



Linking Up: Public-Private Partnerships in Power Transmission in Africa

**LINKING UP:
PUBLIC-PRIVATE
PARTNERSHIPS
IN POWER
TRANSMISSION
IN AFRICA**

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Telephone: 202-473-1000—Website: www.worldbank.org

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Contents

vii	<i>Acronyms and Abbreviations</i>
xi	<i>Acknowledgments</i>
xiii	<i>Foreword</i>
xv	<i>Executive Summary</i>
1	Section 1: Introduction
5	Part A: Financing Power Transmission: Challenges and Opportunities
6	Section 2: Africa Needs Transmission Investment and New Approaches to Financing and Delivering It
6	2.1 Access to Electricity Is Low in Africa
7	2.2 Increasing Access and Consumption Will Require a Major Expansion of Supply
8	2.3 Transmission Is Needed to Tie the Electricity System Together
12	2.4 New Approaches to Finance and Delivery of Transmission Are Needed
15	Section 3: Private Finance of Transmission Has Worked Well Internationally
16	3.1 Model 1: Privatizations
18	3.2 Model 2: Whole-of-Grid Concessions
18	3.3 Model 3: Independent Power Transmission
19	3.4 Model 4: Merchant Investments
20	3.5 Interconnection Projects Can Also Use Some of These Models
25	Section 4: Africa Has Little Privately Financed Transmission, but Substantial Private Investment in Generation
25	4.1 There Has Been Little Private Investment in Transmission
30	4.2 This Contrasts with Africa's Success in Attracting Private Investment in Generation
33	Section 5: Independent Power Transmissions Are the Most Broadly Applicable Business Model for Increasing Privately Financed Transmission in Africa
33	5.1 Applicability of the Model to All Types of Transmission Investment in Africa
35	5.2 Ability of the Model to Achieve Economies of Scale in African Transmission

35	5.3	Competitive Pressure on Private Providers of Transmission in Africa under the Model
36	5.4	Requirements for Investor Confidence in Network Regulation in Africa
37	5.5	Consistency of the Model with Directions in Power Sector Reform
37	5.6	Extent to Which the Model Can Be Tested While African Governments Maintain Existing Models
38	5.7	Evidence That the Model Has Worked Well in Other Low-income Countries
41		Part B: How to Scale-up Private Investment in Transmission in Africa
42		Section 6: Steps to Realize the Potential of IPTs for Africa
42	6.1	Develop Policies That Support IPTs
44	6.2	Develop the Legal and Regulatory Frameworks to Support IPTs
44	6.3	Conduct Trials of IPTs Alongside Existing Business Models for Transmission
45	6.4	Introduce New Models for Concessional Lending
47	6.5	Decide the Stage at Which to Tender Transmission Projects
48	6.6	Determine Payments to IPTs Based on Transmission Availability
49	6.7	Ensure Adequate Revenue Flow and Credit Enhancement for Projects
53	6.8	Tailor IPT Projects to Attract International Investors
53	6.9	Prepare to Implement IPT Transactions
55	6.10	Run Competitive Tenders for IPTs
57	6.11	Next Steps
57		Section 7: Toolkit to Introduce Independent Power Transmission Tenders
59	7.1	Validate the Project
60	7.2	Evaluate the Suitability for Private Finance
61	7.3	Select the Team and Tender Type
63	7.4	Prepare the Preliminary Works
64	7.5	Design the Transaction
71	7.6	Run the Tender
75		Appendix A. Case Studies
93		Appendix B. Pipeline of IPT Projects in Kenya and the Southern African Power Pool
101		<i>List of References</i>

Tables

2.1	11	Sample of Ketraco's planned transmission lines
3.1	16	Business models for private investment in transmission
4.1	26	Examples of concessions and affermage in Africa
5.1	34	Performance of the business models against assessment criteria
5.2	39	Information of winning bids for transmission lines in Peru (1998–2013)
7.1	65	Risk matrix
7.2	66	Main risks of an IPT project
7.3	67	Summary of key provisions to include in the TSA and associated agreements
7.4	69	PPP structures for IPT contracts
A.1	89	Transmission lines by region, 2011–2015 (ct km)
B.1	96	Members of SAPP
B.2	99	Pipeline of potential IPT projects in Kenya
B.3	99	Pipeline of potential IPT projects in SAPP

Figures

2.1	7	Access to electricity and electricity consumption (percentage of population; kWh per person per year)
2.2	8	Installed capacity (MW per million people)
2.3	9	Transmission lines per capita (km transmission lines per million people)
2.4	10	Major potential generation and transmission projects in Africa
2.5	11	Map of Nigeria's transmission system, showing transmission lines being developed and proposed
3.1	21	Basslink transmission line route
3.2	22	The SIEPAC interconnection
4.1	27	Length of transmission and distribution lines in Cameroon (km), 2001–2010
4.2	29	Route of the Cahora Bassa interconnection line
4.3	31	IPPs by year of financial close: Africa (excluding South Africa), 1994–2014
6.1	45	Investments in transmission in Peru (1991–2000)
6.2	46	Evolution of new transmission lines in India, 1985–2017 (ct km of new transmission lines)
6.3	48	Responsibilities under late-stage tenders and early-stage tenders

6.4	50	Comparison of electric supply costs with cash collected in 2014 (US\$/kWh billed)
6.5	52	Financing structure of Azura IPP (Nigeria)
7.1	58	Summary of the process
7.2	62	Responsibilities under early-stage tenders and late-stage tenders
A.1	76	Brazil's power sector main institutions
A.2	78	Successful and unsuccessful tenders (2005–2015)
B.1	95	Evolution of transmission lines, by voltage (2009–2015)
B.2	97	The SAPP Grid

Boxes

2.1	13	Funding gap in transmission sector in Kenya
3.1	19	Summary of outcomes of IPTs internationally
4.1	28	The only attempt in Africa to tender for IPTs
5.1	36	IPTs can reduce whole-of-life costs
5.2	37	Merchant transmission faces risks from open access, regulated networks
5.3	38	IPTs can bring in new sources of finance
6.1	43	Introducing onshore transmission tenders in the United Kingdom
6.2	45	Peru passed new legislation to maintain investor interest in transmission
6.3	46	Developing regulations suitable for IPTs
6.4	46	Privately financed transmission in India has been growing
6.5	47	Example of concessional lending to IPP
6.6	50	Most African utilities do not collect enough cash to cover costs
6.7	51	The use of escrow accounts to attract IPP investments
6.8	51	The role of guarantees in ensuring the Azura IPP (Nigeria) was bankable
6.9	54	Tariff for IPT contracts in Peru
6.10	55	The role of government-owned bidders
7.1	61	Definition of different committees
7.2	62	Early-stage tenders and late-stage tenders
7.3	70	One-stage and two-stage tender process
7.4	73	Contract management
B.1	94	Main companies in Kenya's power sector
B.2	98	SAPP's experience shows how regional power pools can assist transmission planning

Acronyms and Abbreviations

ANEEL	Agência Nacional de Energia Elétrica
AR	Annual Revenue
AVI	Anualidad del Valor de la Inversión
BIA	Bureau of Indian Affairs
BNDES	Banco Nacional de Desenvolvimento Econômico e Social
BOO	Build, Own, and Operate
BOOT	Build, Own, Operate, and Transfer
BPC	Bidding Process Coordinator
CCEE	Câmara de Comercialização de Energia Elétrica
CDEC	Centro de Despacho Econômico de Carga
CEA	Central Electricity Authority
CEC	Copperbelt Energy Corporation
CERC	Central Electricity Regulatory Commission
CIE	Compagnie Ivoirienne d'Électricité
CISEN	Coordinador Independiente del Sistema Eléctrico Nacional
CNE	Comisión Nacional de Energía
CNPE	Conselho Nacional de Política Energética
COD	Commercial Operation Date
COMA	Costos de Operación, Mantenimiento y Administración
Ct km	Circuit Kilometer
CTEEP	Companhia de Transmissão de Energia Elétrica Paulista
CTM	Consorcio Transmuntario
CTU	Central Transmission Utility
DAM	Day Ahead Market
DFI	Development Finance Institution
DIC	Designated Inter-State Customer
DoE	Department of Energy
DRC	Democratic Republic of the Congo
EAE	Strategic Environmental Evaluation
EC	Empowered Committee
EDF	Électricité de France
EDM	Electricidade de Moçambique; Électricité du Mali
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
EPE	Empresa de Pesquisa Energética
EPIRA	Electric Power Industry Reform Act
ERC	Energy Regulatory Commission

ESIA	Environmental and Social Impact Assessment
ESKOM	South African electricity supply company
FERC	Federal Energy Regulatory Commission
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GW	Gigawatt
HCB	Hidroelétrica de Cahora Bassa
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IFC	International Finance Corporation
IPP	Independent Power Producer
IPS	Industrial Promotion Services
IPT	Independent Power Transmission
JV	Joint Venture
Ketraco	Kenya Electricity Transmission Company
km	kilometer(s)
KPI	Key Performance Indicator
KPLC	Kenya Power and Lighting Company
kV	Kilovolt
kWh	Kilowatt-hour
LCE	Ley de Concesiones Eléctricas
LCPDP	Least Cost Power Development Plan
LGE	Ley para Asegurar el Desarrollo Eficiente de la Generación Eléctrica
LGSE	Ley General de Servicios Eléctricos
LTI	Law of Transmission and Interconnection
LTTC	Long Term Transmission Customer
LV	Low Voltage
MAR	Maximum Annual Revenue
MEM	Ministry of Energy and Mining
MHI	Manitoba Hydro International
MIGA	Multilateral Investment Guarantee Agency
MME	Ministry of Mines and Energy
MoP	Ministry of Power
MV	Medium Voltage
MVA	Mega-volt Ampere
MW	Megawatt
MWh	Megawatt-hour
NBET	Nigerian Bulk Electricity Trader
NEM	National Electricity Market
NEP	National Electricity Plan
NGCP	National Grid Corporation of the Philippines
NPC	National Power Corporation
NTP	National Tariff Policy
ODA	Official Development Assistance
OECD	Organisation for Economic Co-operation and Development
Ofgem	Office of Gas and Electricity Markets
O&M	Operations and Maintenance
ONS	Operator of the National Electricity System

PCOA	Put-Call Option Agreement
PEMC	Philippines Electricity Market Corporation
PGCIL	Power Grid Corporation of India Ltd
PhP	Philippine Peso
PIDA	Programme for Infrastructure Development in Africa
PIS	Performance Incentive Scheme
PPA	Power Purchase Agreement
PPP	Public Private Partnership
PRG	Partial Risk Guarantee
PRI	Political Risk Insurance
PSA	Power Supply Agreement
PSALM	Power Sector Assets and Liabilities Management Corporation
PSP	Private Sector Participation
RAPP	Rajasthan Atomic Power Project
REP	Red de Energía del Peru
RFP	Request for Proposal
RFQ	Request for Qualification
ROW	Right of Way
RTE	Réseau de Transport d'Electricité
RTO	Regional Transmission Organization
RTWR	Rules for Setting Transmission Wheeling Rates
SAPP	Southern Africa Power Pool
SEB	State Electricity Board
SEEG	Société d'Énergie et d'Eau du Gabon
SEIN	Sistema Eléctrico Interconectado Nacional
SENELEC	Société Nationale d'Électricité du Sénégal
SERC	State Electricity Regulatory Commissions
SGT	Sistema Garantizado de Transmision
SIC	Sistema Interconectado Central
SING	Sistema Interconectado del Norte Grande
SONEL	Société Nationale d'Électricité
SPV	Special Purpose Vehicle
SSE	Scottish and Southern Electricity
STE	Sociedade Nacional de Transporte de Energia
STU	State Transmission Utility
TBCB	Tariff-based Competitive Bidding
TCN	Transmission Company of Nigeria
TDP	Transmission Development Plan
TSA	Transmission Service Agreement
TSO	Transmission System Operator
TSP	Transmission Service Provider
VATT	Valor Anual de Transmisión por Tramo
VfM	Value for Money
VGF	Viability Gap Funding
WACC	Weighted Average Cost of Capital
WESM	Wholesale Electricity Spot Market
ZESCO	Zambia Electricity Utility

Acknowledgments

This study was authored by a team comprising Rahul Kitchlu (Senior Energy Specialist), Samuel Oguah (Energy Specialist), Emma Grubbstrom (consultant) and John Rennie (consultant) at the World Bank; Jamie Carstairs, Lucila Arboleya, and David Ehrhardt at Castalia Ltd.; and Ramón Nadira from Lummus Consultants International. The work was carried out under the guidance of Lucio Monari, Sudeshna Banerjee, Charles Cormier, and Wendy Hughes.

Substantive inputs were provided by the speakers at workshops hosted in September 2016 in Nairobi and Abuja, including Pedro Antmann, Pedro Sanchez, Burra Vamsi Rama Mohan (Deputy General Manager, Power Grid Corp of India), Rafael Ferreira (PSR), and Ajay Bhardwaj (Sterlite Power).

The team also engaged with many individuals who have enriched the content and rigor of this report. We are grateful to the numerous public stakeholders and private investors, including public utilities, regulators, and transmission companies, who provided invaluable insights.

The team is grateful to colleagues in the Global Energy and Extractives Practice, who contributed insights and recommendations concerning their countries and areas of expertise including the Communications team comprised of Susan Fleming, Anita Rozowska and Aarthi Sivaraman. The team benefited from discussions with Sudeshna Banerjee, Manuel Sanchez, Mariano Salto, Kyran O'Sullivan and Muhammad Wakil. The team also benefited greatly from colleagues across the Bank Group including Robert Schlotterer and Arnaud Braud in the Financial Solutions group, Anabelle Libeau in MIGA, Xavier Muron and Celine Payet in PPIAF.

The team wishes to thank peer reviewers Victor Loksha, Efstratos Tavoulareas, and Pedro Sanchez who provided valuable comments and constructive insights at various stages of this work, including all the participants in the Decision Meeting, chaired by Thomas O'Brien. Highly valued comments have also been provided by Kwawu Mensan Gaba, Teuta Kacaniku and the country management units (CMUs) for the finalizing of this report.

Funding for this publication was provided by PPIAF. PPIAF, a multi-donor trust fund housed in the World Bank Group, provides technical assistance to governments in developing countries. PPIAF's main goal is to create enabling environments through high-impact partnerships that facilitate private investment in infrastructure. For more information, visit www.ppiaf.org

Foreword

Africa lags other regions in access to electricity: two in three Africans, or about 600 million people, do not have access to electricity. This is a major drag on growth. Without electricity, health clinics struggle to provide basic services, children are unable to get a proper education, and businesses cannot grow and thrive in today's global economy. When there is electricity, the quality of supply is often poor. A majority of countries in the subcontinent are still experiencing power shortages. If we do not address the underlying reasons preventing Africans from achieving wider access to reliable and affordable electricity, economic growth on the continent will remain slow, keeping millions trapped in poverty.

A primary cause of the poor quality of supply and low electrification rates lies with weak power networks. Addressing these challenges will require new approaches to development financing; there is a disproportionately large funding gap affecting Sub-Saharan Africa's power sectors which cannot be met by the limited public finances of client countries alone. Scaling up private participation along the energy value chain is necessary. To move the needle significantly in the energy sector, we need to help countries attract sufficient levels of investment.

Although African governments strive to foster private sector participation, this will not materialize without deliberate action. Governments demand investments that serve the public interest and support poverty reduction and growth targets but private capital will flow where rewards demonstrably outweigh risks.

Africa is blessed with huge untapped potential for renewable energy, including hydro, solar, and geothermal but to connect these resources to consumers, Africa will need to invest in transmission lines. Much of the focus in scaling up investments in the power sector has been on the upstream generation capacity expansion and corresponding levels of investments are also required for Sub-Saharan Africa's transmission segment. Without these transmission investments, there is a high risk of creating system bottlenecks leaving generation assets stranded.

The report 'Linking up: Public-Private Partnerships in Power Transmission in Africa' examines the global experience in private sector led investments (e.g. public-private partnerships, PPPs) in transmission and their applicability within the Sub-Saharan African context. Many countries in Latin America and Asia have successfully introduced private sector participation in their transmission networks and have seen reduced project costs and expanded coverage. In Africa, the concept of independent power producers has also yielded good results. The analysis presented draws lessons from these experiences that might be

applicable to the African context, highlights the required regulations and recommends options for attracting private sector participation in the power transmission segment.

Ultimately, the report aims to help African countries achieve scaled-up and sustainable power sector investment for the benefit of their people and their economies as a whole.



Makhtar Diop
Vice President, Africa Region

Executive Summary

The power sector's record of delivering services in Sub-Saharan Africa (Africa) has been suboptimal. Generation capacity remains at 100 gigawatts (GW)—one-third of India's, with a similar population—and an average annual per capita consumption of about 500 kilowatt-hours (kWh), one-fifth of the global average. Electricity is consumed almost exclusively by the affluent. Close to two-thirds of Africa's population—largely rural and poor—are left out of the service delivery paradigm, with adverse consequences on socioeconomic welfare and economic productivity. This reality is at odds with the rising aspirations of the international community and national governments to reach every consumer with reliable, affordable, and sustainable energy solutions by 2030.

Bridging the gap between where Africa is and where Africa aspires to be will require a confluence of new business models, new financiers, and new stakeholders in order to increase its capacity to generate electricity, and to build distribution networks capable of delivering it to consumers, as well as transmission lines to link the two ends of the power supply chain. Generation and distribution, the two ends of the sector value chain, have received more attention from policy makers and financiers as they experiment with new ways of procuring generation capacity, as well as more efficient ways of delivering service to consumers. Independent Power Producers (IPPs) have made investments in generation of US\$25.6 billion, with an installed capacity of 11 GW.¹ In distribution, new models of harnessing private sector efficiencies have emerged in various forms of private-public partnerships (PPPs), as well as in concessions, management contracts, operations and maintenance contracts, and so on.

Transmission, which has traditionally been considered a natural monopoly, and which contributes a relatively small part of the overall cost of the sector value chain, needs to move in tandem with additions to generation capacity in order to achieve timely transmission and final delivery to consumers. Transmission lines reduce overall costs by ensuring economies of scale in generation; creating access to cost-efficient sources of generation; reducing the reserves needed to ensure security of supply; and supporting the integration of renewables into the energy system. Even so, transmission remains a neglected part of the sector value chain.

The average annual investment requirement for the transmission sector over the period from 2015 to 2040 ranges between US\$3.2-4.3 billion. Almost all transmission investment in Africa is financed by state-owned enterprises (SOEs). This was also true for the rest of the world until the 1990s. However, since then a wave of restructuring across Latin American countries, and many of the member countries of the Organization for Economic Co-operation and Development (OECD), has led to new business models for financing the transmission of electricity, with a lower role for public investment and a greater role for private finance. Global experience in this regard is therefore fairly recent. Starting in the developed and Latin American countries, it has rapidly spread to Asia. Today, Africa's gross

domestic product (GDP) is about where these countries were when they opened the sector to private investors. For example, Peru's GDP per capita in 1998 was US\$3,266, and India's in 2006 was US\$1,056. In comparison, Kenya's current GDP per capita is US\$1,113 and Nigeria's is US\$2,535.

This report, in response to specific client needs, asks if the private sector can play a complementary role in scaling up the transmission of electricity in Africa, addressing both its potential advantages and disadvantages. Kenya and Nigeria are actively considering introducing new sources of financing to meet burgeoning investment needs. This report draws from growing global experience in PPP case studies in Brazil, Chile, India, Peru, and the Philippines, and provides a customized account of its applicability to Africa. The preparation of this report benefitted from close collaboration with public and private entities in Africa. At workshops in Nairobi and Abuja, international experts shared their country experiences in attracting private investment with local stakeholders. A third workshop was held in Arusha at the East Africa Power Pool's (EAPP) Ministerial Conference, where preliminary findings were presented to seven ministers of energy from EAPP countries.

Introducing the private sector to electricity transmission is an idea whose time has come in Africa. However, it has to be pursued cautiously and only in selected countries, where conditions are right. This report delves into the implications of such PPP models on the cost of service delivery and efficiency of service provision, and sets forth a toolkit that countries can adapt to their specific local conditions.

Why Is the Scaling Up of Private Investment in Transmission Necessary in Africa?

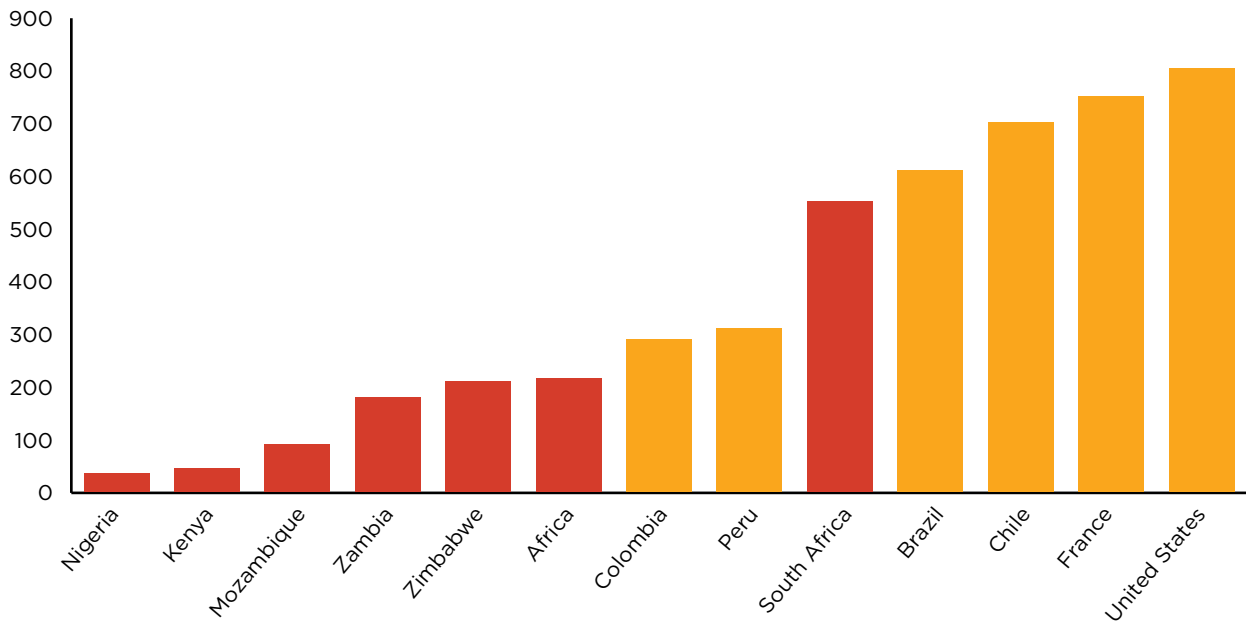
More investment in the transmission sector is urgent. Of 38 countries, 9 have no transmission lines above 100 kilovolt (kV). The combined length of transmission in 38 countries in Africa is 112,196 kilometers (km). The country of Brazil has a longer transmission network than Africa, at 125,640 km, and, at 257,000 km, the United States of America (United States) has more than twice the length of the African transmission network. Despite its large land mass, Africa also has fewer kilometers of transmission lines per capita than other regions. The length of transmission lines in Africa is 247 km per million people: excluding South Africa, this indicator drops to 229 km per million people. In contrast, Colombia has 295km of transmission lines per million people, Peru has 339km, Brazil has 610km, Chile has 694km, and the United States has 807km.

Building more transmission lines and upgrading transmission capacity will be an essential part of the overall expansion of the electricity sector. As Africa needs transmission both within and between countries, investments are required at both the national and regional levels. Africa needs to invest in long-distance lines, using both alternating current (AC) and direct current (DC) technologies, and to expand in-country transmission networks at a range of voltages. Africa has large low-cost hydrogeneration resources, but the realized potential is far below the load they could serve.

Transmission investment, including investment in transmission between countries, is needed to connect these resources to consumers. In-country investments requirements are also large covering various project types. In Kenya, the Kenya Electricity Transmission Company (Ketraco) expects to develop approximately 7,000 km of transmission lines by 2020—including 2,200 km of 132 kV lines; 2,400 km of 220 kV lines; 2,000 km of 400 kV lines; and 612 km of 500 kV High Voltage Direct Current (HVDC) lines.

Public finance is relatively scarce in fiscally constrained environments. The opportunity cost of overwhelming use of public capital in the power sector can be high, especially in countries facing demands to address other socioeconomic deficits.

Project finance can allow state-owned utilities to raise additional capital that would otherwise be unavailable, by separating out a portion of cash flows related to particular

Figure E.1 Transmission lines per capita (kilometers of transmission lines per million people)

Source: Castalia. Data sourced from Trimble, C. et al., "T&D Data—State-owned national grid T&D data," 2016, <http://data.worldbank.org/data-catalog/affordable-viable-power-for-africa> (accessed October 30, 2016); Rafael Ferreira, "Private Participation in Transmission Expansion: the Brazilian Model", Presentation from consultation workshop, Nairobi, Kenya, September 26, 2016.

investments. Under a project finance structure, the government's guarantee on payment does not make the fiscal position worse. Rather, it ensures that a small increase in electricity tariffs intended to pay for a financially viable project will truly dedicated be to that, and will not be used for other debt services or expenditures. Private finance allows the state-owned utility, or the government, to pay competitive and cost-reflective transmission prices. As the private sector invests in financially viable transmission projects, this can also have spillover effects. With higher transmission capacity, utilities can increase electricity sales and reduce generation costs. Finally, private involvement can bring managerial skills, technical know-how, and performance incentives, and stronger accountability to the sub-sector.

What are the business models of private-public partnerships in the transmission of electricity?

Several different business models have been used to attract private investment in transmission. The four main models are privatizations, whole-of-grid concessions, independent power transmissions (IPTs), and merchant investments. Private finance has brought substantial investment in new transmission to the countries using these models.

With the restructuring and liberalization of power markets in OECD countries, the approach to financing transmission investment changed. Private companies now finance a large share of transmission investment in many countries in North and South America, and in Europe. Privately financed transmission has also been introduced in some developing countries. India, for example, has attracted US\$5.5 billion of private investment in transmission since 2002.

Four main business models have been used:

- **Indefinite privatizations** provide ownership of the transmission network to a private company, usually through a trade sale or public flotation of a government-owned

transmission business. The private owner has the exclusive right (and obligation) to develop new transmission in its area of operation.

- **Whole-of-grid concessions** provide similar rights and responsibilities to privatizations, but for a shorter period. In most cases, the government implements this business model with a competitive tender of the concession, and enters a concession contract with the winning bidder.
- **Independent Power Transmissions (IPTs)** provide the rights and obligations associated with a single transmission line, or a package of a few lines. In most cases the government implements this business model by tendering a long-term contract, with payment dependent on the availability of the line.
- **Merchant investors** build and operate a single transmission line (“merchant line”). In many cases this is a High Voltage Direct Current (HVDC) line. The merchant investor benefits from moving power from low-price regions to high-price regions. In most cases, merchant lines are a private initiative, and are not initiated by the government.

In some countries more than one business model is used. For example, the United States and the United Kingdom have lifted the exclusivity of private transmission businesses for new transmission investment, allowing governments to also conduct IPT tenders.

All of these models can work, but the conditions in which they work best are different. Bolivia’s attempt at privatization, for example, did not last, and experiences with concessions in the African countries have failed to yield significant investment. However, where the conditions are right, private finance under these models has brought substantial investment of new electricity transmission to some countries. For example, the three companies involved in privatization in the United Kingdom invested GBP 5.6 billion from 2013–16. And in Peru, IPTs raised US\$1.8 billion in 18 tenders, and on average the winning bids yielded 36 percent lower annual costs than those estimated. In India, the share of private investment—including joint ventures with public transmission company—has been growing since the late 2000s. The private sector has invested a total of US\$5.5 billion, and there is US\$5 billion worth of projects scheduled to follow.

Africa’s experience with private sector participation in the transmission sector has been negligible, primarily through whole-of-grid concessions. Though these have not achieved significant investment in transmission, they have brought some operational benefits. Africa has no experience of privately-financed transmission lines through IPTs or merchant lines. Some preliminary steps have been made to prepare for IPT tenders in Nigeria, but no projects have been awarded.

IPTs could be the most promising business model to involve the private sector in Africa. They have performed well in other developing countries, including the case-study countries. The per capita income level of some of these countries at the inception of IPTs was similar to the per capita income levels of the African countries that are considering the introduction of IPTs today. IPTs in both middle-income and low-income countries have led to substantial private investment in transmission, significant cost savings through tenders, and to contractual agreements that are thus far stable. Further, the risks that IPT investors carry are similar to those that IPP investors carry, and the IPP business model has worked well in Africa.

There are four main alternatives for structuring the IPT, broadly differentiated depending upon the source of capital expenditure (CAPEX) requirements, whether the private company will own the transmission assets, and whether these will be transferred at the end of the term (Table E2). The selected case-study countries did not have identical structures for their IPTs, but they were all successful in attracting private finance to invest in new transmission assets. There were two distinguishing characteristics. First, the stage at which the asset was transferred: in Brazil, Peru, and India the tenders are for Build, Own, Operate, Transfer (BOOT) contracts (Type 1 in Table E2). This transfer condition requires measures such

Table E1 Business models for private investment in transmission

	Indefinite privatization	Whole-of-grid concession	Independent Power Transmission (IPT)	Merchant investment
Term	Indefinite	Long term: often 25 years or more	Long term: often 25 years or more	Indefinite
Coverage	All existing and new lines within a country or region	All existing and new lines within a country or region	Individual line or package of lines. New lines only	Single major new line, often HVDC
Revenues	Annual revenues set by the regulator to ensure a reasonable return on investment and of capital, and subject to periodic regulatory review	Annual revenues set by the regulator to ensure a reasonable return on investment and of capital, and subject to periodic regulatory review or to arbitration clauses under concession law	Annual revenues largely or entirely set by the winning bid	Revenues dependent on energy (MWh) of flow along the line and price differentials between the two ends of the line
Incentives	Related to whole-of-grid performance	Related to whole-of-grid performance	Availability for the line (typically 98%)	Ability to move power from lower-price areas to higher-price areas
Access	Open access to all transmission users on an equal basis	Open access to all transmission users on an equal basis	Open access to all transmission users on an equal basis	Proprietary access. Access rights used by owner or sold
Examples – Global	United Kingdom, Germany, parts of France, parts of Australia, some South American countries (including Argentina, Chile)	Philippines	Mexico, South America (including Brazil, Chile, Colombia, Peru), India, United Kingdom, Canada, Australia, United States	Australia, United States
Examples – Africa	None	Cameroon, Mali, Senegal, Cote d'Ivoire	None	None

as valuation of the asset condition, or requirements for minimum maintenance spending toward the end of the contract term to ensure that the asset is transferred in good condition.

In Chile, IPT contracts are Build, Own, Operate (BOO) (Type 2 in Table E2). This type of contract establishes revenue certainty for an initial period, and is followed by regulatory determinations later in the life of the asset. This was the only example in the case studies of indefinite private ownership of the transmission asset financed under an IPT tender. An alternative is that the private company finances the asset; receives long-term payments based on operational performance; and transfers the asset ownership at a much earlier stage. This is a Build, Transfer, Operate (BTO) contract, Type 3 in Table E2). For example, the asset could be transferred to the government-owned transmission company immediately after commissioning, while the capital costs would be recovered over a contract term of 30 years. An early transfer of ownership is not a usual approach under project finance. It may in theory be able to provide similar incentives to traditional IPT contracts. However, this would require that the transfer of ownership is purely on paper, and does not lead to any intervention by the new owner that would affect cost or performance. It would also

Table E2 PPP structures for IPT contracts

#	PPP structure	Who funds the capital investment?	Who bears construction risk?	Who bears operation risk?	Who owns the assets?	Examples
1	Build, Own, Operate, Transfer (BOOT)	Private company	Private company	Private company	Private company	Brazil, Peru, India
2	Build, Own, Operate (BOO)	Private company	Private company	Private company	Private company	Chile
3	Build, Transfer, Operate (BTO)	Private company	Private company	Private company	Government/SOE	None identified for transmission lines
4	EPC+Finance	Private company	Private company	Government/SOE	Government/SOE	None identified for transmission lines

require that security is provided in some way other than the ultimate security that arises from ownership of the asset.

Risk allocation under these structures are all similar except for the EPC+Finance option (Type 4 in Table E2), in which the public sector bears operation risk. Otherwise, all of the contract forms essentially transfer both construction and operation risk and CAPEX requirements away from the government. There are no efficiency gains from the EPC+Finance approach, as the developer does not bear whole-of-life performance risk.

Despite the success of IPTs in other countries, it should be recognized that the context for transmission investment in Africa differs from those in most countries with IPTs. These differences include the financial viability of the power sector, and the industry structure. Most of the countries using IPTs have sufficient revenue from electricity consumers to ensure the profitability of generators, network businesses, and distribution businesses. This is not the case in most African countries. However, India's experience, where the challenge of low tariffs and high losses has been overcome, demonstrates that overall power-sector profitability is not a necessary precondition for IPTs to work well. Another difference is that most countries using IPTs have already introduced vertical separation between generation, transmission, and distribution. Some African countries have introduced vertical separation, but most have not. Finally, using IPT tenders presents disadvantages relative to other business models. Procuring transmission infrastructure through the IPT model requires running frequent tenders. This generates higher transaction costs than other business models. This is especially true if compared to procuring transmission lines through a whole-of-grid concession.

Ultimately, global experience shows that the benefits of IPTs outweigh the costs of implementing them. However, successful experience with IPPs in the generation of electricity, with similar PPP structures, suggests that IPTs could be used to augment investments in transmission in Africa.

What are the steps to realizing the potential of IPTs for Africa?

Introducing IPTs for electricity transmission in Africa could result in similar benefits to those achieved by IPTs in other countries, and by IPPs in Africa. To realize these benefits, African governments will have to take actions to produce a favorable enabling environment for IPTs. Their approach can draw on the lessons learned from introducing IPPs in Africa, and international experience in IPTs.

The ten steps required are to:

- **Develop policies that support IPTs.** A clear policy direction on how to introduce IPTs, adequately consulted, will be important in order to drive investment. Policy development

will need to consider the arguments both for and against testing the use of IPTs to meet government objectives, and reach a final decision. Development Finance Institutions (DFIs) can also assist through dissemination of knowledge products and technical assistance, including peer-to-peer advice from other developing countries with IPT experience.

- **Develop the legal and regulatory frameworks to support IPTs.** In most countries, introducing IPTs will require changes to legislation, regulation, and other documents such as grid codes. Governments should draw on the substantial body of international experience to identify lessons learned elsewhere. Primary legislation may be required, and the legislation may also need to evolve over time.
- **Conduct trials of IPTs.** Moving to a new model that has worked well internationally but has not been tried domestically is a risk for African governments. They should start with trials of IPTs to better understand the implementation challenges, and revise regulations and policies as necessary to improve efficiency. International experience shows that IPT tenders can be run while existing frameworks for government-financed transmission are kept in place, and this has been the practice in most countries that have used this model.
- **Introduce new models for concessional lending.** Transmission projects are capital-intensive. African governments need to engage with DFIs to ensure that concessional finance is not tied to delivery by government-owned companies, and to develop models for DFI support to transmission projects delivered by IPTs. The low cost of concessional lending helps African governments meet their investment targets at a lower cost to consumers, and any shift to IPTs must safeguard these benefits. African governments can also work with DFIs to ensure that DFI lending policies are not biased toward government ownership of transmission, and do not impede the use of privately-financed transmission.
- **Decide the stage at which to tender transmission projects.** There are two broad choices here. Early-stage tenders allow for more innovation by bidders. However, they also expose them to risk on issues such as approvals and permitting, and require a more complex evaluation. Late-stage tenders are for projects that are already well developed, in which the evaluation can focus on cost. Late-stage tenders are likely to be the best approach for starting off trials of IPTs. They are simpler to evaluate, based on the price offered by different bidders to build and operate a line according to a single detailed design. By contrast, early-stage tenders lead to offers with different designs and require more assessment of the viability of the proposed solutions.
- **Determine payments to IPTs based on availability.** International experience shows that it is best to expose IPT bidders to risk on their performance in ensuring high levels of availability, but not to expose them to risk on the volume or value of flows along the line. The availability targets are typically close to 98 percent and this, together with other requirements, needs to be set out in a Transmission Service Agreement (TSA) with the IPT. The TSA should include an obligation to commission the line in accordance with the technical specifications by a defined date (often referred to as the commercial operation date).
- **Ensure adequate revenue and credit enhancement where needed.** IPTs will be implemented on a project finance basis. Financiers need confidence that the contractual payments will be received, for example, through the use of escrow accounts if the sector as a whole is not profitable. Where escrow arrangements are not enough to make the project bankable, governments may also have to use a government guarantee to back payment obligations to IPTs. If the sovereign guarantees are insufficient, multilateral guarantees may be needed.
- **Tailor IPT projects to attract international investors.** African governments that want to try IPTs should ensure that the tenders offered are of sufficient size; that they face no particular environmental or permitting challenges; and that there is a pipeline of future projects. The projects should be large enough to justify the transaction costs. In some cases, this may mean bundling several projects into a single tender. In Peru for example, capital costs ranged between US\$52.2 million and US\$291.0 million, from a sample of

14 transmission projects tendered between 1998 and 2013. On average, capital costs were US\$116.2 million.

- **Prepare to implement IPT transactions.** Governments will need to seek transaction advisers, prepare TSAs and bid documents, define eligible bidders, and conduct a market sounding. The TSA will include the contract term, payments, performance obligations and incentives, indexation, and force majeure among other things.
- **Run competitive tenders.** The final step will be to run a tender, evaluate bids, and award an IPT contract.

There is potential to develop IPT programs in Africa that will be attractive to international bidders. To achieve this, governments should work with international investors and potential providers of loan finance to build detailed business models that will attract international interest, and can be replicated across the African continent. The next key step is to move beyond merely considering how this business model applies within Africa, and piloting a few projects.

Note

1. A. Eberhard et al., “Independent Power Projects in Sub-Saharan Africa: Lessons from Five Key Countries,” World Bank Publications (2016).

SECTION 1

Introduction

Africans lack access to electricity.¹ Only 35 percent have access, and those who do consume relatively little, face frequent outages, and pay high prices.

Reaching Africa's access and consumption targets will require additional investments in generation. Electricity generation capacity in the region is just 98 megawatts (MW) per million people, well below the 203 MW per million people in South Asia, 604 MW in Latin America and the Caribbean, and 803 MW in Middle East and North Africa.²

Building more transmission infrastructure will also be key to closing the generation and distribution gaps. Africa needs generation capacity to create electricity, distribution networks to deliver it to consumers, and transmission lines to link the two ends of the power supply chain. Investments in transmission will also allow access to low-cost generation capacity and increase security of supply.

Government-owned companies finance most transmission investment in Africa

Government-ownership was the dominant model around the world until the 1990s. However, many countries have replaced, or complemented, the government-owned model with privately financed transmission.

In most countries in Africa, government-owned companies still finance most or all transmission investment. In most cases these companies also have exclusivity over the transmission grid and finance all transmission investments.

In some countries legislation establishes an exclusive franchise for transmission, effectively prohibiting privately financed transmission models. One such country is Senegal. A few countries have two transmission networks. Examples include Mozambique, where the vertically integrated utility, Electricidade de Moçambique (EDM), and the Mozambique Transmission Company (MOTRACO) both own and operate transmission lines.

Government-owned companies almost always finance new investment relying on finance from the national governments, Development Finance Institutions (DFIs), and other financiers such as China. Under these financing models, government-owned utilities generally undertake the preparatory work; manage the construction using a range of contractors for particular tasks; and operate and maintain the transmission line after it is commissioned.

New approaches to financing transmission are needed

Historic investment in the power sector in Africa is below the forecast investment needs. The average annual spending in the past decade in the African power sector has been about US\$12 billion, or 2 percent of the Gross Domestic Product (GDP). This accounts for 19 percent to 36 percent of the estimated investments needs.

Given this trend, Africa's traditional approach to financing transmission needs to be supplemented. In most countries in Africa the utilities are not profitable and their borrowing requires government support. This financing model is hitting constraints on the total level of government borrowing.

A major role for government finance is likely to continue. However, public funding will not be enough to meet the investment needs in the transmission sector. Introducing some degree of private finance would help to meet the access targets.

New sources of private finance for expanding the transmission network can be raised provided the business model is right. In the generation sector in Africa, investors in IPPs carry the risk for the cost, timely completion, and performance of their plant. IPPs have made investments of US\$25.6 billion, with an installed capacity of 11 gigawatts (GW).³

Internationally a similar business model for independent power transmission (IPTs) has raised large

amounts of capital for transmission investments.⁴ Under this business model individual lines are put out to tender. The winning bidder carries the risk on timely commissioning, and capital and operating costs, and performance. Revenues are largely set by the bid and the main performance indicator is the availability of the transmission line. Repayment is over a contract term varying from 20 years to 45 years.

The use of IPTs in Brazil, Peru, Chile, and India collectively raised over US\$24.5 billion of private investment between 1998 and 2015. It also enabled close to 100,000 km of new transmission lines.⁵

Just as private finance has expanded transmission infrastructure in other countries, and generation in Africa, it can also expand transmission in Africa.

Implementing IPTs in Africa, or other models to attract private investment, presents serious challenges. Privately financed transmission in Africa will only happen if governments adopt policies supportive of this, and establish the right business, regulatory, and legal environment to attract investors. Developing such policies and the enabling environment will require building consensus among various entities including Ministries, regulators, and utilities. Some stakeholders may resist private ownership of transmission, particularly given the role of transmission in tying the power system together, and the traditional link with other central functions such as system planning and operations.

However, this report describes why IPTs are the most appropriate business model for privately financed transmission in Africa and sets out practical steps to introduce IPTs in Africa to scale up transmission investments.

The report was developed in response to requests from interested African countries, and through consultation with various stakeholders

Some African countries—mainly Nigeria and Kenya—have started to develop policy frameworks for private sector participation in transmission. During this process, they have been evaluating the right business, regulatory, and legal environment to attract investors.

The report benefitted from close collaboration with public entities in Africa. Preparing the report involved three workshops and several consultations. The first two were hosted in Nairobi and Abuja, where international experts shared their experiences in attracting private investment in transmission with local stakeholders. A third workshop was held in Arusha at the East Africa Power Pool's (EAPP) Ministerial Conference, where preliminary findings were

presented to seven Ministers of Energy from EAPP countries. Private developers and transmission companies also provided inputs on the topic.

Objective and structure of the report

The objective of the study is to support the mobilization of private capital for greenfield IPTs in Africa. To do this, the report analyzes different business models, frameworks, and underlying ecosystems for scaling up IPTs in Africa, and provides recommendations on specific pipeline transactions.

This report is divided into two parts. Part A is structured as follows:

- Section 2 sets out the main facts and data about the power sector in Africa, describes the investments needs, the benefits from increasing transmission infrastructure in Africa, and the rationale for using new approaches to financing and delivering transmission
- Section 3 defines the four main business models used for financing transmission investment globally
- Section 4 looks at experience to date in attracting private investment in generation and transmission in Africa
- Section 5 explains why the IPT business model is the most broadly applicable, and most promising, model to increase privately financed transmission investment in Africa

Part B looks at how to scale-up private participation in transmission in Africa:

- Section 6 looks at the steps needed to implement IPTs in Africa, and potentially realize benefits similar to those achieved by IPTs in other countries, and by IPPs in Africa
- Section 7 includes a Toolkit for government officials and policymakers in Africa to implement an IPT transaction

Appendix A provides case studies of private investment in transmission in Brazil, Chile, India, Peru, and the Philippines.

Appendix B provides a pipeline of transmission projects in Kenya and the South African Power Pool that could be privately financed through the IPT business model.

Methodology

A significant amount of data on transmission projects and power sector figures has been collected and

analyzed for this report. Sources include a series of World Bank databases, including the Private Participation in Infrastructure database, data collected through the study “Making power affordable in Africa and viable for its utilities,” data from the International Energy Statistics, and others. The authors also conducted interviews with different stakeholders and primary and secondary research on new privately financed transmission projects.

The report includes five case studies, of Brazil, Chile, India, Peru, and the Philippines. Four of the case studies look at experiences with IPTs, and the case study of the Philippines looks at the performance of long-term concessions for the whole of the grid rather than individual lines.

The five case study countries were selected because they present successful examples of private sector participation in transmission. Three countries are from South America as the region accounts for “more than one-third of the global power sector project investment with private sector participation in developing countries.”⁶ Brazil, Chile, and Peru also stand out in attracting privately financed transmission through IPTs.

The per capita income levels of some of the selected countries when they introduced IPTs was similar to the per capita income levels of the African countries considering the introduction of IPTs today. For example, Peru’s GDP per capita in 1998 was US\$3,266 and India’s GDP per capita in 2006 was US\$1,056. In comparison, Kenya’s current GDP per capita is US\$1,113 and Nigeria’s is US\$2,535.⁷

The selected countries also had vertically integrated and majorly state-owned power sectors until three or four decades ago, similar to most African countries today. Electricity utilities were mainly vertically integrated and there was little role for competition. Investments were mainly decided through central planning, and financed by government-owned businesses.

However, all the selected countries undertook major power sector reforms. These were underpinned

by legislation; unbundled transmission; and started by attracting private investment into generation before transmission—often IPPs selling to incumbent power utilities under long term PPAs. In the five case studies in this report, private sector participation in transmission came after the development of private finance in generation through IPPs.

Notes

1. Africa in this report refers to Sub-Saharan Africa and excludes North Africa and Djibouti.
2. Castalia. Electricity capacity (million kW a year). Data sourced from International Energy Statistics, “Total Electricity Installed Capacity 2014,” IEA, 2014, <https://tinyurl.com/hqe2nys> (accessed December 2, 2016); data sourced from Trimble, C. et al., “Total installed capacity—calculated excluding regional projects,” 2016, <http://data.worldbank.org/data-catalog/affordable-viable-power-for-africa> (accessed October 30, 2016).
3. A. Eberhard et al., “Independent Power Projects in Sub-Saharan Africa: Lessons from Five Key Countries,” World Bank Publications (2016).
4. This report uses the term IPT for a privately financed transmission line (independent power transmission project) to compare with generation privately financed by IPPs (independent power projects).
5. PPI Project Database, World Bank and PPIAF, ppi.worldbank.org (accessed September 9, 2016). Total investment is defined as the sum of investment in physical assets and payments to the government. Investments are recorded in millions of US\$. From this investment, 87 percent was done after 2006. Data includes only greenfield projects.
6. ESMAP, “Private Sector Participation in Electricity Transmission and Distribution: Experiences from Brazil, Peru, the Philippines, and Turkey,” Knowledge series, no. 023/15, 2015.
7. World Development Indicators, GDP per capita (constant 2010 US\$), World Bank national accounts data, and OECD National Accounts data files, <http://data.worldbank.org/indicator/NY.GDP.PCAP.KD>, (accessed May 10, 2017).

PART A

**FINANCING
POWER
TRANSMISSION:
CHALLENGES
AND
OPPORTUNITIES**

SECTION 2

Africa needs transmission investment and new approaches to financing and delivering it

Across Africa, access to electricity is low. Those with electricity use relatively little and face an unreliable supply. Low electricity access also hinders economic growth. Productivity is lower, fewer jobs are created, the provision of education and health suffers, and fewer people have access to communication.

Increasing access to, and use of, electricity will require substantial investment throughout the power sector. Building more transmission infrastructure will be essential to expanding the power sector. Investment in transmission will be necessary to link generation and distribution infrastructure, to allow access to low-cost generation capacity, benefit from economies of scale, and increase security of supply.

In most African countries, government-owned utilities finance all transmission investments. Given the scale of investment required, private finance can play a role in meeting the energy requirements in Africa.

This section sets out the facts and data about electricity access, consumption, generation, distribution, and transmission adequacy in Africa, and reports on the amount of investment needed across the power supply chain. This section also describes why transmission is an essential part of that overall expansion, and explains the rationale to pursue private finance.

2.1 Access to electricity is low in Africa

Access to electricity in Africa is low. Only 35 percent of people in Africa have access to electricity. This is well below the 78 percent in South Asia, the region with the second-lowest level of access to electricity. Access

in all other regions of the world is above 96 percent. The left side of Figure 2.1 shows the level of access to electricity by world region. Africa is at the top, and the chart includes the world percentage for comparison.

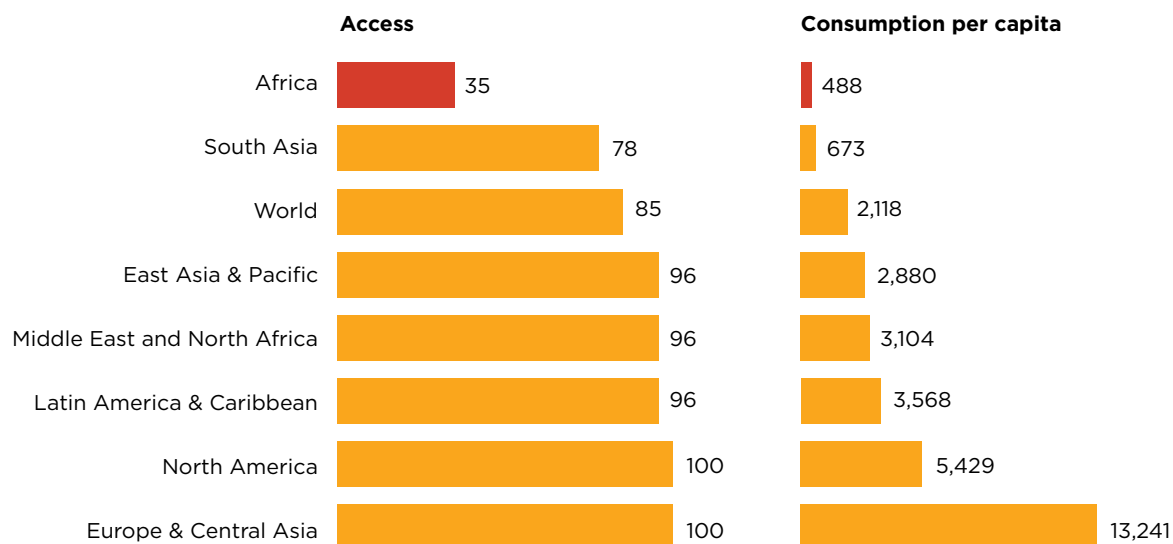
Those with access to electricity use relatively little. Per capita consumption of electricity in Africa is estimated at 488 kilowatt hours (kWh) per year—the lowest in the world, as shown in the right side of Figure 2.1. It compares to 673 kWh per capita in South Asia, the region with the second lowest level of access to electricity. As Figure 2.1 shows, more industrialized regions like North America consume 10 times the level of electricity consumed by Africa.

Consumers in a number of countries in Africa who access the grid also pay high prices and face frequent power shortages. Planned blackouts and unexpected power interruptions result in economic losses estimated at between 1 percent and 5 percent of the GDP of the countries they live in.¹

Low access to electricity and unreliable supply of power hinders the region's development. The low access “result[s] in a loss of significant benefits—such as productivity gains in business, the creation of new jobs, opportunities to study at home, improvements in health, and better communication via television and radio.”² Providing more access to electricity is key to reversing this situation.

International organizations and governments in Africa are aiming for people in Africa to have significantly greater access to electricity by 2030. Yet, reaching these people will be a challenge and require significant investment. The ‘Sustainable Energy for All’ program—a United Nations and World Bank initiative—targets universal access to modern energy

Figure 2.1 Access to electricity and electricity consumption (percentage of population; kWh per person per year)



Source: Castalia. Access to electricity and electricity consumption (Percentage of population; kWh per person per year). Data sourced from World Bank, "Access to electricity (% of population)," SE4ALL, 2012, <http://data.worldbank.org/indicator/EG.ELC.ACCS.ZS> (accessed November 17, 2016); data from World Bank, "Electric power consumption (kWh per capita)," OECD/IEA, 2013, <http://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC> (accessed January 10, 2017).

by 2030. Under this program, Nigeria targets 75 percent access by 2020 and 90 percent by 2030. To meet this target, the Government of Nigeria needs to almost triple the country's on-grid supply by 2030.³

2.2 Increasing access and consumption will require a major expansion of supply

Where generation is scarce, people cannot use much electricity. So Africa needs generation capacity to create electricity, distribution networks to deliver it to consumers, and transmission lines to link the two ends of the power supply chain. Estimates of the annual investments required for generation, distribution, and transmission from 2015 to 2040 range from US\$33.4 billion to US\$63.0 billion.⁴

Increase generation to achieve access and consumption targets

Africa has much lower installed generation capacity than other regions. Africa will need to substantially increase that capacity to achieve its access and consumption targets. Figure 2.2 shows the installed generation capacity per person. In Africa, installed

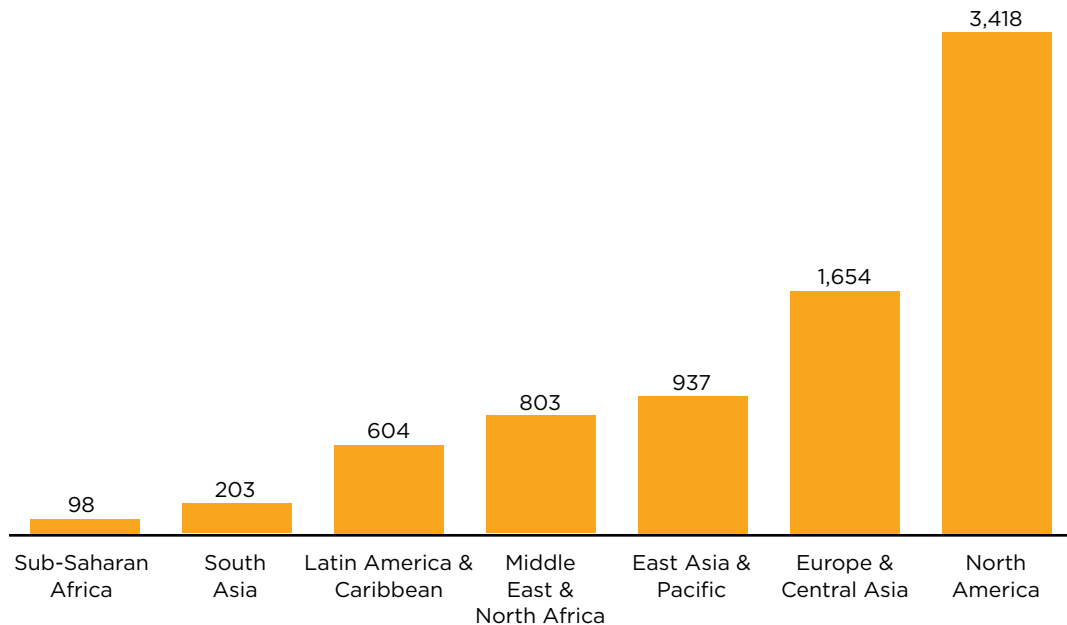
generation capacity is 98 megawatts (MW) per million people, well below the 203 MW per million people in South Asia, 604 MW in Latin America and the Caribbean, and 803 MW in Middle East and North Africa. More industrialized regions like Europe and Central Asia and North America have much higher levels of installed generation capacity per capita.

To reach consumption targets, Africa needs to install 292 gigawatts (GW) of new additional generating capacity by 2040, at an estimated cost of US\$19.6 billion a year between 2015 and 2040.⁵

Invest in, and expand, the distribution network

Building new generation capacity will not be enough; Africa also needs to expand its distribution network to connect people to electricity. Achieving this will require major investment.

In Africa, access to electricity averages 35 percent, and two of three households are not connected. This means that more than 600 million people have no access to electricity. For countries such as South Sudan, Chad, and Burundi, access to electricity averages only 10 percent. Estimates of the annual investments for distribution from 2015 to 2040 range from US\$10.6 billion to US\$14.2 billion a year.⁶

Figure 2.2 Installed capacity (MW per million people)

Source: Castalia. Electricity capacity (million kW per year). Data sourced from International Energy Statistics, "Total Electricity Installed Capacity 2014," IEA, 2014, <https://tinyurl.com/hqe2nys> (accessed December 2, 2016); data sourced from Trimble, C. et al., "Total installed capacity - calculated excluding regional projects," 2016, <http://data.worldbank.org/data-catalog/affordable-viable-power-for-africa> (accessed October 30, 2016).

2.3 Transmission is needed to tie the electricity system together

Africa also lacks transmission capacity. Of 38 countries, 9 have no transmission lines above 100 kV lines. The combined length of transmission in 38 countries in Africa is 112,196 km.⁷ By comparison, Brazil has a longer transmission network than Africa at 125,640 km. And, at 257,000 km, the United States of America (United States) has more than twice the length of the African transmission network.⁸

Africa has fewer kilometers of transmission lines per capita than other regions, as Figure 2.3 shows.⁹ The length of transmission lines in Africa is 247 km per million people. Excluding South Africa,¹⁰ this indicator drops to 229 km per million people. In contrast, Colombia has 295 km of transmission lines per million people, Peru has 339 km, Brazil has 610 km, Chile has 694 km, and the United States has 807 km.

Estimates of annual investments required for transmission in Africa, between 2015 and 2040, range from US\$3.2 billion to US\$4.3 billion.¹¹

Investment in the transmission sector is needed to connect the generation capacity and distribution network. This connection will allow access to low-cost

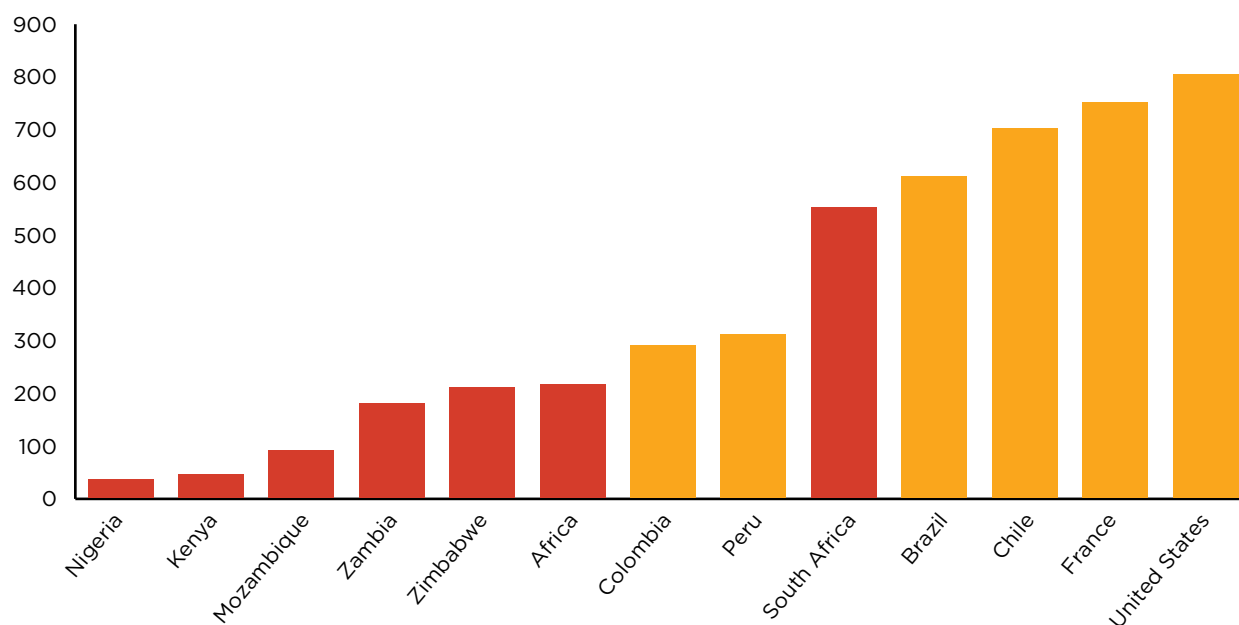
generation capacity, benefiting from economies of scale, and increasing security of supply.

Economies of scale on the supply side mean that generation costs decrease the larger the scale of the power plant. Transmission enables this large-scale generation to connect to load. This is particularly important in Africa, as the region has major hydro-power resources. Economies of scale in transmission also reduce overall costs; as transmission costs decrease, the larger the scale and the higher the voltage. Higher voltages also generate lower transmission losses. In addition, by connecting multiple generators, transmission lines also provide resilience and backup to any generation at the distribution or household level.

Building more transmission lines and upgrading the transmission capacity will be an essential part of the overall expansion of the electricity sector. As Africa needs transmission within and between countries, investments are required at a national and regional level.

Africa needs to invest in very diverse types of transmission lines

Africa needs to invest in long distance lines, using both alternating current (AC) and direct current (DC)

Figure 2.3 Transmission lines per capita (km transmission lines per million people)

Source: Castalia. Data sourced from Trimble, C. et al., "T&D Data – State owned national grid T&D data," 2016, <http://data.worldbank.org/data-catalog/affordable-viable-power-for-africa> (accessed October 30, 2016); Rafael Ferreira, "Private Participation in Transmission Expansion: the Brazilian Model", Presentation from consultation workshop, Nairobi, Kenya, September 26, 2016.

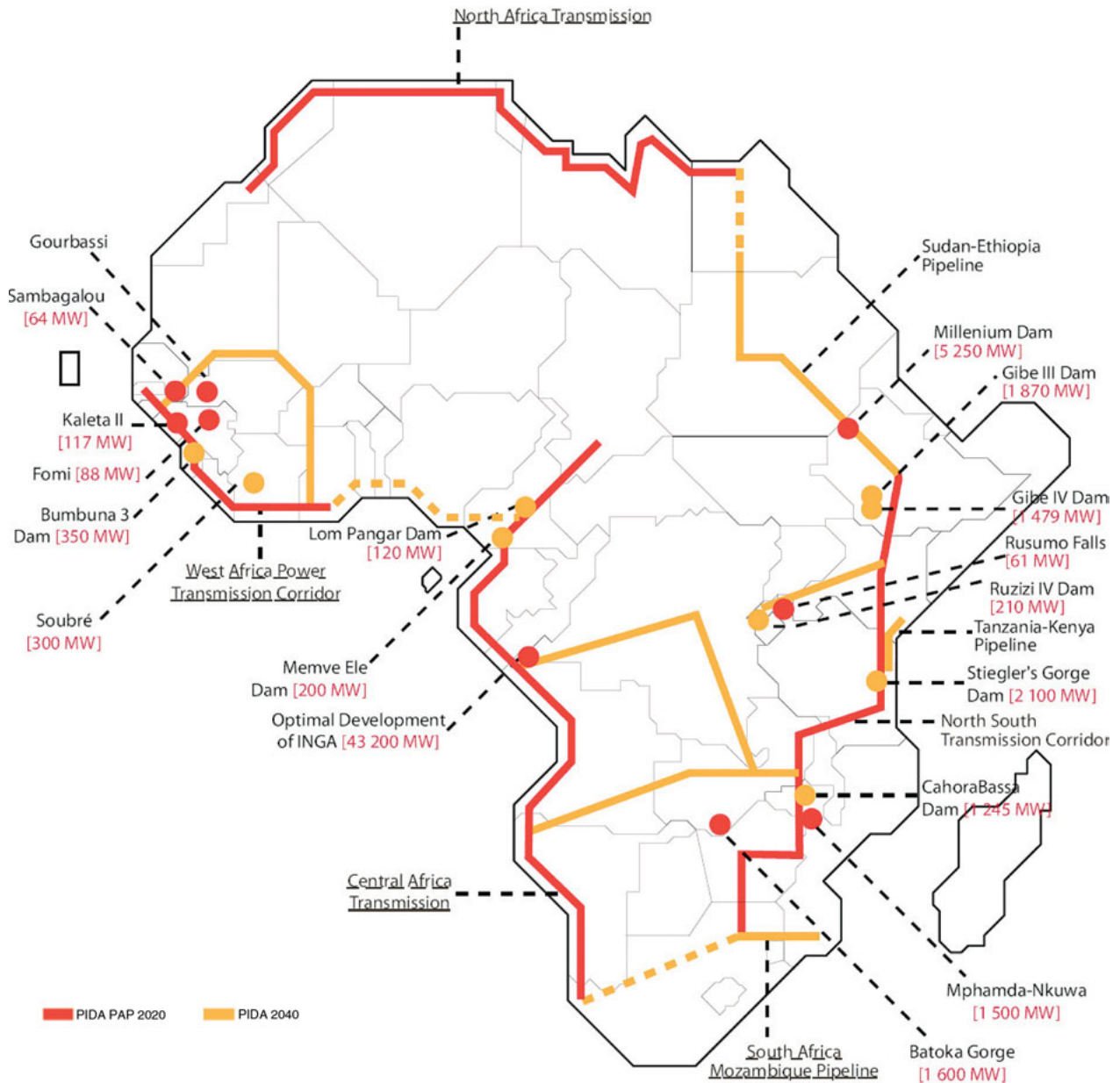
technologies, and to expand in-country transmission networks at a range of voltages. Africa has large, low-cost, hydro-generation resources, but these are mostly far from the load they could serve. Transmission investment is needed to connect these resources to consumers, including investment in transmission connections between countries. As an illustration, the transmission investment needed for the Grand INGA hydro project (of more than 40 GW) to supply the Democratic Republic of the Congo (DRC) and the wider region is estimated at US\$40 billion.¹²

Figure 2.4 locates potential large-scale, hydro-generation plants and major transmission interconnections to be developed in Africa by 2020 and 2040.¹³ The figure shows almost twenty generation projects (hydro dams), and four major transmission projects that will connect the dams to the load, and so help foster regional trade. The four projects are West Africa Power Transmission Corridor, the Central Africa Transmission interconnection, the North South Transmission Corridor, and the North Africa Transmission interconnection.

The projects range in length, transmission capacity, and estimated cost, but all require substantial investment. For example, the estimated length of the West Africa Power Transmission Corridor is

2,000 km. Reaching from Nigeria to Guinea, the project is expected to have a transfer capacity of 1,000 MW and cost about US\$1.2 billion. In contrast, the Central Africa interconnection will cover a 3,800 km line. Reaching from Chad to South Africa, the project is expected to have a transmission capacity of 17,000 MW and cost about US\$10.5 billion.

Investments in transmission are also needed to reduce costs by connecting large generators to consumers within countries, stabilize national transmission systems, and meet growing demand. For example, in 2014 the Transmission Company of Nigeria (TCN) estimated that the country needed to expand its transmission capacity from 7 GW to 10 GW by 2017, and to 20 GW by 2020. Expanding the transmission capacity will require an expansion of the transmission network. TCN prepared an expansion plan that specifies transmission lines to be installed by 2017 and by 2020. Figure 2.5 shows a map of Nigeria's transmission system in 2014. It includes transmission lines being developed in 2014 and the transmission lines included TCN's expansion plan (to be installed by 2017). These lines are divided between 132 kV and 330 kV lines. The existing transmission lines were removed from the map, reflecting how important the transmission in Nigeria needs are.

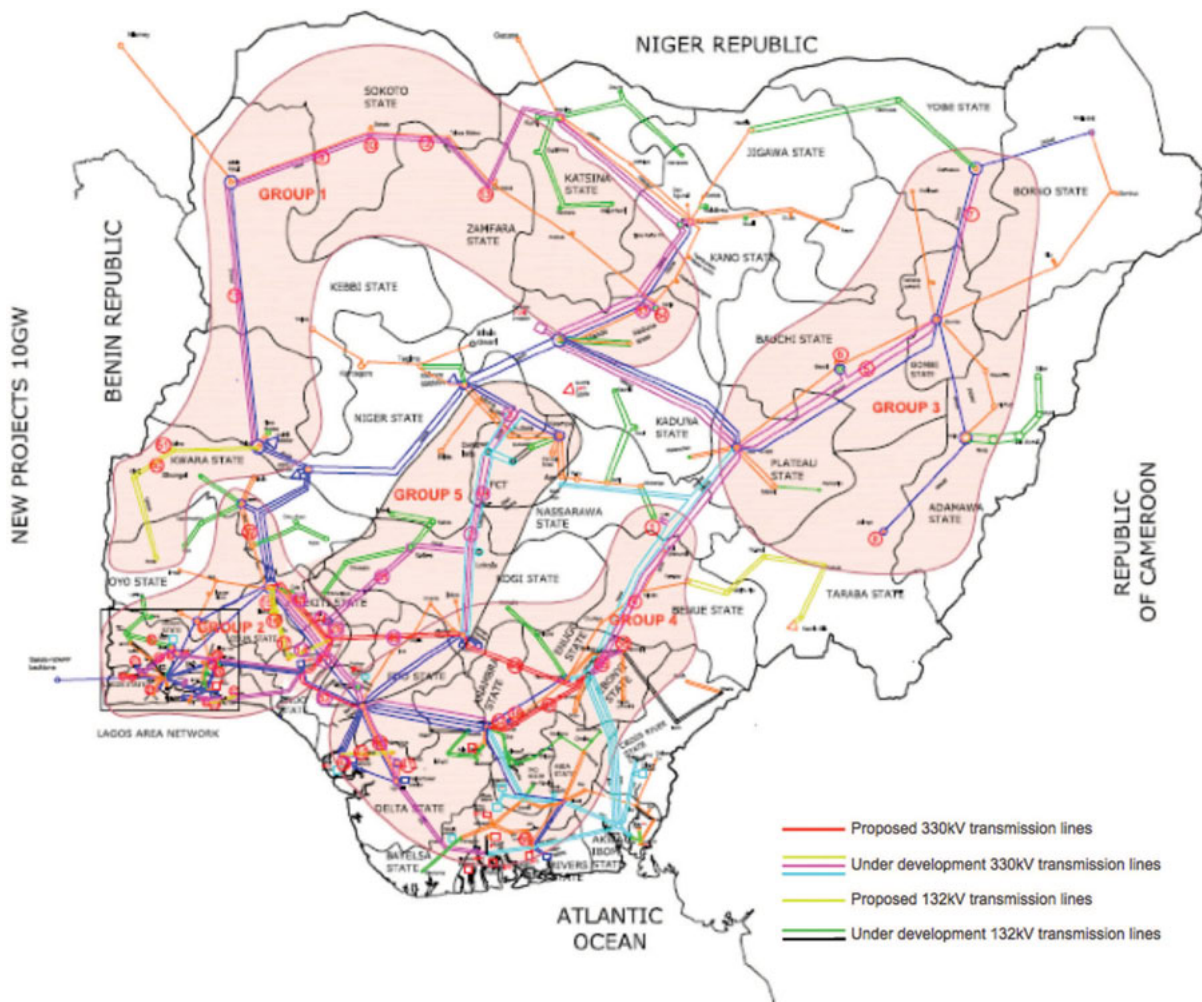
Figure 2.4 Major potential generation and transmission projects in Africa

Source: Figures sourced from African Development Bank (2013), Annex 1.

In-country investments are also of diverse types. Projects range in length, voltage, and estimated costs. In Kenya, the Kenya Electricity Transmission Company (Ketraco) expects to develop approximately 7,000 km of transmission lines by 2020—including 2,200 km of 132 kV lines, 2,400 km of 220 kV lines,

2,000 km of 400 kV lines, and 612 km of 500 kV High Voltage Direct Current (HVDC) lines. Some of these lines are being developed; others are yet to be implemented. Table 2.1 shows a sample of the transmission lines planned for 2020 but not yet being developed, including the estimated cost of each line.

Figure 2.5 Map of Nigeria's transmission system, showing transmission lines being developed and proposed



Source: Transmission Company of Nigeria, "Appraisal of Transmission Projects," (2014), (pers. comm. with Patricia Mong, November 17, 2016).

Table 2.1 Sample of Ketraco's planned transmission lines

Project	Scope	Estimated costs (US\$ million)
Gilgil-Thika-Nairobi East and associated substations	205 km 400 kV Line with Substations in Longonot, Thika, Kangundo and Konza	128.7
Isinya-Konza-Nairobi East	105 km of 400 kV double circuit line and Konza 400/132 kV Substation	41.9
Nyahururu-Maralal and associated substation	148 km 132 kV Line and 1 No. 7.5 MVA Substation at Maralal	25.3
Garsen-Hola-Garissa and associated substations	240 km 220 kV or 132 kV single circuit Line and 1 No. 7.5 MVA Substation at Hola	90.6
Garissa-Wajir and associated substations	330 km 132 kV single circuit Line and 1 No. 23 MVA Substation at Wajir	92.6

Source: Kenya Electricity Transmission Company (Ketraco), "Transmission System Planning and Implementation: Planned Projects and Financing Gap," Presentation from consultation workshop, Nairobi, Kenya, September 26, 2016.

Transmission can also increase security of supply and enable integration of intermittent renewables

Transmission infrastructure also allows consumers to connect to diverse sources of power generation that draw on a range of fuels. This reduces the risks to power supply. For example, the central region of Mozambique has important hydropower and coal reserves. These reserves give it the potential to generate high amounts of electricity that the south region could also benefit from. But the transmission system in the central region and the transmission system in the south region are not connected to each other. If consumers in the south region are to benefit from the additional diverse generation sources, a transmission line is required. The Government of Mozambique has had plans to develop this line for several years—under a project known as Sociedade Nacional de Transporte de Energia (STE)—but the project has not progressed further. This project would be one key way to improve Mozambique's security of supply.¹⁴

Transmission also enables the integration of intermittent renewables (such as wind power and solar power). Transmission ensures that the power system remains in balance, by keeping reserves to offset power fluctuations from such renewables. Providing reserves to support the integration of renewables has substantial economies of scale: the costs are lower for larger regions. Transmission achieves these cost reductions and ensures that the costs of integrating renewables are minimized.

2.4 New approaches to finance and delivery of transmission are needed

In most countries in Africa the government-owned companies finance all transmission investments. Africa has much lower installed transmission capacity than other regions and needs to substantially increase that capacity to meet the access and consumption targets.

Historic investment in the power sector under this model has been well below the forecast investment needs. Estimates of annual investments required for the power sector between 2015 and 2040 range from US\$33.4 billion to 63.0 billion. The average annual spending in the past decade in the African power sector has been about US\$12 billion.

A recent World Bank study¹⁵ shows that only 2 of 39 utilities in Africa collected enough cash to recover their operational and capital costs. The causes of this

very weak performance are a mix of high costs and low revenues. Costs are high because of small size, weaknesses in operational efficiency, and the share of high-cost oil generators. Revenues are low due to underpricing and poor recovery.

In part, these financial problems are caused by high costs. African countries have a high share of expensive oil-fired generation and a range of other cost inefficiencies. A move to best practice could help to reduce costs.

But this will not be sufficient to move most African utilities to financial viability. Those utilities would continue to make a loss even if efficiency were raised to international benchmarks. The study looked at how the finances of African utilities would improve if the cash collection was 100 percent, network losses were reduced to 10 percent or lower, and staffing levels were the same as well-performing utilities in Latin America. If these assumptions became reality, the change would be sufficient to move another 11 African utilities to viability.¹⁶ Even so, most utilities would still fail to recover costs—even after the ambitious improvements in efficiency.

In addition, African governments cannot provide funds for the utilities to reach financial viability. Governments are constrained by fiscal limitations originating outside the power sector, and market perceptions based on their overall fiscal position and on aggregate indicators, such as the ratio of annual deficits or total debt to GDP. This means that they may not be able to borrow to invest, even on financially viable projects that could eventually improve their fiscal position.

Private sector participation can help unleash the financing constraints

A greater role of private finance could help ease the financing constraints and overcome the transmission deficit.

Project finance can allow state-owned utilities to raise additional finance that would otherwise be unavailable. Project finance separates out a portion of cash flows (and risks) related to particular investments. For example, if a government increases electricity tariffs slightly to finance a transmission project, it will not be able to raise additional finance if the borrowing entity (the state-owned company or the government) remains non-creditworthy. However, if a government increases electricity tariffs slightly, and credibly dedicates the increase to servicing the finance of a viable transmission project developed under a project finance structure, then that increase in revenue will secure additional financing. These

increases are likely to be minor given the contribution transmission tariffs in the cost buildup.¹⁷

Under a project finance structure, the government's guarantee on payment does not make the fiscal position worse. Rather, it makes it credible that a small increase in electricity tariffs that was intended to pay for a financially viable project is really dedicated to that, and not to other debt service or expenditure.

This approach can bring costs down in the medium term. This is possible by achieving cost recovery through cost reflective transmission tariffs. Private finance would allow the state-owned utility, or the government, to pay competitive and cost-reflective transmission prices. For example, in all the case studies the use of transmission tenders led to strong competitive tension and downward pressure on prices. As described in the Brazilian and Peruvian case studies, the winning bid was often well under the price cap. Box 5.1 also discusses how IPTs can reduce whole of life costs.

As the private sector invests in financially viable transmission projects, this can also have spillover effects. With higher transmission capacity, utilities can also increase electricity sales and reduce generation costs.

Private involvement can also bring managerial skills, technical knowhow, and performance incentives. Tenders to finance transmission investments will attract international bidders. Several firms are already monitoring possible opportunities for IPT tenders in Africa, a project finance model. International investors would have an equity exposure to the performance of the transmission lines they develop. African countries will benefit from the incentives

these companies have to transfer knowledge and skills, and to develop in-country management and technical capability.

Private investments can also bring stronger accountability. The contract between the government and the private company will include performance obligations. These are specific outputs defined in the contract (project timeline, quality, and quantity). If the private company does not meet these obligations, the government will reduce the payments to the private sector.

Given these conditions, utilities in Africa are already looking to the private sector to finance transmission investments. Ketraco, the transmission utility owned by the Kenyan Government, estimates a financing gap of at least US\$5.9 billion between 2013 and 2030. This represents a financing gap of at least 90 percent. Ketraco is interested in exploring how Public Private Partnerships (PPPs) could assist in financing the transmission projects included in its 2013–2030 Least Cost Power Development Plan (see Box 2.1).

Public finance will likely continue to play a role in funding the transmission sector, but its funding will not meet the energy targets and private finance can help bridge the gap.

African governments could develop an approach to increase private investment in power transmission, based on international experience and African experience in generation. In other countries, privately financed transmission has achieved efficiency gains, reduced costs, and opened up access to new sources of finance. African countries would benefit from introducing at least some degree of private finance in the transmission sector, following their successful experience attracting private investment in generation.

Box 2.1 Funding gap in transmission sector in Kenya

Ketraco is the government-owned transmission company of Kenya, incorporated in December 2008.

Ketraco's mandate is to plan, design, build, own, operate, and maintain HV electricity transmission grid and regional power interconnectors (132 kV, 220 kV, 400 kV and 500 kV HVDC lines).

Ketraco estimates that their Least Cost Power Development Plan 2013–2030 requires US\$6.5 billion in investments in transmission. The committed funds amount to about US\$615 million, leading to a financing gap of at least US\$5.9 billion.

Source: Ketraco, (2016).

By September 2016 Ketraco had completed 13 transmission projects (1,099 km), and more than 4,200 km of transmission lines were being built. Ketraco also plans to build about 7,000 km of transmission lines and associated substations from 2015/16 to 2019/20. These lines include:

- 2,200 km of 132 kV lines,
- 2,400 km of 220 kV lines,
- 2,000 km of 400 kV lines, and
- 612 km of 500 kV HVDC lines.

Notes

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4. A. Castellano et al. (2015).
5. A. Castellano et al. (2015).
6. A. Castellano et al. (2015); A. Miketa and N. Saadi (2015). Estimates of transmission and distribution needs are bundled in Miketa and N. Saadi (2015). The range included in the report assumes that the allocation of transmission and distribution investment needs (as a share of the bundled figure included in the A. Miketa and N. Saadi, (2015)) is equal to the allocation in A. Castellano et al. (2015).
7. Data sourced from Trimble, C. et al., “State owned national grid T&D data,” 2014, <http://data.worldbank.org/data-catalog/affordable-viable-power-for-africa> (accessed October 30, 2016). Data available for the following countries: Angola, Benin, Botswana, Burkina Faso, Burundi (x), Cameroon, Congo, Dem. Rep., Congo, Rep., Côte d’Ivoire, Ethiopia, Gabon, Ghana, Guinea, Guinea-Bissau (x), Kenya, Lesotho, Liberia (x), Madagascar (x), Malawi, Mali, Mauritius (x), Mozambique, Namibia, Niger (x), Nigeria, Rwanda, São Tomé and Príncipe (x), Senegal, Seychelles (x), Sierra Leone, South Africa, Sudan, Swaziland, Tanzania, Togo (x), Uganda, Zambia, and Zimbabwe. The nine countries marked with an (x) have no transmission lines above 100 kV.
8. “Energy Transmission in the United states,” Tribal Energy and Environmental Information <https://teeic.indianaffairs.gov/er/transmission/restech/dist/index.htm> (accessed March 13, 2017).
9. The indicator is based on kilometers of transmission lines (excluding lines below 200 kV). This provides some indication of comparative transfer capacity, but it should be recognized that the share of transmission by voltage—and so the ability of these networks to provide transmission services—varies greatly between these countries.
10. South Africa has 31,107 km of transmission lines.
11. A. CASTELLANO ET AL. (2015); A. MIKETA AND N. SAADI (2015).
12. A. Castellano et al. (2015).
13. These projects are those included in the project investment portfolio of the Programme for Infrastructure Development in Africa (PIDA) Priority Action Plan (PIDA-PAP) up to 2020, and up to 2040, in Sub-Saharan Africa and North Africa. Data from African Development Bank, “Interconnecting, integrating and transforming a continent,” Programme for Infrastructure Development in Africa, 2013, <https://www.afdb.org/fileadmin/uploads/afdb/Documents/Project-and-Operations/PIDA%20note%20English%20for%20web%200208.pdf> (accessed March 11, 2017).
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16. Excluding the costs of making the improvements.
17. In Vietnam for example, the transmission charge is 5.5%–6% of the end-use tariff.

SECTION 3

Private finance of transmission has worked well internationally

Private companies finance all or a large share of new transmission investment in many countries.

Several different business models have been used to attract private investment in transmission. The four main business models are privatizations, whole-of-grid concessions, IPTs, and merchant investments. Private finance under these models has brought substantial investment of new transmission to the countries using these models.

Many member countries of the Organisation for Economic Co-operation and Development (OECD) have **privatized** over the last two decades. The United Kingdom privatized three transmission companies in 1991: National Grid, Scottish Power, and Scottish and Southern Energy (SSE). The three companies invested GBP5.6 billion between 2013 and 2016. The forecasted investment for the 2013–2021 period is GBP 16.6 billion.¹

The Philippines currently applies the **whole-of-grid concession** model. The concession was awarded to the National Grid Corporation of the Philippines (NGCP) in 2009. Since then, NGCP has invested over US\$1.9 billion in transmission.

IPTs have also enabled major investment in transmission. IPT tenders in Brazil, Peru, Chile, and India mobilized over US\$24.5 billion from the private sector between 1998 and 2015, enabling close to 100,000 km of new transmission lines. IPTs are also increasingly being used in countries that previously provided exclusivity to a private transmission company—including the United Kingdom, the United States, Canada, and Australia. Canada has awarded 400 km of 230 kV transmission lines, for a total of US\$452 million.² The United States has also awarded more than sixty IPTs, and more are expected in the coming years.³

Merchant investments have been relatively common in the United States, the European Union, and Australia. Neptune Transmission Line—a 104 km line between the states of New Jersey and New York in the United States—had an estimated cost of over US\$600 million. The estimated investment cost of three transmission lines financed on a merchant basis in Australia was US\$1,094 million.⁴

All these models can work, but they work best under different conditions. International experience provides lessons on the preconditions necessary for different business models to work well. These lessons can help policymakers in Africa decide which business models are most appropriate and how best to implement them.

The main characteristics of these different business models are summarized in Table 3.1. The following sections describe each business model in detail, including information about the term and coverage under each model, the way revenues are set, how incentives are defined, and whether the model provides open access or proprietary access. Examples of countries that have attracted private investment in transmission under each model are also provided.

The term concession is used to refer to different types of contracts in different countries. The literature on PPPs often uses the term loosely. In some cases the term concession is used to refer to O&M contracts, where the concessionaire is not obliged to finance new assets.

In this report, and as described in Section 3.2, the term “whole-of-grid” refers to a contract where the private company is responsible for operating and managing the existing transmission network and for financing and building all new transmission investment.

Table 3.1 Business models for private investment in transmission

	Indefinite privatization	Whole-of-grid concession	Independent Power Transmission (IPT)	Merchant investment
Term	Indefinite	Long term: often 25 years or more	Long term: often 25 years or more	Indefinite
Coverage	All existing and new lines within a country or region	All existing and new lines within a country or region	Individual line or package of lines. New lines only	Single major line, often HVDC
Revenues	Annual revenues set by the regulator to ensure a reasonable return on and of capital, and subject to periodic regulatory review	Annual revenues set by the regulator to ensure a reasonable return on and of capital, and subject to periodic regulatory review or to arbitration clauses under concession law	Annual revenues largely or entirely set by the winning bid	Revenues dependent on MWh of flow along the line and price differentials between the two ends of the line
Incentives	Related to whole-of-grid performance	Related to whole-of-grid performance	Availability for the line (typically 98%)	Ability to move power from lower-price areas to higher-price areas
Access	Open access to all transmission users on an equal basis	Open access to all transmission users on an equal basis	Open access to all transmission users on an equal basis	Proprietary access. Access rights used by owner or on-sold

3.1 Model 1: Privatizations

Privatizations provide ownership of the transmission network in a defined area to a private company. In most cases the government implements this business model by privatizing all or a part of a government-owned transmission company. This can be done through a trade sale or a public flotation.

Once privatized, the private transmission owner is responsible for operating and managing the existing network and for financing and carrying out all new transmission investment.

The main characteristics of this model are:

- **Term:** The private transmission company owns the transmission assets they have acquired and new transmission assets they finance. They own both for an unlimited time.
- **Coverage:** The private transmission company has obligations and rights within a defined geographic area. This may be a whole country or a region within a country.

Many countries have a single transmission company. The geographic nature of these rights and obligations is clearer when the transmission company covers a region rather than the whole country. The United Kingdom provides an example.⁵

Two transmission companies operate in Scotland. SSE is the transmission owner in northern

Scotland through a wholly owned subsidiary, SHE Transmission. The transmission company is subject to general license conditions that apply to all transmission companies in the United Kingdom and special license conditions that only apply to the company. The first special license condition (Condition AA) defines the company's transmission area in northern Scotland. The second special license condition (Condition B) states that the licensee shall not make transmission assets available outside this area.⁶ The license also defines the connection between SSE's region and the region of the neighboring transmission company, Scottish Power.

- **Revenues:** Transmission systems are considered a natural monopoly and are subject to economic regulation. The private transmission owner plans require investment. The regulator confirms the prudence of the investment proposals. The approved investment costs are included in the regulatory asset base for the private transmission company and are recovered through transmission charges.

The application of this approach varies greatly between countries, but has shared characteristics:

- Transmission companies are subject to a cap on overall revenues rather than on the price they charge per MWh that they transfer. A revenue

cap is typically used because their costs do not vary in relation to changes in the MWh flowing across the system. A price cap would expose the transmission companies to risk on the demand for transmission network services, but they are unable to manage this demand,

- The revenue cap is set at a level that provides a reasonable return on capital and return of capital. “Return on capital” means that the returns are sufficiently high for the company to finance its investments; “return of capital” means that the revenues cover the depreciation of the assets, and
- Regulatory independence is important to avoid political pressure to keep down electricity prices. Regulatory independence is secured through legislation and governance arrangements for the regulatory body (such as protection from dismissal).
- **Incentives:** The regulatory regime establishes incentives for the privatized transmission companies. The use of a revenue cap means that the transmission company has incentives to minimize costs, while meeting the required quality of service.

The privatized transmission company typically owns the whole transmission grid for a defined area. As a result, the regulatory incentives can relate to the overall performance of the grid.

One example is the reliability incentive for transmission companies in the United Kingdom. This gives the companies incentives to maintain the networks well and avoid disruptions to supply caused by the transmission network. For each of the three transmission companies in the United Kingdom, a reward or penalty is calculated each year based on the total volume of energy not supplied during loss-of-supply events on their networks.

- **Access:** All users of the transmission networks have to get access on a consistent and nondiscriminatory basis to ensure that the wholesale competitive markets work well. This is typically achieved by requiring the transmission companies to publish tariffs and minimum terms and conditions for access to, and use of, the networks that apply to all potential users.
- **Examples:** Many member countries of the OECD have privatized transmission and have since relied purely on private finance for new investment. Examples include:
 - The three private transmission companies in the United Kingdom (National Grid, Scottish Power, and SSE) following the privatizations

in 1991. National Grid now owns and operates 7,200 km of overhead lines, 1,400 km of underground cable, and 329 grid substations.⁷ The three companies invested GBP5.6 billion between 2013 and 2016. The forecasted investment for the 2013–2021 period is GBP16.6 billion. National Grid and SSE are currently investing in the first bi-directional subsea interconnector—Western Link—to transport renewable energy from Scotland to consumers in Wales and England. The project is valued at GBP1 billion and will be operational by the end of 2017,⁸

- The Government of Victoria privatized generation, transmission, and distribution during 1995–1999.⁹ The privatizations in the electricity sector raised A\$22.5 billion,¹⁰
- The privatization of electricity transmission in the State of South Australia in 2000, and
- The progressive sale of government interests in German transmission companies during the 1990s.¹¹

Examples of mixed ownership also exist. For example, the Réseau de Transport d’Électricité (RTE) is a wholly owned subsidiary of Électricité de France (EDF). EDF is 85 percent owned by the Government of France, with the remaining 15 percent traded on the Paris stock exchange.

Full privatization of the transmission network has been less common in low-income countries. Some countries in South America privatized part or the entire transmission sector in the 1990s. However, the focus of this report is on financing greenfield transmission. The private transmission companies in South America do not have exclusivity for financing new transmission investment, like the case of Argentina and Chile, or did not last long, like the case of Bolivia.

In 1993, the Government of Argentina granted a 95-year concession (in effect privatizing) to operate the national transmission grid (Transener). The contract is to operate and maintain the transmission networks, and the private company is not responsible for the expansion of the system.¹² New transmission investments in Argentina are publicly and competitively tendered by the Government. Transener can bid in the tender.

The Government of Bolivia privatized Ende¹³ Transmisión, the country’s largest transmission company, in 1997. In this case, the private company had the obligation to invest in new assets. However, Ende Transmisión was nationalized in 2012, as part of

a broad program, which also included nationalizing generation and distribution companies.

3.2 Model 2: Whole-of-grid concessions

Whole-of-grid concessions provide similar rights and responsibilities to privatizations, but for a shorter period. In most cases, the government implements this business model by the competitive tender of the concession and enters a concession contract with the winning bidder.

Once the concession contract is awarded, the private concession company (the winning bidder) is responsible for operating and managing the existing network and for financing and carrying out all new transmission investment.

The main characteristics of this model are:

- **Term:** The concession term is defined in the contract. The typical duration is 20–30 years. Some contracts include an option to extend the time for a further period.
- **Coverage:** The concessionaire has obligations and rights within a defined geographic area. In most cases this covers the whole country. The concession may be limited to the main grid and exclude small, isolated grids.
- **Revenues:** The revenues for the concessionaire are set through a regulatory process. This may be an independent economic regulator. Alternatively, the concession contract may define processes for modifying the concessionaire's revenues as the cost base changes and may define processes for arbitration of any disputes between the concessionaire and the government.

The Philippines transmission concession provides an example of the revenues being set by an independent economic regulator. The Electricity Power Industry Reform Act 2001 authorizes the Energy Regulatory Commission (ERC) to establish and enforce a methodology for setting transmission wheeling rates. The rates must allow the recovery of just and reasonable costs and a reasonable return on the rate base to enable the entity to operate viably. The ERC has developed rules for setting a cap on the maximum annual revenues that the concession company can earn from wheeling charges.

- **Incentives:** The regulatory regime establishes incentives for the concession company in a similar way to the incentives for privatized transmission

companies. These incentives also relate to the overall performance of the grid.

The transmission concession in the Philippines provides an example. The performance incentive scheme (PIS) is based on availability, frequency and severity of interruptions, compliance with frequency and voltage limits, and customer satisfaction. The regulatory approved payment (under the PIS) of 609 million Philippine Peso (PhP) in 2012. This compares with a maximum annual revenue of around PhP45 billion. The PIS is low in relation to total revenues, but significant enough to affect the equity returns and to provide an incentive to the concessionaire to act.

- **Access:** All users of the transmission networks get access to the transmission network on a consistent and nondiscriminatory basis.
- **Examples:** The transmission concession in the Philippines provides an example of significant investment under this model. Total investment in transmission in the Philippines was close to US\$4.2 billion. Over US\$1.9 billion was invested in physical assets.¹⁴ NGCP has also reached performance targets. NGCP has consistently exceeded grid loss thresholds and reduced losses through reducing tripping frequency and improving availability. For example, availability for the regions of Visayas, Mindanao, and Luzon was between 99.6 and 99.8 percent in 2016.¹⁵

Whole-of-grid concessions have also been used in Africa, including in Cameroon, Mali, and Senegal (see Section 4.1). In these cases, the government has retained a considerable share of ownership. In the case of Mali, the Mali Government granted a concession in July 2000, retaining 40 of the shares. However, in October 2005, one of the private concessionaires sold its shares and the Government kept 66 percent of the shares, and has been the majority owner of EDM since then.

3.3 Model 3: Independent power transmission

IPTs provide rights and obligations associated with a single transmission line or a package of a few lines. In most cases the government implements this business model by tendering the contract. In some cases the contract is directly awarded.

Once the contract is awarded, the IPT (the winning bidder) is responsible for building and operating the line or package of lines defined in the contract. The IPT has no rights or responsibilities for the

Box 3.1 Summary of outcomes of IPTs internationally

IPTs have led to successful results in various countries:

- Brazil organized 38 tenders of multiple lots from 1999 to 2015. These resulted in the award of 211 concessions and 69,811 km of transmission lines designed, built, and operated under BOOT contracts
- Peru has organized 18 transmission tenders since 1998. These have resulted in more than 6,000 km of transmission lines (and associated substations) designed, built, and operated by the private sector under BOOT contracts
- Chile has organized 7 tenders since 2006. Ten projects were awarded for a total of almost 1,200 km. This includes a recently awarded 140 km, 500 kV line to interconnect their two main systems
- In India, the private sector has developed over 21,000 km of lines between 2006 and 2016. This is equivalent to 10.4 percent of new lines built since the start of the 2002–2007 Electricity Plan, and 6.1 percent of the total network
- Canada has awarded 400 km of 230 kV transmission lines, for a total of US\$452 million. In 2014, the Alberta Electric System Operator also awarded a 500 km 500 kV transmission line for US\$1.4 billion.¹⁶ The estimated operations start date is 2019
- The Federal Energy Regulatory Commission (FERC) of the United States removed automatic rights of incumbent transmission companies in 2011. Since then, over sixty IPTs have been awarded, and more are expected in the coming years, and
- Australia recently tendered a contract to upgrade the Heywood Interconnector (a transmission line between South Australia and Victoria) for an estimated cost of close to US\$80 million.¹⁷

existing network or to new transmission investment other than the rights or responsibilities defined in the contract.

The main characteristics of this model are:

- **Term:** The term ranges from 25 years to 45 years. Some contracts include an option to extend the term for a further period.
- **Coverage:** The IPT provides a single line or package of lines. It has no other obligations in the region or country concerned.
- **Revenues:** The required annual payment is a bid parameter. The winning bid largely establishes the payments to be received over the contract term. As discussed in Section 6.6, there may also be limited scope for regulatory review of some aspects of the payment.
- **Incentives:** The contract establishes incentives for the IPT. The IPT has incentives to reach timely commissioning of the transmission line and to minimize the whole-of-life costs. The main performance incentive is to ensure high availability for the transmission line over the contract term.

The IPT is not responsible for how the integrated transmission grid performs, other than ensuring the transmission line, or lines that it owns, is available.

- **Access:** All users of the transmission networks get access to the transmission network on a consistent and nondiscriminatory basis.

- **Examples:** IPTs are widely used around the world, including Mexico, South America (Brazil, Chile, Colombia, and Peru) and India. An IPT for Pakistan is also being negotiated.

IPTs are also increasingly being used in countries that previously provided exclusivity to a private transmission company. The United Kingdom, Canada, Australia, and the United States have introduced IPTs alongside existing private or government-financed transmission companies that previously had regional exclusivity.

Box 3.1 provides a summary of the outcomes of IPTs in several countries around the world.

3.4 Model 4: Merchant investments

Merchant investors build and operate a single transmission line (“merchant line”). In many cases this is an HVDC line. The merchant investor will build the convertor stations at either end of the line. These stations will convert the current from AC to DC and back again. In most cases, merchant lines are a private initiative and not initiated by the government.

- **Term:** The term depends on the life of the merchant line and of any associated agreements.
- **Coverage:** The merchant investor provides a single line and has no wider rights or obligations

for developing transmission within the region or country.

- **Revenues:** Under a “pure” merchant model, the owner of the merchant line uses or sells the rights to flow power along the line, and the revenues for the merchant line depend on the MWh of energy that flows along the line and the price differences between the two ends of the line. As described below, regulatory intervention may affect the revenues and also how the owner sells the transmission capacity.
- **Incentives:** The merchant investor has incentives to maximize revenues. They can mostly achieve this by ensuring high availability of the transmission line during periods when there are large price differentials between the two ends of the line.
- **Access:** Under a “pure” merchant model, the owner of the line sets the price and the terms and conditions for its access. The regulator does not establish regulated terms for access by a third party. Possible variations to these arrangements are discussed in the examples below.
- **Examples:** The scope for merchant links is strongly influenced by the effect of market design on locational price signals and by the regulatory arrangements.

Merchant investments are based on the price differentials between the two ends of the line. The case for merchant lines depends on the nature and strength of locational price differences in the market:

- Many markets in the **United States** have locational marginal pricing—that is, different wholesale prices at each transmission node. This strengthens the case for merchant investments.

Examples of merchant lines in the **United States** include: The Cross-Sound Cable, a 39 km submarine cable that connects New England to Long Island, New York, acquired by a private firm in 2006 for US\$213 million;¹⁸ Neptune Transmission Line, a 104 km undersea and underground transmission link between Long Island and Sayreville, New Jersey (with an estimated cost of over US\$600 million¹⁹); and Path 15, a transmission line constructed in the mid-1980s that connects the northern and southern sections of the California power grid,²⁰ and

- The Australian National Electricity Market (NEM) establishes prices for five regions (these regions coincide with the five members of the NEM: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South

Australia, and Tasmania). Merchant investments are possible between these five regions but not within them

An example of a merchant line in **Australia** is Basslink, a 370 km HVDC interconnection, connecting Tasmania to the NEM. The rationale for the project was to enable Hydro Tasmania to earn higher revenues for its energy by exporting energy during peak periods when prices are higher and importing off-peak. Hydro Tasmania retains the rights to use the line. Figure 3.1 shows Basslink’s route from the island of Tasmania to the mainland in Australia. The project required 290 km of subsea HVDC cable (then the longest HVDC cable in the world), 13 km of AC line in Tasmania and 63 km in Victoria. The line has a rated continuous power of 500 MW and a dynamic power capacity of 630 MW for shorter periods.

The regulatory framework also has a bearing on the approach taken to merchant investments:

- In the United States, the owners of merchant lines need authority from the Federal Energy Regulatory Commission (FERC) to enter into negotiated transmission rates with users of the line. FERC has established four factors to determine whether it will approve the rates. These are the justness and reasonableness of rates; the potential for undue discrimination; the potential for undue preference, including affiliate preference; and regional reliability and operational efficiency requirements. At first, FERC required merchant transmission to allocate capacity using an open season, but it now allows up to 100 percent to be allocated through direct agreement.
- In the European Union, regulation favors development of regulated transmission by the Transmission System Operators (TSOs). However, the European Commission can exempt merchant investments from regulations under defined circumstances.

3.5 Interconnection projects can also use some of these models

This report focuses on in-country transmission investments. That is, investments within one single jurisdiction. However, transmission investments can also provide **interconnection** between two or more countries.

Figure 3.1 Basslink transmission line route

Source: Basslink webpage, "Maps," <http://www.basslink.com.au/basslink-interconnector/maps/> (accessed March 15, 2017).

Government-ownership is also the dominant approach to financing interconnection projects, particularly in Africa. However, as the project requires investment in two or more countries it is no longer feasible for a single government-owned company to undertake the project. At least two companies are involved. There are two main options for how the two or more companies involved manage the interconnection:

- Government-owned companies in each country can finance their side of the transmission line. This is the model used for the Cahora Bassa line between Mozambique and South Africa, and for the Ethiopia-Kenya interconnector.
- The utilities can establish an SPV to invest in the interconnection. An example is MOTRACO, an SPV formed by three state-owned utilities—ESKOM

(South Africa), EDM (Mozambique), and SEC (Swaziland). MOTRACO owns the assets and the three utilities each own a third of the shares. Other African countries are also exploring similar approaches to financing regional interconnection lines—including the Côte d'Ivoire, Liberia, Sierra Leone, and Guinée (CLSG) interconnection, a 225 kV and 1,300 km transmission line; or the Organisation pour la Mise en Valeur du fleuve Gambie (the Gambia River Basin Development Organization, OMVG) interconnection project, a 1,677 km line of 225 kV capable of handling 800 MW.

However, some of the four business models described above can also be used for interconnections. International experience shows examples of privately financed interconnection projects using merchant investment or the IPT models.

Most interconnection projects have used the merchant investment model. There are various examples in Europe. Most European countries have a single wholesale price across the country. The price differentials that drive merchant investments can only arise for connection between two countries. To date, five transmission lines connecting countries in Europe have achieved some level of exemption from regulatory requirements and can be considered merchant investments. Several more are being developed.

Examples of merchant lines in Europe include:

- EastLink, a 105 km submarine HVDC merchant link that enables transfer of power from Estonia to Finland
- BritNed, a 260 km submarine HVDC line connecting the United Kingdom and the Netherlands. The line has a capacity of 1,000 MW, and was developed in 2011 for €600 million
- East-West Interconnector, an HVDC interconnection linking the United Kingdom and Ireland. The 700 MW line was developed in 2012 and cost €600 million, and

- Channel Fixed Link, a 1,000 MW line linking Britain and France via the Channel Tunnel.

Interconnection projects can also use IPT contracts. There are two possible models to using IPT tenders for an interconnection investment. One, running an IPT tender on at least one side of the frontier, and the other, running a joint IPT tender.

In the first case at least one country uses the IPT model for the investment on their side of the frontier. This is the case of the 1,200 km HVDC Tala line connecting Bhutan to the Indian grid. The line runs from a substation at Siliguri, close to the border, to a substation close to Delhi. The Tala line enables the export of power from the Tata-owned hydro plant in Bhutan. The line is owned by Powerlinks, which in turn is majority owned by Tata Power Company.

The second case is possible, but has not been completed yet. There is no evidence of two or more countries granting an interconnection through a joint IPT tender.

Countries cannot use the privatization or whole-of-grid concession model to finance interconnections. These generally apply to an exclusive obligation to

Figure 3.2 The SIEPAC interconnection



Source: Comision Regional de Interconexion Electrica, "Mapa con linea SIEPAC," <http://crie.org.gt/wp/mapa-con-linea-siepac/>, (accessed May 10, 2017).

finance new transmission within a country rather than between countries

An alternative approach is a hybrid business model between government-owned and private companies. The utilities can set up an SPV and involve third party equity participation. An example is the Empresa Propietaria de la Red (EPR), formed to design, engineer, construct, and own 1,793 km of a 230 kV interconnector that links the power grids of Panama, Costa Rica, Honduras, Nicaragua, El Salvador, and Guatemala. The line is called the Sistema de Interconexión Eléctrica de los Países de América Central (SIEPAC) interconnection.

Figure 3.2 shows the route of the interconnection line in the different countries.

EPR is an SPV owned by:²¹

- The government-owned transmission companies or utilities of Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica, and Panama.
- A private company: ENDESA (Spain).
- Two other regional government-owned transmission companies: ISA (Colombia), and CFE (Mexico).²²

Each of the nine shareholders has an equal ownership stake.

EPR obtains revenues from regulated transmission charges set by the Regional Electric Interconnection Commission (CRIE), the regional regulator.²³ CRIE is the regulating entity of the Central American market. CRIE consists of one Commissioner drawn from the electricity regulatory agency of each country. This was intended to minimize the scope for inconsistency between national and regional regulatory approaches and encourage the standardization of technical and operating standards and procedures.

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SECTION 4

Africa has little privately financed transmission, but substantial private investment in generation

The experience of private investment in the African power sector also provides guidance on the business models that can work in the continent.

Africa has attracted little private investment in transmission under whole-of-grid concessions and a small number of transmission lines connecting generators and the main grid, financed by IPP developers. This has brought operational benefits—like expansion of access and investments in generation—but only a low level of investment. No African countries have introduced private finance in transmission through IPTs or merchant investments.

By contrast, Africa has attracted over US\$25 billion in private investment in IPPs since 1994, creating installed generation capacity of over 11 GW.

This section first summarizes Africa's experience with private finance of transmission. It then draws on the relative success in the generation sector to show how investment can be attracted into the African transmission sector.

4.1 There has been little private investment in transmission

In most countries in Africa the government-owned utilities have exclusivity over the transmission grid and finance all transmission investments. In some cases, this is required in legislation.

Since 1999 three countries in Africa have introduced private sector participation (PSP) in the transmission sector, through whole-of-grid concessions. These have not achieved significant investment in

transmission, though they have brought operational benefits.

Africa has no experience of privately financed transmission lines through IPTs or merchant lines. Some preliminary steps have been made to prepare for IPT tenders, but no projects have been awarded.

African experience with whole-of-grid concessions

This report describes the experience of three countries that have introduced PSP in transmission through whole-of-grid concessions in recent years. The countries are:

- Cameroon, from 2001 to 2021,
- Mali, from 2000 to 2020, and
- Senegal, from 1999 to 2001.

Table 4.1 summarizes these three cases, with information on the period and date of the concession, the scope of the concession, the name of the utility under concession, the parties involved, and their shares in the concession.

The Governments of Mali and Senegal each granted a concession for the vertically integrated utility, including the transmission activities. In the case of Cameroon the Government granted four separate concessions to a single concessionaire, including one for the state-owned transmission company.

Other countries in Africa have also introduced private sector participation in transmission, but not as whole-of-grid concessions. For example, the utilities in Gabon and Cote d'Ivoire signed an affermage¹ with

Table 4.1 Examples of concessions and affermagements in Africa

Country	Period	Scope of concession	Name of utility under concession	Parties and shares
Cameroon	20 years (2001–2021)	Concession for generation, transmission, and distribution. However, the transmission concession ended in August 2015	SONEL (Société Nationale d'Électricité)	<ul style="list-style-type: none"> • AES SONEL (United States): 51% • Government: 44% • Company's personnel: 5% • In 2014, AES sold its stake in AES SONEL to Actis. The company was renamed ENEO
Mali	20 years (2000–2020)	Concession for generation, transmission, distribution, and supply of electricity and water	EDM (Électricité du Mali)	<ul style="list-style-type: none"> • SAUR/IPS-WA(France/Canada): 34% • Government: 66% SAUR and IPS-WA had 39% and 21% of the concession, respectively, until 2005
Senegal	2 years (1999–2001)	Concession for generation, transmission, distribution, and sale of electricity	SENELEC (Société National d'Électricité du Sénégal)	<ul style="list-style-type: none"> • Elyo (France) and Hydro-Québec (Canada): 34% • Government: 66%
Country	Period	Scope of affermage	Related utility	Parties and shares
Gabon	25 years (1997–2021)	O&M contract	SEEG (Société d'Énergie et d'Eau du Gabon)	<ul style="list-style-type: none"> • Veolia² (France): 51% • Government: 49%
Cote d'Ivoire	20 years (1990–2020)	O&M contract	CIE (Compagnie Ivoirienne d'Électricité)	<ul style="list-style-type: none"> • SAUR (France/Canada): 51% • Government: 49%

Source: Developed by Castalia. Table contains examples of African countries that introduced concessions (including transmission) and affermage contracts since 1990.

private parties. In these cases, the private investors had a contract to operate and maintain the transmission lines, but were not obliged to finance transmission assets. The last two rows of Table 4.1 summarize these two cases.

The Government of Cameroon granted a concession for the government-owned and vertically integrated utility, Société Nationale d'Électricité (SONEL), as part of a larger power sector reform introduced in the end of the 1990s. The International Finance Corporation (IFC) supported the Government of Cameroon with the bidding process to grant a 20-year concession to generate, transmit, and distribute electricity in Cameroon.

Five bidders were prequalified; one submitted a bid. The prequalification was based on technical and financial requirements. AES Corporation from the United States was the only bidder. AES signed the concession agreement in 2001, paying US\$71 million³ to acquire 56 percent of the company.⁴ The Government of Cameroon kept the remaining 44 percent. The utility became AES SONEL. AES sold its stake in AES SONEL to British group Actis at the end of 2013. Actis' equity investment in AES SONEL was

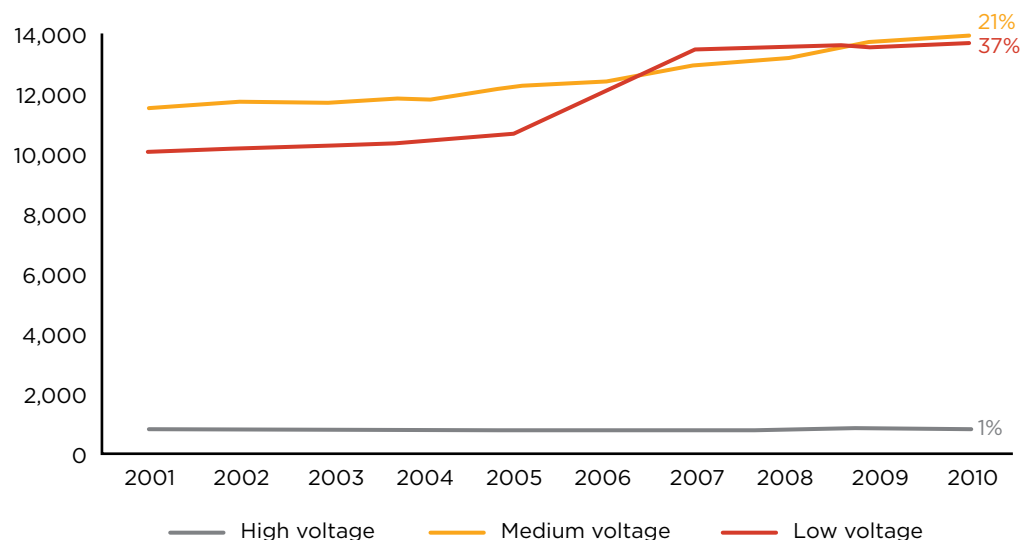
supported by the Multilateral Investment Guarantee Agency (MIGA) which provided Political Risk Insurance (PRI) coverage to Actis through its subsidiary Energy Cameroon Cooperatif B.A. The company was renamed ENEO.

The concessionaire in Cameroon has increased customer numbers by over 340,000,⁵ investing in more than 304 MW of new generation capacity,⁶ and increasing low-voltage (LV) and medium-voltage (MV) lines by 37 and 21 percent respectively (between 2001 and 2010), as Figure 4.1 shows. However, there was minimal expansion of the transmission network. In 2001, the network in Cameroon had 480 km of 225 kV lines and 337 km of 110 kV lines. By 2010, the network had only 3 km more of 225 kV lines.

ENEО operates under separate production, transmission, and distribution concession contracts, and an electricity sales license. A contract renegotiation in August 2015 led to the transfer of the transmission assets to a new public corporation. ENEО will continue to carry out generation, distribution, and sales.⁷

The **Mali** Government also granted a concession for the government-owned and vertically integrated utility, Électricité du Mali (EDM), in July 2000. SAUR

Figure 4.1 Length of transmission and distribution lines in Cameroon (km), 2001–2010



Source: Castalia. Data sourced from G. Tchataat, “Raport Final Cameroun,” (Contribution à la préparation du rapport national pour la formulation du livre blanc régional sur l’accès universel aux services énergétiques intégrant le développement des énergies renouvelables et de l’efficacité énergétique, PNUD), 2014, http://www.se4all.org/sites/default/files/Cameroon_RAGA_FR_Released.pdf (accessed March 10, 2017).

International acquired 39 percent of the shares of EDM, and Industrial Promotion Services (IPS) acquired 21 percent. The Ministry of Mines, Energy and Water Resources retained the remaining 40 percent. The private consortium entered a concession to generate, transmit, distribute, and supply electricity and water.

In October 2005 SAUR International sold its shares to the Government of Mali and IPS. The sale increased the Government’s shares to 66 percent and IPS’ shares to 34 percent. The Government of Mali has been the majority owner of EDM since then. At the same time the concession was converted to an affermage. Transmission received little investment during the period of the concession.⁸

The Government of **Senegal** let a concession for the electric utility, Société National d’Électricité du Sénégal (SENELEC) in 1999. The Government kept 66 percent of SENELEC’s shares. The concessionaire, a consortium between Hydro-Québec (Canada) and Elyo (France) acquired 34 percent.⁹ The concession lasted less than 2 years (18 months). At the end of 2000 the private consortium and the Government decided to end the agreement as the objectives of the concession had not been achieved. Little investment was done during the concession period.¹⁰

In July 2001 the Government started the tender process to re-concession SENELEC. The Government launched a Request for Proposals (RFP) and selected a preferred bidder (Vivendi), but did not complete the negotiation process.

CEC in Zambia: Indefinite ownership of share of the transmission grid

The transmission sector in Zambia is owned and operated by the state-owned power utility, ZESCO, and the private company Copperbelt Energy Corporation (CEC). CEC has exclusive rights over, and owns a share of, the transmission grid in Zambia.

The origins of this alternative model lie in historic contracts for supply of electricity to the mining sector, located mostly in the Copperbelt region. Through several changes of ownership, described below, the company has ended up owning transmission assets in the mining region and combining this with supply of power to the mines under long-term agreements.

The supply to the mines includes charges for wheeling power across CEC’s grid. The company earns additional revenue from wheeling charges in two ways: when ZESCO wheels power to supply non-mining customers connected to CEC’s grid, and when third parties wheel across CEC’s grid to connect with the South Africa Power Pool (SAPP). CEC owns

80 MW of generation capacity, though ZESCO generates most of the energy that CEC supplies. CEC's business model is described more fully in this section.

CEC's shareholders are divided into four groups:

- **Zambian Energy Corporation** (Irish company): 52.0 percent,
- **Private individuals and institutions** (listed shares): 21.4 percent,
- **ZCCM Investments Holdings PLC** (Government of Zambia): 20.0 percent, and
- **African Life Financial Services** (employee share scheme): 6.6 percent.

ZESCO owns and operates the main transmission network in Zambia. CEC owns and operates a regional transmission and distribution network in the Copperbelt region. CEC's network consists of 246 km of 220 kV lines (7.5 percent of Zambia's HV network), 678 km of 66 kV lines, and 41 substations.

CEC's network assets in Zambia include 36 percent of the 142 km 220 kV line that connects the grid in Zambia to the DRC border. ZESCO owns the remaining 64 percent. This line has operated since 1956 and has a transmission capacity of 250 MW.

CEC's business in Zambia is divided into three main services:

- **Power sales to mines:** CEC sources power from ZESCO under Bulk Supply Agreements, and sells it on to several mines located in the Copperbelt area under Power Supply Agreements (PSAs). This is CEC's largest source of revenue. The charges for this service include charges for using CEC's transmission assets.¹¹

- **International wheeling:** CEC wheels power traded within the SAPP through its share in the Zambia-DRC interconnector and earns revenue from these wheeling services.
- **Domestic wheeling:** CEC wheels transports power on behalf of ZESCO to the latter's substations. ZESCO receives the power for onward supply to mostly non-mine customers.

CEC is of interest. Its private ownership of a regional transmission grid is unique in Africa, although consistent with private ownership in other continents. This experience makes it an important example as Africa explores greater private financing of transmission.

However, CEC is distinctive in bundling its ownership of transmission networks with supply to mining customers only, and no other customers, within its region. This is for historical reasons, and it is unlikely this model would be fully duplicated elsewhere.

Africa has no investments in transmission infrastructure through an IPT or merchant investment model

No African countries have introduced private finance in transmission through IPTs. However, Nigeria undertook preliminary steps for tendering transmission projects, as described in Box 4.1.

No African countries have introduced merchant investments in transmission. As illustrated in Section 3, other countries have developed HVDC lines connecting hydro generators to markets using a merchant investment model. In Africa, these types of investments have been publicly funded—like the Cahora Bassa HVDC line.

Box 4.1 The only attempt in Africa to tender for IPTs

The Transmission Company of Nigeria (TCN) requested bids for prequalification of a group of projects in November 2014, under a privately financed business model similar to the IPT. The bids were to rehabilitate, repair, replace, and expand 330 kV and 132 kV lines, as well as the 330/132 kV and 132/33 kV substations and transformers. The projects were based on recommendations from a study prepared by Manitoba Hydro International (MHI) published in 2013.¹²

TCN received 73 applications for prequalification. TCN evaluated the technical and financial capability on a pass/fail basis. Twenty-nine applications were prequalified and

moved to the next stage (commercial stage). The respondents to the request for prequalification were from Nigeria and elsewhere, including Australia, Brazil, China, France, India, Italy, Lebanon, South Africa, South Korea, Spain, Switzerland, Turkey, the United Arab Emirates, and the United States.

TCN did not take this shortlist or the bidding process further. Two reasons were the weak financial viability of the power sector in Nigeria, and the lack of clarity over the transmission business model.

The Cahora Bassa interconnection is a HVDC transmission line (533 kV) from the 2,075 MW Cahora Bassa hydropower plant to the Apollo converter station near Johannesburg. The total length of the interconnector is 1,420 km and it can transport up to 1,920 MW.

The transmission line on the Mozambican part of the frontier is owned by Hidroeléctrica de Cahora Bassa (HCB) while the line inside South Africa is owned by the South African government-owned utility ESKOM. HCB also owns the Cahora Bassa hydropower plant. HCB was originally majority owned by the Government of Portugal, but the Government of Mozambique has been the majority shareholder (85 percent) since 2007.¹³

The interconnection was built mainly to export energy from HCB to South Africa (backed by a supply agreement between ESKOM and HCB). However, 500 MW of power stay available to the government-owned utility EDM.¹⁴ The line earns

revenues from transmission charges collected by ESKOM and EDM.

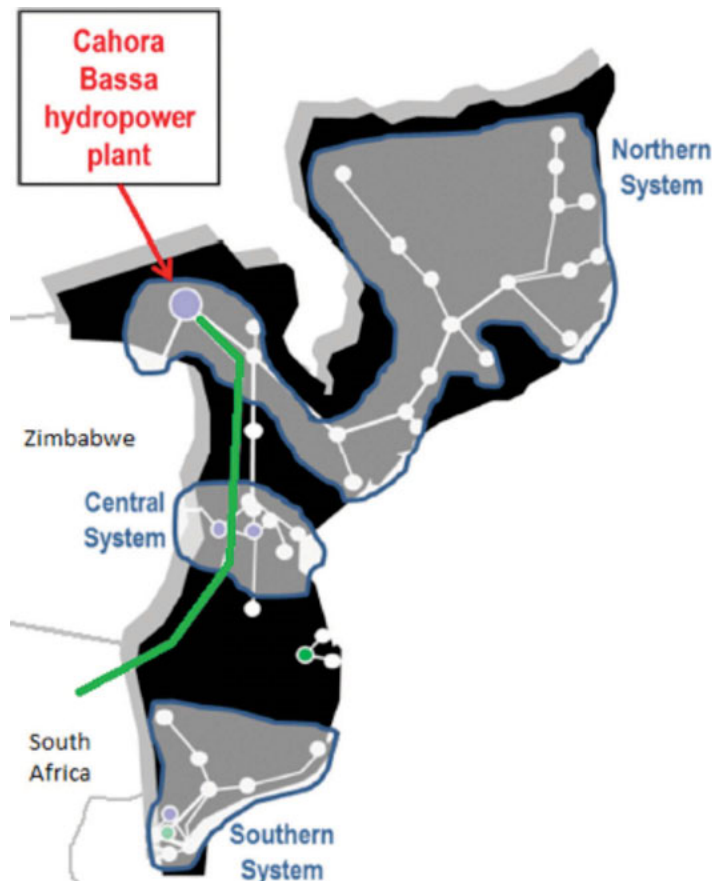
The green line in Figure 4.2 illustrates the route of the transmission line. The figure also shows the three separate grid systems (northern, central, and southern). The Cahora Bassa interconnection connects with the northern and central system, but not with the southern system.

Independent Power Producers have invested in short transmission lines to connect to the grid

A small number of transmission lines connecting generators (IPPs) to the grid have been privately financed. These investments are always attached to generation projects and are most likely a small portion of the overall investment in the project.

Figures vary by project and are generally bundled with the IPP investment. The private investor financing the connection line is the same IPP developer

Figure 4.2 Route of the Cahora Bassa interconnection line



(generally a Special Purpose Vehicle (SPV)) that builds and finances the generation plant. The IPP developer may own and operate the transmission line under a long-term contract, or transfer the line to the system operator or government-owned transmission utility once the line is commissioned.

In cases where the IPP continues to own and operate the connecting line, costs are generally factored in the price set in the Power Purchase Agreement (PPA). One example of a connection line under long-term private ownership in Africa is the 18 km, 225 kV line that forms part of the Azito project in Cote d'Ivoire. The line evacuates power from the 300 MW gas-fired generation plant (upgraded in 2015 to 430 MW) to a substation. Cinergy, the SPV developing the project, has a 24-year build, own, operate and transfer (BOOT) agreement with the Government of Cote d'Ivoire for the generation plant and transmission line.¹⁵ The SPV also signed a 15-year agreement—with a private company owned by two of the SPV shareholders—to operate and maintain the plant and line.¹⁶ The value of generation plant and connection line combined was US\$223 million. The transmission portion was 14 percent.

The Kabompo Gorge project in Zambia, once completed, would also include a 35 km, 132 kV line.¹⁷ The line would connect the 40 MW hydro power plant to the grid, at Kalumbila mine substation. The combined generation and transmission investment is US\$210 million. The private company CEC (the IPP developer) would own and operate the line. However, the project is still being discussed.

An alternative approach is for the IPP to finance the line and transfer it to the system operator or the power utility once the line is commissioned. An example is a 1 km, 330 kV line connecting the Azura 459MW gas-fired plant to a substation (Benin North)¹⁸ in Nigeria. The project has reached financial close with the support of the World Bank Group, including Partial Risk Guarantees from the World Bank, PRI coverage from MIGA, and senior and mezzanine debt from IFC (for further details please see Box 6.8). The project is currently under construction. The SPV that owns Azura will transfer the line and substation once built. Senegal has several examples of IPPs developing and then transferring the connection line to SENELEC, the government-owned utility. In Senegal, the law governing the electricity sector states that SENELEC will have exclusivity over electricity transmission during the concession period—though this aspect of the law is being reviewed.¹⁹

4.2 This contrasts with Africa's success in attracting private investment in generation

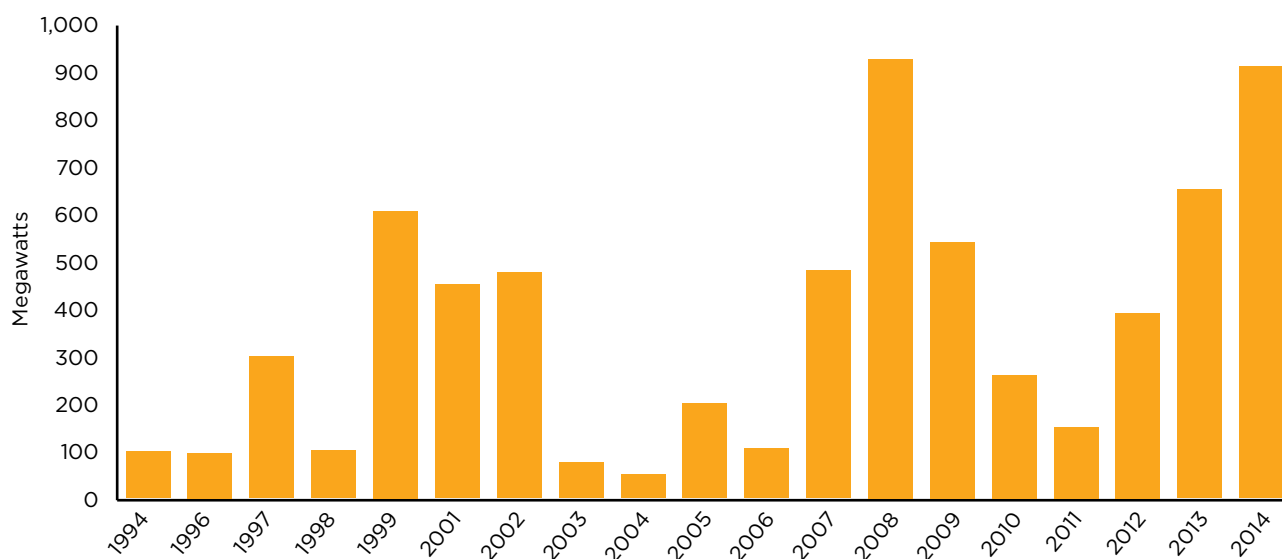
Between 1994 and 2014 the region has attracted US\$25.6 billion into more than 126 IPPs, with a combined capacity of 11GW. IPPs have been developed in 18 countries in Africa.²⁰ While 43 percent of the investment was in South Africa, this still leaves US\$11.1 billion in private finance of generation outside South Africa, for a total of 59 projects with a combined capacity of 6.8GW.²¹ IPP investments have occurred across a wide range of technologies and scale, including Azito in Cote d'Ivoire (300 MW gas-fired IPP); OrPower4 (100 MW geothermal IPP) and Lake Turkana (300 MW wind IPP) in Kenya; and Bujagali in Uganda (250 MW hydro power IPP).²²

Figure 4.3 shows the MW capacity of IPPs by year of financial close, between 1994 and 2014, excluding South Africa. The figure shows that the additional MW per year under IPPs has been quite volatile. The investments can be grouped into three periods: 1990–2002, 2008, and 2011–2014. The spike in the first two periods was due to a few large IPPs reaching financial close. The increase in investment in the third period was because IPP investments started to emerge.²³

Between 1990 and 2013, almost a quarter of new generation capacity (excluding South Africa) was privately financed through IPPs, from near zero in 1990. African governments and utilities have financed just over 50 percent of total investment in generation. Other forms cumulatively contributed 27 percent.²⁴

IPPs are generally contracted under long-term PPAs, structured as two-part contracts, with fixed payments for availability (per MW) and variable payments for energy (per MWh). Under this business model, investors carry the risks they are well placed to manage. Investors face four risks: the costs of building the generation plant; its timely commissioning; its availability after commissioning; and its operating costs. But they do not carry risks they cannot manage, such as demand or how many hours the power station must run. Investors will be profitable provided they manage costs well and ensure the plant is available and performs efficiently.

The risk allocation for IPTs is similar to that for IPPs. The implementation of IPTs in Africa could build on Africa's largely successful experience with IPPs.

Figure 4.3 IPPs by year of financial close: Africa (excluding South Africa), 1994–2014

Source: A. Eberhard et al. (2016). Years 1995 and 2000 are missing from the figure because, as noted in the original document, no projects reached financial close in 1995 or 2000.

Notes

1. An affermage is a form of lease used widely in France. A private entity (the concessionaire) is granted a long-term right to operate and manage the government's assets, and "the government still maintains responsibility for investment and thus bears investment risk." M. Kerf et al. (1998).
2. Originally Groupe Générale des Eaux.
3. IFC, "Public-Private Partnership Stories. Cameroon: SONEL," 2012, http://www.ifc.org/wps/wcm/connect/577489804a5b844a93e59f8969adcc27/PPPStories_Cameroon_SONEL.pdf?MOD=AJPERES (accessed March 10, 2017).
4. The concessionaire had to transfer 5 percent of its shares to SONEL's employees.
5. IFC, "Public-Private Partnership Stories. Cameroon: SONEL" (2012). By 2011, connections had risen to 792,000 from 452,000 in the late 1990s.
6. Two thermal plants were developed: Dibamba Power Development Corporation (DPDC; 88 MW, commissioned in 2009) and Kribi Power Development Corporation (KPDC; 216 MW, commissioned in 2012).
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 20. Includes greenfield, grid-connected IPPs above 5 MW.
 21. A. Eberhard et al. (2016).
 22. In 2011 MIGA provided PRI coverage to Ormat Holding Corp. for its equity investment in the OrPower4 geothermal IPP. In 2012 MIGA provided PRI coverage to Globeleq through its subsidiary Globeleq Holdings (Azito) limited for its equity investment in the Azito gas-fired IPP and expansion. In 2014 MIGA provided PRI coverage to both debt and equity investors for their investments in the Bujagali hydro power IPP.
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SECTION 5

Independent power transmissions are the most broadly applicable business model for increasing privately financed transmission in Africa

IPTs are the business model best suited to the conditions in Africa. They have performed well in other low-income countries. The risks that IPT investors carry are similar to those that IPP investors carry, and the IPP business model has worked well in Africa. This section sets out why a primary focus on IPTs is the best approach.

African governments need to implement a model for private finance of transmission. The four business models discussed in Section 3 have all successfully mobilized private finance for transmission. All can work well under the appropriate conditions. The key question is how well they will work in Africa.

Criteria for assessing the suitability of the different models to Africa's requirements and the performance of each model against the criteria are summarized in Figure 7.2 Responsibilities under early-stage tenders and late-stage tenders and then discussed below.

IPT is the most broadly applicable business model for increasing privately financed transmission in Africa because:

- It can be applied to all of Africa's investment needs (Section 5.1),
- It can realize economies of scale. However, small African countries with a low need for new transmission investment may need to consider whether the IPT model can realize economies of scale (Section 5.2),

- It can create more competitive pressure, compared to other business models, by running a tender for each line or package of lines (Section 5.3),
- It requires a lower need for investor confidence in the country's regulatory capacity (Section 5.4),
- It is consistent with policies being developed by African governments and regional power pools (Section 5.5),
- It can be tested, while keeping other funding arrangements in place (Section 5.6), and
- It is a demonstrated model in low-income countries, and so is more likely to apply than other business models (Section 5.7).

5.1 Applicability of the model to all types of transmission investment in Africa

Africa will need transmission investments at different voltages; providing transmission services within and between countries; and using both HVAC and HVDC technologies. It is desirable that the business model can be applied to all these investments.

Privatizations, concessions, and IPTs can be applied to all types of transmission investment. Where interconnection is needed between countries,

Table 5.1 Performance of the business models against assessment criteria

	Indefinite privatization	Whole-of-grid concession	Independent Power Transmission (IPT)	Merchant line
Applicability Is the model applicable to all types of transmission investment in Africa?	Yes	Yes	Yes	No. Typically used for a single major line, often HVDC, between two markets
Economies of scale Can the model achieve economies of scale in African transmission?	Yes	Yes	Yes in most cases, but may not realize economies of scale in small countries in Africa	Most merchant lines are major enough to realize economies of scale
Competition Does the model ensure competitive pressure on private providers of transmission in Africa?	Only on the initial transaction	Only on the initial transaction and on (infrequent) rebidding on contract expiry	Yes, through competition for each new line	Yes, but only for the merchant line
Investor confidence in African regulatory capability Can the model proceed despite the limited track record of economic regulators in Africa?	No	Uncertain	Yes. Much less need for periodic review by regulators	Not relevant. Merchant projects are not subject to regulated charges
Consistency with power sector reform Is the model consistent with the intention in all African pools to promote open access networks and competition in generation?	Yes	Yes	Yes	No. Works better as a link between markets rather than within markets. Also at risk of stranding from non-merchant investments
Policy flexibility Can the model be tested while African governments keep existing approaches in place?	No. Requires commitment to significant reform	No. Requires commitment to significant reform	Yes	Yes
Track record Is the model proven in other low-income countries?	No. Few examples of successful privatization in low-income countries	Yes, but limited track record	Yes, with substantial track record	No

these models can be applied to the required transmission in each country. These models could be used for all transmission investment required in Africa.

Merchant links might make sense to link countries with low generation costs to those with higher generation costs and high demand. One example could be the major transmission investments to move large volumes of energy from DRC to Southern Africa.

However merchant lines are unlikely to make sense within a single country. Some African power pools (such as SAPP) have zonal price differences, but within African countries the prices are the same at all nodes of the main transmission grid. A business of buying low at one point and transporting the power to sell high at another point—which is the essence of the merchant line—will not be suitable within single countries.

As a result, this business model is not generally suitable for in-country transmission investments. The need to control the power flows also means that merchant links are best suited to HVDC links.

Merchant lines could be a very effective business model for some projects, but could not be used for all of Africa's investment needs. The other models are suitable for all transmission investment.

5.2 Ability of the model to achieve economies of scale in African transmission

Unit costs will be lower for large-scale transmission projects. Some African countries have low needs for transmission investment and will need to ensure the business model adopted can achieve economies of scale.

Privatizations and concessions would result in a single company responsible for all transmission investment. These models would ensure economies of scale are realized in the transmission sector as far as possible given the scale of the investment requirement.

IPTs require a tender for each line, or each package of lines, and could result in several different transmission investors within one African country. The model also requires enough projects of sufficient size to attract bidder interest and to realize economies of scale, even if these projects are awarded to several different bidders. "Sufficient size" is not a precise measurement, but international experience suggests a line or package of lines with a capital cost of US\$100 million should be "sufficient."

Most African countries can realize economies of scale under all business models. However, small African countries with a low need for new transmission investment may need to consider whether the IPT model can realize economies of scale.

5.3 Competitive pressure on private providers of transmission in Africa under the model

African governments can benefit from business models that put competitive pressure on the transmission companies to offer the lowest prices they can accept.

Privatizations and concessions are both implemented through one major competition, leading to the sale of the transmission company or the award of the concession. Privatizations are usually awarded on highest purchase price bid (given a regulated tariff). Concessions are often, though not always, awarded on the least cost bid to enter the obligations in the concession contract. Neither provides ongoing competitive pressure on the cost of future investments.

IPTs create more competitive pressure by running a tender for each line or package of lines. Several countries with a long experience of privatizations are introducing IPTs, as discussed in Box 5.1. The main rationale is the stronger competitive pressure of the IPT business model.

This competitive pressure means that the use of IPTs can also reduce costs by bringing in experience from other countries in managing the lifetime costs of transmission investment—compared to the current business models that focus on contractors managing capital costs.

Using IPT tenders also presents disadvantages relative to other business models. Procuring transmission infrastructure through the IPT model requires running frequent tenders. This generates higher transaction costs than other business models. This is especially true if compared to procuring transmission lines through a whole-of-grid concession. The cost of designing, preparing for, and running a tender for a whole-of-grid concession may be higher than that for one IPT tender, but the frequency of IPT tenders increases transaction costs.

IPTs may also have a lower purchasing power than the incumbent transmission utility—generally a larger company than an IPT, and with a longer track record in the country. The higher purchasing power of the utility might mean that, for example, it could obtain better deals with equipment suppliers.

Box 5.1 IPTs can reduce whole-of-life costs

IPTs transfer risk on the costs to build and operate the transmission line over the contract term. They also transfer risk on availability. This can lead to innovative solutions that can reduce costs.

Governments can already gain the benefits of competition through engineering, procurement, and construction (EPC) tenders. However, IPT tenders require bidders to consider efficient investment and operations over a period of up to 35 years. This brings substantial additional benefits. This should ensure that the full value of investments is realized through good maintenance over the contract term.

Evidence shows that developers under IPT contracts respond to this incentive. For example, Sterlite Power in India introduced the use of unmanned aerial vehicles to inspect overhead transmission lines in response to availability incentives under its IPT contract.

The benefits from a whole-of-life focus are likely to be significant. The potential efficiency gains in the African energy sector are estimated at US\$6 billion a year. More than half of these gains come from eliminating operational inefficiencies.¹

However, this is probably less of an issue in Africa compared to other countries given the relatively small scale of the African transmission utilities.

In addition, IPT contracts also lock in the O&M costs over the contract period, which is typically between 20 years to 45 years. This excludes the possibility to periodically review the O&M costs, and potentially gain from more efficient costs in the future.

After thorough reviews, other countries have concluded that the benefits of IPTs outweigh the costs of implementing them. Box 6.1 describes how the Government of the United Kingdom recently reached this conclusion as it moved towards introducing IPTs.

5.4 Requirements for investor confidence in network regulation in Africa

Transmission networks are a natural monopoly and are usually subject to economic regulation of transmission charges. However, Africa has a limited track record of independent economic regulation that would help investors assess the risks. Models that expose investors to regulatory risk may be less successful than models that minimize this risk.

Privatizations and whole-of-grid concessions are similar. Both work well where regulatory capacity is well developed and where investors are willing to take on the risk of the future performance of the regulatory regime.

Africa has made substantial progress in creating regulators for the energy networks. Twenty-seven countries—more than half the countries in Africa—have established economic regulators for their networks.² African power pools have also established regional associations of network regulators, and the African Forum for Utility Regulators was established in 2002.

However, this still means that many African countries have no network regulators. Many of the regulators established have a relatively short track record. Twelve of the twenty-seven regulators have been operating for less than 15 years.³ In nearly all those 27 cases, government-owned networks are regulated rather than private networks.

African countries vary in how long regulators have been established and the adequacy of their resourcing. The willingness of international investors to take a risk on the performance of regulators will also vary. Discussions with international equity investors suggest a general reluctance to rely on discretionary regulatory regimes that lack a long track record in regulation of private investment in transmission, and a preference for low-discretion contracts in which payments are not subject to periodic review, and enforcement rights are clear.

This may limit the suitability of privatizations and whole-of-grid concessions within some African countries. Concessions may perform better than privatizations against this criterion. In some cases, concessions can put greater reliance on the concession agreement and the arbitration clauses in those agreements.

Box 5.2 Merchant transmission faces risks from open access, regulated networks

Two onshore merchant HVDC lines in Australia were privately financed against the price differences between two States. These price differences were later reduced when the regulated transmission companies expanded.

In New South Wales the government-owned transmission company, TransGrid, had sought approval for a regulated interconnector between New South Wales and South Australia. In 2001, private company TransEnergie built a merchant interconnector called Murraylink between Victoria and South Australia close to the same route. While Murraylink was being built, the regulated interconnector received approval. Murraylink appealed the approval, but the appeal tribunal upheld the approval decision.

In 1997 the Governments of New South Wales and Queensland announced and approved a new

regulated alternating current interconnector between the two States, known as QNI, with a transfer capability of about 700/750 MW.

In 1998 TransEnergie proposed DirectLink, a 180 MW HVDC merchant interconnector between the two States, with a capacity of 180 MW. The merchant line (Directlink) began operating in June 2000. QNI started operating in February 2001.

Both merchant lines subsequently transferred to regulated status, with the regulator setting the maximum allowed revenue. TransEnergie later commented: "Mixing regulated and merchant transmission investment regimes is clearly difficult. It can lead to controversies, litigation, delays, and inefficiencies."⁴

IPTs have a lower requirement for investor confidence in a well-developed regulatory capacity. The annual revenues for the IPT are largely established up front through the tender process. Regulators still play a vital role in ensuring the tender is consistent with the expansion plan and in approving the tender process. However, these roles do not create risk for the private investor.

Merchant lines may also have a lower exposure to regulatory determinations. Much will depend on how this model is implemented. As discussed in Section 3, intervention by regulators in some countries affects the revenues for merchant lines.

5.5 Consistency of the model with directions in power sector reform

African governments and regional power pools are developing reforms to how the power sector operates. They need to ensure the business model for transmission is consistent with these reforms.

The long-term reform objectives are very varied. A common theme is a desire to develop a greater role for competition within the country and regionally in the provision of wholesale electricity. The SAPP is the most advanced regional power pool and has a competitive day-ahead market. Other regional power pools may follow this lead.

Privatizations, concessions, and IPTs are all consistent with these policy reforms. All three business models provide open access to the transmission network under regulated and nondiscriminatory transmission charges.

Merchant lines do not provide open access and are less consistent with this wider reform agenda. This again suggests that merchant lines may be more suitable for links between markets rather than within them.

Merchant lines also work best where they are not exposed to competition from regulated transmission companies. If this precondition is not met, a regulated business that invests later may threaten the merchant transmission. Box 5.2 illustrates this risk with an example from Australia.

5.6 Extent to which the model can be tested while African governments maintain existing models

Africa relies almost entirely on government-financed transmission. Introducing a new business model has risks. So, testing the model to demonstrate its suitability is preferred.

Box 5.3 IPTs can bring in new sources of finance

In India, non-recourse bonds have been issued for IPT transmission lines and received an AAA credit rating. In 2016 Sterlite Power in India issued bonds to refinance loans for one of its power transmission subsidiaries. The bonds did not have a government guarantee, had a 17.5-year tenor, and received a AAA credit rating.

Privatizations and concessions both require a one-off major change to the ownership and operation of the whole transmission network.

IPTs can be introduced on a project-by-project basis. IPTs have been successfully introduced in countries where all other transmission is financed by government. They are also used in countries where all other investment is by an incumbent private transmission company. Existing arrangements can remain. This reduces the level of risk in testing IPTs compared with the first two models. It also might lower the challenges of implementing this model.

The IPT business model enables project finance for transmission investments. This means investors will focus on the costs and revenues of the project itself, and on the ability of the IPT to manage them. This model can bring in additional sources of finance, compared to now where government-owned utilities in Africa finance all transmission investments. Box 5.3 provides one example of an IPT that has successfully accessed new sources of finance in India.

5.7 Evidence that the model has worked well in other low-income countries

Business models that work well in OECD countries may not work well in low-income countries. Africa should prefer those business models for transmission that have been proven to perform in low-income countries.

No low-income countries have adopted the model of full privatization combined with the establishment of independent regulation. Merchant investment has also been minimal in low-income countries.

Several countries in Africa and Asia have used whole-of-grid concessions. Private investment in African transmission under these concessions has

been minimal, and several concessions have ended after a few years in operation. However, to date, the Philippines has been more successful at achieving substantial private investment under its transmission concession.

IPTs perform particularly well against this criterion. IPTs in both middle-income and low-income countries have led to substantial private investment in transmission, significant cost savings through tenders, and (to date) to stable contractual agreements. Box 3.1 provides a summary of the outcomes of IPTs in several countries around the world. The use of IPTs for transmission projects in Brazil, Chile, India and Peru in the last 20 years is discussed in more detail in Appendix A.

Brazil has seen 38 tenders of multiple lots since 1999. These tenders have resulted in the award of 211 transmissions, with a total combined length of 69,811 km.

It is also essential to ensure that private finance does not adversely affect consumers. Transmission accounts for around 10 percent of the costs of supply. Generation accounts for around 55 percent, and distribution for around 35 percent.⁵ There is considerable variation and the share can be higher. Any increase in costs would adversely affect the affordability of electricity. However, IPTs have resulted in lower costs.

In most cases the tenders include a price cap based on expected costs. Bids may be well below this price cap. The Brazilian regulator ANEEL estimates the annual revenue required. The average weighted discount for all tenders awarded between 2000 and 2015 was 22.8 percent of ANEEL's estimate of the AR required. Individual line discounts reached 59.2 percent.

In Peru, the regulator also sets a price cap on investment and O&M costs. Table 5.2 shows that winning bids were, on average, 36 percent lower than the estimated annual costs, according to a sample of 15 tenders between 1998 and 2013.

Notes

1. V. Foster and C. Briceño-Garmendia (2010).
2. A. Eberhard (2015), "Powering Africa: Facing the Financing and Reform Challenges," AFD Research Paper Series, No. 2016-21, February. <https://www.gsb.uct.ac.za/files/PoweringAfricaChallenges.pdf> (accessed March 17, 2017).
3. A. Eberhard (2015), "Powering Africa: Facing the Financing and Reform Challenges."
4. S. Littlechild, "Transmission regulation, merchant investment, and the experience of SNI and Murray-link in the Australian National Electricity Market,"

Table 5.2 Information of Winning Bids for Transmission Lines in Peru (1998–2013)

Year of award	Project	Length of line (km)	Capacity (MVA)	Capital investment (US\$ million)	Annual transmission cost (US\$ millions)		Discount on cost estimate
					Winning bid	Cost estimate (price cap)	
1998	Mantaro–Socabaya	700	300	179.0	27.6	42.6	35
1999	Southern electric transmission system reinforcement	444	180	74.5	11.5	14.3	19
2008	Eléctrica Carhuamayo–Paragsha–Conococha–Huallanca–Cajamarca–Cerro Corona–Carhuaquero	696	360	106.1	10.0	42.6	77
2008	Eléctrica Mantaro–Caravelli–Montalvo and Machupicchu Cotaruse	200	350	35.7	5.4	5.6	4
2008	Chilca–La Planicie–Zapallal and substations	94	1,400	52.2	8.1	14.5	45
2009	Zapallal–Trujillo	530	1,000	167.5	25.8	32.0	19
2010	Chilca–Marcona–Montalvo	872	700	291.0	48.2	61.6	22
2010	Tintaya–Socabaya and associated substations	207	400	43.6	6.7	12.3	46
2010	Talara–Plura	102	—	14.6	2.3	2.5	9
2010	L.T. Machupicchu–Abancay–Cotaruse	204	500	62.5	9.8	14.2	31
2011	Trujillo–Chiciayo	325	—	101.4	15.6	15.8	1
2012	Carhuaquero–Cajamarca Norte–Cáclic–Moyobamba	402	450	106.9	16.2	22.2	27
2013	Machupicchu–Quencoro–Onocora–Tintaya and substations	356	354	114.3	16.7	28.5	41
2013	Mantaro–Marcona–Socabaya–Montalvo	900	—	278.0	41.4	63.5	35

Source: S. Oguah and P. Sanchez, “Private Sector Participation in Transmission Systems: Making It Work. Live Wire,” (World Bank Group), 2015, <http://documents.worldbank.org/curated/en/337861467990990322/pdf/100989-BRI-VC-PUBLIC-ADD-SERIES-Box393254B-Knowledge-Notes-LW52-OKR.pdf> (accessed March 10, 2017).

12 June 2003, <https://www.hks.harvard.edu/hepg/Papers/Littlechild.Transmission.Regulation.Australia.pdf> (accessed March 17, 2017).

5. Energy Information Administration, “Annual Energy Outlook 2015 with projections to 2040,” data

sourced from Table A8. Electricity supply, disposition, prices, and emission, 2015, [https://www.eia.gov/outlooks/aeo/pdf/0383\(2015\).pdf](https://www.eia.gov/outlooks/aeo/pdf/0383(2015).pdf) (accessed on May 12, 2017).

PART B

**HOW TO
SCALE-UP PRIVATE
INVESTMENT
IN TRANSMISSION
IN AFRICA**

SECTION 6

Steps to realize the potential of IPTs for Africa

Introducing IPTs for electricity transmission in Africa could result in similar benefits to those achieved by IPTs in other countries, and by IPPs in Africa.

The approach to introducing IPTs can draw on the lessons from introducing IPPs in Africa, and international experience in IPTs.

Legislation, licenses, and other legal instruments can be amended to provide for multiple transmission providers. Concessional finance can be adapted to this new business model, in the same way that concessional finance has supported both debt and equity for IPPs in Africa.

A small percentage of power sector revenues can be placed into an escrow account to enable a trial of IPTs. Where necessary, additional financial security can be provided, including by Development Finance Institutions (DFIs), until the point is reached where African power sectors are sufficiently profitable.

African governments can build capability in-house and appoint transaction advisors. They can identify projects for initial tenders, prepare the TSAs, run tenders, evaluate bids, and award the contracts.

The World Bank has also developed a toolkit to help decision makers in African governments implement IPT projects. Over time, the pipeline of transmission projects in Africa to be implemented using the IPT model will demonstrate that the IPT business model is suitable for Africa. This will create further investor interest.

The 10 steps needed to realize the potential of IPTs in Africa are:

- Develop policies that support IPTs (Section 6.1)
- Develop the legal and regulatory frameworks to support IPTs (Section 6.2)

- Conduct trials of IPTs alongside existing business models of transmission (Section 6.3)
- Introduce new models for concessional finance (Section 6.4)
- Decide the stage at which to tender transmission projects (Section 6.5)
- Determine payments to IPTs based on transmission availability (Section 6.6)
- Ensure adequate revenue flow and credit enhancement for projects (Section 6.7)
- Tailor IPT projects to attract international investors (Section 6.8)
- Prepare to implement IPT transactions (Section 6.9), and
- Run competitive tenders for IPTs (Section 6.10).

The following sections describe each of the steps above.

6.1 Develop policies that support IPTs

Introducing private finance in transmission is a major shift. It will require changes to legislation, regulation, and to the financing arrangements currently used for transmission investment. Governments control these issues; potential private investors in transmission cannot control them. It will therefore be important for African governments to develop a clear policy direction on how to introduce IPTs.

The policy development will need to consider the arguments for and against using IPTs to meet government policy objectives, and reach a final decision. Box 6.1 illustrates how the United Kingdom conducted

Box 6.1 Introducing onshore transmission tenders in the United Kingdom

The United Kingdom has three transmission companies: National Grid in England and Wales, Scottish Power in southern Scotland, and SSE in northern Scotland.

These three companies were responsible for all transmission investment within their transmission regions. The first move to use competition was for offshore transmission.

Ofgem considers that introducing competition for offshore transmission has saved between £0.6 billion and £1.2 billion since 2009. The vast majority of these savings were associated with the operation of the assets. Analysis of those assets found that competitive tendering led to savings through innovation and different contracting approaches.

An Integrated Transmission Planning and Regulation review concluded in 2015 was that competition should extend to onshore transmission.¹

An assessment of the expected impact of competition was published in January 2016.² The assessment allows for transaction costs of 3 percent of asset value. However, it concludes that cost savings from competitive tendering will more than offset this, drawing in part on the experience of offshore transmission.

Regulated transmission companies already have incentives to minimize costs and already tender elements of the projects they undertake. However, the assessment concludes that the control of all procurements by a single transmission company is likely to lead to a lower level of innovation. Information asymmetry between the transmission companies and the regulator may also reduce the benefits to consumers. In other words, the businesses know more than the regulator about the costs of the project. By contrast, they will only win an IPT tender if they reveal the efficient costs.

Since then, Ofgem has developed proposals for competitively appointed transmission owners for onshore transmission. Competition will only be used for new, separable, and large projects. The projects will be greenfield, but existing assets may need altering to ensure interconnection. The construction cost will be at least £100 million. In November Ofgem consulted on a possible first project to be procured using onshore transmission.³ The line is proposed to connect to 3.8 GW of new nuclear generation in northwest England, and has an estimated construction cost of about £2.5 billion.

Source: Department of Energy and Climate Change, "Impact Assessment: Extending competitive tendering in the GB electricity transmission network," January 2016, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/493712/Impact_Assessment_-_Extending_competitive_tendering_in_the_GB_electricit____.pdf (accessed March 10, 2017).

this assessment before deciding to proceed with tenders for major onshore transmission.

Drawing from international experience

International experience in using IPTs to increase private investment in transmission will help African governments, but they will also face challenges in drawing on and applying that experience. IPTs are a recent development, initially adopted mainly in Spanish- and Portuguese-speaking countries. As a result, many African governments are unfamiliar with the potential of IPTs.

The DFIs that currently support transmission investment in Africa may also have limited familiarity with IPTs. The United States made the regulatory changes that enabled IPTs in 2011. The United

Kingdom is only now moving to use this model for onshore transmission, as described in Box 6.1.

The context for transmission investment in Africa also differs from those in most countries with IPTs. The differences include the financial viability of the power sector and the industry structure.

Most other countries using IPTs have sufficient revenue from electricity consumers to ensure the profitability of generators, network businesses, and supply businesses. In most African countries this is not the case. However, India's experience demonstrates that overall power sector profitability is not a necessary precondition for IPTs to work well.

Low tariffs and high losses in some states in India create problems in funding private transmission. If revenues are insufficient, the state can obtain support

from the Central Government through Viability Gap Funding (VGF). The transmission tariff is determined up front rather than by bids, and the bids determine the level of additional funding required. Bidders sign a Model Transmission Agreement developed by the Planning Commission. Three projects to date have used the VGF mechanism, in Haryana, Madhya Pradesh, and Rajasthan.

This model could be used in Africa, if a funding source was available. The scale of funding required for an IPT trial is discussed later in this section.

A further difference is that most countries using IPTs have already introduced vertical separation between generation, transmission, and distribution. Some African countries have introduced vertical separation, but most have not.

In this case, African experience of IPPs is encouraging, as it shows that full unbundling is not a necessary precondition for introducing private finance. African countries have successfully attracted IPP investors without full unbundling of the generation sector. The important issue has been the risks borne by the IPP investor, not the industry structure. As described in Section 6.6, the risk allocation to IPTs can follow the model used for IPPs.

African governments can be reassured that other countries—including other low-income countries—have successfully attracted large volumes of transmission investment using IPTs. They should draw on this international experience to develop their own policies and their own approach to the practical steps for introducing IPTs as set out in this section. DFIs can assist through dissemination of knowledge products and technical assistance, including peer-to-peer advice from other developing countries with IPT experience as well as mobilizing commercial financing.

6.2 Develop the legal and regulatory frameworks to support IPTs

In most cases, introducing IPTs will require changes to legislation and regulation (for example, changes to the form of the license for transmission companies and the establishment of clear grid codes).

African governments can review existing legislation and regulation to ensure that it enables the introduction of IPTs. Where change is needed, governments can draw on the substantial body of international experience to identify the lessons from elsewhere and in legislation and regulations that support IPTs.

A supportive legislative and regulatory framework will be important for investors. Primary legislation may be required. The United Kingdom introduced legislation to allow competition in offshore transmission in 2009, and made further legislative changes in 2016 to extend competition to onshore competition.

The legislation may also need to evolve over time. Box 6.2 describes how Peru modified its initial legislation to ensure continued investor interest in IPTs.

African governments should also consider what changes are necessary to regulations such as licenses and the Grid Code. Box 6.3 illustrates the potential issues.

6.3 Conduct trials of IPTs alongside existing business models for transmission

Moving to a new model that has worked well internationally but is unproven in the country-specific context involves risk. Governments should therefore maintain existing approaches while conducting trials of IPTs.

International experience demonstrates that IPTs can be introduced alongside other business models for transmission without causing problems.

In India, the majority of transmission investment is by government-owned businesses. India has introduced IPTs alongside this business model. Over time the share of new transmission investment financed by IPTs has steadily grown. This is shown in Box 6.4.

IPTs can also be introduced alongside privately owned transmission. In the United Kingdom all transmission is privately owned. The Government has passed legislation to enable large new transmission projects to be procured through competitive tender. The United States has also combined existing private ownership of transmission with tender for new lines.

Box 6.2 Peru passed new legislation to maintain investor interest in transmission

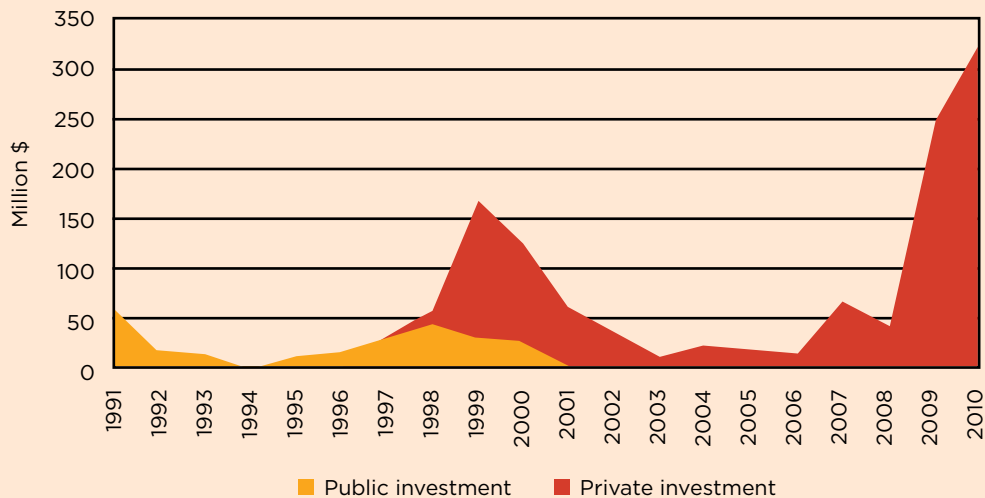
Peru's "Law of Power Concessions" in 1992 enabled PSP in the electricity sector. IPT contracts were initially based on efficient costs drawing on both bids and the regulator's model, which was revised periodically. This exposure to regulatory risk led to a reduction in private investment by the early 2000s. Private investment fell from more than US\$160 million in 1999 to around US\$10 million in 2003, as illustrated in Figure 6.1.

In 2006, Peru introduced the "Law to Ensure the Efficient Development of Electricity Generation." The new legislation established a

change in the tariff setting to ensure that payments under the contracts directly reflected the prices from the winning bid. This change to legislation gave bidders a clear understanding of what their revenues would be, and private transmission investment increased.

The new legislation also included changes to transmission planning and to the governance arrangements for the system operator.

Figure 6.1 Investments in transmission in Peru (1991–2000)



Source: ESMAP (2015).

Source: World Bank, "International Experience with Private Sector Participation in Power Grids: Peru Case Study," (Energy Sector Management Assistance Program," 2012, <http://documents.worldbank.org/curated/en/498461468000021182/pdf/101753-WP-P146042-Box393265B-PUBLIC-Private-Sector-Participation-in-Power-Grids-Peru.pdf> (accessed March 10, 2017).

6.4 Introduce new models for concessional lending

African governments need to maintain their access to concessional lending for transmission projects, but can utilize this lending differently by not tying it to delivery of the projects by government-owned businesses.

The low cost of concessional lending helps African governments meet their targets for access at a lower

cost to consumers. Any shift to IPTs must safeguard these benefits.

Currently, concessional lending is provided to government-owned transmission companies. No examples are available of concessional loans to private transmission in Africa. If this situation continues, it will distort the decision on the best business model for future transmission projects. African governments could continue with existing models and retain access to concessional finance. If they

Box 6.3 Developing regulations suitable for IPTs

Nigeria is one of the African countries that have gone the furthest in preparation for IPTs. The Electric Power Sector Reform Act 2005 established the framework for competition in transmission. A transmission licensee is authorized to carry out construction, operation and maintenance of the transmission systems within Nigeria, or that connect Nigeria with a neighboring jurisdiction. The Act establishes no restriction on the number of transmission licensees. The Act details the application procedure for securing a license.

The Act also establishes vertical separation by requiring that no person shall engage in electricity transmission among other business activities, except in accordance with a license issued under the Act.

The Transmission Company of Nigeria, TCN, is a government-owned transmission company. The Grid Code sets out the operating procedures and principles governing the Transmission System. This will be a sensitive document for IPT investors. It defines their rights and obligations, and also the rights of TCN and other parties.

The Grid Code may need further development to enable IPT tenders. The Code states that it is designed to facilitate competition in generation and supply, but does not refer to competition in transmission. Section 1.4 states that the Grid Code applies to TCN and Users of the Transmission System, but does not state that it applies to other parties such as IPTs. The Code defines the responsibilities of transmission service providers. Some of these responsibilities, such as accepting grid connections to the networks they own, would normally be applicable to IPTs. However, the Code defines the transmission service provider as “the division of TCN that owns and maintains the Transmission Network.”

The changes required are not major, illustrating Nigeria’s preparation for possible IPTs. Other African countries may need to make greater changes to their Codes, licenses, and other documents.

Source: Castalia review of Nigerian Grid Code.

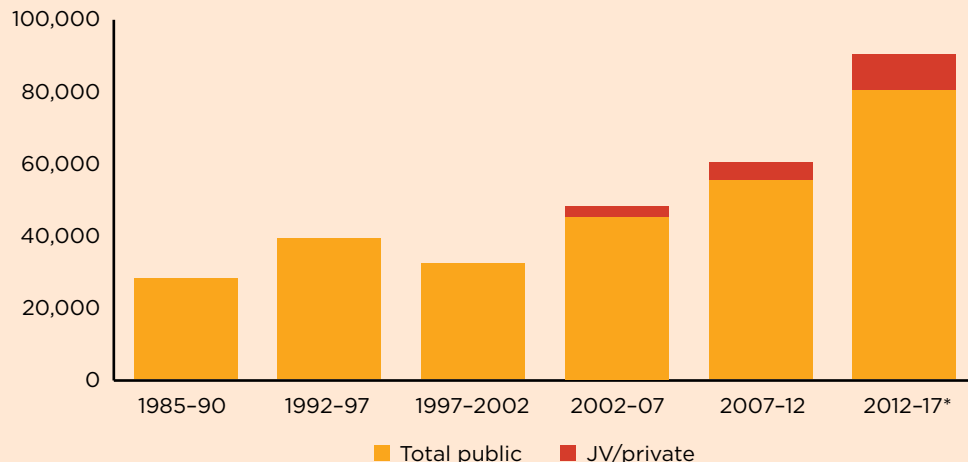
Box 6.4 Privately financed transmission in India has been growing

In India, transmission is planned over five-year periods. Figure 6.2 shows the total kilometers of new transmission investment in the last six five-year plan periods. It also breaks this down between publicly financed transmission (investments by utilities owned by state governments or the national government), and transmission that is privately

financed or financed in joint ventures (JVs) with Power Grid Corporation of India Ltd. (PGCIL). The Government holds a majority ownership of PGCIL.

Privately financed transmission, including JVs with PGCIL, has taken a growing share of new transmission investment, reaching 14 percent in the current plan period.

Figure 6.2 Evolution of new transmission lines in India, 1985–2017* (ct km of new transmission lines)



Source: Castalia. Growth in transmission network (ct km). Data sourced from Ministry of Power of the Government of India, <http://powermin.nic.in/en/content/growth-transmission-sector>, (accessed March 10, 2017); * To end-July 2016. Available data do not include figures for the 1990–1992 period.

Box 6.5 Example of concessional lending to IPP

The Tobene IPP in Senegal is a 96 MW heavy-fuel, oil-fired plant. The IPP agreed to a 20-year PPA with SENELEC, the government-owned power utility in Senegal. In 2014 the World Bank Group signed a €93.4 million financing agreement for the Tobene Power IPP. Under the financing

arrangements the IPP (Melec PowerGen) will own at least 90 percent of the plant, and IFC will retain a 10 percent stake in the project upon completion of a proposed equity investment.

Source: "World Bank Group Finances 96 megawatt Tobene Power Plant in Senegal," IFC, <http://ifcextapps.ifc.org/ifcext/pressroom/ifcpressroom.nsf/1f70cd9a07d692d685256ee1001cdd37/e9c240ad1e4953a885257d2c006e9e78?OpenDocument> (accessed January 20, 2016).

introduce IPTs, they may achieve some efficiency gains but will face higher financing costs.

Transmission projects are capital intensive. If concessional finance is tied to delivery by government-owned transmission companies, then the case for IPTs is likely to be difficult or impossible. In an environment of limited concessional financing, IPTs bring a much needed complement through commercial funds. This may very well be a strategic decision by the government on which part of the transmission network should be funded through concessional funds and which parts can be procured through IPTs.

African governments should work with DFIs to ensure that DFI lending policies are not biased towards government ownership of transmission and do not impede the use of privately financed transmission.

Concessional lending for IPTs can draw on African experience with IPPs

The development of new lending policies for the transmission sector can draw on Africa's experience of working with concessional lenders to support IPPs in the generation sector. A recent study concluded that the role of concessional finance has been key to the successful introduction of IPPs in generation:

There has been a wide variety of African IPP sponsors and debt providers. State institutions have invested in some IPPs, but private sponsors are prominent, including private African partners, European entities such as Globeleq, Aldwych, and Wartsila, and numerous European bilateral DFIs. A smaller number of sponsors are from North America, Asia, and the Middle East. A few multilateral agencies also hold some equity.

In addition to equity investments, DFIs are prominent in the debt financing of IPPs. The

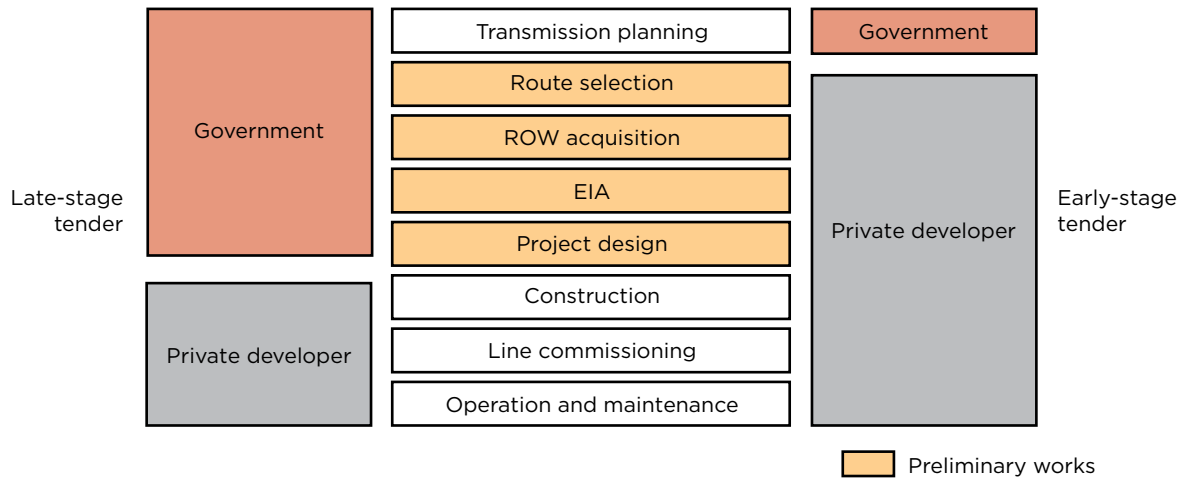
African reality is one in which most IPPs carry substantial risks. Without DFI financing, key projects would not have reached financial close and commercial operation. DFIs have also reduced the chances of investments and contracts unraveling—in part because of rigorous due diligence practices, but also because of the pressure governments or multilateral institutions might bring to bear around honoring investment contracts.⁴ Credit enhancement instruments offered by multilateral finance institutions have also played an important role in IPP financing.

An example of the approach to concessional lending for an IPP is shown in Box 6.5.

6.5 Decide the stage at which to tender transmission projects

Governments can choose between early- and late-stage tenders but this should be decided early in the project design. This decision has a major impact on how the project is prepared, the contract designed, and the tenders prepared.

- Under an early-stage tender, the government sets out the broad transfer requirements between two points. The private investor is responsible for identifying the best solution and preparing all preliminary works.
- Under a late-stage tender, the government does preliminary work, such as selecting the route and acquiring the right of way (ROW).⁵ The private investor is responsible for building and operating the transmission project in accordance with the specification developed by the government.

Figure 6.3 Responsibilities under late-stage tenders and early-stage tenders

Early-stage tenders transfer more risk on preliminary works to private developers, including route selection, acquisition of ROW, environmental impact assessments, and project design. In contrast, late-stage tenders have a high degree of project definition, and the government needs to prepare all preliminary works before tendering. The responsibilities under the two approaches are shown in Figure 6.3.

International experience shows that both approaches can work. In South America, most countries have used late-stage tenders. However, Peru has moved to a more output-based approach, leaving scope for bidders to offer innovative solutions to providing the required transfer capacity. India has also used late-stage tenders.

In the United Kingdom the initial tenders will all be late-stage, with the incumbent transmission company developing the detailed design. Ofgem has left open the possibility of using early-stage tenders later.

In the United States, the Regional Transmission Organizations (RTOs) distinguish between an “Early methodology” and a “Late Methodology.” Under the early methodology the RTO identifies the required upgrades during expansion planning and solicits innovative solutions and proposals. Under the late methodology the RTO also provides the solutions. The developers compete to build, own and operate this solution. The early methodology is used in five regional markets and the late methodology in four.⁶

Both alternatives could be used in Africa. But African governments should consider procuring the first IPT projects through late-stage tenders for two reasons:

- To avoid investors being exposed to risks on route selection, ROW acquisition, and permitting on the initial projects. It can be hard to assess, price, and manage these risks. Later procurements could explore whether these risks could be transferred to bidders once they are more familiar with the use of IPTs in Africa, and
- To ensure a simpler evaluation task for the initial tenders. Late-stage tenders are simpler to evaluate, based on the price offered by different bidders to build and operate a line according to a single detailed design. By contrast, early-stage tenders lead to offers with different designs and require more assessment of the viability of the proposed solutions.

6.6 Determine payments to IPTs based on transmission availability

African governments will need to determine the performance they want from IPTs and develop key performance indicators (KPIs) under the contract. This will be a sensitive issue for investors as it will affect their revenues. The Transmission Service Agreement (TSA) with the IPT will need to set out the requirements on commissioning and the performance after commissioning.

The TSA should include an obligation to commission the line in accordance with the technical specifications by a defined date (often referred to as the Commercial Operation Date). If the obligation is not met, the contract should impose penalties. Prolonged

failure to achieve commissioning should lead to contract termination.

Under the IPT contract, payment can start:

- On the Commercial Operation Date, provided the plant has been successfully commissioned, or
- Immediately on commissioning, even if this occurs before the due date in the contract.

The second approach provides an incentive to achieve early commissioning. This requires confirmation that it is desirable for the line to commission early. For example, if the commissioning of a new power station affects the use of the new line, early commissioning may have little value.

In India the Ministry of Power introduced a policy to incentivize early commissioning in July 2015, with payment to start from the Commercial Operation Date even if this is before the date specified in the contract.⁷

The Rajasthan Atomic Power Project (RAPP) line achieved early commissioning in 2016 and was the first project to benefit from this new policy. The RAPP Transmission Project is a 200 km, 400 kV double-circuit transmission line crossing two Indian states (Rajasthan and Madhya Pradesh). The project was completed in less than 12 months.

The TSA will need to set performance incentives after commissioning. African governments should ensure that their approach to IPTs follows the model that has successfully attracted IPP investment.

IPP investors are typically at risk for the capital and operating cost associated with their plant and for its operating performance. However, they are not at risk for the level of demand and whether the plant is operated at a high or low load factor. (The load factor is the output during the year as a percentage of what could be achieved if the plant ran at full capacity throughout the year. Load factors can vary from only a few percent for a peaking plant to levels above 90 percent for a heavily used baseload plant.)

IPP investors cannot determine how the system operator wants to run the plant. This depends on demand and on the availability of other generating plants. As a result, IPPs typically enter two-part contracts with a capacity payment and an energy payment. The capacity payment is made provided the capacity is available. This payment covers the IPP's fixed costs. The energy payment varies with the electrical energy delivered by the power station.

Transmission lines have high fixed costs, and the owners cannot influence the flow of energy along the line. This depends on the location of generation and

load within the network, and on the system operator's decisions on the dispatch of a generation plant.

As a result, established international practice for IPTs in South America, India, the United States, the United Kingdom, and other countries is to make line availability the dominant KPI as the basis for payment (as opposed to energy delivered or line use). The availability target is typically close to 98 percent.

6.7 Ensure adequate revenue flow and credit enhancement for projects

It will be critical for African governments to take all necessary steps to ensure that IPT projects are bankable in the near future, while continuing long-term measures to move the entire power sector to profitability.

IPTs will be implemented on a project finance basis. Typically, investors will set up a Special Purpose Vehicle (SPV) to undertake the project. The investors will provide the equity for the SPV. The SPV will also borrow from providers of debt finance.

Transmission projects are capital-intensive and their costs are directly affected by the cost of capital for the SPV. Equity costs more than debt (that is, the required returns are higher). The SPV will therefore aim for a high share of debt. It may also refinance after the project has reached commissioning, when the risks are lower. The SPV may be able to reduce financing costs by increasing the share of debt finance. It may also be able to agree to lower costs with existing debt providers.

The returns to debt and equity will depend on the cash flows for the SPV. Debt providers will not have recourse to the balance sheets of the parent companies. As a result, they need to be confident that the cash flows will enable the SPV to cover its debt payments. Equity investors also need confidence that the cash flows will be sufficient for the SPV to be profitable and to provide the expected returns on equity.

The SPV will bid a yearly payment that covers the costs of the project, and that provides the returns to debt and equity. As described in the previous section, after the transmission line is commissioned the SPV will receive a fixed payment based on its availability performance. This payment will enter the cost base to be recovered from transmission charges, and ultimately from final consumers.

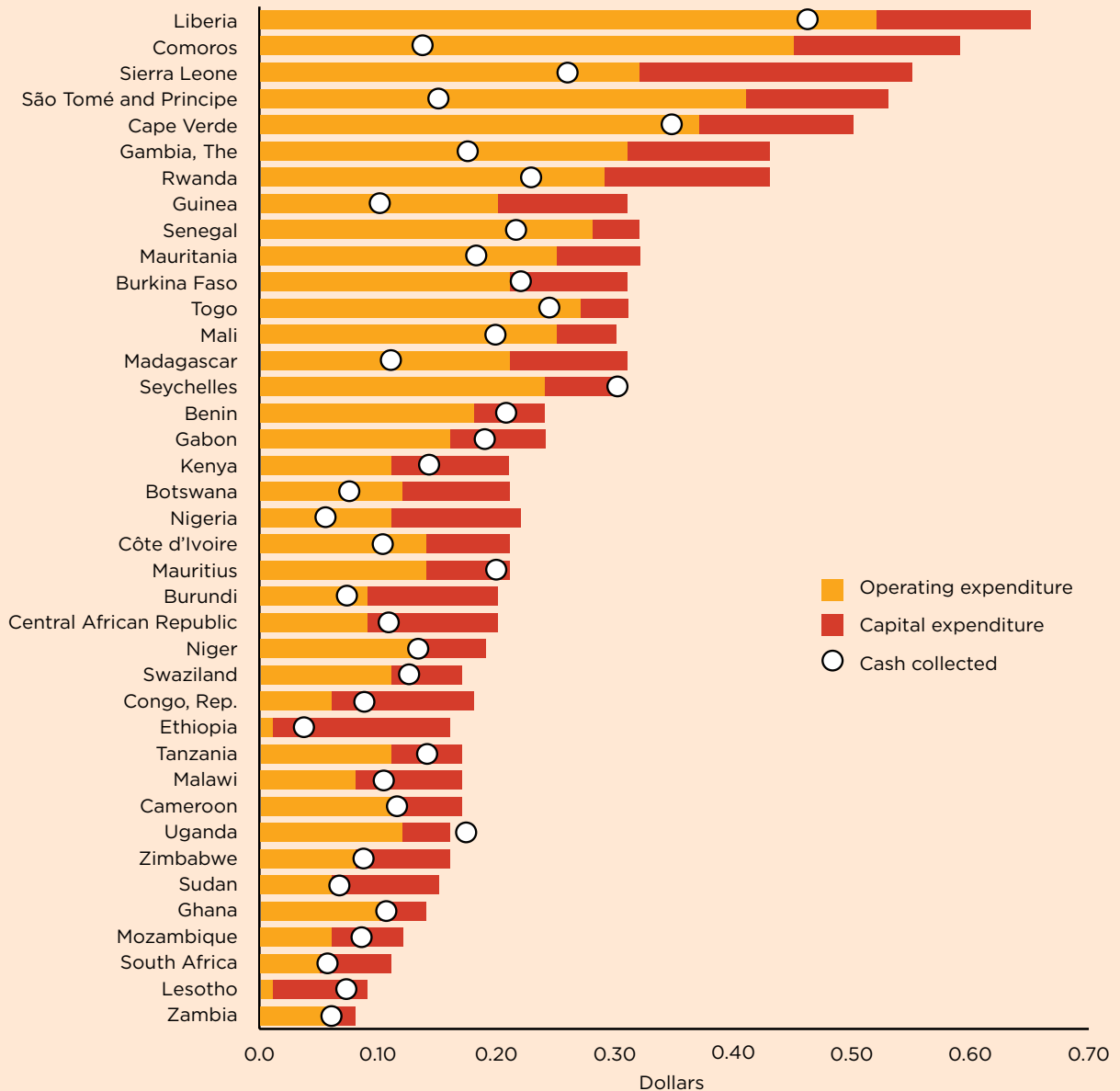
This model has enabled IPT investment in many countries, but Africa is different in one important aspect. Box 6.6 shows that the power sector is not

Box 6.6 Most African utilities do not collect enough cash to cover costs

A study in 2016 found that 37 of 39 countries in Africa did not collect enough cash to recover both operational and capital costs.⁸ Only 19 utilities collected enough cash to cover operational costs.

Figure 6.4 shows the relationship of cash collected to capital and operating costs in 2014, by country. These figures are reflected in the financial viability of the utilities.⁹

Figure 6.4 Comparison of electric supply costs with cash collected in 2014 (US\$/kWh billed)



Source: M. Kojima and C. Trimble (2016).

Box 6.7 The use of escrow accounts to attract IPP investments

Revenue escrow arrangements require cash collected from electricity consumers to be deposited into a special bank account, and paid out in accordance with special rules that ensure monies owed to privately owned generators or transmission providers are paid first. Kenya has successfully attracted IPP investment, supported through escrow accounts. Westmont (46 MW thermal plant), Tsavo (46 MW

thermal plant), and LTWP (310 MW wind farm) are examples. In the case of LTWP (also known as “Lake Turkana”), for example, the money for the escrow account was “to be raised by a tariff increase starting in 2013.” Subsequent IPPs used IDA Payment Guarantee instead and currently, payment securities are no longer required due to the good track record in payments to IPPs.

Source: A. Eberhard et al. (2016).

profitable in most African countries. As a result, investors may attach a high degree of risk to the anticipated revenues from transmission charges.

In most countries in Africa, the power sector's financial weakness means that power sector investment cannot be secured against power sector revenues. In other words, the sector's total income does not provide the required returns to debt and equity if investment is privately financed.

In almost all cases the revenues are sufficient to cover part of the required investment, and so can be used to secure private investment in generation (IPPs) and transmission (IPTs). However, as total revenues are insufficient, investors want to be sure that they will have first claim on these funds.

One option for ensuring that first claim to the cash flows is to use revenue escrow arrangements. Box 6.7 shows how this approach works for IPPs.

Escrow arrangements may be a sensitive issue. If IPP and IPT investors have a first claim on the revenues, then other claims by the government-owned transmission company and its suppliers will be weakened.

This sensitivity may be reduced because the total share of revenues that would need to go through an escrow account to support IPT trials would be low. International data illustrates this: A recent tender in Peru resulted in annual payments of US\$16.7 million, to build, own, and operate a 356 km, 220 kV transmission line, and a transmission capacity of 354 Megavolt Ampere (MVA).¹⁰ If similar annual payments were needed for a trial of IPTs in Kenya, 3 percent of total power sector revenues would have to be secured to cover the repayments. In practice, initial trials may well be on a smaller scale and so require a lower share of power sector revenues.

Where escrow arrangements are not enough to make the project bankable, governments may also have to use a government guarantee to back payment obligations to IPTs. If the sovereign guarantees are insufficient, multilateral guarantees may be needed (from the World Bank, MIGA, African Development Bank, or other DFIs).

Again the experience of IPPs in Africa gives confidence that these guarantees can be provided. Box 6.8 shows the financing structure for the Azura IPP

Box 6.8 The role of guarantees in ensuring the Azura IPP (Nigeria) was bankable

IPP projects can include one or various guarantee products to ensure bankability and reassure the investor on risks. Africa has significant experience structuring bankable IPPs in recent years. Figure 6.5 presents the financing structure of the Azura IPP project in Nigeria—the first project-financed generation investment since the reform of Nigeria's power sector.

The project is to develop, build, and operate a 459 MW open-cycle, gas-fired plant in Benin (Edo State). The IPP is owned by the SPV “Azura Power West Africa.” The IPP has a 20-year PPA with the Nigerian Bulk Electricity Trader (NBET) backed by a Put-Call Option Agreement (PCOA) with the Government of Nigeria.¹¹

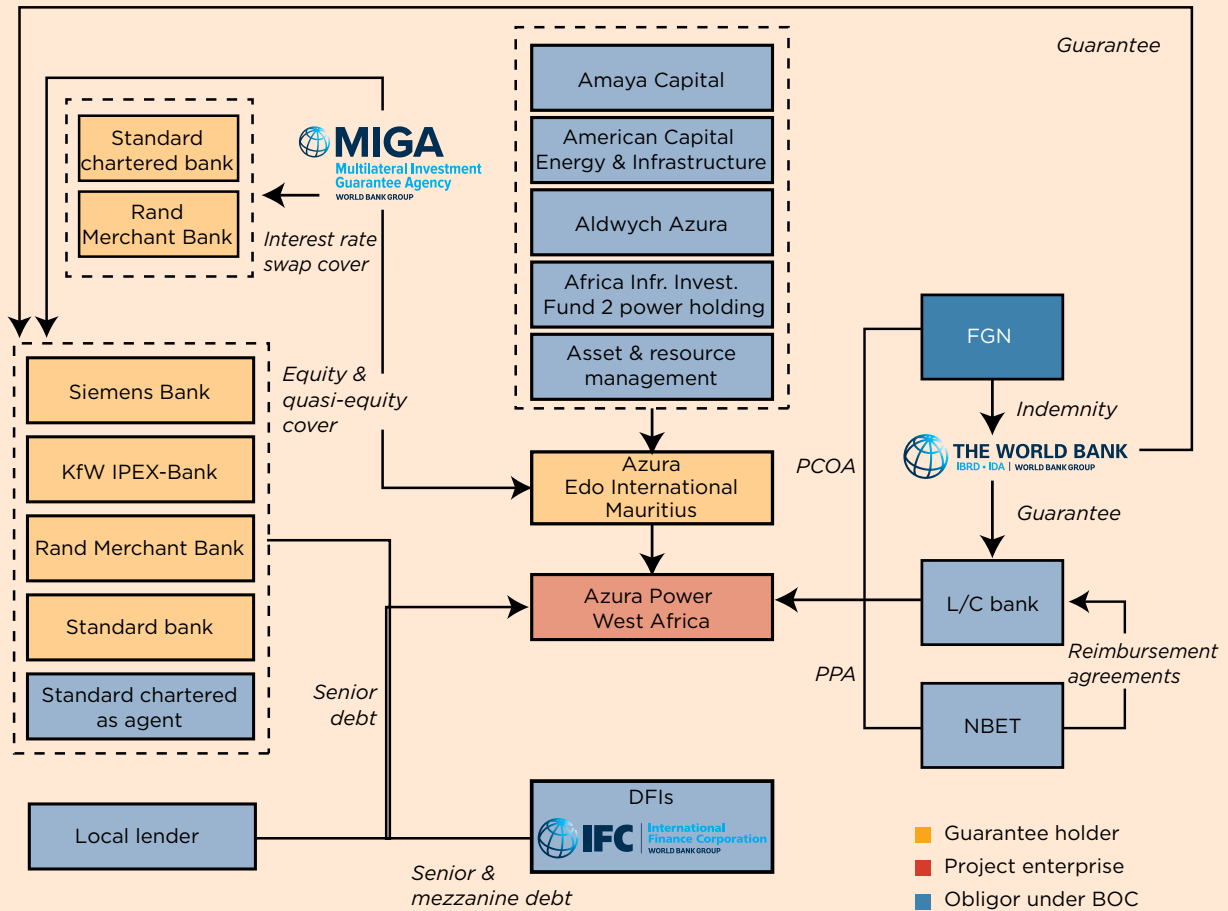
(box continues on next page)

Box 6.8 Continued

To make the project bankable, multiple credit-enhancement mechanisms were used:

- The World Bank provided: (i) a loan guarantee to cover defaults of debt service payments in the form of Partial Risk Guarantees (PRGs); and (ii) a payment guarantee to cover payment defaults by NBET of payment obligations not related to loans from government,
- The Multilateral Investment Guarantee Agency (MIGA) provided Political Risk Insurance (PRI), to: (i) equity investors, through Azura Edo International Mauritius, for their equity and quasi-equity investments in Azura Power West Africa; (ii) a consortium of commercial lenders for their non-shareholder loans to Azura Power West Africa; (iii) hedging instruments, including interest rate swap, were also covered against the risk of breach of contract, and
- The IFC (and other DFIs) provided senior and mezzanine debt.

Figure 6.5 Financing structure of Azura IPP (Nigeria)



Source: Multilateral Investment Guarantee Agency. "Political Risk Insurance and Credit Enhancement Solutions" 2016 (pers. comm. with Annabelle Libeau, February 3, 2017). BOC refers to Breach of Contract.

project in Nigeria, and how loan and payment guarantees made the project bankable.

6.8 Tailor IPT projects to attract international investors

IPT opportunities will only attract sufficient international bidders and ensure bids are competitive if the projects are carefully selected and designed.

Governments should focus on projects that are technically, economically, financially, and environmentally feasible. They should avoid projects that raise controversial environmental or other sensitivities, especially for the first tenders.

The projects should be large enough to justify the transaction costs. In some cases, this may mean bundling several projects into a single tender. In Peru, capital costs ranged between US\$52.2 million and US\$291.0 million, from a sample of 14 transmission projects tendered between 1998 and 2013. On average, capital costs were US\$116.2 million. Alternatively, governments can also attract investor interest by confirming a pipeline of future IPT projects.

6.9 Prepare to implement IPT transactions

Designing an IPT transaction requires expertise in multiple fields. Governments often lack this expertise. They will need to develop in-house capacity and appoint international transaction advisors.

To prepare for IPT transactions, each government and their advisory team will need to prepare TSAs to be signed with the IPT, define the eligible bidders, and conduct a market sounding.

Using IPTs will require more frequent transactions than other approaches. Preparing for this well will reduce implementation costs. The Toolkit in Section 7 provides guidelines on how to do this.

Prepare TSAs

The government advisory team should prepare a model TSA that can be used for all transactions. The team should draw on this model to prepare a TSA specific to each IPT tender.

The case studies attached to this report describe the different approaches taken to TSA contracts. The key issues include:

- **Contract term:** A long-term contract is required to transfer risk on whole-of-life cost and performance to the IPT. International experience shows contract terms vary from 20 years to 45 years. In Chile, contracts are to 20 years, but after that the IPT continues to own the transmission line and the regulator sets the payments. The United Kingdom is considering 25-year terms for the first onshore IPTs. In Peru and Brazil, contracts are for 30 years. India started with 25-year terms, with an option of a further 10-year extension, and moved to 35-year terms from 2008. A 45-year term has reportedly been agreed for the first IPT in Pakistan.
- **Specification:** Late-stage tenders, which include a detailed design for the project are recommended for African countries.
- **Commercial operations:** Contract payments could start on the due date required under the contract, subject to successful commissioning. Alternatively, commercial operations could start as soon as commissioning is achieved. These options are described in Section 6.6.
- **Payment:** The TSA should set out the payment arrangements over the contract term. This may be a fixed annual payment, but some variation is possible (for example, higher payments during the initial 15 years). In India, the phasing of payments has been a bid parameter.

In Peru the contract is awarded to the bidder that proposes the lowest Total Service Cost. This cost is equal to the sum of the annuity of investment costs (calculated using a 12 percent real annual rate for a 30-year period), and the annual O&M cost. The bidder also has to present the details of how the investment costs are formed—including value of supplies, transport and insurance, construction and assembly, indirect costs, administration costs, engineering, surveillance, and financial expenses. If the tender is for a package of lines, or includes substations, the bidder needs to present the disaggregate data for each asset.

Box 6.9 describes how transmission companies are paid in Peru, adjusting the total service cost for under or over-recovery in the previous year.

Box 6.9 Tariff for IPT Contracts in Peru

The transmission companies operating in the main transmission system in Peru are remunerated according to a base tariff as follows:

- Annuity of investment costs (defined during the bid),
- Annual O&M cost (defined during the bid), and
- Annual settlement. This component corresponds to the difference between the base tariff set the previous year and the money effectively collected by the transmission company in the current year.

In Chile, the bid price is defined in a similar way but they refer to it as transmission value per segment (Valor Anual de Transmisión por Tramo, or VATT). The tender is awarded to the bidder that proposes the lowest VATT which is equal to the sum of annual value of investment (Anualidad del Valor de la Inversión or AVI) and the maintenance, operation, and administration cost (Costos de Operación, Mantenimiento y Administración, or COMA), calculated using a 10 percent real annual rate for 20 years.

- **Performance obligations and incentives:** The main performance obligation should be to ensure availability of the line, with a target of about 98 percent. The TSA should set out the penalties (and possibly incentives) for availability below or above the target.
- **Indexation:** A large share of the costs can be fixed up-front through an EPC contract. Other costs are likely to be subject to inflation over the contract period. The TSA should define which costs are subject to indexation and the index to be used. Internationally, TSAs vary in how they treat indexation. In some cases, this can be a bid parameter.
- **Foreign exchange risk:** Transmission projects have a large share of offshore costs. Investors will want to ensure that the payments they receive cover these offshore costs. Approaches vary internationally. In Chile and Peru the payments are fixed in US dollars. Foreign exchange risk is borne by the off-taker and ultimately by power consumers. In Brazil the payments are fixed in Brazilian reals, and in India they are fixed in Indian rupees, with the investor carrying the foreign exchange risk. The approach in African countries should be based on consultation with potential investors.
- **End of the term:** The TSA should define the obligations of the IPT at the end of the contract. The options may include an obligation to transfer the assets, or an option to extend the TSA for a further

term. IPTs in Chile do not have to transfer the assets. In Peru the IPT contracts state that the investor must transfer the assets to the government at the end of the contract term. India also includes a transfer option. Where the government includes an obligation to transfer the asset, the TSA will also need to provide incentives for the IPT to maintain the condition of the asset towards the end of the contract term.

- **Force Majeure:** The Force Majeure clauses should protect investors from unforeseeable circumstances that prevent them fulfilling their contractual obligations.

The preliminary works will include route selection, environmental approvals, and permitting. African governments should start with late-stage projects, and the preliminary works should be undertaken within the government, for example by the government-owned transmission company.

Governments will need to consider how best to transfer these approvals to the successful bidder. Local regulations will affect the approach they select. It is possible that approvals and permits can be transferred to the successful bidder. In some cases, approvals are specific to a particular company. If so, an SPV can be set up to hold these permits and approvals, and the SPV can be transferred or sold to the winning bidder together with the approvals.

Define eligible bidders

It will be important to resolve the role, if any, of government-owned companies in the IPT tenders. The options are discussed in Box 6.10. International bidders are likely to be concerned about the transparency of the evaluation process if government-owned companies are allowed to bid. This decision will also influence which institution manages the preliminary works and the IPT tender.

Box 6.10 The role of government-owned bidders

There are arguments for and against allowing government-owned companies to participate as bidders in IPT tenders.

One option is to allow government-owned businesses to bid. Examples include India, Brazil and Colombia. If existing government-owned businesses are allowed to bid, this could assist with buy-in from the existing utility. However allowing government-owned bidders could prove sensitive and risks discouraging bidders.

Another option is for the government to take a stake in the SPVs that own and operate transmission lines under IPT tenders. This would be similar to the Government of Mali's majority stake in EDM, the concessionaire, or the Government

of Senegal in SENELEC. In India, private bidders can form JVs with PGCIL and jointly bid for an IPT contract.

This may reassure bidders that the government has full insight into the operations of the SPV. However, if the government has to buy the equity stake, it is less successful at reducing the financial demands on public funds. If the equity stake is required to be provided free, as a condition of bidding, then it increases costs of the bids.

A third option is for all bidders to be fully private, with no incumbent utility or other government-owned business taking part in the bidding process. This approach is recommended for those African governments trialing IPTs.

Run market soundings

A **market sounding** evaluates how attractive the business model is for investors. It also tests whether investors will be able to assume the risks that are to be transferred to them through the IPT contract, and generates inputs and requirements from investors and other parties.¹²

Market sounding involves gathering information about the viability of the business model, the ability of the private sector to meet the requirements, and the market's capacity and maturity.¹³ Section 7.2.1 of the Toolkit included in Section 7 provides further information about this.

6.10 Run competitive tenders for IPTs

African governments will need to decide whether to run competitive tenders as the basis for entering contracts with IPTs.

Internationally, almost all contracts have been awarded through competitive tenders. However, in some cases contracts have been allocated without tender to a government-owned company. The reason has usually been that the projects have tight timelines and this avoids any delay in the tendering stage.

African governments will also need to determine whether they will allow government-owned companies to participate in the bids (see discussion in Box 6.10). International experience shows that some countries have allowed this, while other countries have not.

Allowing government-owned companies to bid is likely to deter private bidders, and will not meet the objective of raising additional finance.

6.11 Next Steps

There is potential to develop IPT programs that will be attractive to international bidders. To achieve this, governments can work with international investors and potential providers of loan finance to build the detailed business models that will attract international interest and can be replicated across the African continent.

The key next step is to move beyond merely considering how this business model applies within Africa. This report provides a Toolkit to help practitioners progress with implementing the model in a real setting.

Notes

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2. Department of Energy and Climate Change (2016).
3. Office of Gas and Electricity Markets, "North West Coast Connections—Consultation on the project's Initial Needs Case and suitability for tendering," February 2017, [https://www.ofgem.gov.uk/publications-and-updates/north-west-coast-](https://www.ofgem.gov.uk/publications-and-updates/north-west-coast-connections-consultation)

- connections-consultation-project-s-initial-needs-case-and-suitability-tendering (accessed March 10, 2017).
4. A. Eberhard et al. (2016).
 5. Preliminary works do not necessarily involve the actual acquisition of the ROW. This can be left for the IPT developer to conclude. The government generally reaches an agreement with the land-owners and the IPT (after tender is awarded) pays for the land or ROW. However, this may vary by country.
 6. The early methodology is used by the Alberta Electric System Operator (AESO), the California Independent System Operator (CAISO), the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), and Midcontinent Independent System Operator (MISO). The late methodology is adapted by the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISONE), SPP and PJM Interconnection. Source: "Competition in Electricity Transmission: An international study on customer interests and lessons learned" (2015). The report was prepared by Navigant as part of National Grid's response to Ofgem's consultation on the introduction of onshore competition.
 7. Government of India, Ministry of Power, "Order No. 15/1/2013," July 2015, http://www.powermin.nic.in/sites/default/files/webform/notices/policy_for_incentivizing_early_Commissioning_of_Transmission_Project_0.pdf (accessed March 10, 2017).
 8. M. Kojima and C. Trimble (2016).
 9. The cash collected approach covers cash payments for minor capital expenditures, but does not include future investment needs for "significant replacement or upgrading of existing capacity as well as capacity expansion." M. Kojima and C. Trimble (2016).
 10. S. Oguah and P. Sanchez (2015).
 11. A PCOA provides a framework to protect the interests of the IPP (supplier) in the event of an early termination of the PPA. Early termination will result in the government buying out the facility. The amount paid will be calculated based on clear and predetermined rules, and will differ depending on which party caused the early termination. The Put option is the supplier's right to require the government to acquire the plant (under events specified in the PCOA). The Call option is the buyer's right to require the wholesale supplier to sell the plant to the government (under events specified in the PCOA).
 12. World Bank and Public-Private Infrastructure Advisory Facility, "Market Sounding" (Toolkit for PPPs in Roads and Highways), 2009, <https://ppiaf.org/sites/ppiaf.org/files/documents/toolkits/highwaystoolkit/6/pdf-version/5-92.pdf> (accessed March 10, 2017).
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SECTION 7

Toolkit to introduce independent power transmission tenders

This Toolkit is a guide for government officials and policymakers (“the government”) in Africa who are considering whether to seek private finance for investments in transmission using the IPT model.

Under the IPT model, a private investor enters a long-term contract to build, operate, maintain, and finance a transmission line for a defined period. The contract may be for a new single line or a package of several transmission lines. It may also include transmission substations or (in a few instances) only be for substations. For simplicity, this Toolkit uses the phrase “transmission projects” to refer to projects that include transmission lines, substations, or both; and to refer to both single projects and a package of a few projects.

The IPT receives annual payments typically in monthly instalments. The payments are largely determined by the winning bid. The revenues to make these payments are usually based on revenues from wheeling charges. However, the IPT investor does not carry the risk for the level of wheeling charges or the Megawatt-hour (MWh) of energy that is wheeled.

The IPT typically becomes a licensed transmission company and is subject to a set of obligations and standards set out in the licenses and in associated Codes and other documents. The privately financed line is integrated with the rest of the transmission grid through connection to one or more grid substations.

An IPT also enables the use of project finance. This means investors will focus on the costs and revenues of the project and on the ability of the IPT to manage them. This, in turn, means that procuring transmission projects through the IPT model can unlock additional finance for transmission projects in Africa (compared to the business-as-usual case in which

government-owned utilities finance all transmission investments), and allow more projects to get done. For a further discussion on this, see Section 5.

IPTs have been successful internationally

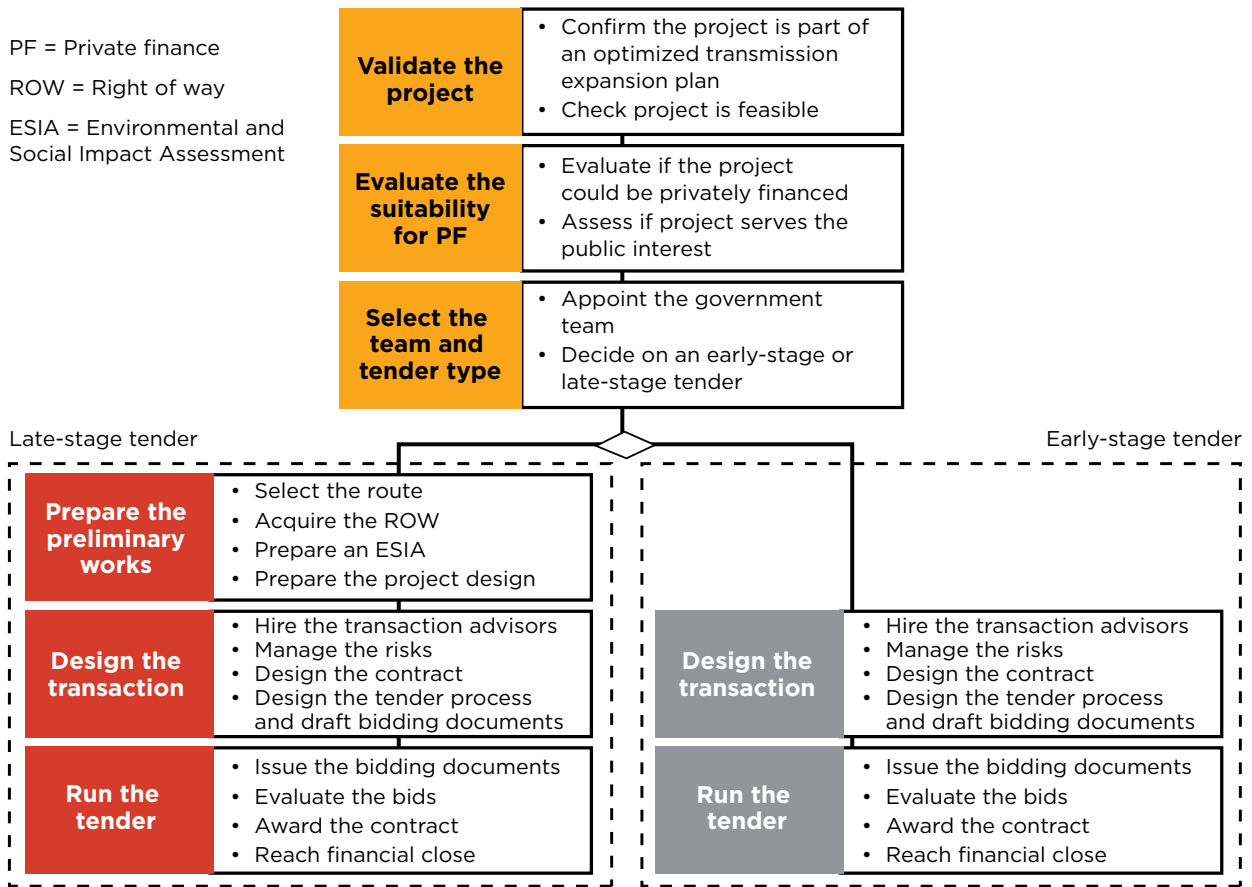
IPTs are widely used around the world, including in Mexico, South America (Brazil, Chile, Colombia, and Peru) India, and Pakistan. IPTs are also increasingly being used in countries that previously provided exclusivity to a private transmission company. The United Kingdom has tendered all offshore transmission using the IPT model, and is moving to tender major onshore projects. IPT tenders have also been used in Australia, the United States, and Canada.

Countries that have used IPT contracts have raised large amounts of funds from the private sector for transmission investments. For example, IPTs in Brazil, Peru, Chile, and India collectively attracted over US\$24.5 billion from the private sector between 1998 and 2015. For more information about the experience of each of these four countries, see Appendix A (which includes each of these countries as a case study).

Summary of the process

Governments can develop and implement IPT transactions through the process described in this Toolkit, and summarized in Figure 7.1. The process consists of six stages:

- **Validate Project:** The purpose of this stage is to validate that the transmission project is part of an optimized transmission expansion plan and is a feasible project. This stage is described in Section 7.1 of this Toolkit.

Figure 7.1 Summary of the process

- **Evaluate Suitability for private finance:** The purpose of this stage is to evaluate if the project could be privately financed and if the project serves the public interest. This stage is described in Section 7.2 of this Toolkit.
- **Select Team and Tender Type:** The purpose of this stage is to select the government team who will manage the transaction. The team may be a single committee, or a working committee that reports to a steering committee. This team's first decision will be to decide on the type of tender for the transaction. IPTs have two types of tender process:
 - Under a **late-stage tender**, the government does preliminary work such as selecting the route and preparing the project's detailed design. The private investor is responsible for building and operating the transmission project in accordance with this. If the government decides to pursue a late-stage tender, it should follow the process described on the left side of Figure 7.2.
 - Under an **early-stage tender**, the government sets out the broad transfer requirements

between two points. The private investor is responsible for identifying the best solution and preparing all preliminary works. If the government decides to pursue an early-stage tender, it should follow the process described on the right side of Figure 7.2.

This stage is described in Section 7.3 of this Toolkit.

- **Prepare Preliminary Works:** The purpose of this stage is to prepare the project's detailed design, select the route, acquire the right of way (ROW), and prepare the Environmental and Social Impact Assessment (ESIA).¹ This stage is described in Section 7.4 of this Toolkit.
- **Design Transaction:** The purpose of this stage is to design a transaction that promotes competitive bidding, delivering value to the public. At this stage the government should hire transaction advisors to help it manage risks, design the contract, and design the tender process and draft the bidding documents. This stage is described in Section 7.5 of this Toolkit.

- **Run Tender:** The purpose of this stage is to implement the transaction designed in the previous stage. The government, assisted by its transaction advisor, should: issue the bidding documents, evaluate bids, award the contract, and reach financial close. This stage is described in Section 7.6 of this Toolkit.

7.1 Validate the project



To validate a project, the government should confirm that it results from an optimized transmission expansion plan (Section 7.1.1) and check that the project is feasible (Section 7.1.2).

7.1.1 Confirm the project is part of an optimized transmission expansion plan

The government should confirm the project was defined as a result of an optimized transmission expansion plan. This ensures that the project is consistent with the power sector strategy and the electricity development plans, considers uncertainty, is used and useful for the long run, and takes into account different costs and benefits.

Preparing an optimized **transmission expansion plan** is a rigorous process that requires:

- Estimating transmission needs for a horizon year (for example, five to ten years into the future) and working backwards to plan implementation from present year up to horizon year,
- Preparing system simulation studies based on accurate data,
- Meeting standard planning criteria (for example, an n-1 criteria²),
- Following an unbiased regional approach (country-wide, pool-wide, multi-country, etc.),
- Modelling uncertainty by assuming different future scenarios,
- Doing a rigorous cost-benefit analysis of transmission alternatives, and
- Updating the plan frequently.

Developing credible scenarios is key to developing the transmission expansion plan. The scenarios should consider existing energy policy objectives set at a countrywide level, and accurate assumptions about the evolution of the generation sector, demand forecasts, and technology and fuel costs.

7.1.2 Check project is feasible

The government should check that the project is technically, economically, financially, and environmentally feasible as part of the optimal transmission system expansion plan. To do this, the government should find out if a recent feasibility study shows the project is feasible.³ If this is the case, the government can move to the next stage. A **feasibility study** assesses whether the risks and uncertainties have been properly modeled, that the costs are accurate, and that the preliminary works (if applicable) are fit for purpose. Feasibility studies can focus on different dimensions of the project. Given the characteristics of transmission projects, feasibility studies should consider the technical, economic, financial, and environmental dimensions.⁴

If no recent feasibility study shows the project is feasible, the government should find out if any recent pre-feasibility study shows the project could be feasible. **Pre-feasibility studies** are commissioned before investing a considerable amount of time and money into the project (and before commissioning a feasibility study). A pre-feasibility study does not ensure feasibility, but should at least: (i) exclude projects that are evidently not feasible; and (ii) suggest how likely it is that the project will be feasible, and identify the key factors in determining feasibility. If this is shown in a recent pre-feasibility study, the government can move to the next stage. However, the government should also start any additional work that may be needed to confirm feasibility—like obtaining permits and approvals. This additional work could be done while undertaking other tasks in Stage 3.

If no recent feasibility or pre-feasibility studies have been completed, the government should commission a study to identify whether the project is likely to be technically, economically, and financially feasible; the ROW can be acquired, and environmental permits are likely to be obtained. Route selection and project design can be prepared at a later stage—by either the government or bidder, depending on the tender type.

7.2 Evaluate the suitability for private finance



The government should evaluate if the transmission project could be privately financed (Section 7.2.1) and assess if the project serves the public interest (Section 7.2.2). This Toolkit presents several factors that the government should consider when evaluating if the project is privately financeable, and suggests organizing a market sounding to consult the level of interest of private investors. It also defines what a Value for Money (VfM) analysis is, and how it could be applied to quantify the costs and benefits of developing the transmission investment through an IPT model, compared to being publicly financed.

7.2.1 Evaluate if the project could be privately financed

The government should consider the following four factors to evaluate if a project could be privately financed:

- **The legal and regulatory framework to support private investment in transmission is in place.** Depending on the country, reforms may need to be made to electricity laws, licenses, and Grid Codes, as well as to regimes for the economic regulation of the monopoly networks or the vertically integrated utility. Economic regulators will also need to adapt their approaches to accommodate charging models used by IPTs.
- **The costs of the project can be recovered from users of the transmission grid.** International experience shows there is not a unique way to structure the contract payment. In Peru, for example, investors sign the IPT contract with the Ministry of Energy and obtain rights to operate the transmission line and receive transmission revenues. In India, IPT contracts are signed with regional Long Term Transmission Customers (LTTs). LTTs are generators, distribution companies, and major load centers. In the future, investors will sign the contract with distribution companies, based on use of the transmission network.⁵ In Chile, the winning bidder becomes party to a multilateral agreement that provides transmission providers with access to the transmission revenues.

- **The transaction has a credit-worthy public counterparty, or it is plausible that credit enhancements to create a bankable arrangement can be arranged.** If the power sector is not financially viable, investments have to be secured through revenue escrow accounts or other liquidity arrangements. However, escrow accounts may not be enough to make the project bankable. Governments may also have to back payments obligations to IPTs with government guarantees, and sometimes also guarantees from multilateral institutions like the World Bank, African Development Bank, or other DFIs. This point is discussed in more detail in Section 6.7.
- **Bidders are interested in the project, because it is large enough to justify the transaction costs for them.** However, bidders will also evaluate if there are reasonable prospects of a future pipeline of other investment opportunities. Therefore, governments should frame the project within a broader pipeline (if it is the case), or consider developing a pipeline of future IPT projects.

It is in the interest of the government to organize a market sounding to consult the level of interest of private investors. A **market sounding** evaluates how attractive the business model is for investors, tests whether investors will be able to assume the risks that are to be transferred to them through the IPT contract, and generates inputs and requirements from investors and other parties.⁶

Market sounding involves gathering information regarding the viability of the business model, the ability of the private sector to meet the requirements, and the market's capacity and maturity.⁷ The government can find further information about what market sounding involves and how to prepare a market sounding in the "Market Sounding" volume of the World Bank "Toolkit for PPPs in Roads and Highways."

7.2.2 Assess if the project serves the public interest

The government should ensure that financing transmission projects through the private sector benefits the country. This involves quantifying the costs and benefits of developing the transmission project under an IPT contract, compared to a scenario where the project is publicly financed. To do so, the government should prepare a VfM analysis.

Value for money refers to "achieving the optimal combination of benefits and costs, in delivering

services users want.” VfM typically involves a combination of qualitative and quantitative approaches, where qualitative analysis “involves sense-checking the rationale for using PPP [Public Private Partnerships]” and quantitative analysis “typically involves comparing the chosen PPP option against a ‘Public Sector Comparator’ (PSC)—that is, what the project would look like if delivered through conventional procurement.”⁸

The government can refer to the World Bank’s “Public-Private Partnerships. Reference Guide” to find further information about what VfM is, and what qualitative and quantitative VfM analysis involves. The Guide also includes various references to other useful related documents.⁹

7.3 Select the team and tender type



The government should appoint a Government Team to manage the process (Section 7.3.1). Managing an IPT transaction requires decision making, time, resources, and coordination among stakeholders. Appointing a specific team to be responsible for this is key to ensuring a smooth process.

Once appointed, the Government Team should decide whether to conduct an early-stage tender or a late-stage tender (Section 7.3.2). This decision determines the point in the process at which the tender takes place. It also impacts on who prepares preliminary works, on risk allocation, on contract design, and on other tasks.

7.3.1 Appoint the government team

The government needs to appoint the Government Team to manage the process successfully. The team may be a single committee, or a working committee that reports to a steering committee. A contract management committee may also be part of the Government Team, responsible for managing contract arrangements after financial close. Box 7.1 defines each of these committees.

Deciding the best option to assemble the team will depend on the government’s experience with similar processes, whether the IPT transaction is the first one or if the government has tendered IPTs previously, budget constraints, and other factors.

For simplicity, from now onwards this Toolkit refers to the appointed Government Team as ‘the government’.

Team composition and responsibilities

Members of the government—either a single, double, or triple committee—typically include officials from the Ministry of Power (or analogous ministry or agency), the Ministry of Finance, the regulatory agency, the government-owned utility (if this is the case), and external consultants (if hired).

The team is responsible for completing all the following stages. This includes deciding the tender type (including preparing preliminary works if the government decides on a late-stage tender), designing the transaction, and running the tender.

7.3.2 Decide on an early-stage tender or a late-stage tender

First, the government should decide between the two tender types: an early-stage tender or a late-stage tender. The main difference between the two approaches is who is responsible, and who carries the

Box 7.1 Definition of different committees

A **steering committee** is typically formed by high-level government officials who prepare the strategy, make the main decisions, and set out the timelines and working arrangements, including responsibilities of each steering committee member. A steering committee generally has an explicit mandate and is headed by a committee chair.

A **working committee** is generally formed by a more junior group of government officials who prepare the day-to-day work, guided by the steering committee. A working

committee typically comprises experts in specific areas of knowledge, and is designated by the steering committee.

A contract management committee is usually formed to manage contract arrangements after reaching financial close. A contract management committee can be formed by a group of people or one person, and is typically appointed by the Ministry of Power.

risk, for preliminary works. Box 7.2 describes the two types of tenders for IPTs.

Early-stage tenders transfer more risk on preliminary works to private developers, including route selection, acquisition of ROW, environmental impact assessments, and project design. In contrast, late-stage tenders have a high degree of project definition, and Government needs to prepare all preliminary works, as described in Section 7.4. The responsibilities under the two approaches are shown in Figure 7.2.

Early-stage tenders require greater time. The Office of Gas and Electricity Markets (Ofgem), the regulator in Great Britain, consulted on the choice between early- and late-stage tenders. Ofgem considered that late-stage tenders would need to be conducted four to five years before the transmission asset is required. Early-stage tenders would need eight to nine years. Identical timelines would not necessarily

apply in other countries, but these can at least provide a reference. In addition, Ofgem states that early-stage tenders would allow for innovation on technology, asset design, and routing and planning approvals. The level of innovation in designs will vary according to the performance requirements set by the tender guidelines. Late-stage tenders focus more on procurement, construction, and financing solutions.

Both tender types could be used in Africa. However, as discussed in Section 6.7, African governments should consider procuring the first IPTs through late-stage tenders. This alternative would avoid investors being exposed to risks associated to preliminary works (which they may not be best placed to manage at the start), and would involve a simpler bid evaluation process.

The costs associated with preparing preliminary works are significant. If the government decides on

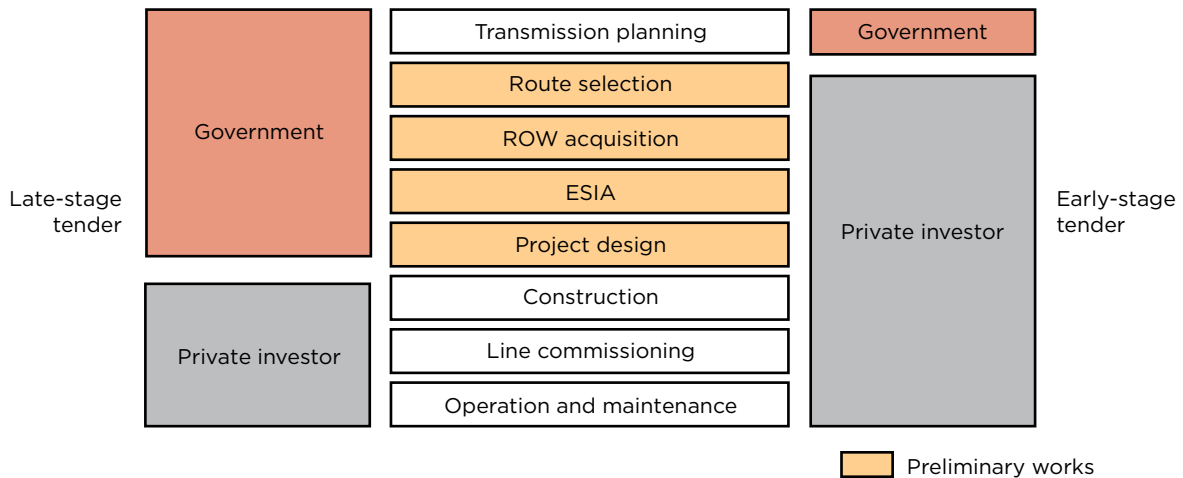
Box 7.2 Early-stage tenders and late-stage tenders

IPTs have two types of tender:

- Under a **late-stage tender**, the government does preliminary work such as selecting the route and preparing the project design. The private investor is responsible for building and operating the transmission project in accordance with this.

- Under an **early-stage tender**, the government sets out the broad transfer requirements between two points. The private investor is responsible for identifying the best solution and preparing all preliminary works.

Figure 7.2 Responsibilities under early-stage tenders and late-stage tenders



a late-stage tender, it should also discuss and define the following activities before preparing preliminary works:

- Setting the scope of work and the expected costs of preparing preliminary works, and the ability to recover these costs from users of the transmission grid,
- Identifying who will prepare the preliminary works,
- Establishing the role of the government in overseeing the preliminary work, and
- Defining how the ROW gets transferred to the successful bidder.

The government may wish to obtain legal advice on how best to transfer the ROW to the successful

bidder. In some countries, the ROW can sit with a shell company which is sold or transferred to the winning bidder. In other cases, preliminary works end once the government reaches an agreement with the owner(s) or occupant(s) of the land and the winning bidder makes payments for the land or ROW easements.

The responsibility of preparing preliminary works under a late-stage tender generally rests with the sector entity in charge of planning (generally within the Ministry of Energy or similar) or the transmission utility. In addition, the government should consider obtaining support from multilateral agencies to fund or provide technical assistance for these activities, especially if the government has little or no experience running IPT tenders.

7.4 Prepare the preliminary works



If the government decides on a late-stage tender, it must prepare the preliminary works. These involve selecting the route (Section 7.4.1), acquiring the ROW (Section 7.4.2), preparing the ESIA (Section 7.4.3), and preparing the design (Section 7.4.4). Once preliminary works are completed, the project will be clearly defined. The private investor will be responsible for building and operating the transmission project in accordance with that process.

7.4.1 Select the route

The government should select the route of the transmission line. Selecting the route is typically an iterative process that requires aerial and field surveys. The result of this task is a preferred route and alternative routes if permits and ROW cannot be obtained for the preferred route.

To complete this task, the government should perform two main activities:

- **Postulating potential routes and gathering data:** This involves conducting aerial and field surveys and considering ancillary facilities required to access the transmission project

- **Evaluating options:** This involves analyzing the data gathered in the previous activity and selecting the preferred and alternative routes.

The sector entity in charge of transmission planning is the party best suited to carry on both activities. In many countries, this is the Ministry of Energy or similar. In others it will be the planning department of the transmission utility (can be a local, regional, or national company, depending on the country). If it is the Ministry of Energy or similar, it should also request the opinion and participation of the planning department of the transmission utility when it performs these activities.

7.4.2 Acquire the ROW

The government should acquire the ROW for the selected route. The **ROW** is the right to cross privately or publicly owned property to build the transmission project.

To acquire the ROW, the government will need to negotiate with the owner(s) or occupant(s) of the land. The negotiations are often based on the quantification of the economic losses that the landowner will

bear due to the impact of the project, or the restrictions imposed on the use of land once the landowners provide the ROW.

Acquiring the ROW is one of the highest risk tasks of the process and can require years to accomplish, depending on the characteristics of the project. It is also a sensitive task that must be handled with care. As with the previous task, the party best placed to perform this task is the sector agency in charge of transmission planning (after they have consulted with the planning department of the transmission utility).

Accomplishing this task can also depend on both property rules and regulations relating to local land. In some cases, the government may have to amend the existing rules and regulations to allow for private investors to acquire the ROW.

7.4.3 Prepare an ESIA

The government should commission an ESIA to evaluate the expected environmental and social impacts of the project, and identify potential environmental and social limitations of the project. Typically, state regulatory agencies require an ESIA to issue permits for the project.

The document that results from the ESIA is called an Environmental Impact Statement (EIS). The EIS should state whether the project complies with environmental and social impact standards, or whether the government should put in place mitigation measures to reduce or avoid those impacts to obtain the necessary permits. However, sometimes mitigation measures can be implemented in parallel with the

next stage. For example, the EIS may suggest that obtaining the environmental permits may be feasible. However, getting the environmental permits may take time. In that case, it may be reasonable to proceed with the next stage, especially if the project is urgent.

7.4.4 Prepare the project design

The government should also prepare the project design. This involves defining the project characteristics and the specifications needed to procure materials and equipment.

The major project characteristics include:

- Year when the transmission project must be in service,
- Start point and end point for the transmission line (or the locations for substations),
- Voltage of line (kV),
- Nominal capacity (MVA),
- Approximate length (km), and
- Number of circuits.

The main set of specifications to procure materials and equipment include:

- Mechanical specifications of tower (for example, lattice or tubular),
- Type of conductors, number of conductors for each phase, and number of earth conductors,
- Grounding, insulator and hardware requirements,
- Construction methodology, and
- Design norms and standards.

7.5 Design the transaction



The government should design a transaction that results in a transparent, open, and competitive tender process. To achieve this, it should start by hiring transaction advisors (Section 7.5.1), especially if this is the first time the country will tender an IPT contract. The government will also need to identify the risks associated to the project, evaluate who is best placed to carry each risk and how to allocate those risks (Section 7.5.2). This will be a key step in designing the IPT contract (Section 7.5.3). However, the success of

the transaction will depend not only on designing the contract correctly, but also on designing an appropriate tender process, and drafting the bidding documents. Section 7.5.4 discusses how the government can design the tender process and draft the bidding documents.

Procuring IPTs will require frequent tenders (compared to other business models). Preparing for this well will reduce implementation costs.

7.5.1 Hire the transaction advisors

Designing an IPT transaction requires expertise in multiple fields: legal and regulatory issues, commercial and financial issues, technical issues, or specifically to draft bidding documents. Governments often lack this expertise and may desire to hire experts to support the process. Transaction advisors are especially important when countries are introducing IPT tenders for the first time. They can also build capacity within the government, reducing the need to hire advisors in future transactions.

When hiring transaction advisors, the government will face choices: hire local or international advisors; hire all advisors from one entity or from different entities; or hire advisors for specific tasks or for all stages of the transaction process. The need for advisors may vary according to the project characteristics, but the hiring process should always be “transparent, fair, cost-effective and free of conflict of interest.”¹⁰

The World Bank toolkit for hiring advisors for private participation in infrastructure¹¹ provides more details on the hiring process. The toolkit includes guidelines for setting realistic timelines, preparing the budget to pay for advisors, selecting advisors, and paying for advisors.

Hiring advisors can be expensive. The government should consider contacting multilateral agencies—like the World Bank, the African Development Bank, and others—to help fund its hiring of advisors. Alternatively, these agencies can also provide technical assistance for the transaction process. This is also discussed in the World Bank toolkit for hiring advisors.

7.5.2 Manage the risks

The government should identify the main risks associated with the project, evaluate which party is best placed to carry each risk, and analyze how to mitigate them. Risks should be allocated to the party that can

best manage the risk or the party that can mitigate the risk at least cost. Managing risks appropriately minimizes project costs and attracts high-quality investors.

The government may wish to complete this task by filling in a risk matrix like the one shown in Table 7.1. To complete a risk matrix, the government should:

- Identify the project risks (first column),
- Evaluate how the risks arise (second column), and
- Assess how to allocate the risks (third column).

The government can refer to the World Bank’s “Concessions for infrastructure. A guide to their design and award” to find further information about identifying and allocating risks, and to help it complete the risk matrix in Table 7.1.¹²

In addition, Table 7.2 describes the main risks of an IPT project (including the risk, and its risk category in bold), most common reasons why each risk arises, and details of how to allocate the risk. The table also clarifies differences, if any, between the risks of late-stage and early-stage tenders.

7.5.3 Design the contract

The government should design an IPT contract that clearly specifies the rights and obligations between the government and private investor. The IPT contract—also known as a Transmission Service Agreement (TSA)—should be drafted in a way that is enforceable and consistent with any other associated agreements (like guarantees or other credit enhancement mechanisms).

A well-defined TSA is key to making the project bankable. The contract should include provisions to mitigate some of the risks identified in Task 7.5.2. In all cases, the terms and clauses in the TSA must be drafted in clear and measurable terms, ensuring that they can be legally enforceable. Table 7.3 summarizes

Table 7.1 Risk matrix

1. What is the risk?	2. How does the risk arise?	3. How should the risk be allocated?

Source: Adapted from Table 3.2. M. Kerf et al., “Concessions for infrastructure. A guide to their design and award,” Technical Paper no. 389, (1998), <https://tinyurl.com/zgamefg> (accessed March 13, 2017).

Table 7.2 Main risks of an IPT project

What is the risk? (Risk category; risk)	How does the risk arise?	How should the risk be allocated?
Preliminary works; Failure or delay in obtaining ROW, permits, or other approvals (not applicable to late-stage tenders)	Landowners along the route refuse to grant the necessary ROW rights to the developer; or Government agencies unreasonably withhold the granting of permits	Can be allocated to government (late-stage) or IPT (early-stage). Where the risk allocated to IPTs Government should ensure timely decision making/arbitration processes and provide reasonable relief measures to IPT in case ROW, or necessary permits, or approvals cannot be secured by the IPT developer, despite best efforts.
Construction risk; Cost overrun	Within IPT's control (for example, due to inefficient construction practices)	Contractor to carry the risk through fixed-price construction contract (typically an EPC contract)
Construction risk; Delay in completion	Within IPT's control (for example, due to lack of coordination of subcontractors)	IPT faces penalties for late commissioning
	Outside IPT's control (for example, due to force majeure events)	Force Majeure risk borne by government, dependent on detailed design of Force Majeure clauses
Construction risk; Finding adverse soil conditions	Required geotechnical studies are generally not available during the early stages of project development (for example, before construction)	IPT to carry the risk
Operating risk; Operating cost overruns	IPT mismanaging operating costs	IPT to carry the risk
Off-taker; Nonpayment by off-taker (due to commercial causes)	Off-taker faces cash flows constraints and cannot cover payment obligation with IPT	Government to carry the risk. To mitigate this risk the government can provide, for example, escrow arrangements, credit enhancement mechanisms, or engage DFIs.
Financing; Funds needed to finance the project are not obtained	A committed lender or sponsor of the IPT project decides to abandon project, faces, for example, insolvency issues or bankruptcy, etc.	IPT to carry the risk
Exchange rate;	Devaluation or fluctuations of local currency	Government to bear risk if revenues defined in US\$. IPT to bear risk if portion of revenues defined in local currency—IPT may hedge against this risk.
Regulatory; Changes in law	The general legal framework changes (taxes, or environmental standards)	Normally, IPT to carry the risk (government could carry the risk when changes are fundamental and completely unforeseeable; for example, switch from free market to central planning)
	Changes in legal or contractual framework directly and specifically affecting the project company	Government to carry the risk

(table continues on next page)

Table 7.2 Continued

What is the risk? (Risk category; risk)	How does the risk arise?	How should the risk be allocated?
Force Majeure; Acts of God	Through Acts of God, which include (but are not limited to) floods, earthquakes, riots, and strikes	Insurer risk, if risk was insured; otherwise, Force Majeure risk borne by government, dependent on detailed design of Force Majeure clauses
Environmental and social; Consultations with affected communities are not successful (not applicable to late-stage tenders)	Communities are engaged too late in the process	Early-stage: IPT to bear the risk which can be mitigated by engaging local consultants with experience in this process Late-stage: Government to bear risk.
Environmental and social; Environmental and Social Impact Assessment studies discover sensitive areas along the route (not applicable to late-stage tenders)	Upon the completion of the Environmental and Social Impact Assessment	Early-stage: IPT to bear the risk. Mitigation will generally entail changes to the preferred route. Late-stage: Government to bear risk.
Political	Through actions such as breach or cancellation of contract; expropriation, creeping expropriation, etc.	Insurer's risk (PRI), if risk was insured; otherwise the IPT will carry the risk; if the contract terminates, the government will pay a compensation
Transfer; Disputes when asset is transferred to government	Quality transfer specifications were not (or poorly) defined	Detailed quality and price specifications should be included in the contract

Source: Adapted from Table 3.2. M. Kerf et al., "Concessions for infrastructure. A guide to their design and award," Technical Paper no. 389, (1998), <https://tinyurl.com/zgamefg> (accessed March 13, 2017).

Table 7.3 Summary of key provisions to include in the TSA and associated agreements

Provision	Description
Output specifications	Exact specification of the output—whether a transmission line, substation, or both; location; length; voltage; transmission capacity, etc. Exceptions are also clearly stated. This provision determines the output that society will obtain from the privately financed transmission project. It must be drafted in clear and measurable terms, ensuring that it is legally enforceable.
Validity and term	Definition and specification of project timeline, key milestones, contract term, and expected end date.
Key performance indicators (KPIs)	KPIs need to be defined and clearly specified in the contract. The main KPIs in a TSA are requirements on: <ul style="list-style-type: none"> • Commissioning (for example, an obligation to commission the line by a defined date), and • Line availability after commissioning (as opposed to energy delivered or the usage of the line). The availability target is typically close to 98 percent.
Monitoring and enforcement arrangements	How KPIs will be monitored, the auditing arrangements, and the consequences of performing outside the levels required by the KPIs. Consequences may include penalties and bonuses. For example, the contract should impose penalties if the investor does not meet the obligation to commission the line by a defined date. Prolonged failure to achieve commissioning should also lead to contract termination.

(table continues on next page)

Table 7.3 *Continued*

Provision	Description
Payment mechanisms	<p>How the private party will be paid for providing the output, and by whom. Payments to IPTs are generally largely determined by the winning bid and are based on line availability. The IPT receives annual payments, typically in monthly instalments. Payment starts once the line is successfully commissioned.¹³</p> <p>In addition, the design of payments mechanisms typically specifies:</p> <ul style="list-style-type: none"> • How payments may be adjusted in response to performance, • Currency of payments, • Indexation arrangements and parameters to be used, and • Frequency of payments.
Response to changes outside the contract	<p>The contract should specify how the rights and obligations of the parties will change in response to changes outside the contract, including:</p> <ul style="list-style-type: none"> • If and under which circumstances a change in law that changes project costs would trigger a change in payments to the private party, • If and how changes in economic variables that could affect the project costs (like interest rates or exchange rate) would be treated, • What would happen if the private party refinances its debt—if potential savings are, or are not, passed on to the public sector, and • Provisions to evaluate changes unspecified in the contract.
Dispute resolution mechanisms	<p>The contract should specify the dispute resolution process. Generally, this involves defining a series of steps before any interested party invokes arbitration to resolve the dispute or terminates the contract.</p> <p>Steps may include notification at a working level, escalation to a senior management level, issuance of formal notice, and submission of a plan by a non-performing party.</p>
Other government obligations	<p>Definition and specification of the Government's obligations. These may include project functions that the Government retains (for example, operating the system, assisting in land acquisition, or waiving of taxes or duties).</p>
Termination provisions	<p>The TSA should clearly state what happens when the contract ends, including:</p> <ul style="list-style-type: none"> • Clauses of contract close. Procedure for end-of-term arrangements, including (but not limited to) transfer obligations if BOOT or similar contract type, or termination payments. • Clauses of early termination. The TSA should clearly specify the conditions for contract termination (by either of the parties or force majeure), the compensation payments in case of, for example, early termination.

Source: Development Bank of Jamaica, "Privatisation Policy Framework & Procedures Manual," <http://dbankjm.com/services/ppp-and-privatisation-division/privatisation/privatisation-policy-framework-procedures-manual/> (accessed March 15, 2017).

the key provisions to include in the TSA and associated agreements.

The government should also evaluate and define which is the best alternative to structure the IPT—whether the private company will own the transmission assets, if these will be transferred at the end of the term, etc. Table 7.4 presents the main PPP structures to consider when designing the most applicable IPT contract for a country. PPP structures where the private company is not responsible for financing and building all new transmission investments are not

included in the analysis. For this reason, the table does not include management, O&M, or lease contracts.

There is not one unique or best structure for IPTs. Rather, "designers of PPP projects need to consider advantages offered by numerous projects and approaches. The analysis of what is needed for a particular project or program needs to be made on a country-by-country, sector-by-sector and project-by-project basis."¹⁴

The selected countries reviewed for this report did not have identical structures for IPTs but they were

Table 7.4 PPP structures for IPT contracts

#	PPP structure	Who funds the capital investment?	Who bears construction risk?	Who bears operation risk?	Who owns the assets?
1	Build, Own, Operate, Transfer (BOOT)	Private company	Private company	Private company	Private company
2	Build, Own, Operate (BOO)	Private company	Private company	Private company	Private company
3	Build, Transfer, Operate (BTO)	Private company	Private company	Private company	Government/SOE
4	EPC+Finance	Private company	Private company	Government/SOE	Government/SOE

all successful in attracting private finance to invest in new transmission assets. One point of difference is the stage at which the asset is transferred.

In Brazil, Peru, and India tenders are for **BOOT** contracts (type 1 in Table 7.4). The asset is transferred at the end of the contract term. As transmission assets are long lived assets they will have a remaining useful life at the end of the term. The transfer condition therefore requires measures such as valuation of the asset condition, or requirements for minimum maintenance spend towards the end of the contract term to ensure the asset is transferred in good condition.

Chile's IPT contracts are **BOO** (type 2 in Table 7.4). The private companies own the assets indefinitely and do not transfer the transmission assets at the end of the contract term. In Chile's case the contract establishes revenue certainty for an initial period and is followed by regulatory determinations later in the asset life. This was the only example in the case studies of indefinite private ownership of the transmission asset financed under an IPT tender.

An alternative is that the private company finances the asset; receives long term payments based on operational performance; and transfers the asset ownership at a much earlier stage. We have referred to this as Build, Transfer, Operate, or **BTO** (type 3 in Table 7.4). For example, the asset could be transferred to the government-owned transmission company immediately after commissioning, while the capital costs would be recovered over a contract term of 30 years.

The selected countries did not present examples of the BOT type. An early transfer of ownership is also not a usual approach under project finance. It may in theory be able to provide similar incentives to

traditional IPT contracts. However this requires that the transfer of ownership is purely on paper and does not lead to any intervention by the new owner that affects cost or performance. It also requires that security is provided in some way other than the ultimate security which arises from ownership of the asset.

A final option is that the private developer finances the transmission asset; transfers ownership after commissioning and has no further operating responsibility; and is paid back over, for example, 30 years. We refer to this model as **EPC+Finance** (type 4 in Table 7.4) There are no efficiency gains from this approach as the developer does not bear whole-of-life performance risk.

Credit enhancement arrangements may be needed

During this task, the government should also consider if credit enhancement arrangements are needed. These mechanisms may be necessary to make the project bankable. If so, the government should design these arrangements during this task. These arrangements are typically governed by separate documents supporting the TSA.

Examples of credit enhancement arrangements include Government Support Agreements, Partial Risk Guarantees (PRG), and credit guarantees. Governments may be interested to contact institutions like the Multilateral Investment Guarantee Agency (MIGA), or other multilateral organizations that offer and provide support in designing credit enhancement products. The World Bank and other multilateral organizations also provide model templates for these arrangements, which the government can also consult as reference.

7.5.4 Design the Tender Process and Draft Bidding Documents

The government should design the tender process by which bidders will be qualified and then invited to bid. In this task the government should:

- Define the evaluation process and the criteria to qualify bidders,
- Define the timeline of the tender, and
- Draft the bidding documents.

To complete this task successfully, the government should consider appointing an **Evaluation Committee** to carry out this and all tasks until financial close. The Evaluation Team may be formed by members of the Committee, other governments officials, transaction advisors (those hired in Task 7.5.1, or others), or any combination of them.

Define the evaluation process and the criteria to qualify bidders

The process can be designed in different ways. It may involve one or two stages. Bidders may, or may not, be prequalified before bidding starts. To choose the design process, the government should study the different alternatives, review the international experience, and take advantage of the publicly available standardized templates.

The government will first have to decide whether to prepare a one-stage or two-stage tender process. The main differences between these two approaches are at the bidding stage, as described in Box 7.3.

Governments or contracting entities typically pre-qualify bidders to ensure that they only receive bids from well-qualified parties. Bidders are also likely to invest more in their bids if the number of comparable bidders is limited. This is generally the case with IPT tenders.

To prepare the **prequalification phase**, the government should define the qualification criteria and the method to assess the applications to prequalify. The qualification criteria generally include meeting technical and financial requirements, providing bid bonds, and others—whether government-owned companies would be allowed to bid or not (see discussion in Box 6.10). The assessment to prequalify applications can be pass-or-fail or through the scoring of the criteria.

To prepare the **bidding phase**, the government should also develop the process and criteria to evaluate bids. This includes:

- Defining the process by which to evaluate bids—this typically involves bidders restating their qualifications, and presenting a technical and a financial proposal,
- Developing the bid evaluation criteria—including the method by which the technical proposals will be weighted, whether the technical proposal must meet minimum thresholds, and setting a price cap, and
- Establishing how to present bids—format, delivery method, etc.

Box 7.3 One-stage and two-stage tender process

The World Bank “Toolkit for PPPs in Roads and Highways” defines the two approaches as:

- **One-stage process:** “When the Government has a precise idea on the technical options and specifications to be chosen. Prequalified firms are asked to submit bids in strict accordance with the specifications imposed by the Government. Final selection is made on a “financial” basis alone and little room for negotiation is left to the selected candidate.”
- **Two-stage process:** “In particular when uncertainties remain on technical options to be retained, it may be

undesirable or impractical to prepare complete technical specifications in advance. This is typical for large and complex PPP [Public Private Partnerships] projects. In such a case, a two-stage bidding procedure may be used. In stage 1, unpriced technical proposals based on a conceptual design or performance specifications are invited. They then are subject to technical and commercial clarifications and adjustments. In stage 2, amended bidding documents are issued and final technical proposals and priced bids are submitted and evaluated.”

Source: World Bank (2009).

The case studies included in Appendix A provide examples of evaluation processes and qualification criteria used in IPT tenders internationally. For example, in Peru the bidder must have a minimum level of equity and assets (which varies according to the specifications of the transmission project) and must show experience operating electricity transmission systems that satisfy minimum conditions regarding length, voltage, and transmission capacity. Bids must be quoted in US\$ and the tender is awarded to the bidder that proposes the lowest service cost—calculated as the sum of annual O&M costs and the annual repayment of investment costs, calculated using a 12 percent real annual rate for a 30-year period.

Module 5 of the “Toolkit for PPPs in Roads and Highways” provides further details on how to implement and monitor the procurement process, and describes the steps to follow when designing the tender process (see Stage 3: Procurement).¹⁵

Define the timeline of the tender

Defining a realistic timeline prepared in advance is key to running a smooth tender. The government should define a timeline that includes all key milestones for the investor until financial close, including:

- Invitation to applicants,
- Deadline to submit applications,
- Notice to prequalified applicants,
- Issuance of bidding documents,
- Bidding conference (if planned),
- Deadline to request clarifications (and changes to draft documents if allowed),
- Deadline to submit bids, and
- Notification of contract award.

However, the government will also need to prepare an internal timeline that includes all the internal steps

required to meet the timeline above. This includes assessing applications, evaluating bids, and finalizing and approving the bidding documents. Some steps may require Ministerial or Cabinet approval—like credit enhancement agreements generally—and the government should factor in these issues.

Draft the bidding documents

The package of bidding documents typically includes:

- A draft of the TSA
- The Request for Proposal (RFP), and
- Other agreements. If the government decides to provide credit enhancement arrangements, these should also be specified, and a draft included in the bidding package.

The RFP generally contains a memorandum of information to bidders, Instructions to Bidders, description of the criteria to qualify bidders and evaluation process, and bid templates.

To draft the bidding documents, the government may find it useful to review the international experience or model templates from multilateral organizations. Many countries publish their bidding documents online. For example, the World Bank offers online templates of standardized bidding documents, guidelines to draft the documents, examples of project bidding documents from countries around the world, and other useful references—like examples of procurement laws or checklists for governments to use while running the tender process.¹⁶

The government may also wish to hire legal experts (if it has not done so yet) to draft the documents (particularly the TSA).

7.6 Run the tender



The government should run the tender according to the timeline defined in Task 7.5.4. The government, assisted by its transaction advisor, should issue the bidding documents, evaluate bids, award the contract, and reach financial close.

7.6.1 Issue the bidding documents

The government will issue the bidding documents to the prequalified bidders. To do so, all bidding documents need to be finalized and approved before the agreed date for the “Issuance of bidding documents” milestone.

The government can choose whether or not to charge bidders for these bidding documents. If the government decides not to charge, it may wish to publish the documents on the webpage of the entity in charge of the tender process.

The timeframe given to bidders to prepare their bids will depend on whether the government decided on an early-stage tender or late-stage tender. During this period, the government should manage interactions with bidders. This includes responding to requests for clarification (and changes to draft documents if allowed) and providing additional information. Sometimes, governments create a virtual Data Room where bidders can access and obtain all the relevant information in one centralized place.

The government will also be responsible for receiving and handling the bids. This involves ensuring that bidders will be able to submit their bids in line with the Instructions to Bidders. For example, if bidders need to provide hard copies, the government must ensure that a tender box is available at the date and place specified. The government should also plan a secure place to keep the bids until evaluation.

7.6.2 Evaluate the bids

The government should evaluate the bids by following the criteria and process included in the RFP. This task generally involves various steps, such as:

- Checking that the bids include all required forms and these are fully completed. Otherwise, the bid(s) should be rejected,
- Confirming that the bidders continue to meet qualification criteria. Otherwise, the bid(s) should be rejected,
- Reviewing the technical proposal and evaluating it against the technical criteria defined in Task 7.5.4. If a threshold was defined for technical proposals, bids that score below it should be rejected, and
- Reviewing the financial proposal and evaluating it against the financial criteria defined in Task 7.5.4.— for example, ranking the bids from lowest to highest bid price.

Once evaluation is completed, the government should prepare an Evaluation Report. This should specify if bids were rejected (which, how many, and why); and include a list that ranks all bidders, clearly stating which bidder was evaluated highest.

7.6.3 Award the contract

The Team should recommend to the government who the preferred bidder is, the main negotiating items,

and the procedure to reach financial close. In some cases, those tasked to evaluate the process may be empowered to decide who the preferred bidder is.

The recommendation should build on the Evaluation Report (prepared in Task 7.6.2), but should also include:

- A detailed description of the project presented by the preferred bidder—and how it meets the evaluation criteria
- The main project risks and estimated costs
- A statement recommending the project and the preferred bidder—including opinion statements from other related and interested government entities (for example, the Ministry of Energy and Ministry of Finance)
- The main negotiating items that the government should consider, and
- The procedure to reach financial close.

The main negotiating items can include various aspects of the project—issues regarding the ROW or land, the concession term, renegotiation alternatives, technical and financial parameters included in the RFP, and other items. However, it is recommended the government limits the number of negotiating items and focus on, generally, two or three of the items listed above.¹⁷

7.6.4 Reach financial close

Many steps need completing between awarding the contract and the private investor starting work. The government needs to ensure that contract negotiations are finalized and the contract—as well as all other related agreements—are signed, and all permits and approvals obtained. But this is not sufficient. The funds needed for the project must be secured. This step is referred to as “financial close.”

Financial close “means that the project’s entire equity has been unconditionally committed, all loan documents have been signed, and disbursement of the loans can start without further problems.” However, this definition may vary according to the country and contract or project type—some also refer to it as “financial closure.” A definition more specific to financial close of greenfield projects and concessions is: “the existence of a legally binding commitment of equity holders or debt financiers to provide or mobilize funding for the project. The funding must account for a significant part of the project cost, securing the construction of the facility.”¹⁸

Box 7.4 Contract management

Designing the Contract Management Plan includes:

- Establishing the main rules—such as:
 - How the contract management committee will ensure that the required quality and technical specifications are met during construction,
 - The process to monitor and report the project’s performance during operation, and
 - Which party pays the monitoring costs.
- Defining the communication and reporting protocols between the private investor, the government, and all other parties,
- Defining the responsibilities of the private investor and the government entities, and how they will be made accountable,
- Monitoring and managing contract risks, and establishing an early warning system to inform the Ministry of Finance if necessary, and
- Planning how to address changes in the TSA.

This task involves:

- Securing all necessary permits and approvals (particularly in early-stage tenders),
- Securing land and ROW if not completed (particularly in early-stage tenders),
- The stakeholders’ agreement—among the stakeholders forming the project company (most likely an SPV),
- The credit enhancement agreement (if planned),
- The financing agreements—the project lenders typically prepare their own due diligence (where they review the main agreements, especially the TSA and credit enhancement agreement) before ensuring and providing their funding sources, and
- The agreements with sub-contractors, insurers, and others—including, for example, the EPC contract with the sub-contractors in charge of the construction and the O&M contract with sub-contractors in charge of operation and management.

Designing and agreeing on a Contract Management Plan and its implementation

The government also needs to design and agree on the process to manage and monitor the contract arrangements. This will constitute the Contract Management Plan.

Designing the Contract Management Plan needs to start during Task 7.6.4, but its implementation will continue until the end of the contract—throughout the construction phase of the project, operation and maintenance, and the transferring of the assets (if the case).

As described in Task 7.3.1, the contract management committee should be responsible for monitoring and managing all contract issues. This committee will be key to, for example, supporting the TSO in managing the IPT (including all communication and reporting between the parties), or establishing an early warning system to inform the Ministry of Finance of any risks that could eventually trigger a government guarantee.

The government can find further information, and guidelines, to prepare and implement the Contract Management Plan in Module 5 of the “Toolkit for PPPs in Roads and Highways” (see Stage 5: Contract Management). Box 7.4 summarizes the main activities the government needs to consider when designing the Contract Management Plan.

Notes

1. Preliminary works do not necessarily involve the actual acquisition of the ROW. This can be left for the IPT developer to conclude. The government generally reaches an agreement with the land-owners and the IPT (after tender is awarded) pays for the land or ROW. However, this may vary by country.
2. The n-1 criteria involves, among other things, that: (1) no system equipment operates outside its long-term design capability and no system voltage is outside safe limits, under “normal” operating conditions (for example, if the system is intact); and (2) unscheduled outages will not cause circuit loadings to exceed applicable ratings, instability or cascading outages, excessive voltage variation, or widespread interruption of load.

3. Ideally, the feasibility study should not be older than two years, but this may vary by project and country.
4. It is not possible to evaluate the feasibility of a transmission project in isolation. It must be evaluated as part of a transmission expansion plan. The feasibility study should validate that the project can be financed or, more accurately, that the time slice of the transmission expansion plan can be financed.
5. The Power Grid Corporation of India Ltd (PGCIL), a utility owned by the national government, acts as the Central Transmission Utility (CTU). The CTU acts as an intermediary, receiving and distributing the revenues from wheeling charges.
6. World Bank, "Toolkit for PPPs in Roads and Highways: Market Sounding," *Public-Private Infrastructure Advisory Facility* (2009), <https://ppiaf.org/sites/ppiaf.org/files/documents/toolkits/highwaystoolkit/6/pdf-version/5-92.pdf>
7. World Bank, "Toolkit for PPPs in Roads and Highways: Market Sounding."
8. International Bank for Reconstruction and Development, the World Bank, Asian Development Bank, and Inter-American Development Bank, "Public-Private Partnerships. Reference Guide," Version 2.0, *Public-Private Infrastructure Advisory Facility* (2014), <http://api.ning.com/files/Iumatxx-0jz3owSB05xZDkmWIE7GTVY A3cXwt4K4s3UyoNtPPRgPWYO1LrWaTUqybQeTXIeuSYUxbPFWlysuYNI5rL6bzMs/PPPReferenceGuidev02Web.pdf> (accessed March 17, 2017).
9. Section 3.2.3. "Assessing Value for Money."
10. World Bank, "A guide for hiring and managing advisors for private participation in infrastructure," Volume 3, *PPIAF* (2001), <http://documents.worldbank.org/curated/en/347941468766772652/pdf/multiopage.pdf> (accessed March 10, 2017).
11. World Bank (2001).
12. M. Kerf et al. (1998), See Section 3.
13. IPT contracts vary in whether payment is made after early commissioning (before the due date in the contract).
14. Delmon, J., "Understanding Options for Public-Private Partnerships in Infrastructure. Sorting out the forest from the trees: BOT, DBFO, DCMF, concession, lease . . .," Policy Research Working Paper 5173, World Bank, 2010, <http://documents.worldbank.org/curated/en/999661468323693635/pdf/WPS5173.pdf> (accessed May 10, 2017).
15. World Bank (2009).
16. Public-Private-Partnerships in Infrastructure Resource Center, "Procurement Processes and Bidding Documents," Last updated August 2016, <https://ppp.worldbank.org/public-private-partnership/overview/practical-tools/procurement-bidding#guidelines> (accessed March 15, 2017).
17. World Bank (2009); see Module 5, Stage 4.
18. World Bank (2009); see Module 5, Stage 4.

APPENDIX A

Case studies

This appendix provides five case studies that describe the experience of Brazil (A.1), Chile (A.2), India (A.3), Peru (A.4), and the Philippines (A.5) introducing private investment in transmission. The first four countries provide examples of countries that scaled up transmission investments through the Independent Power Transmission (IPT) business model, while the last country introduced private sector participation (PSP) through a whole-of-grid model.

The structure of each case study is:

- Motivations for private investment in transmission,
- The structure of the power sector,
- Overview of PSP in transmission,
- Legislative and regulatory framework,
- Transmission planning,
- Contract form,
- Procurement process, and
- Outcomes.

A.1 Case 1: Brazil

This section describes the motivations for private investment in the power sector in Brazil; the structure of the sector; the overview of PSP in transmission; the legal and regulatory framework that enabled PSP; the contract form and procurement process for tendering transmission lines; and the outcomes of PSP in transmission.

A.1.1 Motivations for private investment in transmission

Until the mid-1990s, Brazil's power sector was vertically integrated under state management. All distributors were owned by the state in which they operated. Generation and transmission companies were state-owned, belonging to either the federal Government or the states of Brazil.¹ The

Government² set both wholesale and retail rates. The Government used rates as a means of curbing inflation, and non-cost-reflective tariffs led to severe underinvestment.

The Government embarked on a major reform program in 1995. The sector was unbundled and privatized. A new regulatory framework was established to bring in private investment to deliver services that Brazil could not otherwise afford.

One key objective for reform was the need for expansion to ensure adequate supply. Other objectives included improving the efficiency of utilities, enhancing economic competitiveness, and improving quality of service. To meet these objectives, initial reforms included establishing “free” (large) consumers who could negotiate contracts directly with generators, conditions to allow for independent power producers, and equal access to distribution and transmission grids.

A.1.2 The structure of the power sector

Hydropower accounts for 75 percent of Brazil's installed capacity and almost 80 percent of the energy produced.³ The hydro plants are spread across 12 main river basins and often have large reservoirs with multi-year storage capacity. Brazil's hydro resource has heavily influenced the development of the power system. The generator mix also includes natural gas, coal, oil-fired, and nuclear power.

Ownership of transmission and generation assets is split between state-owned companies belonging to the federal or state Governments, and private ownership. Eletrobras, the largest federal-owned utility, owns 37 percent of total installed capacity. The 64 distributor-retailers are either owned by the state Governments or the private sector.

The customer base is divided into regulated and unregulated (large) customers. Large customers

consume a fourth of the demand. They have the right to contract directly with generators. Regulated clients have to buy electricity from distribution companies.

Government stakeholders

The main government stakeholders in the power sector are:

- The Ministry of Mines and Energy (MME), responsible for power sector policy. The MME is also in charge of planning, granting hydro and transmission line concessions, and issuing bidding process guidelines for public services concessions,
- The Conselho Nacional de Política Energética (CNPE), a council for energy policy under the MME. The CNPE advises the President on energy matters. It also formulates policies and guidelines for energy, which help the Government develop national energy resources,
- Agência Nacional de Energia Elétrica (ANEEL), the Energy Regulatory Agency, a Government agency responsible for administering and supervising power sector concessions, regulating tariffs, settling administrative disputes among agents of the power industry, and defining the criteria and methodology for the determination of transmission and distribution tariffs,
- The Operator of the National Electricity System (ONS), the system operator, is responsible for

ensuring continuity, quality and cost-efficient supply of power for the national interconnected system (SIN) users,

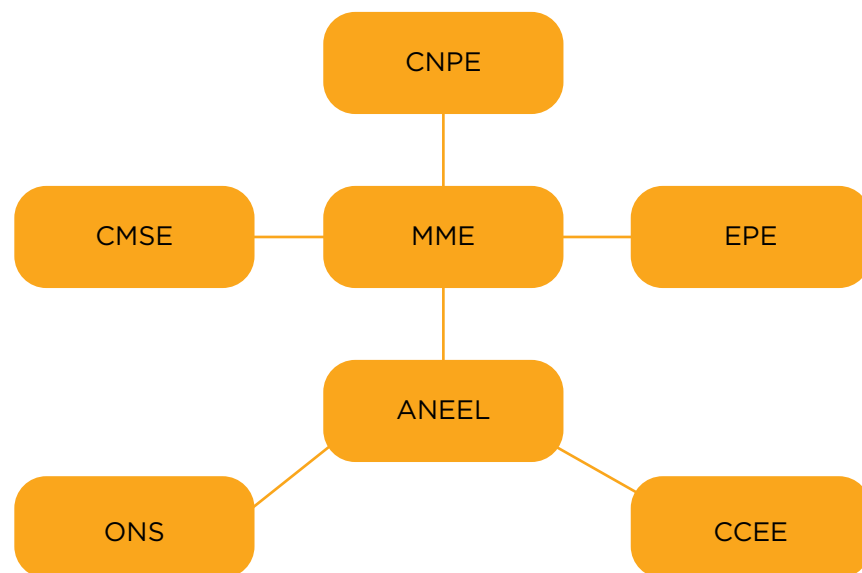
- Empresa de Pesquisa Energética (EPE), the energy research company responsible for conducting strategic research in the electricity and energy sectors. EPE's research supports the MME in its role of devising sector programs, and
- The Câmara de Comercialização de Energia Elétrica (CCEE) is the electricity commercialization chamber, the market operator.

Figure A.1 illustrates the relationship structure of the power sector public institutions. The president's energy advisory group, CNPE, is the highest authority, although MME formulates and implements policy. EPE and ANEEL are constituted under the MME, while ANEEL regulates and supervises ONS and CCEE.

A.1.3 Overview of PSP in transmission

Brazil has approximately 65 transmission companies (including private and state-owned companies).⁴ Federal-owned Eletrobras is the largest and owns approximately 57 percent of transmission assets. The Government of Brazil owns almost 54 percent of Eletrobras. Several companies have a mix of public and state government ownership. For example, the private sector owns 89.5 percent of the transmission

Figure A.1 Brazil's power sector main institutions



Source: Data sourced from ONS webpage, "Relacionamentos," http://www.ons.org.br/institucional_linguas/relacionamentos.aspx (accessed March 15, 2017). CMSE refers to Comitê de Monitoramento do Setor Elétrico.

company of São Paulo (Companhia de Transmissão de Energia Elétrica Paulista, CTEEP); the state of São Paulo owns the rest.

Almost 70 percent of investments in transmission between 2000 and 2010 came from the private sector. Private investors are both local and international. Foreign companies invested 30 percent, local private companies invested 39 percent, and federal and state-owned companies invested 31 percent.

A.1.4 Legislative and regulatory framework

Liberalization reforms undertaken in the mid-1990s were the first step to shape Brazil's current power sector. Concessions for public utilities were introduced by Law 8.987 in 1995. The law sets out the main rules for the concession and permission for tendering public services and specifies that concessions must be awarded through a competitive process.⁵

The Government also introduced legislation in 2004 as a response to major supply shortages in 2001. Law 10.847 (2004) created EPE and established EPE as the main entity in charge of transmission planning. Law 10.848 of 2004 and Decree 5.163 of 2004 defined energy trading between the various sector agents by establishing two markets (regulated and unregulated) for the negotiation of PPAs.

Brazil uses a revenue cap scheme to regulate transmission. Transmission lines are subject to a regulatory cap on AR. This annual cap is mainly set by the outcome of the tenders. As described below, there is also limited scope for regulatory review of aspects of the AR.

A.1.5 Transmission planning

Planning is centralized by the MME, through research and input from EPE and ONS. The three types of planning reports are:⁶

- A long-term plan (10 years) prepared by EPE,
- A short-term plan (5 years) prepared by EPE, and
- A three-year document prepared by ONS listing reinforcement and extension transmission needs.

The long-term plan is indicative. The short-term plan determines the required investment in new transmission lines. This plan is updated each year and forms the basis of the tenders. In addition, the ONS is responsible for identifying reinforcement and extension projects.

The MME has to approve all plans. When the plan is approved, ANEEL carries out the tendering process to procure the transmission projects approved in the short-term plan.

A.1.6 Contract form

Transmission companies enter into BOOT contracts for 30 years. Companies sign contracts with all transmission network users. Transmission service users include generation companies, distribution companies, and large customers located within the region where the transmission line is located.

The contract is awarded to the bidder that proposes the lowest AR. The transmission company will receive the AR in monthly payments, for the entire contract term. The price is defined in the local currency (the real), and subject to indexation.⁷ The price is largely set by the outcome of the tender. However, the regulator can review aspects of the price during five-year price determinations. Revisions are set every fifth July after the concession contract is signed. ANEEL reviews the cost of capital, adjustments for efficiency gains, and other items.⁸

Adjustments in the way ANEEL reviews tariffs have increased perception of regulatory risk since 2012. These adjustments include ANEEL's review of compensation of assets and renewal of concessions, how sub-transmission assets owned by transmission companies are transferred to distribution companies, and minimum schedules and procedures for O&M costs.⁹

Network users provide financial guarantees to transmission companies. Network users establish a revolving fund holding three months of transmission charges. If the account falls below the three-month threshold, users may be disconnected from the network.

The contract specifies that the transmission company:

- Is responsible for obtaining the environmental permit. The contract only comes into force once the permit is obtained,
- Must provide access to third parties who may want to connect to the transmission line,
- Will be paid on availability, and are required to meet 97 percent availability. If the availability of the transmission line falls below the target, the transmission company will be penalized and will receive a lower payment. However, penalties are capped to 12.5 percent of the permitted AR,¹⁰
- Will be penalized for delays to commissioning after the Commercial Operation Date (COD), and
- Must post a bid guarantee equivalent to 1 percent of the estimated investment needed. ANEEL returns the bid guarantee to all except the winning bidder within five business days after publication

of tender adjudication. The winning bidder has to substitute the bid guarantee with a performance guarantee equal to 10 percent of ANEEL's estimated cost for the project. This replaces the bid bond and is repaid in installments subject to meeting set milestones and timelines.

In addition, the contract includes a termination clause that specifies the conditions under which the Government may buy the transmission asset.

A.1.7 Procurement process

ANEEL runs the tendering process. ANEEL starts the process by publishing a tender notice and the technical specifications.

The evaluation of bids is done through reverse bidding and has one stage. The award is subject to a price cap defined by ANEEL. ANEEL sets a benchmark maximum AR. This parameter is calculated based on various factors, including the cost of equipment, the depreciation rate of equipment, O&M costs, and the cost of capital. Bidders must propose a price at or below the benchmark AR.

Bidders must comply with the following requirements:

- **Technical:** The bidder must be registered in the CREA (a regional council that registers and regulates which companies and individuals are qualified in their area of work). The bidder must provide proof of contracts or commitment letters with all relevant subcontractors. The bidder must also provide proof of experience building,

maintaining, and operating transmission systems and substations with a voltage equal to 220 kV or higher, and

- **Financial:** The bidder must have a minimum level of liquidity, equity and capital. The bidder must also fulfill fiscal requirements such as tax compliance with the federal government and state treasury.

In addition, transmission companies that have had delays in past tenders cannot participate in tenders for a certain period.

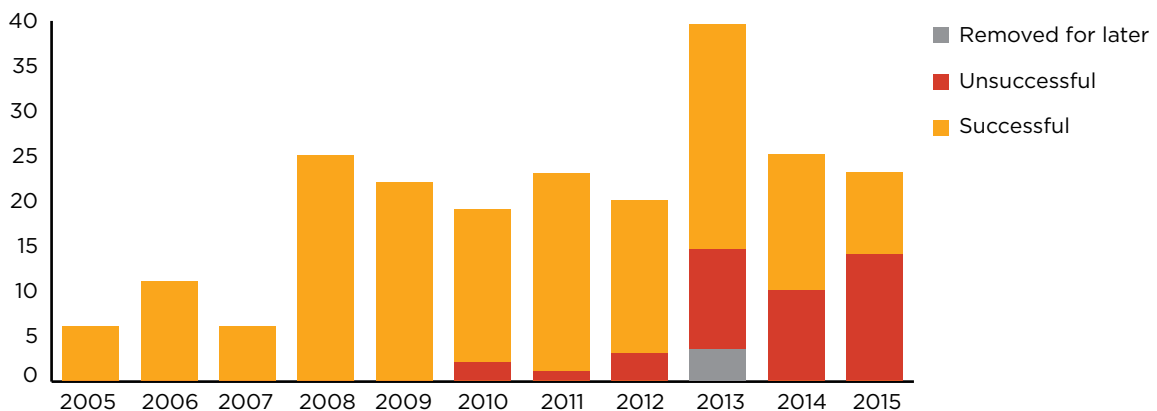
ANEEL publishes details of all auctions, including size, location, winning party, price, and construction costs. It also publishes the contracts. The data are published in Portuguese.

A.1.8 Outcomes

ANEEL has held 38 public auctions of multiple lots since 1999. These have resulted in the award of 211 transmission line concessions. The line concessions total 69,811 km in length. The average length is 295 km. Projects range from 2 km to over 2,500 km.¹¹

Competitive tendering has also reduced costs. The average weighted discount on the winning bid stood at 22.8 percent of ANEEL's estimated AR, for all awarded tenders between 2000 and 2015. Individual line discounts reached 59.2 percent. However, various tenders have been unsuccessful during the last few years, and others postponed for later. Thirty-seven percent of the lots tendered from 2012 to 2015 were unsuccessful (there were no bids). In contrast, all tenders between 2005 and 2009 were successful. Figure A.2 shows the number of lots that were

Figure A.2 Successful and unsuccessful tenders (2005–2015)



Source: Data sourced from ANEEL, "Resultados dos Leilões de Geração." Resumo dos resultados dos leilões de transmissão até, 2015, <http://www.aneel.gov.br/resultados-de-leiloes> (accessed January 10, 2017).

unsuccessful, the lots that were removed to a later tender, and the number of lots that were successfully tendered, from 2005 to 2015.

Tenders have been unsuccessful due to various factors. First, the weighted average cost of capital (WACC) used by ANEEL to define the maximum AR was too low, discouraging investors to bid. Second, implementation risks have increased, mainly related to environmental issues. Several projects have faced delays in the start of operations due to delays in obtaining the environmental permit. ANEEL released details in mid-2016 that 62 percent of the late projects at the time had faced delays when obtaining the environmental permit.¹² Third, from Banco Nacional de Desenvolvimento Econômico e Social (BNDES), the national development bank, has provided fewer low-cost funding as Brazil's economy has slowed in recent years. Brazil's GDP annual growth decreased 3.8 percent in 2015 and forecast growth for 2016 was -3.3 percent.

A.2 Case 2: Chile

This section describes the motivations for private investment in the power sector in Chile; the structure of the sector; the overview of PSP in transmission; the legal and regulatory framework that enabled PSP; the contract form and procurement process for tendering transmission lines; and the outcomes of PSP in transmission.

A.2.1 Motivations for private investment in transmission

During the 1970s the power sector in Chile was vertically integrated and mostly state-owned. Investment in the sector was low and inflation high. In 1982 Chile's economy decreased at an annual rate of 10 percent. Given the economic situation, the Government introduced a reform in the power sector in early 1982 to unbundle the sector and attract investment with a market-oriented approach. Today, Chile is seen as a leading example of power sector reform.

A.2.2 The structure of the power sector

The main characteristics of the Chilean power sector are a result of the Law of General Power Services introduced in 1982 (Ley General de Servicios Eléctricos or LGSE) to privatize and vertically and horizontally unbundle the power sector.

Chile has about 25 generation companies, and the total installed capacity is 20,662 MW. The Central Interconnected System (Sistema Interconectado

Central or SIC) is the largest electric system, corresponding to 79 percent of Chile's installed capacity, located in the central and southern regions of Chile.¹³ The northern system, the North Interconnected System (Sistema Interconectado del Norte Grande or SING), has 20 percent of the installed capacity. The generation mix is primarily hydro and thermal in the SIC, and thermal in the SING.

Customers are divided between regulated and non-regulated customers. Regulated customers are retail consumers with a connected capacity less than or equal to 2,000 kW. Non-regulated ("free") customers are large customers with a connected capacity greater than 2,000 kW. Free customers are mainly mining companies and other industries.

Government stakeholders

The main actors in the power sector are:

- The Ministry of Energy (MINENERGIA), responsible for policy design and planning, as well as providing concessions for hydroelectric plants, transmission lines, substations, and electricity distribution areas,
- The Comisión Nacional de Energía (CNE), the Government's National Energy Commission in charge of setting tariffs and defining the technical norms of the system. The CNE depends on the MINENERGIA,
- The Centro de Despacho Económico de Carga (CDEC), the system operator. The CDEC is divided in two, with separate operators in the SIC and the SING. Each CDEC is composed by representatives of generation and transmission companies, free customers, and owners of facilities connected to the system, and
- The regulator (SEC), responsible for overseeing the legal and regulatory norms, and technical standards for liquid fuels, gas, and electricity.

A.2.3 Overview of PSP in transmission

Chile has about seven main transmission companies in Chile. Transelec is one of the main companies in the transmission sector, operating most of the transmission lines in the SIC. The company has 6,682 km of transmission assets, divided as follows: 548 km of 110 kV lines, 1,163 km of 154 kV lines, 3,961 km of 220 kV lines, and 1,010 km of 500 kV lines.

Other companies include Compañía Transmisora del Norte Chico, Transchile, Transnet, Sistema de Transmisión del Sur, Transquillota, Transemel, and ISA Colombia.

A.2.4 Legislative and regulatory framework

The regulatory framework for electricity in Chile is based on the LGSE and the following laws:

- The *Ley Corta* from 2004 and *Ley Corta II* from 2005, introduced to ensure an efficient development of the power sector. The *Ley Corta I* was particularly important to regulate the remuneration of the lines included in the SIC and SING, according to an efficient model. It also created a “Panel of Experts” to resolve controversies between parties, and
- In July 2016, the Government approved the Law of Transmission and Interconnection (LTI), introducing various changes.

The new legal framework states that:

- The Government must create a new independent entity in charge of coordinating the national electric system (Coordinador Independiente del Sistema Eléctrico Nacional, or CISEN). CISEN started functioning on January 2017 and:
 - Is a non-profit entity,
 - Carries out the functions previously managed by the CDEC, and
 - Is financed by the national annual budget, subject to approval by the CNE.
- The transmission charge will be paid directly by end users, both regulated and unregulated customers, twice a year.
- The MINENERGIA will prepare a Strategic Environmental Evaluation (EAE) to define a preliminary strip of land where the transmission projects could be located. The EAE will consider land, environmental, social, technical, and economic aspects. In the previous regulatory framework, the winning bidder had to define the final route of the transmission line and arrange the corresponding ROW.

A.2.5 Transmission planning

Until mid-2016 the CDEC developed a long-term transmission plan every four years, to define the main transmission lines needed to guarantee a well-functioning system. The LTI states that, starting in 2017, the MINENERGIA will develop a long-term plan for the electricity sector every five years. The long-term transmission plan will be based on different scenarios of expansion of generation and consumption, for a 30-year horizon or longer.

In addition, every year the CNE develops a short-term transmission plan with a timeframe of at least 20 years based on the long-term plan. The annual

revision evaluates whether to include new lines, or to delay or eliminate some of the projects in the long-term plan. The lines included in the short-term plan are tendered out.

A.2.6 Contract form

When the Government awards the tender to a transmission company, the company obtains the rights to build and operate the transmission line, by a Ministerial decree. The decree also gives the company rights to transmission revenues. Transmission companies do not sign a concession contract with any counterparty.

Tenders are awarded according to the lowest annual transmission value per segment (Valor Anual de Transmisión por Tramo, or VATT). The VATT is equal to the sum of annual value of investment (Anualidad del Valor de la Inversión or AVI) and the maintenance, operation, and administration cost (Costos de Operación, Mantenimiento y Administración, or COMA), calculated using a 10 percent real annual rate for 20 years. The VATT and indexation formula agreed with the winning bidder are fixed during five “tariff periods” (20 years).¹⁴ After that, the transmission assets are reviewed and updated during each tariff period.

Transmission companies are paid against timely commissioning and availability of the line. Transmission companies do not incur demand risks or other risks related to the operation of the whole grid.

Until the end of 2016, generation companies paid transmission tolls in proportion to their use of the transmission lines. However, since 2017, the transmission charge is paid directly by end users, both regulated and unregulated, twice a year.

The Government does not own power sector assets, and transmission companies never transfer the assets to the Government.

A.2.7 Procurement process

The procurement process can be summarized as follows:

- The procurement uses an international and public competitive tender process,
- CISEN will run the competitive tender process. The CDEC ran the process before the law changed in 2016,
- The bidding documents include reference values of the investment and O&M costs (the latter defined as a percentage of the investment costs), and construction time (in months), and

- The bidding process has one stage. First, CISEN will evaluate if the bidder complies with the minimum requirements (financial, technical, and legal). Then, CISEN will select the compliant bidder that offers the lowest VATT.

Bidders can be Chilean citizens and foreigners. They can be individual citizens, companies, or consortiums, and must comply with the following requirements:

- Have experience in the power sector,
- Be registered with CISEN (previously with CDEC),
- Have a risk rating of at least BB internationally and at least BBB locally,¹⁵ and
- Have a minimum amount of net assets.

Bids must be prepared in Spanish. Prices must be in US\$ and valid for 120 days. Every bid must include three proposals:

- An administrative offer. This offer must include the legal, commercial, and financial documents of the bidder. This offer must also include:
 - A bank guarantee equal to 2.5 percent of the reference value of the investment (the percentage may vary according to the tender). The guarantee must be issued by a bank incorporated in Chile and addressed to the MINENERGIA, and
 - Records proving the bidder's experience and technical skills working in transmission-related projects. The bidder must have had a share of at least 30 percent in the reference projects,
- A technical offer. This offer must include the project schedule in detail, a warranty that the bidder will comply with the schedule, and a technical description of the project, and
- An economic offer. This offer must include the VATT, detailing the AVI and COMA.

The evaluation process has the following steps:

- Opening of the administrative offer (step 1),
- Opening of the technical offer (step 2),
- Evaluation of the administrative offer (step 3),
- Evaluation of the technical offer (step 4), and
- Opening and evaluation of the economic offer (step 5).

Steps 3 and 4 are performed on a pass-or-fail basis.

The contract is awarded to the bidder that proposes the lowest VATT. If two or more economic offers tie, the winning bidder will be the one that presents the

best technical offer. If a tie occurs again, CISEN will apply a mechanism to select one bid randomly.

A.2.8 Outcomes

Chile has organized at least seven tenders since 2007.¹⁶ Ten projects were awarded for more than 1,200 km, under build, own, and operate (BOO) contracts. This includes a recently awarded 140 km, 500 kV line to interconnect the country's two main transmission systems.¹⁷

A.3 Case 3: India

This section describes the motivations for private investment in the power sector in India; the structure of the sector; the overview of PSP in transmission; the legal and regulatory framework that enabled PSP; the contract form and procurement process for tendering transmission lines; and the outcomes of PSP in transmission.

A.3.1 Motivations for private investment in transmission

The economic crisis of 1991 led to wide-ranging economic reform, including of the power sector. The crisis was mainly driven by unsustainable fiscal imbalances. Chronic losses in the power sector were a large contributor. The Government set electricity prices, which were often below costs. The resulting financial inadequacy heavily constrained public investment in the sector. Power sector reform was intended to draw in private sector investment and management capability.

A.3.2 The structure of the power sector

India has a federal structure. Electricity is a concurrent issue, managed by both the Central and State Governments. The Central Government has limited influence on energy policy at the state level. State Governments are responsible for implementing national laws, but can also issue state laws and regulations.

The Central Government is responsible for HV inter-state transmission and large-scale power projects providing power to several states. The generation projects are all privately owned. Transmission has been developed by a government-owned company and by private developers.

The State Governments are responsible for generation, transmission, and distribution within the state. The majority of this capacity remains state owned, but some private investment has occurred across the supply chain.

Government stakeholders

The main actors in the power sector are:

- The Ministry of Power (MoP) is responsible for designing and implementing power sector policies and for developing a National Electricity Policy. State Ministries set policy at the state level,
- The Central Electricity Authority (CEA) prepares National Electricity Plans (NEP) consistent with the National Electricity Policy,¹⁸
- Regulatory Commissions operate at the central and state levels. The Central Electricity Regulatory Commission (CERC) regulates generation owned or controlled by the Central Government, and regulates and licenses inter-state transmission and trading. The State Electricity Regulatory Commission (SERC) regulates generation, transmission, distribution, and supply at the state level. Each SERC also issues licenses for transmission, trading, and distribution within the state,
- The Central Transmission Utility (CTU) is responsible for developing the inter-state transmission network and for ensuring open access to the network. PGCIL is currently the CTU. Each State has a State Transmission Utility (STU) with a similar role for the intra-state transmission network. The CTU and STUs also prepare shorter-term plans consistent with the NEP, and
- System Operation is managed at the central, regional, and state levels. POSOCO manages the central and regional dispatch centers. These centers coordinate with State Load Dispatch Centers. POSOCO is currently a wholly owned subsidiary of PGCIL.

A.3.3 Overview of PSP in transmission

The transmission network covers five regional grids, recently integrated into one synchronous grid. That grid has 347,741 circuit kilometers (ct km) of transmission lines of 220 kV or above. Inter-state transmission provides HV connection between two or more states at 400 kV or 765 kV. Transmission within the states is mostly at 400 kV or below, although there have been recent state transmission investments at 765 kV.

Transmission is mainly owned by government-owned companies. PGCIL dominates the transmission sector. It owns 131,728ct km of transmission lines and nearly 265,663 MVA transformer capacity as at the end of July 2016.¹⁹ PGCIL is 57.9 percent owned by the Government of India and 42.1 percent listed on the Bombay and National Stock Exchanges. The STUs

dominate at the state level and are owned by the State Governments.

Historically the Government-owned companies undertook transmission projects on an un-competed basis. The 2003 Act laid the basis for private investment in transmission. Investment began in 2006 when the National Tariff Policy (NTP) established that tariffs would be set by multiyear, tariff-based competitive bidding (TBCB).²⁰

The NTP required that all transmission be on the basis of competitive bidding “after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition.”²¹ Since 2006 inter-state transmission has mainly been tendered, although exceptions remain for projects of “strategic importance or time-bound delivery.” These are given to PGCIL on a nomination basis.²² STUs have undertaken most projects at the state level. Some projects have been tendered and privately financed, and that share is likely to grow.

The private sector can only participate in transmission through competitive bidding (TBCB). The procurement process and contract form are described below. In addition to bidding in their own right, private bidders can form JVs with PGCIL for tendered projects. Until recently, the private sector could also be part of a JV for projects provided to PGCIL on a nomination basis. This is no longer the case.

PGCIL is involved in 13 JVs, with private companies (some with IPPs to evacuate power from generation centers) and state-owned utilities for intra-state projects.²³ The longest transmission JV with a private partner is PowerLinks. This is a 1,200 km HVDC line from Siliguri to a substation close to Delhi, enabling the export of power from the Tata-owned Tala hydro plant in Bhutan. PGCIL owns a 51 percent interest in PowerLinks and Tata owns 49 percent.

Eight JVs are with private businesses. They make up a small share of PGCIL's network, yet account for 13 percent of privately developed transmissions since 2002.²⁴

Low tariffs and high losses in some states can create problems in funding private transmission. If revenues are insufficient, the state can obtain support from the Central Government through VGF. The transmission tariff is determined up front rather than being determined by bids. The bids determine the level of additional funding required. Bidders sign a Model Transmission Agreement developed by the Planning Commission. Three projects to date

have used the VGF mechanism, in Haryana, Madhya Pradesh, and Rajasthan.

About ten private companies are involved in private provision of transmission in India.²⁵ Some are transmission specialists. Others are integrated power companies or part of broader industrial conglomerates. The largest private investors are Sterlite Power, Reliance Infrastructure, Essel Infrastructure and Adani Transmission.

Sterlite and Reliance are exploring the possibility of wrapping their assets into investment trusts to reduce the cost of borrowing.²⁶ The government is also considering relaxing rules to allow investment funds to participate directly in transmission projects.²⁷

A.3.4 Legislative and regulatory framework

Power sector reform started in 1991, with the private power policy, and legislative amendments to liberalize generation and introduce IPPs. The main obstacle was the financial weakness of the State Electricity Boards (SEBs) as counterparties. Orissa led the reforms at the state level. These reforms included unbundling, the establishment of independent regulators and, in some cases, privatization. The central government also sought large-scale private generation and established the Power Trading Corporation as an intermediary between investors and the SEBs.

In 1998 the Government passed the Electricity Regulatory Commissions Act, which led to the establishment of SERCs and greater regulatory consistency between states. In 1999 Orissa privatized distribution, followed in 2002 by Delhi.

Despite the reforms in the 1990s, the economic performance of the sector worsened and arrears grew. The Electricity Act 2003 introduced comprehensive reforms in the sector and consolidated various national and state initiatives. That Act unbundled the SEBs, and introduced competition across the value chain and open access in transmission and distribution.

Following these reforms, private investment in transmission was slow to materialize due to tariff uncertainty. This was addressed by the NTP in January 2006.²⁸ The policy mandated that a TBCB process determine tariffs for transmission projects. The winning bid set the annual charge, which created price certainty. The use of TBCB became mandatory for all privately financed projects in 2006. Government-owned companies—PGCIL and the STUs—were given a five-year transition period to 2011.

The approach to regulating inter-state transmission charges is closely related to the contracting arrangements:

- Currently, the transmission developer signs a Transmission Service Agreement (TSA) with Long Term Transmission Customers (LTTCs). These are generators, distribution businesses, and major loads in the states concerned. Transmission charging is on a “postage stamp” basis, effectively charging these users for their contracted capacity, and
- Under new arrangements, transmission charges will be based on use of the network, drawing on load flow analysis. Developers will sign the transmission agreement with Designated Inter-State Customers (DICs). As India now operates as one synchronous grid, this will be a much larger set of customers (including more than 80 distribution businesses). Given the large numbers involved, the CTU will become responsible for collecting and settling transmission charges from all transmission users, on behalf of all the transmission service providers.

A.3.5 Transmission planning

The transmission network is divided into five synchronously interconnected regions—Northern, North Eastern, Eastern, Western, and Southern—each operated by Regional Load Despatch Centres.

Transmission planning is done centrally under the direction of the CEA. The CEA issues a NEP every five years, with annual updates. The current 12th NEP runs from 2012 to 2017.

The NEP has a 5–15 year perspective. The CTU and STUs are responsible for shorter-term transmission planning and development based on the NEP.

Developers are able to propose lines that are not in the NEPs. These proposals can be included in annual amendments to the current Plan if the CEA approves the result of relevant studies. Studies are funded by the developer and conducted either by the developer or by the CTU.

A.3.6 Contract form

Currently, the winning transmission developer signs a TSA with all concerned utilities (LTTCs). These may include the utilities falling in the region where the load is located, any intervening region, and the inter-regional transmission lines between the regions. In

the future, the transmission developer will sign the TSA with DICs.

The contract is awarded to the bidder that proposes the lowest transmission tariff. Lines are built on a build, own, operate, maintain (BOOM) basis for a 35-year period. The term was shorter (25 years) before 2008.

The minimum line availability is defined in the contract in accordance with CERC regulations. The minimum line availability for AC systems is 98 percent and 95 percent for HVDC. Availability above this level is rewarded with a percentage premium on the agreed tariff for the period of excess availability. Penalties are incurred if availability falls below the target. If line availability is below this target for six consecutive months, the Transmission Service Provider (TSP) risks having its license revoked. TSPs are not penalized for outages due to factors beyond their control, such as problems with lines or substations owned by other providers.

Obtaining the ROW for the transmission line is critical. The Bureau of Indian Affairs (BIA) grants the ROW. BIA revised the ROW rules in 2015 to accelerate the approval process. Even so, projects still face delays related to approval of the ROW.

As one of the first steps to obtaining the ROW, the winning bidder has to survey the potential location. Until 2015, BIA had to approve the survey. However, surveys no longer demand BIA's approval, which helps to speed up the process. In addition, BIA has to act on an ROW application within 60 days of receiving a complete application, with a one-month extension. Even so, completing an application requires gathering various documents (including reviewed environmental studies) that can take time to approve.

A.3.7 Procurement process

The Ministry of Power has constituted an Empowered Committee (EC) chaired by a representative of the CERC, with other members drawn from the CEA, MoP, Planning Commission, CTU, plus two sector experts nominated by the Ministry. The purpose of the Empowered Committee is to:

- Identify projects to be developed,
- Facilitate evaluation of bids, and
- Facilitate development of projects.

Once projects have been identified by the EC, they are put out to competitive bidding. The process is

managed by state or central Government-appointed Bid Process Coordinators (BPCs). While the process is the same, inter-state and intra-state projects are managed by different bodies:

- **Inter-state lines:** Tenders are managed by one of two BPCs preselected by the EC (PFCCCL and RECT-PCL). Both are state-owned enterprises, and
- **Intra-state lines:** The relevant state government may appoint an organization or the central Government may appoint one of its BPCs to be the BPC for the state.

PGCIL can bid in auctions on an equal basis as private developers. All bidders must demonstrate experience in the sector and financial strength. The bidder quoting the lowest levelized tariff is considered for award. The proposed levelized tariff must be below a reserve price set by CERC. If PGCIL (the CTU) is bidding for a project, the CTU members on the committee are excluded from discussions related to bidder selection.

The TSP must seek a license within a month from selection. Once the license is granted, the TSP must commission the project within the stated timeframe. The BPC is responsible for helping the successful bidder secure any necessary ROWs.

According to the MoP guidelines, the time between the publication of a Request for Qualification (RFQ) and contract signing should ordinarily be no more than 240 days. This is condensed to 180 days if the RFQ and Request for Proposal (RFP) are combined.

In August 2016, the Government created a new online bidding portal for generation and transmission projects and medium-term power purchasing. This also provides a central source of information to track transmission projects.²⁹

A.3.8 Outcomes

Private investment in transmission lines has grown rapidly since the late 2000s. Figure 6.2 illustrates the length of new transmission lines by source of finance and the percentage of privately financed new lines. The share of private investment—including JVs with PGCIL—has grown in each plan period:³⁰

- In the 10th five-year NEP (2002–2007), the private sector developed 2,284ct km³¹ of new transmission lines, 5 percent of total investment during the period,³²

- During the 11th plan period (2007–2012), privately developed lines were 6,131ct km, 10 percent of total new developments, and
- Four years into the 12th plan (2012–2017), new lines developed by the private sector have more than doubled to 12,719ct km or 14 percent of total new construction.

Privately financed and owned lines at 220 kV and above now total 21,134ct km, equivalent to 6.1 percent of the national network. The private sector invested a total of US\$5.5 billion in transmission lines up to 2015, and there is a pipeline of US\$5 billion worth of projects for the following years.³³

A.4 Case 4: Peru

This section describes the motivations for private investment in the power sector in Peru; the structure of the sector; the overview of PSP in transmission; the legal and regulatory framework that enabled PSP; the contract form and procurement process for tendering transmission lines; and the outcomes of PSP in transmission.

A.4.1 Motivations for private investment in transmission

Before 1993, the Peruvian state had a monopoly over the power sector. Two vertically-integrated state-owned companies, Electrolima and Electroperu, served the capital, Lima, and the rest of the country. The power sector was characterized by power shortages and low quality of service, and imposed a financial burden on the state.

In the 1990s, the Government of Peru undertook a series of economic reforms to reduce the size of the state and privatize state-owned enterprises. The transmission sector was privatized as part of a broader wave of reform to attract private capital to the power sector and to improve the efficiency of the sector.³⁴

A.4.2 The structure of the power sector

Since 1993 Peru has undergone a process of unbundling and privatization in the power sector. This started with generation and distribution, and was later extended to the transmission sector. Transmission was fully privatized by the early 2000s.

Today, the power sector is mostly private. The revenues of the sector were US\$6.37 billion in 2015

and almost three-quarters (72 percent) accrued to the private sector. PSP in the power sector can be summarized as follows:³⁵

- The generation sector has almost 60 privately owned companies. Those companies account for 83 percent of the installed capacity and 77 percent of the annual generation. The country's installed capacity is 11,711 MW. The majority of the capacity (87 percent) is part of the National Interconnected System, SEIN (Sistema Eléctrico Interconectado Nacional). The rest is located in isolated systems around the country,³⁶
- The transmission sector is entirely private, operated by 13 companies. The public sector owns a few MV–to LV transmission lines, in isolated areas of the country. Red de Energía del Peru (REP) and Consorcio Transmántario (CTM) have 40 percent and 20 percent of the market share, respectively, and
- The distribution sector has 11 private companies, representing 66 percent of the revenues. These companies provide electricity to 40 percent of the customers. The customer base is divided into regulated and unregulated (also known as “free”) customers. Unregulated customers are those with an installed capacity of at least 1 MW, or a demand of at least 20 percent of the maximum demand by the distribution concessionaire in the customer's region.

Government stakeholders

The main Government stakeholders in the power sector are:

- MEM, in charge of designing the policies of the energy sector and granting concessions,
- OSINERGMIN, the regulator, a Government entity responsible for the control and supervision of electricity- and hydrocarbon-related companies, regulating tariffs, ensuring service quality, and protecting the consumers,
- COES, the system operator, is made up of representatives of agents in the SEIN (generation, transmission, and distribution companies, and unregulated customers). COES is in charge of planning and operating the system using merit order (least cost) criteria and administering the spot market, and
- PROINVERSIÓN, a Government entity responsible for promoting investment and privatization, and in charge of tendering concessions.

A.4.3 Overview of PSP in transmission

PSP in transmission has come about in two main stages. The first stage started with the introduction of the “Law of Power Concessions” (*Ley de Concesiones Eléctricas*, or LCE) in 1992. The sector was unbundled and two public transmission companies were created, Etecen and Etesur. These companies owned and operated the north-central system and the southern system.

Etecen and Etesur entered Public Private Partnerships (PPPs) to expand the transmission system by tendering single lines. This was done through international tenders for 30-year BOOT contracts. The transmission companies retained 15 percent of ownership of the tendered lines. Once the south and north system interconnected (creating one main transmission network for the country), the residual public assets were privatized in 2002, under 30-year concessions.³⁷

The second stage started once the “Law to Ensure the Efficient Development of Electricity Generation” (*Ley para Asegurar el Desarrollo Eficiente de la Generación Eléctrica* or LGE) was introduced in 2006, to complete the regulatory framework. At this stage, the transmission system was expanded by tendering lines in competitive and international tenders, according to a transmission plan prepared by the Government.

A.4.4 Legislative and regulatory framework

The LCE and LGE were key to establishing the current legislative and regulatory framework for transmission in Peru. The LGE was introduced to complete the framework shaped by the LCE.

The LCE unbundled the power sector and created the COES and OSINERGMIN. The LCE aimed to promote competition in the market and established the basic principles that still exist today. The LCE also established that the OSERGMIN established transmission revenues according to: (i) the Net Replacement Value of existing lines; and (ii) O&M costs calculated based on an “economically adapted” model (based on simulating a hypothetical efficient transmission system), with a 15-year timeframe.

However, this exposure to regulatory risk led to a reduction in private investment by the mid-2000s. Private investment fell from more than US\$160 million in 1999 to about US\$10 million in 2003, as shown in Figure 6.1. By then it was clear that the legal framework was not enough to promote private sector investment.

In 2006 the LGE was introduced, modifying the legal framework of the transmission sector. Three of the main changes were as follows:

- COES became the entity responsible for undertaking the planning of transmission nationwide. COES prepares a transmission plan that OSINERGMIN then reviews and MEM approves,
- The LGE established the “Guaranteed Transmission System” (*Sistema Garantizado de Transmisión*, or SGT). The SGT includes transmission projects identified in the transmission plan, and the law requires those projects to be tendered in competitive and public processes, and
- The contract price of transmission lines included in the SGT is defined during the tender process (by the winning bid), and is not subject to periodic review.

These changes helped encourage investment again. Total investment in greenfield transmission projects from 2006 to 2015 was US\$1.5 billion. This is 85 percent of the greenfield transmission projects in the 1998–2015 period.³⁸

A.4.5 Transmission planning

The transmission plan is prepared by COES, according to criteria and a methodology developed by OSINERGMIN, and approved by MEM.³⁹

Each plan has two products: (1) a short-term plan; and (2) a long-term plan. The short-term plan includes the transmission lines to be tendered out within the first two years. Projects in the long-term plan are indicative and reviewed every two years when the transmission plan is updated.

COES prepares the transmission plan with a 10-year horizon and taking into account:

- Generation plant in operation, generation being tendered or under construction, and planned new generation,
- Demand projection according to three different scenarios, and
- Technical and economic criteria. The economic criteria include, for example, that the plan must satisfy conditions related to economic dispatch and the level of unserved energy.

Once the regulator accepts the plan, COES sends it to MEM for final approval. MEM transfers it to PROINVERSIÓN, which tenders the transmission lines.

A.4.6 Contract form

Private investors enter into BOOT contracts for 30 years. Investors sign the contract with MEM and obtain rights to operate as a transmission company and obtain transmission revenues.

Distribution companies charge end users a tariff that includes three components: generation, transmission, and distribution. Distribution companies and large customers have contracts with generation companies where they pay a fee that includes charges for generation and transmission. Generators, through money collected from distribution companies, then pay transmission companies.

The contract is awarded to the bidder that proposes the lowest Total Service Cost. This cost is equal to the sum of annual O&M cost and the annuity of investment costs, calculated using a 12 percent real annual rate for a 30-year period. The price is subject to indexation.⁴⁰

The contract specifies that the concessionaire:

- Must define the path and alignment of the transmission line. During the contract term the concessionaire owns the transmission line and other project-related assets. The concessionaire must transfer them at the end of the concession,
- Is responsible for obtaining environmental permits, licenses, etc.,
- Must provide access to third parties who may want to connect to the transmission line (as long as their access does not affect the performance of the line),
- Will be paid on availability, and are required to meet 97 percent availability,
- Will be penalized for delays to commissioning after the Commercial Operation Date (COD),
- Must comply with technical requirements throughout the lifetime of the contract. For example, lines are subject to a maximum proportion of losses. This figure varies between 2 percent and 5 percent,
- Will become a member of COES,
- Must pay several compulsory insurance policies during the contract period (such as civil responsibility, and covering the value of the concession assets), and
- Must provide a letter of guarantee to assure the concessionaire's obligations.

Contracts also include provisions to resolve controversies between parties and provide protection for investors. First, the contract specifies that disputes between the parties will first be resolved directly

between the parties up to 60 days from the date one party communicates the dispute to the other. If the dispute is not resolved, the parties will go to international arbitration. Second, the contract includes a clause called "Economic-Financial Equilibrium" that provides an additional protection for the investor. If an unexpected event modifies the market conditions (not a force majeure event) and the tariff becomes significantly affected, this clause allows for a renegotiation of the contract terms. Third, concession contracts in Peru have the force of law, providing additional guarantees for private investors.

A.4.7 Procurement process

PROINVERSIÓN runs the tenders to procure transmission lines. The process has only one stage: PROINVERSIÓN does not issue a RFQ before the RFP. During the first phase of the evaluation, PROINVERSIÓN assesses whether bidders comply with the minimum technical and financial requirements, on a pass/fail basis. PROINVERSIÓN then ranks the proposals of bidders that passed the technical and financial criteria and awards the contract to the bidder that proposes the lowest transmission charge. The award is subject to a price cap defined by PROINVERSIÓN.

Bidders (single firm or consortium) must assign up to two people who reside in Lima, must quote the bid in US\$, and must comply with the following requirements:⁴¹

- **Financial:** The bidder must have a minimum level of equity and assets (the levels required vary according to the specifications of the line), and
- **Technical:** The bidder must show experience operating electricity transmission systems that satisfy minimum conditions regarding length, voltage, and ability to transform a minimum level of MVAs in substations.

A.4.8 Outcomes

The Government of Peru has organized 18 transmission tenders since 1998. These tenders have resulted in US\$1.8 billion of investment and more than 6,000 km of transmission lines (and associated substations) designed, built, and operated by the private sector under BOOT contracts.⁴²

A.5 Case 5: Philippines

This section describes the motivations for private investment in the power sector in the Philippines; the structure of the sector; the overview of PSP in transmission; the legal and regulatory framework

that enabled PSP; the contract form and procurement process for tendering the national grid; and the outcomes of PSP in transmission.

A.5.1 Motivations for private investment in transmission

The state-owned National Power Corporation (NPC) was indebted and had to be recapitalized various times during the 1960s and 1970s. The Government embarked on a reform to attract private sector funds. The reform started with the introduction of IPPs in the late 1980s.

Generators had to contract with NPC. Demand continued to exceed supply. A power crisis in the early 1990s prompted radical reform. In 1990 the Government enabled generators and end users to negotiate supply contracts. In 2001 it introduced the Electric Power Industry Reform Act (EPIRA). EPIRA was intended to bring in private investment and improve electrification rates.

The Government used a grid-wide concession as the means of attracting private participation in transmission. In 2007, the National Grid Corporation of the Philippines (NGCP) won the concession. NGCP started operations in 2009.

A.5.2 The structure of the power sector

Under EPIRA, the Government unbundled the electricity sector into generation, transmission, distribution, and supply. Generation and supply to large customers operate under a competitive environment. The transmission and distribution sectors are regulated.

Ownership or interests in more than one sub-sector is precluded under EPIRA. A number of distribution companies have structured their holdings to enable them to move into generation. The regulator is trying to push back, but is facing resistance from business groups.⁴³

Stakeholders

The main stakeholders in the power sector are:

- The Department of Energy (DoE), responsible for managing all activities related to energy exploration, development, use, distribution, and conservation,
- The Energy Regulatory Commission (ERC), the regulator, responsible for setting regulations, guidelines, policies, and rates; enforcing regulations (including issuing permits and licenses); and resolving cases and disputes. The ERC is also

in charge of monitoring competition within the power sector,

- TransCo, a Government agency created in 2003 under EPIRA. TransCo owns all transmission assets, including those financed by the concessionaire,
- The Power Sector Assets and Liabilities Management Corporation (PSALM), a Government agency overseeing the privatization of state-owned power assets. PSALM also manages the liabilities of NPC,
- NGCP, a private consortium holding the transmission concession. NGCP is owned 60 percent by Monte Oro Grid Resources Corporation and Calaca High Power Corporation (both incorporated in the Philippines) and 40 percent by the State Grid Corporation of China, and
- The Philippines Electricity Market Corporation (PEMC), in charge of managing the Wholesale Electricity Spot Market (WESM). WESM began operations in 2006.

A.5.3 Overview of PSP in transmission

Under the concession, NGCP is responsible for O&M, planning, financing of network expansion, and system operations. NGCP develops new assets and transfers ownership to TransCo upon commissioning. The concessionaire also acts as system operator.

NGCP paid an up-front fee for the rights to revenues from the existing transmission assets. Its costs of financing new investments are recovered through changes to the maximum allowed revenues under periodic regulatory determinations.

The Philippines has three regional interconnected grids: Luzon, Visayas, and Mindanao. Table A.1 shows the evolution of the transmission lines in each region from 2011 to 2015. Luzon is the largest region and accounts for over 80 percent of the national electricity demand. Manila, the national capital, is located in Luzon and accounts for 53 percent of Luzon's demand.

National power demand has grown at an annual rate of 3.4 percent. Even so, the national transmission network shrank between 2012 and 2014, despite investment over the period. This shrinkage was due to divestment of sub-transmission lines to distribution companies.⁴⁴

A.5.4 Legislative and regulatory framework

EPIRA is the main legislation governing the power sector. EPIRA introduced unbundling and privatization; established a new regulator, retail competition, and rules of open access and power trading; and mandated the privatization of TransCo.

Table A.1 Transmission lines by region, 2011–2015 (ct km)

Region	2011	2012*	2013*	2014*	2015
Luzon	9,529	9,374	9,439	9,370	9,428
Visayas	4,918	4,971	4,840	4,821	4,821
Mindanao	5,257	5,257	5,146	5,272	5,832
Total	19,704	19,490	19,425	19,463	20,073

Source: NGCP, "Transmission Development Plan 2014–2015," Volume I. Major network development, December 2015, http://www.ngcp.ph/beta/cms/Attachment-Uploads/TDP_2014-2015_Vol_I%20-Draft.pdf (accessed March 15, 2017). *The number of lines do not sum to the total, as total transmission line length in circuit-km decrease. This was because various sub-transmission assets were modified or divested.

In 2003, the ERC issued the Transmission Wheeling Rate Guidelines (TWRG) for the 2003–2027 period. In 2009, ERC updated and renamed the TWRG to Rules for Setting Transmission Wheeling Rates (RTWR). The RTWR outline the methodology for setting the maximum transmission wheeling rates that TransCo or its concessionaire can charge customers. Under these rules, NGCP proposes the Maximum Annual Revenue (MAR) and the performance bonus (or penalty) for each year, to be approved by ERC. The RTWR also states that ERC has to approve the proposed capital investment program for each regulatory period (5 years).

ERC produces a Grid Code that establishes the basic rules, procedures, and standards that govern the operation, maintenance, and development of the transmission system, as well as the obligations of the grid owner, grid operator, and system manager.

The Open Access Transmission Service Rules cover the rules and regulations related to open access. The rules define the responsibilities of the transmission provider, the functions of the system operator, and the conditions accepted by transmission customers for receiving the transmission services.

A.5.5 Transmission planning

NGCP is responsible for network planning. NGCP prepares a Transmission Development Plan (TDP) on an annual basis with a 10-year time horizon. The ERC has to approve the TDP. Once approved, it is incorporated into the DoE's annual Philippine Energy Plan (which covers the whole energy sector) and submitted to Congress every September.

The TDP must include power demand projections, network performance parameters, current and projected generation capacity, and identified transmission constraints. The TDP provides a list

of transmission projects that must be a least-cost transmission expansion option, and has to meet the Grid Code performance standards and the ERC performance targets.

A.5.6 Contract form

NGCP won the 25-year concession in 2007. The Government tendered the concession through an open, public, and competitive bidding process. NGCP began operations as the power transmission service provider in 2009.

Congress approved a franchise period of 50 years. The concession contract is for 25 years, with an option to extend.

The rights and responsibilities of NGCP under the terms of the concession are:⁴⁵

- To construct, install, finance, manage, improve, expand, operate, maintain, rehabilitate, repair, refurbish, and replace TransCo's transmission assets,
- To prepare the TDP and to implement the projects included in the TDP (after authorization from the ERC),
- To provide transmission services and enter into connection agreements with transmission customers,
- To procure Ancillary Services necessary to support a safe and reliable operation of the transmission assets, and
- To collect the universal charge payable by end users and self-generating entities not connected to a distribution utility, and remit this to PSALM.

NGCP won the concession with a bid of US\$3.95 billion, representing the Net Present Value of future cash flows. NGCP paid 25 percent (US\$987 million) immediately, with the balance to be paid in US\$

denominated installments converted to Philippine Pesos (PHP) at exchange rates prevailing on the transaction dates, over the next 15 years. NGCP funded the down payment through loans and equity, with the remaining 75 percent to be financed using the company's earnings.⁴⁶ By mid-2013, NGCP had paid US\$1.5 billion of the outstanding fee.

Regulation of transmission revenues

NGCP proposes the MAR that NGCP can receive as revenues. The MAR is made up of three components:

- **Power Delivery Service:** The cost of transporting electricity through the grid, payable by generators and load customers,
- **System Operation:** The costs associated with system operation as defined under the WESM Rules, paid by both generators and load customers, and
- **Metering Service Provider:** The cost of metering, testing, maintaining, and reading the meters, paid by all connected transmission customers according to the voltage level.

In addition to these three components, NGCP earns (and collects on behalf of other organizations) other revenues and charges, such as connection charges or rental of assets. The additional revenue is used to reduce customer rates.

ERC has to make a determination on the proposed MAR. The MAR is converted to a per unit wheeling rate. Rates are set in PHP per kW per month. Customers are charged based on the per unit wheeling rate. NGCP collects revenues directly from large customers, distribution companies, and electricity cooperatives (member-owned utilities that provide the majority of power in rural areas). Transmission accounts for around 10 percent of a consumer's bill.⁴⁷

The MAR is developed on a standard building-block approach. NGCP is compensated for O&M costs, depreciation, return on capital for the regulatory asset base (including adjustments to the regulatory asset base for new investment), and under- or over-recovery in the previous year. The MAR is recovered from users through the charges for the three services described above. The Philippines has fully cost-reflective tariffs, without a need for subsidy.⁴⁸

In October 2015 NGCP sought an increase from PHP43.08bn in 2015 (equivalent to PHP308.67 per kW), to PHP45.3bn in 2016. NGCP referred to the need to create a buffer to cover the risk of under-recovery of revenue from customers.⁴⁹ However, in February 2016 the ERC recommended lowering the MAR to PHP41.65 billion.

Performance criteria

NGCP calculates the performance levels, for review by the ERC. Rewards and penalties may take the form of increases or decreases in the MAR for a regulatory year.

Performance is measured against eight criteria for quality and reliability (set out in Chapter 3 of the Grid Code).⁵⁰ Each criterion is weighted as follows:

- System Interruption Severity Index, 25 percent,
- Frequency of Tripping, 20 percent,
- System Availability, 10 percent,
- Frequency Limit Compliance, 10 percent,
- Voltage Limit Compliance, 10 percent,
- Congestion Availability for Luzon grid, 10 percent,
- Ancillary Services Availability Indicator, 5 percent, and
- Customer Satisfaction Indicator, 10 percent.

For each criterion, ERC sets targets and bands (a lower and upper cap). The reward or penalty is limited to 3 percent of the MAR. Last, NGCP is not liable for performance failures beyond its control, such as interrupted generation.

A.5.7 Procurement process

The transmission concession was awarded to NGCP in 2007 through an open bidding process, after three previous failed attempts.

The first attempt was in 2003. The process failed at the prequalification stage as only one party submitted a proposal when a minimum of two were required. Soon after, a second attempt failed for the same reason. PSALM tried again between 2006 and 2007, attracting three prequalified bidders. However, only one of these proceeded to make a formal bid when a minimum of two were required. PSALM decided to re-tender rather than negotiate directly, eventually awarding the concession to NGCP.

A.5.8 Outcomes

NGCP has invested in new transmission lines and reached performance targets. Between January 2014 and December 2015, NGCP developed 647 ct km of new lines, 1,350 MVA, and 600 MVA of substation capacity over 28 projects. Twenty-six projects (lines and substations) were due for completion by the end of 2016, and another 19 projects by the end of 2019.⁵¹

NGCP has met its performance targets since 2011. NGCP has consistently exceeded grid loss thresholds and reduced losses by reducing tripping frequency and improving availability. Availability for Visayas and Mindanao held at 99.8 percent and 99.7 percent

respectively in 2016, and in Luzon it improved from 99.4 percent to 99.6 percent. Availability of critical lines also improved from 99.6 percent to 99.7 percent.⁵²

Notes

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APPENDIX B

Pipeline of IPT projects in Kenya and the Southern African power pool

The IPT is the most broadly applicable business model for attracting privately financed transmission investments in Africa. This model can bring additional sources of finance, compared to the dominant case in Africa in which government-owned utilities finance all transmission investments.

African governments should consider procuring transmission investments through IPT tenders, alongside the existing business model. Section 6 discusses the steps to realize the potential of IPTs in Africa and Appendix B includes a guide for government officials and policymakers in Africa who are considering whether to seek private finance for investments in transmission using the IPT model.

This appendix presents a potential pipeline of transmission projects to be implemented in Kenya and the SAPP, using the IPT model. The pipeline focuses on one country and one power pool that have a relatively developed legal and regulatory framework in the power sector, and have defined interest in considering a privately financed model for transmission. With time, this pilot project could demonstrate that the IPT business model is applicable in all African countries, creating further investor interest in the sector and in the region.

This appendix provides an overview of the power sector in Kenya (Section B.1), and the SAPP (Section B.2), and identifies a pipeline of potential IPT projects in Kenya and the SAPP (Section B.3).

B.1 Overview of Kenya's Power Sector

The power sector in Kenya is partially unbundled. Transmission and distribution have been bundled, but separate from generation, since the late 1990s. IPPs have been able to invest and participate in the generation sector since the mid-1990s, and in 2008 the Government of Kenya created a separate government-owned transmission company. Box B.1 describes the main companies in Kenya's power sector.

In addition, the Ministry of Energy and Petroleum designs and implements the energy policy, the Energy Regulatory Commission (ERC) is the sector's single regulatory agency (dealing with technical and economic issues), and the Rural Electrification Authority is responsible for scaling up rural electrification.

Financial viability of the power sector

The financial viability of Kenya's power sector is relatively weak. The World Bank study "Making power affordable for Africa and viable for its utilities"¹ shows that Kenya's utility (where KPLC is used as reference) collects enough cash to recover its capital costs, but not its operational costs. The study also estimates that Kenya's quasi-fiscal deficit—defined as "the difference between the net revenue of an efficient electricity sector covering operational and capital costs and the

Box B.1 Main companies in Kenya's power sector

The main companies are divided between the generation and transmission and distribution sectors, as summarized below.

Companies in the **generation sector** include:

- The state majority-owned Kenya Electricity Generation Company (KenGen)—responsible for all public power generation activities except those related to geothermal resources,
 - The state-owned Geothermal Development Company (GDC)—responsible for all public geothermal generation activities, and
 - Almost 10 IPPs.
- Source: A. Eberhard et al. (2016).

Companies in the **transmission and distribution sector** include:

- The state-owned Kenya Power and Lighting Company (KPLC, also known as “Kenya Power”)—owns and operates the existing transmission and distribution network, and
- The state-owned Kenya Electricity Transmission Company (Ketraco)—mandated to plan, design, construct, and maintain new transmission lines and associated substations.

net cash collected by the utility—is US\$486 million, or 41 percent of the cash collected by the utility.

However, Kenya has attracted US\$2.4 billion in private investment in IPPs since 1996, in more than 10 projects.²

Demand and electricity generation are expected to grow substantially by 2030

Kenya has a target of 100 percent electricity access by 2022—more than four times the 23 percent access level in the baseline year, 2012. By 2015, 37 percent of the population had access to electricity.³ Improvements have been achieved, though reaching the target will be challenging. Those with access also use relatively little. Kenyans consume 168 kWh per capita a year of electricity.⁴

Demand for electricity has shown a rising trend since 2004, and is expected to continue growing in the next decade. Estimates suggest that energy demand will increase by almost four times by 2022, and ten times by 2030—compared to the baseline year. Energy demand would increase from 8,010 GWh in 2012 to 32,150 GWh in 2022 and 81,352 GWh by 2030.⁵

Kenya's installed generation capacity is projected to increase by almost nine times by 2030—from 1,645 MW in 2012 to 14,676 MW in 2030. Installed generation in 2015 was 2,298 MW—36 percent

hydropower generation, 26 percent geothermal, and 21 percent fuel oil—and the government owned 70 percent of the capacity.

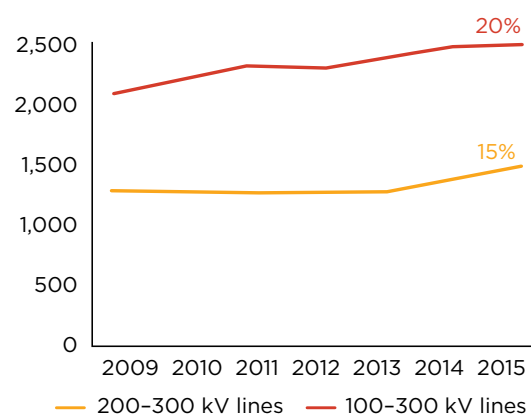
Though IPPs currently account for 30 percent of the installed electricity generation, the share of IPP capacity has increased considerably since 2005 when IPPs had 12 percent. Electricity production from IPPs represents around a third of the total energy generated—31 percent in the July 2013–June 2014 period.⁶

Transmission lines will also be needed to transport the electricity and connect consumers

Kenya currently uses 220 kV and 132 kV lines for its transmission network. The length of transmission lines in Kenya in 2015 was 4,054 km, compared to 3,443 km in 2009. This represents an overall 18 percent increase. Figure B.1 shows the evolution of 100–200 kV and 200–300 kV transmission lines in the period, as well as the accumulated increase (in percentage) over the period. Kenya had no in-country transmission lines above 300 kV.

MV lines (between 1–100 kV) increased faster. Lines between 1 kV and 65 kV increased by 45 percent in the 2009–2015 period (up to 1,212 km), while lines between 66 kV and 99 kV increased by 87 percent in the same period (up to 54,193 km).

Figure B.1 Evolution of transmission lines, by voltage (2009–2015)



Source: Castalia. Data sourced from Trimble, C. et al., “T&D Data—State owned national grid T&D data,” 2016, <http://data.worldbank.org/data-catalog/affordable-viable-power-for-africa> (accessed October 30, 2016).

Despite these increases, Kenya still has a low level of transmission per capita (see Section 2.2). Combined transmission and distribution losses were 17.5 percent in 2015.⁷ Transmission will also be needed to meet Kenya’s electricity access targets and generation expansion plans.

Ketraco expects to develop approximately 7,000 km of transmission lines by 2020—including 2,200 km of 132 kV lines, 2,400 km of 220 kV lines, 2,000 km of 400 kV lines, and 612 km of 500 kV High Voltage Direct Current (HVDC) lines.⁸

ERC is tasked with sector planning and regulation

The **ERC** is the entity **responsible for power sector planning** in Kenya since the Energy Act 2006. Previously, the Ministry of Energy and Petroleum was in charge of planning. ERC prepares the Least Cost Power Development Plan (LCPDP) with a 20-year horizon, and updates the LCPDP every two years—including demand forecasts, generation and transmission planning, and an investment plan. The most recent plan covers the 2015–2035 period.

ERC is also responsible for regulating prices in the power sector. Part 3 of the Energy Act 2006 requires ERC to license transmission. The license shall include charges for the transmission of electrical energy. Contracts for the sale of transmission services (such as a Transmission Services Agreement with an IPT) require ERC’s prior approval.

Currently transmission services are not separately regulated. ERC sets “just and reasonable” tariffs. Retail tariffs are determined at economically efficient levels, to recover the costs of generation, transmission and distribution. Retail tariffs are reviewed every three years.

KPLC collects revenues from consumers. KPLC keeps part of these revenues to recover its own transmission and distribution costs. However, KPLC also pays transmission charges to Ketraco, generation charges to KenGen, GDC, and IPPs, and distribution charges to the Rural Electrification Authority.

The introduction of IPTs might require some modification to regulatory arrangements. The ERC needs to set charges which it considers are just and reasonable. This requires periodic consideration of the efficient costs of providing transmission services to enable the three-yearly review of retail tariffs. Once IPTs are introduced, the review process will be simplified. The tender process will have revealed the efficient costs of the services the IPT will provide. However, the ERC may play a role in ensuring that the tender process is well conducted and can form a sufficient basis for passing the costs on to final consumers.

B.2 Overview of the Southern Africa Power Pool

SAPP is a membership of electricity utilities of Southern Africa, created in 1995. SAPP currently has 16 members from 12 different countries, as listed in Table B.1. All members, except CEC, are (majority) government-owned companies.

To be a member, the utility must be located in a country that was a member of the South Africa Development Community in September 1994. Utilities located in countries that are not members of the Community could also be members. The SAPP Executive Committee would need to approve the utility’s membership.⁹

SAPP has operated for over 20 years, with important results in the generation and transmission sector. Over 15,000 MW were commissioned in the 2004–2015 period, as well as a diverse range of transmission interconnection projects—including the 400 kV interconnector between Mozambique and Zimbabwe (commissioned in 1997), the 400 kV line

Table B.1 Members of SAPP

Name of the utility	Country
Botswana Power Cooperation	Botswana
EDM	Mozambique
Electricity Supply Commission of Malawi	Malawi
HCB	Mozambique
CEC	Zambia
ESKOM	South Africa
Nam Power	Namibia
Swaziland Electricity Company	Swaziland
Zimbabwe Electricity Supply Authority	Zimbabwe
Empresa Nacional de Electricidade	Angola
ZESCO	Zambia
Tanzania Electric Supply Company Limited	Tanzania
Société National d'Électricité	Democratic Republic of the Congo
Lesotho Electricity Corporation	Lesotho
Mozambique Transmission Company ¹⁰	Mozambique
Lunsemfwa Hydro Power Company	Zambia

Source: Southern Africa Power Pool, "Annual Report 2016," <http://www.sapp.co.zw/areports.html> (accessed March 13, 2017).

between South Africa and Mozambique, via Swaziland (commissioned in 2000), and the 350 kV HVDC line between Namibia and Zambia (commissioned in 2012).

Figure B.2 illustrates the interconnections between the SAPP member countries, by voltage. It also specifies the transmission capacities of the interconnections lines, and the available peak generation capacity of each country.

SAPP's current generation and transmission capacity

SAPP has an installed generation capacity of 61,959 MW, and 75 percent of this installed capacity is considered available for operations. SAPP members plan to commission 32,695 MW of new generation capacity by 2022. Over 60 percent of the installed generation capacity in 2016 comes from coal, while hydropower was the second source of generation, with 21 percent.

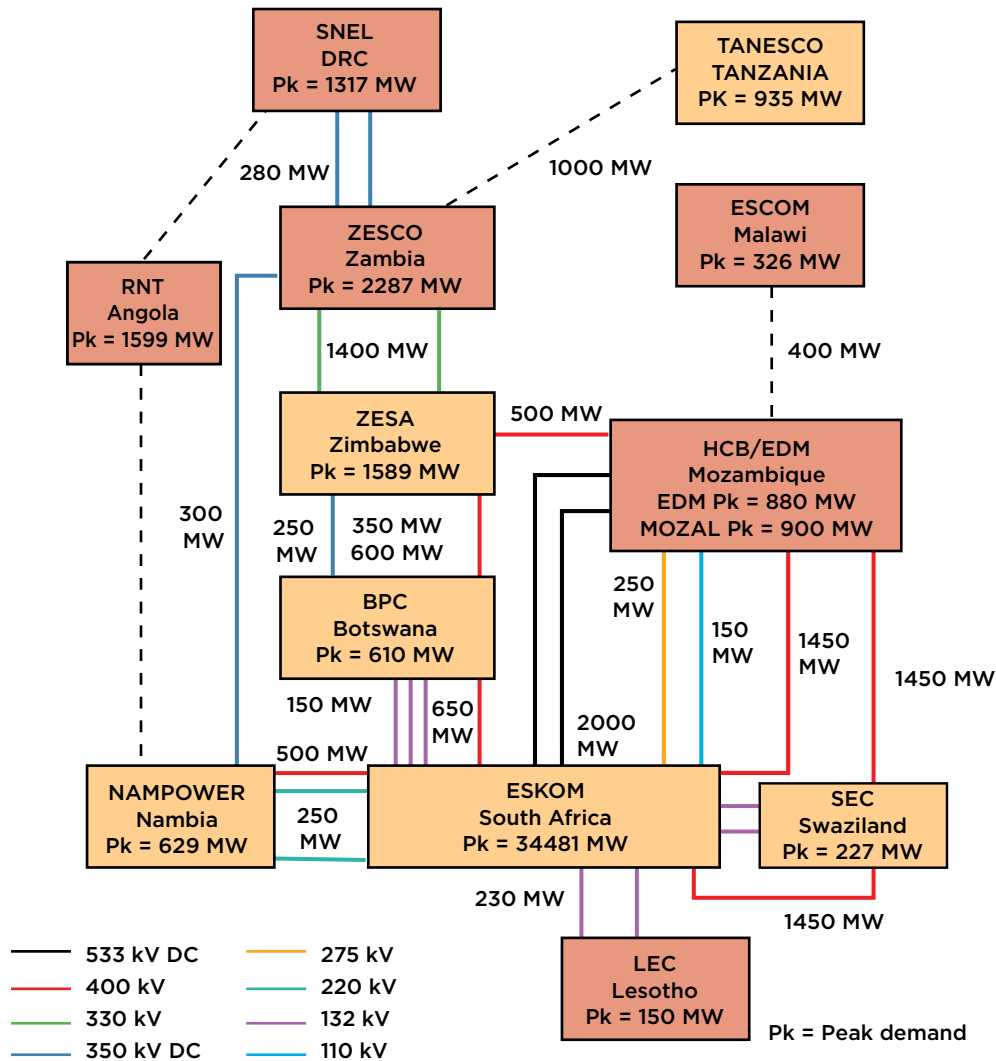
SAPP is the most developed power pool in Africa. As described in Box B.2, its market structure can provide useful information to help those planning future transmission investments.

The planning subcommittee prepares the transmission plan

SAPP is based on an inter-governmental agreement. It is supported by a Memorandum of Understanding between the utilities participating in SAPP. Article 13 of that Memorandum sets out the representation on the planning subcommittee and the duties of the subcommittee.

The duties included an overall Pool Plan that draws on the plans prepared by individual members of SAPP. A Regional Generation and Transmission Expansion Plan Study was developed by SAPP in 2009 and prepared by Nexant. The plan identified several major transmission investments with major benefits to the region—including projects to link nonoperating members of SAPP (for example, the Zambia–Tanzania and Mozambique–Malawi interconnections), reduce congestion (for example, the Kafue–Livingston Upgrade in Zambia), or related to generation projects (for example, the Mozambique Backbone–STE Project).¹¹ The World Bank and other DFIs are supporting SAPP with these transmission projects, by providing technical assistance and grant funding.

Figure B.2 The SAPP grid



Source: Southern Africa Power Pool, "Annual Report 2016."

B.3 Pipeline identification

Ketraco and SAPP are evaluating privately financed models to attract investment to transmission projects. The IPT business model is being considered as one likely suitable model. Public finance will continue being the dominant model, but alternative financing methods could help obtain additional sources of finance to the sector, and relieve the financing constraint that these African countries face.

Selection criteria includes project stage, size, and degree of wayleave risk

Ketraco and SAPP are identifying transmission projects to pilot IPTs. To do this, they have developed criteria to select the projects. The selection criteria are:

- Project has undergone preliminary developments,
- Project size is sufficiently large to attract investors, and
- Risk of wayleave is appropriate.

Box B.2 SAPP's experience shows how regional power pools can assist transmission planning

The market structure of SAPP can provide useful information to help those planning future transmission investments. SAPP operates a day-ahead, regional net market. These terms are explained below:

- “Day-ahead” means that bids are submitted 24 hours before real time. This contrasts with some markets that have intra-day trading nearer to real time,
- “Regional” means that SAPP is divided into several bid areas. Those bid areas are determined by the location of grid constraints. As the networks were originally developed primarily to serve country demand, the borders of the bid areas are primarily the geographical borders between the countries in the SAPP area, and
- “Net” means that the transmission capacity between bid areas is first allocated to bilateral trades. SAPP rules state: “Firm Bilateral Agreements between Participants will be given priority [. . .] for transmission on the SAPP interconnectors.”¹² Where bilateral agreements exceed the transmission capacity, the allocation is based on the maturity of the agreements.

The transmission capacity remaining after the allocation to bilateral agreements is available for trade on the Day Ahead Market (DAM). The system operators determine the available transmission capacity between the bid areas. The market operator then calculates the capacity that can be

used for trade on the DAM, after allowing for the capacity reserved for bilateral contracts.

Bids and offers are submitted for each bidding area. Generators can only bid where they are located (or where they are party to contracts relating to physical delivery). Offers to purchase on the DAM are also based on the bidding area where the purchaser is located.

As is common in markets with this structure, the pricing rules result in a uniform price when constraints are not binding. When transmission constraints between the bidding areas occur, prices also separate. This is known as market splitting.

The price separation also results in settlement residues. This means the market operator buys more power in bid areas with a low price and sells more power in bid areas with a higher price. While different markets use different terms, the existence of these residues is a feature of all regional markets.

As a result the DAM provides a high level of transparency on the frequency of transmission constraints across the regional interconnections and on the materiality of those constraints. SAPP also provides a high level of certainty over access rights when transmission lines are constrained. The information on the frequency and materiality of constraints does not remove the need for transmission planning, but provides useful input to the planning process.

The first criterion considers the stage of development of the project, and whether feasibility studies (ESIA) have been completed. Long-term or urgent projects are also not prioritized, as both Ketraco and SAPP aim to trial IPT tenders in the short term. Piloting urgent projects could also prevent focusing on the learning process.

The second criterion refers to the project size and whether projects are large enough to justify the transaction costs (see related discussion in Section 6.8). To comply with this criterion, the pilot project may have to bundle several projects into a single tender, particularly for in-country projects. According to consultations with private investors and World Bank experts, an estimated minimum threshold (for construction costs) would be around US\$80–100 million. However, this figure may depend on the project or

regional context. Investors will also evaluate if there are reasonable prospects of a future pipeline of other investment opportunities.

The third criterion requires that the risk associated to acquiring the land and ROW is appropriate, given the project characteristics. Selected projects can only have low to medium wayleave risks. Projects with high wayleave risk were removed from the pipeline.

Six identified potential transmission projects to pilot IPTs in Kenya and SAPP

After applying these criteria to Ketraco's overall transmission pipeline and SAPP's priority transmission projects, six potential pilot projects are obtained—four in Kenya and two interconnections within SAPP. The selected pipeline of IPT projects in Kenya is shown in

Table B.2 Pipeline of potential IPT projects in Kenya

Project name ¹³	Est. cost ¹⁴ (US\$ million)	Length (km)	Voltage and line type	Wayleave risk	Need to bundle with another project(s)?
Kiambere– Maua–Isiolo	81	288	220 kV; double circuit	Low: [Ketraco] had successful wayleave experiences with these communities, despite high population density	No
Kisumu– Kakamega–Musaga	35	72	220 kV; double circuit	Low: [Ketraco] has had wayleave experiences with population	Yes
Menengai– Nyandarua–Rumuruti	21	70	132 kV; double circuit	Medium: Registered land but high population density in Menengai	Yes
Karbanet–Rumuruti (Nyahururu)	20	111	132 kV; double circuit	Partially Low, Partially High: privately owned land, but some pastoralists in Kabarnet	Yes

Source: Ketraco, “Support to develop a framework for transmission infrastructure through PPP,” Draft Report, March 2017, (pers. comm. with Samuel Oguah, March 6, 2017). Adapted from Table 12. We need to select pilot line(s) from the shortlist of 11 lines.

Table B.3 Pipeline of potential IPT projects in SAPP

Project name	Countries involved	Estimated cost (US\$ million)	Length (km)	Capacity and line type
Zambia–Tanzania	Zambia and Tanzania	780 ¹⁵	700 ¹⁶	400 MW; 330 kV; double circuit
Mozambique Backbone (STE)	Mozambique	1,700 ¹⁷	1,300 ¹⁸	3,100 MW; 800 kV; HVDC line

Source: World Bank, “Project appraisal document on a proposed grant in the amount of SDR13.2 million to the Southern Africa Power Pool for a Southern Africa Power Pool (SAPP)—Program for accelerating transformational energy projects,” (Report No: 86076-AFR), October 2014, <http://documents.worldbank.org/curated/en/988471468002999129/pdf/860760PAD0P126010Box385343B000U0090.pdf> (accessed March 15, 2017). Adapted from Table 5. Priority Transmission Projects.

Table B.2 and the selected pipeline of IPT projects in SAPP is shown in Table B.3.

As suggested in the last column of Table B.2, three of the selected projects in Kenya would need to be bundled to fulfill the criteria. Bundling the three projects (those in the last three rows of the table) would involve an estimated cost of US\$76 million, which is almost the minimum suggested threshold.

The Zambia–Tanzania project shown in Table B.3 is a priority transmission project for SAPP that will help relieve congestion in the power pool, and the STE project is related to the development of low-cost generation. The STE project connects the Zambezi Basin hydropower region downstream of Cahora Bassa to southern Mozambique and South Africa. The World Bank is currently updating feasibility studies of this project.

Notes

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2. A. Eberhard et al. (2016).
3. “National Workshop Targets Kenya’s Electrification Challenges,” Energy Sector Management Assistance Program, <https://www.esmap.org/node/55495> (accessed March 10, 2017).
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6. A. Eberhard et al. (2016).
7. Trimble, C., et al., “T&D Data – T&D Network Losses (as percent of total dispatch),” 2016, <http://data>

- .worldbank.org/data-catalog/affordable-viable-power-for-africa (accessed October 30, 2016).
8. Kenya Electricity Transmission Company (Ketraco), "Transmission System Planning and Implementation: Planned Projects and Financing Gap," Presentation at from consultation workshop, Nairobi, Kenya, September 26, 2016.
 9. "Membership," Southern African Power Pool (webpage), <http://www.sapp.co.zw/members.html> (accessed March 13, 2017).
 10. The Mozambique Transmission Company is an SPV formed by ESKOM (South Africa), EDM (Mozambique), and Swaziland Electricity Company (Swaziland). These three utilities each own a third of the shares.
 11. World Bank, "Project appraisal document on a proposed grant in the amount of SDR13.2 million to the Southern Africa Power Pool for a Southern Africa Power Pool (SAPP) – Program for accelerating transformational energy projects," (Report No: 86076-AFR), October 2014, <http://documents.worldbank.org/curated/en/988471468002999129/pdf/860760PADoP126010Box385343BooOUO090.pdf> (accessed March 15, 2017).
 12. Southern Africa Power Pools, "Day Ahead Market. Book of rules," January 2009, <http://www.sapp.co.zw/docs/SAPP%20DAM%20Book%20of%20Rules%20%final%20version%20January%202009.pdf> (accessed March 14, 2017).
 13. New substations required for the project are shown in bold.
 14. This is the estimated construction cost.
 15. Lead2Business, "Project Details. Zambia–Tanzania–Kenya Power Interconnector Project," <http://www.l2b.co.za/Project/Zambia-Tanzania-Kenya-Power-Interconnector-Project/9262> (accessed March 15, 2017).
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