Technical Assistance to Regional Electricity Regulators Association of Southern Africa (RERA)

Market and Investment Framework for SADC Power Projects – Recommended Market Model

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Acronyms

AFDB	African Development Bank
ATI	African Trade Insurance Agency
BEWRA	Botswana Energy and Water Regulatory Agency
BPC	Botswana Power Corporation
CEAC	Central American Electrification Council
CEC	Copperbelt Energy Corporation
CRIE	Regional Commission on Electrical Interconnection
DAM	Day Ahead Market
DBSA	Development Bank of Southern Africa
DFI	Development Finance Institution
DNEE	National Directorate for Electrical Energy
DOE	Department of Energy
DOEA	Department of Energy Affairs
DOS	Department of State
DSE	Dar es Salaam Stock Exchange
DSO	Distribution System Operators
ECA	Export Credit Agency
ECB	Electricity Control Board
EDEL	Empresa de Distribuição de Electricidade
EDM	Electricidade de Mocambique
ENE	Empresa Nacional de Electricidade
EOR	Ente Operador Regiona
EPC	Engineering Procurement and Construction
EPP	Emergency Power Producers
EPR	La Empresa Proprietaria de la Red
ERA	Electricity Regulatory Act
ERB	Energy Regulatory Board
ESCOM	The Electricity Supply Company of Malawi
ESI	Electricity Supply Industry
EU	European Union
EWURA	Energy and Water Utilities Regulatory Authority
FCT	Fair Competition Tribunal
FIT	Feed in Tariff
HCB	Hidroelectrica de Cahora Bassa
IMF	International Monetary Fund
INEP	Integrated National Electrification Program

IPP	Independent Power Producer
IPTL	Independent Power Tanzania Limited
IRSE	The Regulatory Institute of the Electrical Sector
LEC	Lesotho Electricity Company
LEWA	Lesotho Electricity and Water Authority
LHDA	Lesotho Highlands Development Authority
MCH	Market Clearing House
MEM	Ministry of Energy and Minerals
MER	Regional Electricity Market
MEWD	Ministry of Energy and Water Development
MEWT	Ministry of Environment, Wildlife, and Tourism
MGDS	Malawi's Growth and Development Strategy
MHP	Muela hydropower plant
MME	Ministry of Mines and Energy
MMEWR	Ministry of Minerals, Energy, and Water
MNREE	Ministry of Natural Resources, Energy and Environment
MO	Market Operator
MOF	Ministry of Finance
MOTRACO	Mozambican Transmission Company
NEPAD	The New Partnership for Africa's Development
NERSA	The National Energy Regulator of South Africa
NIPA	National Investment Promotion Agency
OTC	Over-the-Counter
PPA	Power Purchase Agreement
PRG	Partial Risk Guarantee
PSP	Private Sector Participation
QOS	Quality of Service
REIPPP	Renewable Energy Independent Power Producer Procurement Program
RERA	Regional Electricity Regulators Association of Southern Africa
REU	Rural Electrification Unit
RG	Regional Generators
RPS	Retail Public Suppliers
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SEC	Swaziland Electricity Company
SERA	Swaziland Energy Regulatory Authority
SIEPAC	Central American Electrical Interconnection System

SOU	State Owned Utility
TANESCO	Tanzania Electric Supply Company
TSO	Transmission System Operator
USADF	United States African Development Fund
USAID	United States Agency for International Development
WBG	World Bank Group
ZCCM	Zambia Consolidated Copper Mines
ZERA	Zimbabwe Energy Regulatory Authority
ZESA	Zimbabwe Electricity Supply Authority
ZESCO	The Zambia Electricity Supply Corporation
ZETDC	Zimbabwe Electricity Transmission and Distribution Company
ZPC	Zimbabwe Power Company

FOREWORD

The authors would like to express their gratitude to all institutions and individuals that provided input to this Report. This includes particularly the Regional Electricity Regulators Association of Southern Africa (RERA), the Southern African Power Pool (SAPP) Coordination Center, all Southern African Development Community (SADC) Member State governments, utilities, regulators, the development and commercial financing community, and too many others to mention by name.

This document continues to evolve. It is anticipated that it will be adjusted and amended as more information becomes available and further feedback is received from stakeholders.

EXECUTIVE SUMMARY

- The Southern African Power Pool (SAPP) estimates that US$90 billion of investment will be required to provide the Southern African Development Community (SADC) region with the electricity services it will require over the next two decades. Much of this US$90 billion will have to come from the private sector, as neither the region's utilities nor the region's governments have the necessary budgetary resources to fund this level of investment.
- Although there has been a large increase in the amount of private investment flowing into developing country power sectors globally over the last ten years,[1] taking into account the huge funding requirements described above, the power sectors in the SADC countries (Member States) have and will, if the status quo continues, remain starved for capital. This is because the current investment environment, both at the Member State and regional level, poses too many risks for private sector investors and developers.
- Most of these risks can be categorized as legal and regulatory, operational or technical, institutional, or financial in nature. For example, the lack of clear rules for cross border dispute resolution poses a legal and regulatory risk, variations or lack of detail in national grid codes presents an operational risk, and a lack of detailed information sharing between utilities creates an institutional risk.
- While it cannot hope to solve all the challenges the SADC power sector faces, many of these risks can be reduced or mitigated by putting in place a '*Market and Investment Framework for SADC Power Projects*'[2] that provides more certainty to local, regional, and international investors, supports regional power trade, and improves the operating environment for IPPs, utilities, regulators, and ministries of energy.
- Once implemented, the Market and Investment Framework will attract increased private sector participation (PSP) in the expansion and development of the SADC power sector, and bring other advantages, such as:
    - Greater security of energy supply;
    - Greater competition for markets resulting in better services;
    - More secure and stable power system operation;
    - More efficient and more economically viable utilities, as a result of changes such as:
        - A more organized system of bi-lateral contracts;
        - A balancing market that properly assigns the risks and costs of non-delivery for energy transactions;
        - Less Member State reliance on imports of expensive and foreign-controlled energy sources; and

[1] *World Investment Report 2015*, United Nations Conference on Trade and Development

[2] As a result of stakeholder feedback, the name of the Framework was changed from "IPP Framework" to "Market and Investment Framework for SADC Power Projects."

- The transfer of some investment risk from Member States and their utilities to the private sector.

- Working on the basis of a phased-in approach over multiple years that employs the fewest possible changes to existing Member State legal and regulatory frameworks, operating procedures and institutional set up, the Market and Investment Framework will help Member States to gradually build a market structure that supports larger, regionally focused projects that are supported by private sector capital and expertise. The Market and Investment Framework will also reduce the overall risk level for regional projects by, for example:
  - Authorizing Member State regulators to issue licenses to Market Participants engaged in regional projects and cross border trade;
  - Developing regional technical protocols and codes, based to the extent possible on existing national models, that can be promulgated in each Member State, by harmonizing methodologies and procedures for interacting with transmission service providers and for transmission pricing;
  - Creating tools to manage and cost the financial impact caused by inadvertent power flows, particularly with regard to wheeled power;
  - Providing template documents and common approaches to Grid Connection Procedures & Requirements, Connection Charging Methodologies, Dispatch Rules & Agreements, Network Congestion Management Rules, and Transmission System Operator to Transmission System Operator (TSO/TSO) Agreements;
  - Improving regional transmission line procurement and planning to attract private funding;
  - Enabling Member State regulators to resolve cross border disputes; and
  - Suggesting approaches to enhance the creditworthiness of power offtake agreements.
- The Market and Investment Framework will use the energy legislation in Member States as a basis for continued sector development. It will also build upon the institutional arrangements that SADC and its Member States have already put in place to improve the performance of the SADC power sector, for example, SAPP’s Operating Guidelines (2013) and the Regional Electricity Regulators Association of Southern Africa’s (RERA) Guidelines for Regulating Cross-border Power Trade (2010).
- Regional markets most often develop and thrive where similar or common rules encourage cross-border power exchange, and where transactions are enforced in the same way and with the same probable outcome wherever electricity is sold. The Market and Investment Framework attempts to promote this principle throughout.
- The recommended Market and Investment Framework therefore includes a unified market structure that is supported by a New Legal and Regulatory Framework, constituting a body of harmonized legal and regulatory rules that will be applicable in each Member State for all regional projects.
- The Market and Investment Framework also includes an Operating Framework to mitigate technical risks that are preventing increased PSP; an Institutional Framework, that intends to highlight the institutional support required for the successful implementation of the Market and Investment Framework; and a Financial Framework, that seeks to enhance the credit worthiness of power offtake agreements and reduce investment risk for developers;

- The effect of implementing such a framework will be to create larger markets, increase wholesale competition, and augment the predictability of results. This will help to unlock investment capital, thereby enabling SADC to benefit from the private sector investment boom developing country power markets are enjoying.
- Changes such as these will also result in increased energy access, more availability of, and higher quality, power, and a regional power system that can be sustained over the long term by lower tariffs. As well as promoting cross border power trade, by providing support to economic development across the SADC region in this way, the Market and Investment Framework will help SADC achieve its twin objectives of increased regional integration and poverty eradication.

1. INTRODUCTION

The Southern African region suffers from widespread energy poverty brought about by poor power sector performance. Social and economic development will remain constrained unless new investments in generation assets are forthcoming. Contemporaneous investment in new transmission infrastructure, coupled with more competitive and transparent power trade throughout the region, including via the Southern African Power Pool, will allow the evacuation and sharing of electricity across regional markets, thereby increasing the viability of generation plants while also maximizing the benefit of new generation sources. Improved regional market access will also reduce risk for new generation projects as project economics are not solely associated with any given individual country's power market, many of which currently lack adequate load to support larger infrastructure investment.

SADC-member states' electricity sectors are dominated by state utilities which have limited budgets available for financing of new power plants and power delivery networks. If SADC countries are to meet their development objectives, private sector investment in electricity markets is therefore essential. In order to mobilize private investment on the scale required – SAPP estimates US$90 billion of investment will be required to provide the region with the electricity services it will require over the next two decades - strong policy, legal, regulatory, operating and institutional frameworks that reduce risk and incentivize investment in IPP projects are required. While Member States have implemented some reforms, these frameworks are largely absent from most countries within the region.

Through the Department of State's Bureau of Energy Resources, Deloitte is supporting RERA in its efforts to promote (i) improved regulation of the electric power sectors of the SADC member countries, (ii) increased private sector investment, and (iii) greater use of renewable energy sources. The Market and Investment framework described herein will assist RERA in its effort to facilitate increased harmonization across national power markets, which in turn will allow investors to access a larger regional market.

1.1 The Market and Investment Framework

The proposed Market and Investment Framework described in this document will not be implemented on a blank slate. Indeed, it is important to note that ten of SADC's fifteen Member States[3] already have some experience in promoting and implementing IPPs in their local markets. A detailed discussion of Member State IPP programs is found in Annex 2. Each country identified as having some experience in attracting and implementing IPPs shares certain sector features in common, such as:

- Increasing electricity consumption;
- Large and growing levels of unmet demand, yet often subscale markets (outside of South Africa) too small to fully account for the power output their resource potential suggests;
- Dependence on imports;
- Security of foreign supply issues;
- Transmission system and interconnected system constraints;

[3] Namibia, Tanzania, Malawi, South Africa, Zambia, Angola, Zimbabwe, Botswana, Lesotho and Swaziland have all taken steps to attract IPPs into their domestic electricity markets.

- Politically strong, highly entrenched State Owned Utilities (SOU) selling power at below cost, and therefore suffering budgetary challenges and/or decapitalization:
- Many bulk users of electricity;
- Significant untapped renewable potential;
- Policy commitment to sector reform and demonstrated willingness to implement some changes;
- Unease at the thought of more complete sector unbundling and the loss of control of key power sector assets;
- High offtake risk; and
- High regulatory risk.

Some of these countries have independent regulatory authorities. Some do not. Whether or not they are legally or practically independent, all SADC Member State regulators are dominated by strong sector participants. Given that very few, if any, Member States have implemented cost reflective tariffs,[4] no country can boast of having a coherent and attractive pricing scheme for IPPs. In addition, some countries have implemented investment promotion schemes. Most however, have not. What is lacking is a comprehensive, coherent program that puts all the pieces together in a way that can be packaged for potential investors. While not all of the Member States' IPP experiences have been successful or even beneficial, they all can serve as the foundation for a comprehensive program of harmonized policies, rules, and procedures that can be implemented in each Member State. Indeed, in many cases, the track record these IPP program experiences afford reveal the acute need for the regional Market and Investment Framework this Report describes.

The proposed Market and Investment Framework comprises a matrix of evolving and expanding relationships among generators, buyers, and sellers that will allow regional trade to flourish. It includes a proposed Market Model as well as the legal, regulatory, technical/operational, and financial supports that the model requires in order to function. The Market and Investment Framework does not describe a fully open market or full retail competition, although some Member States already have policies in place that will lead to such an opening[5]. Rather, the Market and Investment Framework describes the gradual evolution of relationships and contractual arrangements between Market Participants and Market Service Providers[6] that will expand markets and enliven competitive forces. The Market and Investment Framework is designed for gradual implementation over a number of years, in six stages. A full discussion of the Proposed Market Model and its implementation stages is found in Section 4 of this Report.

By the conclusion of Stage 6, each Member State will have a market structure with largely identical Market Participants and Market Service Providers operating under substantially similar laws, rules, and regulations.[7] They will also conduct their transactions pursuant to substantially similar

[4] See *RERA Publication on Electricity Tariffs & Selected Performance Indicators for the SADC Region, 2012 and 2013*
[5] The Government of Tanzania, for example, has recently published "Road Map 2025" which describes a path to full market opening.
[6] Including Self-Producers, IPPs, Traders, Consolidators for small projects, Retail Public Suppliers and Eligible Customers and Tariff Customers (market participants) and the Transmission System Operator, Transmission Licensees, the Market Operator, the Distribution System Operator (if any) and Distribution Licensees (market service providers).
[7] Because implementation of common rules will be at the Member State level, perfect harmonization of governing rules and processes is not anticipated.

contracts, agreements, licenses, codes, and standards. This will greatly reduce the risk created by the current investment environment.

1.2 Regional Market Supports

Implementing the Market and Investment Framework will require legal and regulatory changes in each Member State. The Market and Investment Framework requires:

- A ***legal framework*** that will facilitate the development of the Proposed Market Model in each Member State; and
- A ***regulatory framework*** that will be super-imposed on each Member State's existing regulatory framework, and applied by each Member State regulator.

Together, these two elements are referred to in this Report as the New Legal and Regulatory Framework[8]. Its implementation at the Member state level will lead to:

- Common rules supporting generators (including IPPs), wholesale traders, consolidators (as required), and eligible and tariff consumers;
- Market Rules and procedures to increase transparency and protect against market abuses;
- The separation of the technical and dispatch functions of the Transmission Licensee to create (in addition to the transmission function) an independent TSO in each Member State;
- The separation of the balancing and settlement functions of the Transmission Licensee to create an independent Market Operator (MO);
- The establishment of harmonized market monitoring and data reporting processes to increase transparency and regulatory effectiveness;
- A set of standard form bilateral contracts, such as Intergovernmental Agreements for Power Trade;
- Other standardized agreements (including balancing and settlement services) that will facilitate higher volumes of imports and exports; and,
- A transparent and binding dispute settlement mechanism that operates uniformly across borders.

The New Legal and Regulatory Framework will catalyze these changes by expanding the powers and competencies of Member State regulators. In the existing (domestic) context, economic regulators are primarily involved with the following kinds of activities:

- Issuing licenses for regulated activities (generation, transmission, distribution, supply, etc.);
- Setting tariffs for regulated activities that are not subject to competition;

[8] The legal and regulatory framework described above is based on the "Energy Acquis", the series of legal and regulatory requirements that support regional trade in electricity among the Member States of the European Union. See Annex 1 for an extended discussion.

- Approving and enforcing technical and service standards;
- Settling disputes between regulated suppliers;
- Regulating planning and emergency preparedness;
- Developing, reviewing and approving all PPAs;
- Issuing orders, enforcing compliance and applying sanctions; and
- Monitoring the regional market for abuse.

Under the New Legal and Regulatory Framework, the Member State regulator's jurisdiction will be expanded to cover all aspects of regional trade that occur within that Member State[9], including:

- Working with other Member State regulators to ensure uniform treatment for service providers involved in regional projects;
- Issuing licenses for activities related to regional projects;
- Setting tariffs for regional services that are not subject to competition;
- Setting technical and service standards for regional projects, specifically including access and interconnection;
- Settling disputes related to regional supply and trade among service providers in other countries;
- Regulating planning and emergency preparedness in respect of regional projects;
- Developing, reviewing, and approving all PPAs, contracts, and all other contracts related to regional project development;
- Approving the design for all cross-border trading arrangements including the Southern African Power Pool (SAPP);
- Issuing orders, enforcing compliance, and applying sanctions;
- Monitoring the regional market for abuse; and
- Recommending market design changes to SADC.

While the New Legal and Regulatory Framework will form the basis of the Market and Investment Framework, we also include within it:

- **An Operating Framework**, that includes a regional grid code, tools to manage inadvertent power flows, and common approaches to Grid Connection Procedures & Requirements, Connection Charging Methodologies, Dispatch Rules & Agreements, Network Congestion Management Rules, TSO/TSO Agreement, and other areas;
- **An Institutional Framework,** that intends to highlight the institutional support required for the successful implementation of the Market and Investment Framework; and

[9] Whether the Member State regulator should operate according to the "acts doctrine" or the "effects doctrine" is a matter for RERA and the Member State regulators to resolve on a case-by-case basis through consultation. "Acts" refers to activities that occur within the territorial jurisdiction of the Member State regulator. "Effects" refers to activities that occur outside of the jurisdiction but exert an effect within the regulatory jurisdiction of the given regulator.

- **A Financial Framework,** that seeks to enhance the bankability of investment projects, including by enhancing the credit worthiness of power offtake agreements, and reducing investment risk for developers;
- Approaches to structuring, and mobilizing funding for, new transmission line capacity.

1.3 RERA's Role

RERA's principal task in implementing the Market and Investment Framework is to develop and roll out the New Legal and Regulatory Framework, and, along with support from SAPP and other counterparts, such as utilities and Member State governments, to help facilitate the adoption of the Operating, Institutional and Financial Frameworks. RERA is selected as the primary institution because the additional work corresponds to RERA's existing mandate and because that body is already consulting with and building consensus among the Member State regulators, within SAPP, and among other Market Service Providers and Market Participants. The precise elements of the New Legal and Regulatory Framework, and the Operating, Institutional and Financial Frameworks are set out in detail in Section 4 of this Report.

During the development of this Market and Investment Framework, Member State regulators have expressed strong views that initial implementation of the New Legal and Regulatory Framework at the Member State level should not lie with RERA, but rather with the Member State regulators. This top down approach to regulatory harmonization will avoid the greatest barrier to the implementation of regional trading among SADC Member States – Member State diversity.[10]

1.4 Road Map

RERA will lead the gradual development and roll out of the Market and Investment Framework to the Member States. A regional pilot project scheme will be used to fully establish the Market and Investment Framework in a small number of identified Member States. Upon successful completion of the pilot project, all other SADC countries will be invited to fully implement it in their countries. A more detailed discussion of this approach is found in Section 6 of this Report.

[10] Today, Member States have:

- Different legal traditions (Common Law and Civil Law);
- Different types of power sector laws with varying scopes;
- Different market structures;
- Different Institutional structures for administering policy and laws;
- Different views on the role of an independent regulator;
- Different approaches to the settlement of regulatory disputes; and
- Regulators operating at different speeds and according to different national priorities and policies.

2. PROJECT SCOPE AND DEFINITIONS

2.1 Scope

The scope of this Report is to recommend the steps that SADC and its Member States can take to encourage private sector investment into new generation and transmission projects in the SADC region. This Report focuses specifically on those steps that are necessary to implement the Market and Investment Framework, which is comprised of a Proposed Market Model, the New Legal and Regulatory Framework, the Operating Framework, the Institutional Framework and the Financial Framework. Specific comments pertaining to the related issues of national policies and legal and regulatory frameworks that can be implemented at the national level to encourage PSP are only briefly addressed. Together with the legal and regulatory support structures, the Market and Investment Framework includes elements intended to mitigate the institutional, financial, technical, and operational risks that currently discourage the flow of investment capital into the SADC region's power sector.

2.2 Definitions

Creating a common lexicon is an important step towards creating a Market and Investment Framework that can be discussed and implemented across national borders. The Proposed Market and Investment Framework draws a distinction between Market Participants and Market Service Providers. **Market Participants**[11] include Consolidators for Small Projects, Eligible Customers, IPPs, Retail Public Suppliers, Self-Producers, Tariff Customers, Traders and Wholesale Power Companies. **Market Service Providers** include Distribution Licensees, the Distribution System Operator (DSO), the Market Clearing House (MCH), the Market Operator (MO), SAPP, the TSO (including regional TSOs as required), and Transmission Licensees. A full discussion of the role of these entities is found in Annex 5 to this Report. In these definitions, all references to the regulator mean the economic regulator for the electricity sector in the relevant Member State.

In this Report, the following terms shall have the meanings:

2.3 Market Participants

Consolidators: Consolidators collect and re-sell the energy produced by small and medium sized (typically renewable) power plants, which individually have little human or economic capability to enter the competitive wholesale market. Consolidators are not specifically identified in the proposed Market Model, but represent a logical extension of Wholesalers and other mentioned Market Participants as competition increases.

Eligible Customers: During market transition, this entity is entitled by national legislation or sub-legislation[12] to purchase power directly from any licensed source for its own consumption. In order

[11] Listed in alphabetical order rather than order of importance for market design.

[12] In this Report the term "legislation" is used to describe principal acts or laws. "Sub-legislation" is the term used to describe binding Regulations and Rules. Regulations are used to describe sub-legislation at the ministry level while Rules is the term used to describe sub-legislation promulgated at a subsidiary level, i.e., by an administrative body such as an economic regulator. Both types of sub-legislation are issued pursuant to specific provisions of a principal act.

to be permitted to do so, this entity is usually required to commit to a minimum amount of absolute volume per year.

Large and Medium IPPs: New power projects beyond a specified capacity will fall into this category. While the definition of large and medium may vary from country to country, under the Market and Investment Framework qualifying thresholds for these categories will be set by the New Legal and Regulatory Framework. All technologies are included in this definition. Under the legal framework existing in most Member States, Medium and Large IPPs must sell a defined, minimum amount of their output to the domestic SOU. The rationale for such a rule lies in the fact that a Member State where an IPP is situated should have an opportunity to reap the benefits of that project's output, given the social and environmental impact of constructing and operating a power plant. Under the Market and Investment Framework, Large and Medium IPPs will be entitled to conclude long-term bilateral agreements and to enter into short-term transactions in the balancing market. To ensure security of supply, the New Legal and Regulatory Framework will require Large and Medium IPPs to demonstrate to the TSO that they have sufficient capacity and energy to satisfy the domestic SOU's requirements.

Retail Public Suppliers: Where markets are in transition and some customers are Eligible Customers, the Retail Public Supplier (RPS) is the supplier of last resort at the retail level to tariff customers, and its prices are set by the regulator. Where an RPS is trading in the regional market, it will be governed by the New Legal and Regulatory Framework.

Self-Producers: Self-Producers are consumers that generate a significant amount of power for their own consumption. Under national legal frameworks, they will be required to consume a minimum absolute amount of the power they generate. The remainder they can offer for sale to the State Owned Utility using pre-agreed terms and conditions.

Small IPPs: Small IPP generators, the threshold for which will be made uniform under the New Legal and Regulatory Framework. All technologies are included here, not simply renewable based technologies. Where an RPS is trading in the regional market, it will be governed and regulated by the New Legal and Regulatory Framework. Where it is only trading in the domestic market, it will be regulated according to the domestic law of the Member State.

State Owned Utility (SOU): The power sector in each SADC country is dominated by a single State Owned Utility (SOU) that is responsible for generation, transmission, and, in many cases, also distribution services. Under existing frameworks, it is also responsible for System Operation and Market Operation and for trading through SAPP. Under the New Legal and Regulatory Framework, the SOU will conclude bi-lateral wholesale power supply agreements for a significant portion of the output generated by IPPs. All medium and large IPPs situated in the country of the SOU will be required to sell a portion of their output to that SOU. That portion will be harmonized for all Member States under the New Legal and Regulatory Framework.

Traders: A Trader is licensed by the regulator to buy and sell electricity to all buyers except Tariff Customers. Under the New Legal and Regulatory Framework Traders will be able to buy and sell electricity on domestic and foreign markets, but will need a license to operate in each country.

Wholesale Power Company: This entity can, under the proposed Market Model, buy and sell power from an SOU, from any size IPP, and from any other Wholesale Power Company. Rules related to the functioning of a Wholesale Power Company operating in the regional market as well as regulatory oversight will be established in the New Legal and Regulatory Framework.

2.4 Market Service Providers

Market Clearing House (MCH)**:** The MCH will ensure that traders have enough collateral to protect the national or regional market from a default. Having established collateral adequacy, the MCH will instruct the MO that it can proceed to match bids and offers (i.e. determine a strike price), or that one Market Participant can purchase from another based on a proposed level of transacted energy at a negotiated price. Wholesale transactions (bids and offers) in electricity (both capacity and energy) will typically be cleared by the MCH, which is a special-purpose independent entity with exclusive obligations to carry out this function. The MCH may be an existing financial institution, such as is currently employed by SAPP. Rules related to the functioning and processes of the MCH as well as regulatory oversight will be established in the New Legal and Regulatory Framework. It is anticipated that there will be an MCH in each Member State, one or several of which could also be used to facilitate regional trade.

Market Operator (MO): The MO manages the balancing market and ensures that energy purchase and sale quantities contracted for under bilateral contracts are balanced, by ensuring that balanced energy is available. The MO differs from the MCH in that the MO balances the market and sends the market clearing data to the MCH for settlement. Rules related to the functioning and processes of the MO as well as regulatory oversight of the entity will be established in the New Legal and Regulatory Framework. It is anticipated that there will be an MO in each Member State.

Southern Africa Power Pool (SAPP): SAPP will continue to operate as the regional power exchange, and will see its trading volumes grow. SAPP may also act as a regional MO. Any Market Participant that receives a license to trade on SAPP will be entitled to do so. In addition to exchange trading, other cross-border trades may be executed here, including bi-laterals and Over the Counter (OTCs) trades. SAPP will be governed and regulated pursuant to the New Legal and Regulatory Framework.

Transmission Licensee: The Transmission Licensee owns the assets of the transmission system and is responsible for its physical operation, including maintaining and expanding the system as necessary to meet forecasts through long-term development and investment. Under the Market and Investment Framework, Transmission Licensees will be subject to the New Legal and Regulatory Framework where their activities have a regional dimension. They will also be subject to the domestic legal and regulatory regime for matters that are strictly local in nature.

Transmission System Operator (TSO): The TSO manages the security of the power system in real time and coordinates the supply of and demand for electricity in a way that avoids frequency fluctuations and supply interruptions. It also conducts planning to ensure that supply can meet demand and system security can be maintained in the future (short-, medium- and long-term). A discussion of system security is found in Annex 5 of this Report. Rules applicable to each Member State's TSO will be harmonized in the New Legal and Regulatory Framework. The TSO could also play the role of Market Operator. As with the MCH and MO, it is anticipated that there will be a TSO in each Member State. Regional TSOs are also possible.

2.5 Other Definitions

Financing Framework: Availability and affordability of financing for IPPs will depend on the extent to which investors and lenders believe the revenues anticipated to be generated by the project are secure. The Financing Framework will therefore incorporate mechanisms that seek to provide/enhance this assurance.

Institutional Framework: The policy roles, functions, responsibilities, and procedures of each of the primary government and energy sector institutions, such as regulators and utilities that have a role to play in enabling and implementing the Market and Investment Framework.

New Legal and Regulatory Framework: The legal and regulatory supports (including contracts and other agreements) that are required in each Member State to enable the Member State regulator to implement the Proposed Market Model.

Off Grid Systems: These are stand-alone generating and distribution systems that are not connected to the national transmission infrastructure. Typically they will be small in size, incorporating one or two generating units, and serve solely a local load. These systems will not be subject to the New Legal and Regulatory Framework unless they involve cross-border activities.

Operating Framework: A set of technical documents and contracts intended to ensure the safe, secure, and reliable operation of the regional grid, and provide Market Participants and Market Service providers with clear, transparent, and predictable operational rules to support regional power trading activity.

Operating Guidelines: In 2013, SAPP issued a revised edition of its Operating Guidelines to ensure that all its Operating Members (i.e. license holders) operate the interconnected Southern African electric power network safely, efficiently, and effectively, providing instruction on how to address problems by isolating certain sections of the synchronized system and resynchronizing. All interconnected utilities in SAPP must comply with the requirements set out in the Operating Guidelines, which are also intended to provide a basis for more detailed documents governing the operation of individual networks.

Regional Power Trade: Power trade between SADC Member States takes one of three forms. It is either bilateral between neighbors, bilateral via transit countries, or cleared on the SAPP exchange. 'Regional power trade' encompasses all of these types of trade throughout this document.

3. BARRIERS PREVENTING THE DEVELOPMENT OF REGIONAL PROJECTS

There are numerous barriers that constrain power sector investment and regional power trade within SADC Member States. Many of these are well documented, and have also been communicated to us by SADC lenders, investors, regulators, and utilities. Given so much has already been written on the challenges the sector is facing, below we provide no more than a limited discussion of the most significant legal and regulatory, operational or technical, financial, and institutional issues causing concern among private sector participants.

3.1 Legal and Regulatory Issues

Regulatory independence, licensing, tariff setting, network access, service quality, transparency, and stakeholder participation have all been cited as barriers to increased private investment and regional trade in SADC.

3.1.1 Regulatory Independence

Regulatory independence[13] thrives where it is supported by political will and a sound legal framework. However, even where the legal framework is perfectly drawn, in the absence of a strong rule of law, independence is extremely difficult to sustain. In the absence of optimal conditions, independence requires regulators to balance legal obligations with political realities. Regulatory independence is comprised of three principal elements: financial independence, political independence, and independence from industry capture.

Financial Independence: Some regulators in the SADC region are financially independent and can therefore operate autonomously from their sector ministries. Others are fully dependent on the government budget for their financial resources. Most regulators find themselves somewhere in between. Some are financed under a line item in the government's budget. Others set their budgets and raise their operating funds through license fees or levies on regulated suppliers. Most take a middle ground, collecting fees and/or levies but turning them directly over to the national budget. In turn, they are funded from the treasury according to a budget approved by the minister responsible or by the minister of finance.

Political Independence: Independent regulation relies heavily on political will. To some extent, political interference is a fact of life for economic regulators. They are particularly susceptible to interference where legal frameworks fail to separate regulatory matters from government policy matters, and where the rule of law is weak. The key to avoiding political capture is to legally establish the relationship between political and regulatory bodies. The government should be responsible for policy development while the economic regulator's activities should focus on monopoly service issues including market entry (licensing), prices (tariffs), protecting the public from the abuse of monopoly power, and service quality. In conducting its regulatory tasks the economic regulator should also concentrate on implementing government policies on issues including expanding the use of renewables and protecting the environment.

[13] Because regulatory bodies are creations of, and in some way answerable to government, regulatory independence is never absolute.

Independence from Industrial Capture: In many southern African countries where SOUs continue to dominate, regulatory capture by industry is common. In those countries, the key to ensuring industrial independence lies in the establishment of a legal framework that carefully defines regulatory jurisdiction and clearly distinguishes between the tasks of the regulator and the government.

3.1.2 Licensing

With the exception of the generation, transmission, and distribution functions, there is little uniformity in Member State legislation regarding electricity services licenses or licensing requirements. Although in most Member States regulators license utilities, sometimes those utilities receive their authorization to provide services from the ministry responsible for the sector. In some circumstances, SOUs, which have existed significantly longer than the regulators, have no formal license or authorization at all. With regard to system and market operations (TSO and MO functions) and trading, legislation, and regulatory practices vary considerably. Sometimes TSO and MO functions are carried out by the SOU. Elsewhere, those functions have been separated and licensed by the regulator. In some Member States, system operation has been further divided into the separate functions of TSO and Distribution System Operation (DSO).[14] Although these matters are normally addressed in sector legislation, sometimes they are also affected by administrative inertia.

3.1.3 Tariffs

At its meeting in Zambia in February 2008, the SADC Council of Ministers resolved that Member States should endeavor to reach cost reflective tariffs by 2013. While RERA's Publication on Electricity Tariffs & Selected Performance Indicators for the SADC Region 2012 and 2013 (2015) indicates progress is being made, only two[15] Member State report they have reached full cost reflectivity to date. Indeed, at the recent meeting of Energy Ministers in July 2015, the SADC Council urged SADC Member States that have not taken all the necessary steps to reach full cost reflectivity to do so by 2019.

As well as the general lack of cost reflectivity, in most Member States, tariffs remain bundled into a single rate for end users, rather than being separated into generation, transmission and distribution services. This is in contrast to best practice, whereby within markets that are not competitive, such as those within SADC, an economic regulator would be required to set individual tariffs for each component of the supply chain, reflecting the cost of service for each activity. Additionally, until deregulation[16] of electricity prices occurs, tariffs should be set by the regulator in a way that fully reflects the separate costs associated with various classes of electricity customers.

In most cases, best practice also requires that the regulator is authorized to adjust an applied for rate, provided that certain conditions are met such as protection of consumers from monopoly prices and sufficient return for the investor.

In some Member States, however, the legal framework limits the national regulator's power to set tariffs. In those circumstances, regulators only act in an advisory capacity to either the minister

[14] South Africa has TSO and DSO roles separated. However, both entities are housed within Eskom.
[15] Namibia and Tanzania
[16] Deregulation here is used to mean removing regulatory price setting for market principles

responsible or the cabinet of ministers. This can be described as legislatively authorized political capture. Even where the regulator's tariff setting powers are clearly set out in the legal framework, sometimes it is not politically feasible to exercise them.

Applicable legislation should in fact authorize the regulator to establish the tariff methodology it will employ in all circumstances. It should also supply tariff-setting criteria the regulator must rely upon. Procedurally, the legislation should authorize the regulator to determine applications and procedures it will use in response to a tariff application, as well.

To recap, the regulator should set tariffs in compliance with national energy policy, applicable legislation (electricity act, renewable energy act, etc.), and the Regulator's own rules and procedures.

The principles underlying a regulator's tariff methodology are normally found in the electricity act. Usually, it requires a regulatory decision based upon the principle of full cost recovery. Depending on the type of customer involved, the regulator's tariff methodology may include (depending on the type of customers):

- Seasonal tariffs;
- Peak load (day and night tariffs);
- Step tariffs (based on consumption volume);
- Long-term pre-set tariffs (including marginal tariffs); and
- Marginal tariffs (to take into account long-range marginal costs).

3.1.4 Network Access

The legal frameworks in some Member States forbid discrimination on matters such as network access and dispatch. However, either formally or informally, most Member States do grant priority access and dispatch rights to SOUs (i.e. themselves) and to domestic producers. Such domestic preferences can serve as a barrier to market entry. One of the principal pillars of economic regulation is that exercise of monopoly power should be curtailed and, where possible, competition should be promoted. Some economic regulators however, cede their competition-related powers to a separate administrative body, such as a Fair Competition Commission.[17] Others seek to deal with competition matters that fall within the sector on the basis that the sector law or the law establishing the regulator authorize it to deal with competition issues. Both in the developed and developing world, there is no set approach to the matter.

Although advanced grid codes exist in the SADC region, such as in South Africa, some Member States do not have a formal Grid Code.[18] Rather, separate technical and access rules cover the

[17] Many of the countries in the East African Community operate in this way.

[18] A Grid Code is a regulatory instrument approved by the regulator and developed in consultation with Market Participants and Market Service Providers that defines the technical and operational requirements for connecting to the interconnected power system. It addresses issues including grid administration, grid access, interconnection procedures, system operation, metering, tariffs, and information exchange. Its precise parameters will be defined in the

right to use the high voltage grid and the distribution network. In many instances, these rules were developed by the SOU in consultation with the minister responsible well before any economic regulator came into existence. In the absence of new sector legislation, some Grid Codes are not subject to the approval or even the input of the regulator. If there is any general rule on the matter, it is that regulatory approval of a Grid Code is a relatively new phenomenon and goes hand in hand with unbundling of sector service providers. The same is true with respect to Market Operation. Where legislation is old, Market Rules[19] are developed by the commercial operator (usually still operating within the Transmission Licensee) in consultation with the minister responsible. These are not subject to the oversight of the regulator. Under best practices and most modern legislation however, the economic regulator does approve Market Rules.

To summarize, under most modern legal frameworks, separation of market functions go hand-in-hand with independent regulation. If specific licensed activities have been identified in the legislation, and if the power to issue licenses has been vested in a sector regulator, it is probable that that regulator has also been vested with the power to approve Grid Codes and Market Rules.

3.1.5 Service Quality

The power to develop and apply quality of service standards (QoS) varies from one Member State regulator to another. In some countries, the power of the regulator to set QoS standards is provided by modern legislation that grants regulatory discretion to further develop the QoS regulatory principles through rules, licenses, and performance agreements. In others, the issue is often lightly and unevenly addressed. Additionally, many Member State regulators continue to struggle with the adoption of appropriate and effective Key Performance Indicators (KPIs) for network service providers and utilities.

3.1.6 Transparency and Stakeholder Participation

All Member State governments (and regulators) profess a commitment to transparency of process and stakeholder participation. Too often, however, regulatory actions do not match that commitment. This is true not merely in SADC countries, but worldwide. Oftentimes, a regulator's dedication to transparent processes and public participation are directly related to its independence. The more the regulator is seen as just another arm of the government however, the greater the likelihood that its procedures will reflect more of a top-down approach to communication and stakeholder participation. Some regulators within the SADC region work unceasingly to bring transparency to their regulatory processes. The power of the applicable sector law to influence transparency and stakeholder participation cannot be overstated. The same is true with respect to regulatory efforts to engage media and to foster public awareness of utility and regulatory practices.

New Legal and Regulatory Framework. Under the Market and Investment Framework the regulator will approve the Grid Code.

[19] Market Rules are the rules Market Participants must follow when participating in a Member State's electricity market. These rules must be accepted as a condition of being a Market Participant. Its precise parameters will be defined in the New Legal and Regulatory Framework. Under the Market and Investment Framework the regulator will approve the Market Rules.

3.1.7 Conclusions

The above-described general observations are supported by a RERA survey undertaken in 2008,[20] which made the following findings:

- Most countries have well intended policies, but they need to be reviewed and updated in line with best practices;
- In some countries, the regulator's capacity to implement policies is inadequate;
- Sector reforms are, in most cases, incomplete and need to be finalized in line with adopted policies;
- Tariffs are generally not cost reflective to sustain the industry, and do not provide appropriate signals for new investment and energy efficiency;
- It is difficult to reconcile regional and national plans and interests because countries have different policy priorities. Some place more emphasis on policies of self-sufficiency than on regional cooperation; and
- Country legal and regulatory frameworks are distinct and pose challenges to the establishment of a viable regional market.

These issues are addressed in the New Legal and Regulatory Framework.

3.2 Technical or Operational Barriers

In this section, we highlight a number of technical or operational barriers to PSP, including those related to planning, that either make it difficult for IPPs in Member States to trade power regionally, or present IPP investors with a high level of risk. These issues relate to transmission congestion management, dispatch and curtailment risk, rules for the drawing of inadvertent power, and planning, metering, and communications.

3.2.1 Transmission Congestion Management

Power trade between SADC Member States takes one of three forms. It is either bilateral between neighbors, bilateral via transit countries, or traded on SAPP's exchange. SAPP includes three synchronized control areas, which are managed by the dominant SOUs in South Africa (ESKOM), Zambia (ZESCO) and Zimbabwe (ZESA).

SAPP has developed mechanisms to facilitate the trade of power between Member State utilities, including allowing for the sharing of spinning reserves, which has improved system performance and led to lower reserve requirements across the region. In 2013, SAPP issued a revised edition of its Operating Guidelines, prepared by its Operating Sub-Committee and updating the previous 1996 version. The Operating Guidelines describe protocol and requirements in vital areas such as system control, system security, emergency operations, operations planning, and telecommunications, amongst other things, and are intended to ensure that all Electricity Supply Enterprises operate the interconnected Southern African electric power network safely, efficiently, and effectively. Electricity Supply Enterprises are defined as follows:

[20] http://pdf.usaid.gov/pdf_docs/pnadu388.pdf)

An entity which (i) operates a control center around the clock; (ii) owns or controls through other means, the operation of several generating units and regularly operates such units to meet a portion or all of its load obligations; or (iii) owns a transmission system already interconnected internationally with neighboring Electricity Supply Enterprise(s) or may be so interconnected sometime in the future. An Electricity Supply Enterprise is either a Power Utility, Independent Power Producer, Independent Transmission Company, and/ or a Service Provider.

All interconnected utilities in SAPP must comply with the requirements set out in the Operating Guidelines, which are also intended to provide a basis for more detailed documents governing the operation of individual networks. Indeed, the Operating Guidelines can be viewed as apex protocol that sits above national legislation (although not legally), the various components of which are at different stages of development in each Member State.

While SAPP must be commended for such progress, SADC cross border and regional trade remains generally limited to national power utilities that control their national power system, and own and operate their own power transmission infrastructure. And although the Operating Guidelines do relate to IPPs (and ITCs), they have been prepared first and foremost to ensure the SAPP system is operated safely, efficiently, and effectively, rather than as an attempt to create an operating environment that puts privately financed and owned power plants on a level footing with the generating fleets of SOUs.

They do not, for example, provide instruction on how to operate the SADC power system in a way that allows third party access to the interconnected SAPP grid. In the event of a deviation from schedule within the system, they also generally leave IPPs at the mercy of Control Area Operator resolutions and decision making. This situation can create concern for potential IPP investors because they fear they will not necessarily receive fair restitution in the event that they lose grid access, particularly since the poor state of some of the system's power infrastructure increases the likelihood of a system failure that a Control Area Operator may, perhaps quite rightly, define as an emergency situation.

If new commercial entities such as IPPs are to contribute a significant volume of electricity to the cross border and regional market, new rules that build on the platform already put in place by the Operating Guidelines will need to be established. These rules should allow for non-discriminatory access to cross border and regional power delivery infrastructure, as well as setting the minimum technical standards for such connection. Furthermore, IPPs, and indeed, all Market Participants, must have confidence that *all* Grid Users will adhere to such non-discriminatory rules, including, for example, during times of transmission congestion, and meet the required standards in a disciplined manner, whether they are IPPs, SOUs, or other licensed entities.

SAPP's Operating Sub-Committee is aware of the need for many of the required, additional rules, and fully expects some of them to be included within the Market Rules the SAPP Markets Sub-Committee is currently working on. Some can also be included in new national technical legislation, such as Grid Codes and Interconnection Agreements. Documents such as these can be written specifically to facilitate the addition to the electricity system of commercial power plants seeking to trade internationally, and can be prepared by RERA, in consultation with SAPP and its subcommittees, and rolled out for adoption in each Member State[21].

3.2.2 Dispatch & Curtailment Risk

Although South Africa is making attempts to establish an Independent System and Market Operator (ISMO), there are no Independent System Operators (ISO) within the SADC region. It is therefore the TSOs within the vertically integrated SOUs that are responsible for setting dispatch order and scheduling, and for unit loading of all dispatchable power plants, whether state owned, privately owned or leased. SOUs can also curtail generation, should they believe there is a need, for example, to alleviate unanticipated grid congestion or during minimum generation emergencies when load falls below expectations.

While direct contracts between SOUs and IPPs, and/or national dispatch and operations guidelines, may dictate the terms of an IPP's dispatch order and associated arrangements, the risk that an IPP will either not receive a dispatch order, or will be curtailed, exists. Under either a non-dispatch or curtailment scenario, the IPP may not be able to meet its contractual obligations, without at a minimum incurring considerable expense.

There are varying approaches to managing the cost of non-dispatch and curtailment. Generally, there are three options, with costs being born by the generator, the system operator, or shared between the two. SADC will need to decide on a suitable approach, make sure this approach is clearly communicated to all Market Participants, and, if, the approach requires additional funding, ensure the funds are available. The approach can also be incorporated into the Grid Code referenced above.

3.2.3 Inadvertent Power

Power flows do not necessarily follow the commercially agreed upon path, as they are entirely dependent on technical variables such as resistance and voltage. On any given day, a synchronized cross border grid, such as those within the SADC region, will therefore have a certain amount of inadvertent power interchange, as load exceeds generation, or as generation falls below what was scheduled. To remedy this 'normal' inadvertent energy, SADC operators perform 'inadvertent balancing' to account for differences. When one national power system or control area is "owed" energy from another due to inadvertent interchange, the difference is usually repaid in energy, not in cash. Under normal circumstances, system operators will "pay back" the accumulated inadvertent interchange energy megawatt-hour for megawatt hour, and, as per the Operating Guidelines, are required to do so during the same season and peak or off-peak period. However, differences in the value of the power at the time of the inadvertent flow are sometimes ignored. While this approach has been somewhat acceptable to SADC SOUs, it presents more of an issue for commercial plants whose economics can be particularly sensitive to short term variations in the market value of electricity.

Given the shortage of supply across the SADC region, and the poor state of much of the infrastructure, there is also a risk of the unsanctioned drawing of power, where current is drawn

[21] This "regional" Grid Code will not be applicable on a regional basis. Rather, it will be approved by each Member State regulator and implemented on a state-by-state basis. It can only be that way, as there is no legal mechanism for implementing regulation on a regional level.

from the system intentionally to meet an unmet need. In markets outside of the SADC region, such incidents have been known to reach hundreds of MW, with large financial and technical implications. As market principles for cross border energy trade are increasingly adopted and adhered to in SADC, the potential for deliberate draw poses a significant risk to commercial developers. Inadvertent draw also threatens system reliability and can be akin to losing a generating unit of equivalent, or larger, scale than the volume of the draw.

While SAPP's Operating Guidelines do allow for financial settlement of inadvertent flows, there is no specificity on a potential approach. Additionally, although Control Area Operators are required to report inadvertent balances to the SAPP Control Centre on a monthly basis, the sanctions for failure to do so are small compared to the potential market value of lost power. More work is needed to provide IPP investors with the confidence that they will not be left facing a hefty bill if they are unable to meet contractual requirements due to either inadvertent or unsanctioned draw.

The introduction of market arrangements that provide frequency, capacity regulation and operating reserve capabilities, as well as other ancillary services, would also help improve regional power system reliability, and improve the operating environment for IPPs.

3.2.4 Planning, Metering & Communications

While SAPP's Operating Guidelines provide a good basis upon which to build an integrated market, the need to more fully connect regional transmission and generation planning, and to monitor cross border and regional power flows, is imperative if a substantial number of sizeable IPPs are to enter the market.

The creation of SADC over twenty five years ago, and the subsequent establishment and growth of SAPP itself, have facilitated significant enhancements in the level of regional power sector planning. The SADC Energy Sector Master Plan provides firm and undisputable evidence of such regional collaboration, as do the power trades that take place on SAPP's Day Ahead Market (DAM).

The development of a broader based and more transparent planning process is a natural next step. A regional Integrated Resource Plan (IRP) would help, and would require using improved analytical tools, to identify a desired mix of resources for the power regional sector. This planning process should directly compare demand side resources, supply-side resources, and transmission resources in an integrated manner, considering a wide range of costs and benefits, including environmental costs. A Regional IRP could be prepared with a view to ensuring harmonization with the recently updated and comprehensive South African IRP, since South Africa is by far the largest buyer of power in the region, and will likely be involved in many of the envisaged larger scale IPP projects, as an off-taker or as a participant, or both.

While a regional IRP would be useful, there is also a need to improve planning between countries and control areas. Increasing transparency around the availability of transmission capacity would be useful, possibly including auctioning capacity into the market on a year or month ahead basis.

Moving from a market controlled almost entirely by SOUs to a more competitive environment where IPPs also play an important role has implications for metering and communications infrastructure. While SAPP's Operating Guidelines do require a minimum level of metering equipment, more is needed. For example, all Grid Connection Points (electrical point of connection where the assets of a Grid User are physically connected to the Transmission or Distribution Grid) should be equipped with appropriate metering equipment. This should not be the case solely for new IPPs, but all generating assets, including, for example, each SOU's existing fleet of plants, as well as load centers. Such meters are required to record power flows (e.g. plant output, load, import, export points), so they can be compared to schedules for evidence of deviation, which is useful in the case of identifying the cause of inadvertent flows, for example. Meter reading data such as this should be automatically communicated to a central data exchange, requiring significant investment in telecommunications infrastructure and meter data repository equipment. SAPP's Operating Guidelines already stipulate some basic requirements for metering infrastructure. More detail could be included in a Metering Code.

3.2.5 Conclusions

Some of the issues raised above have been described in previous studies, such as the need for a Regional IRP. Overall, while the SADC region and SAPP have made strong progress in supporting the evolution of a regional power market, more remains to be done to facilitate the introduction of a large number of IPPs. Areas of possible initial focus include:

- Design and adoption of an approach to transmission congestion management that allows for non-discriminatory third party access to the grid
- Design and adoption of an approach to failure to dispatch and curtailment that is acceptable to IPPs.
- Design and adoption of an approach to allow for financial settlement of inadvertent flows that reflect the market value of lost power.
- The introduction of market arrangements that provide frequency regulation and operating reserve capabilities, as well as other ancillary services.
- Investments in planning, metering, and telecommunications infrastructure to improve market operations and discipline, and encourage adherence to market rules.

These issues are addressed in the New Legal and Regulatory Framework and/or in the Operating Framework.

3.3 Financial Barriers

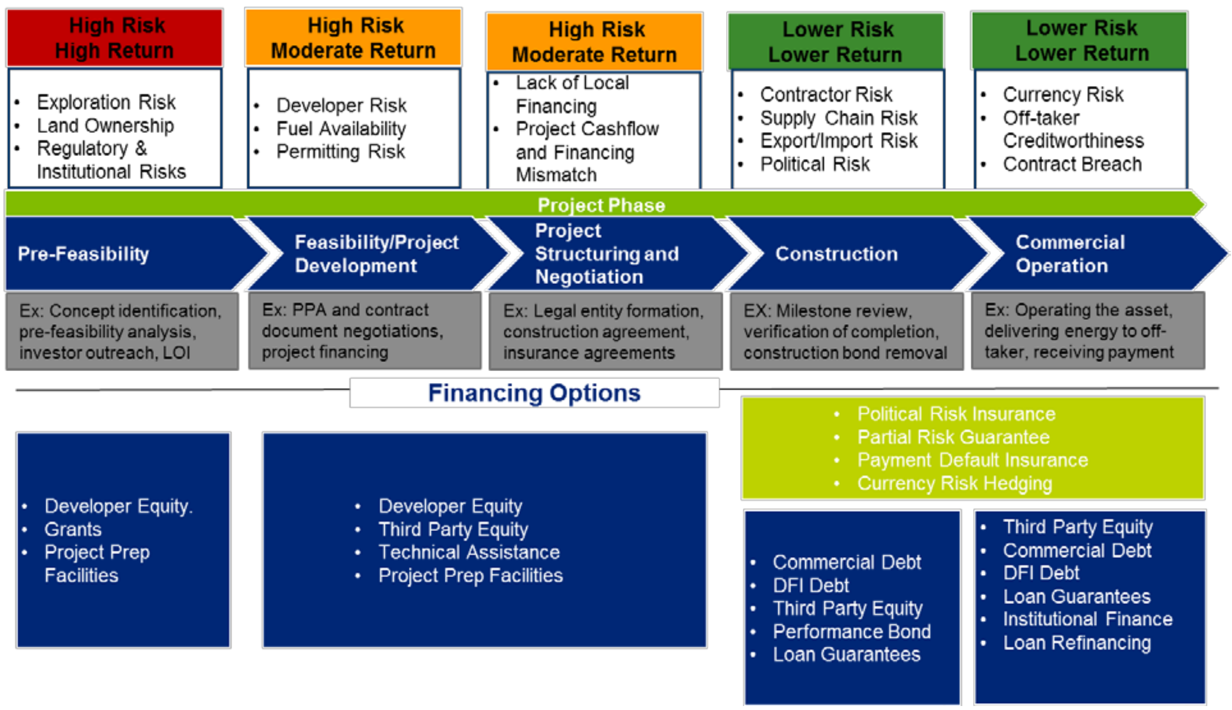
While each of the issues we have raised above result in a lack of funding being made available to project developers, these issues are generally related to broader enabling environment issues. In this next section, we now focus more specifically on project level financing, and the different funding needs at each stage of the project development cycle.

The availability of financing, and its affordability, for IPP projects within SADC will depend upon the extent to which financiers are confident that revenues derived from project investments are secure over the life of their project contracts, which can often stretch to 20 or 30 years. The lack of a legal and regulatory environment supportive of cross border trade and operational and technical barriers such as those described above undermine this confidence as they put payments, under a long term PPA for example, at risk. In the next section, we look at some of the financial risks that currently concern potential SADC power investors, and also briefly introduce some possible solutions and mitigation techniques. As a result of the risks created by factors such as these, the SADC energy sector has remained capital starved, in spite of a booming global IPP market.

Securing financing requires sponsors and host governments to identify and mitigate the risks inherent in energy project development, from a project's pre-feasibility stages through to commercial operation. Mitigating risk means using different approaches and mechanisms to increase developer and investor / lender confidence in the reliability of an IPP's long term revenue forecasts. This in turn is dependent on variables such as the ability of a tariff mechanism to account for changes in costs over the duration of the project contracts, the dependability and enforceability of the PPA, and the ability of the offtaker to pay its bills on time and in full. It is the intent of the Market and Investment Framework to help create mechanisms that address issues such as these, and thereby increase the probability that an IPP's long term revenue forecasts will prove correct.

Figure 1 below illustrates some of the major risks identified during each project development phase, and the types of financing available within each phase. Regional projects have higher risk profiles than country-level projects in certain respects, which will be discussed below. These higher risk profiles make it even more difficult for developers and their partners to secure financing until these risks are properly mitigated and addressed.

Figure 1: Risk Profiles and Financing Options for Regional IPP Projects



The top section of Figure 1 identifies the primary risks associated with each project development phase. During feasibility phases, very limited external financing is available within the region, with funding structures generally limited to equity, grants, and forms of technical assistance. Often, a project developer funds the technical analysis, site studies, fuel verification reports, and early-stage negotiations with governments and stakeholders that need to be completed. Assigning project preparation and feasibility analysis to a specific developer can shift costs from government agencies to the private sector, but reduces project transparency by limiting the opportunity to bring in a more qualified or attractive development team at a later stage. Many experienced developers only accept technical reports and data validations prepared by independent third parties, and will not rely on information prepared by a competitor. There are various project preparation facilities available to support feasibility-stage energy projects in the SAPP region, including the Development Bank of Southern Africa's (DBSA) Development Fund, and the New Economic Partnership for Africa's Development's (NEPAD) Project Preparation and Feasibility Studies Facility, administered through the African Development Bank (AfDB). Donors and development agencies may offer selected grant programs that can benefit early-stage projects. These grants often target a specific agency for support rather than an individual project, but can be structured to mitigate risks tied to priority SAPP regional projects.

As a project secures approvals and moves closer to financial close, sources of new equity investment from third parties may become more readily available. Private developers often bring in partners with prior development expertise or capabilities involving a specific fuel source, such as natural gas or hydropower. Targeted technical assistance and project preparation facilities may also provide financing support, where a competitive selection of project developers is still taking place. The United States Agency for International Development (USAID) supports regional or host governments to develop competitive tender processes and secure final approvals and contract negotiations that can migrate a priority energy project towards financial close. The US African Development Foundation (USADF) provides due diligence research and project development assistance for host governments during later feasibility stages on priority African energy projects.

3.3.1 Conclusions

Financing remains a major hurdle for IPP projects across SADC. This will only change if the risks that are currently undermining developer and investor / lender confidence in the reliability of a specific IPP's long term revenue forecasts are identified, and mitigated or removed. The Market and Investment's Financing Framework includes mechanisms that will provide, or increase the level of, such confidence.

3.4 Institutional Barriers

As has been shown by the scarcity of projects brought to financial closure and completion across SADC, market forces alone are currently insufficient to encourage project development. National and regional institutions must therefore take responsibility to lead, coordinate, supervise, and foster the processes required to encourage IPP investment. They must also be prepared to govern the market in an appropriate manner. SADC governments recognize this, and have taken steps to build up the institutions that will support regional projects and cross-border trade. Key institutions in this regard are RERA and SAPP whose current and anticipated roles and responsibilities are discussed throughout this report. Additionally, many Member State energy ministries are publically committed to pursue a regional strategy, as indicated by their mandating SAPP to identify and promote priority regional generation and transmission projects.

Challenges with regard to institutional set up persist, however. In the section below, we highlight some of the more significant challenges that are cause for concern for potential IPP investors in the SADC power markets. These issues relate to procurement, regulation and governance, and system and market operation. Regulation and governance is covered in detail within the New Legal and Regulatory Framework, which accounts for the primary component of the Market and Investment Framework. Below, we therefore highlight issues in the other categories.

3.4.1 Procurement

It is difficult to overstate the impact the tender process can have on the success or failure of an IPP program. An effective tender requires defining the procurement methodology and its sequencing, identifying and preparing key bidding documents, and assessing the procuring entity's ability to implement the chosen methodology. Information should be communicated to potential bidders evenly, producing and publicizing reasonable expectations for the project, and maintaining the schedule, structure, and integrity of the overall procurement process. Aspects to consider also include:

- Tender Prequalification Procedures. Establish pre-qualification procedures intended solely to identify qualified contractors capable of completing the project.
- Tender Bid Criteria. Outline bid evaluation criteria that intends to ensure that bids are comparable and consistent with project requirements.
- Tender Selection Criteria. Selection criteria must be clearly defined in advance in the tender documents, and should not be changed during the tender process.
- Tender Confidentiality. Governments must ensure that confidentiality is upheld during all phases of the tender during discussions, communications, and negotiations. Furthermore, a bidder's authorization must be obtained prior to any information regarding a bid being shared externally.

Currently many of the entities procuring IPPs, typically departments within ministries of energy, do not have a strong grasp of best practice procurement methodology. This results in failed tenders, or tenders that are awarded to unqualified developers, leading to failed projects.

3.4.2 System Operation

SADC power markets are operated by TSOs, which are typically one of the elements of the vertically integrated SOU. From an IPP investor's perspective, this poses a serious risk to its operations as there is no guarantee that the TSO will treat the IPP in exactly the same way that it treats its own generating fleet. Markets seeking to attract high amounts of private sector investment take a variety of approaches to institutional set up to mitigate this risk.

One such approach is to create a TSO as a separate company that owns and operates transmission assets. Under this approach, the TSO is independent of the SOU and has no more or less interest in the SOU's performance than it does in all of the other power plants or Grid Users. Under this model, some transmission asset ownership is allowed by other parties but it is the exception. With an unbundled and separate TSO as a part of the institutional set up, IPPs have more confidence that they will receive equal treatment to the SOU in terms of transmission access and service.

Another approach to resolving the potential conflict of interest created by a vertically integrated SOU is to create an ISO as a separate institution. Larger markets have also set up independent Regional System Operators (RSO). As its name suggests, an ISO/RSO, like the detached TSO described above, is unbundled from and has no direct ties to the SOU, or any of the power plants or other Grid Users in the system it operates. The ISO/RSO can be a non-profit generating entity whose board is made up of representatives from Market Participants. Its purpose is to foster competitive neutrality in wholesale electricity markets and reliability in power systems. An ISO carries out similar functions as a TSO; planning, operating, and dispatching, as well as providing open-access (i.e. non-discriminatory) grid service, usually for a single tariff, and purchasing balancing services. In order to carry out its function, the ISO requires functional control of the transmission system. ISOs and RSOs are regulated entities and must meet criteria that intend to promote grid reliability. While ISOs tend to own the main backbone power delivery system, other independent transmission companies can be allowed to pay for, own, and operate new lines, which is particularly the case in South America.

3.4.3 Market Operation

In some cases, the ISO also plays the role of MO. An MO operates and monitors open, fair, and competitive activity on whatever form of wholesale electricity market exists, including a power exchange, often managing the pricing and settlement system for the balancing market as well, in accordance with competitive market rules. In SADC's case, an MO would ensure adherence to SAPP's anticipated Market Rules.

An MCH is a further institution that can be introduced to give all Market Participants confidence in the management and operation of the power system, by acting as the legal counterparty to electricity trades and to ensure the financial performance of the trading parties. An MCH enables trading to take place in a safe, secure and reliable manner i.e. it enables buyers and sellers to trade. The MCH guarantees that the seller will receive payment – it assumes counterparty risk. The MCH provides this service for fees (subscriber + per trade + per delivery), and can therefore itself operate as a money making business, though usually any revenue should be limited to what is necessary to fund operations. In a competitive electricity market with high private participation, this service (i.e. financial settlement) is often also the responsibility of the MO. SAPP currently asks for full payment for power trades to be made in advance, which limits volume. The introduction of an MCH could boost market liquidity because it can use and introduce other mechanisms to insure against non-payment.

3.4.4 Conclusions

The current institutional set up within the SADC power market is not conducive to IPP investment. The dominance of SOUs and the ability they have to control the power system in a way that potentially works in their favor, at the expense of other Grid Users, poses high risk to investors. Key areas for consideration in this context include:

- How to resolve the conflict of interest currently presented by the fact that so many SOUs own and control generating plant and communal power delivery infrastructure.
- Whether to adopt a policy that results in the creation of a separate, unbundled TSO, or an ISO within each Member State and regionally.
- Whether to create an MO for each Member State, in addition to SAPP.
- Whether to establish a MCH for each Member State, and regionally.

Issues such as these are further addressed in the New Legal and Regulatory Framework and the Institutional Framework.

4. RECOMMENDED MARKET AND INVESTMENT FRAMEWORK FOR SOUTHERN AFRICA

Section 3 above detailed the risks and barriers constraining private power sector investment and regional power trade within SADC Member States. The recommended Market and Investment Framework is designed to mitigate or remove these risks. The Market and Investment Framework consists of a Proposed Market Model, the New Legal and Regulatory Framework, the Operating Framework, the Institutional Framework and the Financing Framework.

4.1 The Proposed Market Model

The Proposed Market Model is the center-piece of the Market and Investment Framework as it details and describes the varying and evolving power trading relationships between the principal Market Participants.

4.2 Identification of Principal Market Participants

Before describing the Proposed Market Model, it will be helpful to identify the Market Participants (defined in Section 1 of this Report) that will operate within the Model. In each Member State they are: the SOU, Small IPPs, Large and Medium IPPs, Off Grid Systems, Self-Producers. Wholesale Power Companies and Eligible Consumers. SAPP, as a Market Service Provider, is also referenced. Below, we present diagrams of the proposed trading relationships between these entities, and also describe the phased approach – we use six Stages but more or fewer are also possible - we recommend to the implementation of the trading scenarios included in the fully evolved regional power market. In these diagrams, we do not include any reference to a new institutional set up, such as including an unbundled TSO, an ISO/RSO, or an MO or MCH. Recommendations for steps required to arrive at possible inclusion of these institutions are covered later in the Report.

4.3 Description and Diagrams of the Proposed Market Model

Stage 1: Trading Arrangements

In Stage 1, a Small IPP in Country A and a Self-Producer may sell to the SOU[22] and to other entities such as Eligible Customers.[23] In Stage 1, the SOU is entitled to sell its supplemental electricity through SAPP. The trading arrangements under Stage 1 are shown in Figure 2.

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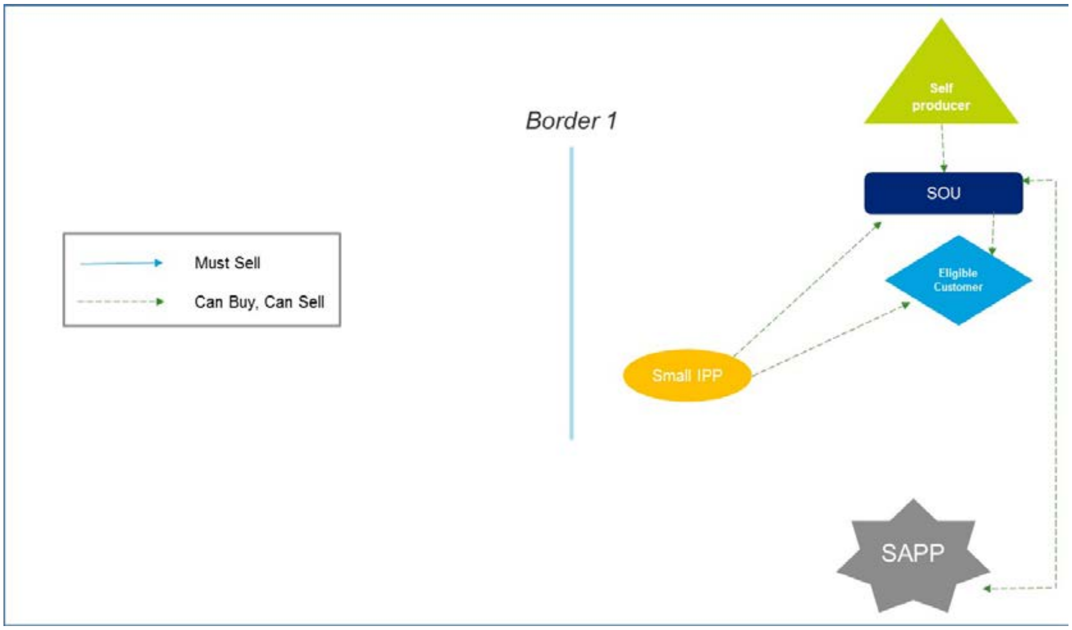
[22] Most countries give the SOU a right to buy a percentage (or all) of the energy produced by other entities such as Self-Producers or IPPs. The percentage will be harmonized under the New Legal and Regulatory Framework.

[23] If Eligible customers do not yet exist under Member State laws or regulatory instruments, the New Legal and Regulatory Framework will establish them.

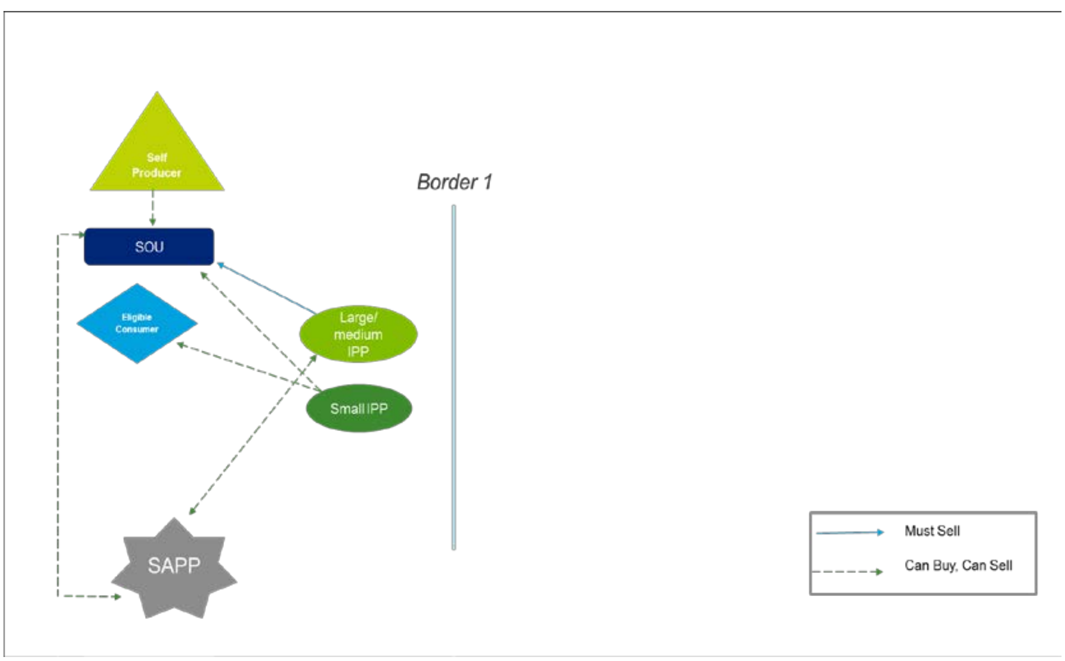
Figure 2: Stage 1 Trading Arrangements



Stage 2: Trading Arrangements

In Stage 2, Country A remains the only country involved. Now, a Large or Medium IPP (traditionally required to sell all of its output to the SOU) will be entitled to sell a portion of its power through SAPP. Small IPPs will also be entitled sell either to the SOU, to Eligible Customers, or to an Off Grid System. The trading arrangements under Stage 2 are shown in Figure 3.

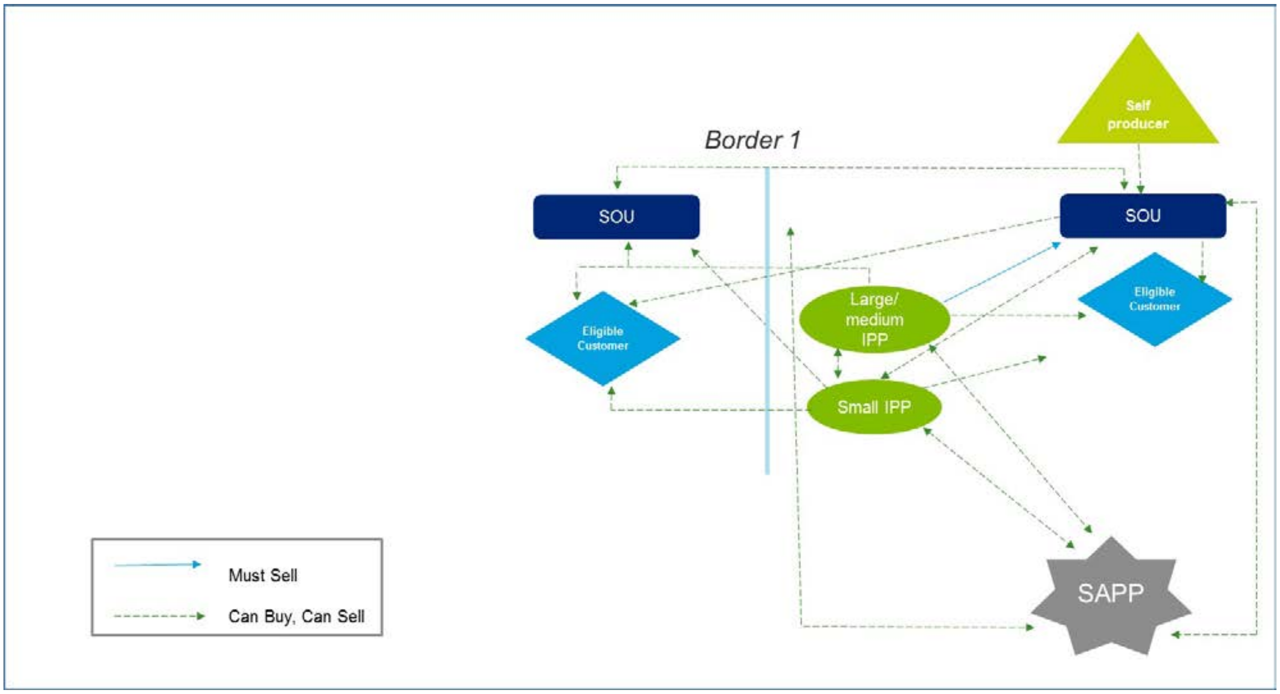
Figure 3: Stage 2 – Trading Arrangements



Stage 3: Trading Arrangements

In Stage 3, a second country, Country B, is added. Now, the Large and Medium IPPs in Country A, which, as we have seen, traditionally have a must sell obligation to the SOU in Country A, will also be entitled to sell their energy through SAPP in Country B. In addition, Large and Medium IPPs and Small IPPs in Country A will be entitled to sell to the SOU, or to Eligible Customers in Country B. The trading arrangements under Stage 2 are shown in Figure 4.

Figure 4: Stage 3 – Trading Arrangements

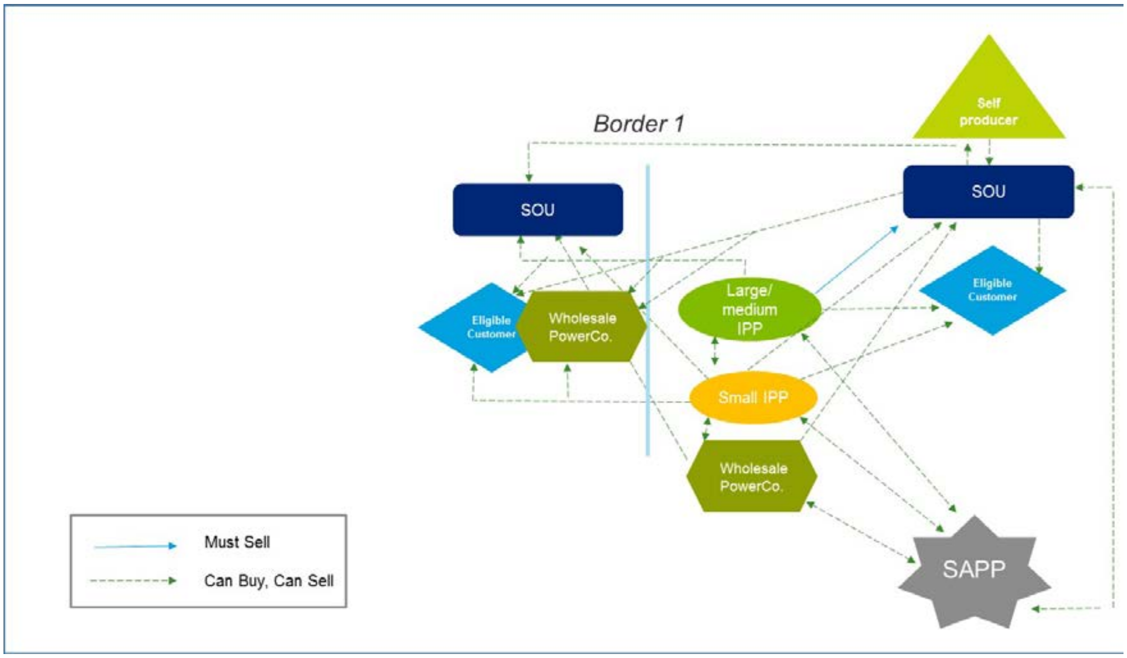


Stage 4: Trading Arrangements

Stage 4 involves only two Countries, A and B. All of the buy-sell relationships described in Stages 1-3 continue to apply. Now, however, a Wholesale Power Company is added to the Market Participants in both countries as shown in Figure 6. Although this Wholesaler is not authorized to generate, it may buy and sell under a trader license issued by the Member State regulator.[24] A Wholesaler in Country A has no must sell obligation to the SOU in that country. Under its license, it can trade (buy or sell) cross border either with the SOU in Country B, with Eligible Customers in Country B, or with a Wholesale Power Company in Country B. The same will be true for a Wholesaler in Country B seeking to trade with Market Participants in Country A. The addition of Wholesalers in both countries significantly raises the opportunity for trading and greatly increases competition in the market. The trading arrangements under Stage 4 are shown in Figure 5.

[24] If Trader licenses do not yet exist under Member State laws or regulations, the New Legal and Regulatory Framework will establish them.

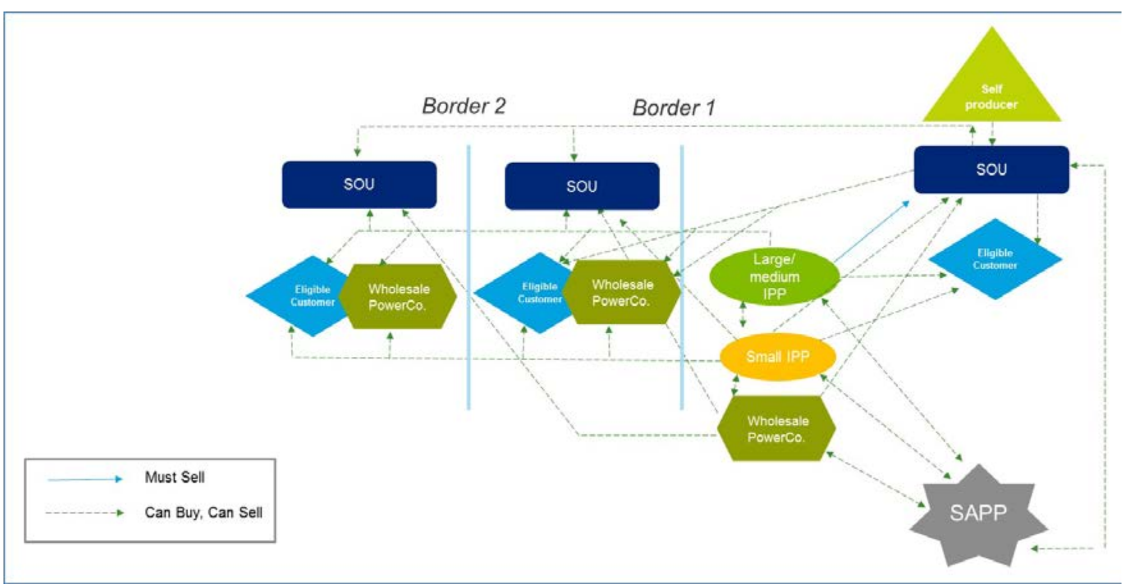
Figure 5: Stage 4 – Trading Arrangements



Stage 5: Trading Arrangements

In Stage 5, Country C (together with its SOU, its Wholesale Power Company and its Eligible Customers) is added to the model. Now there is a Wholesale Power Company in each of the three countries with no must sell obligation to the SOU in its home country. These wholesalers can sell to any Market Participant in any of the three countries. In Stage 5, only the Large and Medium IPPs have a must sell obligation to the SOUs in their countries of establishment. The trading arrangements under Stage 4 are shown in Figure 6.

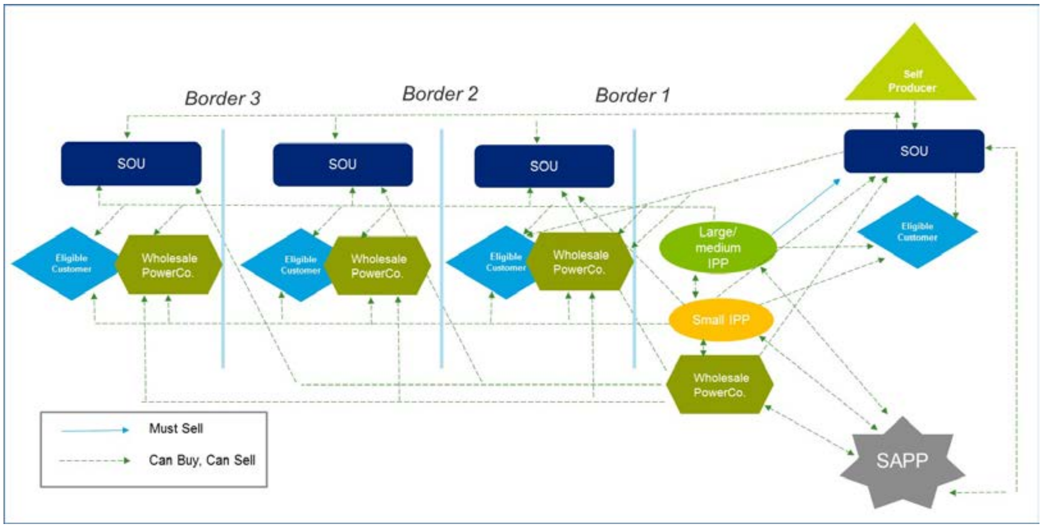
Figure 6: Stage 5: Trading Arrangements



Stage 6: Trading Arrangements

Stage 6 extends the structure described in Stage 5 to all contiguous SADC Member States as shown in Figure 7 below.

Figure 7: Stage 6 – Trading Arrangements



4.4 Legal and Regulatory Framework

The legal and regulatory framework supporting the proposed Market and Investment Framework has two parts. The first is the *existing legal and regulatory framework* in each Member State. The second is the *New Legal and Regulatory Framework* that will bring harmonized treatment in each Member State to all regional projects and all cross-border trades.

Currently, the existing legal and regulatory framework is developed and applied in each Member State. Generally speaking, the existing framework was not designed with regional trade in mind. Because the key to implementing regional projects is harmonized legal and regulatory treatment across Member States, the new framework's principal elements will be substantially the same in each Member State. This New Legal and Regulatory Framework will be overlaid on the Member State's existing framework and promulgated either by way of legislative amendment or sub-legislation. Much of the new framework will require only regulatory adjustments. Other elements may require significant amendments to existing legislation. RERA will develop the New Legal and Regulatory Framework in consultation with Member State regulators.

4.5 Existing Regulatory Framework

4.5.1 Framework Elements

By changing market structures and the regulatory paradigm, the New Legal and Regulatory Framework will establish a regional market that has the following characteristics:

- Effective regulation by the Member State regulator of all regional projects and of regional trading;
- Unbundled Market Participants including:
    - o Generators (including IPPs);

  - Traders (including import and export activities);
  - Consolidators; and
  - Eligible and Tariff Customers.
- Codes and Rules (specifically a Grid Code, possibly other codes also, and Market Rules);
- Technical and dispatch functions unbundled from the Transmission Licensees to create an independent TSO;
- The establishment of an independent MO in each Member State that is responsible to provide balancing and settlement services;
- Effective market monitoring and data reporting processes;
- A strengthened regional bilateral contracts market with service providers (including balancing and settlement services);
- Greater use of risk mitigation tools including financial derivatives, over-the-counter trading, and balancing; and
- A transparent, binding and harmonized cross-border dispute settlement mechanism.

4.5.2 Tasks of the Member State Regulator

The tasks of the Member State regulator under the New Legal and Regulatory Framework will include:

- Issuing licenses covering all services provided in regional projects;
- Approving codes and standards;
- Approving agreements;
- Setting rates and tariffs for all regional services;
- Setting standards for interconnection;
- Settling disputes;
- Ensuring the protection of the environment;
- Regulating planning and emergency preparedness;
- Issuing orders, enforcing compliance and applying sanctions pursuant to its powers under the New Legal and Regulatory Framework; and
- Monitoring the market for abuse, and recommend regional market design changes.

4.5.3 RERA's Role in the Development of the New Legal and Regulatory Framework

Currently, RERA's mandate includes assisting all SADC Member State regulators to improve their regulatory capacity and functions. For that reason, RERA is the logical institution to develop the common set of documents, rules, procedures, and methodologies that will comprise the New Legal and Regulatory Framework.

While developing the New Legal and Regulatory Framework, RERA's mandate will not change. Its human resources will, however, need to be strengthened to accomplish its tasks on a schedule. RERA will employ consultants and additional staff who will develop and present the New Legal and Regulatory Framework to the Member State regulators for adoption and implementation. The Member State Regulator, not RERA, will be the driving force in implementing the New Legal and

Regulatory Framework in each Member State. Once adopted, the New Legal and Regulatory Framework will be implemented monitored and enforced by the Member State regulator.

Substantial Compliance

It is impossible for each element of the New Legal and Regulatory Framework to be implemented in precisely the same way in each Member State. However, substantial[25] rather than strict compliance may be sufficient to satisfy investors that harmonization of the principal elements has been achieved.

Elements of the New Legal and Regulatory Framework

The Market and Investment Framework will comprise of the following characteristics:

- Strong control and market monitoring (including transparent accounts);
- Unbundling of existing market participants (and the establishment of new ones) to make competition transparent;
- Common Market Rules and a common Grid Code (and other related codes and procedures) to provide system security and protect against unfair practices;
- An independent TSO in each Member State (to avoid market abuse and increase transparency);
- An independent MO in each Member State to manage energy balancing and settlement services (to avoid market abuse and increase transparency);
- A bilateral contracts market to create a competitive export/import market; and
- A binding dispute settlement mechanism that is fair, transparent, and operates uniformly and across borders.

Taking into account the Framework Elements described above, RERA will develop and present to the Member State regulators an overview of what the Market and Investment Framework will require in each Member State, including:

- Institutions and roles;
- Market Structure;
- Regulatory instruments, including:
  - Licenses;
  - Codes;
  - Standards;
- Contracts and agreements, including:

[25] Substantial Compliance is compliance with the substantial or essential requirements of the New Legal and Regulatory Framework that satisfies the purposes and objectives of the framework even though its formal requirements are not complied with.

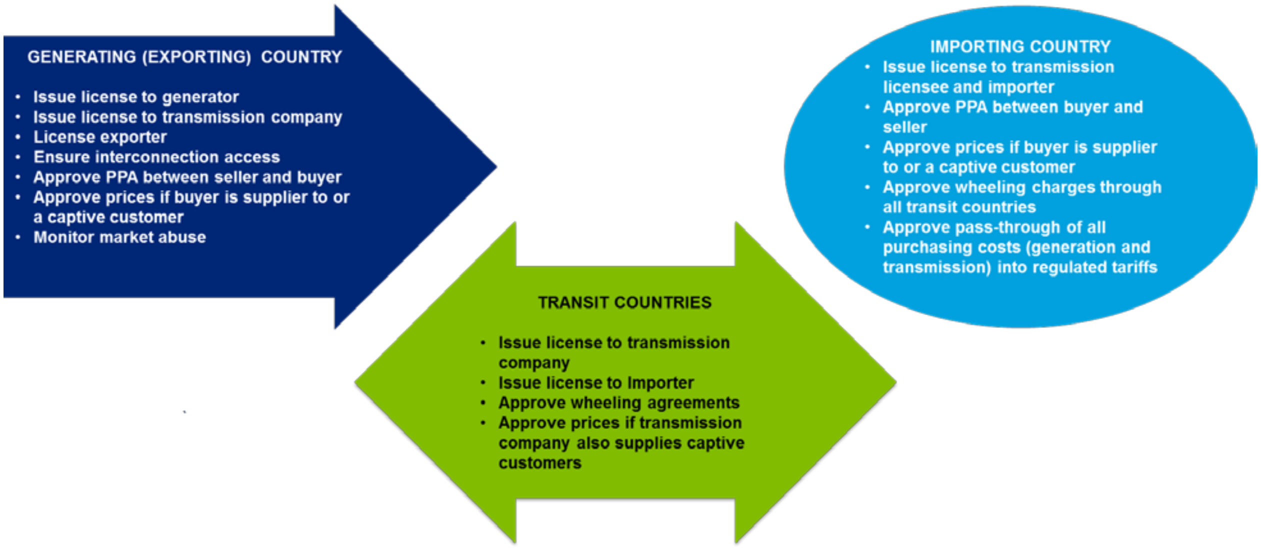
- PPAs;
  - Connection Agreements;
  - Interconnection Agreements;
  - Use of System Agreements;
- Methodologies (access, pricing);
- QoS Standards;
- Reporting and Monitoring Rules;
- Dispute settlement and appeals procedures;

On the basis of that list, RERA will develop a standard form New Legal and Regulatory Framework that it will present to the Member State regulators for consideration and adoption. The elements of the framework will be delivered incrementally in modules. Each module will include a discussion paper outlining the goal of the module, a discussion of the substantive provisions of each element of the module, and how it will contribute to the harmonization of regional projects and cross border trade. When the modules have been implemented at the Member State level, the Member State Regulator will have all of the tools it requires to carry out all of the tasks described in Figure 9.

Upon receipt of each module, the Member State regulator will enter into consultations with relevant Member State stakeholders as they discuss and adopt the modules elements. RERA will assist each Member State as may be required to conduct seminars, training, and workshops on the module. While it is not expected that the consultation process will result in perfect harmonization of the module elements, it is expected that substantial harmonization can be achieved.

During the period when Member State regulators are conducting stakeholder consultation, RERA will continue its work of developing and rolling out subsequent modules until the legal and regulatory framework has been fully delivered to the Member State regulators.'

Figure 8: Regulatory Tasks of Member State Regulators under the New Legal and Regulatory Framework



4.5.4 Dispute Settlement Issues

Introduction

Dispute settlement under the Market and Investment Framework will be managed by the Member State regulators. Because a regional project or cross-border trading will by definition involve a number of Member State regulators, harmonization of dispute procedures is of paramount importance. Without harmonization on this point, regulatory risk in regional projects will increase rather than decrease. This section will address three related aspects of a regulator's dispute settlement powers:

- The regulator's power to settle complaints and disputes;
- The regulator's enforcement powers, including tariff, police, and licensing powers; and
- Appellate procedures.

The Regulator's Power to Settle Complaints and Disputes

In the economic sphere, utility regulators usually spend most of their time addressing issues of market access, pricing, and service quality. Nevertheless, regulatory conflicts are not uncommon. Regulators and service providers will take different views on, among other matters, how to set tariffs, how to enforce obligations related to QoS, and what penalty is appropriate for a given infraction. Conflicts may also arise between regulated companies or between service providers and users, for example, on matters such as right of access to networks, or on interconnection or wheeling charges. These issues are multiplied as the number of countries and regulators increase.

Various regulatory governance models have been developed to resolve conflicts and reduce regulatory risks for private investors. Approaches typically range from placing detailed regulatory mechanisms in legal instruments, such as licenses and contracts (with possible appeals to the judiciary organs of the state) to establishing specialized bodies to take regulatory decisions on the basis of pre-established rules and processes. Case studies on dispute settlement matters are found in Annex 3 of this Report.

Implementing any one of these governance models can be challenging, particularly in developing countries. Existing legal institutions are sometimes unprepared to make technically complex decisions owing to the scarcity of specialized judges or the time-consuming procedures typical of ordinary courts. The regulatory institution model requires adequate institutional capacity as well as safeguards for autonomy in decision making, both of which are difficult to ensure in countries with new institutions and scarce human and financial resources.

A sector dispute may be a matter of extreme importance to the sector and to the financial soundness of the service providers concerned. In these situations, regulators often serve as a court of first instance to settle the matter. This is where the regulator's role as a quasi-judicial body is most visibly exercised. When settling disputes in a quasi-judicial way, regulators must make their decisions on the basis of natural law, taking into account the need for notice, opportunity to be heard, and opportunity to confront adverse witnesses, public access, and transparent decision-making. In order to ensure that natural law is respected many regulators have developed detailed substantive and procedural rules governing the settlement of sector disputes.

Enforcement Powers of the Regulator

Every day, regulators make findings of fact and issue rules, orders, and instructions. They also apply levies, fines, and penalties. Although each of these acts directly affects a regulated entity, none are self-executing. As a result, regulators need to be able to tie their actions to a constraint that cannot be ignored or avoided. In highly developed regulatory frameworks, a regulator's power to constrain and enforce compliance comes in a number of ways. First (and most commonly), the power comes through the regulator's authority to set and adjust tariffs. Second, it comes by way of the policing power of the state. Its power may also be found in its power (under law) to withdraw a regulated entity's right to deliver regulated services. Lastly, it may be found in the regulator's legislative powers to settle a complaint between a licensed service provider and a customer or a dispute between a licensee and a regulator or between two or more licensees. Because in developing countries some or all of these power mechanisms may be limited, either by legislation or political realities, we will examine each.

(a) Tariff Power

In developed regulatory regimes, regulators normally force compliance by way of a tariff order. Failure to comply with one or more of an order's provisions will be reflected in a subsequent tariff order. Compliance will be viewed favorably. Non-compliance will result in the utility being financially penalized in the next order. It is implicit that, for this to be effective, the regulator must have the power to set tariffs. Further, this tariff setting power must be unburdened by political or industrial influences. If the regulator's power over the tariff is limited, this will not be a foolproof way to enforce regulatory will. Care must be taken that the regulator's power as an economic regulator is clear and undiminished, either by legislation or by other administrative or governmental actions.

(b) Police Power

A regulator's power to invoke police powers is normally provided for in the basic legislation. Oftentimes, legislation will provide that an order of the regulator is enforceable as a judgment of the High Court. If that is the case, the only thing that the regulator needs to do to enforce a penalty or a fine or to issue an injunction to a regulated entity is to formally register it with the relevant judicial body. At that point the appropriate police authority will take measures to enforce it. Whereas the paragraph above raises issues of tariff power, this subsection raises rule of law issues. Where the judiciary and the police force are independent and operate on the basis of the law and enumerated powers, resort to police powers will be automatic. Where there are political or financial considerations, or where there is corruption, this enforcement approach may be beyond the power of the regulator to use effectively.

(c) Licensing Powers

A regulator's power over a licensee is similar to the power of a contractual party to monitor and enforce the terms of a contract. Most legislation, as well as virtually every license, gives the grantor the power to revoke or cancel a license where the licensee is found to be in breach of its license conditions. Where licensees and utilities are private companies, this is unremarkable and appears straightforward. However, where a regulated entity is an SOU, the regulator's power to revoke or cancel a license may be forever out of reach. As an alternative, under some legislation and regulations, a regulator is empowered, if not to revoke the license, at least to force the utility to make management changes. Again, where political or financial considerations enter into the regulator's decision, or where there is corruption, this too may be a largely unusable power.

Appellate Procedures

In well-established legal regimes, regulators hold enormous power. According to best practices, that power is governed by legal constraints that require transparency, respect for natural law, and stakeholder participation. Also under best practices, that power is not absolute. In order for it to be legitimate, it must be coupled with substantive legislative provisions stating that every decision of the regulator that affects the substantive rights of a regulated entity is subject to review by a separate administrative or judicial body.

Typically, a regulator makes a preliminary decision and there is an opportunity for an aggrieved party to appeal the regulator's decision to a court of law or to a specialized tribunal specializing in regulatory matters. In a number of countries in the SADC region, that body is called the Fair Competition Tribunal that is composed of former High Court judges. Some go further, allowing, in limited circumstances, an appeal from that body to the Court of Appeal.

The specific mechanisms and procedures for developing, reviewing, and appealing regulatory rules and decisions vary from system to system because they depend on historical and institutional peculiarities. Nevertheless, general principles of best regulatory practices such as inclusiveness, transparency, and citizen participation continue to apply.

Any consideration of the review and appeal processes for regulatory decisions should include a discussion about:

- The regulator's decision making procedures, generally;
- The roles of stakeholders and the government in the decision making process;
- The regulatory tools employed in the original determination; and
- The appeals mechanism.

Regulatory instruments include among others, laws and licenses. Sometimes substantive provisions are found in the relevant legislation. Other times an act may be broadly drafted and the specifics are supplied in the license or rules of the regulator. The choice of one or the other approach is generally based upon the regulator's legal tradition and the relative ease of changing existing instruments. For example, in most countries licenses are easier to change than legislation. If, in a particular country, regulation is politicized, regulatory stability may require that substantive rules be located in legislation rather than under a license. In some countries, regulatory decisions are subjected to ministry review. This also politicizes regulation. To avoid this, most legislation provides that only a court or an administrative tribunal is entitled to review a formal decision of the regulator. Other countries protect regulators by only allowing courts to overrule the regulator on legal or procedural grounds, not on the substantive grounds of the regulatory decision itself. Sometimes legal processes are used to delay regulatory decisions, so much so that they interfere with the performance of the entire sector. Where courts can be so abused, some countries avoid national judicial organs altogether in favor of alternative dispute resolution mechanisms, such as binding arbitration.

The choice of regulatory instruments may fundamentally affect the appeals process. For example, legislation often defines regulatory powers and procedures as well as the appeals process. These generally include a regulatory role and a role for a court or administrative body (or a mediator). On the other hand, rights under a contract (such as a PPA) may have a completely separate avenue of recourse, perhaps involving international arbitration. In that respect, different stakeholders may be treated in completely different ways.

Most countries provide for two levels of appeals from a regulator's decision. The first level of recourse is to the regulator itself, where an aggrieved party can seek reconsideration of a decision by the regulator. A second level is to an administrative tribunal or the nation's judicial system. Some systems provide yet a third level, where appeals from an appellate body of second instance can be lodged with an appeals court or even a constitutional court. Usually, by statute, the grounds for such an appeal are narrow indeed.

Standards for review of a regulator's decision also vary widely. Sometimes appellate bodies may only consider whether the regulator followed the law in making its decision. Under other legislation, some courts or administrative tribunals can also consider whether the regulator's decision was correct as to substance. This goes directly to the merits of the particular case and requires second-guessing the regulator's actions. For that reason, some courts will defer to the regulator's more specialized knowledge and only address procedural claims.

Owing to the costs and delays inherent in many legal systems, some regulators employ alternative dispute resolution processes such as:

- ***Negotiation:*** a voluntary process of discussion in the absence of third party facilitation;
- ***Mediation:*** where a third party or mediator facilitates the process and may suggest, but not impose, a resolution; and
- ***Arbitration:*** where the parties voluntarily place the matter in the hands of a third party or arbitrator, thereby committing to be bound by its decision. The arbiter is often a collegiate body of persons, with expertise in the matter being disputed.

Elements of each of these dispute settlement mechanisms may be found among SADC members.

Appropriate Dispute Settlement Mechanisms Under the New Legal and Regulatory Framework

For a number of reasons, developing an appropriately harmonized dispute settlement mechanism is more difficult than simply overlaying a new legal and regulatory framework. First, dispute settlement doesn't go so much to substance as it does to procedure. Procedure, by its nature, involves fundamental rights that are set in legislation or even in a constitution or other fundamental law. These go to the heart of state sovereignty, so may be largely off limits. How then can sub-legislation and practices be adjusted to substantially harmonize dispute settlement and appellate procedures?

The first step is to accept that there will be differences on the Member State level. We have already noted that where implementation is at the Member State level, perfect harmonization will not be possible. The second step is to require RERA, when developing the New Legal and Regulatory Framework, to include guidelines on dispute settlement that emphasize the following elements:

- Transparency of process;
- The need for timeliness;
- Respect for natural law (also known as due process), specifically the right to notice, hearing, and to confront adverse witnesses;
- The need (subject to exceptions) for all processes to be open to the public;
- Publication of decisions (with decision-maker rationale included); and
- The right to appeal that includes all of the elements identified above.

During the process of developing the New Legal and Regulatory framework, RERA should also work with each Member State Regulator to conduct a self-assessment that measures that regulator's regulatory practices against the above-identified criteria, and to develop and implement a plan to modify its practices in a way that fully respects them.

4.6 The New Legal, Regulatory and Contractual Framework

4.6.1 Harmonizing the Basic Regulatory Framework—Assessment of the Existing Framework

From a regulatory perspective, the defining feature of the SADC countries can be reduced to one word — diversity. Because these countries are distinguished by so many divergent characteristics, it will first be necessary to conduct a comprehensive base-line study of the frameworks that currently exist in each SADC country seeking to participate in the regional market.

The task of harmonizing legislation is not merely a cookie-cutter exercise – it is much greater than merely handing out templates of what Member State laws and practices should be. Although the work of incorporating the New Legal and Regulatory Framework will be undertaken by the Member State regulator, RERA should do all that it can to help the Member States to achieve that harmonization. The following are a list of subjects that could be addressed by the Member State Regulator when conducting these assessments. This list is illustrative only.

- The theft of electricity is a crime;
- Customers should be protected from monopolistic prices;
- Service providers are entitled to full cost recovery including:
    - the cost of fuel purchased at a reasonable price;

- operation and maintenance costs;
- the current and capital repair costs;
- payments of the principal amount and interest on loans taken as liquid assets;
- costs of licenses and other regulatory costs including fees; and
- reasonable and fair investment revenue sufficient to attract investments for sector rehabilitation and development;

- Economic efficiency within the electricity sector should be improved:
  - by setting short-run and long-run marginal costs; and
  - by forecasting dynamics of prices with regard for probable surpluses or deficits of electricity generation;
- The national energy policy should be taken into account, particularly as it relates (if it relates) to governmental priorities established in respect of the categories of electricity consumers;
- A service provider should be entitled to require a consumer to pay for services and to disconnect a customer for failure to meet its payment obligations;
- Tariffs should reflect different service fees for different categories of customers; and
- Service costs incurred by a licensee, importer, system commercial operator and supplier shall be covered from the amounts received from each category of customers in proportion to the costs of services rendered to that category.

The assessment surveys should specifically address the following topics:

- Regulatory power and authority;
- Dispute resolution mechanisms;
- Wholesale trading issues;
- System capacity reserve and energy balances;
- Electricity trading by power projects of various sizes;
- Tariffs and tariff methodologies; and
- Incumbent priorities.

A more extensive discussion of each of these elements is found in Annex 4 of this Report.

The assessment surveys described here are essential to the development and rolling out of the New Legal and Regulatory Framework. They can be considered a benchmarking exercise from which, all subsequent steps can properly be determined and implemented. Though the surveys will be developed by RERA, most of the work entailed in the due diligence exercise will be in the hands of the Member State regulator. In the furtherance of transparency and best regulatory practices, this exercise should be clearly documented and reported, not only to SADC, but also to the general public of the Member States.

4.6.2 Overlaying the New Legal and Regulatory Framework

The New Legal and Regulatory Framework will ensure that the following legal and regulatory powers are in place in each Member State:

- To implement Uniform System of Accounts;
- To issue at a minimum the following licenses:
    - TSO (Dispatch function);
    - MO (Commercial operation);
    - Market Clearing House function;
    - Market Participants (including IPPs and Traders);
    - Establishment of common licensing procedures;
    - Licensing of a TSO in each Member State;
- To approve performance indicators;
- To approve the Grid Code;
- To approve market rules;
- To monitor markets and deal with market abuse;
- To approve PPAs;
- To approve clearing, balancing and settlement rules;
- Reporting;
- Contracts (discussed below in part (iii));
- To approve Interconnection capacity allocation rules;
- To cooperate with regulators from other Member States on any identified matter to achieve regional markets;
- To cooperate with regulators from other Member States to:
    - Establish of a Regional Grid Code addressing:
        - Metering;
        - Communications;
        - IT system;
        - Protection;
        - Equipment;
    - Establish transmission tariff methodology;
    - Set regional transmission tariffs, charges for network access, and ancillary services;
    - Design a regional transmission code (and eventually a regional distribution code) including congestion management rules;
    - Establish regional market rules;
- To settle regional disputes; and
- To adopt regional dispute settlement procedures.

In summary, under the New Legal and Regulatory Framework, each Member State regulator will have full powers to carry out the following tasks:

- Issue, renew, and cancel licenses to market participants;
- Set tariffs, charges and fees related to transmission, distribution and supply;
- Monitor and enforce license terms;
- Approve a Grid Code developed by the TSO(s) in consultation with all sector participants (the grid code template is the product of regional harmonizing activities of RERA and the Member State sector participants);
- Approve the market rules (including the balancing market rules);
- Monitor, review and require amendments to (and enforce) codes and rules;
- Establish, approve and enforce performance standards for market participants;
- Approve regulated contracts to be concluded by market service providers;
- Establish and approve customer service standards;
- Establish, approve and monitor technical and safety standards;
- Settle unresolved complaints between licensees and customers; and
- Participate collaboratively with the Minister and RERA, on regional and international matters relating to electricity, particularly as they relate to the regional transmission of electricity.

4.7 Standardized Contracts

The elements of the New Legal and Regulatory Framework described above are indispensable to the implementation of the proposed Market Model. Equally indispensable is the suite of contracts and other agreements that are required to establish and operationalize regional trading. These agreements must accurately and fairly reflect the obligations and rights of Market Service Providers and Market Participants. They must also reflect appropriate risks and their representative liabilities. The regulator should prepare model contracts using plain English that ensures consistency across all models. Contracts governing the provision of services that should be subject to review and approval by the relevant regulator are briefly described below.

TSO-TSO Cross-Border

Each Member State's TSO (or the entity carrying out the system operator function until the TSO is established) will require interconnection agreements (covering connection and operational issues) with each operator of the transmission system in countries with which that Member State is interconnected.

MO-MO Cross-Border

The Market Operator (or the entity carrying out the commercial operator function until the MO is established) in the Member State will require agreements with the entities providing MO services in each country with which the Member State is interconnected.

MO-TSO, Domestic

The MO (or the entity carrying out the commercial operator function until the MO is established) in a Member State will also require an agreement with the TSO in that same Member State covering coordination of data transfer. The Member State regulator will approve this contract.

Balancing Responsible Party, Domestic

The Balancing Responsible Party (BRP) is a generating company in the Member State where energy flowing across a border from another country is received. It will be necessary for the selling party to conclude a contract with a BRP, pursuant to which the BRP agrees to generate electricity on short notice (normally from spinning reserve) to ensure that any interruption of the flow into the receiving country will be covered internally in the receiving country.

TSO-DSO, Domestic

The TSO and each DSO in a given Member State will conclude a contract covering the technical conditions of interconnection of the Transmission System with the relevant distribution system, and metering. The Member State regulator will approve this contract.

TSO-Regulated Generators, Domestic

The TSO in a given Member State will conclude a contract with each of the Regulated Generators in that Member State for the purchase of ancillary services and for the purchase of electricity to cover transmission system losses. The TSO will also conclude contracts with generators for the settlement and management of the real-time imbalances. The Member State regulator will approve this contract.

Transmission Companies-Generators

The transmission companies (owners of the Transmission System) will conclude a contract with each generator that is connected to the Transmission System covering the technical conditions for connection to the System, and metering. The Member State regulator will approve this contract.

Transmission Services

Transmission Services contracts are between the transmission companies and each Market Participant using the transmission system. These contracts cover the provision of electricity transport service. The Member State regulator will approve this contract.

Balancing Market Member

An agreement among generators to provide balancing services, under which each generator agrees to provide support services will also be concluded. The Member State regulator will approve this contract.

Market Clearing House Member

The MCH will require a standard agreement pursuant to which prospective members agree to the rules applicable to clearing and settlement. The Member State regulator will approve this contract.

4.8 Issues Related to the New Regulatory Framework

Challenges

On the political side, there are regional as well as national issues to be addressed. At the regional level the development and roll out of the New Legal and Regulatory Framework will require strong support and guidance from SADC. At the Member State level the Member State regulator and others in positions of authority will be required to clearly articulate the benefits of regional markets and of the changes necessary to make such markets workable. On the technical side, RERA and the Member State regulators will require significant guidance from SAPP.

The Role of SAPP

Under the proposed Market Model, SAPP and RERA's relationship will be close and mutually beneficial. RERA cannot do its work properly in the absence of technical guidance from SAPP and its members. On the other hand, an effectively functioning RERA, and effectively functioning Member State regulators will greatly expand SAPPs volume of trade. Greater volumes and numbers of trades without mishap will reduce perceived risks and increase confidence in the regional system. RERA will rely on SAPP's technical expertise, particularly during the development of the New Legal and Regulatory Framework, as codes, standards, practices, and procedures are developed and refined. As the modules are implemented on the Member State level, SAPP will itself become a regulated entity. If this entire process is managed correctly, SAPP can look forward to being regulated according to common rules and procedures that have been jointly developed and agreed.

The Role of SADC

The proposed Market Model cannot succeed without the active and guidance of SADC. SADC's energy policy should provide a policy basis for all substantive and procedural rules on regional trade. SADC should make clear policy statements in support of programs that will increase regional trade and a single market, including:

- The establishment of independent regulators with clear jurisdiction and legal authority, including:
  - The power to regulate market entry (licensing);
  - The power to set and publish tariffs;
  - The power to impose terms and conditions on system operators (TSO and DSO);
  - The obligation to monitor the management and allocation of interconnector capacity, including congestion management;
  - The obligation to settle disputes related to:
    - Contracts;
    - Refusal of access;
    - Refusal to purchase;
- The introduction of third party access, which guarantees access of producers, suppliers, and customers to the transmission and distribution grids;
- The removal of any obstacles that incumbent monopolies may have on the construction of new plants;
- The removal of technical and institutional barriers to cross-border exchange of electricity;

- Encouraging competition through the gradual unbundling of generation, transmission, and distribution and supply, beginning with functional unbundling and moving to legally mandated unbundling of incumbent, vertically integrated utilities;
- The dispatch function and the market operation function should be identified as licensed activities and separated from any other licensed activity and placed under the jurisdiction of the regulator (separate and independent TSO and MO functions);
- The integration of renewable energy;
- Dispatch of electricity on the basis of non-discrimination between incumbents and new entrants and on the principles of merit dispatch;
- The right of Member States to impose public service obligations relating to security, including security of supply, quality and price of supplies, and to environmental protection;
- The establishment of fair and transparent rules for cross-border exchanges;
- The harmonization of cross-border transmission charges and the allocation of available interconnection capacities; and
- The emergence of *legal entities* that act as technical and economic power pools.

Such statements will go a long way to support the work of RERA and the Member State Regulators to conduct appropriate due diligence prior to developing and rolling out the New Legal and Regulatory Framework.

The Role of Member States through their National Energy Policies

Member States should have an energy policy that drives legislative and institutional reform in a specific and time-bound way. The most important elements of the Energy Policy will include goals that are Member State specific. A given policy may include many of the following elements:

- Recognition of need to attract domestic and foreign investment to the electricity sector;
- Recognition of need to develop competition both in the Member States and across the region;
- Recognition of the need to facilitate cross-border trade in electricity for the benefit of the state and the SADC region;
- Recognition of need to improve the sector's economic sustainability by, *inter alia*, expanding the use of direct contracts between power generators and wholesale purchasers;
- Recognition of need to put in place of tariffs and tariff policies that ensure the long-term sustainability of service providers and protect consumers from monopolies and the abuse of monopoly power;
- Recognition of the goal of commercialization of the electricity sector through privatization;
- Recognition of need to improve of the electricity sector's economic viability both within the Member States and regionally;
- Recognition of need to simplify and harmonize license requirements and licensing procedures; and
- Recognition of need to promote renewables in power sector planning.

As stated above with respect to the SADC energy policies, the energy policies and pronouncements of the various Member States will also be critical to the successful work of RERA and the Member State Regulators. While the publication of national energy policies by Member States will not be part of the New Legal and Regulatory Framework, consultation with members of government who may be in the process of developing or revising a national energy policy may reap dividends when the time comes for the Member State regulator to implement or promulgate the elements of RERA's modules. Ideally, all of the elements of a SADC energy policy should be mirrored in a Member State's policy.

4.9 Operating Framework

4.3.1 Model Contracts, Codes and Regulations

In the immediate and near term, the Market and Investment Framework will build on the work already put in place by SAPP's Operating Guidelines, by making available to SADC Member States template contracts, codes, and technical documents related to topics such as Connection Procedures, Connection & Transmission Charging Methodologies, and Grid Code(s). While most of the countries in the SADC region are limited to a basic regulatory and operating framework, others, such as South Africa, have quite advanced market structures and enabling instrumental frameworks, including standardized contracts and regulator-approved grid codes and distribution codes. As well as ensuring consistency with SAPP's Operating Guidelines, the new Market and Investment Framework templates will integrate and build on existing documents, promoting technical harmonization to the extent possible. Examples of various contracts, codes and regulations are provided below.

Connection Procedures

Connection Procedures will establish basic principles and a set of minimum technical, design, and operational conditions for Grid Users (i.e. IPPs and SOU's generating plant) to connect to and use the grid. Their purpose will be to protect grid facilities and Grid Users' plant and apparatus, and to ensure safe, stable, and secure operation of the power system at the national level, much as SAPP's Operating Guidelines do on a regional basis.

Connection Procedures will also provide detail on the performance characteristics of the grid at the point where Grid Users will connect, to enable IPPs and other Grid Users to design their own facilities accordingly and to provide suitable control and protection schemes for them. There may be additional provisions in the individual Connection Agreements between the SOU/TSO and IPPs, defining, in greater detail and in more specific terms, the mutual obligations of each party.

The objectives of the Connection Procedures will be as follows:

- Provide a set of fair and non-discriminatory basic rules and standards for accessing and using the transmission grid which must be complied with by all IPPs (and all other Grid Users, including SOUs);
- Specify the normal transmission grid performance standards at the connection point;
- Specify the technical design and operational criteria at the Connection Point; and
- Clearly define the technical function, operational criteria, and ownership of the equipment connected to the Transmission Grid in accordance with the relevant Site Responsibility Schedule.

Connection & Transmission Charging Methodologies

These documents will set out the methodology to be used to charge IPPs for the cost incurred by the Grid for any new connections, or additions or increases in existing connections required to meet their needs. They will also set out the methodology for charging IPPs / Grid Users for use of the transmission system to deliver power, taking full account of ongoing work that SAPP and other bodies are already working on.

The Connection & Transmission Charging Methodologies describe and will cover:

- The general provisions of connection procedures;
- The treatment and principles of charging new connection to the grid;
- An approach to the charge calculation;
- Application and connection process description;
- Indicative pricing;
- Appeals; and,
- Necessary application forms.

The most important provisions with respect to the Connection & Transmission Charging Methodologies should be:

- All existing users of the Grid or perspective users should be treated equally.
- Each new connection should not cause any negative impact on the existing Users and new connections should not be influenced by negative effects of the existing Users.

Regional Grid Code

The Grid Code, as the primary technical document regulating the grid, provides procedures for both system planning and operational purposes and covers both normal and exceptional circumstances. It should be followed by all Market Participants. It is however a live working document. It will be, from time to time, subjected to changes and/or revisions as the power sector evolves.

The Grid Code will define the rules and regulations for various Market Participants for accessing and using the transmission grid.

The main objectives of the Grid Code will be to:

- Establish the obligations of the TSO/SOU, Transmission Companies, and grid users—Generators (including IPPs), directly-connected customers (such as Eligible Customers) and Other Users —for accessing and using the transmission grid;
- Define obligations, responsibilities, and accountabilities of all parties towards ensuring open, transparent, non-discriminatory, and economic access and use of the transmission grid while maintaining its safe, reliable, and efficient operation;
- Define minimum technical requirements for all participants;
- Set out the information exchange obligations of all participants.

The proposed Grid Code will not replace or substitute any existing dispatch rules, procedures and manuals. Rather, it will provide a general framework for their revision to ensure the safe, secure, and reliable operation of each national transmission grid as the Market and Investment Framework develops. It will work in conjunction with other legal and regulatory documents that may exist within SADC countries, such as national laws on electricity, market rules, regulatory guidelines issued by the regulatory authorities, and interconnection capacity auctioning and allocation procedures.

Summary Diagram of Proposed Operating Framework

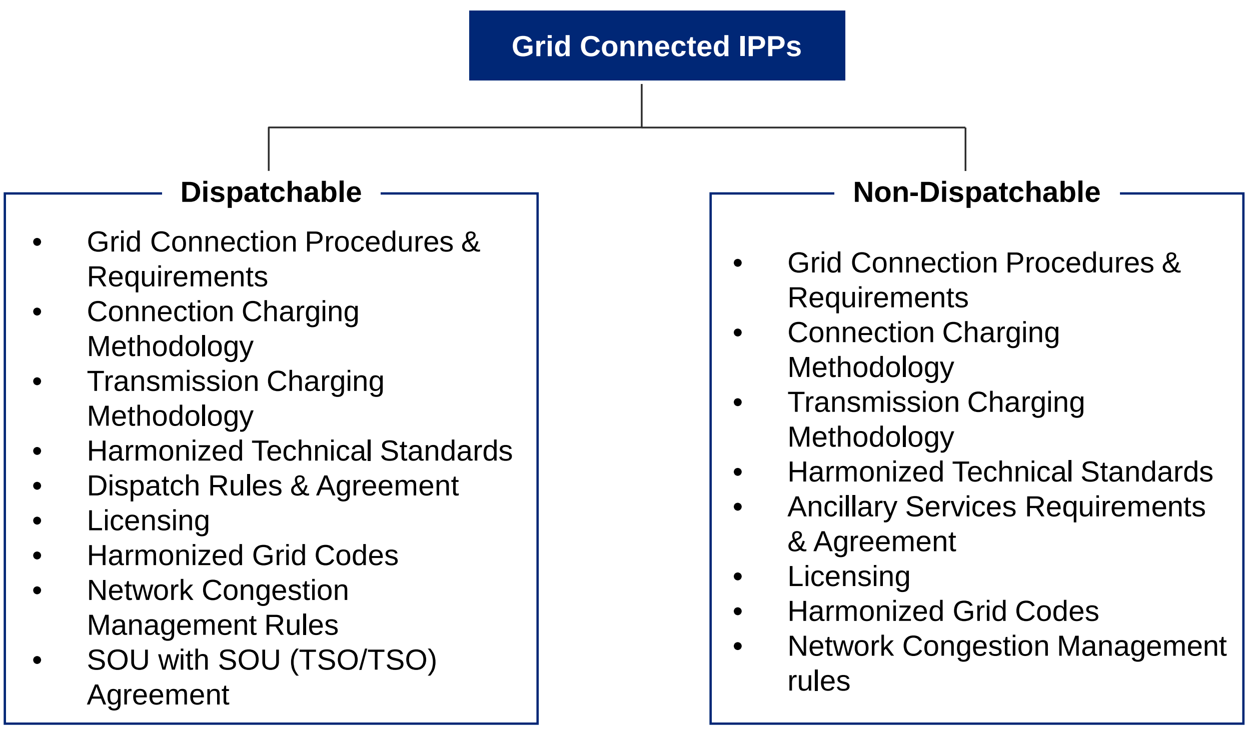
Figure 9 below summarizes the main components of the proposed Operating Framework. Model Contracts, Codes and Regulations are divided up into dispatchable and non-dispatchable technologies.

Dispatchable / Non-Dispatchable Generation

Dispatchable generation refers to sources of electricity that can be dispatched at the request of power grid operators; that is, generating plants that can be turned on or off, or can adjust their power output on demand. This can refer to time intervals of anywhere between a few seconds and 2-3 hours.

In contrast, non-dispatchable refers to everything else. This includes all nuclear power plants, most coal power plants, and run-of-river hydroelectric plants. It also includes intermittent energy sources such as wind, solar photovoltaics, and wave energy. These power sources cannot be relied upon to meet demand in a short amount of time, so they are non-dispatchable.

Figure 9: Proposed Operating Framework



4.3.2 Other Templates and Documents

The Operating Framework could also include other model contracts and regulations that intend to ensure that transparency and non-discrimination are guaranteed for private investors, including:

- Implementation agreements (typically granting land or rights);
- Power purchase agreements;
- Fuel supply agreements;
- Operation and maintenance agreements;
- Engineering Procurement and Construction (EPC) agreements;
- Licenses;
- Environmental and construction permits;
- Financing agreements;
- Inter-creditor agreements;
- Insurance agreements; and
- Government support agreements.

4.4 Financing Framework

In addition to the New Legal and Regulatory Framework and the Operating Framework discussed above, there is need to develop a robust Financing Framework in order to reduce or mitigate the risks that are keeping private investment out of regional projects. Below, we present some of the tenets of a regional Financing Framework.

4.4.1 Key Financing Components

Table 1 summarizes the risks and mitigation strategies available.

Table 1: IPP Financing Risks and Available Mitigation Program

Energy Project Finance: Common Risks to be Mitigated	Potential Financing Market Solutions
• **Offtaker Creditworthiness** – financial capability of the buyer of energy services (distributor, TSO, others) to pay for all energy delivered under the PPA.	• Sovereign guarantee (if available) • Payment default coverage • Partial Risk Guarantee • Intercept Payments • Escrow Account(s) • PPA Guarantee
• **Country Risk** – threat of loss from asset nationalization, currency inconvertibility, war, civil unrest, terrorism, or other forms of *force majeure*.	• Political risk insurance
• **Contractor Risk** – failure of the EPC contractor or project developer to perform	• Performance Bond

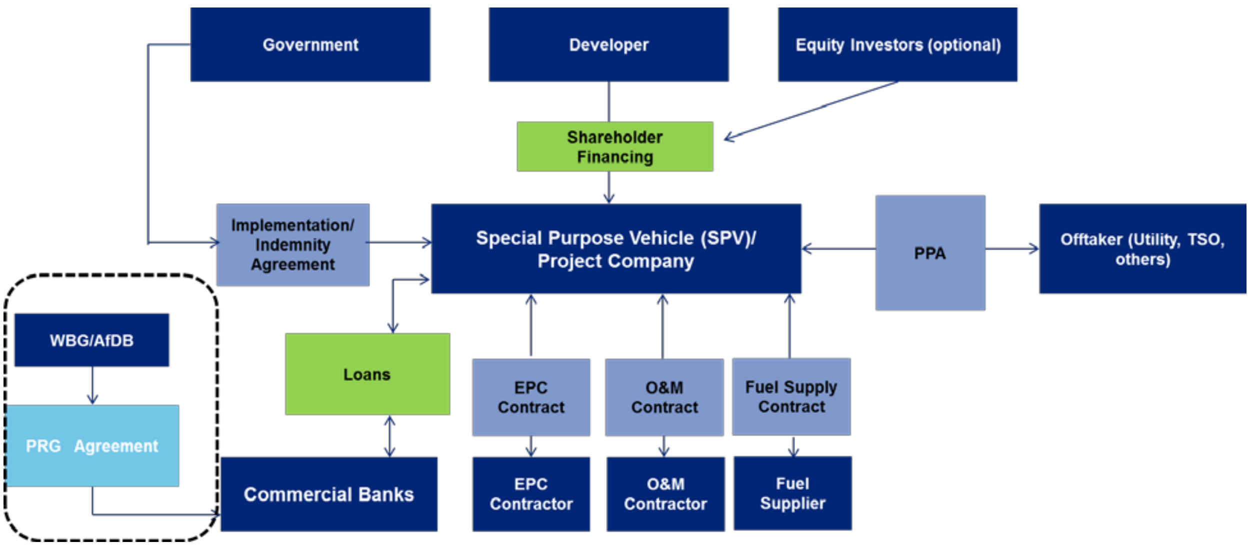
services on-time, within budget, or to agreed-upon standards.	
• **Currency Risk** – exchange rate fluctuation that devalues host country currencies used for debt service or payments for energy delivered, also establishment of currency controls and foreign exchange limits.	• (1) Currency swap • (2) Investor protection under PPA
• **Political Risk** – changes in relevant political frameworks, laws, tax or regulatory policies, tariff methodologies.	• Political risk insurance
• **Interest Rate Risk**– rapid increases in interest rates that cause debt service payments to increase.	• Fixed interest rate on long-term borrowing
• **Operating Risk** – capability of the generation facility operator to perform under the terms required by the PPA.	• Performance bond • Qualification hurdles during project tender process

Below, we discuss each of these potential financing solutions and their application to regional IPPs in the southern Africa region as they relate to the Market and Investment Framework.

- **Sovereign Guarantees –** Given some SADC countries lack formal credit ratings, a guarantee may not have a lot of value. However, we promote the use of sovereign guarantees where available and worthwhile. We also note that sovereign guarantees can be difficult to implement on multi-country IPPs, as each individual country may be asked to accept joint liability for payment performance of multiple offtakers procuring energy services from an IPP. Sovereign guarantees also restrict country-level IMF borrowing capacities, so are used sparingly in Africa. However, many IPPs will demand them.
- **Payment Default Coverage** - A limited number of private insurers have begun offering short-term payment default coverage for bankable IPPs in Africa. These include African Trade Insurance Agency (ATI), funded through the World Bank Group (WBG), which is based in Nairobi. ATI may provide short term guarantees (3 – 6 months) on offtaker payments under an agreed PPA, which creates additional comfort for financial partners in the creditworthiness of an IPP. Securing default coverage insurance is easier when experienced developers, DFIs, and other partners are engaged during project development stages. For regional IPPs in southern Africa, default coverage insurance is most likely to be available when a single offtaker with reasonable credit standing and repayment history will be procuring the majority of energy (75% or greater) from a planned IPP.
- **Partial Risk Guarantees (PRGs)** – PRGs are available through the WBG and AfDB, and cover private lenders against the risk of a government entity failing to perform its obligations with respect to an IPP. PRGs ensure payment in the case of default resulting from the nonperformance of contractual obligations undertaken by governments or their agencies in private sector projects. PRGs have been approved on African energy projects that provide short-term payment guarantees, similar to the payment default coverage discussed above. Most recently, this included an AfDB PRG for $184 million to support Nigeria's energy privatization program and to provide 3-month payment coverage for the national offtaker (the NBET) on PPA agreements with private generation companies in

Nigeria. PRGs can cover other risks relating to government performance including, changes in law, obstruction of an arbitration process, changes in tariff laws, and failure to issue licenses, approvals, and consents in a timely manner. Figure 10 below shows an IPP project structuring example that illustrates the protection offered by a PRG on a potential regional IPP project. The protection is usually afforded only to lenders, and not to equity investors.

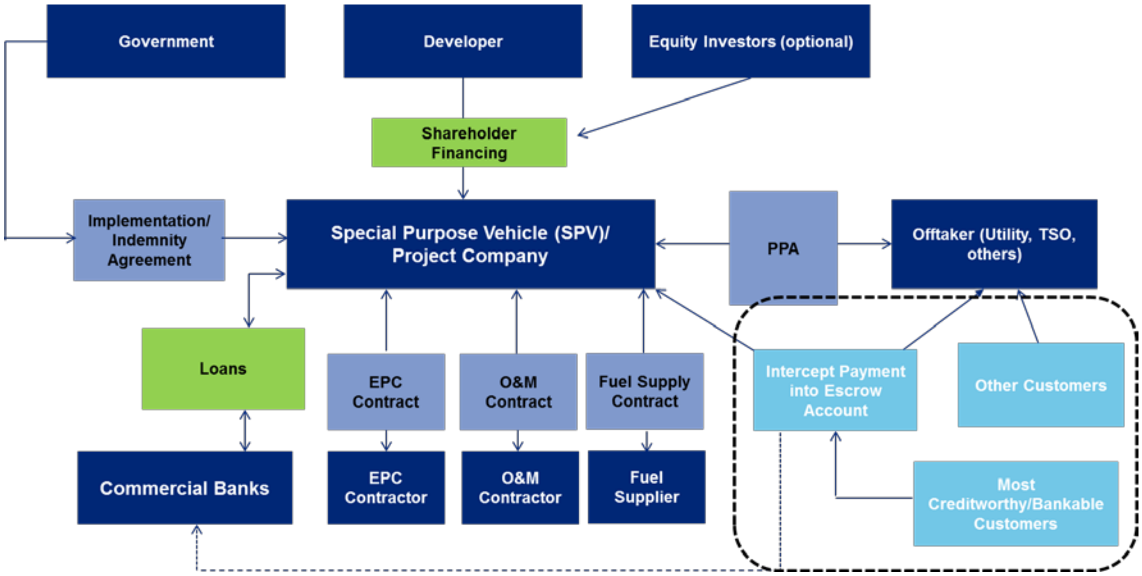
Figure 10: Partial Risk Guarantee Structure



PRGs typically cover risks such as political force majeure, changes in law, currency convertibility and a government's failure to fulfill its payment obligations relating to the PPA or other project contracts.

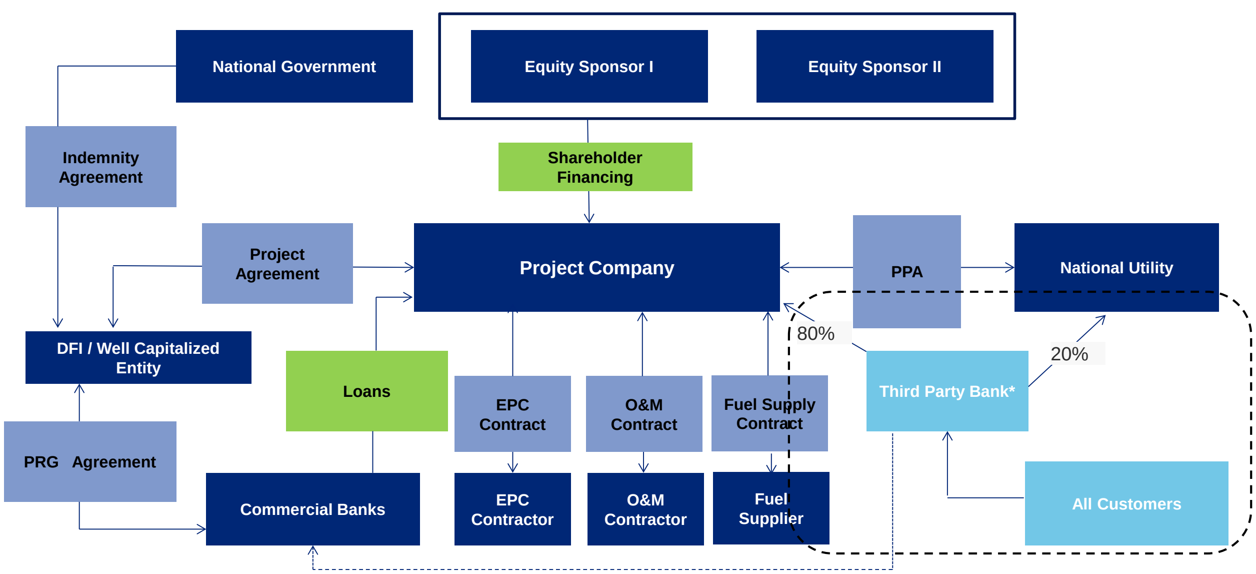
Intercept Payments - A further project structure we include in the Financing Framework is for certain creditworthy customers to make payments directly to a project SPV, or in certain cases to lenders, bypassing the offtaker with these payments. Intercept structures as shown in Figure 11, are most commonly used where larger industrial or commercial customers are expected to purchase a significant share of the energy to be generated by an IPP. Financing sources may decide that the end-customer is a better credit risk than an energy sector offtaker, and thereby require that partial or full payments for energy services be made through this structure. The logistics and administrative costs of intercept structures limit their application to IPPs involving one major or several significant customers. This structure does nevertheless present a viable alternative in southern Africa, given the creditworthiness of select large energy users who may procure electricity directly from a new IPP in the region.

Figure 11: Intercept Payment Structure



- **Direct Payment into Escrow Account(s) –** Similarly to the intercept payment structure described above, another approach include in the Financing Framework will be payments into an escrow account managed by a third party, including a lending bank. All customers deposit their bill payments into this account, with the utility receiving its share only after debt has been paid. Cahora Bassa in Mozambique, wherein the Government of Mozambique used private debt finance to fund its purchase of the hydro plant from Portugal, uses a project structure similar to this.

Figure 12: Customer Payment into Escrow Account



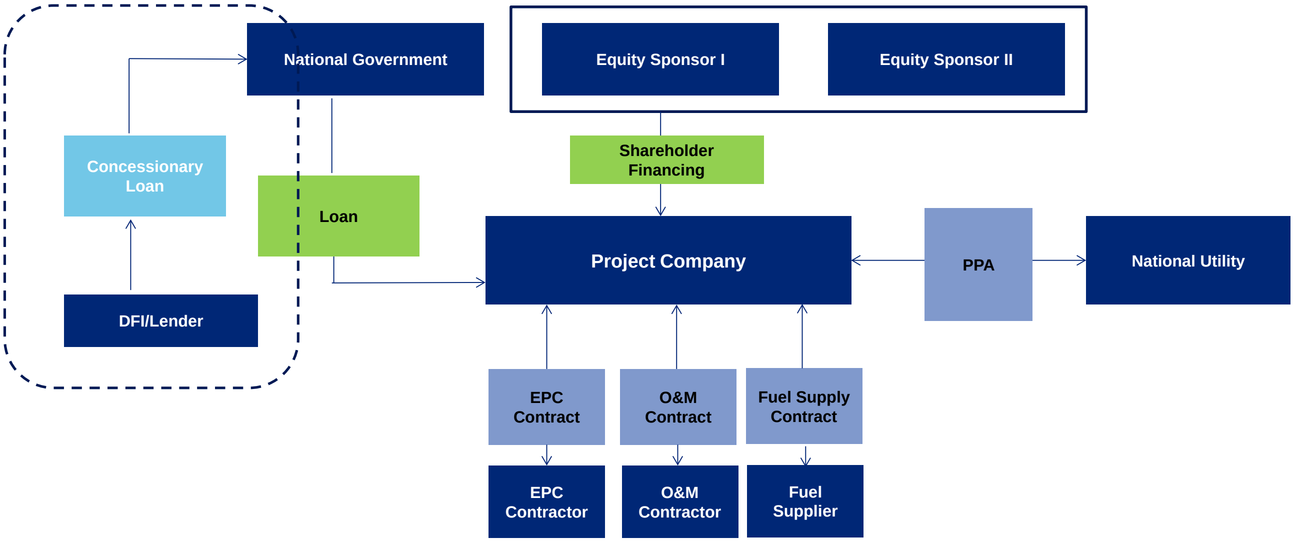
* *Payment can also be made directly into lending bank's account*

- **Political Risk Insurance** – is common protection sought by private investors and lenders, especially involving countries with limited experience developing IPPs. This product is offered by DFIs including the WBG's MIGA and OPIC, with participation from private insurance companies depending on the IPP project. Political insurance can protect against uncontrollable events that restrict an IPP's ability to meet its financial obligations, including war, sabotage, civil unrest, and other events referred to as *force majeure* in the PPA. These conditions are negotiated closely prior to the PPA signing. This insurance can also provide coverage against political or legislative changes that impair an IPP's repayment capacity, including changes to tax laws, currency inconvertibility, or new regulatory policies that materially harm project revenues. Political risk insurance is available to both equity investors and lenders on qualified projects.
- **Performance Bonds** - Also known as a contract bond, this is by an insurance company or a bank to guarantee satisfactory completion of a project by the EPC contractor or developer awarded the project. Governments will usually require a bid bond from private developers during the tender process. When the IPP project is awarded to a specific bidder or developer, a payment and performance bond will then be required as a security to the job completion. If the developer fails to complete the IPP project according to the specifications laid out in the PPA, financing partners are guaranteed compensation for any monetary loss up to the amount of the performance bond. Terms of the bond may include failure to complete the project on-time, significant cost overruns, or material defects that would all limit the IPPs ability to generate the revenue projected to repay loans (or investments). Commercial banks, DFIs, and host governments on southern African IPP projects may all require developers to post performance bonds at the time of finalizing a PPA and commencing with project construction.
- **Currency Swaps –** Experienced private developers typically require that payments for energy services under a PPA be made in hard currency or converted at the time of payment based on an agreed exchange rate format. To this extent, the offtaker rather than the developer bears the currency or exchange rate risk on a regional IPP project, since tariff customers pay for energy in local currency. When multiple local currencies are involved, especially inconvertible currencies, exchange rate risks are increased. Governments in the SAPP region should pay careful attention to currency exchange formulas in PPAs prior to agreeing on terms and conditions. Long-term currency swaps are available in limited cases where IPPs collect revenues in one currency and repay loans in another. Countries that have inflationary conditions or currencies subject to frequent devaluations can end up paying significantly higher costs for procured energy when payments must be converted to dollars, euros, or other global currencies based on current market exchange rates.

4.4.2 DFI On-Lending

A further option that can be explored is DFI on-lending, wherein a DFI such as World Bank or another development finance institution lends directly to SADC government which them lends on to a project. This scheme, which puts the repayment obligation on the government rather than the project, and therefore mitigates some of the political risk, is shown below.

Figure 13: DFI On-Lending



4.4.3 Bulk Energy Buyer

A further possible solution to the poor bankability of many of SADC's largest offtakers across SADC that has been referenced in past reports[26] is the creation of an independent, creditworthy bulk energy buyer, an approach that has been used elsewhere, such as in India and Nigeria. Such a bulk buyer could be capitalized using a variety of sources, including local governments, DFIs, and the private sector. The bulk buyer could enter into PPAs with IPPs, and have its own back to back agreements with SOUs and other less creditworthy off takers.

4.5 Institutional Framework

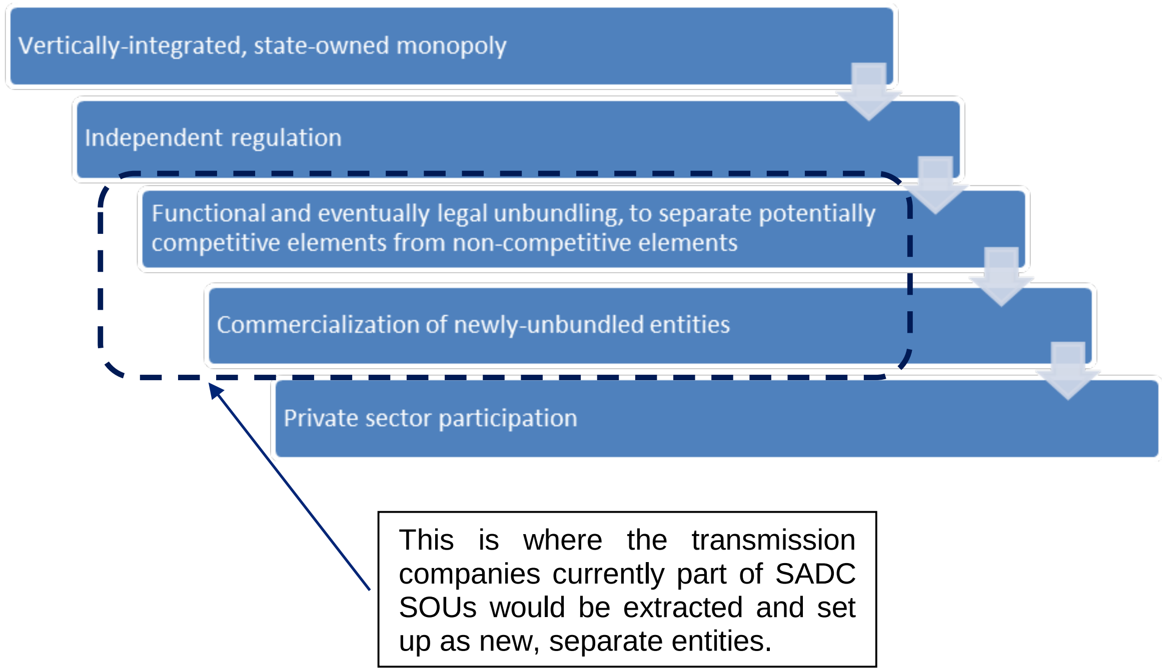
A robust institutional framework is required to support and facilitate the adoption of the Market and Investment Framework as discussed above. Below we detail some of the institutional changes required to support the successful implementation of the proposed Market and Investment Framework.

4.5.1 Separate Transmission from each SOU

As described above, the current institutional set up across SADC is not conducive to IPP activity, or to commercial cross border power trade. One of the main institutional challenges is that SOUs currently own and control almost all of the generating plant and power delivery infrastructure. The conflict of interest inherent within such a structure could be removed by unbundling the national transmission function in each SADC country into a separate entity, either a transmission company that retains state ownership but is entirely separated from the state's power plants, or an ISO. The introduction of a MO should also be considered. These are standard steps in the market unbundling process, as shown in Figure 14 below.

[26] E.g. A Study of Cross Border Financing Models for Regional Power Projects in the SADC Region (2009)

Figure 14: Common Steps in the Evolution of a Power Market



The implementation of the Market and Investment Framework will require some degree of institutional and enterprise restructuring. Indeed, the New Legal and Regulatory Framework calls for the creation of the following unbundled or new institutions: transmission companies, MO and MCH. These are significant steps and require strong policy guidance and commitment from government. They are, however, probably unavoidable, and each SADC country must decide when it wishes to begin this process. Below, we summarize what needs to be done.

4.5.2 Near-Term Unbundling Steps

In order to create an institutional framework that supports commercial IPPs, we recommend the following unbundling steps are taken in each SADC country as part of Market and Investment Framework implementation in the **near term**:

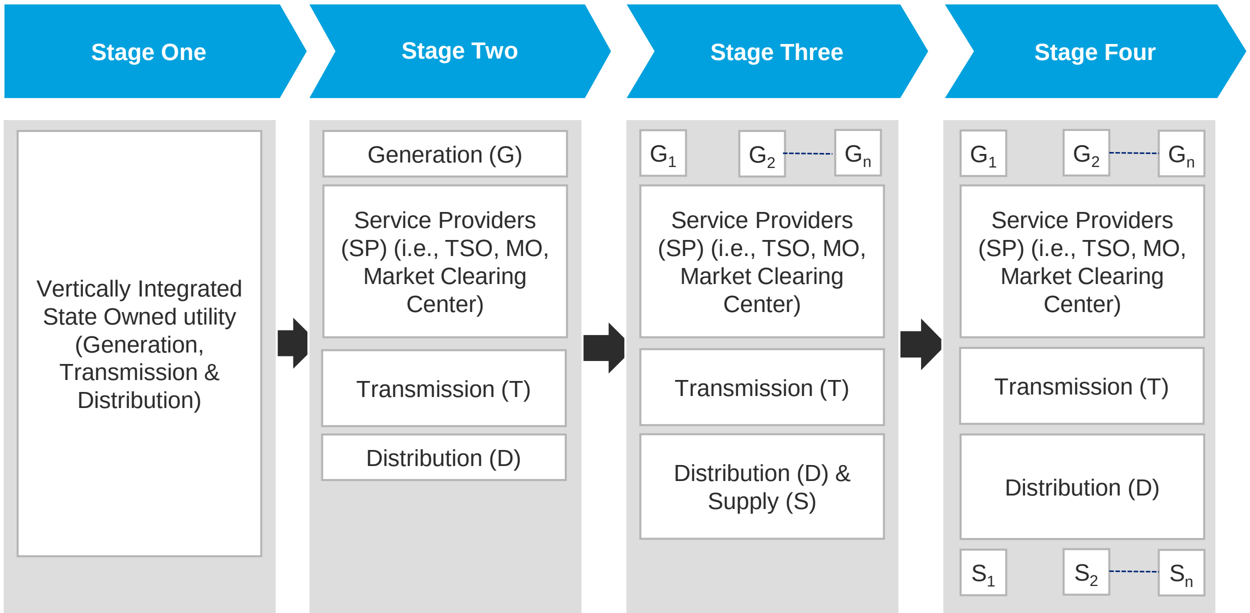
- Functionally & ***legally*** separating transmission from generation (and distribution)
- Making each function a separately-licensed, regulated activity
- Unbundling generation into separate and potentially competitive plants and units

In the **mid-term**, we also recommend the following steps:

- Privatizing unbundled generation plants and using funds either for infrastructure (T&D) development or for low rate financing of IPPs
- Separating retail activities from distribution (wires) activities
- Privatizing distribution & retail functions

These steps are depicted graphically in Figure 15 below:

Figure 15: Steps in Unbundling



4.5.2 Rationale for Unbundling

International experience demonstrates the advantages[27] that come from unbundling, including:

- Significant improvements in plant operations
- More efficient wholesale trading
- More efficient investment decisions, including transmission investment
- Lower prices over the long term
- Discouragement of market power
- Incentives to invest in generation

All of these are indispensable for the long-term development of an efficient market.[28]

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[27] http://www.naruc.org/international/Documents/20.Unbundling_and_vertical_integration_Eng_Vidmantas_Jankauskas.pdf
[28] Rationale for unbundling:

http://www.naruc.org/international/Documents/Vertical%20integration%20and%20unbundling%20in%20electricity%20sector_Kaderjak2_eng.pdf

http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.384.3106&rep=rep1&type=pdf

http://www.bain.com/Images/unbundling_energy_distribution_supply.pdf

4.5.3 Additional Measures within Institutional Framework

Some additional measures that can be taken to remove institutional barriers to IPP investment include:

- *Making the integration policy in regional cross-border power trading explicit and part of the domestic policy.* Regional integration is not usually considered as one of the main policy objectives of the SADC energy ministries. Other issues are usually given more attention and include issues such as meeting the demand reliably, and ensuring access to energy to all the population.
- *Providing legal support to regional institutions such as SAPP and RERA.* Regional institutions generally require legal support to be able to act. Absence of legal support generally turns these regional institutions into empty shells with no instruments to achieve their stated goals.
- *Coordinating different initiatives that deal with cross border trading*. Too many initiatives often result in an inefficient use of resources and generates the risk of not achieving the primary objectives. Coordination among already existing regional initiatives should be structured so that each can build on the advances already achieved and secure early wins for regional initiatives.
- *Elimination of taxes to import/export electricity.* Taxes on cross-border trading often leads to sub-optimal benefits because taxes have a way of distorting prices. Taxes to exports or imports may prevent a transaction that is economically sound from being achieved, because of the distortions introduced into the transaction.
- *Acceptance of a strategy that includes regional and sub-regional variables into the domestic generation and transmission system planning process*. In the case of generation planning, this may mean that projects that are not feasible from a domestic perspective may become feasible if considered from a regional context.

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http://www.iea.org/publications/freepublications/publication/lessonsnet.pdf

africa-toolkit.reeep.org/Power%20Point%20Presentations/Renewable%20Energy%20-%20Module%208%20Presentation.ppt

5. POWER TRANSMISSION UNDER THE RECOMMENDED MARKET AND INVESTMENT FRAMEWORK

The transmission sub-sector is the centerpiece of a restructured regional electricity market described by the Market and Investment Framework. It will enable the evacuation of power from generation points to load centers. The requirement that all Market Participants have nondiscriminatory access to the transmission system is a key element of that centerpiece because it will facilitate competitive markets and encourage private sector participation across the power industry value chain. If non-discriminatory access to the transmission grid is not guaranteed, IPP investors will be reticent to invest in the generation sub-sector, as they might reasonably have concerns of host country discrimination. As established above, this is especially true where a generation market participant (possibly a SOU) also owns or controls transmission assets and might favor their own output over other generators.

In order to fully support the implementation of the Market and Investment Framework, SADC and its Member States will need to apply a transmission sub-sector business model that will encourage the adoption of the Market and Investment Framework and facilitate the development of a competitive and sustainable electricity industry. Several factors need to be taken into consideration when deciding which business model is most suited for the requirements of the region, including:

- Political feasibility;
- Amount of transmission grid investment required;
- Responsibilities for governance and regulatory oversight;
- Transmission access and interconnection policy;
- Market efficiency; and
- Operational efficiency and system reliability.

The situation on the ground will help decision makers to prioritize these factors and to select an appropriate model. While it is recognized that political considerations will play a fundamental part in selecting a model, the Market and Investment Framework is based on the unbundling of SOEs and on guaranteeing equal rights of network access. Failure to take these fundamental steps will significantly reduce the possibility of successfully attracting IPPs to the sector.

5.1 Recommendations for Transmission System Model(s) Under Proposed Market and Investment Framework

Compared to the other sub-sectors of the power industry, investments in the transmission sub-sector are typically considered to be extremely risky. In addition to requiring long lead times for the planning process, they also require significant stakeholder involvement (including thousands of miles of right of way), which can delay implementation. Transmission projects also often face extensive siting and environmental issues that can make cost recovery challenging. As a result, investors requiring predictable, sustainable, and reasonable returns may well direct their investments into other sectors that are perceived to offer better returns and less risk. Below we highlight a number of steps that SADC and its Member States can take to attract greater investment in the transmission sub-sector.

1. ***Link transmission projects to generation projects.*** This would apply to cases where a generation project under development is expected to export some or all of its energy produced to other countries. The transmission project costs become part of the total project

costs and reduce the need to raise financing for standalone transmission infrastructure, which might raise questions regarding cost recovery. When a generation project involving a cross-border line with a PPA is identified, the possibility of increasing the capacity of the cross-border transmission line can be evaluated in such a way as to accommodate other flows that do not correspond to the PPA. That transmission line can be augmented by making marginal additional investments in line capacity. This takes advantage of an investment that will be made anyway. It also leverages the fixed costs that are incurred in siting, permitting, and purchasing right of ways. The spare capacity generated by the transmission line can be used for power exchange and the owner of the line will be compensated for the use of the spare capacity.

2. ***Break up big transmission projects into smaller projects:*** This will facilitate transmission sub-sector investments in two ways. First, it will reduce the transaction size and, as such, possibly increase the number of potential investors. Second, breaking the project into smaller phases will allow for learning, both by the regional entities and by private investors. This learning process will facilitate confidence building both in the process and in the results, and will make subsequent phases easier to implement. Taking the ZIZABONA project, for example, instead of seeking one investor or one consortium of investors, the project can be broken into smaller sections; from Pandamatenga Substation to Victoria Falls Substation, from Hwange Power Station to Victoria Falls Substation, etc. Once investors who invest in these early sections and phases have shown positive results, other investors can then be sought for the other section/phases.
3. ***Adopt a policy that encourages private ownership and operation of transmission lines.*** We recommend that SADC governments allow private businesses to invest in and own power delivery infrastructure. This could be by establishing an SPV to own and operate transmission lines, charging users a commercial tariff for making the service available.
4. ***Mitigate the most commonly identified risks:*** SADC has labeled several transmission undertakings as high priority projects. However, most of these projects are severely behind schedule. While they have been promoted to a number of private investors, their feedback indicates that they see the projects as being insufficiently prepared to be bankable. These kinds of risks should be mitigated before well before bringing the projects to market. The proposed Market and Investment Framework addresses some of the issues identified by investors. The Financial Framework set out in Section 4.4 highlights some of the concerns with regional generation projects, which are also generally applicable to transmission projects.
5. ***Utilize standardized transmission agreements:*** Another method of encouraging investments in transmission infrastructure is to employ standardized agreements and contracts that allow for clear pricing terms, and consistency and continuity of application. While reducing uncertainty in projects, using standard form agreements also reduces transaction costs, as both parties to the agreement know what to expect before entering the negotiation process. Finally, the wide-spread use of standardized transmission agreements will build confidence in the process and contribute to the success of the infrastructure program.

5.2 Changes to Tariff Methodology

Together with the harmonization of entities and institutions that is at the heart of the proposed Market Model, IPP Member States will also need to harmonize their tariff methodologies for regional projects. As indicated, harmonization will significantly reduce the diversity and inherent complexity that arises when countries utilize different methodologies in calculating the allowed tariffs. SAPP has been at the forefront in designing transmission prices that are cost reflective and that provide signals that encourage network investments.

Because of its importance to investors, transmission pricing is an important factor in encouraging transmission investment. SAPP uses the MW-km[29] method where the purchaser pays a charge comprising a rental fee and reimbursement of costs for use of transmission assets on the wheeling path. A wheeling study commissioned in 2001 on the wheeling methodology recommended rates of USD 1.4-28/kW per year. This reflects the significant variations that exist in the costs and lengths of transmission assets used for transactions. The study noted that these charges compared well to those in other international markets: USD 1-23/kW/year in England and Wales and USD 2-17/kW per year in Brazil.[30]

While the MW-km is a simple method that works well for a few transactions using existing assets, it does not provide adequate incentives for investing in new facilities.[31] It also loads all costs on the purchaser. For this reason SAPP is now considering adopting zone or nodal transmission pricing. Using this methodology, transmission costs are more equitably shared by sellers and buyers within a given trading zone. When there are no transmission constraints in the power pool, the entire pool is treated as a single trading zone. When transmission bottlenecks appear, the pool is split into zones with different prices that reflect the zonal costs. Such zonal costs act as a signal to the market for transmission investment opportunities.

[29] http://www.sapp.co.zw/psc.html

[30] https://www.irena.org/DocumentDownloads/Publications/SAPP.pdf

[31] Ibid

6. ROAD MAP TO ESTABLISH A REGIONAL MARKET

The process of establishing a regional market will require extensive planning and collaboration among the various stakeholders. Below we provide a preliminary roadmap that describes some of the envisioned processes that will enable the establishment of a regional market.

6.1 Approve Proposed Market Model

- The Market and Investment Framework, including the Proposed Market Model and the principal elements of the required legal and regulatory supporting structures, should be approved by the SADC Ministerial Group.
- The Market and Investment Framework should also be specifically supported by SADC's Energy Policy and the energy policies of the Member States.

6.2 Establish Donor IFI Working Group

- SADC should establish a donor IFI working group that will assist with the implementation of the Market and Investment Framework. The SADC Energy Secretariat should also develop the IFI working group's mandate and, if necessary, issue its bylaws. Alternatively, the working group might also be governed by the rules and bylaws of the sponsoring donor IFIs.
- Each member of the donor IFI community should appoint one member to serve in the Executive Committee of the IFI working group. Working groups typically have leadership positions that include, the Chair, the Vice Chair, the Secretary, the Treasurer, and an executive committee.

6.3 Approve Plan to Implement the Proposed Market Model

SADC should approve a reasonably detailed plan to implement the Market and Investment Framework and its constituent elements. The plan should include:

- Institutional changes (if any) required in RERA (including ramping up of staff);
- Identification of technical expertise that will be required within RERA in order to develop the New Legal and Regulatory Framework;
- Identification and development of the specific elements of the New Legal and Regulatory Framework in sequenced phases according to identified time priorities;
- Procurement of the technical assistance required to develop the New Legal and Regulatory Framework;
- Procurement of the technical assistance required to develop the Financing Framework;
- Procurement of the technical assistance required to develop the Institutional Framework, including national transmission company unbundling.
- Development of transparent rules and procedures to roll out the New Legal and Regulatory Framework, the Operating Framework, the Financing Framework, and the Institutional Framework, according to the identified phases and modules;
- Establishment of a unit in RERA that will support the Member State Regulatory authorities and other identified administrative bodies at the Member State Level that have a role in

implementing the Market and Investment Framework and its components (i.e. New Legal and Regulatory Framework; the Operating Framework; the Financing Framework and the Institutional Framework.)

- Establishment of a unit in RERA to manage stakeholder consultations both at the SADC and Member State level.

6.4 Staff RERA

6.4.1 Tasks

Pursuant to the plan described in 6.3, RERA should be staffed and resourced to accomplish the principal tasks identified in this report. Immediate staffing and capacity building should be focused on RERA's tasks during Stage 1. These tasks include:

- Conducting a RERA survey of the existing legal and regulatory framework in each Member State in order to assess its sufficiency to support the New Legal and Regulatory Framework;[32]
- Conducting a RERA survey of the existing operating, financial and institutional framework in each Member State in order to assess their sufficiency, and the required adjustments needed, to support the Operating Framework; the Financing Framework; and the Institutional Framework;
- Consulting with Member State regulators and other administrative bodies as recommended by the Member State regulator to obtain input on changes that may be necessary to existing legislation to implement the New Legal and Regulatory Framework;
- Consulting with ministries of energy other bodies as recommended by the Member State regulator to obtain input on changes that may be necessary to implement the Operating Framework, the Financing Framework, and the Institutional Framework;
- Assisting the Member State regulators to conduct self-assessments to determine the regulatory capacity to implement the New Legal and Regulatory Framework;
- Developing a sequenced series of modules that Member States will use to implement the New Legal and Regulatory Framework;
- Developing a sequenced series of modules that Member States will use to implement the Operating Framework; the Financing Framework; and the Institutional Framework;
- Rolling out the modules of the New Legal and Regulatory Framework to the Member State regulators for implementation in their respective Member States; and

[32] Many of the elements of the New Legal and Regulatory framework relate to regulatory instruments and tasks. Each of these must be supported by the Member State's legal framework. Those Member States with new sector legislation may have most of the supports already in place to allow the regulator to implement the New Legal and Regulatory Framework. However, if the existing legal framework does not support the regulatory changes required by the Market and Investment Framework, changes to the existing legal framework will be required. These changes may be by way of amendment to existing legislation, or by way of new legislation.

- Rolling out the modules of the Operating Framework, the Financing Framework, and the Institutional Framework to regulators, ministries, and counterparts for implementation in their respective Member States.

6.4.2 Developing the New Legal and Regulatory Framework

As indicated, RERA will have to expand its staff to manage the development and rolling out of the New Legal and Regulatory Framework. A modest expansion of existing staff is foreseen, comprising experts in

- Tariffs and tariff methodologies;
- Market development;
- Customer service; and
- Legal.

In addition, RERA will rely heavily on the input of consultants who can assist with:

- The identification of areas for regional harmonization;
- The development of common approaches, standardized documents (licenses, contracts), and rules;
- The establishment of liaison groups in each Member State that will legitimize the consultation process;
- The identification of capacity building and training needs;
- The carrying out of regulatory training as well as training for key personnel in ministries, procurement authorities and other administrative bodies; and
- The establishment of reasonable and binding time frames for finalizing and implementing modules.

6.4.3 Roll Out and Implementation

Roll out is the term used to describe the consultative process of implementing the Market and Investment Framework (i.e. New Legal and Regulatory Framework, Operating Framework; the Financing Framework; and the Institutional Framework) in the Member States. Because a lot of the Market and Investment Framework is regulatory in nature, the process should be coordinated by the each Member State's regulator. It can be compared to a rule making process that many regulators already use when developing new licenses rules, procedures, or methodologies. It requires close coordination with Member State stakeholders. However, to a greater extent than a rule making, in a roll out, consensus is required.[33] The goal of the roll out is to achieve consensus as rapidly as possible. Part of the consensus will be on which Member State entity will be responsible to conduct next steps at the Member State level. After Consensus has been achieved

[33] This is because RERA, unlike Member State regulators, has no power to compel the regulated entities to comply with the new rule or regulatory instrument. This inability to force compliance on the regional level must therefore be mitigated by substantive buy-in by Member State stakeholders. This is accomplished by making the development process highly consultative at the Member State level.

at the Member State Level, the various entities will be responsible to promulgate the appropriate legislation and sub-legislation at the Member State level. Timing will be all-important.

7. CAPACITY BUILDING REQUIREMENTS FOR IMPLEMENTATION OF THE MARKET AND INVESTMENT FRAMEWORK

Discussions of the Market and Investment Framework with stakeholders identified several issues common to the power sectors in most SADC countries. One of the issues identified is the lack of human capacity within national and regional organizations as it pertains to project development and implementation. Left unaddressed, these human capacity constraints and issues will impede the development of a regional power market.

7.1 Beneficiaries

Restructuring of Member State power markets in the SADC Member States is a large undertaking. It will require detailed planning and rational decision makers. One of the reasons is that restructuring is a political task. Another reason is that decision makers will require a clear understanding of why it is important and how it will assist in bringing new investments to the sector. This can only come through education. A number of training beneficiaries can already be identified. Others will reveal themselves as the process unfolds. They include:

- ***SADC***: SADC is a principal stakeholder in the implementation of the Market and Investment Framework. The Energy Secretariat and other key personnel it identifies will benefit greatly from frequent briefings from SAPP and RERA and from close collaboration in the development of RERA's implementation modules.
- ***SAPP:*** SAPP must be one of the principal focal points in the Implementation of the Market and Investment Framework. If a concept or an approach is considered by SAPP to be inappropriate, it must be abandoned. When it is appropriate, SAPP will give its assent to be governed by the new scheme, and to be regulated by the Member State regulator. SAPP must be involved not only in being educated on the elements of the New Legal and Regulatory Framework, but in training SADC, RERA, and the SOUs in the various Member States regarding its initiatives and how they will fit within the Market and Investment Framework.
- ***RERA:*** As developer of the Market and Investment Framework and its components, RERA must understand every facet of the new process, including how each module is developed and implemented in the Member States and how every piece fits into the Market and Investment Framework as a whole. Its complete understanding will help it to more effectively develop and present the modules on the Member State level and how to work with other stakeholders in the process. All of this will be of inestimable value to RERA if Member State regulators decide RERA should assume any duties as a regional regulator. This has been discussed as potentially occurring during Phase 3 of the implementation process.
- ***Member State SOUs:*** Together with Member State ministries, SOUs play a critical role in the implementation of the Market and Investment Framework in the Member States. Educating key personnel within the SOUs will be essential to successful implementation.
- ***Member State Regulatory Authorities:*** These will be the key liaison entities in each Member State. RERA and these bodies will be required to work hand-in-hand at each step of the process. This will require a great deal of capacity building within the Member State regulator. So educated, the regulator can carry out its tasks of identifying key stakeholders on the Member State level and rolling out the required capacity building at that level. RERA will work closely with the Member State regulator in capacity building at the Member State level.

- ***Regional Meetings:*** Capacity building will not occur only at the Member State level. Regional meetings sponsored by RERA dedicated specifically to the development and roll out of the New Legal and Regulatory Framework can go a long way towards putting each Member State on a level playing field. Knowing that other Member States are facing the same issues may help to identify common approaches in overcoming obstacles and gaining consensus.
- ***Training in the Member States:*** Regulators will not be the only entities where capacity building will occur at the Member State level. The Member State regulator will be in a position to identify key stakeholders and to conduct training that will lead to consensus and a smooth role out of the RERA modules.

7.2 Subjects

Below is a preliminary list of sample topics that capacity building programs can target in enabling a regional power market in the SADC region.

- Regulation
    - Regional and domestic regulatory needs;
    - Standardizing technical and grid codes through regulation;
    - Functions of a regional regulator (or of a regulator of regional issues);
    - Legal Issues in power trade; and
    - Drafting trading agreements and regulating cross border exchanges.
- Tariffs
    - Cost reflective tariffs;
    - Setting cross border exchange tariffs; and
    - Commercial settlement in trading.
- Operations And Management
    - Principles of project development and finance;
    - Project management;
    - Commercial agreements; and
    - Utility management.
- Planning
    - Demand forecasting;
    - Generation and transmission expansion;
    - Regional cooperation in planning; and
    - Energy planning.
- Data and Information Management
    - Standardizing data for regional use;
    - Data for measuring and monitoring power sector performance; and

- o Information technology needs for utilities and regulatory agencies.

7.3 Timing

Given the breadth of the capacity building requirements in the region, an effective capacity building program will necessarily require significant time and investment to be effective. Additionally, in order to maintain relevancy of the materials, the capacity building will need to be phased in order to align with the phased implementation of the Market and Investment Framework. Given this approach, the capacity building program is anticipated to last for the entire multi-year duration of the Market and Investment Framework implementation, at a minimum.

8. ROLE OF DONORS AND DEVELOPMENT PARTNERS

Timely and efficient implementation of the Market and Investment Framework will require coordination among the development partners for each of the phases. Below is a brief breakdown of each of the phases in the Market and Investment Framework implementation and the responsible institutions.

8.1 Approve Proposed Market Model

The Proposed Market Model must be approved by the SADC Ministerial Group. It must be specifically supported by SADC's Energy Policy

TARGET:	End 2015
INSTITUTION RESPONSIBLE:	SADC
AGENT OF CHANGE:	RERA
SUPPORTED BY:	SAPP and the SADC Energy Secretariat

8.2 Establish Donor IFI Working Group

SADC should establish this group, develop its mandate and issue its bylaws.

TARGET:	June 2016
INSTITUTION RESPONSIBLE:	SADC
AGENT OF CHANGE:	SADC
SUPPORTED BY:	RERA AND SAPP

8.3 RERA Staffing

TARGET:	June 2016
INSTITUTION RESPONSIBLE:	SADC
AGENT OF CHANGE:	RERA
SUPPORTED BY:	SAPP AND SADC Energy Secretariat

8.4 Establish Milestones and Time Frames and Progress Reporting Requirements

The Plan should include a time frame for accomplishing all of its principal tasks, milestones, and progress reporting obligations.

TARGET: June 2016

INSTITUTION RESPONSIBLE: SADC

AGENT OF CHANGE: RERA

SUPPORTED BY: SAPP and SADC

8.5 Conduct Stakeholder Meetings

The Plan should place special emphasis on the need for transparency, stakeholder meetings (both pre-determined and ad hoc), and the publication of relevant activities on both the Regional Regulator and the Member State Regulatory Authority's web site.

TARGET: June 2016

INSTITUTION RESPONSIBLE: SADC

AGENT OF CHANGE: RERA

SUPPORTED BY: SAPP AND SADC Energy Secretariat

8.6 Financing for Implementation of Recommendations

Donors and development partners will be required to facilitate the financing of the implementation of the Market and Investment Framework. A separate study on the comprehensive budget for implementing the Market and Investment Framework will be required. This budget will be drawn up in consultation with RERA and SAPP.

9. NEXT STEPS

Building on the consensus gained over a two-day workshop held in Cape Town South Africa in 2015, the Deloitte team has identified the following crucial next steps in moving forward with the implementation of the Market and Investment Framework. These next steps are based upon the principle of *Phased-in Implementation:* The Market and Investment Framework should be implemented in phases to ensure first, that there is sufficient capacity among the recipients, and second, that there is sufficient support among all stakeholders. Implementation should take place in three phases:

a. *Phase 1 -- Short Term:* The short term is defined to mean the next two years. During this phase the status quo continues, with a small number of willing implementation partners identified and prepared.

b. *Phase 2 -- Medium term:* This is defined to mean the next three to five years. During this phase, two or three of the willing countries identified in Phase 1 would implement the Market and Investment Framework. Implementation would entail identifying a regional project and shepherding it through the entire project development process to financial closure. In parallel, additional willing countries — taking into account the progress made — would express interest and would also prepare to implement the Market and Investment Framework.

c. *Phase 3 -- Long Term:* This is defined to mean five-plus years in the future. During this phase, the Market and Investment Framework will be rolled out to all the Member States. Given the initial hesitation in agreeing to establish a regional regulator as a legal entity, it is hoped that by this time, the advantages of having a regional regulator would have made themselves self-evident. At that time, the process of concluding a treaty establishing RERA as a regional regulator with some authority could be well under way.[34]

In keeping with this phased-in regional approach, further technical assistance will be required to implement the short term measures identified above. The Deloitte team recommends that Technical Assistance be provided to both RERA and SAPP to identify a regional project that can be guided through to completion. Such technical Assistance will comprise of conversations with all Member State SOUs and regulators and evaluating the Member States and entities that are best prepared and willing to implement the regional Market and Investment Framework. Once

[34] A fully harmonized regional electricity market can best be implemented by establishing one regional regulator that has the authority to develop, issue monitor and enforce the rules necessary to apply the market model in all Member States. This approach requires a treaty establishing such a regulator. Under the treaty, RERA, the regional regulator, would have its own legal personality as well as regulatory jurisdiction over all aspects of regional trade including licensing, setting prices (tariffs), establishment and monitoring of technical, economic, service standards, resolving regional disputes and establishing rules and procedures for all regional power projects and in all participating Member States that are stakeholders in such projects. The most attractive feature of this approach is that it avoids the most significant regulatory barrier to harmonization, namely that Member States are burdened by their diversity. This diversity, multiplied fifteen times, raises what may be an insurmountable obstacle to the deep harmonization required to realize regional projects and expand regional trade. This approach is not politically feasible at the present time, and for that reason we have recommended an approach that can be implemented immediately. If at a later time the establishment of a regional regulator does become more feasible, it should be carefully considered.

identified, a regional project that can supply power to these two countries can then be identified, and other short-term measures implemented.

ANNEX 1: CASE STUDIES—HOW OTHER COUNTRIES/REGIONS ENABLE MARKET AND INVESTMENT

The move to market liberalization in general and the establishment of regional markets for electricity in particular has been going on throughout the world for a number of decades. Primarily, it has been driven by massive investment and capital requirements that often exceed the resources of governments and state-owned utilities. It also reflects an awareness that increased transparency and competition all along the electricity value chain will encourage that investment. Finally, it acknowledges that regional trading (and competition) can improve not only security of supply, but also the quality of electricity services.

Case Study: The EU Energy Community

Although the trends described above have been identified world-wide, they can probably most clearly be seen in the liberalization of the European markets, driven by a series of legislative initiatives (the "first, second, and third packages) in 1996, 2003, and 2009, respectively. While the EU and SADC regions are easily distinguishable on a number of levels, these legislative initiatives are relevant for SADC for a number of reasons. First, the goals of the initiatives as stated are similar. They include increasing competition for the purpose of raising efficiency and security of supply. The EU saw unbundling and market opening as being the most effective ways of introducing greater competition to the sector. Second, these changes were introduced into the European Union, a community of sovereign states that has already taken a number of steps to create a single market. Similarly, SADC is also a community of sovereign states, though less tightly joined. Third, the evolution of the European Energy Community allows an observer to clearly see where the Energy Community began back in 1993, and to measure the progress it has made in a relatively short period of time. Lastly, it provides a model, both for top-down decision-making (EU Directives drove the process), and for harmonization at the member state level. Both of these approaches (top-down and bottom-up) will be required in the SADC countries.

The progress of SADC member states in creating a regional electricity market can be identified on the EU's liberalization timeline that began in the early 1990s. Some SADC member states have made steady progress towards market liberalization and transparency while others still have a long way to go in order to be ready to participate in more comprehensive regional electricity sector integration. During the 1990s, when most of Europe's national electricity and natural gas markets were still state monopolies, the European Commission (the Commission) determined gradually to open these markets to competition. Specifically, the Commission decided to:

- Treat the competitive and non-competitive parts of the industry (generation and supply on the competitive side and network operation on the non-competitive side) not as distinct parts of the same function, but uniquely, according to their specific characteristics;
- Require the operators of the purely monopolistic parts of the industry (e.g. the networks and other infrastructure) to allow third parties access to the infrastructure;
- Remove barriers preventing alternative suppliers from importing or producing energy in order to open up the supply side of the market;
- Remove gradually any restrictions on customers from changing their supplier; and,
- Require the establishment of independent regulators to monitor the sector.

All of these steps were taken by the EU Member States in response to the top-down requirements of the European Commission (the Commission) as reflected in the three principal Directives, Directive 96/92/EC, (First Package) Directive 2003/54/EC, (Second Package) and Directive 2009/73/EC (Third Package), together known as “the Electricity and Gas Packages. The creation of independent regulators has been critical to the success of the EU market in developing regional trading and achieving the first four objectives listed above.

Policy

The Electricity and Gas Packages were implemented for the purpose of establishing a fully integrated and competitive market for electricity and gas within EU Member States. By the implementation of the Third Package, all of the unnecessary barriers to cross-border electricity trade would be removed and customers would be provided a free choice of suppliers. Although SADC’s principal aim is to attract more investment into the sector through the attraction of IPPs, the mechanism to do so is the same—efficient regional trade of electricity.

The goal of the First Package was at once less grandiose and more prosaic. It was to gradually and partially open the electricity markets of the Member States, allowing both producers and consumers an opportunity to freely negotiate purchases and sales of electricity. The Second Package introduced an important next step: fully-opened markets in all Member States. The Second Package removed any obstacles that national utilities might be able to exert on the construction of new plants, the rationale being that it was an abuse of a dominant position. This was achieved by mandating the implementation of a system of third party access to the transmission and distribution systems for all “eligible” customers (those permitted to trade in the un-regulated market). The Second Package required Member States to appoint independent transmission or distribution system operators. In turn, these were charged to ensure efficient and economic balance of transmission and distribution services. They were also required to ensure equal, non-discriminatory access to the transmission system. While currently these system operators remain in the hands of incumbent monopolies, their activities and financial accounts are required to be separately kept from any other licensed activities such as generation or supply. The systems operators are also required to comply with regulations that are designed to protect their independence.

The Second Package also sought to establish fair and transparent rules for cross-border exchanges. Its objective was to harmonize cross-border transmission charges and the allocation of available interconnection capacity. The Second Package primarily addressed three distinct issues:

- Compensation mechanisms for cross-border flows;
- Harmonized principles on cross-border transmission charges; and,
- Allocation of available interconnector capacity.

As a result of the liberalization process defined by the First and Second Packages, a number of new players were introduced into the electricity market. Instead of only one supply contract, numerous contracts would be required between suppliers and system operators, system operators and consumers, etc. <u>The goal was to ensure grid access.</u> Member States were also required to ensure that all parties negotiate in good faith and that no party abused its negotiating position by preventing the successful outcome of negotiations.

Under the Third Package, the Commission required the separation of transmission and distribution networks from other energy activities. This step fully institutionalized the concepts of full unbundling, independent transmission operator and independent system operator. This effort, which required more than fifteen years to fully implement, was crucial to ensuring that incumbent monopolies could no longer control transmission access. Given the importance of independent transmission for creating open market access and competition, SADC may want to prioritize the immediate implementation of a similar system to more quickly meet its market goals. Parallel to this implementation, the EU has also driven a series of measures for the development of renewable energy. Each of these efforts is of immediate relevance to the SADC regional initiative, which has also recognized the importance of renewables.

Regulation

Regulation of Cross-Border Transmission Services

The European Network of Transmission System Operators (ENTSO-E) represents 41 electricity transmission system operators (TSOs) from 34 countries across Europe. It was established and given legal mandates under the Third Package. Its goal is to promote closer cooperation across Europe's Transmission System Operators (TSOs) in order to support the implementation of the Energy Community and to achieve Europe's energy & climate policy objectives, which are changing the very nature of the power system.

ENTSO-E contributes to the achievement of these objectives by:

- Drafting of network codes;
- Developing pan-European network plans (TYNDPs);
- Ensuring technical cooperation among TSOs;
- Publishing summer and winter outlook reports for electricity generation; and,
- Ensuring the coordination of R&D plans among the TSOs.

To achieve these, the Third Package provides ENTSO-E with a tool box of tasks and responsibilities, including network codes, infrastructure planning and adequacy forecasts.

In furtherance of the Electricity and Gas Packages, Regulation (EU) 838/2010 on guidelines relating to the inter-TSO compensation mechanism defines the compensation methodology pursuant to which TSOs cover their costs incurred in managing cross-border electricity flows. This mechanism is intended to encourage TSOs to facilitate cross-border flows. This, in turn, facilitates an expanding European electricity market across all of the Member States.

Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure came in force in April 2013. The Regulation defines European Projects of Common Interest, PCIs, which are electricity projects that have significant benefits for at least two Member States. It also stipulates that ENTSO-E's ten-year network development plan, TYNDP, be the sole basis for the selection of PCIs. ENTSO-E is also mandated to develop a corresponding cost-benefit methodology for the assessment of transmission infrastructure projects.

Regulation (EU) 543/2013 on submission and publication of data in electricity markets, (the Transparency Regulation), entered into force in June 2013. Pursuant thereto, ENTSO-E is required to redesign and upgrade its existing transparency platform, www.entsoe.net. The body's new central information platform is expected to be up and running by January 2015. It will provide fundamental market data on generation, load, transmission, outages, balancing and other issues.

National Regulation

In addition to ENTSO-E, Member State regulation was significantly affected by the Second Package. As stated, that legislation required Member States to designate a national regulatory body that should be independent, and exercise its powers impartially. National regulators are responsible for:

- Setting transmission and distribution tariffs;
- Cooperating on cross-border matters;
- Monitoring the investment plans of the National TSOs; and,
- Ensuring access to customer consumption data.

Even prior to the First and Second Packages, Member States were required under 96/92/EC to designate "a competent independent authority" to settle disputes relating to contracts, refusal of access or refusal to purchase. Where cross-border disputes arise, the dispute settlement authority was to be the one covering the system either of the single buyer or the system operator that refused the use of or access to the system. While most Member States appointed the Member State's competition authority of the Member State to act in this capacity, others appointed the national regulatory body (usually where regulated TPA was used to determine access) to fulfill this task. 96/92/EC also required the national regulator to set tariffs.

The Commission has also established the Agency for the Cooperation of Energy Regulators (ACER). The ACER Electricity Department is divided into four key areas of work, each of which supports the market integration process:

- Framework Guidelines and Network Codes;
- Electricity Regional initiatives;
- Infrastructure and Network Development; and,
- Market Monitoring.

Upon a request from the Commission, ACER is responsible for developing a vision on changes needed on a particular energy subject. The result is a framework guideline that triggers the development of a relevant network code by ENTSO-E. During the drafting procedure, which can last up to twelve months, ENTSO-E gathers national experts on the subject to draft the network code. In order to ensure the support of all branches of the energy sector, ENTSO-E works in close cooperation with stakeholders and holds to a set of principles in the development of on-going and future codes. In summary, although ACER has no effective power, it uses its office to facilitate among national regulators:

- Transparency: encouraging the publication of any and all relevant material (e.g. early drafts and analysis of important issues for feedback);
- Open engagement: a commitment to listening to all viewpoints from all interested parties;
- Explanation: clearly explaining the rationale for the choices made in the development of the network codes; and,
- Consistency: that each part of an overall regulatory initiative will mutually work towards the same goal.

ACER also reviews network access codes to ensure they are in line with the framework guidelines and, after which they are submitted to the Commission. Lastly, the network codes should go through a process whereby they are scrutinized and agreed by Member States, before becoming directly applicable legislation across the EU.

Financial

Although the establishment and organization of power exchanges or power pools are not regulated by the electricity directives, some restrictions nevertheless apply, including rules on access to cross-border networks and the rules on reciprocity. Market liberalization has led to the development of large power exchanges across the EU. These spot markets match demand and supply hourly while providing a public price index and can be viewed as a competitive wholesale spot trading arrangement that facilitates the buying and selling of electricity.

Owing to the success of the Three Packages, an ever-increasing amount of electricity is being traded on European electricity exchanges. In 2013, over 50% of total electricity was traded on exchanges as distinct to being negotiated through PPAs. In addition, the level of market liquidity has risen from 39% at the end of 2010 to 51% at the end of 2013. Lastly, cross-border flows of electricity traded on these exchanges has trended upward since 2010, reaching nearly 10% by the end of 2013. These statistics suggest that many of the goals of the EU packages are coming to fruition.

Tariffs

As stated, although Member States participate in the regional electricity market, Member State regulators continue to approve tariffs at individual country levels. EU tariffs currently vary from (EUR 0.294 per kWh in Denmark to EUR 0.133 per kWh in Hungary), reflecting differences in domestic generation mix, national renewable energy targets, and other policy directives that impact customer pricing to the customer. It may also be argued that there has been a lack of tariff convergence due to still-limited cross-border flows of electricity.

Concluding Points

During the course of the past quarter century, the European Union has succeeded in transforming itself from a number of individual electricity markets into a regional one. The work of achieving an “ever-closer union” is ongoing, but the following achievements should be noted:

- The EU has, by-and-large, introduced competition at the point of generation by ensuring access to the grid and access to transmission capacity for qualified participants;
- The EU has also allowed for competition at certain levels for commercial and industrial customers, leading to market choice, transparency, and efficiency. The introduction of competition has brought additional efficiency to legacy generation companies who have needed to improve service and reliability in order to retain large industrial customers;
- Generators actively sell electricity in day-ahead markets, in fact over 50% of European power sales occur through exchanges rather than through PPAs; and,
- Europe does not face a supply-demand imbalance, and the EU market includes a number of healthy utilities with strong credit ratings.

If SADC seeks to realize any or all of these achievements, arguably, the EU Model is the most far-reaching and successful one.

Case Study: The Nordic Electricity Trading System

Chronology

- 1962 — Physical interconnection between Norway and Sweden.
- 1963 — Nordel is established as cooperative for the exchange of information between the nation's system operators and market participants in all countries.
- 1990-1996 — Nordic electricity sectors (beginning with Norway) begin the process of deregulation and market opening.
- 1963 — Participants in Nordel (Norway, Sweden, Iceland, Finland and Denmark) conclude System Operation Agreement and develop related instruments.
- 1995 — The framework for an integrated Nordic power market contracts trading is submitted to the Norwegian Parliament for approval and Nord Pool is licensed by the Norwegian Water Resources and Energy Administration for cross-border trading.
- 1996 — Nord Pool is established between Norway and Sweden.
- 1999 — Finland joins Nord Pool.
- 2002 — Denmark joins Nord Pool.
- 2002 — Nord Pool Spot established.
- 2009 — Nordel wound up.

Today, Nord Pool (also sometimes referred to as "the Nordic model", "the Nordic Power Exchange" or "Nord Pool Spot") manages the leading power market in Europe. It offers both day ahead and intraday trading to its 350 customers. In 2010, it had a total turnover of 310TWh.[35] The Nord Pool market is larger than the U.K. market and it has been so successful that many see it as the model for a future single electricity market that is wider than the EU itself. However, the exchange had rather more modest beginnings.

Origins

The Nordic trading system began in 1963 as Nordel, a cooperative body of transmission system operators in Norway, Sweden, Finland, Denmark and Iceland. The founding members of Nordel viewed it as being a first step toward the establishment of a harmonized Nordic electricity market. It was initially seen as being a forum for contacts between the transmission system operators and representatives of market participants in each of the member states. One of its principal activities was to issue recommendations for the promotion of an efficient electric power system in the Nordic region, taking into account the conditions prevailing in each country.

[35] Its structure and policies are consistent with the goals of the EU initiatives on a single electricity market, including increased efficiency through competition, more consumer choice, assured electricity supply, leveling off and lowering of electricity prices, decreased waste, better quality and reduced reserve capacity.

A driving force behind the establishment of the Nordel exchange was the generation mix pertaining to Nordel's member countries.[36] These differences made it economically attractive to optimize production in all the member states by trading of electric power. In addition, when Nordel was created the Scandinavian power sectors were very different from their current configurations. Then they were oligopolies composed of dominant state-owned enterprises that also controlled the national grids.[37] One of Nordel's underlying principles was that each member would continue to build enough generating capacity to be self-sufficient. Trading, therefore, was not intended to satisfy the capacity need of its members; merely to help each country to achieve an optimal dispatch within the larger system. The investments required to interconnect were justified, not on projected profits from exports, but on the savings that each country would be realizing by pooling available generating capacity. Nordel facilitated this by acting as the vehicle through which member countries exchanged information about their marginal costs of production. When there was a difference, they could also make a trade at a price that would be the average of the two marginal costs. Although, in time, this arrangement would lead to overinvestments in the member states' power sectors and poor return on equity, because the system retained some degree of competition, utilities did not suffer from operating efficiency problems.

The System Operation Agreement

The background to the first System Operation Agreement, concluded in 1963, was that operation of the interconnected Nordic power system would require operational collaboration and co-ordination between each nation's system operators. Under the Nordel model, the supervisory authorities of Norway, Sweden, Finland and Denmark appointed system operators[38] which then concluded a comprehensive System Operation Agreement (the Agreement). The collaboration required by these parties under the Agreement would provide the technical prerequisites for trading in power on an open electricity market.

The Agreement established operational terms and conditions for links between the sub-systems. It also required coordination and communication by the parties on all matters arising within their subsystems that might affect the operation of the joint system. Specifically identified were operational planning, system services, management of transmission limitations between the sub-systems, management of operational disturbances and balance regulation. The Agreement also

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[36] Norway relied entirely on hydropower while Sweden's energy mix was half-hydro and half-nuclear. Finland's mix was 25 percent hydro, 45 percent conventional thermal and 30 percent nuclear while Denmark relied on thermal power from imported coal.

[37] Norway's power sector was dominated by the government-owned integrated utility, Statkraft, which also operated the national grid. There were also between fifty and sixty small local and regional utilities involved in the transmission of electricity at the regional level. The local and regional utilities gained access to the national grid in 1969 and could buy and sell power through the local spot market. Electricity was distributed by about 200 municipally owned companies. In Sweden, about half the generation was owned by Vattenfall, a state owned enterprise. Vattenfall also operated the national grid and provided distribution services. Although approximately ten other integrated utilities of various sizes also used the national grid, a relatively high network fee made it uneconomical for smaller utilities. Like Norway, Sweden also had a large number of municipally owned distribution companies. In Finland, the largest utility was the state-owned IVO which also operated the national grid. Much of the power generation was owned by Finnish industries. They formed a transmission company, TVS, to interconnect their generation and supply areas. In Denmark the grid was divided into two main parts, one that serves Jutland and the other that serves the island of Sjelland. In each of these two areas the generation and distribution utilities, mostly owned by municipalities, formed special purpose vehicles to manage the extra high voltage grids and to coordinate operation.

[38] (Energinet.dk for the Danish *subsystem*, including Bornholm, Fingrid for the Finnish *subsystem*, Statnett for the Norwegian *subsystem* and Svenska Kraftnät for the Swedish *subsystem).* The Agreement was revised from time to time and remained in effect until Nordel was wound up in 2009.

set the rules for power exchange between the countries and established procedures related to hourly exchange plans and trading plans, the exchange of supportive power between parties with adjacent subsystems, and the calculation of balancing power. The agreement also made provisions for settlement rules and identified settlement points. Specifically, settlement procedures were to be regulated bi-laterally in separate agreements between the parties. Rules on power shortages and risks related to power trade were also included. The Agreement, which was subject to revision by mutual consent of the parties, remained in effect until 2009. The last version of the Agreement was concluded in 2006 and can be found on the ENTSO-E website.

Nord Pool

In 1996, the participant countries began the transition from the Nordel model to "Nord Pool", a joint electricity trading exchange that would operate on competitive market rules. The decision was triggered by power sector reforms in Norway in the early 1990 and in other countries soon after.[39] As a first step, Norway established a spot-market for electricity trading in 1992. Sweden was not included because its two largest generating companies controlled 75 percent of the nation's generating capacity. Due to the fact that all of the power in Norway is hydro-generated, its new spot market was very volatile. It was recognized that the problem could be addressed by combining the Norwegian and Swedish markets. Finland joined in 1998 and Denmark joined in 2002.

Pool Structure

Nord Pool is owned by the two principal national grid companies, Statnett SF in Norway and Svenska Kraftnat in Sweden (each holding 50 percent). Nord Pool is comprised of three organized markets that exist alongside the existing bi-lateral trading system. Nord Pool, which acts as market operator, is responsible for the clearing process in the three organized markets. When Nord Pool was established in 1996, around 30 percent of generation in Norway was traded through the pool and the rest was traded as bi-lateral contract engagements. Today, the amount has grown to between 60 and 70 percent. The three markets are:

1. **The Spot Market:** This is a day-ahead market operated by the power exchange (Nord Pool). In the spot market, traders submit offers to sell or bids to buy electricity they expect to produce or consume. The spot price is set equal to the marginal offer to supply or bid to buy accepted by the Exchange. Electric power is traded in the spot market on a daily basis for delivery on the following day. Participants set bids for purchases for every hour during

[39] In Norway, Statkraft's transmission activities were spun off into a new national grid company, Statnet SF. In addition, all transmission networks were opened to TPA and vertically integrated companies were required to adopt separate accounting for generation distribution and supply. In Sweden, reform was driven by discontent among private power companies stemming from Vattenfall's control of the national grid and dissatisfaction on the part of smaller power companies over their lack of access to the market for occasional power. The first major steps began in 1991 when Vattenfall's Generation and Distribution activities were privatized (the national grid which also serves as the system operator) was retained as a government owned institution, Svenska Kraftnat). Networks were gradually opened to new participants, and a new electricity act allowing a competitive market entered into force in 1996. Finland introduced new energy legislation in 1995. The state-owned and vertically integrated electricity monopoly, IVO, had already separated its grid activity to a separate company IVS, and there was also a privately owned grid company, TVS. These were merged in 1997 into Fingrid which today also acts as the system operator. In 1996, Denmark's electricity sector introduced competition for large consumers, distributors and generators, and the two grids (one in Jutland and one in Sjaeland) were opened to negotiated third party access.

the day. In order to be registered, each contract must include the hour during which the electricity will be delivered, the load in MWh/h and the price (NOK[40]/MWh). On the basis of the contracts submitted, Nord Pool determines the market equilibrium price (the balance price for the aggregated supply curve and the aggregated demand curve). This price is called the system price. The system price is used for settlements of electrical power and participants use area prices as price signals for future planning and other purposes, because they indicate participant's total costs and income for purchases and sales of electricity.[41]

2. **The Regulating (imbalance) Market:** This market employs a single buyer model for the purchase of network frequency support. The purpose of this physical market is to make short-term adjustments. Imbalances between trades in the daily spot market and the actual amounts produced or consumed by traders are settled here. As is the case for the spot market, trading in this market is also non-mandatory.[42]
3. **The Futures Market:** This over-the-counter (OTC) forward trade in energy market is a financial market that affects money flows, but exerts no physical effects on the system. This market, comprised of weekly contracts, reflects purely financial commitments.[43]

As indicated, alongside the spot and futures market there is also direct trading between parties by way of bi-lateral forward contracts. These are normally for physical deliveries and are usually tailor-made.

Roles and Responsibilities of Key Market Participants

In order for the power system and the markets operating under the "Nordic Model" to work properly, the power exchange, the TSOs and the market participants must each work together. In addition, the relevant regulators in each country must also have clearly defined roles and responsibilities.

***Grid Owners*:** The grid owners operate monopolies. As such, their performance must be monitored by appropriate regulatory bodies, which also define grid owner responsibilities. A grid owner's principal responsibilities are:

- To build, operate and maintain the grid within the defined area;
- To set grid transmission tariffs;
- To connect customers to the grid;

[40] Norwegian Kroner.
[41] The spot market organized by Nord Pool trades in hourly contracts for the following day. It is open to all companies that have signed the necessary agreements for Nord Pool. Bids are submitted each morning and supply and demand curves are then constructed to provide the system price and the traded quantity for each hour of the next day. The price of the power to balance the system is also determined through a bid process. At the beginning, Statnett, Svenska Kraftnat and Fingrid were each responsible for balancing the system in their country. The rules have since been harmonized.
[42] Prices in this market are set as follows: if total demand exceeds total demand in the spot market, the price for the imbalance market is set equal to the highest accepted offer to supply; and if total demand is less than total demand in the spot market, the price for imbalance market is set equal to the lowest accepted bid to buy.
[43] These futures contracts are purely financial contracts used for price hedging. About fifteen brokering companies immediately began offering their services to the electricity market. The majority of the trading was in standardized financial contracts often referred to as over-the-counter (OTC) contracts. The liquidity of the OTC market has always been quite high, particularly for the nearest season. These contracts can be resold or they can be netted out by making an opposite contract.

- To collect metered hourly values for all customers or calculate hourly values based on a load profile;
- To submit hourly values to TSOs and power generators in the grid owner's area; and,
- To purchase energy equal to the grid's energy losses.

TSOs: The main responsibilities of TSOs are to handle non-predictable imbalances and unexpected events during real-time operations that cannot be relieved by trade in the market. This is accomplished by:

- Establishing rules to ensure secure supply and a reasonable quality of electricity within the framework of the industry's regulatory bodies and in close-cooperation with generators;
- Establishing incentives to maintain short-term power reserves;
- Building, operating and maintaining the main grids;
- Working out appropriate tariffs for the main grids;
- Managing real time system operations;
- Managing the real time market—balancing generation with consumption;
- Cooperating with the TSOs of interconnected grids;
- Calculating imbalances for all participants in the wholesale market; and,
- Managing the financial settlement of imbalances.

Power Exchange**:** The principal responsibilities of the Power Exchange are:

- To provide a price reference to the power market;
- To operate a spot market and an organized market for financial products including forward futures and operations contracts;
- To act as a neutral and reliable power-contract counterparty to market participants;
- To use the spot market's price mechanisms to alleviate grid congestion (opening bottlenecks) through optimal use of available capacity; and,
- To report all traded power delivery and off take schedules to the TSO for the area.

Because TSO companies play such an important role in restructured power markets, no market concept or solution can be allowed to interfere with the TSO's obligations to maintain the reliability and quality of the power supply system.

The Regulator: The regulator establishes rules and guidelines to regulate monopolies within the power sector, including:

- Rules related to cost recovery through network rates and tariffs;
- Settlement of disputes as to network rates and tariffs;
- Rules for power system operation;
- Rules for metering and calculation of power imbalances; and,
- Monitoring Grid owners' costs and profits.

Market Participants: These are legal entities that operate in the wholesale and or retail markets. They may play multiple roles, but generally they fall into the categories of generators, retailers, traders or end users.

- Generators may operate in both the wholesale markets and the power exchange markets. They contribute to the leveling out of any price differences between markets. They also use the spot market to balance their generation schedules to delivery commitments close to the time of operation;
- Retailers normally serve end users based on their own generation or power purchased in wholesale markets;
- End users have various power volume requirements. Large-scale end users may operate in the wholesale market while retailers serve small-scale end-users; and,
- Traders: All participants act as traders in some sense, in that they trade in both physical and financial contracts to profit on price differences and volatility.

Ancillary Services: The grid operator runs the power exchange for ancillary services and energy balancing. Although bilateral contracts are handled outside the market, contract parties are charged for energy imbalances based on their contribution to the actual imbalance. Network constraints are modeled in the Nord Pool using a simplified model that provides zonal prices. Ancillary services are provided by the network operator and recharged on a pro-rata basis to suppliers. In the balancing market, on a daily basis the System Operator buys power or demand reduction, as required, and re-charges market participants as a capacity fee on a pro-rata basis. If an overload (congestion) is discovered, the market-clearing price for each area is adjusted to create enough imbalances in each area to relive the congestion. In Sweden, grid operators also use counter trades to mitigate congestion, where energy supply bids that would eliminate contracts for differences, and as such, reduce risk and save money for some transacted parties. This market promotes customer choice since trading in the market is optional. In addition, the responsibility for dispatching and managing generating units remains with owners.

Conclusions

- Nordic model's success and continued development can be attributed to:
    - The long-standing relationship of its member countries in energy trade and exchange and to the operation over many years of its cross-border transmission structures;
    - The fact that its establishment did not require privatizing government-owned companies. Even today, a mix of companies continues to operate in the Nordic power sectors—from large government-owned utilities to privately and municipality owned companies of various sizes. However, ownership of the interconnections has been transferred to the grid company in each country, and this has opened trading to all the wholesale market participants, generators, distributors and large consumers;
- It has not been necessary for the Nordic countries to harmonize their tax or environmental laws, nor has it been essential for the system to acquire a single system operator. Statnett, Sevenska Kraftnat and Fingrid each have the responsibility for managing and balancing the national system in their countries;
- In addition to traditional power companies, other players can also trade in the market, including brokers, oil companies, power companies and power trading companies;

- Strict regulation of the network service ensures that third party access works. But the market is largely assumed to be able to take care of itself under the supervision of national competition authorities. This approach is different from that adopted in England and Wales, where the pool is heavily regulated. Because the Nordic countries already had a large number of players, reform was easier to implement;
- In contrast to the English and Welsh pool, where only the producers can participate in the bidding, the Nordic pool is a market for both buyers and sellers. Also, in the Nordic model, generators are <u>not obligated</u> to offer their power to the pool. To keep the business from going elsewhere, the pool must ensure that it is an attractive marketplace;
- The initial competition related problem was that the high costs of installing hourly metering limited the ability of small consumers to change suppliers. This was addressed by adopting a system of predefined customer consumption profiles;
- Regarding environmental matters, since 1996 there has been a marked increase in the use of wind power by all Nord Pool countries. Nord Pool has filled a niche in the power consumption market that was not explored prior to the pool and is satisfying these countries' growing demand for renewable and environmentally friendly energy production. Denmark is profiting from an increased demand for its product and the rest of the countries are profiting by having more satisfactory choices for their populations' power consumption. Although the share of wind energy is admittedly very low compared to other energy types, the trend is still there. In short, the Nord Pool has had a positive effect on the environment in general. It has meant the diversification of electricity types for general use, the positive trend toward green power use (wind) and more energy consumption;
- Expansion of the pool has led to a need to increase transmission capacity between countries. As the free market has opened up, the cross-border power flow generally tends to increase if the international power exchange had previously been limited to optimizing marginal production;
- One problem in the Nordic market is that there was no clearly defined rule prescribing when network expansions must be built by the grid companies or how they should be financed; and,
- Because it is quite sophisticated, the Nordic model in its current form may not be a suitable model for developing countries moving from a traditional monopoly utility to a more market oriented structure. It may, however, be an attractive option for developing countries with small power systems.

Case Study: The SIEPAC Project

The Central American Electrical Interconnection System (SIEPAC) project is an initiative to create an integrated regional electricity market among six Central American countries: Guatemala, El Salvador, Honduras, Costa Rica, Nicaragua and Panama. The projects comprises of two interdependent activities:

- To develop a regional electricity market (MER) based on a standard set of trading rules at the regional (supranational) level. This includes:
    - The establishment of a regional regulator;
    - The establishment of a regional transmission and market operator; and,

- To develop and complete a new 1,800 km international transmission line, running from Panama in the south to Guatemala in the north, that will increase transfer capacity at all borders in the region to 300 MW.

The SIEPAC project was formalized in an intergovernmental framework agreement, known as the Marco Treaty. This agreement is fundamental to the project and provides the legal foundation on which the regional market and the supporting institutional and physical infrastructure are established. The institutional design and development have been carried out by the regional planning organization that represents the six national utilities. A series of planning, advisory and steering groups have been set up within this entity.

The range of institutional development and capacity in the national electricity sectors was recognized as an important element affecting the design of the regional market. To accommodate the differences, the MER is designed to be a seventh market that connects the six national markets while remaining separate from them. This design allows the individual countries to develop their sectors at their own pace while also enabling trade within the region. The focus on gradualism is explicitly required in the Marco Treaty.

As stated, the regional market is supported by two new regional institutions, a regional market and system operator and a regional regulator. These institutions have supranational legal status, which grants them independence from any of the six national legal systems.

The Marco Treaty provides the legal foundation on which the regional market and the supporting institutional and physical infrastructure are built. The principal stakeholders are:

- The governments of the six host countries and their administrative bodies;
- The transmission, system and market operators in each country;
- The regional planning body, the Central American Electrification Council (CEAC) which is directing the development of the institutions;
- One private utility which is a shareholder in the regional transmission company (state utilities of neighboring countries are also shareholders);
- Governments of neighboring countries, and regional cooperation organizations;
- International financial institutions led by the Inter-American Development Bank; and,
- Private contractors for project design, management and supervision, construction works and procurement.

One of the goals of the SIEPAC project is to overcome size and efficiency restrictions imposed by the combination of small national markets and limited interconnection and the resulting fragmentation of the sector at the regional level. It is part of a broader initiative toward economic integration among the Central American countries and with their neighbors. The stated objectives of the SIEPAC project are:

- To improve security of supply by widening reserve margins;
- To reduce the problem of electricity rationing in capacity deficit countries;
- To achieve improved operating efficiency and reduce generation fuel consumption;
- To introduce greater competition into the domestic markets;
- To lower end-user electricity costs;

- To attract foreign investment to the region's energy sector; and,
- To contribute to the economic development of the region.

The SIEPAC project and its participating countries are diverse, both in terms of market development and institutional capacity. The need for a regional institutional design that would recognize and accommodate the differences among the participating countries was recognized early in the process and is required by the Marco Treaty. This feature, which is reflected in the institutions that have been developed, is one of the defining characteristics of the regional market.

Governance Institutions

The Marco Treaty facilitated the creation of three permanent international organizations as legal entities. These are the core regional market organizations:

- The Regional Regulator (the Regional Commission on Electrical Interconnection (CRIE));
- The Regional System Operator and Dispatcher and Regional Market Administrator (Ente Operador Regional (EOR)); and,
- The Regional Transmission Line Company (La Empresa Proprietaria de la Red (EPR)).

CRIE

The Marco Treaty establishes CRIE as a supranational entity with its own juridical identity and powers under public international law. As such, CRIE is subject to and governed by international law through the Central American Court of Justice. Its work lies outside the jurisdiction of national courts. This provides the multi-country market with a unified legal structure that sits above the legal structures supporting the individual country markets. This legal status creates a potentially powerful institution at the regional levels. It also reflects a serious commitment on the part of national governments that have ceded authority to it via the treaty.

CRIE's role is to regulate the MER with the aim of promoting market development and competition in coordination with the national regulators. CRIE's responsibilities include:

- Approving regulations for the market and coordinating these with the country level regulators;
- Setting tariffs for use of the transmission system;
- Facilitating the evolution of the regional market by facilitating competition and guarding against the exercise of a dominant market positions;
- Imposing penalties for noncompliance with market rules;
- Settling disputes among participants; and,
- Approving extensions to the regional transmission network.

CRIE is headed by a board of commissioners comprised of one representative from each of the six member countries. Commissioners are appointed for a term of five years.

The Regional System and Market Operator

The tasks of EOR, the regional system operator, include:

- Proposing rules for MER and transmission system use for approval by CRIE;
- Ensuring quality and security of supply in the electricity system;
- Carrying out the market operation function in an efficient manner; and,
- Settling market transactions among participants.

EOR is also responsible to provide information on market conditions and to develop and publish generation and transmission expansion studies and centrally planning extensions of the regional network.

EOR is also responsible to coordinate market transactions made over the network. MER participants must send their bids and offers for day-ahead transactions in the regional market to EOR which then verifies the technical feasibility of proposed transactions in coordination with market operators in each country.

EOR's board of directors is made up of two representatives for each country, and each are appointed for five-year terms. Like CRIE, EOR is established by the Marco Treaty and it has rights and powers over and above national legislation.

The administrative costs of CRIE and EOR are met through contributions from the governments, fees paid by market participants, and penalties imposed for noncompliance with rules. Both entities have been supported during their design and set up and capacity stages by technical assistance from international donor organizations.

Other Issues

The Regional Regulator and National Regulators

Each country has an electricity regulator. At the regional level, the responsibility for regulation of trade has been ceded by each country to CRIE. The role of the national regulators with respect to the regional market is to monitor and approve firm contracts for international trade to ensure that there is a corresponding firm transmission right. These approvals must be made by regulators in both the buyer and seller countries. If these conditions are not met, CRIE has authority to impose penalties on the generator.

The Marco Treaty

The treaty forms the Intergovernmental Framework Agreement for the Central American Electricity Market and the SIEPAC Project. It is based on the following principles:

- Competition in the electricity market, including nondiscriminatory access to the transmission system;
- Gradual development of the market and expansion to include new participants; and
- Reciprocity in the dealings between countries on the basis of mutually agreed rules.

Under the treaty the countries agree to:

- Form a regional electricity market (MER).
- Create a regional system and market operator (EOR).
- Create a regional regulatory authority (CRIE).

- Establish the regional transmission company (EPR) with each country taking a minority stake; and,
- Build the international transmission line.

Second Protocol to the Marco Treaty

The second protocol to the Marco Treaty with additional adjustments to the Framework Treaty for the MER was reached in 2007. The objectives of this protocol are to:

- Support the treaty's clauses, adapting them to the market's continuing development;
- Define actions or omissions that would violate CRIE's regulations, and establish the respective sanctions; and,
- Establish regional regulation and operation charges to provide financing for the regulator and the regional market operator.

The protocol also requires governments to perform the necessary actions to gradually harmonize their national framework with the regional regulations, thereby facilitating the coexistence of the regional and national markets. The protocol also provides that each country will define the rate at which it will harmonize national regulation with regional.

Dispute Resolution in the Regional Market

The Marco Treaty provides for the settlement of disputes by arbitration and binding resolution. The treaty provides for 2 levels of arbitration:

- For disputes between market participants, CRIE makes binding determinations; and,
- For disputes between treaty signatories, in relation to the interpretation of the Treaty, or the obligations imposed directly on the states under the treaty, resolution is by the Central American Court of International Justice.

Under the MER Regulations, a state may also choose to submit the dispute to CRIE for resolution on a binding basis, or such other forum as the parties may agree.

These treaty provisions and procedures for resolution of disputes through CRIE are expanded upon in the MER Regulations. The regulations provide for a three-step escalating process of negotiation, conciliation and, as a last resort, binding arbitration. CRIE is responsible for both the conciliation and arbitration processes. Dispute resolution is subject to the rules and regulations established within the SIEPAC structure; it is not governed by domestic laws.

The MER Regulations apply to all disputes between the following parties:

- Market Participants;
- National system operators;
- National regulators;
- The EOR and an Market Participants; and,
- The EOR and a national System Operator.

A three-person tribunal, appointed by the Board of Commissioners, acts as the arbitration tribunal. A requirement of their selection is that their nationality does not match that of either party to the dispute.

The procedures do provide for one, limited form of appeal of a decision. An aggrieved party may appeal to CRIE on the basis that the arbitral tribunal acted outside of its legal powers or the decision contravenes overriding norms and principles.

Conclusion

While all of its approaches may not be relevant or applicable to circumstances in the SADC region, the SIEPAC project demonstrates that it is possible to create a relatively advanced regional electricity trading arrangement among countries at different stages of market development and with different electricity industry structures and institutional schemes.

ANNEX 2: A SURVEY OF MARKET AND INVESTMENT FRAMEWORKS IN THE SADC REGION

The following is a brief discussion of the profiles of the electricity sector in each of the SADC Member States. It addresses, *inter alia*, the generation mix, key players in the country, presence or absence of IPPs, as well as other noteworthy national characteristics as they pertain to formulating a regional Market and Investment Framework.

Namibia

Namibia has roughly 420 MW of power generation capacity spread among four major power plants, although available domestic supply falls well short of current demand. Hydroelectricity produces roughly 75% of Namibia's available generation, with three medium-sized thermal generation plants producing the balance. Energy consumption has been growing at 3.5% - 5% annually over the past fifteen years, and the country is dependent on imports, largely through SAPP, for roughly 60% of electricity consumed. Namibia has significant untapped potential in renewables, especially solar PV and wind power, and has ongoing reforms of the legal and policy environment to enable IPPs in the renewables sector in the future. The transmission grid is a major technical limitation for addressing Namibia's power needs. A high voltage DC line (400 kV – 600 MW) that connects Namibia, Botswana and Zambia was commissioned in 2010, and Namibia is connected to Angola and South Africa with AC lines.

The Ministry of Mines and Energy (MME) is responsible for the formulation of energy policy and development. NamPower is the state-owned integrated utility that operates the country's existing power generation and transmission assets, as well as some distribution facilities. The transmission system and trading of electricity are fully managed by NamPower, which is the single buyer and market operator in Namibia.

The Electricity Control Board (ECB) is responsible for regulating electricity generation, transmission, distribution, supply, import and export in Namibia by setting tariffs and issuance of licenses. The transformation of ECB into a regulator with responsibility for both the electricity and gas sectors is underway. A draft of the Energy and Electricity bill establishing ECB's regulatory authority has been submitted to MME for final approval.

ECB approved a bulk tariff for NamPower for the 2014/2015 period of N$ 1.17 (US$ 0.117)/kWh, representing a 13.22% increase over the 2013 tariff. Distribution companies, of which there are several, received approvals for tariff increases in a range of 3% - 15%, and the average retail tariff in Namibia now stands at US$ 0.184/kWh.

In addition to setting tariffs, the ECB issues licenses for any entity involved in generation, transmission, distribution and trade of electricity. An IPP seeking to generate power obtains a license from the ECB, which must then also be approved by MME. After a license is issued, the IPP must negotiate a PPA with NamPower. ECB has granted licenses for 19 IPPs, including one 44 MW wind farm and 13 separate solar PV facilities, although none of these facilities are currently operational.

The MME is reviewing a number of Namibia's energy laws and policies with a goal to allow for increased public sector and IPP generation, especially in renewable technologies. A Renewable Energy Act and an overall Energy Efficiency Act are in preparation. ECB is overseeing additional projects to determine the optimal resource mix for electricity generation in the country, and to allow for transparent tendering by the private sector for all power projects exceeding 5 MW. ECB and the MME are reviewing policies for REFiTs on projects less than 10 MW. NamPower has negotiated PPAs with several IPPs to develop new renewable energy projects, although capacity factors associated with intermittent supply and the reliability of the transmission network are an ongoing issue.

The Kudu Power Plant (800 MW CCGT), to be developed by NamPower, has been designated a national priority. The government will seek an EPC contractor for Kudu but intends to retain ownership of the project.

Malawi

Malawi has roughly 315 MW of power generation capacity, with four hydropower facilities on the Shire River supplying over 90% of grid-connected electricity. Energy consumption has been growing annually and domestic supply falls well short of demand. Load shedding has been a frequent occurrence in Malawi in recent years. Malawi has untapped potential in renewables, especially wind and additional hydro potential, and has ongoing reforms of the legal and policy environment to enable IPPs in the renewables sector in the future. Roughly 85% of Malawians live in rural areas that are underserved by grid connections, and off-grid/rural generation projects are likely to be a major component of the country's long term energy planning.

The Electricity Supply Company of Malawi (ESCOM) is the state-owned integrated utility controlling most of the country's generation, transmission, and distribution assets. ESCOM has suffered from under-investment over many years, and the current transmission and distribution infrastructure is susceptible to overloading, bottlenecks, and poor performance. Additional investment is needed in transmission infrastructure to fulfill planned expansions in generation capacity.

Malawi's National Energy Policy is the primary legal document governing national energy development. The Department of Energy Affairs (DoEA) is housed within the Ministry of Natural Resources, Energy and Environment (MNREE) and has oversight over the development and delivery of energy policy in the country. Target energy reforms and policies are also espoused in Malawi's second Growth and Development Strategy (MGDS) for 2011 – 2016. MGDS II's main energy pillars involve strengthening the transmission and distribution networks and developing additional generation projects, especially hydropower, to address the current supply shortfall.

Malawi's energy regulator, the Energy Regulatory Authority (MERA), was established in 2007 to oversee tariff policies and regulate the electricity sector. MERA approved a phased, four-year tariff increase to migrate retail tariffs from $.0742/kWh to $.1017/kWh, starting in 2014. The initial 13.5% tariff increase took effect in April 2014.

MERA issues licenses for any proposed entity involved in generation. Private generators must sell to ESCOM through a PPA. There currently are very few, if any, IPPs selling into the national grid in Malawi.

South Africa

South Africa's installed capacity of about 47,500 MW consists almost entirely of thermal generation, with coal fired power stations contributing approximately 90% of capacity, nuclear power contributing about 5%, and the remaining 5% coming from hydroelectric plants and a small amount from wind stations. While South Africa's renewable energy market is still nascent, the country has made strides to achieve its plans to expand renewable electricity capacity to 18,200

MW by 2030. The South African economy is extremely energy intensive. The mining and industrial sectors consume about 60% of the power in the country, while the inclusion of commerce increases the share to about 75%. Residential consumers only account for 16- 18% of the power consumed, and poorer households account for an even smaller portion.

The electricity sector in South Africa remains mostly vertically integrated at the generation and transmission levels, with Eskom, the national utility supplying approximately 95% of the electricity, with the remainder coming from IPPs and imports. Although Eskom is involved in every area of the electricity sector, from generation, to transmission and retail, distribution activities are also handled by 175 re-distributing municipalities, as remnants of the restructuring efforts of the Electricity Distribution Industry Holdings. While Eskom does not have exclusive generation rights – see notes on the IPP program below -- it has a near monopoly on wholesale power. Eskom sells in bulk to municipalities which distribute to consumers within their borders, supplies electricity directly to commercial farmers, and through the Integrated National Electrification Program (INEP), supplies to a large number of residential customers. It also operates the high voltage transmission system in the country.

The Department of Energy (DoE) is the primary government institution responsible for energy policy and planning. The National Energy Regulator of South Africa (NERSA) is the regulatory authority that presides over the electricity supply industry. NERSA's functions include issuing licenses, setting and approving tariffs and charges, mediating disputes, gathering information pertaining to gas and petroleum pipelines, and promoting the optimal use of gas resources. In February 2013, NERSA announced the third Multi-Year Price Determination and approved an 8% average tariff uplift per year for the following five years. The average tariff was set to increase from ZAR 0.6551 (US$0.06)/kWh in 2013/2014 to ZAR 0.8913 (US$0.08)/kWh in 2018.

South Africa has two acts that direct the planning and development of the country's electricity sector; the National Energy Act of 2008 and the Electricity Regulatory Act (ERA) of 2006. In August 2011, the DoE instituted a competitive bidding process called the Renewable Energy Independent Power Producer Procurement Program (REIPPP). The REIPPP was initially designed to deliver a target of 3,725 MW of renewable energy to stimulate the renewable energy industry in South Africa. Bidders are required to bid on tariff and identified socio-economic development objectives of the DoE. The tariff will be payable by the buyer (Eskom) according to a PPA entered into between the buyer and the bidder's project company. The generation capacity allocated to each technology and the maximum amount that a bidder may bid were set out by the DoE.

In the latest bidding window, the auction was characterized by high levels of competition which resulted in the lowest bid prices to date. The large number of competitive bids prompted the government to consider awarding additional capacity. The successful bids, totaling 1,456 MW, comprised 787 MW of wind projects, 450 MW of PV projects, 200 MW of solar thermal, 18 MW of landfill gas capacity, and a 16.5 MW biomass project. The successful projects will enter into PPAs with Eskom and receive guaranteed payments for 20 years.

Table 2: ESKOM Tariff Increases

Year	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
Average Price (c/kWh)	65.51	70.75	76.41	82.53	89.13
Percentage Price Increase	8%	8%	8%	8%	8%

Mozambique

Mozambique has a total installed generation capacity of 2,308 MW, comprised almost entirely of one hydropower facility (2,075 MW) with natural gas contributing the remainder. The country is a net exporter of electricity with 73% of the 2,075 MW generated by the Hidroelectrica de Cahora Bassa (HCB), which is exported to South Africa. Mozambique's electrification rate is just 14% and it is estimated that 26% of urban areas have access to power, while only 5% of the rural areas do. Power transmission in Mozambique is a major constraint to sectoral advancement. The size of the country and the dispersed nature of its settlements render grid connectivity to the whole population unfeasible. Further, HCB, which is located in western Mozambique, must first sell power to Eskom, which in turn sells some of it back to Southern Mozambique at an increased rate. As such, there is no direct line between the power source and main load center, Maputo. Additionally, the long distances involved wastes a considerable amount of power due to line losses. Energy demand has grown considerably, at an average of 7-8% per year, leading to blackouts.

Electricidade de Mocambique (EDM), the state-owned, vertically integrated electricity supplier, is the major player in the Mozambican electricity sector. While ECB is vertically integrated, it has limited generation capacity of its own. HCB, the major generator and largest hydroelectric scheme in Southern Africa, is an IPP owned by the Mozambican government. The Mozambican Transmission Company (MOTRACO) is an independent transmission company owned by EDM, Eskom and Swaziland Electricity Board (each owning 33%), and is responsible for supplying electricity to the Mozal aluminum plant in Mozambique, and the wheeling of power to EDM in Mozambique and Swaziland Electricity Company. The Ministry of Energy (Ministerio de Energia, hereinafter, "ME") is responsible for all energy resources, while the National Directorate for Electrical Energy (DNEE) is the central technical body within the ME responsible for the analysis, preparation and elaboration of energy policies.

The Electricity Law, enacted in 1997, provides that the state will ensure the participation of the private sector in the electricity sector and guarantees the use of energy resources while protecting the interests of the state. The construction and operation of power plants and the production of electricity in Mozambique can be done under a concession agreement granted by the Government of Mozambique. The granting of concessions is subject to public procurement and for plants with a power output of more than 100 MW, approval of the Council of Ministers is required.

The concession contract will set out the standard of performance required by the project company, the rights of inspection to be granted to government bodies, the rights of the concessionaire to suspend performance where it is affected by force majeure and the circumstances in which the concession contract may be terminated. The Electricity Law also acknowledges that, where the authority granting the concession issues a termination notice, the concession contract may require that notice is also given to the concessionaire's lenders and that the lenders have the right to cure the default giving rise to termination within a period stated in the notice. The concessionaire is also permitted to terminate the concession where the state has committed a material breach of its obligations, which prevents the concessionaire from complying with the concession contract. Upon termination for a default by the state, the state is required to pay compensation covering the outstanding value of the unamortized investment made by the developers. The concessionaire is required to pay annual concession fees based on its gross revenues.

In addition to entering into a concession contract, the project company will need to enter into a PPA for the sale of its capacity and energy. There is no prescribed form of PPA and as such tariffs are essentially set by contract, rather than being subject to regulatory approval. The Energy Law requires that tariffs are fair and reasonable.

Angola

Angola's electricity infrastructure was severely damaged during its civil war. At present, the country has a generation capacity of 1,700 MW which consists mainly of hydropower (60%) with the remainder coming from fossil fuels, which is insufficient to meet current demand. The country does not have a national grid, but instead relies on three independent systems that provide electricity to different parts of the country. The government hopes to link the three independent systems as part of a national grid, and eventually link up with neighboring SAPP countries. Estimates indicate that only 40% of Angolans have access to electricity, however, in 2011, the Angolan government announced its intentions to invest $16 billion in the electricity sector by 2016 to improve the country's distribution and transmission infrastructure. Some analysts indicate that Angola's hydropower capacity is more than 10 times the current installed capacity, but no tangible plans to develop the country's hydroelectric resources have emerged. Given Angola's intent to commercialize its natural gas resources, natural gas fueled generation is likely to become more important.

The Ministry of Energy and Water is responsible for the electricity industry and preparation of regulations in the sector. The Regulatory Institute of the Electrical Sector (IRSE) is the Angolan regulatory authority responsible for regulating the generation, transmission, distribution and sale of electricity. It has the mandate of regulating the business relationships between agents in the power sector, including the specification of tariffs and of revenue transfer models between players, as well as performing arbitration duties.

The 1996 General Law of Electricity and the Law on Delimited Areas of Economic Activities are the fundamental laws that underpin the legal framework of the Angolan power industry. The Delimited Areas of Economic Activities law states that the generation, transmission and distribution of electrical power for public consumption are "relatively reserved areas", meaning private entities require a state concession to enter the sector. While Angola's legal framework does not prohibit private sector investment, the low tariffs caused by the government's direct and implicit subsidies and concessions make it unattractive to private sector players. Further, though a National Investment Promotion Agency (NIPA) was created in July 2003, and though an Act on privatization was enacted in April 2002, no major privatization in the energy sector has been scheduled or realized.

Various laws and regulations have been instituted regarding the energy and electricity sectors. The General Electricity Law of 1996 states that the Council of Ministers has the power to grant concessions (for projects greater than 1 MW or when there are more than 50 000 inhabitants), while provincial governments have the power to grant licenses. More recently, the government set out the Policy and Strategy for National Energy Security and indicated focus will be on, among other things, defining an attractive model for private sector investment and its legal framework as well as reinforcing powers of the IRSE while progressively eliminating electricity price subsidies.

Zambia

Zambia has a total installed capacity of 1,967 MW, which is predominantly hydropower (96%), with the rest thermal (4%). Demand for power in Zambia has been growing steadily over the past few years with growth rates estimated at 6% per year, while generation capacity has remained fairly stagnant over the past 30 years. The mining sector still accounts for nearly half of Zambia's electricity consumption, and as such the performance of the mining sector is important for electricity demand. On the other hand, only 25% of the Zambian population has access to electricity and in the rural areas, the level of access is less than 5%.

The Zambia Electricity Supply Corporation (ZESCO), the largest power utility in Zambia, is the state-owned, vertically integrated company responsible for the vast majority of national generation activities. Copperbelt Energy Corporation (CEC) is a privately owned company created after the privatization of the Zambia Consolidated Copper Mines (ZCCM) power division. The company owns transmission and distribution networks in the copper belt region of Zambia and purchases 55% of the power generated by ZESCO, which it in turn supplies to the mines. CEC also owns an additional 90 MW. Finally, Lunsemfwa Hydro Power Corporation is a privately owned IPP created after the privatization ZCCM. It is the only IPP in the country and has an installed capacity of about 38 MW (2% of national design capacity) that it sells to ZESCO under a PPA.

The Energy Regulatory Board (ERB) is the regulatory agency in Zambia responsible for, among other things, ensuring utilities earn a reasonable rate of return on investments sufficient to provide quality services at affordable prices to the consumer, ensuring that all energy utilities are licensed, monitoring levels and structures of competition, and tariff setting. The Ministry of Energy and Water Development (MEWD) has the overall responsibility for power and both ZESCO and ERB report to MEWD.

Zambia has some of the lowest electricity tariffs in the region. For example, in 2011, while revenue collection was high (96.5%), estimated cost recovery was very low (39.1%) due to non-reflective tariffs. Some observers posit that underpricing and related subsidies in the power sector can easily cost the country over $150 million per year. To stimulate private investment in the ESI, Zambia initiated power sector reforms that entailed unbundling and privatization of the national power utility, an increase in electricity tariff, and stimulating private sector involvement through additional incentives. In April 2014, the ERB approved the application by ZESCO and CEC to increase the bulk power supply tariff by 29%, from 5.31 cents/kWh to 6.84 cents/kWh. Subsequently, in July 2014, following an application made by ZESCO in July 2012, the ERB approved a 25% tariff increase for domestic customers. The tariff levels had remained unchanged since 2010.

Studies indicate that Zambia has potential hydropower capacity of about 6,000 MW, with only a third of the potential utilized. In order to undertake a project in the electricity sub sector, any licensee or unlicensed entity intending to construct a new generation, distribution or transmission asset will have to complete and submit and investment endorsement form to the ERB. The project developer must also submit together with the investment endorsement form, a business plan, audited financial statements, proof of funds, certificate of incorporation, and diagrams and schematics of the proposed works. Following the submission of documents, the ERB will inspect the site and if the site passes the inspection, economic valuation for the purpose of tariff determination will start. The project developer is expected to justify their proposed tariff and the ERB will let the developer know which costs are deemed reasonable, justifiable and purposeful. Subsequently, the ERB will advise the developer of the tariff as well as provide an endorsement that includes the tariff, the approved technical specifications of the project as well as the timetables for completion.

Botswana

Botswana’s installed capacity of 132 MW consists almost entirely of thermal generation (mainly coal). Peak power demand was expected to increase from 578 MW in 2012 to 902 MW in 2020, representing a 56% increase. With peak demand currently around 598 MW, and current supply of 392 MW (excluding 200 MW emergency supply from Eskom), there is an energy shortfall of around 200 MW. The country is over dependent on imports which poses a threat to the energy security of the country. Eskom, for instance, has been struggling to meet its own demand, and as such has been forced to cut down on imports. Eskom supplied 350 MW of electricity to Botswana in 2009, which was cut back to 250 MW in 2010 and further cut to 150 MW in 2011 and 2012. Therefore, Botswana had to find alternative sources of imports, such as securing 90 MW from Mozambique. New generation capacities will most likely be based on coal, given the country's focus on coal exploration as well as the large untapped deposits in the country. Botswana aims to become a net exporter of power in the region.

Botswana Power Corporation (BPC) is a state owned vertically integrated national utility with a monopoly over the power sector. In 2007, the government amended the Energy Act to facilitate the participation of IPPs in the country. There are plans to restructure the electricity supply industry in accordance with the country's membership in SAPP. There are, however, no current plans to restructure BPC. The decisions on energy policy are split between two ministries; the Ministry of Minerals, Energy, and Water (MMEWR) and the Ministry of Environment, Wildlife, and Tourism (MEWT). MMEWR is responsible for national energy policy formulation and provision of energy while the MEWT is tasked with conservation and sustainable use. A regulatory agency, the Botswana Energy and Water Regulatory Agency (BEWRA), is in the process of being established. It is envisioned to be an independent agency that will hopefully help attract private investment into the power sector by guaranteeing cost recovery tariffs, among other things.

The tariff rates in Botswana are still below cost reflective levels despite some recent tariff increases. In March, BPC was given permission to increase its tariff rates by 10%, following a 7-10% increase for domestic customers and 7%- 20% increase for business customers announced in April 2013. Even after these recent tariff increases as well as significant tariff increases in 2010 and 2011, the government continues to subsidize the cost of electricity by providing revenue support to BPC. The Energy Minister noted that losses at BPC had necessitated the increases in tariffs. Additional generation capacity is more likely to be owned by IPPs given the limited financial means available to the loss making BPC.

Botswana is introducing feed-in tariffs for a renewable energy scheme, which was approved in July 2012, and was proposed to be implemented in 2013. The purpose of the scheme is for BPC to purchase electricity produced from renewable energy resources at cost reflective prices. The use of renewable energy at present is minimal in Botswana but the Government has started to develop a low carbon energy portfolio. Also, the country's National Development Plan (NDP 10) aims to see an increase of renewable energy usage to 15% by 2015 and 25% by 2030.

Lesotho

Lesotho has an abundance of hydroelectric power, which generates most of its electricity needs. However, improving electricity access continues to be a major challenge for the country. Even though the country is relatively small, two-thirds of it is sparsely inhabited and is comprised of rugged mountains and deep valleys with small scattered villages on mountain sides. The vast majority of the population (76%) lives in rural areas, with the majority of the villages lacking electricity access. Currently, Lesotho's internal generation satisfies only 63% of its demand and the shortfall is covered by purchasing electricity from Eskom (South Africa) and EDM (Mozambique).

The electricity supply industry (ESI) is dominated by two state-owned entities—the Lesotho Electricity Company (LEC), the monopoly transmitter, distributor and supplier of electricity and the Lesotho Highlands Development Authority (LHDA), the main internal generator through the Muela hydropower plant (MHP). LEC's own combined generation from four small-hydro power stations is only 3.25 MW while MHP has a generating capacity of 72 MW. While an attempt was made to privatize LEC in 2001, the efforts were not successful, and the company is still wholly owned by the government. To date, LEC and the LHDA remain the main players in the Lesotho ESI. However, due to the planned extension of the electricity grid, and the goal of privatization of the energy sector as set out in the Energy Policy for the Kingdom of Lesotho, there might be room for development for small role players.

The Department of Energy (DoE), which falls under the Ministry of Natural Resources, is the government department responsible for the implementation of all energy policies. The DoE is responsible for overall national energy policy, coordination, and monitoring of energy projects and programs. Since 2013 Lesotho's ESI is regulated by a multi-sector regulator known as the Lesotho Electricity and Water Authority (LEWA). Activities regulated by LEWA encompass the generation, transmission and distribution of electricity, and the supply as well as import and export of electricity. LEWA's prime responsibility is to ensure that the supply of electricity is provided to customers in an affordable, reliable and cost effective manner through the implementation of mechanisms and policies that promote, monitor and evaluate local private sector participation in the efficient financing and timely construction of electricity programs. LEWA is also responsible for granting licenses, reviewing and approving tariffs, monitoring their quality of supply and solving disputes among industry players.

LEC has been granted tariff increases in all of the recent years. In April 2014, LEWA granted the LEC an average tariff increase of about 12%, raising the domestic use tariff to about US$0.10/kWh.

LEC is responsible for electrification within its service territory. Outside of LEC service territories, rural electrification efforts are managed by the Rural Electrification Unit (REU) which falls under the DoE. LEWA has set up a Universal Access Fund which disburses monies for purposes of subsidizing the capital costs of electrification in the country to facilitate the development and expansion of electricity service infrastructure in areas which have been identified by the government. The source of the money in the fund is an electrification levy from the Lesotho Electricity Company (LEC).

Swaziland

Swaziland's installed capacity of 64 MW consists almost entirely of hydropower. The national utility, Swaziland Electricity Company, operates four hydropower stations that serve as peaking and emergency power stations. These stations contribute 15-17% of the total energy consumed in the country with the vast majority of the supply (~80%) coming from Eskom and EDM. A further 9 MW of diesel fired generators are installed at Edwaleni, however, they are no longer used due to high operational costs. There are also five cogeneration plants in the sugar industry and the paper and pulp industries. The sugar industry, however, uses bagasse during the milling season and coal in the off-milling season.

The Swaziland Electricity Company (SEC) has a monopoly on the import, distribution and supply of electricity in the country. One of the private co-generation plants, Ubombo Sugar Limited, is also an IPP as it sells some of its excess power to SEC, providing about 3% of the country's power needs. The sugar industry, however, is still a net buyer of electricity from SEC. The legal energy policy and planning framework in Swaziland is controlled solely by the government via the Ministry of Natural Resources and Energy. Regulatory authority in the sector lies with the Swaziland Energy Regulatory Authority (SERA). SERA's responsibilities include receiving and processing applications and modifications of licenses, approving tariffs, prices, charges and terms and conditions of operating a license, and monitoring the performance and the efficiency of licensees. SERA is also responsible for investigating and adjudicating complaints.

After lodging an application for a 16% tariff increase, the SEC received approval for a 10% increase by SERA in January 2014. Given the country's dependence on power from Eskom, tariffs in Swaziland are usually tied to bulk tariff increases instituted by Eskom on SEC. Eskom has increased the tariff to SEC by an average of 9% previously and the 16% increase requested by SEC was viewed to be too high. SERA also approved an increase of 6.8% on fixed charges, in line with inflation. For 2013/2014, the SEC submitted an application for a tariff increase of 36.5%. However, SERA's approval was for an increase of only 9%.

The Government has stated that rural electrification will continue to be a priority and efforts in that regard shall be led by the State. The Electricity Act (2007) and the Swaziland Electricity Company Act (2007) created a regulatory authority for the electricity sector and instituted a structural reformation of the national utility. The Electricity Act also created the framework for IPPs to enter the electricity sector, with licensing provided SERA. Uptake by IPPs, however, has been limited.

The Ministry of Natural Resources and Energy commissioned a study to establish a database on the potential of developing mini-micro hydropower electricity schemes. A report produced from the study identified 35 sites, ranging from 0.032 MW to 1.525 MW. It is estimated that Swaziland has a gross hydropower potential installed capacity of 200 MW. For project developers, the main identified barriers to developing projects in the country include the difficulty of mobilizing funding for investments which leads to severe delays in project implementation, the small size of the local energy market, limited natural resources in the country.

Zimbabwe

Zimbabwe's installed capacity of 1,990 MW is split between hydropower (57%) and thermal (43%). In recent years, as various Zimbabwean facilities have either partially or completely gone off-line, much of the country's electric power (30%) has come from Mozambique, South Africa, the Democratic Republic of Congo and other countries in the region. No major new project developments have occurred in the generation sector of the country since the commissioning of the Hwange coal plant (the largest thermal facility in the country) in 1988. It is estimated that only 60% of the country's installed capacity is available. While there are large coal deposits in the country, the company that provides coal to the Hwange Thermal Power Plant does not have the financial resources to significantly boost output. Access to electricity is estimated nationally at nearly 40%, with urban access standing at nearly 80%. Access to electricity in the rural areas, however, is much lower, at about 19%, due to prohibitive costs of extending national electricity grids.

In accordance with government policy to embark on reforms in the electricity sector, a new Electricity Act was enacted in 2002, which brought about the restructuring and unbundling of the Zimbabwe Electricity Supply Authority (ZESA) from a vertically integrated utility into unbundled successor companies. These reforms were meant to encourage private participation through IPPs, however, there has been limited private participation, and as such the successor organization, the government-owned ZESA Holdings and its subsidiaries still dominate the sector. The vast majority of internal generation is still done by the Zimbabwe Power Company (ZPC), a ZESA Holdings subsidiary which owns and operates four thermal stations and the Kariba Hydropower Station. Transmission and distribution is still solely done by the Zimbabwe Electricity Transmission and Distribution Company (ZETDC), another ZESA Holdings subsidiary. Regulation of the sector is done by the recently formed Zimbabwe Energy Regulatory Authority (ZERA). ZERA is responsible for issuing licenses in the energy sector as well as receiving and evaluating tariff applications. Formulation of the legislative and regulatory frameworks of the electricity sector is handled by The Power Development Department within the Ministry of Energy and Power Development. The

Power Development Department is also responsible for administrating the national utility, ZESA Holdings and its subsidiaries.

Electricity tariffs in Zimbabwe are still lower than the regional average of about US$0.14/kWh. While the government conducted a cost of service study in 2004 which recommended tariff levels and tariff methodology to be used in determining electricity tariffs, the resultant tariffs proved uncompetitive for private investors. Consequently, there was little uptake by private players leaving the power utility ZESA with a monopoly over the country's power supply. After the adoption of the multi-currency regime in 2009, a tariff of US$ 0.0983/kWh was awarded to ZETDC, but was later reversed and replaced by a lower tariff of US$.0.0753/kWh. A 31% tariff increase was approved in 2011, restoring the tariff level back to US$0.0983. In 2013, a 0.3% tariff increase was approved raising the tariff to US$0.0986 and more recently, in August 2014, ZERA declined ZETDC's request to lift the average tariff by 5%, opting instead to maintain the US$0.0986. However, ZETDC instituted a tiered pre-payment tariff for its customers, which ranged from US$0.02/kWh for the first 50 kWh to US$0.15/kWh for customers exceeding 300 kWh.

Zimbabwe has been actively seeking IPP bids to improve its power supply situation. The country has invited bids for a number of projects including the construction of the 1,400 MW Gokwe North coal station on the Sengwa coal field, and its associated transmission infrastructure. On the smaller end of the scale, a 1.1 MW run of the river mini-hydro plant was commissioned in August 2010. The plant is operated by Nyangani Renewable Energy (Pvt.) Ltd., and all generated power is sold to the ZETDC under a PPA at a tariff of US$0.16/kWh. The company has also been issued a license for the construction of a further 18 MW of capacity in the area.

Tanzania

Tanzania's installed capacity of 1,583 MW is almost equally divided among Hydro (561 MW), natural gas (527 MW), and liquid fuels (495 MW). Given Tanzania's traditional reliance on hydropower, the country has been very susceptible to drought induced power shortages. As such, droughts in 2010 resulted in significant power supply shortages and the utility was forced to engage emergency power producers to bridge the gap. While demand for electricity in the country is growing on average between 10 to 15% every year, only about 24% of the mainland Tanzanians have access to electricity.

The Ministry of Energy and Minerals (MEM) is responsible for all energy related matters on mainland Tanzania. Under MEM, the Tanzania Electric Supply Company (TANESCO) is the state owned, vertically integrated utility, responsible for generation, transmission and distribution in the country. Regulatory responsibilities of the electricity sector lies with the multi-sector regulatory agency - Energy and Water Utilities Regulatory Authority (EWURA). EWURA has a myriad of responsibilities including licensing, tariff review, and monitoring performance. Tanzania has two large IPPs in operation; Independent Power Tanzania Limited (IPTL), a 100 MW HFO powered plant which was the first IPP to sell power to TANESCO and Songas, an 189 MW natural gas fired plant. TANESCO also engages Emergency Power Producers (EPPs) during drought years and recently, the government engaged with Aggreko (100 MW) and Symbion (112 MW + 105 MW) to generate power on a short term basis. Tanzania also imports power from Uganda (10 MW), Zambia (5 MW), and Kenya (1 MW).

Tariffs in Tanzania are still among the lowest in the East Africa region. In 2013, after requesting a 68% increase in average tariffs from EWURA, TANESCO received approval for an average increase of 39% effective in January 2014, raising the average tariff from US$0.12/kWh to US$0.16/kWh. While this tariff level is expected to remain in force until December 2016, TANESCO will be subject to quarterly reviews to ensure it implements projects cited in the tariff increase application. This latest increase in January 2014 followed another 40% tariff increase approved 2011 and together brought the tariff level much closer to cost reflectivity.

Tanzania is actively trying to remedy the power situation in country and, in June 2014, MEM introduced the Tanzania Electricity Supply Industry Reform Strategy and Roadmap. The roadmap, which covers the period from 2014 to 2025, proposes a framework for the reform of the electricity sector. The Roadmap covers pertinent issues such as restructuring the market from a vertically integrated national utility structure, as well the proposed reform timeline. The roadmap envisages that the ESI market in Tanzania in 2025 will consist of an unbundled distribution segment with zonal distribution companies listed on the Dar es Salaam Stock Exchange (DSE), an unbundled generation segment, with a DSE listed generation company and IPPs, an independent system operator and an independent market operator.

In the renewable energy sector, Tanzania has had a feed-in tariff scheme in place for small power producers (up to 10 MW). These Feed-in tariffs for small power producers based on avoided cost of electricity and are undifferentiated by technologies. While the FiT are adjusted annually by EWURA, there is no guaranteed price over the long term even if a PPA is signed for a 15-year period. For projects bigger than 10 MW the FiT is negotiable. More recently, EWURA has been working on another framework for REFIT IPPs. The effort is meant to address some of the shortcomings of the original FIT program, such as non-specificity of the tariff to technology type, seasonal tariff fluctuations and the tariff being denominated in Tanzanian shillings.

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ANNEX 3: CASE STUDIES IN DISPUTE SETTLEMENT AND APPEALS PROCEDURES

Chile: Expert Panels to Settle Regulatory Disputes

For more than thirty years Chile has used expert panels, that is, specialized independent, ad hoc entities affiliated with neither the government nor the sector regulator, to resolve disputes arising from regulatory decisions. The Chilean experience offers useful lessons for SADC region policy makers.

Another option is to create a specialized independent, ad hoc entity, affiliated neither with the government nor the regulator that can be called upon to provide a decision or opinion on a dispute. This mechanism known as an expert panel, is a common enough institution for the resolution of disputes on the interpretation of commercial contracts and conflicts relating to foreign investment and international trade. Its use in economic regulation is less common.

Expert panels in Chile have the following features:

- Their functions are defined narrowly by law and involve resolving regulatory disputes between government regulators and private companies (in the electricity sector they can also settle disputes between companies);
- The panels are not intended to replace sector regulators or the courts, but they may, according to the law, be assigned some of their traditional duties;
- Their aim is to resolve specific conflicts based on economic and technical criteria defined in legislation, sub-legislation and regulatory instruments; and,
- They co-exist with other entities that also serve as appeal bodies, such as the courts.

The 1982 Electricity Law in Chile sets out the market structure and regulatory framework, including mechanisms for determining distribution and transmission fees. The law was amended in 2004 at least in part to modernize the mechanisms for resolving regulatory disputes. The law established a permanent expert panel to resolve the wide range of disputes that arise in the power sector between the regulator and regulated companies. The expert panel can also consider disputes arising between companies such as on transfer of payments due to power and capacity exchanges between generation companies.

The panel consists of seven members with six-year staggered terms. They are nominated by another independent body, the Competition Tribunal, according to a competitive public process. In order to foster greater independence, consistency and specialization, a permanent body rather than a number of ad hoc bodies was chosen.

Decisions by the panel are binding, strengthening its powers of conflict resolution. It is interesting that the panel's powers to craft a decision are narrowly drawn, in that it is required to select the proposal of one of the parties to the dispute rather than develop its own or to "split the difference". This was intended to prevent excessive demands as well as to make the panel's work easier. Under these rules, the panel does not need to identify the optimal solution, only the "least worst" one. The law sets out in detail rules and procedures for the panel in order to ensure transparency and due process (a specified calendar, mandatory hearings, justification and publication of decisions). The panel's costs are approved annually by the regulator, the National Energy Commission, and are paid by all power sector companies in proportion to their fixed assets.

Tanzania: Regulatory Tribunals

The Energy and Water Regulatory Authority of Tanzania (EWURA) is the electricity sector regulator. The act establishing the regulator (the EWURA Act) provides for two types of procedures to settle contentious matters (excluding internal reviews).

- First, a procedure to resolve a customer's complaint. It addresses the matter of an unresolved complaint brought by a customer against a service provider that has been raised to the awareness of the authority.
- Second, the settlement of a dispute between service providers or involving service providers in a sector regulated by the Authority.

Related to every EWURA Proceeding (defined as a formal process of fact finding and decision making undertaken by the Authority in the discharge of its legal obligations) is the possibility that EWURA will need to conduct a formal investigation into a matter before issuing a decision.

EWURA's role in conducting investigations and settling contentious matters (either under the complaint procedures or the dispute procedures) is quasi-judicial in nature. When the Authority takes a decision related to any of these matters, it is doing so in a way that will unavoidably result in legal consequences. For an unsatisfied participant in the process, the Authority's decision will also trigger the right of an appeal to the Fair Competition Tribunal (FCT). The Fair Competition Tribunal is a specialized dispute settlement body established under the Fair Competition Act. The tribunal is the assigned appellate body for all of Tanzania's regulated infrastructure sectors (Water, Electricity, Petroleum, Gas, Telecoms, Air and Marine Transport, etc.).

As stated, the grounds for an appeal to the FCT from a decision of the regulator are extremely limited. The FCT will not conduct a full review of the matter. It will not revisit the facts adduced by EWURA (the de-facto and de jure court of first instance). It will simply look at issues such as:

- Was the decision supported by the evidence?
- Was there a misapplication of law?
- Was there respect for established procedures?
- Did the Authority have appropriate jurisdiction over the matter in the first place?

If these questions can be answered affirmatively, the regulator's decision will stand.

The FCT is comprised of a number of High Court Judges who sit on this specialized judicial body. The FCT establishes its own rules of procedure but is required to sit in a three judge panel when hearing an appeal. The FCT may, after hearing the appeal dismiss the appeal in whole or in part or set aside the award in whole or in part and refer the matter back to the Authority for re-determination with or without directions as to the matters to be taken into account in the re-determination. It may also make such orders as to the payment of any personal costs of the appeal as it deems appropriate to any person aggrieved by the decision or order of the regulator.

Any party aggrieved by a decision of the FCT may apply for revision to the High Court which also sits in a bank of three judges. The High Court judge sitting as Chairman of the FCT shall not sit as a member of that revision panel.

Finally, any person aggrieved by a decision of the High Court sitting in revision of an FCT decision may appeal to the Court of Appeals.

Central America: CRIE and SIEPAC

The CRIE and SIEPAC (Central American Electrical Interconnection System) Regulatory Model are discussed elsewhere in this Report. It is relevant, however, to recapitulate here its provisions related to dispute settlement and appeals.

The Marco Treaty provides for the settlement of disputes by arbitration and binding resolution. The treaty provides for 2 levels of arbitration:

- For disputes between market participants, CRIE makes binding determinations; and,
- For disputes between treaty signatories, in relation to the interpretation of the Treaty, or the obligations imposed directly on the states under the treaty, resolution is by the Central American Court of International Justice.

Under the MER Regulations, a state may also choose to submit a dispute to CRIE for binding resolution or to such other forum as the parties agree to.

These treaty provisions and procedures for resolution of disputes through CRIE are expanded upon in MER's Regulations. They provide for a three-step escalating process of negotiation, conciliation and, as a last resort, binding arbitration. CRIE is responsible for both the conciliation and arbitration processes. Dispute resolution is subject to the rules and regulations established within the SIEPAC structure. It is not governed by domestic laws.

The MER Regulations apply to all disputes between the following parties:

- Market Participants;
- National system operators;
- National regulators;
- The Regional System Operator and an Market Participants; and,
- The Regional System Operator and a national system operator.

A three-person tribunal appointed from the CRIE board acts as the arbitration tribunal. A requirement of their selection is that their nationality does not match that of either party to the dispute.

The procedures do provide for one, limited form of appeal of a decision. An aggrieved party may appeal to CRIE on the basis that the arbitral tribunal acted outside of its legal powers or the decision contravenes overriding norms and principles.

Analysis

Each of the above-cited case studies brings something to the table. The CRIE/SIEPAC example is useful because it takes into account the fact that there may be disputes that rise to the level of international law and require high-level procedures. For its part, the Tanzania model recognizes the need for specialization, the need to avoid the courts (while taking advantage of High Court professionalism) as much as possible, and the need for transparency, and the need for quasi-judicial treatment at all levels. The Chilean model echoes that need for expertise, to protect independence and to avoid national judicial systems.

Each model also has drawbacks and unfeasible solutions. For example, under the proposed regional regulator model, there will be no possibility to appeal to a court because RERA, being established by a treaty, sits above Member State institutions. Without recourse to a judiciary the only avenue for an appeal is by way of arbitration. Arbitration opens the door to a discussion of whether institutional arbitration is appropriate or whether ad hoc arbitration is more useful. Chile made the choice for institutional arbitration and established the institution itself. Then, there is the issue of procedural rules. The need to protect and respect due process (natural law) has already been recognized. A number of arbitration rules and procedures exist outside of institutional arbitral bodies (ICC—Paris, LCA—London, ICSID—Washington, etc.) including the UNCTRAL Rules, which are widely employed in ad hoc arbitration proceedings. The Chilean model also raises questions about the equity of requiring the arbitral panel to only select “one or the other” proposed solutions. An accommodation might be made to use a panel but to allow it to widen the door to other possible outcomes besides the “least worst” option.

ANNEX 4: THE ROLE OF DUE DILIGENCE IN DEVELOPING THE NEW LEGAL AND REGULATORY FRAMEWORK

Part 1: The Role of Due Diligence in Developing the New Legal and Regulatory Framework

Sector legislation should clearly provide a separation between policy making and regulation. Typically this is done in the Electricity Act, which provides that the Ministry responsible for the electricity sector is also the relevant policy making body. The Ministry's obligations should include:

- The promotion of medium and long-term investment in the sector;
- The identification and mobilization of credit resources;
- Liaising with the regulatory body and other sector stakeholders;
- Participating in the development of appropriate legal and regulatory frameworks;
- Promotion of environmental protection;
- Support for the development of transit and import/export relationships in the sector;
- The implementation of state programs to increase energy efficiency; and,
- The promotion of renewable sources of generation.

While in some countries, the Minister will approve such things as the Electricity or Energy Balance, the Electricity Market Rules and other rules of operation, use of technical facilities and other technical facilities in the energy sector, these are matters that should be left for regulatory rather than ministerial approval. As the legal and regulatory regimes are gradually revised, a clear line should appear between matters that are ministerial in nature and those that are for the sector regulator to address.

The legislation (law or laws) governing the electricity sector will typically address other matters besides the role of government in the sector. Usually it will also address the following matters:

- Generation;
- Transmission and dispatch;
- Distribution;
- Import and export;
- Consumption;
- Electricity system operation; and,
- The trade in wholesale electricity (capacity).

Usually legislation will establish a sector regulator and indicate its powers. Sometimes this is found in the electricity act; other times it is in the act that establishes the sector regulator. Wherever it is found, it should clearly distinguish between powers that are regulatory in nature and those that are purely policy oriented which should be left to the minister responsible. Applicable legislation should also state that the Minister may develop sub-legislation (often called "Regulations") on matters of electricity sector policy. Clear separation of roles and responsibilities is the first step on the road to good sector governance.

The electricity sector legislation often has the following kinds of objectives:

- The development of competition in order to accurately reflect the costs of generation in the electricity sector;
- The encouragement of priority use of indigenous hydropower resources, renewable, alternative sources of energy and natural gas;
- The establishment of the main principles of generation;
- The establishment of an independent regulatory framework for the electricity sector;
- Consumer protection; and,
- The long-term financial stability and development of the electricity sector.

Regulatory Oversight and Enforcement

To the greatest extent possible, the jurisdiction and powers of the regulator should be set out in sector legislation rather than in sub-legislation. The act should state that the regulator is authorized to issue subsidiary legislation in the forms of rules or orders of general or specific applicability. The powers of the regulator should include:

- The power to issue licenses and to develop sub-legislation (rules) and procedures for those processes;
- The power to regulate activities of licensees including, generation, transmission, distribution, supply, importers, exporters, the commercial operator (MO), the system operator and traders. *Note:* In some Member States, legislation will not identify all of these as being licensed activities; however, to support regional trade, all of these activities should be licensed by the regulator. It is not specifically necessary for the act to require legal and financial unbundling of the activities (for example, by a state-owned incumbent), so long as the activities themselves are licensed by the regulator;
- On the basis of its rules and government policies, sets and regulates tariffs for generation, transmission, dispatch, distribution, import, export and consumption of electricity;
- Settles customer complaints;
- Resolves sector disputes;
- Monitors and enforces license terms and applicable law; and,
- Overseas the certification of electrical technicians (this is common but not universal, and it is not relevant to the development of IPPs or regional trade).

Licensing

Because the economic regulator is responsible to regulate, among other things, market access, the right to license should lie within the regulator's hands. Electricity legislation generally establishes the terms and conditions pursuant to which regulator issues all electricity licenses. The rules governing the monitoring and control of licensed activities are generally addressed in sub-legislation such as the regulator's rules on the issuance of licenses and the regulation of licensees. The law should state the types of licenses that the regulator will issue and regulate. Usually they include:

- Generation;

- Transmission (often including the dispatch function);
- Distribution; and,
- Importer/Exporter of electricity.

As stated above, this is insufficient to support regional trade matters and will be expanded under the New Legal and Regulatory Framework.

Sometimes the legislation will also address how import and export activities are carried out. Sometimes this will be by way of direct contracts that are not subject to regulation, per se. Some legal approaches require direct contracts to be registered with the Dispatch Licensee (SO) which, in order to protect the reliability of the system, may hold in reserve a certain amount of the transmission line capacity.

Legislation will usually also deal with how own-use generation is to be regulated. Whether it is licensed may well depend on whether it is connected to the grid.

Deregulation

Some electricity legislation will also provide a framework for the full or partial deregulation of certain electricity sector participants, including generation licensees. Deregulation often occurs by way of an administrative order issued by the minister responsible for the sector or sometimes, the sector regulator.

Obligations of a Licensee

Electricity legislation usually establishes a term of years for a particular type of license. In many places, terms are indefinite. A license usually entitles the holder to generate electricity and to connect to the transmission or distribution network pursuant to an agreement with the transmission or distribution licensee.

Typically, the legislation will require a licensee to:

- Be a commercial entity, fully formed and registered under applicable law;
- Comply with applicable laws;
- Comply the terms and conditions of its license;
- Maintain separate records in respect of its licensed and unlicensed activities;
- Comply with sub-legislation and orders of the regulator;
- Comply with the Market Rules as they relate to generation issues;
- Comply with the requirements of the Dispatch Licensee regarding operation of the transmission and distribution facilities;
- Make its generation facilities available to the Dispatch Licensee at the connection point pursuant to the terms of the power purchase contracts or approved prices, terms and conditions of service;
- Not terminate, reduce or increase licensed services without the consent of the regulator (except for technical or safety reasons or where a counterparty defaults on a payment obligation);

- Conduct licensed activities in an economically efficient manner;
- Insofar as may be practicable, minimize cost;
- As required, make reports to the regulator regarding past activities (annual reports) future plans, and any other information that may be required;
- Fully meter electricity flowing through its facilities and make information about such metering available to the regulator or the Dispatch Licensee; and,
- Pay its regulatory fees as provided by law in a timely manner.

Sometimes the legislation will provide specific terms for a given type of license. Other times, those terms will be left to the regulator to define.

Licensing Procedures

Legislation will also set out basic provisions related to licensing procedures. In order to obtain a generation license, an applicant must submit a standard application form to the regulator, together with the following kinds of information:

- A report certifying possession (usage of generation assets);
- A report on compliance of the technical condition of the generation assets with standards;
- A list of fixed assets and audit report on the enterprise;
- An environmental impact assessment report;
- Technical conditions for connection to the electricity network; and,
- A scheme of the electricity network, relevant to the license application.

Usually the legislation grants some leeway to the regulator to expand these requirements as appropriate.

Part 2: Due Diligence Surveys

Due Diligence of Regulatory Power and Authority

As stated, the Member State regulator will be the Agent of Change to implement the Proposed Market Model by way of the New Legal and Regulatory Framework. For that reason it is important to ensure that the regulator has the legal authority to do what is necessary to implement or to drive the implementation of that framework. A robust due diligence of the Member State Regulator will identify gaps in regulatory power and in regulatory tasks.

Those conducting the due-diligence must first determine whether the regulator's powers arise from legislation or from sub-legislation. Either the sector act or the act establishing the regulator (if they are different) should provide that the powers of the regulator should include:

- The power to act as an economic, technical and service standards regulator;
- The power to issue licenses and to develop sub-legislation (rules) and procedures for those processes;
- The power to regulate activities of licensees including, generation, transmission, distribution, supply, importers, exporters, the commercial operator (MO), the system

operator and traders. *Note:* In some Member States legislation will not identify all of these as being licensed activities; however, to support regional trade, all of these activities should be licensed by the regulator. It is not specifically necessary for the act to require legal and financial unbundling of the activities (for example, by a state-owned incumbent), so long as the activities themselves are licensed by the regulator;

- The power to set and regulate tariffs for generation, transmission, dispatch, distribution, import, export and consumption of electricity;
- The power to settle sector disputes and customer complaints, (see below for a fuller discussion);
- The power to monitor and enforce license terms and applicable law; and,
- The power to issue rules and orders that are binding on sector service providers.

Due Diligence of Dispute Resolution Powers

Because the Recommended Market and Investment Framework cannot operate in the absence of an effective dispute settlement mechanism, the due diligence should also carefully consider the mechanisms that have been put in place at the Member State level to resolve electricity sector disputes. Sometimes this is accomplished by way of national or sector specific courts; other times it is a two-tiered process whereby the regulator acts as a first-level settlor of disputes from which an appeal may be lodged either with a specialized tribunal or with the courts.

Due Diligence of Wholesale Trade Issues (including Market Rules)

Because one of the main purposes of the Proposed Market Model is to expand wholesale trading, due diligence should carefully examine what if any provisions exist in legislation in force on the subject. Where it is absent, it will have to be included, either by way of amendments to the existing sector legislation, or perhaps by way of new legislation such as an “Act on Electricity Markets”.

Sometimes legislation will provide for the establishment of codes, technical specifications or rules related to a specific activity, including wholesale trade. Market Rules typically govern:

- The operation of the electricity market and Market Operator (MO) (or its equivalent—a commercial operator);
- Commercial, financial and technical matters arising from direct contracts and electricity purchase and sale, transmission, dispatch, operation of electricity system in parallel regime and consumption of generated electricity by Generation licensee for its own needs through the MO;
- The establishment of electricity (capacity) balances and rules for their implementation;
- Terms of execution, enactment, validity and termination of the direct contracts;
- Terms for conclusion of direct agreements and their enforcement;
- Definition of the categories of electricity sellers or for the establishment of terms of sale, or for the registration of “qualified enterprises”; and,
- Technical Standards for Wholesale Trade.

Such Market Rules usually require parties to conclude direct agreements for the purchase and sale of electricity and capacity to register their contracts with the Dispatch Licensee.

The commercial operator (MO) is licensed by the regulator and governed principally by the Market Rules. Usually under the law or the Market Rules, the MO:

- Sells and buys balance electricity and capacity (including medium and long-term bi-lateral import/export contracts);
- Provides the electricity system with the reserve capacity;
- Supplies the Dispatch Licensee with the information it requires to carry out supply and consumption planning;
- Creates and manages unified data (including the unified metering register) on wholesale trade;
- Identifies the volume of electricity sold and purchased by electricity sellers and buyers and submits the information for the settlement purposes; and,
- On the basis of information provided by the Dispatch Licensee, identifies the number of electricity sellers and buyers and the quantity of electricity sold and purchased and provides that information for settlement purposes.

The MO fulfills its legal obligation on the basis of information received from qualified enterprises and parties to transit arrangements. A qualified enterprise is an entity authorized under the Market Rules to participate in the wholesale trade of electricity. Qualified enterprises include:

- Generation and distribution Licensees;
- Direct Customers;
- Importers;
- Exporters;
- Small hydro power plants; and,
- The Market Operator.

Due Diligence as to System Capacity Reserve and Energy Balances

- The Dispatcher (or the TSO) is licensed by the regulator to conduct dispatching activities. It does so pursuant to the Electricity Law, its license and the Market Rules;
- The Market Rules require specifically identified market participants (distribution licensees, direct consumers and exporters) to provide system capacity reserve to the Dispatch Licensee who uses it to balance electricity supply and consumption;
- In order to ensure the reliable operation of the power grid and to balance supply and consumption, the Commercial Operator (MO) tops up reserves that have not been covered by qualified enterprises. The costs related to such top up are to account for such enterprises;
- The MO is required by its license and the Market Rules to submit forecast energy balances to the regulator (sometimes this is to the Minister, but appropriately, it should be to the regulator);
- On the basis of approved balances and in the interest of the reliable operation of the power system, the Dispatch Licensee (TSO) conducts daily and hourly planning of electricity supply from generation facilities and other sources of power;

Due Diligence Regarding Electricity Trading by Power Projects of Various Sizes

The rules related to Small, Medium and Large power projects vary greatly. Typically, legislation will define the difference between a small capacity power plant and a large one. 10-15 MW is a common dividing line. Oftentimes, a small capacity power plant may sell electricity to a qualified enterprise or a retail consumer. The legislation will often define a retail consumer as any person, other than a direct consumer that receives electricity (capacity) from a generation, transmission or distribution licensee for its own consumption and not for re-sale. But as indicated, these may vary.

Due Diligence on Tariffs and Tariff Methodologies

Typically a government's energy policy will identify as a goal the gradual deregulation of electricity prices, and that until that occurs, tariffs should reflect the separate costs associated with various classes of electricity customers. Sometimes government policies are not this specific. As an economic regulator, the regulatory authority should be responsible for setting prices (tariffs) in regulated sub-sectors. This should be stated in the legislation, not the government's policy. A number of countries in the SADC region have not yet implemented cost-reflective tariffs. While the transition to cost-reflective tariffs is often a gradual one, it should nevertheless be government policy consciously to move in that direction. This policy should be clearly reflected in the applicable legislation.

Applicable legislation should authorize the regulator to set electricity tariffs. Further, the legislation should authorize the regulator to establish the tariff methodology it will employ in all circumstances to do so. Procedurally, the legislation should also authorize the regulator to determine applications and procedures it will use in response to a tariff application. To recap, the regulator should set tariffs in compliance with national energy policy, applicable legislation (electricity act, renewable energy act, and the Regulator's own rules and procedures.

The principles underlying a regulator's tariff methodology are found normally in the electricity law. Usually it requires a decision based upon the principle of full cost recovery. Depending on the type of customer involved, the regulator's tariff methodology will include (depending on the type of customers):

- Seasonal tariffs;
- Peak load (day and night tariffs);
- Step tariffs (based on consumption volume);
- Long-term pre-set tariffs (including marginal tariffs); and,
- Marginal tariffs (to take into account long-range marginal costs).

The regulator's tariff setting procedures commence upon receipt of a completed tariff application that includes specifically identified substantive and financial information, some of which must be audited. Oftentimes electricity laws enumerate the entities that are entitled to file a tariff application, e.g., licensees, importers, the commercial operator and direct customers.

Regulators should consider a tariff application in a public hearing held by the regulator pursuant to its rules. Those rules typically address:

- The tariff review process;
- The receipt by the regulator of comments by consumers and other interested parties;

- The acquisition of additional information necessary to assessing tariff applications;
- Financial reimbursement for regulatory costs; and,
- Time Frames for an application.

Due Diligence on Market Access

Access to transmission and distribution networks is generally governed by the Electricity Act and the Market Rules. Oftentimes, the legislation will say that in exchange for the tariff established by the regulator, a transmission or a distribution licensee must wheel within its network electricity that is destined for cross-border sale. Third parties wheeling electricity using the assets of other licensees are usually required to do so pursuant to a direct agreement with that licensee. Similarly, small capacity power plants should also be required by law to enter into direct agreements with such licensees or plants. The law should state that wheeling cannot be denied by the owner of a transmission or distribution network, unless restrictions are caused by the capacity of the network or unless they are justified by the failure of the third party to pay the wheeling tariff.

RERA should assist each Member State Regulator in conducting a survey of the legislation and sub-legislation on all of the above matters. After the “gap analysis” is finished, a strategy for amendment or for new legislation will be required.

ANNEX 5: THE ROLE OF MARKET SERVICE PROVIDERS AND MARKET PARTICIPANTS UNDER THE NEW LEGAL AND REGULATORY FRAMEWORK

Market Service Providers

Market Service Providers perform essential services for the efficient operation of the regional market, including, Transmission and Distribution, Market Operations and Market Clearing.

TSO

The Transmission System Operator (TSO) manages the security of the power system in real time and coordinates the supply of and demand for electricity in a way that avoids frequency fluctuations and supply interruptions. This obligation (or function) is separate from its role as owner of the Transmission System (transmission licensee). In the near term, that is until the Member States have unbundled in accordance with the terms of the new legal and regulatory framework, the TSO will probably be a unit (the TSO Unit or Dispatch Unit) inside the Transmission Licensee. In the longer term, the TSO will be solely responsible for undertaking the dispatch function and be licensed as such. The new legal and regulatory framework should follow the road map of the first and second EU energy packages and embrace unbundling of functions, starting with ring fencing, financial unbundling and later legal unbundling. Until this happens the dispatcher function will still be subject to the jurisdiction of the Member State regulator.

In maintaining a continuous balance between electricity supply from generators and demand from consumers, the TSO must also ensure the provision and availability of reserves to cover for sudden contingencies and imbalances in the Transmission System. The TSO accomplishes this task by:

- determining the optimal combination of generating stations and reserve providers;
- instructing generators when and how much electricity to generate;
- procuring ancillary services to support the power system; and,
- managing any contingent events that cause the balance between supply and demand to be disrupted.

In addition, the TSO or dispatcher will conduct planning to ensure that supply can meet demand and system security can be maintained in the future (short-, medium- and long-term). To ensure that this is so, the new legal and regulatory framework should require the TSO to review the information provided by the DSO in order to determine that Market Participants have secured all the resources needed to supply all load and to cover distribution losses on a periodic (annual, monthly, weekly and day-ahead) basis. Toward that end, the TSO should be authorized:

- To require the DSOs to make purchases consistent with the amount of supply required to meet the load of Tariff Customers and for distribution losses;
- To require Eligible Customers to provide information demonstrating that they will be able to secure sufficient supply for themselves;
- To require Traders to demonstrate that they will be able to secure sufficient supply for Eligible Customers; and,

- To request regional generators (RGs), IPPs, Small power producers and dispatchable loads to demonstrate that they have the capacity or the load to meet their commitments.

The TSO should also:

- Forecast and purchase ancillary services from RGs and other generators, on an annual, weekly, day ahead and real time basis;
- Purchase electricity from RG and other generators required to cover losses in the Transmission System; and,
- Have the right to receive compensation for its services from the Market Participants pursuant to tariffs approved by the regulator.

Forecasting

Highly reliable forecasts are necessary in order to maintain the quality, continuity and reliability of electricity supply, to ensure that demand will be satisfied with proper electricity supply and to guide Market Participants. The TSO in each Member State should be responsible for power system forecasting, including electricity demand, supply and transmission system projections. There are two main time groups for forecasting purposes: long-term (one and more years) and short-term (less than one year).

Demand Forecasts

The demand forecast section should cover:

- Forecasted total demand and losses for the country;
- Information related to peak demand during the previous year;
- Seasonal demand analyses; and
- Sector demand development, etc.

The DSO, Retail Public Suppliers (RPSs) and Eligible Customers should submit all information necessary for demand forecasts to the TSO.

Generation Capacity Projection

The TSO will be required to prepare a Generation Capacity Projection. This document, based on demand forecast prepared by DSOs and RPSs, is finalized by the TSO and submitted to the Member State regulator for approval. It is all based on information provided by the licensed generators. The generation section includes:

- Total existing installed capacity in the Member State during the previous year;
- Power plants that are licensed but not yet commissioned and generating facilities currently under construction;
- For each year, power plants that will be non-operational for longer than year as well as power plants that will be added to the grid; and,
- Import-export volumes for the previous year and an estimation for subsequent years.

Transmission System Planning

Based upon demand forecasts and capacity projections, the TSO will prepare a minimum 10-year transmission system progress report that identifies:

- New, economically justified connection opportunities;
- An estimation of the existing transmission system and guidance for investors.

The Transmission System planning report should also evaluate current performance of the System and System planning including improvements and investment plans. Each year the TSO should prepare the 10-year Power System forecast progress report. This obligation requires the TSO and other Market Participants to revise and update their forecasts. Any discrepancy between forecasted and actual information should be analyzed and investigated. The TSO is also required to protect the confidentiality of information provided by Market Participants where disclosure would harm competition. To ensure the development of sufficient expertise, the TSO should establish a separate department to carry out the forecasting function.

Short-term Forecasting

The TSO also performs:

- Month ahead;
- Week ahead;
- Day ahead; and,
- Intraday forecasting.

In order for the TSO to do so, Generators and other Market Participants will be required to provide proper information of their scheduled productions and expected loads.

Real-Time Balancing

Real-time balancing principles include the activities performed by the TSO to overcome supply and demand imbalances that occur in real-time. Real time balancing principles cover the activities performed by TSO within the scope of equilibration power market and/or ancillary services in order to remove the supply and demand imbalances arising at real time and matters related to informing TSO regarding technical and commercial parameters by market players contributing to equilibration power market and/or real entities providing ancillary services and matters related to the fulfillment of instructions informed by the TSO. Real-time balancing is performed by:

- The generation plants, by providing primary frequency control service and secondary frequency control service by automatically increasing or decreasing their output powers;
- Balancing units within the scope of equilibration market loading and/or load shedding, according to instructions issued by the TSO;
- Activation of standby reserves in order to provide sufficient tertiary reserve in real time; and,
- Application of emergency measures in case of critical and unstable operating conditions.

Transmission Licensees

The Transmission Services Companies (Transmission Licensees) own the assets of the Member State Transmission Systems. These licensees are responsible for the physical operation of the Transmission System, i.e., maintaining and expanding the system as necessary to meet forecasts through long-term development and investment. Transmission Services Companies are obligated:

- To connect generating plant to the Transmission System;
- To connect DSOs to the Transmission System; and,
- To decide on matters of new investment and rehabilitation required to support forecast loads on the Transmission System.

Market Operator and the Balancing Market

The MO's principal function is to operate the balancing market and ensure that energy purchase and sales quantities contracted for under bilateral contracts are balanced, by ensuring that "balanced energy" is available. To do so, the MO is required to develop a balancing mechanism that matches offers and bids. To do so, the MO must ensure that it has access at all times to the necessary information related to available generation, electricity flows and the bilateral contracts between Market Participants. The MO will be required to work closely with the TSO and the regulator to ensure that all required information is forthcoming. The MO's responsibilities include:

- Operating the hourly balancing market for the regional electricity market;
- Closely coordinating its operation with the TSO and the Member State regulator;
- Calculating settlements for electricity and capacity Market Participants according to agreed and regulated procedures and providing this information to the Market Clearing House (MCH);
- Suggesting modifications to the rules governing the electricity market; and,
- Training new entrants to the balancing market.

Market Clearing House

Wholesale transactions (bids and offers) in electricity (both capacity and energy) are typically cleared and settled by a special-purpose independent entity with exclusive obligations to carry out this function. Market Operators do not clear trades; they do, however, require knowledge of the trade in order to maintain generation and load balance.

A new entity should be created to perform this function, the Market Clearing House (MCH). The MCH is obligated to determine the margins that each electricity buyer and seller trading in the market will be required to provide in order to be permitted to trade in the competitive electricity market. The role of the MCH is to ensure that all trades will be cleared. It also will give market participants the following benefits:

- guaranteed settlement & delivery of the contracts;
- effective book keeping, reporting and risk management control; and,
- handling of physical deliveries.

The MCH might be an existing bank or commodities house, or it could be newly established special purpose entity. In any case, it should be created by way of a competitive tendering process.

Distribution System Operators (DSOs)

Currently throughout the Member States, the distribution companies own, maintain and operate the electricity distribution Systems. They also provide retail electricity supply to tariff customers. In order to introduce a competitive electricity market and to ensure that revenue from the monopoly distribution (wires) business is not used to subsidize electricity generation and sales, it is necessary to separate the retail electricity supply function from the distribution function. Existing distribution licensees that perform two separate functions (wires and supply) should be performed by two separate units within the DSO. The functions should be split into:

- Maintenance and operation of distribution systems, to be performed by the existing distribution companies, to be called Distribution System Operators (DSOs); and,
- Retail electricity supply, to be performed by a unit called the Retail Public Supplier.

The DSO’s obligations are to:

- Provide, on a non-discriminatory basis, connection and metering services to electricity customers (tariff customers and eligible customers) that are connected to a distribution system;
- Ensure the delivery of electricity received by the distribution system from the transmission system;
- Provide wheeling services to eligible customers, auto generators and generators located on their distribution system;
- Meet the standards of service imposed under their licenses and the distribution Code; and,
- Purchase electricity to cover losses on the distribution system. A DSO may purchase such any from any Market participant at prevailing market rates.

Electricity tariffs and terms and conditions of distribution service provided by DSOs are subject to regulation (either the Regional Regulator under Option 1, or the Member State Regulator under Option 2). DSOs should also be required to reduce technical and non-technical losses in the distribution system in accordance with the terms and conditions of their license. Tariffs should provide incentives for the reduction of such losses.

Market Participants

Market Participants include Generators (including IPPs), Traders (including import and export activities), a Consolidator (that provides electricity marketing and trading services to small and medium sized generators), Eligible Customers (those who have the right to choose their supplier) and Tariff Customers (purchases of electricity from a RPS at regulated prices).

Under the Proposed Market Model, the market is comprised of various types of participants including Self-Producers, IPPs, Traders, Consolidators for small projects, Retail Public Suppliers and Eligible Customers and Tariff Customers. To the extent that these entities are operating in the regional market, they will be subject to the New Legal and Regulatory Framework and regulated by the Member State regulator. The following is a brief discussion about the role of each under the Proposed Market Model.

Self-Producers

Self-Producers generate power for their own consumption. Under most national legal frameworks, they must consume a minimum amount of the power they generate. The remainder, they can sell to the SOU, which, under most national frameworks, has the exclusive right to buy (a right of first refusal) on all such power.

IPPs

New power projects that are above a determined capacity will fall into the IPP category. IPPs will be free to sell electricity wherever they choose. Under Option 1, these generators will be licensed by the Member State Regulator if they are only selling on the national level, but by the Regional Regulator if they are selling regionally. IPPs may enter into long-term bilateral agreements or short-term transactions in the balancing market, or both. IPPs will be required to demonstrate to the TSO that they have sufficient capacity and energy to satisfy their customer's requirements. They require only a Generation license when selling to Traders. They will not need a trading license unless they buy as well as sell electricity.

Traders

A Trader is licensed to buy and sell electricity except for sales to Tariff Customers. Traders may be foreign or domestic entities. Traders will be able to buy and sell electricity on domestic and foreign markets. Domestically they may buy electricity from the regulated generators, IPPs and small generators for the purpose of onward sales to eligible customers, or the TSO or the DSOs to cover distribution losses. IPPs can also be Traders and engage in wholesale transactions, provided that they obtain a Trading License. Traders may enter into long-term bi-lateral agreements or short-term transactions in the balancing market.

The Regulator should ensure that licenses and licensing procedures for Traders are transparent and non-discriminatory, and do not create an undue burden on the entry of traders into the regional market. This will be under a finding by the Regional Regulator under Option 1 or by the Member State Regulator under Option 2. In either case, the key is for the regulator to determine that reciprocal arrangements are available for the Member State entity seeking to trade in markets of foreign entities. License terms for Traders will include requirements to provide information (regarding their activities and technical and financial information) to the regulator and to comply with all applicable regulations and Market Rules and the Grid Code.

Consolidators for Small Projects

Small and medium sized (typically renewable) projects by themselves have little human or economic capability to enter the competitive electricity market. To support the development of these projects on commercial terms, it is helpful to consolidate their output for the purpose of marketing and sales. An entity called the Consolidator should be established to provide these trading services for such projects and also balancing assistance. A Consolidator will require a Trader License in order to conduct activities. The Consolidator will market and arrange sales of output of small projects to relevant buyers. It will also serve as a balancing group for its members, thereby reducing the overall payments that otherwise would be payable for imbalance services. The Consolidator can freely trade with eligible customers on the national level and with other traders DSOs and the TSO. A Consolidator might also sell to regulated customers at regulated prices. On the matter of contracts, agreements will be required between the generators and the Consolidator and between the Consolidator and the MO.

Retail Public Supplier

The Retail Public Supplier (RPS) sells electricity only to tariff customers under tariffs and pursuant to contracts that have been approved by the national regulator. They will be required to provide to the TSO and the MO the annual, weekly and day-ahead schedules of its expected load. This will enable the MO and TSO to develop their own schedules. These sellers should be required to reduce non-collections from tariff customers under conditions determined by the Member State regulator.

Eligible Customers and Tariff Customers

In the Regional market, there will eventually be two categories of retail customers. The first, the Eligible Customers, are entitled to purchase electricity from any source. The second category is comprised of tariff customers. They are consumers that are connected to a distribution system and purchase electricity at rates set by the Member State Regulator.

There will always be consumers that elect not to choose a supplier. These will have to be supplied by the Retail Public Supplier. Even if the RPS is phased out under the full market opening, there will always be a supplier of last resort. The Member State Regulator will select this entity when the time comes, using a transparent selection process.