, resource constraints and operability constraints. We also incorporate the indirect costs of greenhouse gas emissions and direct forest loss. We devise and model different scenarios to observe the technically feasible options for electricity supply that satisfy future demand under four growth assumptions and then observe their economic and environmental trade-offs. Our central finding is that local resources including solar and biomass waste technologies can contribute to the generation mix at lower cost and environmental impact than the additional dam construction. Our case study of Borneo represents many energy related megaprojects being developed in emerging economies and our proposed method of assessment can support the current conversations on development of natural resources and potential sustainable solutions.

Keywords: Renewable Energy, Economic Development, Development Tradeoffs, Borneo

1. Introduction: Mega Projects and Long Term Energy Planning

Energy megaprojects have become a defining feature of the modern energy transition. Whether driven by growing demand stemming from urbanization and industrialization - or by energy security concerns over foreign dependence and price volatility - large, centralized, national and transnational energy projects are now common centerpieces of energy strategy in many developing countries [1]. Development of large infrastructure is generally characterized by the involvement of a wide spectrum of actors. These projects can be conceptualized as socio-technological systems - embedded in the surrounding socio-economic environment and co-evolving with socio-political institutions. There is, understandably, inherent inertia against departing from the established, centralized patterns of control [2]. This can be a barrier to addressing the multi-dimensional nature of energy access needs.

A critical aspect of energy infrastructure is scale. Because of considerations such as population density, connectivity, rurality or the delocalized nature of industry, scale becomes a key element in determining how to plan and manage infrastructure. Likewise, though the mantra of energy security is often used to justify large-scale energy projects, electricity demand is often overstated and the projects themselves often serve to exacerbate existing social tensions and conflicts, intensifying various manifestations of insecurity [3]. Balancing the need for large infrastructure with locally appropriate solutions thus presents a very real governance challenge.

While there is widespread agreement on the need for a combined approach, most national energy or electrification strategies contain very few details on the integration of decentralized systems and little information on the potential for distributed solutions is available for public discourse [4]. We see this story playing out across Asia, Latin America and Africa where the mega-dam has become a resurgent solution for energy service. A renaissance of

World Bank funding for large hydropower projects after a decade long lending hiatus during the 1990s along with infusions of new capital from middle-income countries is driving investment in these large-scale national energy projects. The Three Gorges Dam of China was completed in 2006 [5], [6] while the Nam Theun Dam (completed in 2010) and the Xayaburi Dam (under construction) in Laos are the first of a series of dams being built in the transboundary Lower Mekong Basin [7], [8]. Construction on the Grand Inga Dam in the Democratic Republic of Congo begins this year [9], while the Belo Monte Dam in northern Brazil is expected to be completed by 2019 [10]. Tension is growing between civil communities and policy makers as decisions affecting land rights, resource use, industry, and social and ecological health are being made with little discussion of necessity, risk and alternatives.

Our research aims to address this gap and contribute to the literature on management of energy transitions. We present an adaptation of a long term energy planning and analysis tool and demonstrate its use in comparing transition pathways using contemporary mega-dam development in Borneo, East Malaysia as a case study [11].

The island of Borneo has abundant natural resources, immense global ecological importance, a largely rural population and an agrarian economy on the cusp of major industrial transformation. It is a relevant case study to explore the role of decentralized energy systems as well as the direct and indirect costs of supplying energy service. We create a capacity expansion model, which incorporates existing energy infrastructure stocks, resource constraints and system operability constraints to determine technically feasible options for clean electricity supply that satisfy future demand. We use this model to explore the economic, technical and land-use trade-offs of various future energy system configurations under different assumptions of demand growth and different policy scenarios. Our findings are applicable to other developing countries where assessment of large-scale energy infrastructure is critical to public policy discourse.

The remainder of this paper is organized as follows: Section 2 presents our case study. Section 3 describes the methodology, software simulation tool used, demand growth forecasting, data collection and policy scenario development. Section 4 summarizes the results and our model limitations. Section 5 presents our conclusions and a discussion of the implication for other developing countries.

2. Background: The Sarawak Corridor of Renewable Energy

In 2006, the Federal Government of Malaysia embarked on a number of initiatives to promote balanced regional development and accelerate growth in designated geographic areas through the Ninth Malaysia Plan [12]. The Plan describes a philosophy of development focused on decentralizing economic growth away from the federal capital through the establishment of *economic corridors* in different states[1]. The Sarawak Corridor of Renewable Energy (SCORE) is a corridor in central Sarawak, an East Malaysian state on the island of Borneo. SCORE differs fundamentally from the other Malaysian economic corridor projects in its predominant emphasis on hydropower [13].

Sarawak, located along the northern coast of the island of Borneo (Fig 1), is the poorest and most rural state in Malaysia. An increased focus on cheap electricity to attract manufacturing and industry is the state's approach to achieving high income economy status. The current peak annual energy demand in Sarawak is 1250 MW, met by a mix of diesel, coal and natural gas generation either operated or purchased by the state utility company. Over the long term SCORE involves building out 20 GW of hydroelectric capacity in Sarawak through a series of 50 dams.

At least 12 large hydroelectric dams and two coal power plants, together constituting 9380 MW of capacity, are scheduled to be built before 2030 [11][14]. Six dams are scheduled to be completed by 2020 with three major dams already under different stages of development (see Fig 1) [21]. In 2012 the 2400 MW Bakun dam became operational [15]. At 205 meters high it is Asia's largest dam outside China. The dam's reservoir submerged 700 km^2 of land and displaced about 10,000 people. In 2013 the 944 MW Murum dam was completed and its reservoir is currently being filled. Access roads for the 1200 MW Baram dam have been cleared but preparatory construction work has been stalled since 2013 due to road blockades by local community protesters [16].

[1] The five prescribed corridors are: Iskandar Malaysia in Johor; The Northern Corridor Economic Region (NCER) covering the states of Kedah, Pulau Pinang, Peris and Perak's four northern districts; The East Coast Economic Region (ECER) covering the states of Kelantan, Pahang, Terengganu and Johor's Mersing district; The Sarawak Corridor for Renewable Energy (SCORE) and The Sabah Development Corridor (SDC).

With this hydropower backbone the SCORE plan involves attracting investment to promote a number of priority industries in hubs across the state. These priority industries include heavy industry such as glass, steel and aluminum as well as resource based industry such as livestock, aquaculture, tourism and palm oil. The SCORE plan will also involve doubling land area under palm oil plantation concession (to 2 million hectares) by 2020 [11]. The state anticipates these projects will attract over 334 billion Malaysian Ringgit (RM) (US$100 billion) in investment – 80% as private funding for the hydropower projects and industrial development, 20% as government funding for basic infrastructure and human capital. There is also discussion of Asian Development Bank (ADB) funding for a transmission line to export power across Borneo from Sarawak to West Kalimantan. Though two of the dams have already been built the private investment is yet to realize. The cost of the Bakun Dam has escalated over many years of delay to RM7.3 billion (US$2.3 billion) – more than double initial price estimates. Construction has been funded primarily through loans from the Malaysia Employees Provident Fund and the Malaysia Pension Fund [15].

Sarawak has a population of 2.47 million, more than half of which are indigenous groups living in rural village communities [17]. Many of these village communities are being impacted or displaced by the SCORE dam construction, causing civil unrest. In addition to the displacement of roughly 30-50,000 indigenous people, the 12 dams would result in an estimated 2425 km^2 of direct forest cover loss [18]. The three initial dams discussed above will flood an expected 1357 km^2 alone. Indigenous groups protest the rationale for the dams given low local energy demand, the quality of social and environmental impact assessment and the history of past failed resettlement schemes. They claim indigenous rights are being violated in the decision to build on native customary lands [19].

These indigenous groups are supported by a larger international NGO community concerned for human rights and the ecological impacts that the dams present. In particular, Borneo has been identified as one of Earth's 34 biodiversity hotspots and a major evolutionary hotpot for a diverse range of flora and fauna. Borneo's forests house the highest level of plant and mammal species richness in Southeast Asia [20] [21]. Civil society groups argue that efforts to conserve Borneo's forests are critical as their size and quality are deteriorating rapidly [22][23]. Our study adapts a commercial energy modeling platform to create a framework for discussing the cost and benefits of various transition pathways in this context.

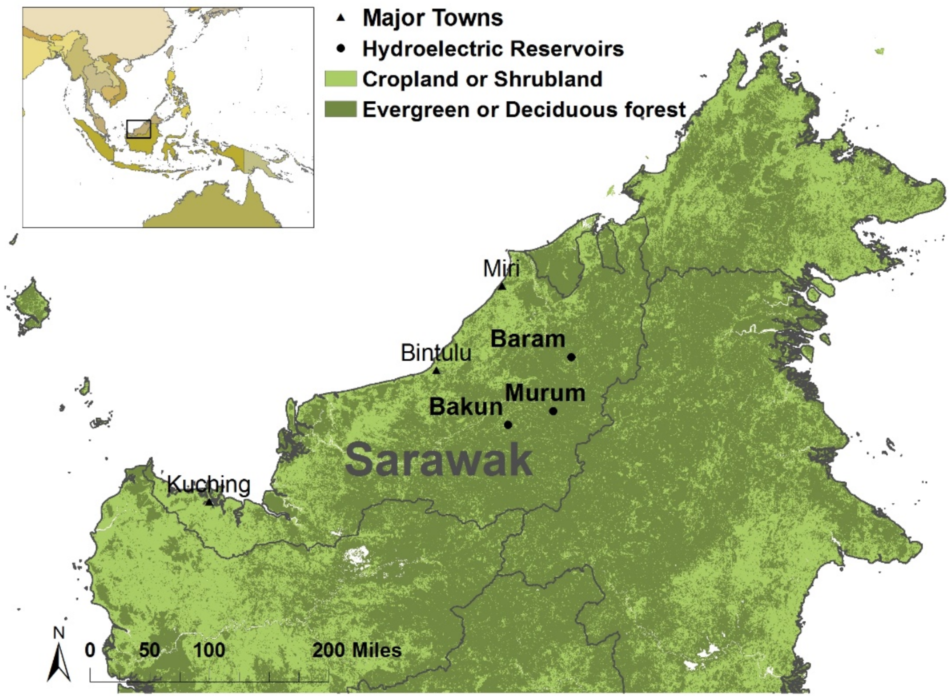

Figure 1 Location of Sarawak, its major towns and the three SCORE dams completed or under construction

3. Methodology and Data Inputs

3.1. Energy Modeling Tools

PLEXOS[2] is a commercial linear mixed integer power sector model developed and commercialized by Energy Exemplar [24]. It is used by academia, industry and planning agencies in many countries. We selected a commercial software package to make our modeling directly accessible to state planning agencies. We also use PLEXOS because of its flexible framework which is very adaptable to client needs and data constraints. We use PLEXOS first to map available primary energy resources, existing generation and potential generation options and then to analyze optimal system configuration under various constraints and assumptions of demand growth and implemented policy.

PLEXOS allows for expansion planning for any number of years ahead using mixed integer programming which minimizes NPV of total cost of expansion and production. The transmission module includes optimal power flow (OPF) with losses, thermal limits, forced outages and maintenance, pricing and variable load participation factors at different nodes, thereby accounting for congestion, security and marginal losses. The thermal generation module uses unit commitment, heat rate functions, fuel constraints, fuel price escalation, emissions constraints and taxes, generator 'must run' and other operating constraints, dynamic bidding, a Monte Carlo Simulation of forces outages and optimized maintenance [25]. We do not simulated forced outages as will be explained in Section 4.3.

The Capacity Expansion problem is solved through a mixed integer linear program (the LT Plan) which finds the optimal combination of generation new builds, retirements and transmission upgrades that minimizes the net present value (NPV) of the total system costs subject to energy balance, feasible energy dispatch, feasible builds and integrality over a long-term planning horizon. The LT Plan can be run in chronological mode or non-chronological mode using Load Duration Curves (LDC). We decided to use a yearly LDC with twelve blocks per curve where the slicing is done using a quadratic formula that creates a bias toward placing blocks at the top (peak) and bottom (off-

[2] See Plexos details at http://www.energyexemplar.com

peak) of the curve, with less blocks in the middle. This method allows for greater emphasis on the system's ability to meet demand in the extremes. While in chronological mode the LT Plan would capture the dynamic effects of intermittent generation and load uncertainty on generator cycling (co-optimizing), it requires high resolution load data not available at the time of this study. Rather, in non-chronological mode, an algorithm uses the given LDC to estimate how often each class of unit will run based on marginal operating cost and will select units for investment by optimizing capital and operating costs compared to the expectation of hours operated [26].

The LT Plan can also be run in deterministic or stochastic modes. In stochastic mode it can be used to find the single optimal set of build decisions in the face of uncertainties in any input e.g. load, fuel prices, hydro inflows or wind generation using probability distributions that govern the data. Deterministic models observe the outcome of discrete inputs. We decided to run a series of deterministic scenarios because we are less concerned with the likelihood of different outcomes and more concerned with the feasibility of various expected scenarios. We apply a standard discount rate of 8% to all cash flow analysis to represent the opportunity cost of capital investment [27]. Limitations of the LT Plan design are discussed in Section 4.3. Detail on PLEXOS modeling can be found in [24]. Our Model XML and data CSV files can be found at: www.rael.berkeley.edu/sustainableislands.

In the following section we describe the physical and economic information regarding energy resources that were locally available at the time of study to populate and parameterize the model.

3.2. Electricity Demand Forecasts

The Sarawak Electricity Supply Corporation (SESCO), privatized in 2005, is the organization responsible for the generation, transmission and distribution of electricity in the state. The parent holding company is Sarawak Energy Berhad (SEB), wholly owned by the Sarawak State Government. SEB owns a number of other generation subsidiaries [28] and in 2012 the total generating capacity of SEB stood at roughly 2,550 MW: 555MW from SESCO, 795 MW from other subsidiaries and 1,200 MW from the Bakun Hydroelectric Dam's (four of its eight generators are currently operational) [29]. This represents more than a 100% reserve margin, compared to an average of 30% across other states of Malaysia.

Current maximum energy demand in Sarawak is 1250 MW. Demand is shared among the industrial (51%), commercial (26%) and residential (21%) sectors [29]. According to the National Energy Report growth rates for electricity sales and maximum demand in Sarawak average 8.6% and 7.0% respectively from 2000 to 2012 (see Figure 2a) [29], [30]. The National Planning and Implementation Committee for Electricity Supply and Tariff (JPPPET) performs long term load forecasting based on current economic trends and the latest electricity demand performance [31]. For Peninsula Malaysia JPPET forecasted an electricity sales growth rate of 4.0% per annum for the 2012 – 2015 period, followed by a decline to 3.6% in 2016-2020 and to 1.9% from 2021 – 2030 with similar rates for Total Generation and Peak Demand.

The SCORE plan revolves around a targeted nine-fold increase in energy output between 2010 and 2020, or from 5,921GWh to 54,947GWh, which represents a 16% growth rate. In terms of installed capacity this translates to an expansion from 1,300MW in 2010 to between 7,000MW and 8,500MW in 2020 [28].

In our model we forecast demand to 2030 under four different assumptions in order to observe the effect of demand growth on optimal system configuration (see Figure 2b). We model both the SCORE growth assumption and a conservative historic growth assumption. We then model two intermediate growth rates – 7% per annum and a more ambitious 10% per annum. We describe the demand growth assumptions here:

(i) The 'Business as Usual (BAU)' projection: We apply the JPPPET projections to historic SEB data to obtain a BAU demand forecast for Sarawak (see Figure 2a,b). Though conservative, this growth assumption is still high projection given that energy demand in Sarawak has historically grown at a slower rate than Peninsula Malaysia;

(ii) The 'Seven Percent Growth' Projection: We assume that energy demand from 2012 increases at a 7% growth per annum for both total annual energy (GWh) and maximum demand (MW). This rate is higher than the average projected for Peninsula Malaysia yet is plausible given the primary energy demand growth rates across the region [32] (see Figure 2b);

(iii) The ‘Ten Percent Growth’ Projection: We assume that energy demand from 2012 increases at 10% growth per annum for both total annual energy (GWh) and maximum demand (MW);

(iv) The ‘SCORE’ Projection: We model SEB’s assumptions for demand growth (and required generation capacity) as anticipated in SEB documentation. Though sustaining such a level of growth is unprecedented, we model SEB’s assumption for completeness.

To represent load PLEXOS takes a "base" year's profile of demand (i.e. period-by-period demand) and a forecast of both total energy (GWh) and maximum demand (MW) over the forecasting horizon. PLEXOS then applies a linear growth algorithm to create a forecast profile or time series [33]. The Energy Commission provides daily and hourly grid system reports for each state utility company in Sabah and Peninsula Malaysia, which show relatively little diurnal or weekly variation in demand [27]. Sarawak specific monthly averaged maximum demand and electricity sales data for 2003-2004 was obtained from the Energy Commission [34] and was compared with monthly averaged trends in Sabah and Peninsula Malaysia to create the base year of data for Sarawak (see Figures 3 a,b).

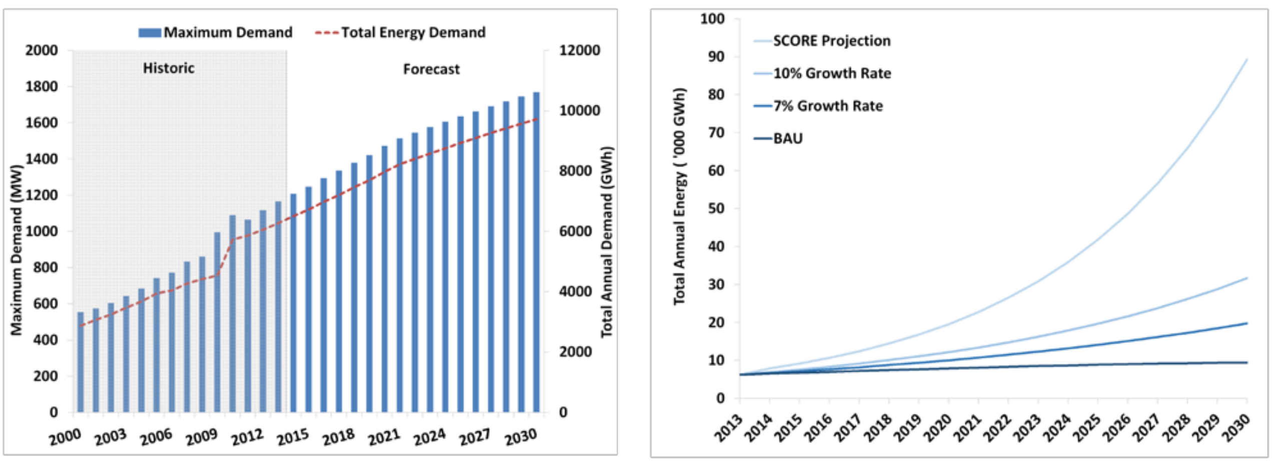

Figure 3 (a) Showing State Growth Forecast (BAU Assumption); (b) Long Term Load Demand under Four Different Growth Assumptions

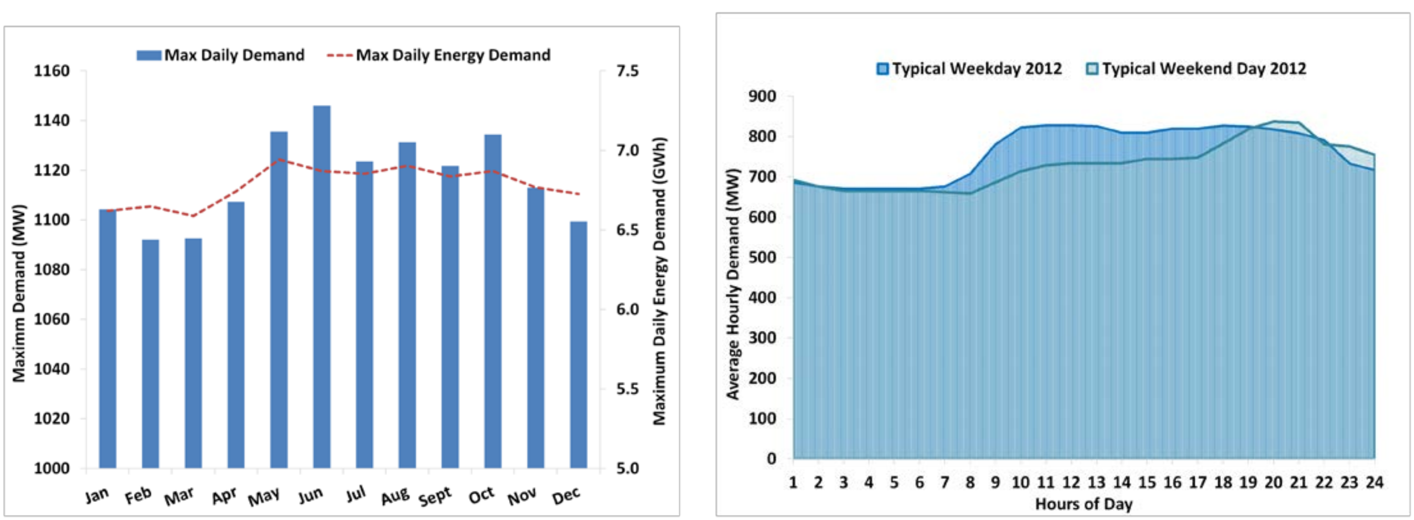

Figure 3(a) Showing Monthly Averaged and (b) Hourly Averaged Demand in Sarawak

3.3. Energy Resources Available in Sarawak

Together the SEB generation portfolio is comprised of large scale coal, diesel, gas and hydro capacity along with about 50 MW of off grid diesel generation in rural communities. Together, fossil fuels (natural gas, coal and diesel) represented roughly 92% of both installed capacity and annual generation in the state of Sarawak until 2012. With the start of Bakun Dam operations, hydropower is now 64% of installed capacity, while natural gas, coal and diesel are 16%, 16% and 4%, respectively [28]. In this section we discuss the scope of various energy resources in Sarawak and highlight our data sources for resource quality, fuel prices and technology costs.

3.3.1. Fossil Fuel Resources

Malaysia's oil reserves are the third largest in the Asia-Pacific region after China and India. Malaysia held proven oil reserves of 4 billion barrels as of January 2011 and total oil production in 2011 was an estimated 630,000 barrels per day (bbl/d). Nearly all of Malaysia's oil comes from fields offshore Peninsula Malaysia [35]. This oil was the main source of electricity in Malaysia until the energy crisis in the 1970s, which prompted investment in other resources. Oil share in the national energy mix fell from a high of 87.9% in 1980 to a low of 2.2% in 2005. Natural gas and to a lesser extent, coal, have become more dominant fuel sources for the country over the past 20 years [36]. Malaysia held 83 trillion cubic feet (Tcf) of proven natural gas reserves as of January 2011, and was the fourth largest natural gas reserves holder in the Asia-Pacific region. Gross natural gas production has risen steadily, reaching 2.7 Tcf in 2010. Most of the natural gas reserves are in the eastern territories, predominantly offshore Sarawak.

Malaysia's domestic coal industry is much smaller than its domestic oil and gas industry. Most of the nation's reserves are located in Sabah and Sarawak where together there are 1,938 million metric tonnes (tonnes) of reserve. Production of coal has increased gradually from 1990 while consumption and imports have increased dramatically [36]. There are government plans to extract more coal resources from Sarawak and as discussed two large coal power plants are part of the SCORE proposal. There was a government proposal to build a 300 MW coal power plant in Sabah, but this was rejected in 2010 by the state government on environmental grounds. Information on the individual fossil fuel generators currently operational in Sarawak including capacity and output are taken from Energy Commission annual performance reports [29], [30], [34], [37]–[39] and SEB annual reports [28]. Current and future forecasted fossil fuel prices are taken from the EIA Energy Outlook [40].

3.3.2. Hydroelectric Data and Resource

Until 2012 there were over 3,000 MW of hydropower capacity in Malaysia, representing 11.4% of total installed capacity [30]. The largest of these was the 600MW Pergau Dam in Peninsular Malaysia. The 2.4 GW Bakun Dam is the most recent large scale hydropower plant built in the country. Sarawak has one of the country's densest river networks and abundant rainfall. The northeast monsoon, usually between November and February, brings the heaviest rain, while the southwest monsoon from June to October is milder. The average rainfall per year is between 3,300 mm and 4,600 mm, depending on locality. According to the state government, which has surveyed a number of potential large hydro sites in Sarawak, there is at least 20,000 MW of potential capacity in the state [41].

The capacity, expected reservoir size and status of dams taken from the Bruno Manser Fund (BMF) Geoportal Database [42] can be seen in Table 1. We model Bakun, Baram and Murum - the three dams either built or currently under construction - using data on the specific dam dimensions directly from [43] (see Table 2). From the Department of Irrigation and Drainage we obtain historic monthly average maximum and minimum stage data for respective river basins [44] [45]. This data was used to estimate monthly peak and minimum energy outputs for their respective dams as inputs for the annual hydro resource profile [46].

Much uncertainty exists over the cost of dam construction in Sarawak [15]. Sovacool and Bulan [47] estimate capital costs for all of the prospective dams, reporting US $4,643 million for Bakun based on direct interviews. This corresponds to US$ 1935/kW and corresponds with other cited ranges for Bakun [11], [15]. A recent Oxford study by Ansar et al. [48] analyzes a sample of 245 large dams built between 1934 and 2007. The researchers find that three of every four dams suffer from cost overruns and for one of every two dams costs exceed benefits. The study finds actual costs are on average double their estimated costs and suggests a cost uplift of 99% to reduce risk of overrun to 20%. We apply this uplift to the Sovacool and Bulan cost estimates and obtain an average capital cost value of US $3870/kW, very similar to the NREL 2012 estimate for hydro power plant capital cost of US $3500/kW [49]. We apply this capital cost value to all major dams and use NREL values for all other cost estimates (Fixed O&M Cost, VO&M Cost). We also include the standard US $0.1/kWh water levy as a Variable O&M cost for dam operation [15].

In Malaysia, and Sarawak more specifically, many small hydro projects have been designed and implemented by different non-governmental agencies including UNIMAS, PACOS and Green Empowerment. These projects are particularly useful given the disbursed and largely inaccessible nature of rural settlements in Sarawak. Local reconnaissance studies find that there are a number of sites suitable for low head large flow small hydro run of river schemes near to existing settlements. Researchers have identified at least twenty sites in Sarawak alone with head above 50m suitable for small hydro development [50]. According to surveys done by SEB there are over 4400 kW of small hydro that can be developed in districts across Sarawak [51].

Table 1 Showing Dams planned and being developed under SCORE

Dam	Status	Resevoir Area (km2)	Water Level (m)	Affected Settlements	Output (MW)	Commencement of Construction	Date Operational	Estimated Cost (Mill USD)
Bakun	Built	700	255	31	2400	1994	2011	4,644
Baleh	Planned	527.3	241	1	1300	2019		2,424
Baram	Under Construction	412.5	200	36	1200	2014		1,515
Batang Ai	Built	76.9	125	59	108	1981	1985	387
Belaga	Planned	37.5	170	0	260	2015		242
Belepeh	Planned	71.8	570	5	114	After 2022		49
Lawas	Planned	12.4	225	1	87	After 2022		95
Limbang	Planned	41.3	230	11	245	After 2022		439
Linau	Planned	52	450	3	297	After 2022		264
Murum	Under Construction	241.7	560	10	944	2008	2013	1,061
Pelagus	Planned	150.8	60	78	410	2015		424

Table 2 Showing Hydroelectric Dam and Reservoir Dimensions

Dimension	Units	Murum Dam	Batang Ai Dam	Bakun Dam
Capacity	MW	944	108	2,400
Crest Length	m	473	810	814
Dam Height	m	141	85	206
Catchment Area	km^2	2,750	1,200	14,750
Resevoir Gross Storage	km^3	12.04	2.87	44.00
Dead Storage	km^3	6.57	1.63	24.99
Full Supply Level	m	540	108	228
Min Operating Level	m	515	98	195
Reservoir Area at Full Supply Level	km^2	245	85	695
Reservoir Area at Min Operation Level	km^2	234	77	594

3.3.3. Biomass Resources

Sarawak is a largely agricultural economy generating large volumes of agricultural waste from the palm oil industry on a monthly basis. Malaysia produces roughly 19 million tonnes of crude palm oil annually [52]. As land for cultivation becomes scarce on peninsular Malaysia, cultivation in Sarawak has drastically scaled up in recent years. Sarawak alone now represents 45% of national production with an average of 8.5 million tonnes annually (see Fig 4). In 2010, there were over 919,000 hectares of oil palm plantation in the state. The Sarawak Department of State Land Development has stated that it plans to double plantation area to two million hectares by 2020, making Sarawak the biggest crude palm oil producing state in Malaysia. There are a number of palm oil refineries near major load areas including Miri, Bintulu and Sibu that allow palm oil waste to energy to be a feasible option for energy production. According to SEB there are 41 palm oil processing plants across Sarawak (see Figure 5) [53]. Plants vary in size and processing capacity with the average across Malaysia being 600 tonnes fresh fruit bunches (FFBs) processed per day. Individual palm oil mills are thus able to act as small power producers (SPPs), selling electricity to retail customers or to the national utility on the main grid.

While a certain volume of dry biomass waste, mostly empty fruit bunches (EFBs), is usually retained on plantation land as fertilizer, a large volume remains which can be directly combusted, or gasified for use in a steam turbine. All palm oil mills also produce a large volume of Palm Oil Mill Effluent (POME), which is usually treated in settling ponds and discharged to water bodies. This POME can be anaerobically digested producing biogas as a by-product. Thus there are a number of ways that palm oil waste can be converted to electricity. In this paper we focus on EFB biogasification and POME biogas recovery. See [54]–[60] for detailed descriptions of biomass waste to energy conversion techniques.

Given the size of the palm oil industry, both in Sarawak and Malaysia more generally, the government of Malaysia initiated the Biomass Power Generation and Cogeneration in Palm Oil Industry Project (BIOGEN) in 2002 with support from the UNDP to strengthen local capacity and help promote the palm oil waste to energy sector [61]. According to the Malaysia Energy Commission, by 2012 there were 64 MW of licensed power generation coming from palm oil mills registered as SPPs between Peninsula Malaysia and Sabah. There are eight of these registered mill projects in total, using EFB and POME as fuel, and ranging from 0.5 MW to 15 MW installed capacity.

There are also 13 licensed agricultural waste co-generators with a total of 35 MW installed capacity on the grid. Predominantly palm oil mills, a small number of these operators are also rice and paper mills using other types of biomass such as rice paddy husk, wood dust and wood chips. There is also a large number of licensed self-generators. These are mills that use agricultural waste to generate electricity for on-site mill consumption only and do not sell electricity to the grid. These generators are generally less than 5 MW each and together totaled 475 MW across Malaysia in 2012 [29].

There is therefore significant precedent for electricity generation from palm oil wastes. A growing body of literature finds the economics of oil palm waste to be feasible in Malaysia and Sarawak [54], [55], [58], [62], [63], [59], [60]. In fact the government's National Biomass Strategy estimates that by 2020 Malaysia's palm oil industry will be generating about 100 million dry tonnes of solid biomass waste [64]. According to the strategy, the biomass waste to energy industry could result in some 66,000 jobs nationwide and a number of existing local projects POME biogasification plants may sustain Investor Rate of Returns (IRR) of 7-17% and higher [65], [66]. Though an emerging sector, there are a number of challenges to scaling up the palm oil waste to energy sector which we discuss in Section 5.

The Sarawak Palm Oil Board keeps monthly records of state-wide production which we have used to estimate dry and wet biomass waste production into the future [67]. SEB publishes residue ratios (volume of EFB and POME produced per ton of FFB processed at a mill). SEB makes projections based for current and future potential power output from biomass waste resources as seen below and we use these published assumptions on productive residue ratio, energy content, conversion efficiency and waste price [53].

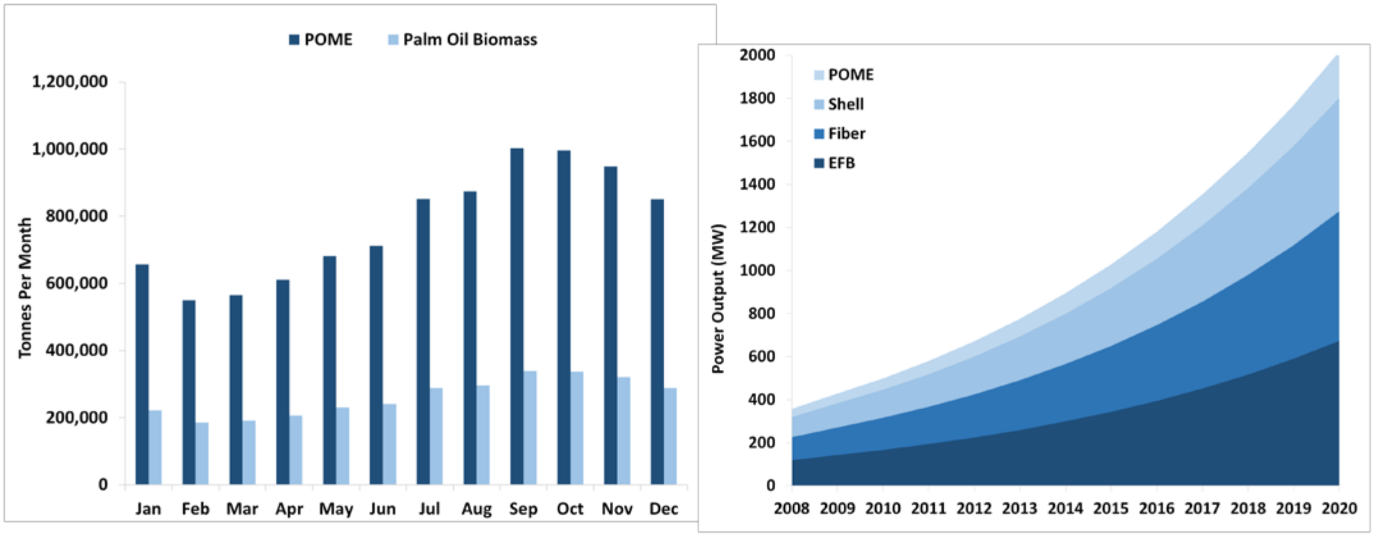

Figure 5 (a) Palm Oil Waste Monthly Availability; (b) Palm Oil Waste Power potential based on Future Expansion

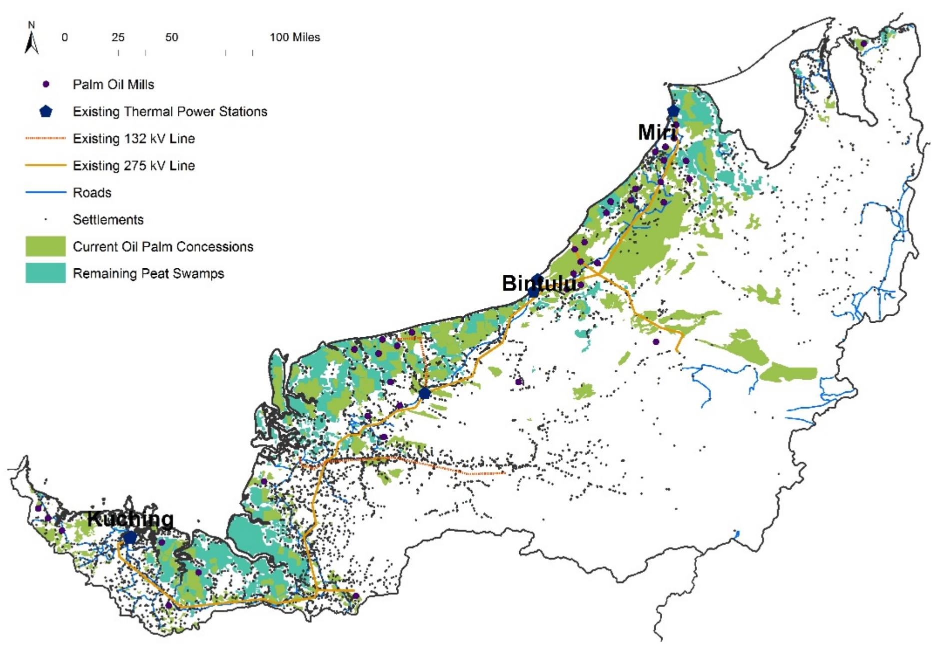

Figure 5 Map of Sarawak showing Current Oil Palm Plantations and remaining Peat Swamp lands

3.3.4. Solar and Wind Resources

Malaysia lies entirely in the equatorial region. The tropical environment has been characterized by constantly high temperature, abundant sunshine and solar radiation but also by heavy rainfall, and high relative humidity, so that it is in fact rare to have an entirely clear day even in periods of severe drought [68]. We use the NASA Surface meteorology and Solar Energy Global Data Set (Release 5) which provides 10-year monthly and annual average Global Horizontal Irradiance and monthly and averaged Wind Speed at 50m above earth surface data both at one degree resolution [69].

The minimum monthly average for insolation in Sarawak is found in the month of January at 3.26 kWh/m²/day, and maximum monthly value in April at 6.91 kWh/m²/day with the annual average being 5.00 kWh/m²/day. Monthly averages are consistently lower in the west, near the capital Kuching and are higher in the east (see Figure 7) [70]. Though a good quality resource, according to the Malaysia Energy Commission, there are only 10 MW of photovoltaic capacity installed in Peninsula Malaysia through a number of small distributed SPPs ranging from 0.5 MW to 5 MW in size [29]. Thus there is significant opportunity to develop the sector.

The wind resource however, is relatively poor. The minimum monthly averaged wind speed is 1.51 m/s in April and the maximum is 5.27 m/s in August, with an annual average of 2.6 m/s. Wind speeds are strongest at the coast and weaken moving in toward the forested highlands of the interior.

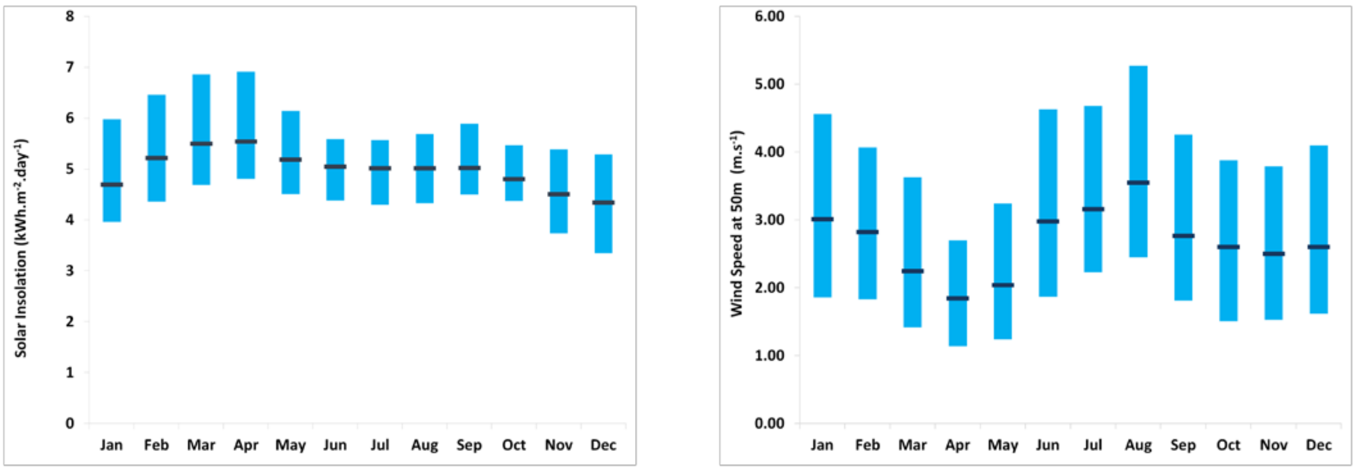

Figure 7 (a) Maximum, Minimum and Monthly Averaged Solar Insolation for Sarawak; (b) Maximum, Minimum and Monthly Averaged Onshore Wind Speed

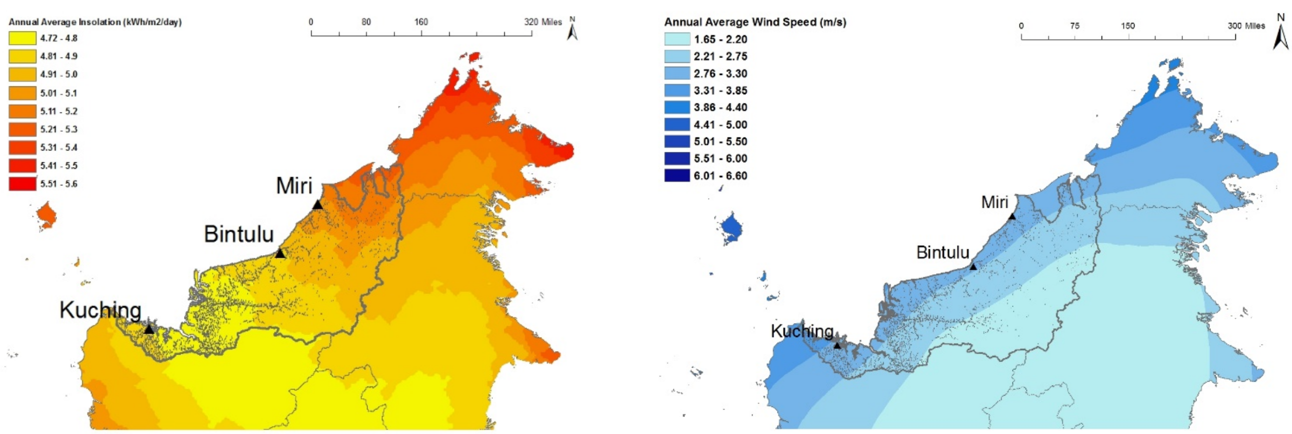

Figure 7 (a) Annual Average Insolation and (b) Annual Average Winds Speed for Sarawak

3.4. Generator Build, Fixed and Variable Costs

In 2012 SEB's cost of producing electricity was US $0.078/kWh, a steep increase from US $0.060/kWh in 2008. However SEB purchases electricity at US $0.036/kWh from independent power producers. Overall cost to the utility was thus US $0.044/kWh in 2012. The average selling price for domestic customers is US $0.097/kWh while commercial customers pay US $0.068/kWh and industrial consumers pay US $0.077/kWh [29].

For each generation technology modelled we take overnight build cost, variable cost and fixed O&M cost from NREL (see Table 4) [49]. Hydropower cost estimates are previously described in Section 3.3.2. POME methane capture costs are taken from [60] as the technology is not included in NREL's study. We also consider the effect of the Malaysia Feed-in Tariff (FiT) program currently being rolled out in the state in accordance with Renewable Energy Act 2011 and Sustainable Energy Development Authority Act 2011 [71]–[73]. The FiT system obliges utility companies to purchase electricity from certified renewable energy producers and sets the FiT rate. The maximum installed capacity for eligible installations is 30MW. The rates vary according to technology type and are degressive, decreasing annually according to prescribed rates (see Table 3) [74].

Table 3 Feed-in-Tariff Rates prescribed by the Sustainable Energy Development Authority

	Biogas	Biomass	Solar	RoR
Max FiT Rate RM/kWh	0.31	0.31	0.88	0.23
Max FiT Rate US/kWh	0.094	0.094	0.267	0.094
Annual Degression Rate (%)	0.005	0.005	0.080	0.000
2014	0.093	0.093	0.245	0.094
2015	0.093	0.093	0.226	0.094
2016	0.093	0.093	0.208	0.094
2017	0.092	0.092	0.191	0.094
2018	0.092	0.092	0.176	0.094
2019	0.091	0.091	0.162	0.094
2020	0.091	0.091	0.149	0.094

	Biogas	Biomass	Solar	RoR
2021	0.090	0.090	0.137	0.094
2022	0.090	0.090	0.126	0.094
2023	0.089	0.089	0.116	0.094
2024	0.089	0.089	0.107	0.094
2025	0.088	0.088	0.098	0.094
2026	0.088	0.088	0.090	0.094
2027	0.088	0.088	0.083	0.094
2028	0.087	0.087	0.076	0.094
2029	0.087	0.087	0.070	0.094
2030	0.086	0.086	0.065	0.094

3.5. Integration of Indirect Impacts

We attempt to include indirect costs of major environmental impacts in the assessment of technology mixes. In this section we describe the data and assumptions used in estimating green-house gas (GHG) emission factors and direct loss of land attributed to different technologies.

3.5.1. Emission Factors

Generator-specific emission rates for conventional generation in Sarawak was obtained from CDM studies on Sarawak's commercial grid [75], [76]. These studies report rates that are similar to average US generation emission rates from NREL reports [49] (see Figure 8b). We use the NREL emissions rates and heat rates for analysis purposes (see Table 4). For Palm Oil biomass technologies we take heat rates from SEB [53]. Emission rates for EFB biomass gasification plants are averaged across local CDM biomass project reports [77][78]. An emission rate for POME methane capture plants is taken from [79]. We choose US \$10/ton $CO_{2\text{-eq}}$ as the emission or carbon cost and increase this cost to US \$25/ton $CO_{2\text{-eq}}$ during sensitivity analysis. These carbon price points are taken from EIA outlook scenarios [40].

Estimating emissions from hydroelectric generation is still an evolving field. There is however broad consensus among the scientific community that methane is the main GHG species of concern for freshwater reservoirs [80], [81]. Major emission pathways for fresh water storage reservoirs include diffusion of dissolved gases at the air-water surface, methane emission from organic matter decomposition, and downstream dam emissions from degassing at turbine and spillway discharge points [82]. Especially given the global warming potential of methane, reliable estimation methods are necessary, however the rate of emission is highly variable, being related to age, location biome, morphometric features and chemical status [83]. Preliminary emissions estimates for hydroelectric dam reservoirs in Southeast Asia are still emerging [59].

As net GHG emissions cannot be measured directly, their value is estimated by assessing total (gross) emissions in the affected area and comparing the values for pre- and post- impoundment conditions based on reservoir age, mean annual air temperature, mean annual runoff and mean annual precipitation [80, p. 3]. For our purposes we employ the International Hydropower Association (IHA) GHG Measurement guidelines and GHG Risk

Assessment tool which estimates gross GHG diffusive fluxes of methane and carbon dioxide from a fresh water reservoir based on limited and available field data [85]. The tool requires values for the following parameters: reservoir age, mean annual air temperature, mean annual runoff and mean annual precipitation. For a description of the IHA modeling approach see [85, p. Annex 2]. The results from the IHA Risk Assessment Tool are the predicted annual gross carbon dioxide and methane fluxes and their associated 67% confidence intervals over a 100 year period (see Figure 8a). Across the SCORE reservoirs average initial emission rate is predicted to be 72.92 lb$CO_{2\text{-}eq}$/MWh while the average long term emission rate is 52.84 lb$CO_{2\text{-}eq}$/MWh.

A number of studies are currently furthering our understanding of the contribution of methane emissions. Deshmukh et al. in [86] study the Nam Theun 2 Dam in Laos and find that methane ebullition may contribute 60-80% of total emissions from the surface of a dam reservoir, suggesting that ebullition may actually be a major methane pathway for young tropical reservoirs though little considered in current estimations. Yang et al. in [87] collate the recent progress in estimating dam emissions across the tropics. Taking these higher estimates into consideration we observe the effect of high estimates for dam emissions on our model through sensitivity analysis.

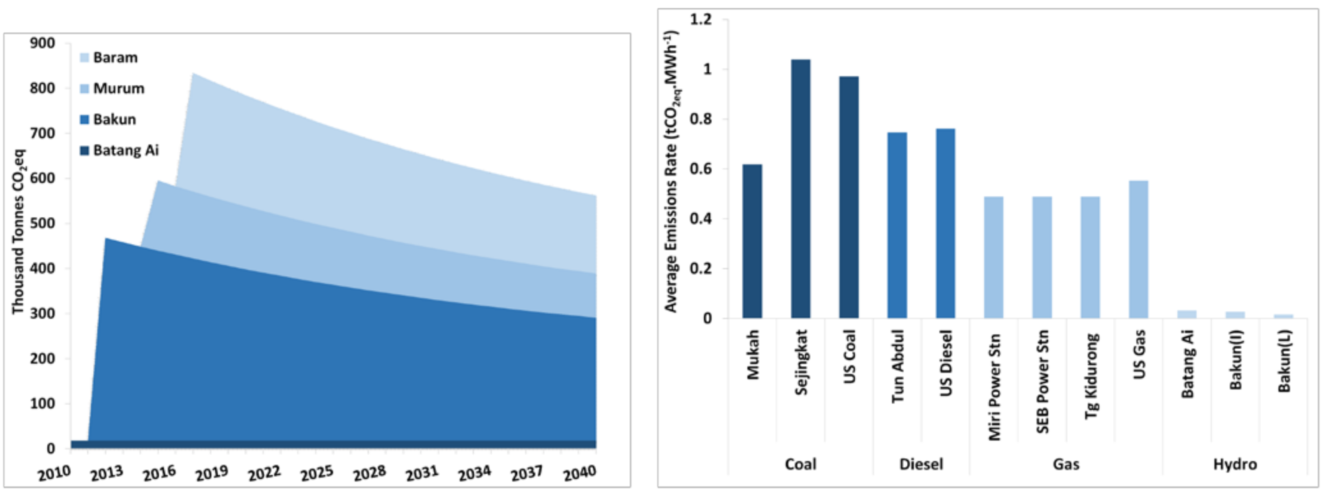

Figure 8 (a) Results from IHA GHG Assessment Tool for SCORE Dams; (b) Average Emissions Rate from various Technologies

3.5.2. The Value of Forest Lands and Services

The Bornean economy is highly dependent on its natural capital despite the fact that resource rents are rarely collected and the cost of negative impacts commonly externalized. Recent literature highlights the importance of valuing the benefits that ecosystems provide though there is much debate surrounding the cost values attributed to such services [88]–[90]. Alongside the environmental services that forest land provides - including carbon storage, protection of watersheds, provision of non-timber forest products and ecotourism - there is also a growing awareness of the role of biological diversity in the providing distinct ecosystem goods and services [91]–[94].

This field of study is particularly relevant for Borneo, identified as a global biodiversity and evolutionary hotspot. Borneo's forests house the highest level of plant and mammal species richness in Southeast Asia [20] [21]. Accelerated efforts to conserve Borneo's forests are therefore critical in the face of unabated commercial logging and agricultural expansion as the size and quality of remaining forests deteriorates rapidly [22][23]. Emerging literature establishes the importance of protecting both primary and degraded or logged forests for conservation and preserving ecosystem service value [88], [95]. Edwards et al. in [95] compare the species-richness of once and twice logged forests in the neighboring state of Sabah, Malaysia and find degradation to have little impact on bird diversity.

Generation technologies affect ecosystem service provision in different ways. While high land intensity technologies have a large impact through direct land clearing, other technologies have more diffuse impacts on water quality or air quality, which indirectly affect services [96][97]. A full discussion of the impacts on biodiversity and ecosystem service from generation technologies is beyond the scope of this paper. We estimate the area of forest land that would be directly affected by land clearing for technology development. We then incorporate the cost of direct forest land loss using land value estimates taken from the 2012 WWF Heart of Borneo (HoB) Study [98].

The HoB study used a non-linear macroeconomic system dynamics model to show that shifting toward a green economy can promote faster long term economic growth for Borneo, as land use trends are tightly coupled with social and economic drivers. The authors provide estimates for the value of different ecosystem services from forested areas in Borneo [98]. They find the estimated value of forest land (including primary and secondary forest, swamp forest and mangrove forest) to be US$900 ha^{-1} $year^{-1}$ over the past decade and project a doubling by 2030. This is based on estimates of the weighted average potential profit from different land uses. By combining this with land intensity for generation types from literature (ha/kW) [96] we can apply an annual Forestland Value charge ($/kW-$year^{-1}$) to our least cost optimization model to account for the direct loss of land (see Table 4).

3.6. Scenarios

As discussed we analyze four different demand forecasts: (i) BAU, (ii) 7% growth, (iii) 10% growth, and (iv) the SCORE Projection (see Section 3.2 for an explanation of demand forecast). We also design policy scenarios to observe the effect of policy instruments relative to the mega-dam strategy. The scenarios modeled are:

(i) The 'Reference' scenario, where we commit the generators that are currently on the SEB grid including the Bakun Dam. We do not commit (i.e. force) any other mega-dam projects;
(ii) The 'SCORE' scenario where the Bakun dam and the two dams currently under impoundment or construction (Murum and Baram) are built along with 7GW of other hydroelectric power;
(iii) The 'Feed-in-Tariff' scenario where the SEDA approved FiT rates in effect across Peninsular Malaysia and Sabah are applied to their respective renewable technologies in Sarawak;
(iv) The '20% 2020 RPS' where a 20% generation-based Renewable Portfolio Standard is implemented.

In all scenarios other than the SCORE scenario, generators are committed according to the standard optimization function for least cost. In SCORE the Bakun, Baram and Murum dams must run after their completion. We are interested in system cost, system reliability and environmental impact as observed through emissions and land loss. We address each of these criteria incrementally. We first optimize for least cost, then impose a reliability constraint into the linear program and then include emissions costs and PES costs. We observe the impact of these costs across policy scenarios and through further sensitivity analysis.

Table 4 Power Plant Parameters used for Optimization Modeling (Data Sources see Section 3.4-3.5)

Power Plant Type	Heat Rate (Btu/kWh)	Emissions Production Rate (lb/MWh)	Build Cost ($/kW)	FO&M Cost ($/kW-year)	VO&M Cost ($/MWh)	2015 Forestland Value Charge ($/kW-year)
Coal	9370	2291	2890	23.0	3.7	6.8
Gas	6705	1080	1230	6.3	3.6	10.7
Diesel	10991	1647	917	6.8	3.6	7.8
HEP Batang Ai	0	72	3870	15.0	10	21.9
HEP Bakun	0	36	3870	15.0	10	21.9
HEP Baram	0	92	3870	15.0	10	21.9
HEP Murum	0	44	3870	15.0	10	21.9
HEP Other	0	69	3870	15.0	10	21.9
Oil Palm Biomass	10625	500	3830	95.0	15	375
POME Plant	9480	200	3030	120.0	15	375
Run Of River	0	0	1300	10.0	10	0
Solar PV	0	0	2357	48.0	0	9.5
Wind	0	0	2213	39.6	0	22.1

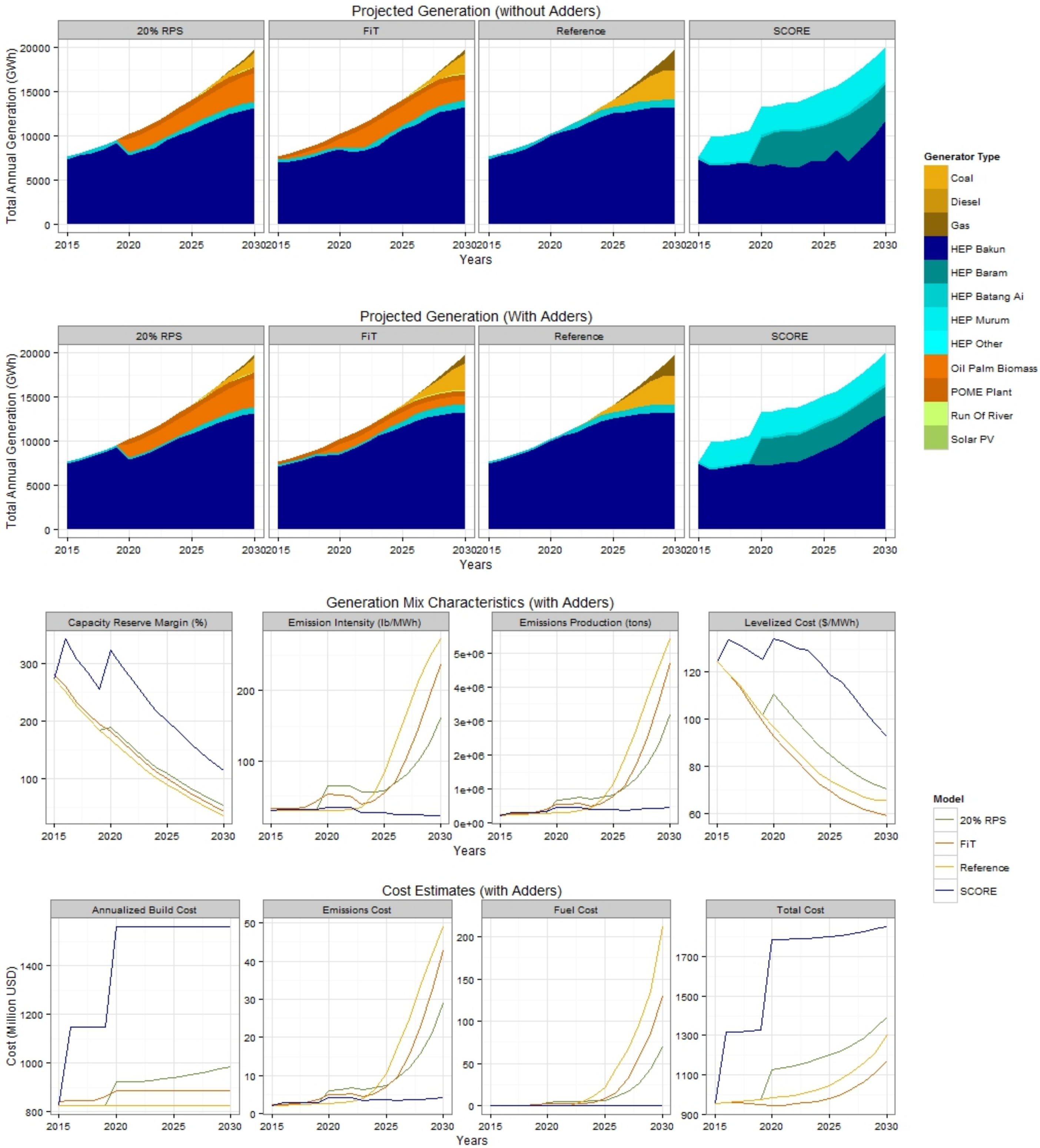

Figure 9 Generation Profile, Cost Components and Generation Characteristics of Scenarios under 7% Demand Growth

4. Results and Discussion

4.1. 2030 Energy Scenarios

We find that Sarawak's current installed capacity including Bakun already exceeds expected demand in 2030 under the BAU growth assumption. So there is no additional build out and no investment differences across policy scenarios under the BAU growth forecast. We focus here on the 7% and 10% growth forecasts, which are highly ambitious yet plausible. All results for the 7%, 10% and SCORE growth forecasts are found in the Supporting Information (SI). See Figure 9 for an example of results presented in SI.

Demand Forecasts	Scenarios	Priorities	Sensitivity Analysis
BAU Growth	20% 2020 RPS	Least Cost	Emission Pricing Scheme
7% Growth per annum	Feed-in Tariff	Minimum Reserve Margin	Emission Production Rates
10% Growth per annum	Reference	GHG Emissions Cost	Technology Build Costs
SCORE Forecast	SCORE	Forestland Value Adder	Land Limits

Figure 10 Levels of Variability in Analysis (taken from NREL and the HoB)

4.1.1. Examining Scenarios Under 7% Demand Growth

The model results show that there are a number of alternative capacity expansion choices that meet future demand at this growth rate. Under a 7% growth forecast energy demand grows to a peak demand of 2730 MW in 2030 (20,000 GWh/year in 2030). In the Reference case under 7% growth we see that current generation capacity – comprised of the two existing dams (Batang Ai and Bakun) and recently installed combined gas and coal-fired generators - are sufficient to meet future demand. In the SCORE scenario where the Bakun, Murum and Baram dams are built and committed, we see that these three dams meet future demand with a large excess of undispatched energy (note Capacity Reserve Margin in Figure 9). The other cases show that local resources including solar PV, biomass gasification and POME conversion can all contribute to future demand as well. Both the FiT Scenario and the 20% 2020 RPS Scenarios call for the build out over 450 MW of biomass waste capacity.

We consider the additional cost of environmental impacts including GHG emissions and direct loss of forest land. We apply the emissions factors discussed in Section 3.5.1 and assume that a carbon price of \$10/tonne $CO_{2\text{-eq}}$ is applied in 2015. A charge based on Forestland Value is applied as a fixed charge per kW-year as described in Section 3.5.2. We find that inclusion of the carbon adder changes the optimal configurations selected while the land value adder has little significant impact on the choices made. Emissions cause total annual cost in 2030 to be 4% greater for the SCORE scenario while increasing the total cost by a much larger margin for other scenarios. The FLV adder causes no observable change in any cost property for any scenario. Inclusion of the environmental cost adders also causes fuel switching: the 20% 2020 RPS scenario again build out 490 MW of biomass gasification and POME biogas capacity while the FiT scenario switches to 596 MW of Solar PV.

When both environmental adders are included the SCORE scenario has a higher total cost and a higher levelized cost than all other scenarios. While it has a low fuel cost and emissions cost, the high annual build cost and associated fixed costs are high. This is because the system is over-built. Building three dams causes the Capacity Reserve Margin to rise to over 300% and the reserve margin stays well above 100% in 2030, much higher than the 15% minimum constraint imposed. The SCORE scenario has 6 GW installed capacity by 2030, almost 33% greater than any of the other scenarios which each have roughly 4 GW installed. Nevertheless, the SCORE scenario has one of the lowest emissions production and emission intensity rates. The overall total cost per year is quite similar across the other scenarios, though the various cost components differ. We find the Reference and FiT scenarios have the lowest total cost and levelized costs across the fifteen year time horizon.

4.1.2. Examining Scenarios Under 10% Demand Growth

Under a more aggressive 10% growth forecast, energy demand peaks at 3635 MW in 2030 (30,000 GWh/year). The resultant energy matrix varies more than under the 7% growth scenario as a significant amount of new capacity is required to satisfy the higher demand growth. Unlike in the 7% growth scenarios, we find that additional natural gas capacity is built in every scenario other than SCORE, where again the three dams and existing coal and gas are already sufficient installed capacity. In the 20% RPS and FiT scenarios non-conventional sources, including biomass gasification and POME biogas capacity are called upon. In both of these scenarios all potential Run of River hydro and significant amounts of PV (50MW and100MW respectively) are chosen as well. In each of the four scenarios total capacity is built to over 5 GW and by 2030 the Capacity Reserve Margin of each scenario is between 20-30%.

The inclusion of the carbon adder has a greater impact at this growth rate, increasing the cost of the SCORE Scenario by 11% and the total cost of other scenarios by as much as 23% (see Figure). However the emissions intensity, total emissions production and emissions cost of the Reference scenario meets that of SCORE by 2030. The FLV adder is again largely insignificant. When both environmental adders are included under 10% growth we find the overall total cost under different scenarios is quite similar. As some amount of natural gas and coal is required in each scenario, the fuel cost, the emissions intensity, production and cost are more similar here than under the 7% growth assumption. The SCORE scenario is marginally more expensive than others while the FiT scenario is again the least expensive by a significant margin. While the build cost for SCORE is still higher, the fuel costs, fixed O&M and emissions costs for the other scenarios have increased due to the additional capacity requirements.

It should be noted that these levelized cost values are much higher than the 2012 reported SEB average generation cost of \$0.047/kWh [29]. Likewise the emissions rates are much lower than reported through CDM (see Section 3.5.1 above) where total 2011 emissions were 5.48 million tonnes with an intensity of 1898 lb/MWh. The shift in primary generation from gas and coal to hydropower significantly lowers the emissions of the entire system. Mega-dams represents 76% and 64% of total generation for the Reference scenario under 7% growth and 10% growth respectively.

Note here that we ran a fifth scenario, called the 'Low Conventional Fuel Price' scenario where we assumed lower gas, diesel and coal prices in the future according to the EIA's Low Fossil Fuel Cost projections [40]. However the resultant matrices under this scenario were identical to their respective Reference scenarios, showing fossil fuel cost to have limited impact on selections. As such we do not include this scenario in the results description.

4.2. Sensitivity Analysis

We describe here the impact of various sensitivity analysis tests on the generation matrix and cost results obtained by running the models with different discrete parameters. We describe results for the impact of sensitivity on the 7% Growth scenarios while the results of all other Sensitivity Analysis runs can be found in the SI.

Sensitivity to Carbon Pricing (\$25/ton $CO_{2\text{-}eq}$): When we apply a higher carbon price there is little change to the generators selected except that new coal switches to gas, and gas takes up a larger share of the matrix in each scenario. With regard to emissions production however, the effect of the change in pricing is significant. While SCORE total emissions do not change, the FiT, 20% RPS and Reference scenario emissions all decrease by more than 30% by 2030. This decrease likely comes from switching coal to gas. Despite reducing emissions production, the emissions cost and thus the total annual system cost in these scenarios still increases over the horizon (by about 10% each). Thus the Carbon Pricing Scheme would have impact on the proportion of conventional fuels selected.

Sensitivity to Hydro emission factor: When we double the hydropower dam emissions factor there is minimal effect on the generators selected in the 7% growth scenarios. However it does double the total emissions produced every year of the time horizon under the SCORE scenario. It also significantly impacts emissions for the other scenarios, though to a lesser extent. High hydro emissions cause the total cost of both the Reference and SCORE scenarios to double while increasing total cost under FiT and 20% RPS by more than 75% each. We find that because emissions cost accounts for such a large proportion of the total annual system cost, the dam emissions factor is very essential to future energy planning if the cost of GHG emissions are to be internalized. This is one of the parameters with most uncertainty.

Low Renewable energy Technology (RET) Prices: We test the impact of reducing the RET build costs (Biomass: $1500/kW; POME: $2000/kW, Solar PV: $1100/kW and Wind: $2210/kW). This changed the resulting generation matrix in the FiT scenario, which called on as much Palm Oil Biomass generation and PV generation as possible, with no conventional generation chosen. Subsequently, the total emissions did not change for any of the scenarios other than FiT, where total emissions in 2030 were almost 60% lower than normal, due to the switch away from fossil fuel sources. The total cost also did not change for scenarios other than the FiT, where the total annual system cost declined every year and was almost 30% of the original by 2030.

Biomass limited by palm oil moratorium: While the SCORE development plan includes doubling palm oil plantation acreage to 2 million hectares by 2020 [13], there is significant opposition to this plan amidst international environmental pressure to place moratoriums on palm oil expansion into high-carbon forest areas. In 2011 for instance, Indonesia decreed a 2 year moratorium on the issuance of forest licenses for logging and palm oil, though the transparency of enforcement has been brought into question [99]. Using palm oil waste for electricity potential may present a perverse incentive to intensify palm oil production or increase forest land conversion.

We therefore also tested a scenario where the total Palm Oil Biomass waste available for biomass gasification and POME capture is limited by a moratorium that caps the total area of land cleared for plantations to one million hectares. In effect this means no future palm oil expansion. Such a moratorium would involve strict zero deforestation sourcing regulations and enforcement mechanisms. These policy tools exist in practice today though with varying degrees of success [100]. We find that this policy effectively halves the total amount of generation potential from either biomass source. The impact is only felt on the 20% RPS and FiT scenarios where biomass waste capacity is then replaced by larger capacities of solar PV.

4.3. Limitations

A number of limitations impact our modeling approach. As described in Section 3.1, we chose to use a deterministic optimization for the LT capacity expansion plan which uses expected values for variable inputs. Stochastic programs have greater capability in handling uncertainty as they assume that the probability distributions governing data are known. The differences and trade-offs between these two modeling approaches are well described in the literature [101]. Given that our aim is to generally observe the feasibility of alternative generation technologies, we opt for deterministic optimization as it greatly reduces the number of constraints observed and simplifies the model. However future studies that employ a stochastic approach would be very useful in yielding specific policy and strategy suggestions for Sarawak’s electric utility operation.

Another inherent impact of this decision is that, without stochasticity we do not observe the impacts of random outages on the system. Thus our metric for system adequacy is the satisfaction of a zero unmet load constraint. Observation of higher resolution metrics for system reliability, such as Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE), will be possible in future studies where the stochastic approach is used. These metrics will be useful for operation decisions and management.

In our LT plan we also opted to use a non-chronological LDC method rather than a chronological method. There is a spectrum of general methods for integrating non-dispatchable technologies into capacity expansion modelling. Trade-offs between fine and coarse spatial and temporal resolution requirements make different choices applicable for particular applications [26]. Given the data limitations we use a LDC method for aggregating time blocks combined with least cost dispatch and augmented with reliability constraints. This method does not include start-up costs, ramping constraints, minimum turndown or other system considerations, and so is an approximation of unit commitment. As we have shown, this first order approximation is nevertheless very useful for estimating the impact that various investments may have, including fuel savings, emissions reductions and shifts in generation mix to different types of capacity (e.g. between base, intermediate and peak-load capacity). PLEXOS is a detailed operational program that can be expanded to include production cost modeling and chronological optimization. Future work will involve expanding our model to take advantage of these capacities as utility data becomes available.

We have noted the limitations of data availability in our case study. For instance, our demand forecast is based on hourly data for neighboring states from the Energy Commission since Sarawak generation data is not publicly available. Where local data for costs and emission factors were not obtained, values from well accepted authorities such as the EIA and the IEA were used which adds an element of uncertainty to results. As mentioned we do not include the impact of specific generator ramp rates, start up and shut down costs or minimum down and up time due to lack of data. However as data or credible estimates become available these can be easily added to the model in future revisions to increase the number of operation variables considered.

The lack of data on river flow rates for the respective rivers impounded by the SCORE dams was also a significant factor limiting our ability to model hydro-thermal interactions at high temporal resolution. We provided the model with seasonal maximum and minimum output constraints in lieu of extensive stream flow data and intend to revise the model as data from Bakun's operation becomes available from the relevant utilities. This will be an important improvement as hydropower may have some role to play in balancing variable generation in the future.

Finally, we faced a number of limitations in attempting to incorporate indirect environmental impacts into the economic cost framework. The \$/kW-year^{-1} Forest Land Value applied is understandably not a direct metric for either biodiversity or ecosystem service value. Services such as flood risk mitigation and watershed function or biodiversity services are not included in this land value. Without further economic valuation studies, it is difficult to include the impacts of other indirect land use impacts such as air or water pollution in the model.

The HoB study mentioned earlier [98] is the most recent attempt to quantify the localized economic value of natural capital and discuss avenues for its incorporation into mainstream decision making. HoB uses a non-linear macroeconomic system dynamics model to show that land use trends in Borneo are tightly coupled with social and economic drivers and estimates the net present value of natural capital stocks under different development scenarios (green economy vs BAU). Further ecological economic studies that disaggregate ecosystem services and assess value are critical for the conversation on development pathways.

5. Discussion and Conclusions

Our application of a capacity expansion methodology has implication for many other regions where the need for assessment of alternatives to large-scale energy infrastructure may exist. The Lower Mekong River Basin for instance, is currently undergoing massive hydropower development. The transboundary basin passes through Myanmar, Lao, Thailand, Cambodia and Vietnam. It is home to a large rural population of more than 40 million people and is the site of one of the biggest inland fisheries in the world, making infrastructural development in the basin both an important food security concern for these countries and a major biodiversity priority more globally [102].

Similar large-scale energy infrastructure projects are under way across Africa and Latin America commonly rationalized through the discourse of national energy security [3], [9]. Such projects are often characterized by information shortage, a lack of rigorous analysis on the assumptions of demand, and narrow definitions of cost that impede broader evaluation of risk and tradeoff. Here we demonstrate a simple and effective framework for assessing critical assumptions embedded in energy-infrastructure development strategy while also providing directionality for appropriate solutions.

The method we present explores potential paths of least cost capacity expansion over a fifteen year period in Malaysian Borneo where cost includes indirect environmental costs of greenhouse gas emission and direct land loss. We also observe the effects of different possible policy/market conditions including low fuel costs, high and low RET build costs and the implementation of renewable energy incentive schemes. We find that the Bakun Dam itself can provide more than 10,000 GWh per annum. Under a 7% electricity demand growth assumption, this represents half of expected demand by 2030. Even under the more aggressive 10% growth assumption, Bakun alone will satisfy a third of demand in 2030. Completion of the two additional dams currently under construction (Murum and Baram) would oversupply 2030 demand under 7% growth, leading to a large excess capacity, and would require a marginal amount of additional generation under 10% growth.

These results highlight the gross overestimation of generation capacity required to satisfy high expectations of growth. Similar study could be very useful for public conversation in other energy megaproject debates across the developing world. The modular design of PLEXOS allows for consideration of cascading hydropower systems, where multiple dams are built within the same river system, as well as the exploration of hydro-thermal interactions. These capabilities would be very useful in a context such as the Mekong Basin hydropower developments which include a series of main-stem and tributary dams [102].

We also find that distributed solar and biomass waste technologies can contribute significant capacity to the state's energy portfolio. These findings are consistent with other studies that find solar and biomass waste to be effective solutions for Borneo given their large resource potential [54], [55], [58], [64]. In our model these technologies become cost effective only under incentive schemes such as an RPS or FiT. This supports the case for incentivizing and formally incorporating SPPs into energy infrastructure development plans.

In fact, small renewable energy power production was a large part of Malaysian energy policy in the early 2000s and was the cornerstone of the country's Firth Fuel Diversification Plan and featured prominently in the Eight Malaysia Plan [103]. The Small Renewable Energy Program (SREP) was established in 2001 to tap into waste fuels from the palm oil industry and to stimulate local innovation and capacity through grid-connected SPPs of less than 10 MW. The SREP's 500 MW goal was scaled back to 350 MW of renewable energy technology installed by 2010, and has yet to be met. The SREP was revised on multiple occasions to increase tariffs offered to SPPs but this did not accelerate participation in the program. In 2011 SREP was suspended and has been replaced by the SEDA FiT mechanism. Independent studies cite reasons for the slow growth of the Malaysian renewable energy sector as including high risk premiums for financing and bureaucracy of the application process among others [104], [71], [105], [106], [103]. Along with investment transaction costs, technical integration issues and poor policy design, a lack of local capacity is frequently cited as one of the largest barriers to renewable energy development in Malaysia [107].

Nevertheless, regional and local successes with PV and biomass waste technologies (such as Kina BioPower and TSH Bioenergy Sdn Bhd in Sabah) demonstrate the potential for deployment. This challenge thus presents an opportunity for diversification of the labor market. This is in line with the Tenth Malaysia Plan which calls for increased technical and vocational training for the labor workforce [12]. Beyond knowledge capacity, integration of decentralized energy solutions involves more detailed discussion on regulation, financing, incentives, purchase agreements and payment structures, permitting, licensing, quality of service standards and more. While this discussion is outside the scope of our paper, resources such as [4] detail best-policy practice for integration of SPPs.

Our study is the first instance of a commercial energy model being applied to SCORE, and one of the first instances of PLEXOS being used in Southeast Asia in the academic literature. Our study represents an important contribution to the public conversation by demonstrating a framework for integrated analysis despite data constraints. Many further studies on socio-cultural and ecological impacts are urgently needed. However, using Sarawak as our case study, we demonstrate the potential for effective energy analyses in the information-scarce contexts where many large-scale energy projects are now emerging. Future work will involve data collection to simulate hydropower operation at higher resolution and observe its interactions with variable generation.

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