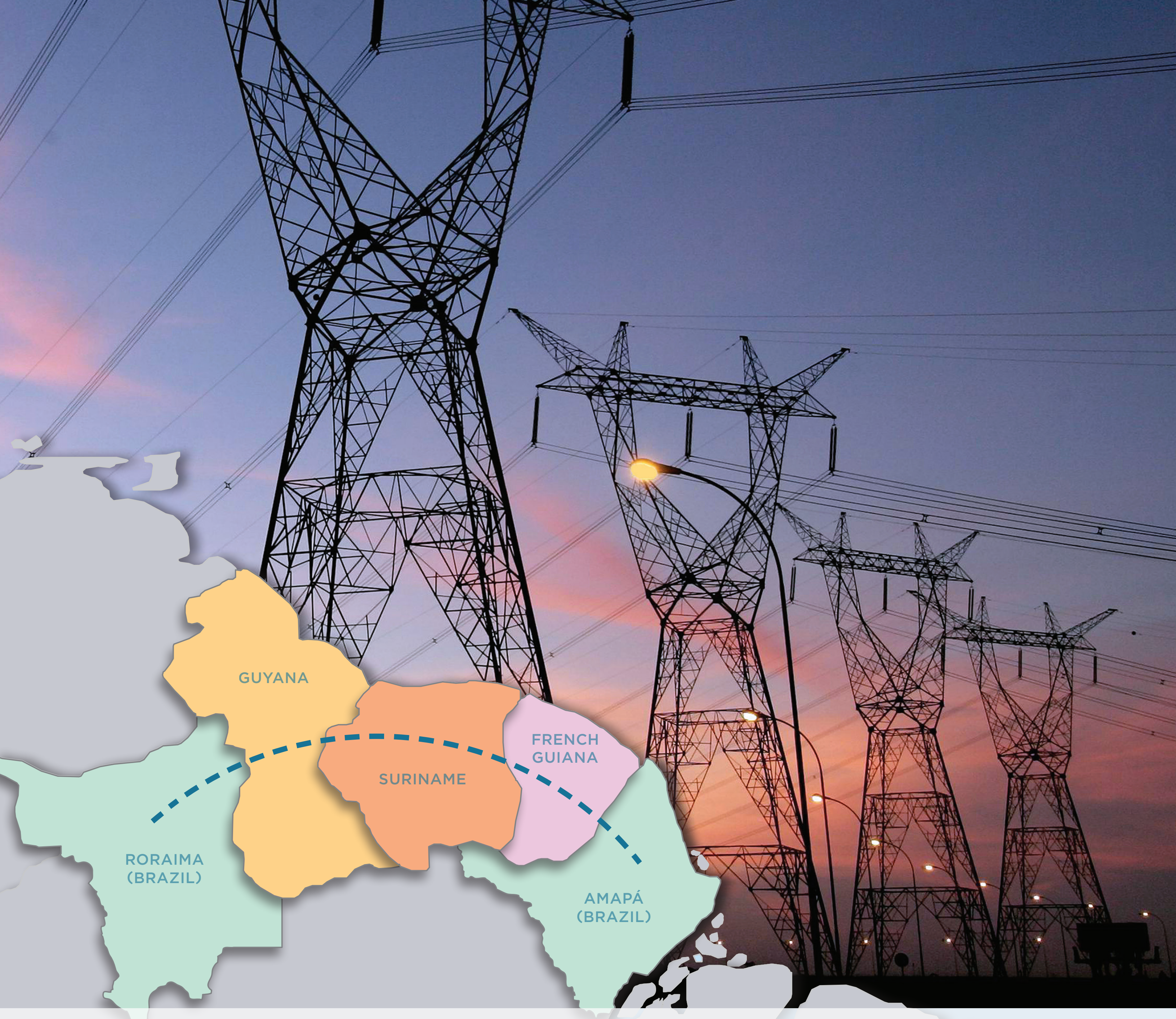
ARCO NORTE
ELECTRICAL INTERCONNECTION STUDY

COMPONENT I – BASELINE STUDY

JULY 2016



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Sylvia Larrea, Silvio Binato,
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Acronyms and Abbreviations

CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CRE	Commission de Régulation de l'Énergie (France)
EBITDA	Earnings Before Interest, Taxes, Depreciations and Amortization
EBS	N.V. Energiebedrijven Suriname
EDF	Électricité De France
ELETROBRAS	Centrais Elétricas Brasileiras S/A
EPAR	Electricity Paramaribo
EPE	Empresa de Pesquisa Energética (Brazilian Energy Research Company)
GDP	Gross Domestic Product
GPL	Guyana Power and Light Inc.
HFO	Heavy Fuel Oil
HPP	Hydropower Plant
IDB	Inter-American Development Bank
IMF	International Monetary Fund
IPP	Independent Power Producer
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
NPV	Net Present Value
PPA	Power Purchase Agreement
PV	Photovoltaic
SIEPAC	Sistema de Interconexión Eléctrica de los Países de América Central (Electrical Interconnection System for Central American Countries)
SIN	Sistema Interligado Nacional (Brazilian National Interconnected System)

Preface

Latin America and the Caribbean (LAC) countries are rich in energy resources including hydrocarbons, hydroelectricity, wind, solar, geothermal and biofuels, but this wealth is unevenly distributed. In particular, this is a region with ample hydropower resources, although only 25 percent of this potential has been developed and about 24.5 million people in the region still lack access to electricity. Looking ahead, electricity demand in the region is expected to expand by more than 90% by 2040 reaching over 2.970 terawatt-hours (TWh).[1]

The IDB's goal in the energy sector is to help increase the access of LAC countries to efficient, sustainable, reliable, and affordable energy, in a diversified and secure manner, while reducing poverty, promoting improved quality of life, and fostering competitiveness and economic development. In this context, regional energy integration is one of the four pillars of IDB's Energy Sector Framework, together with energy access, sustainability and governance. At the IDB we consider integration as an engine for growth, development and energy security, moreover, it is estimated the LAC region could realize benefits by increasing regional integration, including lower energy prices, increased system reliability and improved competitiveness.

The objective of the Arco Norte Study is to assess the potential for electrical interconnection of power systems in the Arco Norte region consisting of the countries of Guyana, Suriname, French Guiana, and the States of Roraima and Amapá in Brazil. The Study has been carried-out in collaboration with the Guyana Energy Agency (GEA), EnergieBedrijven Suriname (EBS), Électricité de France (EDF), Centrais Elétricas Brasileiras (Eletrobras), and Agence Française de Développement (AFD). I am grateful to the support received by these institutions in preparing this Study in a truly collaboration spirit. During the last years we carried-out technical workshops with these institutions leading to this publication summarizing the Component I (Baseline). I was encouraged to read in the report that an electricity transmission line that interconnects these four countries is technically and economically viable. Moving ahead, I am looking forward to Component II which will further analyze the technical, economic, social and environmental aspects of the most promising interconnection alternative.

The IDB is committed to building capacity and creating knowledge on the importance of regional energy integration. This Study is a move in this direction of disseminating knowledge and supporting the sustainable development of energy in the region. For additional information regarding this Study please contact Sylvia Larrea at SYLVIAL@IADB.ORG.

Ariel Yépez
Chief of the Energy Division
Inter-American Development Bank

[1] *Lights on? Energy Needs in Latin America and the Caribbean to 2040.* IDB, 2015.

1

Objective of the Study

The objective of this study is to assess the potential for electrical interconnection of power systems in the *Arco Norte* region of South America (the Arco Norte region). The Arco Norte region consists of the countries of Guyana, Suriname, Brazil (with its northern states of Amapá and Roraima) and French Guiana (an overseas department of France); together these are known as the Arco Norte countries.

The electrical interconnection of the Arco Norte region would improve the regional electricity system, allowing electricity trading among these countries. This would allow for an optimal power generation expansion plan, under which the region could use the most efficient sources of electricity, minimizing costs and environmental and social impacts. Regional electricity trading would also help guarantee security of supply.

Another advantage of regional interconnection is that it would allow for trade among French Guiana, Guyana, Suriname and the national Brazilian grid. The Brazilian state of Amapá recently joined the Brazilian Interconnected System (SIN) and the state of Roraima is expected to join the system in the near future. Once the states of Roraima and Amapá are connected to the SIN, interconnection in the Arco Norte would allow for energy exports from French Guiana, Guyana, and Suriname to the rest of Brazil. The potential for exports could encourage the development of large clean energy sources (mainly hydropower) in these three countries, given the hydrological complement to the Brazilian electricity system, as rivers in the northern hemisphere have high flows at times when flows in southern Brazil are low, and vice versa.

A regional plan for optimal generation expansion could allow for increased use of local energy sources (such as hydropower and biomass), reducing generation costs and dependence on imported fuels while minimizing the environmental and social impacts of new power plants. Moreover, the development of an interconnected power system could allow for the extension of existing transmission networks into areas that are not currently served, thus eventually expanding electricity access in the Arco Norte region.

The study is divided in two components:

- Component I – Baseline Study
- Component II – Pre-Feasibility Study.

This report, Component I – Baseline Study, describes and evaluates options for interconnection of the Arco Norte region. Different interconnection alternatives were assessed in terms of transmission capacity and route, taking into account characteristics of the Arco Norte region, the historical and future development of the Arco Norte countries, power supply options, and potential energy exports to Brazil. We analyzed the alternatives from an economic, technical, and socio-environmental point of view, and selected the best ones to analyze in greater depth during the next phase of the study: Component II – Pre-Feasibility Study.

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Background

The Arco Norte region stretches across the northeastern part of South America. The name describes the arc shape formed by the aforementioned countries and states.

Across the Arco Norte region, annual GDP growth rates ranged from 1.7 percent (in Brazil) to 3.8 percent (in Guyana) from 2010 to 2014.[2] Total population of the region is estimated at

FIGURE 2.1: The Arco Norte Region

[2] Data from IMF and INSEE (for French Guiana).

more than 2.8 million, of which 57 percent live in French Guiana, Guyana and Suriname, and the remaining 43 percent live in the Brazilian states of Amapá and Roraima.

Population density in the Arco Norte region is low, at between 2 and 5 people/km^2 in Guyana, French Guiana, and Suriname. However, the population is fairly highly concentrated in the capitals of Georgetown, Paramaribo, and Cayenne (where population density approaches 1,000 people/km^2), in the coastal strip and along the banks of the great rivers, and close to main roads.

The region is primarily covered by the Amazon rainforest, which includes vast water resources and geomorphological characteristics that are well-suited for the development of hydropower. The Amazon's environmental importance means that much of it is protected from development—including 71 percent of land in French Guiana, 13 percent of Suriname, 8 percent of Guyana, 64 percent of Amapá, and 38 percent of Roraima. There are numerous important indigenous lands in the region as well.

The Arco Norte countries have varying levels of protection for indigenous lands and environmentally protected areas. In Suriname, the Government does not officially recognize indigenous lands. On the other hand, in Brazil's integral protection conservation units (*unidades de conservação de proteção integral*), natural resources may only be used indirectly, such as for scientific research or ecological tourism. As a result, the process for developing new hydropower plants and other electricity infrastructure in protected areas varies widely by project.

For these reasons, the environmental and social impact of new infrastructure (including both generation and transmission assets) is a critical issue for regional electricity interconnection. We considered these potential impacts when comparing possible corridors for interconnection of the region's power systems. We will analyze mitigation measures in the next phase of the study.

Several previous studies have addressed the feasibility of hydropower plants in the region.[3] This study is a necessary complement to that work, since an interconnected system should

[3] Example of previous studies of hydro potential in the Arco Norte region:
- Montreal Engineering Company (1976). "HEPS – Hydroelectric Power Survey of Guyana;"
- STAATSOLIE (2011). CNEC; Worley Parsons Resources & Energy. Tapajai Hydropower Project, Suriname. Final Report;
- Eaucéa (2008). Etude du potentiel hydroélectrique de la Guyane – Revision du Sdage, June 2008. Rapport Final.

also be seen as a prerequisite to transforming relatively large potential hydropower projects, which are too big for local markets, into feasible projects with a regional scope. Although many previous studies have addressed the high potential of local energy sources, only one study addressed the feasibility of interconnection. The previous study looked at a link between the power systems of Suriname and French Guiana (a 30 MW link between Menckendam in Suriname and Margot in French Guiana). Therefore, this is the first study to investigate an interconnected grid across the entire Arco Norte region.

Electricity Markets in the Arco Norte Region

3

Across the Arco Norte region, electricity demand is growing quickly. This growth averaged 5 percent per year from 2008 to 2014. Thermal plants fired by oil products account for a large share of generation in the region, although the Petit-Saut hydro plant meets up to 60 percent of French Guiana's electricity demand and a single hydro plant in Suriname meets about half of that country's demand. Many components of individual transmission systems in the Arco Norte region are old and require revamping. Where available, generation expansion plans are generally adequate, though some improvements are needed to ensure reliable supply. These similarities exist despite very different institutional and regulatory frameworks, ranging from the single government-owned monopoly that dominates the sector in Guyana and Suriname, to Brazil's unbundled and competitive electricity market.

3.1 Electricity Demand

Total non-coincident peak demand[4] in the Arco Norte region reached 908 MW in 2014, and consumption was 6,233 GWh. Demand has grown quickly over the past six years, with a compound annual growth rate (CAGR) of 4.6 percent for peak demand, and 5.4 percent for consumption. Amapá, Suriname, and Roraima have the highest consumption in the region, with 30.0 percent, 27.7 percent, and 16.0 percent of the regional total, respectively (see Table 3.1).

[4] Sum of individual countries' peak demand.

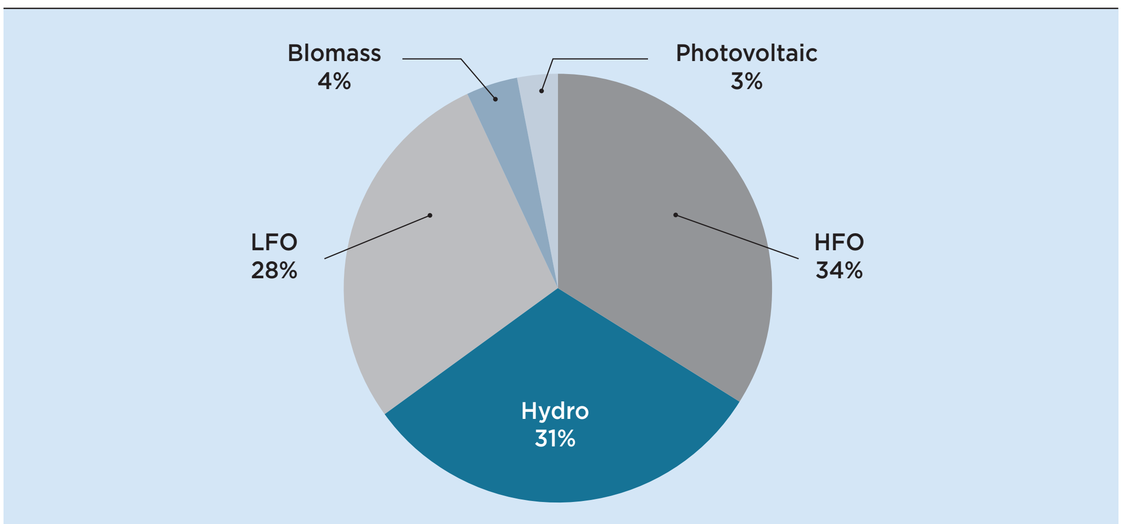
TABLE 3.1: Historic Electricity Demand in the Arco Norte.

Year	French Guiana		Guyana		Suriname		Amapá		Roraima		TOTAL	
	GWH	MW	GWH	MW	GWH	MW	GWH	MW	GWH	MW	GWH	MW
2008	750	113	540	92	1,041	150	1,445	220	777	118	4,553	693
2009	782	118	564	95	1,178	160	1,497	228	805	123	4,826	724
2010	830	122	602	101	1,292	174	1,551	236	834	127	5,109	760
2011	836	122	629	104	1,356	182	1,607	245	864	132	5,292	785
2012	853	128	667	110	1,443	200	1,665	253	895	136	5,523	827
2013	874	131	690	109	1,520	202	1,767	262	950	141	5,801	846
2014	900	135	737	116	1,726	230	1,871	278	1,000	149	6,233	908
CAGR	**3.1%**	**3.0%**	**5.3%**	**4.0%**	**8.9%**	**7.5%**	**4.4%**	**4.0%**	**4.3%**	**4.0%**	**5.4%**	**4.6%**

3.2 Existing Generation, Transmission, and Distribution Systems

Installed generation capacity in the region was 1,246 MW[5] in 2014. Figure 3.1 shows that 62 percent of the installed capacity uses oil products—heavy fuel oil (HFO) and light fuel oil (LFO), 31 percent is hydropower, and 7 percent uses other renewable sources (such as solar photovoltaics in French Guiana and sugar cane bagasse in Guyana).

FIGURE 3.1: Fuel Types in the Installed Generation of Arco Norte, 2014



[5] Excluding Roraima's temporary emergency units and its interconnection with Venezuela.

Table 3.2 shows the detail of the installed generation in French Guiana, Guyana, Suriname, Amapá, and Roraima.

TABLE 3.2: Installed generation in the Arco Norte[a], 2014

Country/ Region	Name	Fuel	Capacity (MW)	Fuel Type (%)
French Guiana	Pet it Saut	Hydro	114	40.3%
	Dégrad Des Cannes	HFO	68	24.0%
	Dégrad Des Cannes	LFO	40	21.2%
	Kourou	LFO	20	
	Solar	Photovoltaic	34	12.0%
	Saut Maman Valentin	Small Hydro	5	1.8%
	Biomass	Biomass	2	0.7%
		Total	**283**	
Guyana	Demara Power1	HFO	22	71.1%
	Demara Power2	HFO	22	
	Demara Power3	HFO	37	
	Demara Power4	HFO	26	
	Canefield	HFO	11	
	Skeldon	HFO	9	
	Skeldon	Biomass	30	16.9%
	Canefiled	LFO	5	12.0%
	Garden of Eden	LFO	11	
	Garden of Eden	LFO	6	
		Total	**180**	
Suriname	Sarama	HFO	130	52.7%
	Staatsol	HFO	98	
	Afobaka	Hydro	189	43.6%
	Sarama	LFO	16	3.7%
		Total	**433**	
Amapá	Santana	LFO	178	73.5%
	Thermal	LFO	44	
	Coaracy Nunes 3	Hydro	30	25.8%
	Coaracy Nunes 1–2	Hydro	48	
	Biomass	Biomass	2	0.7%
		Total	**302**	
Roraima	Thermal	LFO	33	68.8%
	Biomass	Biomass	10	20.8%
	Jatapu	Hydro	5	10.4%
		Total	**48**	
	Total		**1246**	

[a] This table presents the installed capacity of Guyana in MW, but for the purpose of the study the capacity was in MVA, which has a power factor of 0.8 compared to MW.

The main transmission systems in Guyana, Suriname, and French Guiana run east–west along the northern coast of South America.[6] The transmission system in Amapá also runs east to west, and was integrated with the main Brazilian system in March 2015. The Roraima transmission system is expected to be interconnected with the main Brazilian system in the near future through a new 500 kV, 715-km double circuit line, from the substation at Boa Vista to Manaus. Four of the Arco Norte systems operate grids at 60 Hz—only French Guiana operates at 50 Hz.

3.3 Generation and Transmission Adequacy

To assess the ability of each power system to meet future demand, we performed power flow simulations and a preliminary generation adequacy analysis for 2014–2028, considering each country's generation and transmission expansion plans.

Generation adequacy: French Guiana, Guyana, Suriname and the Brazilian states of Roraima and Amapá have power generation expansion plans that are adequate to meet future demand. French Guiana, Guyana, and Suriname are capable of meeting their own demand without electricity imports.

The state of Amapá is connected to the rest of the Brazilian system and, in the past, has been a net electricity importer. However, with the expected commissioning of 1,041 MW of new hydroelectric power plants between 2015 and 2018,[7] it is poised to become a net exporter to the south of Brazil. There is a plan to connect the state of Roraima to the Brazilian system in the near future, as it currently relies on Venezuelan supply and emergency generation to meet demand. Nonetheless, Roraima is also expected to become a net exporter to the south of Brazil once its 708MW Bem Querer hydro plant is commissioned.

Transmission adequacy: The transmission systems in French Guiana, Guyana, Roraima, and Amapá performed adequately in 2014—all systems meet the N planning criterion, which requires that peak demand must be met when all components of the network are in service. Suriname's largest power system EPAR does not comply with the N planning criterion due to some existing overloads, and its system of isolated networks must be reinforced to improve performance.

[6] Suriname's transmission system, however, does not cover the entire coastline, and the different systems are not fully interconnected. Exceptions to the east–west orientation include a long structure connecting Garden of Eden to the Georgetown area in Guyana and a 161 kV corridor connecting the hydropower plant of Afobaka to Menckendam (in the Paramaribo area) in Suriname.
[7] Ferreira Gomes – 252 MW, Santo Antônio do Jari – 370 MW Cachoeira Caldeirão – 219 MW and Coaracy Nunes 2 – 220 MW.

In both Suriname and Guyana, transmission and distribution infrastructure are old, and much of each must be replaced or rehabilitated. In Guyana, a plan to rehabilitate equipment that is specifically intended to reduce high technical losses was recently finalized. For all systems, reinforcements are needed to avoid network constraints under N-1 operative conditions.

3.4 Institutional, Regulatory, and Commercial Aspects

Regional interconnection will require complex commercial and legal agreements among the Arco Norte countries. Reaching these agreements could be complicated by the diverse institutional and regulatory arrangements in the countries' electricity sectors, which in some cases limit competition and institutional and financing options for new infrastructure.

For example, in Guyana, Guyana Power and Light Inc. (GPL), a state-owned company, has a monopoly on generation (with the exception of hydroelectric generation), transmission, and distribution. GPL could develop the parts of the Arco Norte interconnection that fall within the country, although Guyana's legislation also allows for Independent Power Producers (IPPs) under Power Purchase Agreement (PPA) contracts.

In Suriname, the vertically integrated state-owned monopoly, N. V. Energiebedrijven Suriname (EBS), exists alongside other operators. EBS owns and operates Electricity Paramaribo (EPAR)**,** making it the largest electricity network in Suriname covering Paramaribo and the surrounding area. EBS also owns and operates six other systems. Suralco, a private aluminum company, owns and operates the 189 Afobaka MW hydropower plant. Suralco sells most of the electricity produced by the Afobaka plant to EBS for use on the EPAR system. Staatsolie Power Company, the state-owned oil company, owns a 98 MW thermal power plant.

In French Guiana, Électricité de France (EDF) is responsible for bulk generation, transmission, distribution, and commercialization, and acts as a single-buyer of all electricity produced by private generators. The French energy regulator (*Commission de Régulation de l'Énergie*–CRE) adjusts market conditions and prices. If needed, EDF would almost certainly build and retain ownership of a new regionally interconnected Arco Norte transmission line in French Guiana, and would act as the offtaker for any electricity that French Guiana imports.

The Brazilian electricity sector is based on a liberalized market model, and includes multiple public and private transmission, generation, and distribution companies. As a result, a wide variety of private and public companies could participate in the building, ownership, and operation of the Brazilian portion of an Arco Norte interconnection. Transmission and distribution are regulated monopolies in Brazil. There are 63 concessions, including those in Amapá and Roraima.

An assessment of commercial options and an analysis of those options are needed to give stakeholders a background for discussions of these issues during project implementation. Therefore, we recommend that the following points be included as part of any future feasibility study:

- Diagnosis and development of the required national and regional regulatory frameworks
- Identification of necessary institutional restructuring, or possible new institutions
- Necessary harmonization of operational practices
- Options for financing and paying for the interconnection
- Options for ownership and operation of the project
- Required personnel training, with regard to operation and regulation.

4

Electricity Demand Forecasts by Country

To determine the potential need for regional electricity interconnection, we first projected electricity demand for each of the five countries and states in the Arco Norte Region. In general, we forecast electricity demand as a function of GDP growth, but we also considered other expected developments in each electricity sector. For the base scenario, we used GDP projections from the International Monetary Fund (IMF) where available.[8] We also developed high and low demand scenarios, in which GDP growth is one percentage point higher or lower than the IMF's projections.

In the base scenario, peak demand and electricity sales are expected to double between 2014 and 2028—sales will increase from about 6,233 GWh to over 12,439 GWh. Demand growth will be highest in Suriname and Guyana, with average annual growth rates over 6 percent. Suriname's growth is expected to come from increased consumption at the Rosebel and Newmont gold mines. Guyana's projected consumption growth is largely due to factors other than economic growth: major new loads coming onto the grid, the interconnection of Linden (the second-largest city in Guyana), self-generators coming onto the grid, and non-technical losses converted to electricity sales.

Table 4.1 summarizes the base scenario forecasts by country.

Large investments in transmission and generation will be required to meet expected demand increases and to ensure security of supply. In Section 5, we assess electricity supply options to meet this demand.

[8] IMF projections for French Guiana were unavailable. In this case, we used data provided by EDF.

TABLE 4.1: Arco Norte Region: Power sales forecasts (Energy in GWh and Peak Demand in MW)

Year	French Guiana		Guyana		Suriname		Amapá		Roraima		TOTAL	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW
2014	900	135	737	116	1,726	230	1,871	278	1,000	149	6,233	908
2015	928	139	834	132	2,127	278	1,991	296	1,052	156	6,932	1,001
2016	956	143	867	137	2,308	302	2,085	310	1,105	164	7,322	1,056
2017	986	148	899	142	2,500	327	2,193	326	1,163	173	7,741	1,116
2018	1,017	153	1,061	168	2,678	351	2,293	341	1,224	182	8,273	1,193
2019	1,049	157	1,167	184	2,861	375	2,400	357	1,285	191	8,762	1,264
2020	1,082	162	1,279	202	2,975	390	2,514	374	1,329	198	9,180	1,325
2021	1,117	168	1,311	207	3,095	405	2,632	391	1,329	198	9,484	1,368
2022	1,153	173	1,343	212	3,222	421	2,756	409	1,329	198	9,803	1,413
2023	1,190	179	1,377	218	3,356	439	2,885	429	1,365	203	10,173	1,466
2024	1,229	184	1,414	223	3,497	457	3,019	449	1,402	208	10,562	1,521
2025	1,270	191	1,582	250	3,647	476	3,161	470	1,440	214	11,100	1,600
2026	1,312	197	1,621	256	3,806	497	3,308	491	1,479	220	11,526	1,661
2027	1,356	203	1,661	262	3,973	518	3,463	514	1,519	226	11,972	1,724
2028	1,402	210	1,701	269	4,150	541	3,625	538	1,561	232	12,439	1,790
CAGR	3.2%	3.2%	6.3%	6.3%	6.6%	6.4%	4.8%	4.8%	3.2%	3.2%	5.1%	5.0%

5 Energy Supply Options

To meet expected growth in demand, the Arco Norte region can expand generation from a variety of renewable and non-renewable sources. To develop a generation expansion plan for the Arco Norte region, we identified and evaluated candidate generation projects in each country, including renewable and non-renewable options. This section presents our methodology for evaluating candidate projects.

5.1 Supply Options for the Arco Norte Region

The Arco Norte region has remarkable unexploited hydropower potential—more than 10 GW, or more than ten times current peak demand. Most of this potential is in Guyana. International rivers such as the Corantijn River (Guyana and Suriname), the Oyapock River (French Guiana and Amapá), and the Maroni River (Suriname and French Guiana) also present considerable hydropower potential. However, generation expansion based solely on hydro would expose countries to hydrological risks, since low river flows during droughts or dry seasons would endanger continuous supply. Reserve thermal capacity could be used to mitigate this risk.

In addition to meeting demand in Guyana, French Guiana and Suriname, new hydro capacity could also be developed to increase the security of supply in the region and to export electricity to the Brazilian grid, complementing the existing Brazilian capacity which consists mostly of large hydro plants in the south.

The Arco Norte and southern Brazil have complementary hydrological seasons. As a result, rivers in the Arco Norte typically have high flows at times when rivers in southern Brazil have lower flows, and vice versa. Therefore, new large hydro plants in the Arco Norte would increase the security of supply for both the Arco Norte and the Brazilian grid.

However, more detailed and updated studies are needed to fully assess the technical and economic potential for hydropower in the Arco Norte, and its social and environmental impacts. The most recent studies of most candidate projects were completed in the 1970s or 1980s. Developments in hydro and surveying technologies and social and environmental safeguards make it necessary to update these studies. New studies may find alternative options or new technologies that could reduce costs and environmental and social impacts. For example, projects could be designed to use diversion schemes (such as tunnels and channels) to flood smaller areas, to install smaller capacity plants in a greater number of sites, or to use more efficient modern technologies (such as low-head turbines). Even so, new studies will be costly and time-consuming.

A major drawback to expanding hydro capacity is the potential for social and environmental impacts brought about by flooding and river diversions. For this study, we considered only hydro candidate projects with power densities greater than 1 MW/km^2—that is, those that would have more than one MW of installed capacity for each square kilometer flooded by the reservoir. This is a lower threshold than the standard of 4 MW/km^2 recommended by the United Nations.[9] We used this lower threshold because many of the considered projects could be re-designed using newer technologies and techniques that reduce their environmental impact. We did not want to remove these projects from future consideration.

We also considered non-conventional renewable options as candidate power projects for generation expansion. The region presents large solar photovoltaic (PV) potential, which may be adopted to replace or to complement diesel-fired generation used in isolated regions of the country, or in grid-tied projects where it is lower-cost than conventional alternatives. A small amount of wind power could be developed in coastal areas of the Arco Norte region. However, because solar PV and wind power are intermittent sources, they must be supplemented with firm sources. Biomass from the rice husk, wood chip and sugar cane bagasse produced throughout the region can provide firm power, but on a small scale and only during the harvest period.

Finally, we considered thermal candidate projects that use oil products, coal,[10] and natural gas. Fossil fuels may be least-cost in some cases, and can also help ensure security of supply, since they provide reliable firm power.

[9] ACM0002 – Large-scale Consolidated Methodology for Clean Development Mechanism (UNFCCC, 2014).

[10] In this version of the study (Component I), coal-fired thermal candidates were modeled, but no project was selected in the expansion plan. In Component II of the study, coal-fired thermal candidates will be disregarded in French Guiana and Guyana.

5.2 Candidate Projects for Electricity Generation in Guyana, Suriname, and French Guiana

Below we describe renewable and fossil fuel supply options in French Guiana, Guyana, and Suriname. We did not analyze supply options in Roraima and Amapá because transmission interconnections to the Brazilian national interconnection system (SIN) and additional generation capacity are already planned or under construction.

5.2.1 French Guiana

French Guiana's hydropower potential is concentrated mainly in candidate projects on two international rivers—the Oyapock and the Mana. The projects would have a combined capacity of 460 MW. While these are promising projects, developing the Oyapock project would require bi-national agreements.

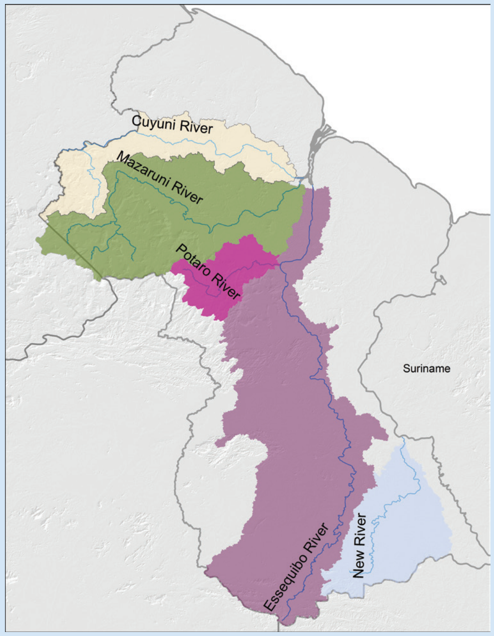
French Guiana's solar resources are significant, with irradiation levels of 2,000 kWh/m^2 per year in some places. Recent cost reductions in solar PV panels mean that solar generation may be economically viable as a substitute or complement to diesel-fired generation, both for off-grid systems in the interior of the country and in grid-tied projects. However, off-grid solar projects would also require battery storage to ensure continuous supply. Although French Guiana's wind power potential is relatively low, at 100MW, wind power may still be an interesting source to consider given its competitive levelized cost.

5.2.2 Guyana

Available information suggests that technical hydropower potential in Guyana is about 8.4 GW. In principle, the Mazaruni, Potaro, Cuyuni, and Essequibo rivers have favorable conditions for hydro development, including large drainage areas, high water flows, and good morphology—the map in Figure 5.1 shows these areas. For example, these rivers have high slopes, an unusual topographical feature that provides a large head difference. This can be seen, for example, at the abrupt transition from the highlands to the Amazon forest. The Amaila Falls project, a proposed 165 MW hydro plant along the Kuribrong River (a tributary of the Potaro River) is the hydro project in the most advanced stage in Guyana, although its development is currently stalled.

Like French Guiana, Guyana has strong solar resources, with irradiation levels of about 2000 kWh/m^2 per year in favorable areas of the country. The country's wind potential has not been well-surveyed, but there may be some potential in coastal areas. Biomass generation from sugarcane, wood chip, and rice husk could be developed, and would provide firm supply

FIGURE 5.1: Hydropower Potential in Guyana



on a small scale during the harvest period. Alternative fossil fuel sources such as coal and LNG would likely be more expensive than developing the country's large hydro potential.

5.2.3 Suriname

Although previous studies[11] identified a total technical capacity of about 3 GW for potential projects on the Corantijn, Maroni, Tapanahony, and Kabalebo rivers, one barrier to the development of these projects is the low ratio of installed capacity to flooded area (lower than 1 MW/km^2). Similarly to other hydro projects in the region, the capacity estimates and project assessments come from studies completed in the 1970s, so although updated studies might be costly and time consuming, they are the best way to identify feasible candidate projects with reduced environmental impacts.

Suriname's potential for solar and wind power resembles that of Guyana and French Guiana. Solar resources show great potential, and PV could be competitive with oil products for

[11] Norconsult A.S., Electro-Watt (1976). Feasibility Study of Hydroelectricity Development in the Western Suriname, Volume 1: The Kabalebo Hydroelectric Scheme, Appendix 1: Hydrology.

FIGURE 5.2: Hydropower Potential in Suriname

Source: Maps of the World (Map Store).

utility-scale projects or for mini-grids. Less is known about the country's wind potential, but some low-cost capacity could be developed along the coast. Biomass generation from rice husks, wood chips, and sugarcane bagasse could supplement other sources during the harvest period.

Taking into consideration the analysis of the supply options for each country, Table 5.1 presents the candidate projects that we considered for each country.

TABLE 5.1: Candidate Projects in Arco Norte

	French Guiana		Guyana		Suriname	
	MW capacity	Type of candidate projects	MW capacity	Type of candidate projects	MW capacity	Type of candidate projects
Hydro	460	2 large, binational and 2 small	8,500	33 run-of-river and reservoir hydros	260	2 new plants, 1 hydro diversion project, 1 expansion
Thermal	2,000	LNG, HFO, LFO	2,000	LNG, HFO, LFO	2,000	LNG, HFO, LFO
Other RE	390	Solar, wind, biomass	120	Wind, biomass	100	Solar, wind, biomass
Total	**2,850**		**10,620**		**2,360**	

6

Optimal Generation Expansion

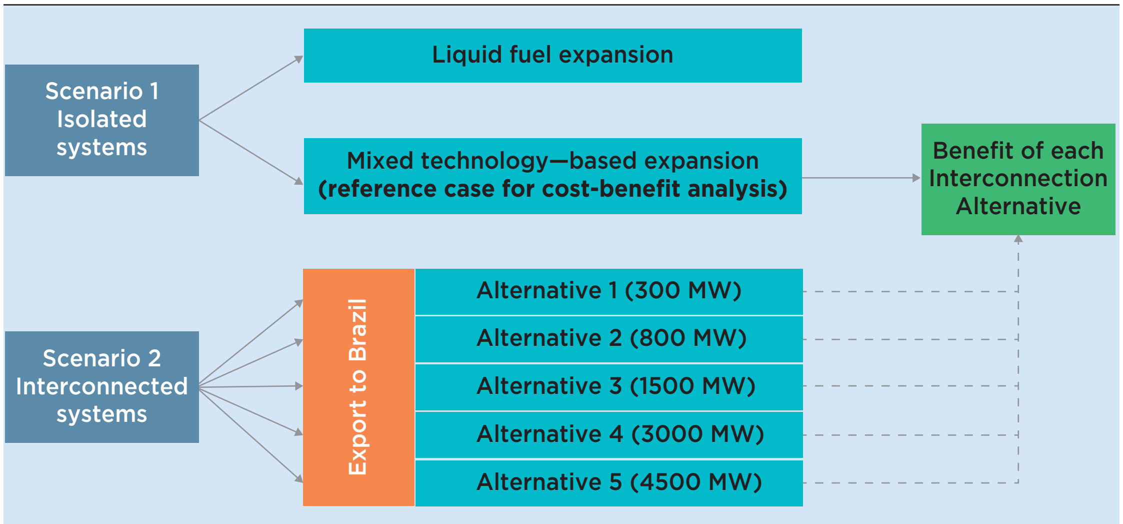
Based on the supply options and candidate projects identified in Section 5, we assessed two main generation expansion scenarios for French Guiana, Guyana, and Suriname:

- **Scenario 1: Isolated Systems**: Each country plans and builds assets to meet its own electricity demand—this is the current situation, as there is no interconnected line in the Arco Norte region. For this scenario, we identified the least-cost generation mix for each individual country. We evaluated two alternatives: a liquid fuel–based expansion, in which demand continues to be met with oil products, and a mixed-technology expansion.
- **Scenario 2: Interconnected Systems**: This scenario assumes the existence of an interconnected power system across Arco Norte countries. Therefore, the countries are able to coordinate electricity sector planning to meet the combined regional demand.[12] For this scenario, we identified the least-cost generation mix for the region as a whole, and we evaluated five levels of electricity exports to Brazil, from 300 MW to 4,500 MW.[13] In Section 7 we evaluate options and costs for building the interconnected line itself.

Figure 6.1 summarizes the two scenarios and the alternatives under each.

[12] During this baseline analysis the interconnection was treated as a single project, with all parts implemented within a timeframe. Component II of this study (Pre-Feasibility) will consider partial implementation options for the interconnection study.
[13] The levels of power included in the export contract between Arco Norte countries and Brazil were established based on the capacity of transmission options that could be built between Guyana and Roraima.

FIGURE 6.1: Generation Expansion Scenarios



6.1 Methodology

All scenarios and alternatives were based on the demand projection described in Section 4. We forecasted electricity demand for French Guiana, Guyana and Suriname for the planning horizon of 2014–2028. Then we identified a set of generation candidate projects—hydro, thermal, and non-conventional renewables—from the energy supply options discussed in Section 5. We applied simulation models to determine the optimal generation expansion to meet forecast demand. The simulation models established a temporal sequence of generation projects that minimized all-in costs—a combination of up-front capital costs (for new generation and transmission assets) and ongoing operating costs (including fuel costs, maintenance, and other non-fuel operating costs).

The candidate projects considered come from the Guyana and Suriname generation expansion plans, and are complemented with additional projects identified during the study. In Guyana and Suriname, the plans are being developed by the national electricity utilities, GPL and EBS. In French Guiana, energy sector authorities are developing a generation expansion plan through a competitive process among private generators, managed by the French regulator.

We did not project generation expansion for Brazil. The Arco Norte Project does not affect the expansion plans of the Brazilian electricity system given the project's marginal impact on that large system. The SIN has already backed a Ten-Year Energy Expansion Plan (*Plano Decenal de Expansão de Energia*—PDE), which forecasts demand and proposes new power plants and transmission lines through 2024. This plan aims for optimal system development based on electricity auctions.

For our forecasts, we used the following assumptions and approaches:

- To compare the costs of new generation and transmission assets, we evaluated the net present value (NPV) of capital costs in 2014 for the planning period 2015–2028
- We used the United States Energy Information Administration's reference fuel-price scenario from its Annual Energy Outlook 2015
- We assumed a 12 percent discount rate
- We assumed that the cost of unmet electricity demand was US$1,500 per MWh.[14]

6.2 Scenario 1: Isolated Systems

We evaluated generation costs for two alternatives in which French Guiana, Guyana, and Suriname maintain isolated electricity networks:

A. **Liquid fuel–based expansion**. For this alternative we considered only those future generation projects that would use diesel or heavy fuel oil (HFO). This reflects the status quo, in which the countries depend on diesel or HFO to meet a large share of their electricity demand.
B. **Mixed technology–based expansion**. We evaluated a wide range of generation alternatives, including hydropower, non-conventional renewables, and natural gas delivered as LNG.

The mixed technology expansion would result in lower all-in generation costs, since it allows for lower-operating-cost generation options than do oil products. All-in generation costs consist of capital plus operating costs, divided by the electricity produced by the plants. As a result, we consider this alternative the reference case for comparison with Scenario 2: Interconnected Systems.

6.2.1 Alternative A: Liquid fuel–based expansion

Table 6.1 summarizes the new HFO- and diesel-fired plants that would be needed to meet demand in French Guiana, Guyana, and Suriname.

In this alternative, total capital costs in French Guiana would be about US$53 million, which would all go toward one 52 MW HFO-fired plant. French Guiana's estimated average

[14] As per Brazil's Ten-Year Energy Expansion Plan.

TABLE 6.1: Scenario 1: Isolated Systems
(Alternative A: Liquid Fuel–Based Expansion)

Country	Entrance schedule	Name	Type	Capacity (MW)	Capital cost	
					US$/kW	Million US$
French Guiana	2018	FG_GGOC50-1	HFO	52	1008	53
	Sub-total			**52**		**53**
Guyana	2017	DP4-4	HFO	11	600	6.5
	2017	DP4-5	HFO	11	600	6.5
	2025	SKEL-DG3	DIESEL	3	600	2
	2025	GU_GGOC50-1	HFO	52	1008	53
	Sub-total			**77**		**68**
Suriname	2015	BEMLAND4	HFO	18	700	13
	2017	Paranam1	HFO	63	700	44
	2019	Paranam2	HFO	21	700	15
	2020	Paranam3	HFO	21	700	15
	2021	Paranam4	HFO	42	700	29
	2022	Paranam5	HFO	42	700	29
	2023	Paranam6	HFO	21	700	15
	2024	Paranam7	HFO	42	700	29
	Sub-total			**270**		**189**
Total				**399**		**310**

Source: Existing plans complemented with additional projects identified during the study.

generation cost[15] from 2022 to 2028[16] would be US$66 per MWh. In Guyana, total capital costs would be US$68 million, for four thermal units with a combined capacity of 77 MW. The average generation cost from 2022 to 2028 would be US$96 per MWh. Suriname would spend US$189 million to add 270 MW of eight HFO-fired plants. The average generation cost for the period 2022 to 2028 would be US$92 per MWh.

6.2.2 Alternative B: Mixed technology–based expansion

Table 6.2 lists the new power plants, capital costs, and generation costs under an isolated expansion scenario using a variety of generation technologies. In this Alternative B, total new

[15] The average generation cost is the total cost of generation in a country (operating + capital costs), divided by the total demand in that country.
[16] Year 2022 is the earliest year the interconnection project could be commissioned. Thus, we report average costs beginning in this year.

TABLE 6.2: Scenario 1: Isolated Systems
(Alternative B: Mixed Technology–Based Expansion)

Country	Entrance schedule	Name	Type	Capacity (MW)	Capital cost	
					US$/kW	Million US$
French Guiana	2019	FG_TGNL100-1	LNG	100	600	60
	2021	Mana 1B	HPP	62	2720	168
	2022	Mana 2	HPP	16	2945	47
	Sub-total			**178**		**275**
Guyana	2017	DP4-4	HFO	11	600	6.5
	2017	DP4-5	HFO	11	600	6.5
	2021	Amaila	HPP	165	3400	561
	Sub-total			**187**		**574**
Suriname	2015	BEMLAND4	HFO	18	700	13
	2017	Paranam1	HFO	63	700	44
	2019	Paranam2	HFO	21	700	15
	2020	Paranam3	HFO	21	700	15
	2021	Paranam4	HFO	42	700	29
	2022	Paranam5	HFO	42	700	29
	2023	Paranam6	HFO	21	700	15
	2024	Paranam7	HFO	42	700	29
	2024	Marowijne 1	HPP	80	3152	252
	2024	Afobaka Exp	HPP	40	1290	52
	2024	Afobaka Exp2	HPP	40	1151	46
	2024	Afobaka Exp3	HPP	40	1046	42
	2028	Marowijne 2	HPP	60	3806	228
	Sub-total			**530**		**809**
Total				**895**		**1,658**

Source: Information supplied by the countries complemented with projects proposed by the study.

installed capacity would be 895 MW, with a capital cost of US$1,658 million. In Alternative B, total capital costs in French Guiana would be US$275 million for one LNG and two hydro power plants, with a combined average generation cost of US$51 per MWh and an installed capacity of 178 MW. In Guyana, total capital costs would be US$574 million for two thermal plants and one hydropower plant with a combined capacity of 187 MW and an average generation cost of $70 per MWh. Lastly, Suriname would spend $809 million on eight HFO-fired plants and five hydropower plants. The average generation cost for Suriname would be $57 per MWh.

6.2.3 Comparing Alternative A and Alternative B

Table 6.3 shows that all countries have higher installed capacity and capital costs in Alternative B, compared to Alternative A. This is because lower operating-cost options, such as hydropower and natural gas-fired plants, are available in Alternative B and because hydro plants have to be supported by thermal capacity since low-river flows during droughts or dry seasons would risk continuous supply. Moreover, in Alternative B new plants would replace older thermal units that would otherwise remain in operation in Alternative A.

French Guiana: In French Guiana, capital costs in Alternative B, US$275 million, would be more than five times higher than in Alternative A. Installed capacity would be more than three times higher—52 MW in Alternative A, compared to 178 MW in Alternative B. However, average generation costs would be 23 percent lower, falling from US$66 per MWh in Alternative A to US$51 per MWh in Alternative B.

Guyana: The most important difference between Alternatives A and B is that a hydro plant would be built in Alternative B, coming online in 2021. This would lead to much higher capital costs—US$574 million, compared to US$68 million in Alternative A. However, it would also lead to a 27 percent reduction in average generation costs, falling from U$96 per MWh in Alternative A to US$70 per MWh in Alternative B.

Suriname: In Alternative B, the optimal expansion plan includes a 120 MW expansion of the existing Afobaka hydro station and the new 140 MW Marowijne hydropower plant, which would be built in two stages. Capital costs in Alternative B would be US$809 million, more

TABLE 6.3: Summary of Generation Expansion Results for Scenario 1: Isolated Systems

Country	Alternatives (types of fuels used in expansion plan)	MW	Capital cost (million US$)	NPV in 2014 (million US$)			Average Generation Costs (US$/MWh)
				Capital Costs	Operating Costs	Total Costs	
French Guiana	A: Liquid fuels	52	53	35	368	403	66
	B: Mixed generation	178	275	93	263	356	51
Guyana	A: Liquid fuels	77	68	17	674	691	96
	B: Mixed technology	187	574	179	300	479	70
Suriname	A: Liquid fuels	270	189	80	1,069	1,149	92
	B: Mixed technology	530	809	156	817	973	57
Total	A: Liquid fuels	399	310	132	2,111	2,243	n.a.
	B: Mixed technology	895	1,658	428	1,380	1,808	n.a.

than four times the capital costs in Alternative A. However, average generation costs would be reduced by 38 percent from US$92 per MWh in Alternative A to US$57 per MWh in Alternative B.

6.3 Scenario 2: Interconnected Systems

The potential benefits of regional interconnection are significant. Coordinating the planning and operation of electricity systems across the Arco Norte region could lead to important benefits, mainly:

1. Reduced generation costs due to greater efficiency in the choice of generation sites and larger-scale projects that could result in lower electricity prices for consumers
2. Improved security of supply due to the possibility of mutual support in the case of power shortages
3. Reduced environmental impact through the use of cleaner generation sources
4. The possibility for electricity exports to meet incremental demand in southern Brazil
5. Greater technical collaboration among neighboring nations.

In Section 8 we evaluate these potential benefits and the costs of implementing electrical interconnection in the Arco Norte region—including all costs and benefits of additional generation capacity and an interconnected electricity line.

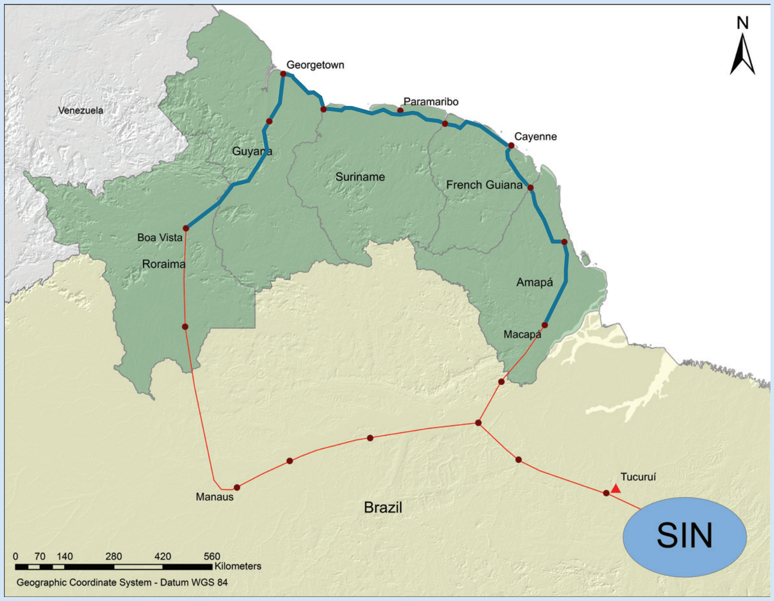
It is against this background that Scenario 2 – Interconnected Systems assumes the existence of an interconnected electricity system among the Arco Norte countries, allowing them to trade electricity—Figure 6.2 shows the path of this proposed interconnection. In addition to the possibility for trade among French Guiana, Suriname, and Guyana, the interconnection would allow these power systems to export electricity to the Brazilian Interconnected System (SIN) through Boa Vista (in Roraima) and Macapa (in Amapá).

In this scenario, we considered five alternatives:

- Alternative 1: 300 MW of electricity exports to Brazil
- Alternative 2: 800 MW of electricity exports to Brazil
- Alternative 3: 1,500 MW of electricity exports to Brazil
- Alternative 4: 3,000 MW of electricity exports to Brazil
- Alternative 5: 4,500 MW of electricity exports to Brazil.

In each alternative, we assume that electricity is exported to Brazil under a contract for firm capacity.

FIGURE 6.2: Representation of the Interconnected System in the Simulation Model



Legend:
Blue line: proposed Arco Norte Interconnection.
Red line: existing or planned Brazilian SIN.

FIGURE 6.3: Additional Installed Capacity in Each Expansion Alternative

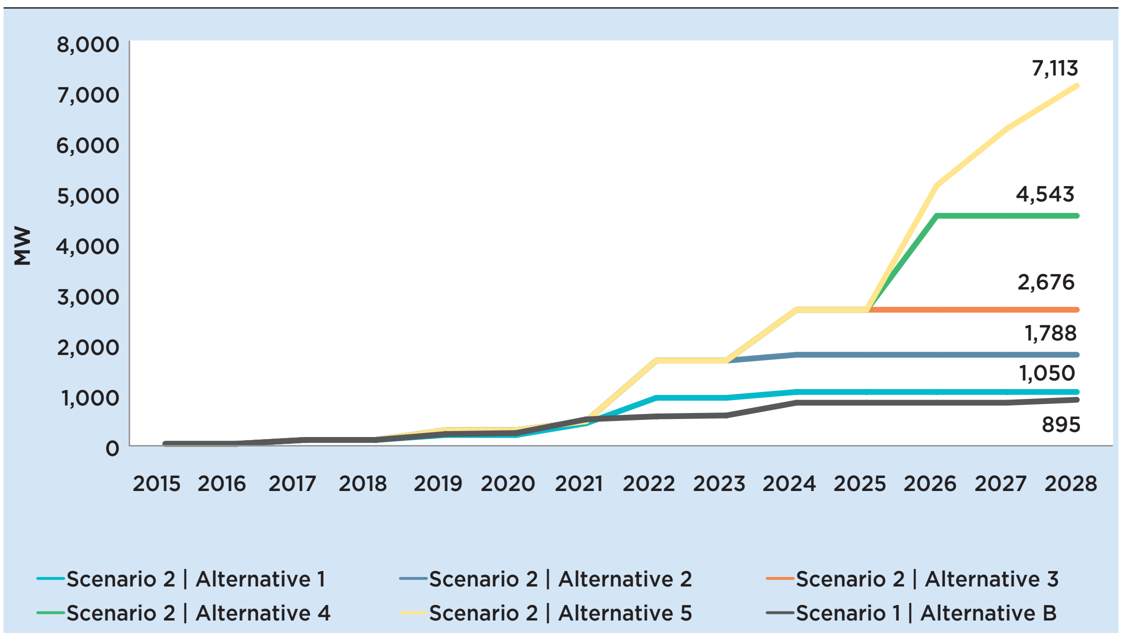


Figure 6.3 shows the increase in generation capacity during the study horizon for each interconnection alternative. It also shows the proposed increase in generation capacity for Alternative B, the reference case from Scenario 1.

Table 6.4.0 to Table 6.4.5 summarize the optimal generation expansion plan in French Guiana, Guyana, and Suriname for each interconnection alternative. The expansion plans minimize the total cost of meeting regional demand for electricity and the power export contract with Brazil.

TABLE 6.4.0: Generation Expansion Plans: Isolated Scenario

Isolated (0 MW)						
Year	Name	Type	System	Capacity (MW)	Investment Cost	
					(US$/kW)	(MUS$)
2015	BEMLAND4	HFO	SR	18	700	13
2017	Paranam1	HFO	SR	63	700	44
2017	DP4-4	HFO	GU	11	600	7
2017	DP4-5	HFO	GU	11	600	7
2019	Paranam2	HFO	SR	21	700	15
2019	FG_TGNL100-1	LNG	FG	100	600	60
2020	Paranam3	HFO	SR	21	700	15
2021	Paranam4	HFO	SR	42	42	29
2021	Amaila	HPP	GU	165	3400	561
2021	Mana 1B	HPP	FG	62	2720	168
2022	Paranam5	HFO	SR	42	700	29
2022	Mana 2	HPP	FG	16	2945	47
2023	Paranam6	HFO	SR	21	700	15
2024	Paranam7	HFO	SR	42	700	29
2024	Marowijne 1	HPP	SR	80	3152	252
2024	Afobaka Exp	HPP	SR	40	1290	52
2024	Afobaka Exp2	HPP	SR	40	1151	46
2024	Afobaka Exp3	HPP	SR	40	1046	42
2028	Marowijne 2	HPP	SR	60	3806	228
Total				895	n.a.	1,658
Sub-totals:		HFO		292		
		LNG		100		
		HPP		503		

TABLE 6.4.1: Generation Expansion Plans: Alternative 1

Alternative 1 (300 MW)						
Year	Name	Type	System	Capacity (MW)	Investment Cost	
					(US$/kW)	(MUS$)
2015	BEMLAND4	HFO	SR	18	700	13
2017	Paranam1	HFO	SR	63	700	44
2017	DP4-4	HFO	GU	11	600	7
2017	DP4-5	HFO	GU	11	600	7
2019	FG_TGNL100-1	LNG	FG	100	600	60
2021	Mana 1B	HPP	FG	62	2,700	167
2021	Amaila	HPP	GU	165	3,400	561
2022	Turtruba Fir	HPP	GU	500	1,752	876
2024	Afobaka Exp	HPP	SR	40	1,290	52
2024	Afobaka Exp2	HPP	SR	40	1,151	46
2024	Afobaka Exp3	HPP	SR	40	1,046	42
Total				**1,050**	**n.a.**	**1,875**
Sub-totals:		HFO		103		
		LNG		100		
		HPP		847		

TABLE 6.4.2: Generation Expansion Plans: Alternative 2

Alternative 2 (800 MW)						
Year	Name	Type	System	Capacity (MW)	Investment Cost	
					(US$/kW)	(MUS$)
2015	BEMLAND4	HFO	SR	18	700	13
2017	Paranam1	HFO	SR	63	700	44
2017	DP4-4	HFO	GU	11	600	7
2017	DP4-5	HFO	GU	11	600	7
2019	FG_TGNL100-1	LNG	FG	100	600	60
2019	SR_TGNL100-1	LNG	SR	100	600	60
2021	Amaila	HPP	GU	165	3,400	561
2022	Sand Landing	HPP	GU	600	3,303	1,982
2022	Sand Landin2	HPP	GU	600	1,209	725
2024	Afobaka Exp	HPP	SR	40	1,290	52
2024	Afobaka Exp2	HPP	SR	40	1,151	46
2024	Afobaka Exp3	HPP	SR	40	1,046	42
Total				**1,788**	**n.a.**	**3,597**
Sub-totals:		HFO		103		
		LNG		200		
		HPP		1,485		

Note: The presented expansion plans are indicative. Some variation in these plans may occur as the solutions identified by the expansion model include some alternative optimal solutions with the same total capital and operating costs (considering the assumed convergence tolerance for system optimization).

TABLE 6.4.3: Generation Expansion Plans: Alternative 3

Alternative 3 (1,500 MW)						
Year	Name	Type	System	Capacity (MW)	Investment Cost	
					(US$/kW)	(MUS$)
2015	BEMLAND4	HFO	SR	18	700	13
2017	Paranam1	HFO	SR	63	700	44
2017	DP4-4	HFO	GU	11	600	7
2017	DP4-5	HFO	GU	11	600	7
2019	FG_TGNL100-1	LNG	FG	100	600	60
2019	SR_TGNL100-1	LNG	SR	100	600	60
2021	Amaila	HPP	GU	165	3,400	561
2022	Sand Landing	HPP	GU	600	3,303	1,982
2022	Sand Landin2	HPP	GU	600	1,209	725
2024	Afobaka Exp	HPP	SR	40	1,290	52
2024	Afobaka Exp2	HPP	SR	40	1,151	46
2024	Afobaka Exp3	HPP	SR	40	1,046	42
2024	Aruwai	HPP	GU	888	1,490	1,323
Total				**2,676**	**n.a.**	**4,921**
Sub-totals:		HFO		103		
		LNG		200		
		HPP		2,373		

TABLE 6.4.4: Generation Expansion Plans: Alternative 4

Alternative 4 (3,000 MW)						
Year	Name	Type	System	Capacity (MW)	Investment Cost	
					(US$/kW)	(MUS$)
2015	BEMLAND4	HFO	SR	18	700	13
2017	Paranam1	HFO	SR	63	700	44
2017	DP4-4	HFO	GU	11	600	7
2017	DP4-5	HFO	GU	11	600	7
2019	FG_TGNL100-1	LNG	FG	100	600	60
2019	SR_TGNL100-1	LNG	SR	100	600	60
2021	Amaila	HPP	GU	165	3,400	561
2022	Sand Landing	HPP	GU	1200	3,303	1,982
2022	Sand Landin2	HPP	GU	0	1,209	725
2024	Afobaka Exp	HPP	SR	120	1,290	52
2024	Afobaka Exp2	HPP	SR	0	1,151	46
2024	Afobaka Exp3	HPP	SR	0	1,046	42
2024	Aruwai	HPP	GU	888	1,490	1,323
2026	Mana 1B	HPP	FG	62	2,700	167
2026	Mana 2	HPP	FG	16	2,900	46
2026	Turtruba Fir	HPP	GU	500	1,752	876
2026	Kaieteur	HPP	GU	540	2,285	1,234
2026	Chitigokeng	HPP	GU	658	1,713	1,127
2026	Sakaika	HPP	GU	91	2,569	234
Total				**4,543**	**n.a.**	**8,606**
Sub-totals:		HFO		103		
		LNG		200		
		HPP		4,240		

TABLE 6.4.5: Generation Expansion Plans: Alternative 5

Alternative 5 (4,500 MW)						
Year	Name	Type	System	Capacity (MW)	Investment Cost	
					(US$/kW)	(MUS$)
2015	BEMLAND4	HFO	SR	18	700	13
2017	Paranam1	HFO	SR	63	700	44
2017	DP4-4	HFO	GU	11	600	7
2017	DP4-5	HFO	GU	11	600	7
2019	FG_TGNL100-1	LNG	FG	100	600	60
2019	SR_TGNL100-1	LNG	SR	100	600	60
2021	Amaila	HPP	GU	165	3,400	561
2022	Sand Landing	HPP	GU	600	3,303	1,982
2022	Sand Landin2	HPP	GU	600	1,209	725
2024	Afobaka Exp	HPP	SR	40	1,290	52
2024	Afobaka Exp2	HPP	SR	40	1,151	46
2024	Afobaka Exp3	HPP	SR	40	1,046	42
2024	Aruwai	HPP	GU	888	1,490	1,323
2026	Mana 1B	HPP	FG	62	2,700	167
2026	Mana 2	HPP	FG	16	2,900	46
2026	Turtruba	HPP	GU	1100	1,954	2,149
2026	Kaieteur	HPP	GU	540	2,285	1,234
2026	Chitigokeng	HPP	GU	658	1,713	1,127
2026	Sakaika	HPP	GU	91	2,569	234
2027	OyapockPlan1	HPP	FG	190	2,600	494
2027	Marowijne 2	HPP	SR	60	3,806	228
2027	Tumatumari	HPP	GU	152	2,594	394
2027	Peaima	HPP	GU	105	3,523	370
2027	Chi-Chi Div	HPP	GU	605	2,555	1546
2028	SR_TGNL100-2	LNG	SR	100	600	60
2028	OyapockPlan2	HPP	FG	190	1,400	266
2028	KgGeorge V	HPP	GU	222	2,751	611
2028	Manarowa	HPP	GU	346	2,219	768
Total				**7,113**	**n.a.**	**14,615**
Sub-totals:		HFO		103		
		LNG		300		
		HPP		6,710		

6.3.1 Alternative 1 (300 MW electricity exports to Brazil)

The main difference between Alternative 1 and the reference case for isolated systems (Alternative B) is that Guyana would build the first stage of the Turtruba Hydro Plant (500 MW) in 2022. The Turtruba plant would provide enough power to meet export demand from Brazil (300 MW), and would also replace thermal production in the region. For example, six of Suriname's planned HFO-fired Paranam plants (Paranam 2 through Paranam 7) would not be needed. Instead, Suriname would import electricity from Guyana to meet this demand.

The total investment cost for Alternative 1 would be US$1.9 billion. The net present value in 2014 of these investments is US$551 million (for the 2014–2028 planning period). In this interconnection scenario, the average generation cost for Guyana, French Guiana, and Suriname for the period 2022–2028 would be US$41 per MWh.

Figure 6.4 shows the peak load and installed capacity by plant under Alternative 1.

Figure 6.5 illustrates the energy exchanges estimated for 2028 in the Arco Norte region under Alternative 1. Guyana accounts for nearly all electricity exports, largely to Brazil through Roraima.

FIGURE 6.4: Installed Capacity and Peak Load in Alternative 1 (300 MW of Exports)

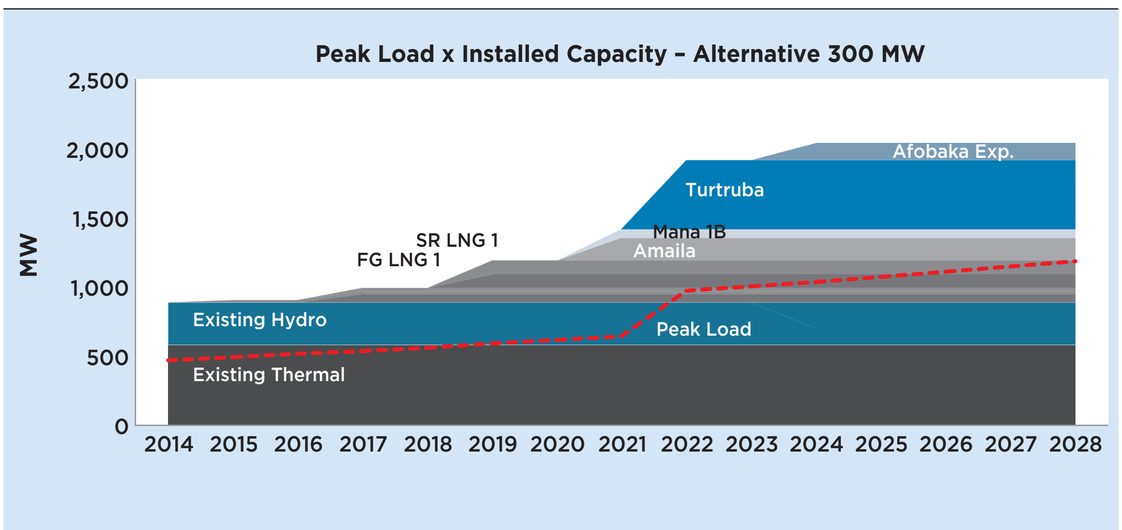
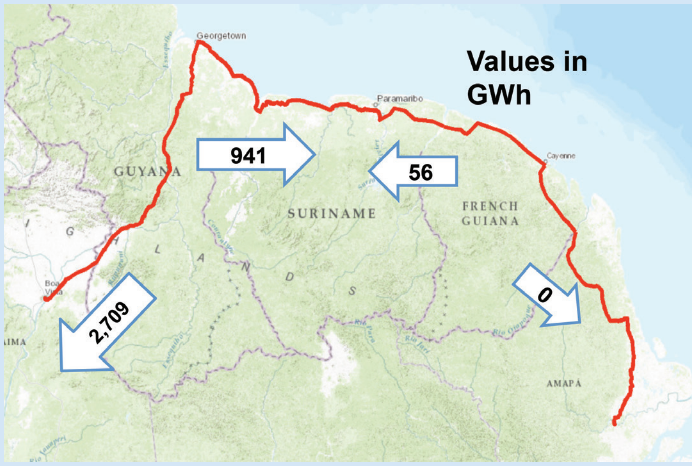


FIGURE 6.5: Energy Exchange in 2028 in Alternative 1 (300 MW)



6.3.2 Alternative 2 (800 MW electricity to Brazil)

The main difference between Alternative 2 and Alternative 1 is that in 2022 the Sand Landing Hydro Plant (1,200 MW) would be built, instead of the first stage of Turtruba (500 MW). Sand Landing's higher capacity would allow it to meet additional export requirements to Brazil.

The total capital cost of the assets for Alternative 2 would be US$3.6 billion. The net present value in 2014 of these assets is US$1 billion (for the 2014–2028 planning period). The average generation cost for Guyana, French Guiana, and Suriname for the period 2022–2028 would be US$43 per MWh.

Figure 6.6 shows the peak load and installed capacity by plant under Alternative 2.

Figure 6.7 illustrates the energy exchanges estimated for 2028 in the Arco Norte Region under Alternative 2. Guyana accounts for over 9,000 GWh of electricity exports, largely to Brazil through Roraima.

FIGURE 6.6: Installed Capacity and Peak Load in Alternative 2 (800 MW of Exports)

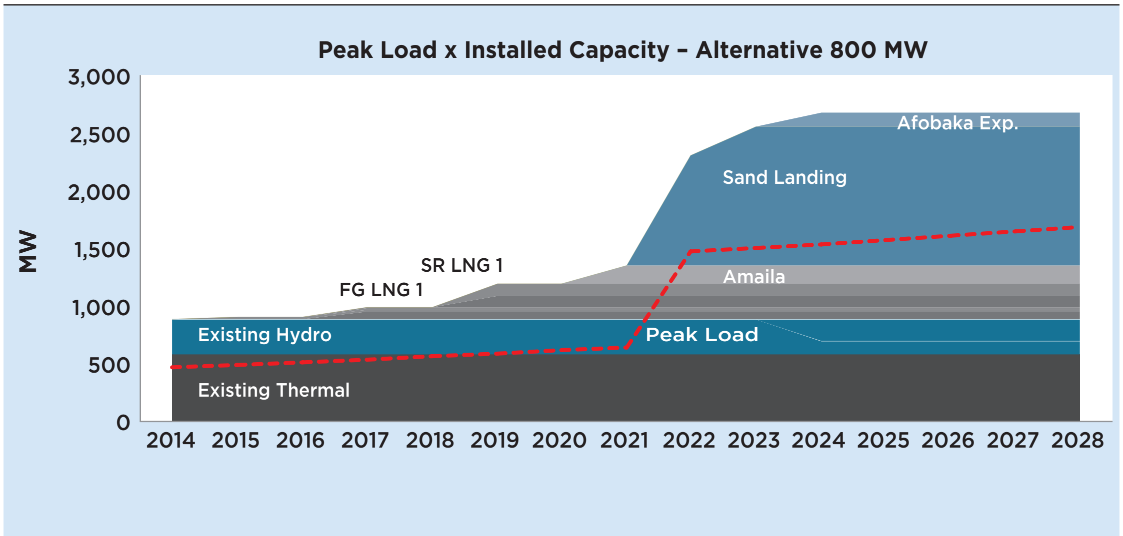
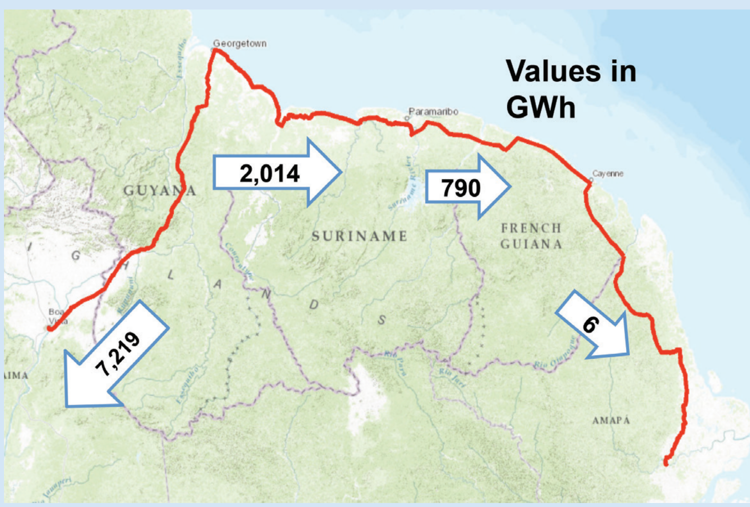


FIGURE 6.7: Energy Exchange in 2028 in Alternative 2 (800 MW)



6.3.3 Alternative 3 (1,500 MW electricity exports to Brazil)

The main difference between Alternatives 2 and 3 is the inclusion of Aruwai HPP (888 MW) in the generation expansion plan to meet additional demand from Brazil. The total capital cost of the assets for Alternative 3 would be US$4.9 billion. The net present value in 2014 of these assets is US$1.2 billion (for the 2014–2028 planning period). The average generation cost for Guyana, French Guiana, and Suriname for the period 2022–2028 would be US$41 per MWh.

Figure 6.8 shows the peak load and installed capacity by plant under Alternative 3.

Figure 6.9 illustrates the energy exchanges estimated for 2028 in the Arco Norte Region under Alternative 3. Guyana accounts for over 15,000 GWh of electricity exports, largely to Brazil through Roraima.

FIGURE 6.8: Installed Capacity and Peak Load in Alternative 3 (1,500 MW of Exports)

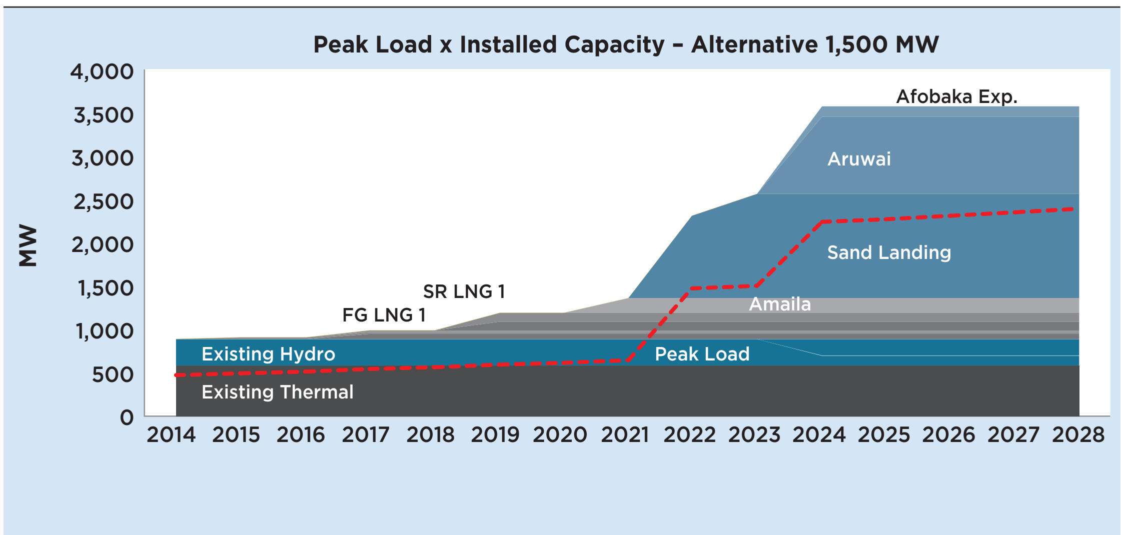
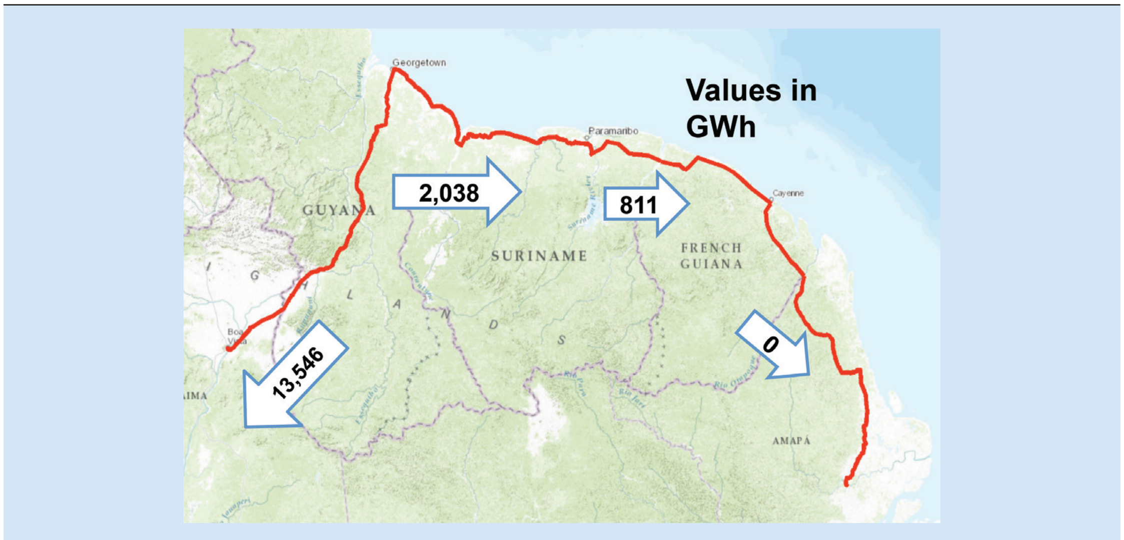


FIGURE 6.9: Energy Exchange in (2028) in Alternative 3 (1,500 MW)



6.3.4 Alternative 4 (3,000 MW electricity exports to Brazil)

In addition to the generation plants from Alternative 3, Alternative 4 would include:

- Two hydro projects in French Guiana—Mana 1B (62 MW) and Mana 2 (16 MW) commissioned in 2026.
- Four hydro projects in Guyana—Turtruba First Stage (500 MW), Kaieteur (540 MW), Chitigokeng (658 MW), and Sakaika (91 MW), all commissioned in 2026.

The total capital cost of the assets for Alternative 4 would be US$8.6 billion. The net present value in 2014 of these assets is US$1.6 billion (for the 2014–2028 planning period). The average generation cost for Guyana, French Guiana, and Suriname for the period 2022–2028 would be US$42 per MWh.

Figure 6.10 shows the peak load and installed capacity by plant under Alternative 4.

Figure 6.11 illustrates the energy exchanges estimated for 2028 in the Arco Norte Region under Alternative 4. Guyana would export 27,003 GWh of electricity directly to Brazil, and 1,143 GWh to the rest of the Arco Norte region.

FIGURE 6.10: Installed Capacity and Peak Load in Alternative 4 (3,000 MW of Exports)

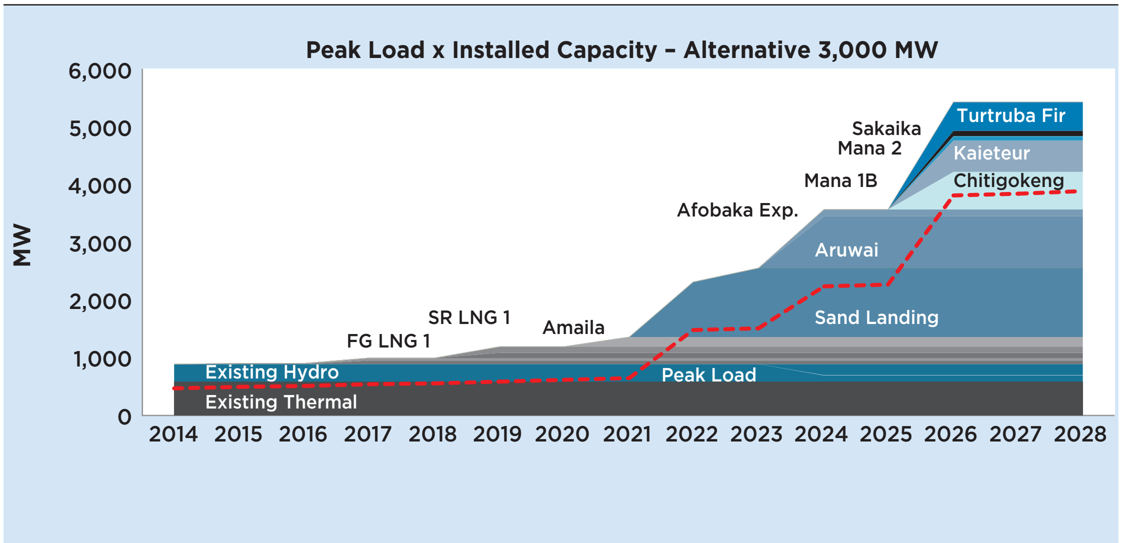
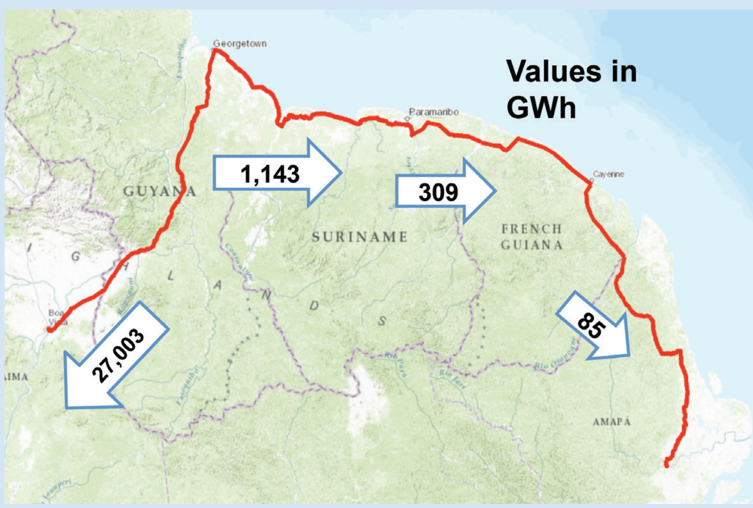


FIGURE 6.11: Energy Exchange in 2028 in Alternative 4 (3,000 MW)



6.3.5 Alternative 5 (4,500 MW electricity exports to Brazil)

In addition to the generation plants from Alternative 4, Alternative 5 would include:

- Seven new hydro projects in Guyana
  - Four of these would be commissioned in 2027: Chi-Chi Diversion (605 MW), Peaima (105 MW), Sakaika (91 MW) and Tumatumari (152 MW)
  - Two of these would be commissioned in 2028: King George (222 MW) and Manarowa (346 MW)
- Two new projects in Suriname
  - Marowijne 2, a 60 MW hydro plant commissioned in 2027
  - A 100 MW natural gas-fired plant commissioned in 2028
- One new hydro plant on the border of French Guiana and Brazil—consisting of two 190 MW Oyapock projects, which would come online in 2027 and 2028.[17]

The total capital cost of the assets for Alternative 5 would be US$14.6 billion. The net present value in 2014 of these assets is US$1.9 billion (for the 2014–2028 planning period). The average generation cost for Guyana, French Guiana, and Suriname for the period 2022–2028 would be US$46 per MWh.

Figure 6.12 shows the peak load and installed capacity by plant under Alternative 5.

Figure 6.13 illustrates the energy exchanges estimated for 2028 in the Arco Norte Region under Alternative 5. Guyana would export 38,282 GWh of electricity to Brazil, while French Guiana would export 2,352 GWh. Suriname would become a net exporter for the first time. Levels of electricity trading within Arco Norte would be lower.

[17] In the bi-national (French Guiana and Brazil) Oyapock project (2×190 MW), half of the power is in 50 Hz and half in 60 Hz.

FIGURE 6.12: Installed Capacity and Peak Load in Alternative 5 (4,500 MW of Exports)

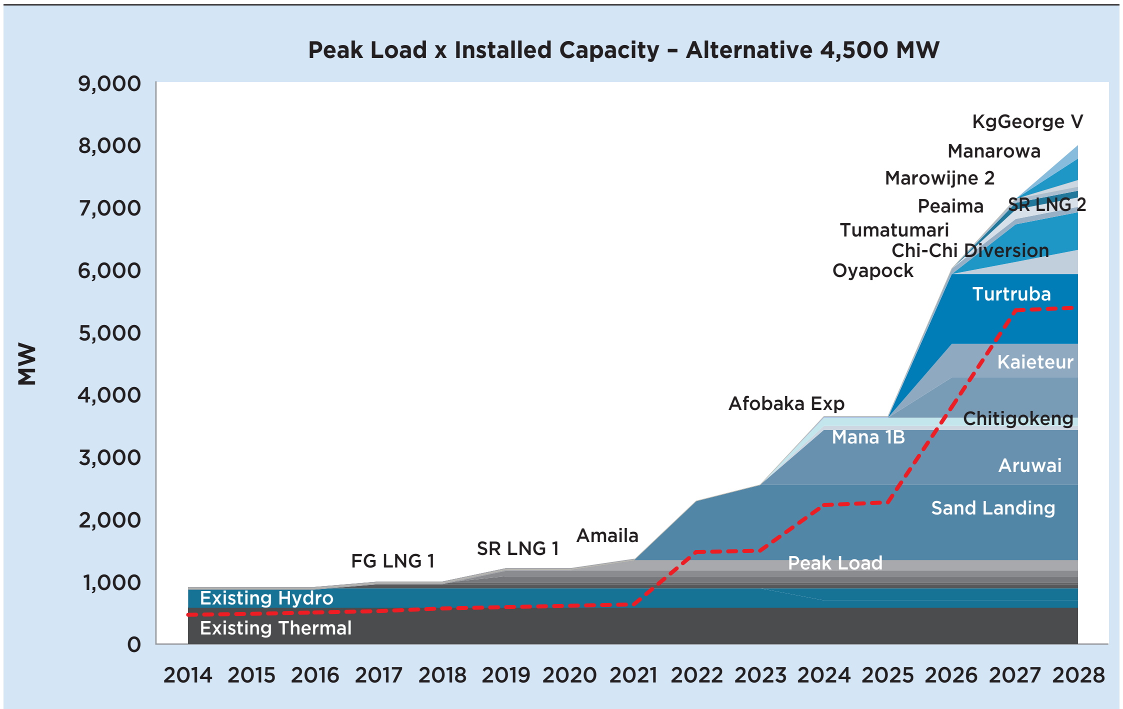
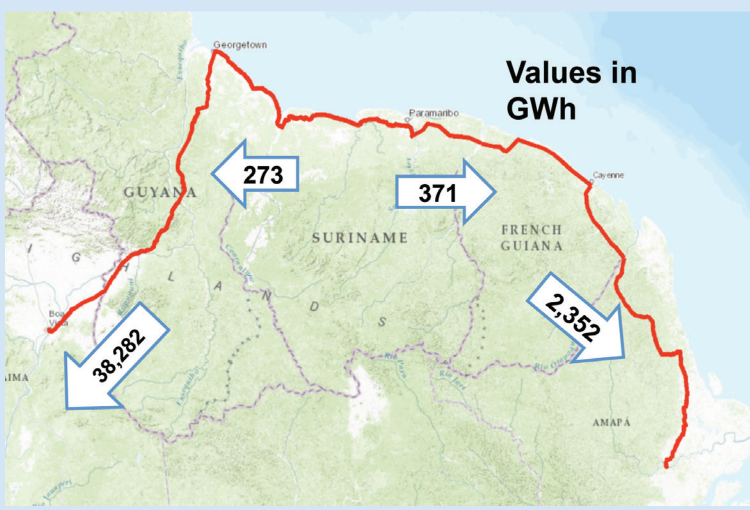


FIGURE 6.13: Energy Exchange in 2028 in Alternative 5 (4,500 MW)



The capital costs obtained for Scenario 2: Interconnected Systems are summarized in Table 6.6. and the comparison of the average generation costs is presented in Table 6.7.

All five interconnection alternatives could lead to a substantial reduction in the cost of electricity generation for all three countries, compared to Scenario 1—Alternative B (see Table 6.7). Cost reductions would range from US$29 per MWh for Alternatives 1 and 3 in Guyana, to US$5 per MWh for Alternative 5 in French Guiana. However, these estimates do not include the costs of the international transmission links needed to implement Scenario 2. Section 7 presents potential pathways for the interconnection, and costs for each option.

Guyana, with most of the hydropower potential in the region, would become a net electricity exporter in all scenarios, reaching about 38,000 GWh in Alternative 5. French Guiana would be a net importer in most alternatives, only turning into a net exporter in Alternatives 1 and 5. Suriname would import electricity in all alternatives except for Alternative 5. Table 6.8 below shows the net energy exchange among the four Arco Norte countries for each interconnection alternative at the horizon year (2028). These results show that reduced generation costs across the region would be due to trading among Arco Norte countries, allowing for the most efficient generation assets to be used at the regional level, and the increased scale of a regional market.

TABLE 6.6: Generation Costs in Scenario 2: Interconnected Systems

Alternative	CAPEX (US$ million)	NPV of capital costs 2014–2028 (US$ million)	NPV of operating costs 2014–2028 (US$ million)	NPV of total costs 2014–2028 (US$ million)	Average generation cost 2022–28 (US$ million)
1 (300 MW)	1,875	551	1,254	1,805	41
2 (800 MW)	3,597	1,003	1,217	2,220	43
3 (1,500 MW)	4,921	1,244	1,209	2,453	41
4 (3,000 MW)	8,606	1,563	1,217	2,780	42
5 (4,500 MW)	14,615	1,897	1,306	3,203	46

TABLE 6.7: Average Generation Cost in Scenario 1 vs. Scenario 2 (2022–2028)

Scenario 2: Alternative	Scenario 2: Average gen cost	Average gen cost in Scenario 1—Alternative B (US$/MWh)		
(MW exports)	(US$/MWh)	French Guiana	Guyana	Suriname
1 (300)	41			
2 (800)	43			
3 (1,500)	41	51	70	57
4 (3,000)	42			
5 (4,500)	46			

TABLE 6.8: Energy Exchange Potential (GWh) in 2028

Alternative	Net electricity exports (exports-imports) in 2028 (GWh)			
	Guyana	Suriname	French Guiana	Brazil
1 (300 MW)	3,650	−997	56	−2,709
2 (800 MW)	9,233	−1,223	−785	−7,225
3 (1,500 MW)	15,585	−1,228	−811	−13,546
4 (3,000 MW)	28,146	−834	−224	−27,088
5 (4,500 MW)	38,010	644	1981	−40,634

6.4 Environmental and Social Impact of Generation Expansion Plans

The largest potential environmental and social impacts from generation expansion would come from new hydropower plants. To rate the impact of each alternative, we estimated an impact indicator for each hydroelectric power plant included in the generation expansion plans. Each plant's indicator was made up of a combination of nine factors:

1. Power density—the ratio of installed capacity to flooded area (MW/km^2)
2. Reservoir surface area
3. Biomass flooded—an assessment of the types of vegetation in the reservoir area
4. Length of river impounded by the reservoir
5. Length of river left dry due to water diversion
6. Likelihood of reservoir stratification—when deeper parts of the reservoir lose oxygen and become stagnant, making them unsuitable for aquatic life
7. Length of access roads built through forests
8. People displaced by the project
9. Critical natural habitats affected.

For each alternative in Scenario 2, we summed the indicators for each plant that would come online. The result was a single indicator of the combined adverse impact per MW installed for each alternative. The purpose of the index is only to compare impacts across alternatives; it does not provide an objective assessment of the environmental and social impacts of the alternatives. The higher the value of the indicator, the greater the environmental and social impacts caused by the expansion program. This methodology did not contemplate the climate impacts from CO_2 emissions from thermal plants; Component II of the study will include this analysis.

TABLE 6.9: Project Alternatives: Environmental Impact Indicators (Points/MW)

Alternative	Social and environmental impact index (per MW)
1 (300 MW)	2.12
2 (800 MW)	1.04
3 (1500 MW)	0.74
4 (3000 MW)	1.05
5 (4500 MW)	1.08

Table 6.9 summarizes the results. Alternative 3 would have the lowest potential environmental and social impact (0.74 per MW of installed capacity). Alternatives 2, 4 and 5 have similar results—between 1.04 and 1.08 per MW of installed capacity. Alternative 1 would have the greatest environmental impact (2.12 per MW of installed capacity).

Some of the largest proposed hydropower plants, whose size makes them central to the regional interconnection scheme, would also have the largest socio-environmental impact. This could make it costly and time-consuming to obtain permits for these projects. For example, the proposed Sand Landing Hydro Plant in Guyana would create a large reservoir, and would therefore require a large resettlement. The Tapajai Plant in Suriname and associated diversion schemes would change water flows downstream, with direct effects on the ecosystem and on indigenous communities. Another example is the proposed Kaieteur Plant in Guyana, which would be located in a protected area, and would also affect a popular tourist site in the country.

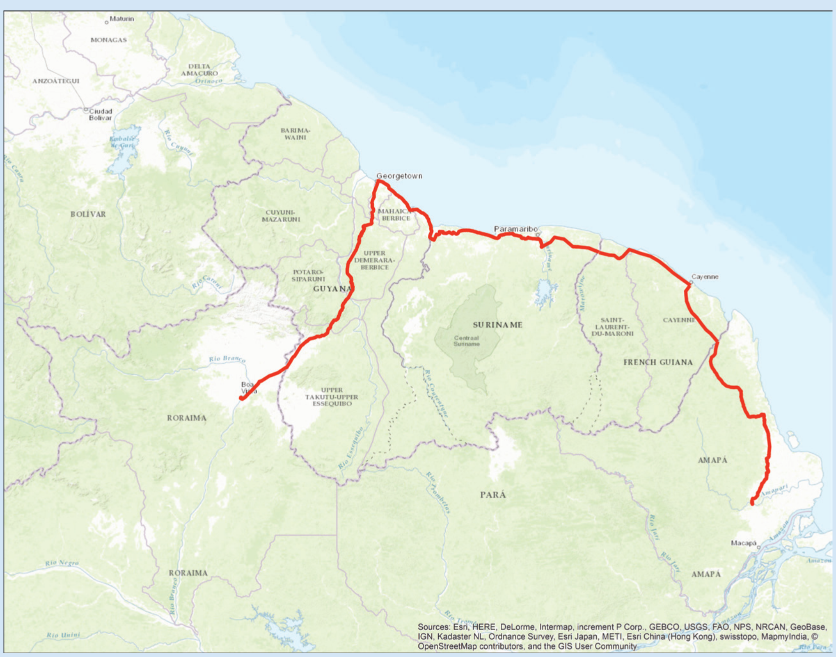
However, because the most recent feasibility studies for most of the proposed hydro projects are decades old, they may not accurately reflect the impacts if the projects were to be developed today. For example, modern technologies such as the low-head turbines used in recent projects built on the Madeira River in Brazil could reduce reservoir sizes and increase power density. In addition, the old studies do not consider modern environmental and emissions standards. As previously mentioned, Component II will include an analysis of CO_2 emissions for the isolated and interconnected scenarios.

7

Interconnection Alternatives and Costs

Electricity interconnection in the Arco Norte region would span over 1,900 kilometers (see Figure 7.1). Options for building this interconnected line—including roads and other associated infrastructure in addition to the transmission lines themselves—are constrained by technical requirements and social and environmental impacts. Technically, an interconnected network must integrate with the existing networks in the Arco Norte countries. It must also connect to

FIGURE 7.1: Proposed Path of the Arco Norte Electricity Interconnection



Source: ESRI, HERE, DeLorme, Intermap, IncrementP. Corp, GEBCO, GeoBase, OpenStreetMap the national load centers, which are mainly concentrated in the capital cities along the coast. In order to minimize the environmental impacts and the need for vegetation removal, the study prioritized existing roads when establishing the route of the transmission lines. Moreover, whenever possible the study also avoided crossing indigenous lands and natural protected areas.

These constraints mean that there are relatively few options for building interconnected infrastructure. In the most likely interconnection scenario for the Arco Norte, transmission lines and substations would be needed in:

1. Boa Vista (Brazil) – Skeldon (Guyana)
2. Skeldon (Guyana) – Saint Laurent du Maroni (French Guiana) via Menckendam (Suriname)
3. Saint Laurent du Maroni (French Guiana) – Saint Georges (French Guiana)
4. Saint Georges (French Guiana) – Ferreira Gomes (Brazil).

We describe each of these corridors in the following sections.

7.1 Boa Vista (Brazil) – Skeldon (Guyana)

Figure 7.2 shows that the proposed transmission line from Boa Vista in Brazil to Skeldon in Guyana would follow the 401 Road from Boa Vista up to the Guyana border. From there, it would run along the road to Linden until it reached the Demerara River, where it would continue along the Soesdyke Linden Highway. The line would next either follow the East Bank Public Road to Sophia (alternative A) or Garden of Eden (alternative B). Finally, the line would follow the coastal road to Skeldon, crossing the Berbice River in New Amsterdam.

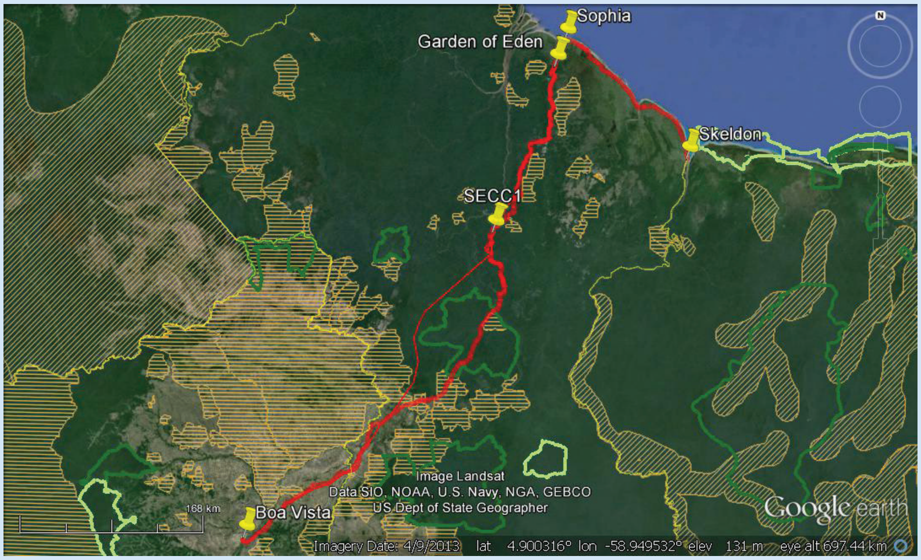
The route would cross a number of environmentally and socially sensitive areas:

- Iwokrama Forest, a legally protected area in Guyana
- Three Amerindian areas in Guyana
- The vicinity of an indigenous area in Roraima state.

However, because the route follows an existing road (BR 401) up to the Brazilian border, and then follows the Linden Lethem road (an unpaved road that also crosses Iwokrama Forest), the need to remove vegetation would be minimized.

Avoiding protected areas and indigenous areas, the deviation shown by a thinner red line in Figure 7.2, would not change the length of the line. However, this alternative would require more vegetation removal, as it does not follow an existing road. The alternative route, like

FIGURE 7.2: Boa Vista (Brazil) – Skeldon (Guyana)



Horizontal hatch: officially recognized indigenous areas.
Diagonal hatch: traditional occupation and use areas (not officially recognized).
Green line: protected and sustainable use conservation areas.
Red line: proposed transmission line (thinner line for deviation from the original route).

most of Guyana's territory, is covered by forest and has very low population density. As a result, new access roads would have to be built to construct the transmission line.

While indigenous areas and protected areas are sensitive, infrastructure development that crosses them can be approved. In Brazil, several recently built transmission lines cross indigenous and protected areas, in cases where it was proven that avoiding these areas would make those lines unfeasible. In cases like these, self-supporting transmission lines installed above the canopy are compulsory, and permanent road access is not allowed. Further, consultation with indigenous people is required before a project can be approved, and they must receive some of the project's economic benefits.

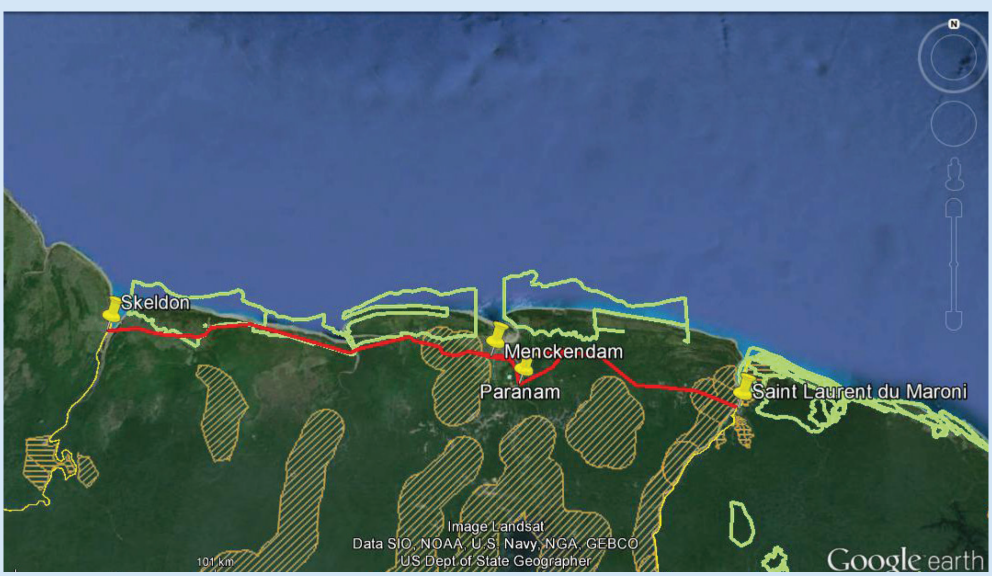
For the Boa Vista to Skeldon line, large resettlement is not expected to be necessary, since there are no large settlements along the roads in forested areas. Therefore, we recommend that the line from Boa Vista to Sophia (or to Garden of Eden) follow the existing roads. To move forward with this line, the Guyanese Environmental Protection Agency would need to be consulted about the feasibility of constructing a transmission line in the Iwokrama Forest. Initial consultations with the Brazilian FUNAI (*Fundação Nacional do* Índio—National Foundation of the Indian), the foundation for indigenous people, and representatives of potentially affected Amerindian communities are also needed.

From Roraima (Boa Vista) to Guyana, we considered a corridor up to the proposed SECC1 substation, where future large hydroelectric power plants in Guyana could be connected. In Guyana, we compared two corridors from the SECC1 substation. The first, the Sophia substation, would end closer to Georgetown, where most of the national load is concentrated. The second would end in the south and pass through Garden of Eden, where an important thermal power plant is installed. Both corridors continue towards the Skeldon area at the border with Suriname. The corridor passing through Sophia is the most appropriate, since no internal reinforcements would be needed and because losses would be lower, compared with injecting power in Garden of Eden.

7.2 Skeldon (Guyana) – Saint Laurent du Maroni (French Guiana) via Menckendam (Suriname)

The line from Skeldon, Guyana to Saint Laurent du Maroni, French Guiana would pass through Menckendam in Suriname (see Figure 7.3). From the Skeldon substation, the line would follow

FIGURE 7.3: Skeldon (Guyana) – Saint Laurent du Maroni (French Guiana) via Menckendam (Suriname)



Horizontal hatch: officially recognized indigenous areas.
Diagonal hatch: traditional occupation and use areas (not officially recognized).
Green line: protected and sustainable use conservation areas.
Red line: proposed transmission line (thinner line for deviation from the original route).

the coastal road, crossing the Berbice River in New Amsterdam, and then the Corantijn River at the border of Guyana and Suriname. Finally, the line would cross the Maroni River to reach the substation in Saint Laurent du Maroni.

The line would cross two indigenous areas in Suriname that are not officially recognized. However, the route follows an existing road, the coastal East–West Road that also crosses those areas. Therefore, we recommend that the line follow the existing road. Still, it is necessary to consult the relevant permitting agencies in Suriname about the route's feasibility.

In Suriname we considered two corridors for the transmission line. The first would pass through the meshed area close to Paramaribo (the Menckendam substation). The second, farther south, would lead to the Paranam substation between Menckendam and Afobaka. Both corridors would continue towards Saint Laurent du Maroni, at the border of Suriname and French Guiana. The corridor that includes Menckendam is more appropriate, since only small internal reinforcements at 33 kV would be needed, compared to the larger reinforcements of the 161 kV corridor that would be needed to inject power in Paranam. Moreover, power injections in Menckendam produce lower additional losses compared to power injections in Paranam.

7.3 Saint Laurent du Maroni (French Guiana) – Saint Georges (French Guiana)

Within French Guiana, the transmission interconnection would follow an existing road, crossing the Mana, Iracoubo, Counamama and Sinnamary Rivers (see Figure 7.4). It would connect to the existing high-voltage network through a substation in Kourou or Malouin, and through another substation in Saint Georges. The route would border some protected areas in French Guiana. However, the fact that the route follows an existing road would minimize the need for vegetation removal. Further, sustainable development is permitted in these areas.

The corridor from Saint Laurent du Maroni would either connect through the intermediate substation in Kourou (close to the Petit Saut Hydro Plant) or through the Malouin substation (close to Cayenne, the main load center in French Guiana). The corridor would arrive in a new substation in Saint Georges, on the border between French Guiana and Amapá (Brazil).

The connection through Malouin is the most appropriate, since no internal reinforcements are needed and the losses are lower compared with the alternative route through Kourou. We defined only one corridor for interconnection between French Guiana and Amapá, following the only existing road between Saint Georges and Ferreira Gomez.

FIGURE 7.4: Saint Laurent du Maroni (French Guiana) – Saint Georges (French Guiana)

Horizontal hatch: officially recognized indigenous areas.
Diagonal hatch: traditional occupation and use areas (not officially recognized).
Green line: protected and sustainable use conservation areas.
Red line: proposed transmission line (thinner line for deviation from the original route).

7.4 Saint Georges (French Guiana) – Ferreira Gomes (Brazil)

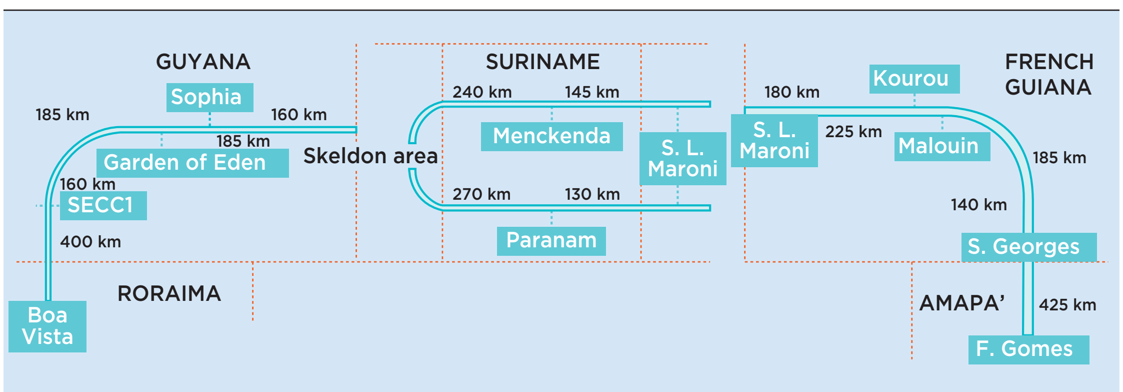
The proposed transmission line would connect Saint Georges to Ferreira Gomes with substations in Calçoene (Amapá)—see Figure 7.5. The route would cross the Oyapock River and then follow the 156 Road, crossing the Calçoene and the Amapá Grande Rivers. It would also pass through the savanna and cross the Flechal, Itaubal, Tartarugalzinho, Tartarugal Grande, and Araguari Rivers before reaching Ferreira Gomes.

Although the route follows an existing road, it would cross an indigenous territory in Brazil. This route would require negotiation with FUNAI according to Convention 169 of the International Labor Organization, which regulates rights of indigenous and tribal peoples, and is recognized by Brazil. This process can be time consuming. Thus, we recommend a deviation from this route, although it may increase the need for vegetation removal. According to Ordinance No. 419 of the Brazilian Ministry of the Environment (October 26th, 2011), transmission lines should be located at a minimum distance of 8 km from indigenous lands in the Amazon forest. A deviation to meet this requirement would increase the length of the line by 20 km.

FIGURE 7.5: Saint Georges (French Guiana) – Ferreira Gomes (Brazil)

Horizontal hatch: officially recognized indigenous areas.
Diagonal hatch: traditional occupation and use areas (not officially recognized).
Green line: protected and sustainable use conservation areas.
Red line: proposed transmission line (thinner line for deviation from the original route).

FIGURE 7.6: Available Corridors for Developing the Interconnections



Legend:
Blue lines: Options for interconnection lines.
Red lines: Country boundaries.

Figure 7.6 illustrates the corridor options, while Table 7.1 presents the recommended corridors, which would have a total length of 1,920 kilometers. Where the proposed route crosses indigenous lands or protected areas, alternative paths of similar length were included. However,

TABLE 7.1: Recommended Corridors for the Arco Norte Interchange Project

Countries	Starting in	Ending in	Length (km)
Roraima – Guyana	Boa Vista	SECC1	400
Guyana	SECC1	Sophia	185
	Sophia	Skeldon	160
Guyana – Suriname	Skeldon	Menckendam	240
Suriname – French Guiana	Menckendam	Saint Laurent du Maroni	145
French Guiana	Saint Laurent du Maroni	Malouin	225
	Malouin	Saint Georges	140
French Guiana – Amapá	Saint Georges	Ferreira Gomes	425
Total			**1,920**

these may require additional access roads, and therefore more deforestation. In addition, some resettlements were identified in those corridors, near villages and roads. These impacts will be further analyzed in Component II.

7.5 Interconnection Costs and Links

Each of the five alternatives in the Scenario 2 generation expansion plan includes a different level of electricity exports to Brazil. Therefore, each alternative requires a different interconnection scheme to link Guyana to Brazil for energy exports, and different bi-national links among Guyana, Suriname, French Guiana, and Brazil. For each alternative in Scenario 2, we analyzed a number of interconnection options with varying voltage levels and numbers of lines, as well as varying capital and operating costs. Table 7.2 shows the recommended interconnection option for each alternative.

Table 7.3 shows the basic characteristics of the recommended interconnection option for each alternative, and the estimated capital cost of the interconnection. The route or distance of the interconnected line does not change across the alternatives—all follow the recommended 1,920-kilometer path. What does change are the capacities of the transmission lines and substations, which rise along with exports. These rising capacities in turn lead to rising capital costs to build the interconnection, from US$701 million in Alternative 1 to US$985 million in Alternative 5.

For all alternatives, the recommended interconnection links between SECC1, Sophia, and Menckendam are 230 kV double circuits. Between Menckendam, Malouin, Saint Georges, and Ferreira Gomes, the interconnections are 230 kV single circuits with back-to-back converter stations—these stations are necessary due to the frequency differences (50Hz in French Guiana and 60 Hz in other countries).

TABLE 7.2: Interconnection Options for Each Scenario 2 Alternative

Alternative	Brazil – Guyana	Guyana	Guyana – Suriname	Suriname – French Guiana	French Guiana – Brazil
	Boa Vista – SECC1	SECC1 – Sophia	Sophia – Menckendam	Menckendam – Malouin	Malouin – Ferreira Gomes
1 (300 MW)	2 x 230 kV	2 x 230 kV	2 x 230 kV	1 x 230 kV	1 x 230 kV
2 (800 MW)	1 x 500 kV	2 x 230 kV	2 x 230 kV	1 x 230 kV	1 x 230 kV
3 (1500 MW)	1 x 500 kV	2 x 230 kV	2 x 230 kV	1 x 230 kV	1 x 230 kV
4 (3000 MW)	2 x 500 kV	2 x 230 kV	2 x 230 kV	1 x 230 kV	1 x 230 kV
5 (4500 MW)	3 x 500 kV	2 x 230 kV	2 x 230 kV	1 x 230 kV	1 x 230 kV

TABLE 7.3: Interconnection Alternatives and Capital Costs

Alternative (exports)	Line route	Km	Substation	MVA	Capital cost (US$ million)		
					Transmission line	Substation	Total
1 (300MW)	Boa Vista – SECC1	400	SECC1	800	100	16	701
	SECC1 – Sophia	185	Sophia	800	46	16	
	Sophia – Menckendam	400	Menckendam	800	100	15	
	Menckendam – Malouin	370	Malouin	400	184	8	
	Malouin – S. Georges – F. Gomes	565			215		
2 (800MW)	Boa Vista – SECC1	400	SECC1	1,600	120	30	735
	SECC1 – Sophia	185	Sophia	800	46	16	
	Sophia – Menckendam	400	Menckendam	800	100	15	
	Menckendam – Malouin	370	Malouin	400	184	8	
	Malouin – S. Georges – F. Gomes	565			215		
3 (1,500MW)	Boa Vista – SECC1	400	SECC1	2,400	120	44	749
	SECC1 – Sophia	185	Sophia	800	46	16	
	Sophia – Menckendam	400	Menckendam	800	100	15	
	Menckendam – Malouin	370	Malouin	400	184	8	
	Malouin – S. Georges – F. Gomes	565			215		
4 (3,000MW)	Boa Vista – SECC1	400	SECC1	3,800	192	61	837
	SECC1 – Sophia	185	Sophia	800	46	16	
	Sophia – Menckendam	400	Menckendam	800	100	15	
	Menckendam – Malouin	370	Malouin	400	184	8	
	Malouin – S. Georges – F. Gomes	565			215		
5 (4,500MW)	Boa Vista – SECC1	400	SECC1	5,300	312	88	985
	SECC1 – Sophia	185	Sophia	800	46	16	
	Sophia – Menckendam	400	Menckendam	800	100	15	
	Menckendam – Malouin	370	Malouin	400	184	8	
	Malouin – S. Georges – F. Gomes	565			215		

8

Economic Evaluation of the Arco Norte Interconnection Project[18]

To determine the economic attractiveness of each of the five interconnection alternatives (from 300MW to 4,500MW), we analyzed the Gross benefits and Costs of each alternative during a planning period of 2015–2028, and compared them to a reference scenario in which the power systems of Guyana, Suriname, French Guyana and Brazil are not interconnected. The results of this analysis, in addition to the environmental considerations presented above, will guide a more detailed analysis in Component II.

The cost-benefit analysis deducts all Costs from the Gross benefits to determine the net effect of implementing each alternative. Gross benefits included cost savings estimated for: (i) capital costs of new generation; (ii) operating and maintenance costs of new and existing generation; plus (iii) revenues obtained from electricity exports to Brazil; and Costs included: (a) capital costs of new transmission; (b) operating and maintenance costs of new transmission;[19] and (c) costs of transmission electricity losses.

[18] We evaluated the economic viability of interconnection for Guyana, Suriname, French Guiana, and the interconnection between these three countries and Brazil. We did not assess the economic viability of generation in Roraima and Amapá, or of the interconnection of these states with the Brazilian SIN given that generation expansion plans in Brazil are already set, and interconnecting lines from these states to the Brazilian SIN are already constructed or planned. Therefore, these investments are not included in the costs of this study.

[19] Includes fuel and non-serviced energy costs.

8.1 Gross Benefits of a Regional Generation Expansion Plan

In the first part of the cost-benefit analysis, we evaluated the Gross benefits from the regional generation expansion plans—Scenario 2 in Section 6. For this exercise, we did not include the capital and operating costs of interconnection—those are included later. Table 8.1 summarizes the results of the Gross benefit analysis for the generation expansion plans in Scenario 2, compared with the reference expansion plan in the isolated Scenario 1 (Alternative B, which considers mixed generation technologies).

We estimated the following Gross benefits for each interconnection alternative: (i) savings in capital costs for new generation for Guyana, French Guiana, and Suriname; (ii) savings in operation and maintenance of the new and old generation systems (which were negative for alternatives 2 through 5 due to the required investment in generation expansion to supply electricity exports to Brazil); and (iii) revenues from energy exports to Brazil.

As exports rise in Alternatives 1 through 5, capital costs also rise, since more and larger power plants are needed to meet Brazilian demand. However, when considering the revenues from electricity exports, all interconnection alternatives yield a benefit, suggesting that interconnection would produce benefits compared to continuing with isolated systems. Alternative 4, which provides the capacity to export 3,000 MW to Brazil, leads to the highest present value of generation benefits in the period 2015–2028, US$793 million.

TABLE 8.1: Results of the Gross Benefit Analysis for Each Interconnection Alternative (Generation Analysis, without Costs of the Interconnection Line)

Alternative	NPV in 2014 (US$ million)					
	Capital cost	Operating cost	Total	Savings compared to Scenario 1-Alt B	Electricity export revenue	Gross benefit from generation
B (Isolated)	428	1,380	1,808	0	0	—
1 (300 MW)	551	1,254	1,805	3	304	307
2 (800 MW)	1,003	1,217	2,220	−412	810	398
3 (1,500 MW)	1,244	1,209	2,453	−645	1,257	612
4 (3,000 MW)	1,563	1,217	2,780	−972	1,765	793
5 (4,500 MW)	1,897	1,306	3,203	−1,395	2,084	689

Note: Energy export revenues were calculated by multiplying the amount of the export contract to Brazil by 56 US$/MWh, the Brazilian long-run marginal cost in 2014.

8.2 Transmission Costs

For each of the five interconnection alternatives, we estimated the Costs of the recommended transmission infrastructure. The Costs for each alternative were: (i) capital costs; (ii) operating and maintenance costs; and (iii) costs of transmission electricity losses. We estimated annual operating and maintenance costs at 2 percent of capital costs for transmission lines and 3 percent of capital costs for substations. For all assets, we assumed a useful life of 25 years and a discount rate of 12 percent.

To calculate the total cost of each option, we used the net present value in 2014 of all the cost components from 2022 to 2028. In general, we recommend the least-cost interconnection option for each alternative. However, we recommend slightly more expensive options (exceeding the least-cost option by no more than 5 percent) if these would be more reliable than the least-cost option.

The net present value in 2014 of costs to build, operate, and maintain the transmission interconnection would vary between US$240 million for Alternative 1 and US$377 million for Alternative 5. Table 8.2 summarizes the costs of each interconnection alternative.

TABLE 8.2: Transmission Costs

Alternative	NPV in 2014 (US$ million)			
	Capital cost	Operating and Maintenance costs	Costs of transmission losses	Total Costs
1 (300 MW)	180	30	30	240
2 (800 MW)	188	32	39	259
3 (1,500 MW)	191	32	67	290
4 (3,000 MW)	211	36	85	331
5 (4,500 MW)	236	37	104	377

8.3 All Alternatives Are Economically Viable

For all five interconnection alternatives, the Gross benefits from more efficient and lower-cost generation plus the revenue from increased electricity exports exceed the Cost associated to the transmission interconnection. Alternative 4 would have the highest present value of Net Benefits (US$461 million), followed by Alternative 3 (US$322 million) and Alternative 5 (US$312 million). Alternative 4 has the highest ratio of Gross benefits to Costs, at 2.39, followed by Alternative 3 (2.11) and Alternative 5 (1.83). Preliminary estimates indicate internal rates of return (IRRs) from 12 to 16 percent for all alternatives.[20]

Table 8.3 summarizes the economic indicators for the five interconnection alternatives, and shows that the alternatives with the highest Net Benefit would also have the lowest social and environmental impacts. This is because, in general, economic benefits rise as exports rise, reflecting economies of scale in generation and in building the interconnection line. Similarly, the social and environmental impacts in Alternative 1 would be significant compared to the relatively small installed capacity. As installed capacity rises in Alternatives 2–5, relative impacts are also lower. However, the general trend of greater Net Benefits and lower environmental and social impacts as exports rise does not hold in all cases—possibly because the additional projects needed to meet Brazilian demand in Alternatives 4 and 5 could require relatively high unit-cost investments and produce greater environmental and social impacts than other projects identified in Alternatives 2 and 3.

TABLE 8.3: Summary of Economic Indicators

Alternative	NPV in 2014 (US$ million)			Ratio, Ranking and Index		
	Gross Benefit from generation	Total Costs	Net Benefits	Ratio Gross Benefit to Costs	Ranking	Soc-Env impact index (per MW)
1 (300 MW)	307	240	67	1.28	5	2.12
2 (800 MW)	398	259	139	1.54	4	1.04
3 (1500 MW)	612	290	322	2.11	2	0.74
4 (3000 MW)	793	332	461	2.39	1	1.05
5 (4500 MW)	689	377	312	1.83	3	1.08

8.4 Conclusion

While all of the interconnection alternatives explored are economically viable, the level of electricity exports from Guyana, Suriname and French Guiana to the Brazilian SIN drives the net benefits of the interconnection project. For interconnection capacities from 300 MW to 3,000 MW, the Net Benefits increase from about US$67 million to US$461 million for the

[20] Component II of the study will present the internal rate of return (IRR) for each of the five alternatives.

period 2022–2028. For larger interconnection capacities (4,500 MW), the Net Benefits decrease to US$312 million—this could be due to the need to build projects with relatively higher investment costs after the least-cost projects in the region are built in Alternatives 2, 3, and 4.

Overall, Alternatives 4, 3, and 5 are the most attractive, since they present the highest Net Benefits and low environmental indexes.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9 Risks for the Arco Norte Project

Risks that could prevent the Arco Norte project from being implemented can be categorized into four main groups: institutional and legal risks, financial risks, social and environmental risks, and geopolitical risks.

9.1 Institutional and Legal Risks

To finance and operate an interconnected regional power system, all participating countries would need to agree to new institutional, legal, and commercial arrangements. Legal and commercial agreements would regulate sales, set operating standards, and provide a framework for settling disputes, and new institutions would be needed to operate the system. Other multinational electricity interconnections in Latin America and around the world show that it is possible to reach these agreements, and provide blueprints that could be used in Arco Norte. However, completing these agreements can take a long time, and there is no guarantee that all parties will be able to reach a consensus.

9.2 Financial Risks

In Brazil and French Guiana, financial risk is relatively low. Brazil has a competitive and diverse electricity sector, with many financially sound public and private companies. In French Guiana, EDF, the national electricity utility of France, is a bankable offtaker. As a result, both countries are likely able to arrange financing for the large investments needed for regional interconnection if adequate profitability and risk profiles are demonstrated.

However, building and operating new large generation assets and transmission interconnection lines in Guyana and Suriname presents major financial risks. GPL and EBS, the state-owned, vertically integrated electricity utilities, are not bankable offtakers, and likely do not have the balance sheets needed to finance new investments themselves. This will present challenges to the financing of investments in these countries—large financial guarantees may be required, potentially from multilateral financing institutions.

9.3 Social and Environmental Risks

The environmental and social risks are the impacts of the transmission lines and new hydro plants on:

- Numerous indigenous lands, though not all of these are officially recognized by Arco Norte governments
- Virgin rainforest and ecosystems with high biodiversity.

These risks will likely lead to long environmental and social review processes and call for an extensive and integrated environmental and social impact study at the feasibility stage. Public consultations and negotiations with affected communities are absolutely necessary, since they are crucial to successful licensing processes.

9.4 Geopolitical risks

Binational cooperation will be required to develop many of the hydro plants on which the Arco Norte interconnection depends. Most of the new hydro plants would be built in Guyana, in parts of the country that are claimed by Venezuela.[21] Other proposed hydro plants would be built along rivers that serve as international boundaries, and developing them would require binational agreements on financing, construction, operations, and electricity sharing.

[21] Venezuela claims the land west of the Essequibo River, about two-thirds of the land area of Guyana (see map in Figure 5.1), contending that the Arbitral Award of 1899, which established a boundary with Guyana, is null and void.

10

Conclusions and Recommendations

An electricity transmission line that interconnects Guyana, French Guiana, Suriname, and the Brazilian states of Roraima and Amapá is technically and economically viable. The main benefits of the interconnection would be:

- Lower-cost generation in Guyana, French Guiana, and Suriname. A regional interconnection would allow these countries to exploit the most efficient generation sources at the regional level and meet regional demand through trade.
- Lower electricity prices for consumers in Guyana, French Guiana, and Suriname, due to lower-cost generation and greater competition in the regional market.
- More secure supply in all four Arco Norte countries—Guyana, French Guiana, Suriname, and Brazil. Trading across international borders would allow each country a larger reserve margin, since they could tap into foreign electricity when domestic sources were inadequate.
- The opportunity to develop renewable energy sources in the region, gradually displacing liquid fossil fuels.
- Export earnings, especially for Guyana. The most efficient large generation sites in the Arco Norte are potential hydro projects in Guyana. By developing these sites and exporting excess generation to Brazil, Guyana—and to a lesser extent French Guiana and Suriname—could become large energy exporters.

We analyzed five alternatives for regional interconnection. The main difference among these alternatives is the level of export capacity from Guyana, Suriname, and French Guiana to Brazil. We found that all the alternatives explored are economically viable, and an interconnection with export capacity of between 1,500 MW and 3,000 MW would have the highest net benefit. These alternatives also have some of the lowest environmental and social impacts, relative to the newly installed generation capacity. For all options, there could be significant environmental and social impacts—indigenous communities and protected forests would be affected by new large hydro projects and transmission lines.

In the next stage of the study, Component II – Pre-feasibility study, we will select the most promising interconnection option and a corresponding generation expansion plan for the Arco Norte region. To do so, we will further analyze technical, economic, social, and environmental aspects of the interconnection alternatives, including additional feedback provided by stakeholders.

Component II of the study will also present a more detailed review and recommendation on the institutional and regulatory frameworks to facilitate the electricity integration, including a roadmap with an implementation plan.

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