Framework for Regulatory Oversight for the EA-SA-IO Energy Market

Consultancy to develop a Framework for Regulatory Oversight for the Regional Energy Market in EA-SA-IO

Final Report

Report for COMESA/RAERESA
Service Contract No. CSIADM/10-06.19/40MEG

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ABOM	Agreement Between Operating Members
ADAM	Eastern African Power Pool Day Ahead Market
AFUR	African Forum for Utility Regulators
AGC	Automatic Generation Control
ARENE	Energy Regulatory Authority (Mozambique)
APS	Arizona Public Service
CC	Coordination Centre
COMESA	Common Market for Eastern and Southern Africa
DAM	Day-Ahead Market
DRC	Democratic Republic of Congo
DSM	Demand Side Management
EAC	East African Community
EAPP	East African Power Pool
EA-SA-IO	Eastern Africa, Southern Africa and Indian Ocean Region
ECOWAS	Economic Community of West African States
ERB	Energy Regulation Board
EREA	Energy Regulators Association of East Africa
ERERA	ECOWAS Regional Electricity Regulatory Authority
EU	European Union
EUD	EU Delegations
FERC	The Federal Energy Regulatory Commission
FIT	Feed-in-tariff
FPM	Forward Physical Market
GC	Governance Code
GMS	Greater Mekong Subregion
HVDC	High Voltage Direct Current
IDM	Intraday Market
IEC	Information Exchange Code
IGAD	Inter-Governmental Authority on Development
IOC	Indian Ocean Commission
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRB	Independent Regulatory Board of EAPP
ITC	Independent Transmission Company
ISO	Independent System Operators
MC	Metering Code

MOU	Memorandum of Understanding
MP	Market Participants
MTP	Market Trading Platform
MSB	Modified Single Buyer
MW	Megawatt
MWh	Megawatt Hour
NARUC	National Association of Regulatory Utility Commissioners
NRA	National Regulatory Authority
OC	Operation Code
OPF	Optimal Power Flow
PC	Planning Code
PM	Particulate Matter
PMU	Project Management Unit
PPA	Power Purchase Agreement
PTSC	Programme Technical Steering Committee
PV	Photovoltaic
RE	Renewable Energy
RERA	Regional Energy Regulators Association of Southern Africa
RAERESA	Regional Association of Energy Regulators of Eastern and Southern Africa
RRA	Regional Regulatory Authority
RTIFF	Regional Transmission Infrastructure Financing Facility
RTO	Regional Transmission Organisations
SACREE	SADC Centre for Renewable Energy & Energy Efficiency
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SARERA	SADC Regional Energy Regulatory Authority
SEA	Strategic Environmental Assessment
SO	System Operator
SOTC	System Operator Training Code
SRMC	Short run marginal cost
SWOT	Strengths, Weaknesses, Opportunities, Threats analysis
TCA	Transmission Connection Agreement
TO	Transmission Operator
ToR	Terms of Reference
TSO	Transmission Service Operator
TUOSA	Transmission Use of System Agreement
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
URA	Utility Regulatory Authority
USA	United States of America

USAID	United States Agency for International Development
USD	United States Dollar
VRE	Variable Renewable Energy
ZAR	South African Rand

Executive Summary

This report presents the findings from a study that was commissioned by The Regional Association of Energy Regulators for Eastern and Southern Africa (RAERESA), reporting to the Common Market for Eastern and Southern Africa (COMESA). RAERESA is the implementing agency for a European Union-funded project "Enhancement of a Sustainable Regional Energy Market in Eastern Africa, Southern Africa, and the Indian Ocean (EA-SA-IO) Region".

The study was carried out under two Workstreams, addressing:

- Workstream A: The development of a Framework for Regulatory Oversight of the Regional Energy Market; and
- Workstream B: The design of a responsive training programme for strengthening the capacity of national and regional regulatory institutions and Power Pools to proactively influence power trading and developments in the energy sector.

Workstream A: Framework for Regulatory Oversight

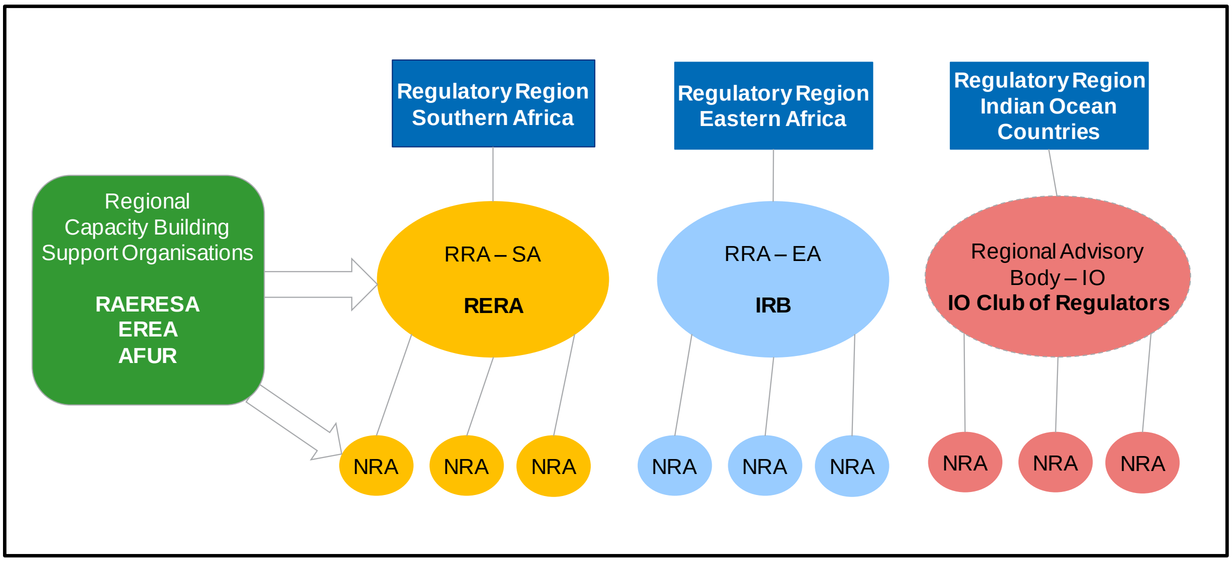
A recommended **institutional structure** has been proposed for regulatory oversight of the EA-SA-IO Electricity Market, under which the countries will be grouped into three different regulatory regions. A regulatory authority is recommended for Southern Africa, with a separate regulatory authority for Eastern Africa and a regulatory advisory body for the island states of the Indian Ocean region.

This structure should build upon the existing framework of regulatory organisations in the region, comprising the Regional Electricity Regulators Association of Southern Africa (RERA), the EAPP Independent Regulatory Board (EAPP IRB), RAERESA, the Energy Regulators Association of East Africa (EREA) and the Indian Ocean Club of Regulators. The recommended measures are:

- to establish a new regional regulatory authority for the Southern Africa regulatory region that builds on the knowledge and capacity of RERA;
- to amend the existing IRB mandate in order to establish it as fully independent regional regulatory authority for the regulatory region of Eastern Africa;
- to establish regional regulatory advisory association denominated the Indian Ocean Club of Regulators as regulatory advisory body for the island states of the Indian Ocean region; and
- to support the newly created institutional framework for regulatory oversight in EA-SA-IO with an adequate capacity building framework focused on a Centre of Excellence, i.e. through a new African School of Regulation or through the already existing framework of organisations with mandates and knowledge on regional regulatory issues (RAERESA, EREA and AFUR)

The recommended regional regulatory institutional structure is illustrated below.

Recommended regional regulatory institutional structure



It is recommended that **harmonised regulations** are developed in the region in a number of areas, specifically covering:

- **Licensing arrangements**;
- **Market surveillance**;
- **Transmission contracts and agreements** (which will help to incentivise investment in interconnection);
- **Technical standards**, including the development of a **Regional Grid Code**; and
- **Regional planning regulations**, to increase regional interconnection capacity.

These harmonised regulations will help to create a level playing field across the EA-SA-IO region such that investors will be encouraged to pursue new projects against a backdrop of stable and consistent regulatory practices.

In addition to regulatory harmonisation it is proposed that the two Regional Regulatory Authorities (RRAs) for EA and SA work with the relevant National Regulatory Authorities (NRAs) and the national transmission utilities to develop a **standardised methodology for wheeling charges** across the region. By definition this is only applicable to the interconnected countries, where national transmission utilities are required to provide wheeling services in order to facilitate the operation of the interconnected EAPP and SAPP markets. It is recommended that a point-to-point MW-km transmission pricing method is adopted. This would provide a basis for recovering the capital and operations and maintenance costs associated with the use of interconnected network assets and international interconnectors for wheeling.

In order to promote **environmental sustainability** in the power sector, it is recommended that the RRAs develop and implement a standard approach and methodology for the inclusion of **Strategic Environmental Assessment** (SEA) in the development of national Integrated Resource Plans. This should focus on the encouragement of energy efficiency measures, increased renewable generation penetration and increased interconnection as integral parts of future national development plans.

An **action plan** for the introduction of institutional changes and regulatory harmonisation has been proposed, comprising:

- Short-term actions, to be implemented over a period of 1 - 3 years (2021 – 2023);
- Medium-term actions, to be implemented over a period of 4 - 8 years (2024 -2028); and
- Long-term actions, to be implemented beyond 8 years (after 2028).

Short-term measures should include the implementation of the institutional arrangements, in two key areas:

1. The completion of the creation of national regulatory bodies responsible for the energy sector and the full implementation of their regulatory mandates; and
2. The setting up of the RRAs for EA and SA and the creation of the Club of Regulators for the Indian Ocean.

In parallel with the creation of strong national and regional regulatory bodies, the proposed Centre of Excellence should be created that can act as a focal point for the development of training and capacity building activities in the region.

Work should commence on the development of the Regional Grid Code documentation and the development of a reference Grid Code for the Indian Ocean countries in the short-term.

The development of standardised licences and agreements by the RRAs and the Club of Regulators should be undertaken as a short-term priority measure, though we recognise that the ability of the RRAs to promote the adoption of these will depend on the RRAs being set up as effective institutions. Planning and agreeing the content of these documents can be undertaken in the short-term however.

Medium-term actions should include the development and implementation of a harmonised approach to transmission charging for international wheeling of power across and between the EAPP and SAPP systems. Preparatory work on this can be undertaken in the short-term, however the implementation of this will be required when trading across the integrated market is fully established.

The medium-term timeframe will also see the implementation of licences and agreements that are based on the standardised models that will be developed by the RRAs during the first phase of their setting to work. This will include the recommendation of standardised approaches to be adopted by the regulators of the IO countries with advice from the Club of Regulators.

The long-term phase is likely to consist primarily of monitoring and development of the regulatory framework by the RRAs and the NRAs, the basic model of regulatory harmonisation having been defined in the short-term phase and implemented in the medium-term.

The above measures are required to be implemented in parallel with the wider initiatives being pursued across Eastern and Southern Africa to integrate the EAPP and SAPP markets. The **benefits of market integration** have been widely discussed in other studies, by unlocking the huge potential for energy resource sharing, decarbonisation of the electricity sector and greater access to electricity at lower cost for end consumers. For this to be possible, it will require a strong platform of regulation both to protect consumers' interests and to create an environment in which new investors will feel confident to come forward and participate in the energy market. If sufficient buy-in can be obtained from regulators, government ministries, utilities, investors and other stakeholders to the market reforms that are being proposed, and to the recommendations on regulatory harmonisation contained in this study, these wider benefits of integrated energy trading will become achievable.

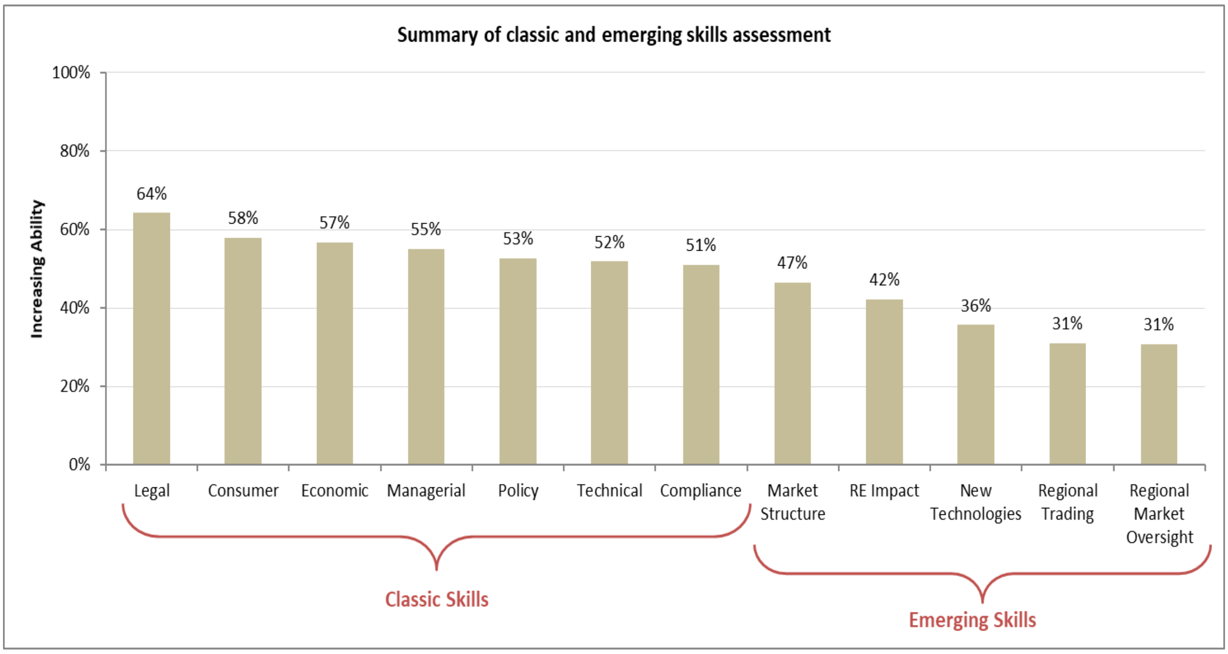
Workstream B: Capacity building

A detailed questionnaire formed the basis of an interactive **skills and competencies assessment process** conducted amongst regulatory bodies. The fact that 20 out of 31 participants (65%) responded to the questionnaire is an indication of the interest and importance that institutions have in developing their people.

The majority of organisations that responded consider that they are both understaffed and inadequately trained. Key staffing vacancies were predominantly in professional (technical, economic, consumer and legal) or managerial roles, and vacancies relate to critical focus areas for regulators. Staff vacancies have a serious impact on organisations and prevent them from discharging all their duties and responsibilities within acceptable time periods and the appropriate quality standard.

The survey assessed regulatory organisations' capabilities in areas of classic skills and those relating to emerging requirements in regulatory work. The skill levels amongst the regulatory bodies that emerged from this review are summarised in the figure below.

Classic and emerging skill levels amongst regulatory institutions



An overarching finding is that whilst regulators have an adequate basic understanding of the skills and abilities required to carry out their duties, their ability to develop and apply regulation, maintain and adjust methodologies and frameworks, and monitor and report on outcomes, is limited. The emerging skills assessment additionally reinforced the requirement for further capacity building, with lower average skills overall, when compared with the classic skills assessment. It is therefore recommended that capacity building programmes factor in not just traditional regulatory skills and techniques, but also focus substantially on developing skills to address emerging trends and issues relating to changes in market structure, renewable energy technologies, trading, market oversight, wheeling, network pricing and market governance and reporting.

A key element of this study relates to research carried out into **Women in Energy**, from which it is clear that certain key employment areas, including technical and managerial roles, are disproportionately dominated by men, given the overall employment split between genders. Furthermore, there is clearly misalignment in the application of policies and programmes designed to support the role of women in the energy regulatory environment. It is recommended that further support is given to align regulators on the application of these policies as well as providing increased mentoring and career guidance to women. A clear baseline and KPIs may be developed to measure progress in this respect.

A **training needs assessment** was carried out, from which it emerged that training in technical, economics and compliance skills are particularly required. The respondents identified exchanges, workshops and mentorship as the preferred training methods in their institutions. This provides clear guidance on how future training should be delivered. A proposed Capacity Building programme has been developed resulting from these findings. This includes capacity building in a number of specific technical areas, including regional markets, energy market reforms, licensing and technical frameworks, planning, renewable energy, economic frameworks and market governance. A series of measures is also proposed addressing the need to facilitate the increased participation of women at senior levels in the energy sector.

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1 Introduction

1.1 Project Context

The Regional Association of Energy Regulators for Eastern and Southern Africa (RAERESA) reports to the Common Market for Eastern and Southern Africa (COMESA) and has been appointed as the implementing agency for a European Union-funded project "Enhancement of a Sustainable Regional Energy Market in Eastern Africa, Southern Africa, and the Indian Ocean (EA-SA-IO) Region". The Project which covers five Regional Economic Communities (RECs) has an over-arching objective of promoting a regional energy market in the EA-SA-IO region, with the dual objectives of attracting investment and encouraging sustainable development. The RECs covered by the project include the East African Community (EAC), COMESA, Indian Ocean Commission (IOC), Inter-Governmental Authority on Development (IGAD), and the Southern African Development Community (SADC).

The project contract commenced on 13 September 2019 and began with a desk review that provided project context and early observations. Ten sample countries, five from Southern Africa, four from Eastern Africa and one from the Indian Ocean, were selected as representative regional countries for detailed investigation. Each country had its existing power sector structure, national energy policies, laws, regulations and institutional frameworks reviewed. The regional energy markets and regulatory bodies were reviewed in parallel. The analysis provided early observations and trends of the regional power sector that would need to be addressed under the scope of this project.

Field missions to the 10 sample countries occurred between November and December following an inception workshop hosted in Lusaka, Zambia. Ricardo organised meetings with regulators, ministries, and locally situated regional associations and regulatory bodies.

A consultation workshop was hosted in Dar es Salaam, Tanzania attended by regulators from 25 countries and regional stakeholders. The work completed to that point, and the associated early recommendations, were presented and discussed with those in attendance.

The consultation shaped the final recommendations which are contained in this report, and were discussed with stakeholders at a Validation Workshop held online rather than in Kigali, Rwanda, due to the ongoing global Covid-19 pandemic, on 13 May 2020. This report has been finalised in the light of comments received at that workshop.

1.2 Structure of this report

The remainder of this report is structured around the two main workstreams in the project:

- Workstream A: Development of a Framework for Regulatory Oversight of the Regional Energy Market
    - Section 2 reviews key trends in the existing energy policies, laws, regulations and institutional frameworks in the EA-SA-IO region;
    - Section 3 reviews regional and international best practices for regulating energy markets;
    - Section 4 summarises the main obstacles to regulatory oversight and introduces our high-level proposals for regulatory harmonisation in the EA-SA-IO region;
    - Section 5 develops detailed recommendations for regulatory oversight of the EA-SA-IO electricity market;
    - Section 6 summarises the implications of our key recommendations and associated budgetary requirements.
- Workstream B: Design of a responsive training programme for strengthening the capacity of national and regional regulatory institutions and Power Pools to proactively influence power trading and developments in the energy sector
    - Section 7 covers the skills assessment, assessment of the roles of women in energy and develops training and capacity building recommendations.
- Section 8 summarises the conclusions and recommendations from both Workstreams A and B.

2 Workstream A: Key trends in existing energy policies, laws, regulations and institutional frameworks

2.1 Introduction

Field missions and a desk study were undertaken to review the national legislation, regulations and institutional frameworks of the 10 sample countries. The aim was to uncover trends and observations that are relevant to the development of a regional market to feed into recommendations. This section details the key areas of assessment that the desk report and field missions targeted.

2.1.1 Primary Legislation

Energy sector targeted primary legislation is the legal foundation for sector related activities. It sets out the expectations of the sector and the roles and responsibilities of key stakeholders. Primary legislation that enables competition and enables private sector participation in the electricity market is seen as an important commitment for a regional market. It also provides context and understanding to investors and project developers on how they can participate in the market.

It is clear from reviewing the 10 sample countries that all have some form of primary legislation in place that defines the basic structure of the electricity and key roles and responsibilities within it. The level of detail in which these are described varies significantly, however. Some jurisdictions have separate Acts that define the roles and responsibilities of the electricity or energy regulator specifically, e.g. Mauritius, South Africa, Zambia, Zimbabwe. Others have supporting secondary legislation or rules (e.g. Tanzania) that set down the regulator's responsibilities in areas such as licensing.

2.1.2 Regulatory bodies

Regulatory bodies are independent bodies who make executive decisions in the energy sector. Regulatory bodies should be technically competent and understand the needs of the sector while remaining free from political interference. They should aim to ensure a level playing field for market players and ensuring that customers get the best value for money.

Most of the countries in the EA-SA-IO region have regulatory bodies overseeing their power sector[1]. All of the ten sample countries chosen for review in the desk study have clearly identified regulatory bodies. They vary, however, in their level of maturity and experience. Utility Regulatory Authority (URA) in Mauritius and Energy Regulatory Authority (ARENE) in Mozambique are relatively new to their positions and are therefore newly evolving into their roles. Other regulators, such as the Energy Regulation Board (ERB) in Zambia, have been established for many years and are comfortable and competent in fulfilling their remit. Consequently, it was expected that the level of capacity building required would vary significantly from country to country. This was proven correct during Workstream B of this project where participants assessed their capacity weaknesses. More detail can be found in Section 7 of the report.

The degree of independence also varies between regulators. In the European Union (EU) regional market, for example, it is a binding requirement for member states to have regulatory authorities that are "wholly independent from the interests of the electricity industry[2]". Independence is required in different aspects of the regulator's activity and its absence creates uncertainty for investors and concerns about possible political interference in the power sector that could affect future projects. For example, many regulators have been instrumental in promoting cost-reflective tariffs as a transparent and stable pricing methodology which can avoid challenges posed by government policies to influence electricity prices.

The key requirement of regulators is independent and transparent decision making. Financial independence is also required to ensure the regulator is self-sustaining, and this is most readily achieved through licence fees. Lastly, independence in appointing regulatory commissioners and executive staff should be exercised to avoid influence from politically strategic appointments. This is best achieved by ensuring a wide field of candidates is reached when advertising senior positions and adopting a

[1] Countries that do not are Comoros, Djibouti, DRC, Eritrea, Libya, Somalia, South Sudan
[2] DIRECTIVE 2003/54/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL Article 23

transparent approach to the assessment of skills and experience in the application and interview processes.

It was found during the field missions and the desk study that independence is a common issue amongst COMESA countries. There is wide variation in the degrees of independence that are achieved. The general trends are towards independent organisations that nevertheless have a direct connection with the Ministry of Energy or equivalent. This connection typically takes the form of ministers or civil servants being appointed to the board of the regulatory body themselves, or being actively involved in the approval of those appointed. How the regulators are funded also varies from fully state funded to fully funded by industry licence fees.

2.1.3 Electricity industry structures

It is important to understand the structure of the electricity sector within COMESA countries. Single buyer structures can be restrictive with limited transparency. Vertically unbundled structures have been international best practice since the 1990s. This allows each unit to focus on its core mandate without the distraction of trying to support other parts of the business. It provides transparency on matters of financial management and accounting within the system. It is also a requirement for good governance that can create a more attractive environment for investors.

In all the countries examined the electricity industry is structured around a state-owned utility acting as the “Single Buyer” of electricity generated either from its own resources or from IPPs with whom it enters into Power Purchase Agreements (PPA). The most significant change to this model seen in the countries that have been examined is the case of Namibia, where a Modified Single Buyer (MSB) model has recently been introduced. Under this arrangement it is possible for certain consumers to contract directly with IPPs, and also for IPPs to be constructed specifically to export power into the Southern African Power Pool.

Trading between private entities is also permitted in the South African power sector, provided that the parties have the relevant trading licences and grid access. In practice, the degree of control over network access that is exercised by the state-owned utilities at transmission and distribution levels makes it difficult for new entrants to participate in the electricity market.

Some countries, e.g. Kenya and Mauritius, have expressed the intention of ring-fencing the transmission system operator function within the industry, either legally, functionally or financially, in order to give a degree of separation of system operation from other power sector activities. This would be a positive step towards creating a “level playing field” for existing generators and new entrant IPPs to participate in the electricity market. In the case of Zimbabwe, however, it is understood that the industry structure may revert from the current degree of unbundling that has been achieved back towards a fully vertically integrated utility.

2.1.4 Power import and export

Generally, where cross-border trading is undertaken today (which is currently the case for the interconnected members of South African Power Pool (SAPP) and the bilateral transfers taking place from countries such as Egypt and Kenya, that will in future become trading parties within East African Power Pool (EAPP)), this is being led by the integrated power utilities. The possibility of IPPs trading internationally has been opened up with the change to the MSB model in Namibia, and in a number of jurisdictions primary legislation permits the existence and licensing of trading parties empowered to import and export electricity. SAPP has recently changed its membership categories to make it easier for IPPs to become SAPP members.

2.1.5 Power sector planning

Practices vary as to the extent to which government ministries take responsibility for the development and/or approval of expansion plans and/or investment plans for power utilities. There are broadly three models in evidence:

- The Government sets overall policy direction, but leaves planning to the power utilities with or without the Regulatory Authority approving the plans;
- The Government takes responsibility for the overall planning process, drawing on information from the utilities and the Regulatory Authorities; or
- The Regulatory Authorities develop plans, with inputs from the utilities.

Generally, it may be expected that national governments should take responsibility for setting overall policy objectives. The goal of developing an efficient power sector would suggest however that utilities should be free to develop their plans within these overall strategic objectives, but with regulatory oversight to ensure that customers do not end up paying for assets that may become stranded or for levels of investment that are inappropriate for the quality of service that they deliver.

2.1.6 Tariff unbundling

One of the important steps towards ensuring full transparency in electricity pricing is the unbundling of tariffs into their different components, such that the costs of networks can be separated from the costs of energy generation and supply. This way it becomes possible to ensure that the costs of each part of the electricity supply chain are accurately signalled to the users of the related services. In the case of network charges, these should be applicable to both consumers and generators; they should be set according to a cost-reflective methodology and subject to regulatory scrutiny, given the monopolistic nature of network services. In some countries, e.g. Egypt, Ethiopia, Mauritius, Namibia, South Africa, transmission tariffs are either already unbundled or in the process of being defined. This is a generally positive development that should be replicated by all countries wanting to participate in a regional market.

The introduction of variable renewable energy capacity across the full size-spectrum, from small rooftop to large utility scale installations, poses new challenges to the industry in particular in respect of the unbundling of electricity services and tariffs. These variable renewable energy sources require new laws, improved technology and infrastructure to provide customers with access to new services such as net-metering, storage and balancing.

2.1.7 Grid Code documents

All the countries examined have Grid Codes in some form, either as drafts that are going through stages of stakeholder consultation, or in final agreed forms that are already operational. Generally, these incorporate the core elements of Planning, Operations, Information Exchange and Governance codes, although the specific coverage varies between countries. During the fact-finding visits that have accompanied the desk study, discussions in Mauritius highlighted the importance of paying attention to the specific network characteristics of the different countries and the different requirements for dynamic performance of systems with increased Independent Power Producer (IPP) penetration. This has a particularly significant impact on the dynamic performance of island systems, which needs to be considered in any proposals to harmonise Grid Code provisions.

The regions' grid codes reviewed included the EAPP regional grid code and the grid codes from South Africa, Egypt, Ethiopia, Kenya, Tanzania, Mauritius, Namibia, Zambia and Zimbabwe. A number of these grid codes were developed from the South African Grid Code and hence there is reasonable consistency between the codes. The EAPP code was developed from a combination of the United Kingdom (UK) and European grid codes.

The South African Grid Code has recently been updated to include a renewable energy code. This code is absent from a number of the other countries' grid codes.

Key criteria in each section of the EAPP and country grid codes have been reviewed and are captured in Appendix A.

A summary of the consistencies of the key criteria for all of the country codes is listed in the tables below:

Table 1: Governance Code

Criteria	Summary
Board structure	All grid codes board chairpersons appointed by the Minister or Director General. Most countries the board is appointed by the Minister or Director general.
Voting majority	Voting has a mixture of consensus; 50% majority and Minister decides.
Grid code compliance committee	Regulator is responsible for formation of grid code compliance committee and enforcing grid code.
Noncompliance penalties	Noncompliance penalties are in most of the grid codes.
Derogations allowed	Derogations allowed in all of the grid codes.
Process to change grid code	Most grid codes have a similar approach to grid code changes: Step 1: all the request shall be submitted to grid code review panel Step 2: After discussions, review panel shall make recommendations to Board

	regarding the proposal Step 3: Board shall take the final decision

Table 2: Synchronous Generation Connection Code

Criteria	Summary
Frequency tolerance requirements	All Countries meet the international norm of: Normal range 49.0 - 51.0 Hz Extreme 47 - 51.5 Hz with the exception of Egypt which has a tighter band of 48.5 - 51 Hz.
High frequency control requirements	All countries have mandatory high frequency requirements. Some countries allow a 0.5 Hz deadband. This will have to be coordinated to prevent interconnectors from being overloaded.
Low frequency control requirements	Some countries have mandatory low frequency requirements while some countries have this as an ancillary service. Some countries allow a 0.5 Hz deadband. This will have to be coordinated to prevent interconnectors from being overloaded.
Voltage tolerance requirements	Most countries have a continuous band within 10% of nominal voltage and few have tighter requirements of 5% of nominal voltage.
Fault ride through	Less than half the countries have fault ride through capability for synchronous generators. The remaining codes need updating. Fault clearance time in EAPP grid code represent most international standards: 80ms (400kV, 500kV) 100ms (220kV - 230kV) 120ms (<=132kV) International standards for loss of power during fault need to be specified - a good reference is the Agency for the Cooperation of Energy Regulators (ACER) code.

Table 3: Nonsynchronous Generation Connection Code

Criteria	Summary
Frequency tolerance requirements	All Countries meet the international norm of: Normal range 49.0 - 51.0 Hz Extreme 47 - 51.5 Hz with the exception of Zambia which has a tighter band of 48.5 - 50.5 Hz.
High frequency control requirements	Most countries have mandatory high frequency response above 50.5 Hz.
Low frequency control requirements	Most countries require System Operators (SO) to define the low frequency requirements.
Voltage tolerance requirements	Most countries have continuous band within 10% of nominal voltage and few have tighter requirements of 5% of nominal voltage.
Fault ride through	Most countries have fault ride through capability for non-synchronous generators. There needs to be some alignment between the codes.
Synthetic inertia	Half of the grid codes have synthetic inertia specifically from wind power plants. This should be introduced specifically for battery technologies.

Table 4: Operations Planning Code

Criteria	Summary
Data for operational security analysis in operational planning	Most codes have data requirements for security analysis in operational planning.
Year ahead planning scenarios	Year ahead planning scenarios defined in most grid codes. Grid codes need to be updated to include high non-synchronous penetration scenarios.
Common model development	Most grid codes state that the SO is responsible for creation and maintenance of models.

	1) Generators to provide dynamic models, control systems, power capabilities like rated capacity 2) Transmission entities to provide transformer and line data 3) Distributors to provide models for complex load and protection relay settings
Operational security analysis	Most countries codes require: 1) Load flow Studies 2) Short circuit studies 3) Transient stability studies 4) Steady - state stability studies 5) Voltage collapse analysis 6) Electro-magnetic transient analysis 7) Reliability analysis
Regional operational security coordination	Regional operational security cooperation is required by most grid codes as per the power pool rules.
Regional outage coordination	Regional outage planning cooperation is required by most grid codes as per the power pool rules.
Methodology for outage coordination	For outage coordination most grid codes require: 1) Each Generating unit has to provide their proposed planned outage plans to Transmission System Operator (TSO). 2) TSO shall co-ordinate the annual outage plan ensuring sufficient reserves all the time 3) Generating units are expected to apply before each individual outage with the relevant details 4) upon study, TSO shall give the final approval for the corresponding outage

Table 5: System Operational Security Code

Criteria	Summary
Operational security alert condition	Operational alert condition in most grid codes is shortage of generation or frequency outside limits.
Operational security emergency condition	Operational alert emergency in most grid codes is partial blackout or major loss of generation.
Operational security blackout state	European regional code defines a blackout as the loss of half the TSO's system. No country codes specifically define a blackout.
Operational voltage security limits	Operational voltage security limits in most grid codes are: 1) Normal 0.95-1.05 pu 2) N-1 contingency 0.9-1.1 pu
Short circuit analysis	TSO's are responsible for short-circuit analysis in all grid codes that require short circuit analysis to be done.
Power flow limits	TSO's are responsible for determination of operational limits in most grid codes. Thermal limits are mentioned in most grid codes and very few mention dynamic limits.

Table 6: System Operations Code

Criteria	Comments
Primary frequency control reserves	Primary frequency control is mandatory in all grid codes except for South Africa where this is an ancillary service.
Control area agreements	Control area agreements are mandatory and bound by their respective power pool rules. Power pool rules are consistent for a control area.
Cross border reserve activation	Southern Africa (SA) countries grid codes refer to SAPP rules which allows cross border activation of reserves.
Frequency control targets	Frequency control targets in SA governed by SAPP rules. EA and IO countries have their own frequency control targets. Once countries interconnect targets will become consistent.
Ramping restrictions	Ramp rate restrictions are in most grid codes and specifically mention limiting of wind and solar power plants.
Reserve dimensioning	Reserve dimensioning is TSO function in most grid codes. Primary frequency control reserve dimensioning determined from the largest

	unit for primary frequency control. Secondary frequency control reserve dimensioning determined from frequency control targets. None of the country codes require dimensioning for variable renewable energy uncertainty.

Table 7: Information Exchange Code

Criteria	Summary
Mandatory information monitoring	Mandatory information requirements are reasonably consistent throughout all the grid codes. No mention of inter TSO data exchange.
Forecast Data exchange between TSOs	Forecast data exchange between participants reasonably consistent throughout all the grid codes. No mention of inter TSO data exchange.
Real-time data exchange between TSOs	Real-time data exchange between participants reasonably consistent throughout all the grid codes. No mention of inter TSO data exchange.
Generation data to TSO	Generation data exchange to TSO reasonably consistent throughout all the grid codes.
Demand data to TSO	Demand data exchange to TSO reasonably consistent throughout all the grid codes.
Communication protocol	IEC 101/104 standards required in most grid codes for internal country communications and Inter-Centre Communications Protocol for inter-TSO communications.

Table 8: Metering Code

Criteria	Summary
Meter period	All grid codes require at least 60-minute metering with most grid codes require 30-minute metering.
Meter accuracy	All grid codes have accuracy Class 0.2 or better.
Calibration and inspection	All grid codes require main transmission network meter inspection and testing to be done at least once every 5 years. Some grid codes require once a year.
Security	Security requirements in all grid codes are very similar and consistent.
Disputes	Meter dispute procedures in all grid codes are very similar and consistent.
Meter data confidentiality	All grid codes require meter data to be confidential.
Operational metering	Operational metering requirements in all grid codes require active (kW and kWh) and reactive (kVA and kVAh) measurements in both directions.

2.1.8 Renewable Energy (RE)

All of the countries examined have policies in place to support the growth of renewable energy in the generation mix. These range from high level policy objectives to achieve specific levels of renewable penetration by target dates, through the creation of specific bodies empowered to promote the development of RE, to targeted measures such as declared rounds of tendering for RE IPPs and the provision of FiTs and net metering arrangements to encourage both self-generation and export to the grid[3].

Across the region, as the market for RE matures, it is becoming clear that the need for advantageous tariffs for RE is reducing, and in our work to develop a set of recommendations for harmonised policies to promote RE we will need to take cognisance of the rapid advances in technology particularly in solar

[3] EREA has advised that the situation in specific countries regarding net metering is as follows:

- Burundi- no regulations on net metering,
- Kenya- Regulations exist but need realignment with the Energy Act 2019,
- Rwanda- regulations are being developed with a planned completion date of June 2020,
- Tanzania- Regulations exist but do not involve financial compensation hence are not operational,
- Uganda- A study is underway to study possibility of net metering

photovoltaics (PV) and wind generation that are driving costs downwards. The ultimate objective should be for RE to compete with other generation types in the regional electricity markets, and the minimum set of regulatory measures required to enable this needs to be identified.

2.2 Regional regulations and institutions

From the work carried out to date we have made a number of observations relating to the regional regulatory institutions that currently exist:

1. Regional Energy Regulators Association of Southern Africa (RERA) is the most mature of the regional bodies, and through the parallel project "Development of a framework and roadmap for the establishment of a Regional Energy Regulatory Authority for SADC", consultants have made a clear set of recommendations for the enhancement of RERA's regulatory role and powers. The study has developed a recommended mandate and sets of functions and powers that should be given to RERA under a charter from Southern African Development Community (SADC), and these are focused on the regulation of regional power trade, the facilitation of investment and capacity building to promote regional power trading;
2. The Independent Regulatory Board (IRB) is a regional regulatory body established by eleven-member regulators of the Eastern Africa Power Pool. It was established on the 30th of March, 2012 by the 5th COM meeting. The IRB steered by the policy decisions of the Conference of Ministers and deriving its authority from the Intergovernmental Memorandum of Understanding (IGMOU), it imposes the regional market rules and grid code upon the EAPP and participants. Currently the IRB has eleven mandates, some of the major mandates include monitoring and enforcing adherence to the rules, arbitrating disputes, setting regulated tariffs & wheeling charges for regional transmission lines, monitoring and surveillance of the Power Market and carrying out all duties pertinent to the role.

   The Vision and Mission statements are:

   IRB Vision

   To be a world class regional power sector/energy regulator that fosters investments and enhances the reliability of power/energy supply in the Eastern Africa Region.

   IRB Mission

   Provide regulatory services to the regional power market in an efficient, transparent and non-discriminatory manner and thereby contribute to the regional market's sustainable development.

   Currently the IRB is in the process of fully operationalising the institution and is developing its 10 Year Strategic Plan and 3 Year Action Plan;
3. For the Indian Ocean region, there is currently no equivalent organisation to RERA and IRB representing the regulators of the island countries. We understand that the IO nations are members of SADC and therefore have a degree of engagement with RERA. Whilst there are undoubtedly areas of common interest in utility regulation between the interconnected countries of SAPP and EAPP and the IO nations, nevertheless further consideration needs to be given to the extension of the "Club of Regulators" that is understood to exist within the IO region to ensure that the specific needs of island regulators are fully represented; and
4. RAERESA has a clear vision for strengthening the capacity of regulators throughout the EA-SA-IO region and is very well connected with regulatory bodies in the region, as well as institutions in Europe and the USA. The organisation has also published its strategic plan for the future, and has a clear vision of its role going forward. In developing recommendations for the future role of RAERESA it will be important to recognise its importance in supporting the development of regulatory capacity across the region.

Regarding regional regulations, key concerns amongst investors seeking to enter electricity markets are the need for transparent rules, clearly defined commercial arrangements and stable charges for access to and use of networks.

Our desk study results indicate that many of the national regulators have arrangements either in place or under development to support third-party access and the development of clear transmission charges for

IPPs. Building on this trend, we have developed proposals for regional harmonisation of regulations in these areas, coupled with recommendations on the development of a Regional Grid Code. All these measures would contribute to creating a positive environment for investment in power generation, including the connection of renewable generators, and enabling IPPs to participate in the interconnected EAPP and SAPP markets. They would also ensure that connecting generation to the networks in the Indian Ocean countries is achievable on similar terms to those applying elsewhere in the region. It will be important to avoid distorting the signals given to potential investors about the opportunities that exist in EA-SA markets compared with the IO region, which could happen if regulatory environments differ markedly between the interconnected markets and the island countries.

2.3 Key findings from related studies

We have reviewed a number of studies that were relevant to inform our work, focusing on any conclusions or recommendations that align with the objectives of the project. The summary and key findings from the most relevant documents can be found below.

We note that a core document that defines the future integrated electricity market for Eastern and Southern Africa is the Aurecon "SAPP-EAPP Impact Study", which defines a proposed market model involving "tight coupling" of the two power pools. We have taken this as the starting assumption in our work, and sought to develop recommendations regarding regulatory arrangements that will be compatible with this approach. Whilst other forms of market coupling would be possible, and are evaluated in the Aurecon study, it is beyond the scope of this report to critique these proposals in detail.

2.3.1 Aurecon "SAPP-EAPP Impact Study"

The study was initiated to consider the technical feasibility and impacts of connecting the SAPP and the EAPP, to identify issues and make recommendations pertaining to the safe operation of the interconnected network, and to analyse the power exchange options between the two power pools, for both bilateral and competitive market trading. Several key topics were highlighted as important in the context of legislation and regional policy.

2.3.1.1 Intergovernmental MOUs

From an enforcement perspective, it will be necessary for the participating member states to enter into and adopt an intergovernmental memorandum of understanding at an inter pool level in order to regulate:

- co-operation between members of the EAPP and SAPP in respect of the development of a tightly coupled market and trading between SAPP and EAPP;
- that way that national utilities and IPPs enter into a contract regarding their own obligations resulting from an interconnection contract;
- choice of applicable law/define a common legal system (to apply when there are conflicts in the domestic law of different countries);
- the dispute resolution procedures to be applied across the regions; and
- recognition or enforcement of a foreign judgment.

The above principles must be regulated at a national level to ensure that the choice of applicable law and the regulation of disputes are enforceable against the member states. It is important to note that an intergovernmental memorandum of understanding may not be automatically enforceable at a national level.

We note that this finding implies that careful consideration is required of the way in which the proposed RRAs and associated regional regulations are connected with over-arching regional decision making bodies and legislation. The effectiveness of regulations agreed regionally will also depend on the processes that exist to translate these into national legislation. We address this further in Section 5.

2.3.1.2 SAPP/EAPP Agreement Between Operating Members

The participating members need to enter into an agreement in order to establish the key principles to be followed in establishing, putting in place, and enforcing rules of practice covering technical planning, operations, and commercial aspects of regional power system integration and defining ownership of assets and other rights. This should include the requirements to develop and agree a regional transmission wheeling charging methodology that includes consideration of system losses.

For example, an intergovernmental agreement cannot prescribe open access to a transmission system for all market participants, if this is restricted by domestic legislation. Each member of SAPP and EAPP will need to assess and ensure that its own domestic law and practices are consistent with what is agreed in the operating members agreements.

2.3.1.3 SAPP-EAPP Operational Agreement

Any interconnection between the members of SAPP and EAPP will require an operating agreement to harmonise the standards and technical parameters of the day to day operation of the interconnected system. Consideration will need to be given to the grouping of control areas, and the legislative mandate in domestic law and agreements at a power pool level to realise this.

2.3.1.4 Other Aurecon findings

Enabling domestic law

States must enact enabling national domestic legislation to ensure that domestic law and practices are consistent with agreements reached at an intergovernmental level. This is particularly important in jurisdictions where national law takes precedent over international law.

Customs duties

Bilateral power trade will be subject to different tax and custom duties depending on the jurisdictions tax framework. Treaties and protocols of the different economic blocks (SADC, East African Community (EAC) and COMESA) will need to be considered when assessing custom duty and tax implications. This will require in-depth analysis by a tax practitioner to analyse the implications for each jurisdiction.

Currency of energy trade

Where the seller and the buyer undertake the sale and purchase of electricity in different currencies, the parties would have to negotiate regarding which of them will bear the foreign exchange risk. When a trading platform is established, however, countries can elect a currency in which to trade. In the SAPP, for example, South Africa trades in South African Rand (ZAR) while the other SAPP countries trade in United States Dollars (USD). An independent study should be completed to consult with all stakeholders.

2.3.1.5 Final recommendations for harmonisation

1. A more detailed MOU between EAPP and SAPP on the cooperation of developing common tightly coupled market(s) and trading between the two Power Pools;
2. Development of an Agreement between the members in EAPP – replicating the SAPP ABOM (Agreement Between Operating Members);
3. Harmonisation between this agreement and the SAPP ABOM – should ideally be done as part of one process;
4. Agreement between SAPP and EAPP on calculation and management of interconnection capacity between the two Power Pools including but limited to how to manage (and calculation the financial management of) wheeling, losses, emergencies and outages;
5. Cooperation agreement on the cooperation of market(s) and trading between the two Power Pools;
6. An operational agreement on the use and adaptation of the current SAPP Market Trading Platform;
7. Harmonised System Operational procedures; and
8. Harmonised Market Book of Rules.

2.3.2 RERA, Guidelines for Regulating Cross-Border Power Trading in Southern Africa: Regulatory Duties (2010)

SADC mandated RERA to help address major regulatory constraints in the enabling environment for cross-border power trade. As a response, RERA issued Guidelines for Regulating Cross-border Power Trading in Southern Africa to represent best regulatory practice for SADC countries. The guidelines drew on international best practice and discussions with RERA members on existing regulatory rules and practices. They targeted major, long-term cross-border transactions that are more likely to have a direct impact on decisions to invest in new generation and transmission facilities. RERA believed that investment in such facilities (or the lack thereof) is the primary and overriding concern of the SADC countries. Some fundamental recommendations that also apply to a regional market are:

a) Issuing licences to entities that will be engaged in cross-border electricity trading, such as electricity generators and transmission companies, traders, importers and exporters (Guideline 4);
b) Approving the terms of power purchase agreements (PPAs) and transmission wheeling agreements in cross-border electricity imports and exports (Guidelines 5, 6 and 7) as they relate to technical system security issues;
c) Approving the recovery of the costs of electricity imports through the tariffs charged to price-regulated customers (Guideline 5);
d) Approving agreements to export electricity by parties that supply price-regulated customers to safeguard their interests (Guideline 6);
e) Approving transmission wheeling agreements in transit countries where the transmission provider supplies price-regulated customers to safeguard their interests. (Guideline 7);
f) Mandating access to transmission and distribution facilities for cross-border electricity trading in accordance with national legislation and transmission licence conditions (Guideline 8); and
g) Approving domestic and cross-border transmission charges (Guideline 8).

2.3.3 African Union Commission, Strategy for the Development of a Harmonised Regulatory Framework for the Electricity Market in Africa

The European Union SE4All Technical Assistance Facility funded a project managed by the African Union Commission Department of Infrastructure and Energy to develop a strategy for harmonising a regulatory framework for cross border trade across the continent of Africa. The report develops a batch of activities at a National, Regional and Continental level. The activities of highest relevance to the ESREM project are detailed below:

2.3.3.1 National

- Establish and designate a national regulator which meets the requirements of financial, operational and organisational independent;
- Adoption of electricity sector law and/or regulatory legislations;
- Develop tariff guidelines and methodology: grid connection, including feed-in-tariffs (FIT);
- Implement cost reflective tariffs and tariff unbundling;
- Develop integrated resource planning;
- Develop and implement licensing framework: large and small power plants;
- Develop and implement grid codes;
- Develop system operations or technical operations manual;
- Develop connection and transmission service agreements;
- Develop model PPAs;
- Develop market models for market opening, to promote non-discriminatory third-party access;
- Develop dispute resolution procedures;
- Develop and implement technical connection guidelines for renewable energy technologies;
- Develop and implement quality of service enforcement guidelines for RE;
- Develop and implement technical and quality of service standards; and
- Develop demand side management (DSM) monitoring guidelines and standards.

2.3.3.2 Regional

- Develop and implement regional transmission pricing guidelines, including principles of determining wheeling charges and cost allocation of network losses;
- Develop principles and harmonised rules for pricing ancillary services and balancing services;

- Develop harmonised codes of practice and technical standards for system operators to facilitate regional electricity trading;
- Develop model contracts to facilitate regional electricity trade and power pooling;
- Implement guidelines for dispute resolution procedures;
- Implement rules and guidelines for monitoring and surveillance of operation of power pools;
- Implement harmonised codes of practice and technical standards;
- Cross border transaction frameworks accepted, implemented and enforced; and
- Dispute resolution appeals via an independent appeal structure at the regional level.

3 Review of regional and international best practices for regulating regional energy markets

3.1 Introduction

This section briefly analyses existing international best practice for regional electricity regulatory oversight that are relevant to the development of recommendations for the EA-SA-IO region. We summarise the learning from the regulation of three regional markets:

- the European Union and the activities of the European Union Agency for the Cooperation of Energy Regulators (ACER);
- the United States, focusing on the role and responsibilities of the Federal Energy Regulatory Commission (FERC); and
- West Africa, assessing the role and functions of ERERA, the ECOWAS Regional Electricity Regulatory Authority.

3.2 EU Best Practice: the European Union Agency for the Cooperation of Energy Regulators (ACER)

General Mandate/Objectives: the general mandate of ACER is to assist the national regulatory authorities (NRAs) of the EU Member States in exercising, at European Union level, the regulatory tasks performed in the Member States and, where necessary, to coordinate their action. ACER is therefore formally not a regulatory authority but an EU body responsible for promoting regulatory cooperation and for coordinating NRAs' activities in the EU.

Enabling Legal Framework: ACER was set up in 2009 is set up as a Union body with legal personality. Its legal functions and powers are governed by the Third Energy Package and Regulation (EC) 713/2009 establishing the agency in 2011 which was repealed in 2019 by Regulation (EU) 2019/942 (recast). Regulation (EU) 2019/942 (recast) states that in each member country, ACER will be granted the most extensive legal person status allowed under the national law.

Key functions and powers: in order to fulfill its mandate, ACER:

- drafts non-binding framework guidelines for network codes upon the request of the European Commission, i.e. comprising connection codes, operations codes, market codes;
- issues non-binding opinions and recommendations to NRAs, TSOs, and the EU institutions, i.e. regarding network development planning, list of projects of common interests, proposals to enable permanent bi-directional physical capacity or on exemption requests;
- issues binding individual decisions in specific cases and sets conditions about cross-border infrastructural issues; and
- conducts market monitoring regarding network access conditions, retails prices, consumer rights and wholesale trading.

Key Regulatory and enforcement instruments: as mentioned previously, ACER is not a regulatory authority with direct enforcement capacities. Its regulatory key instruments are limited to issuing opinions and recommendations on issues within the scope of its tasks and responsibilities. However, in terms of enforcement, ACER has to rely on enforcement by other European institutions, in particular the European Commission.

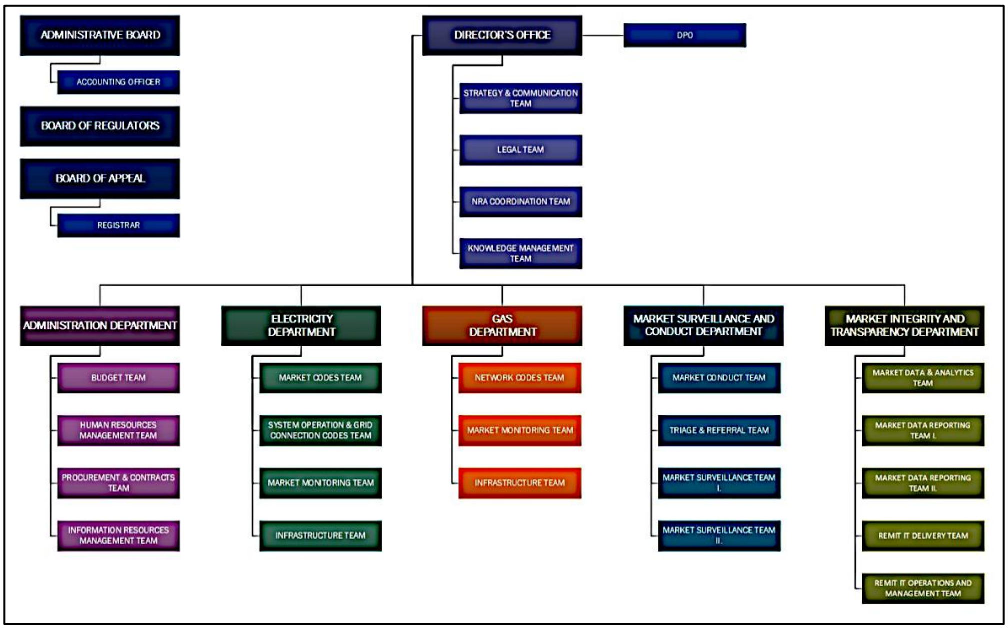
Budget/Financing: ACER must cover its expenditure (staff, administrative, infrastructure and operational expenditure) mainly from EU contributions, fees, voluntary Member State contributions and donations and grants (provided these grants and donations are in compliance with existing legal rules). The annual budget is adopted by the Administrative Board based on a detailed expenditure estimation by the Director. In the case that the Administrative Board agrees with the budget it must forward it to the European Commission who will then submit it as part of the general EU budget for adoption to the European Parliament and to the European Commission.

Governance/Organisational Framework: the organisational structure of ACER comprises the Administrative Board, a Board of Regulators, a Director and a Board of Appeal.

- The Administrative Board of ACER is composed of the Chair of the Board of Regulators and the Director of ACER and 9 members and 9 alternates who are appointed by the European Parliament, the EU Council and the European Commission. Amongst other tasks the Administrative Board formally appoints the members of the Board of Regulators, the Board of Appeal and the Director and adopts ACER's annual Work Program and revised a multi-annual work program.
- The Board of Regulators (BoR), which consists of senior representatives of the National Regulatory Authorities (NRAs) and one non-voting representative of the European Commission, amongst other tasks provides opinions to the Director on ACER's opinions, recommendations and decisions and approves ACER's Work Program and presents it to the ACER Administrative Board.
- The Director represents and manages the Agency, implements the Work Program, adopts and publishes ACER opinions, recommendations and decisions, prepares the annual Work Program and the Agency budget and appoints the staff of the Agency.
- The Board of Appeal, which comprises 6 members and 6 alternates selected from current or former senior staff of national regulatory authorities, competition authorities or other national or EU institutions with relevant experience, amongst other tasks considers appeals lodged by any natural or legal person, including NRAs, against ACER decisions.

The outlined organisational structure is illustrated by the chart in Figure 1.

Figure 1: ACER organisation chart



3.3 USA Best Practice: The Federal Energy Regulatory Commission (FERC)

General Mandate/Objectives: FERC is an independent agency in the United States that regulates interstate transmission and wholesale sale of electricity, the interstate transmission and wholesale of gas, the interstate transportation of oil by pipelines and reviews proposals to build interstate natural gas pipelines, natural gas storage projects, liquefied natural gas (LNG) terminals, and the licence for non-federal hydropower projects.

Enabling Legal Framework: FERC's powers and responsibilities were granted by the Congress and are described in numerous laws including the Federal Power Act, Public Utility Regulatory Policies Act, Natural Gas Act and Interstate Commerce Act.

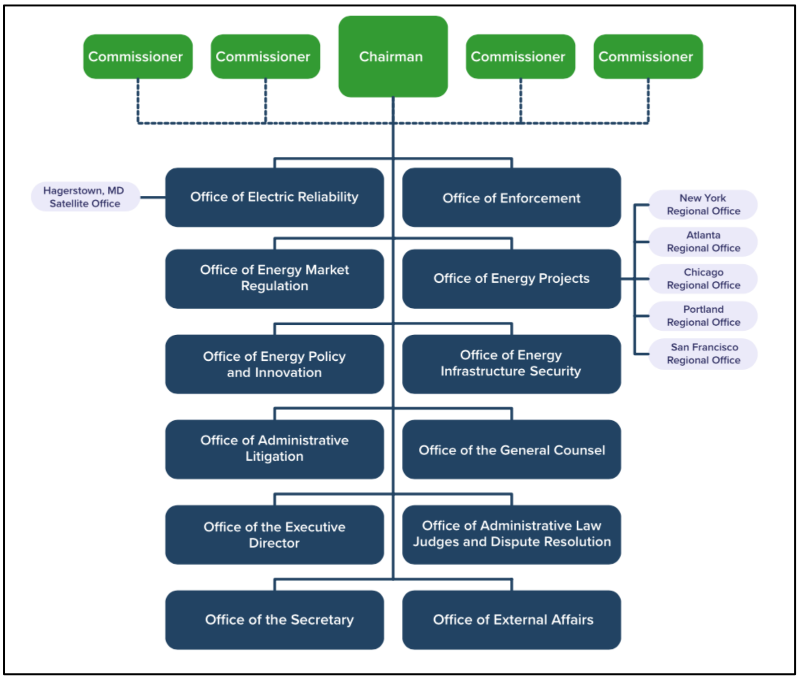
Key functions and powers: FERC's regulatory mandate in the field of electricity covers interstate transmission and wholesale sale of electricity. As a horizontal objective FERC must exercise its functions and responsibilities as required in order to achieve that consumers have access to economically efficient, safe, reliable, and secure energy. The key regulatory responsibilities of FERC in the field of electricity comprise:

- regulating the transmission and wholesale sales of electricity in interstate commerce;
- reviewing certain mergers and acquisitions and corporate transactions by electricity companies;
- reviewing the siting applications for electric transmission projects under limited circumstances;
- licensing and inspecting private, municipal, and state hydroelectric projects;
- protecting the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- monitoring and investigating energy markets;
- enforcing FERC regulatory requirements through imposition of civil penalties and other means; and
- administering accounting and financial reporting regulations and conduct of regulated companies.

Key Regulatory and Enforcement Instruments: the key regulatory instruments that FERC has at its disposal to carry out its responsibilities are industry-wide decisions (i.e. through adoption of new statutes, regulations or rules) and party-specific orders. While FERC generally aims at encouraging compliance with such statutes, rules and orders, it also has a series of robust instruments at its disposal to enforce them in case some form of fraud or market manipulation, anticompetitive conduct, serious violations of the electric reliability standards or conduct that threatens the transparency of regulated markets is detected. Enforcement instruments include the imposition of compliance commitments, disgorgement (repayment) of unjust profits resulting from the violations and civil penalties.

Governance/Organisational Framework: the organisational structure of FERC is headed by a commission that is appointed by the US President with the consent of the Senate for a maximum term of five years. This commission comprises up to five commissioners and coordinates the work of twelve offices that deal with the day-to-day implementation of the responsibilities and tasks of the FERC. This organisational structure is summarised in the chart below.

Figure 2: FERC organisational structure



3.4 Regional Best Practice: ECOWAS Regional Electricity Regulatory Authority (ERERA)

General Mandate/Objectives: ERERA's general mandate is to regulate cross-border electricity exchanges, creating an enabling investment environment for regional power projects and providing technical support to national regulators of the electricity sector of the Member States of the ECOWAS.

Enabling Legal Framework: ERERA was founded in 2008 by the ECOWAS Heads of State through regulation C/REG.27/12/07 of 15 December 2007. This regulation was as amended by Regulation C/REG.24/11/08 of 29 November 2008. The mandate, functions, powers and regulatory instruments and governance/organisational structure of ERERA are defined by this Regulation.

Key functions and powers: the key functions of ERERA amongst others comprise:

- regulating the cross-border power pooling among ECOWAS Member States;
- overseeing the implementation of the necessary conditions to ensure rationalisation and reliability of energy;
- contributing to setting up a regulatory and economic environment suitable for the development of the regional market;
- overseeing compliance with the principle of freedom of electricity transit;
- overseeing the establishment of a clear, transparent and predictable tariff setting methodology for regional power pooling;
- responsibility for technical regulation of regional power pooling and the monitoring of regional market operations;
- assisting the ECOWAS Commission in defining the strategic direction of the regional policy and the harmonisation of policies, legislations and regulation of national power sectors;
- establishing effective dispute resolution procedures between regional power market players and controlling their proper application; and
- maintaining relations with ECOWAS national regulatory authorities and providing them with technical advice and assistance at their request.

In order to carry out the above functions ERERA has the following key powers:

- setting and interpreting technical and commercial rules on cross-border power pooling;
- making recommendation to regional or national ECOWAS power sector participants;
- authorising, approving and controlling the activities of regional power market participants;
- investigating and sanctioning breaches of established rules on cross- border power pooling; and
- resolving disputes between regional power market participants.

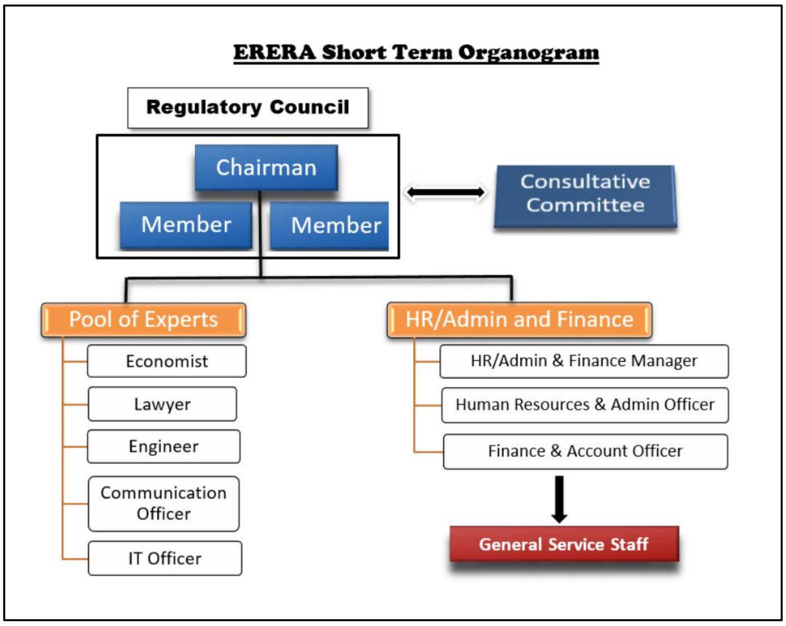
Key Regulatory Instruments: ERERA relies on a range of robust and soft regulatory instruments in order to carry out its responsibilities. In terms of robust regulatory instruments ERERA may adopt commercial and technical rules for ECOWAS cross border power trade, investigate and sanction breaches of the adopted rules and authorise and control the activities of market participants. In addition, ERERA may make non-binding recommendations to regional and national power market and is available as dispute resolution authority for regional market participants.

Budget/Financing: ERERA expenditure comprises ordinary and extraordinary sources of funding. Ordinary funding sources comprise annual fees levied on cross-border power pooling and charges for processing cases, inspection and supervision and procedural charges under ERERA rules. On the other hand, extraordinary funding sources comprise loans, state subsidies and grants from public or private national or international organisations as well as gifts and legacies.

Governance/Organisational Framework: ERERA is organised through the Regulatory Council. The Regulatory Council is the decision-making and managerial body of ERERA. It comprises three members including a Chairperson. The Regulatory Council Members are appointed for a fixed, non-renewable term of five years. The Regulatory Council is supported by a multidisciplinary pool of experts that are responsible for the regulatory matters and by a Human Resources, Administration and Finances Unit. This organisational structure is summarised in

Figure **3**.

Figure 3: ERERA Organisation Chart



3.5 Observations

The three examples of regional regulatory bodies that have been reviewed demonstrate differing characteristics that are relevant in considering the appropriate institutional structures and responsibilities that could be developed in the EA-SA-IO region. The key points to note are:

- in Europe, ACER is not an authority with direct enforcement capacities. Its primary role is issuing opinions and recommendations on issues within its overall remit. However, it is reliant on other EU institutions or on Member State regulatory authorities to provide enforcement powers – this includes the European Commission itself which issues Directives that are binding on EU member states. Thereby, although this is likely to change gradually over the next years, the role of ACER, is presently mainly limited to an advisory function for national regulators;
- in the United States, FERC has a key role in regulating the electricity sector under delegated powers from Congress. It effectively therefore acts as a regulatory authority in respect of interstate trading of electricity and has enforcement powers in key areas of technical and commercial regulation. However, its remit is of course limited to one nation;
- ACER and FERC do not in our view present best practice examples that can be recommended as organisational models for a regional regulatory framework for EA-SA-IO region. In this respect, both ACER and FERC are embedded and function in political and institutional framework conditions that are entirely different from those in the EA-SA-IO region and aim significantly beyond establishing a sectoral regional regulatory system. Both ACER and FERC are part of complex institutional systems in which they are not only sectoral regulatory powers, but also legislative, executive and judicial powers that have been transferred to a central regional or federal level, in the case of the EU to the EU institutions (European Parliament, European Commission, European Court of Justice), in the case of the US by different states to the federal US government;
- the example of ERERA in West Africa is highly relevant to the EA-SA-IO region. ERERA has a range of powers to regulate participants in the regional electricity market delegated to it by the ECOWAS Heads of State and is able to regulate cross-border power trading, decide and administer sanctions where necessary and act to resolve disputes.

In developing our recommendations for the EA-SA-IO region, we have drawn on ERERA as a possible model for the RRAs that will take responsibility for the Eastern African and Southern African markets.

The advisory role of ACER is perhaps most relevant to the future role of the Club of Regulators in the Indian Ocean, which will act as a focus for promoting good regulatory practice in the region.

4 Obstacles to regulatory oversight and proposals for regulatory harmonisation

The desk review and field missions highlighted a number of regulatory issues across the 10 sample countries that will need to be addressed in order to enable a regional market to be established successfully. These challenges fall across 3 key themes; licensing, network regulations and market regulations.

4.1 Licensing

Licensing can be seen as the first step for a market participant joining a power market. Currently, national market participants must apply for a licence based on varying conditions set by their respective national authoritative entity to operate nationally. A regional market would require participants to apply for licences that align with common standards. The key reason why a common licensing standard is required is to ensure participants are required to adhere to technical conditions that would ensure system safety, reliability and efficiency. The standards would be transparent and publicly accessible to promote new entrants into the market. A common standard can give prospective developers confidence that they would be able to participate from any country within the regional market. Licences would need to be applied for:

1. Generation;
2. Transmission;
3. Distribution;
4. Interconnection;
5. System operation; and
6. Import and export.

Harmonised licence guidelines will level the playing field for new projects joining the market. Investors will only be required to comprehend one set of guidelines, thereby understanding the entire region and promoting the opportunity for swift repeat investment.

In many jurisdictions the provisions of the Transmission Licence can also cover the requirements for the development, ownership and operation of interconnectors. The reason for proposing a possible separate category of Interconnection Licence is to cater for the situation where private sector developers of international interconnectors may come forward, for whom the full range of obligations incorporated in the transmission licences signed by national transmission utilities maybe inappropriate.

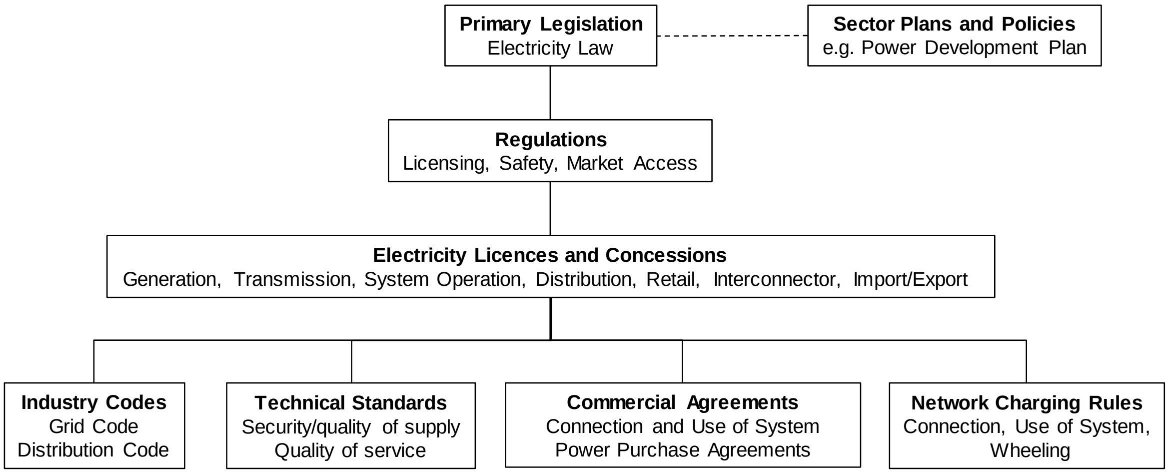
4.2 Network regulations

As part of being licensed, a market entrant must comply with network regulations. Participants must operate to technical standards, to ensure quality of service and quality of supply criteria are maintained.

To facilitate the introduction of a regional market, regulations should be defined that are consistent across Southern and Eastern Africa and are presented in a standardised format or as templates that can be utilised by the NRAs in each country. This will ensure that base requirements are defined, transparently and there is less burden on market participants, regulators and utilities in developing and negotiating terms.

The overall structure of the regulations that are required to support the electricity sector both nationally and regionally is shown in Figure 4.

Figure 4: Power sector regulatory structure



Each national market will typically have in place enabling regulations within or beneath primary legislation that define the requirements for licences, safety compliance and arrangements for applying for market entry. The specific obligations on power sector participants are defined in the structure of electricity licences and concessions, as summarised in Section 4.1 above.

To promote access to the national and regional electricity markets, harmonisation of the codes and agreements that are a requisite of licencing is required. This will ensure that potential market entrants are able to participate on an equal basis irrespective of which country they are located in, which is particularly important for a future integrated EA-SA market. In addition, however, achieving this harmonisation between the countries of the IO region is also desirable, as this will remove any artificial barriers that may be perceived by investors seeking to develop new generation in one specific country compared with another. If, for example, the grid code obligations in one country are unnecessarily conservative, these could hamper the development of new generation technologies in one island that are fully accepted elsewhere. At the same time, if code requirements are too lenient, there could be an erosion in supply quality and security that will act against the economic interests of one island over another.

The priority areas that we have identified for harmonisation of regulations are the following:

- **Grid Code documents** – seeking to promote the development of a single Regional Grid Code for the EA-SA region, and clear guidelines throughout EA-SA-IO for NRAs and national utilities on the provisions that should be included in national Grid Codes. Grid codes would also contain provisions for regional planning to optimise investments in the regional context, connection standards to guarantee technical conformity, a code for renewable energy and guidelines for sector governance;
- **Technical standards** – many of these are incorporated in the Grid Codes themselves, but where standalone documents are cross-referenced by these codes, the standards incorporated in them should be harmonised as far as possible;
- **Commercial agreements** – particularly focusing on the agreements that are required to secure third-party access to the transmission networks in the region. Market agreements will also require harmonisation between EAPP and SAPP when market coupling takes place, to ensure that obligations on market participants are aligned; and
- **Network charging rules** are a specific aspect of the regulatory regime that require careful consideration, as these are core to the provision of transparent and non-discriminatory access to the electricity markets. The objective here should be to ensure that fundamental principles of cost-reflective, stable and non-discriminatory charging are adopted, together with a uniform approach to the methodology that is used for calculating regional wheeling charges.

Transmission tariffs are inconsistent amongst countries and some have not unbundled the various costs of service of their system. This means that TSOs or DSOs attempting to reconcile usage of their network by import/export trade could be overcharging or failing to recover the costs of their network assets. It is proposed that a single pricing methodology is devised that considers the value of assets on a system and their utilisation in providing wheeling services. The implementation of such a methodology would give investors confidence in the competitive nature of the regional market and in the long-term stability of the costs of the transmission service. The point to point MW-km methodology is recommended as a first iteration of the regional market with the opportunity to further develop the methodology at a later stage – we discuss this further in Section 5.4.4.

4.3 Market regulations

Participants who are licensed and are operating as per network regulations should be permitted to trade in the regional markets subject to qualifying for membership under the relevant market rules. Some participants are already trading on SAPP's established market platforms. EAPP's market has yet to trade but the markets are different to those in SAPP. If they are to be interconnected, market access and regulation would need to be harmonised so that both markets are available to participants on the same trading platform.

Table 9: Comparison of established SAPP markets and proposed EAPP markets

SAPP markets	EAPP markets
• Bilateral trading • Forward Physical Market (FPM) • Day-Ahead Market (DAM) • Intraday Market (IDM) • Balancing Market – under development	• **Bilateral trading** • **Short-term trading (ADAM)[4]**

We note that the SAPP-EAPP Interconnector Impact Study[5] has made a series of detailed recommendations on the harmonisation of market regulations – these include identifying the need for an Intergovernmental Memorandum of Understanding to be entered into between the relevant countries participating in SAPP and EAPP, an agreement between the operating members of the two markets to agree the principles and rules for operation of the interconnected SAPP-EAPP markets, and a specific operating agreement that will detail how the pools work together in practice.

SAPP has an established set of market platforms running over different timeframes, and market participants in a combined EAPP and SAPP market will therefore be able to trade different quantities of energy over different time schedules of trades. Each market will continue to have its own set of regulations to ensure it is accessible and non-discriminatory. SAPP in particular has well evolved market regulations that could be used as a template for future market platforms in the wider region. Regional market regulations will also need to be able to interface successfully with national market rules, which will require detailed consideration at the national level.

Market surveillance will require implementation so as to ensure that all market participants are abiding by the market rules and related regulations. A key question will be the extent to which the market will be monitored, whether through an external regulatory body or through self-regulation. We discuss this further in Section 5.3.

[4] The ADAM market operates on similar principles to the SAPP Day-Ahead Market, however ADAM has to date only been used for shadow trades, whereas the SAPP Day-Ahead Market is used extensively for actual trading.
[5] SAPP-EAPP Interconnector Impact Study – Final Report – Aurecon AMEI Limited, October 2018

5 Recommendations for regulatory oversight of the EA-SA-IO Electricity Market

5.1 Roles of regional and national regulatory institutions

5.1.1 Existing Regional Challenges and Realities

It is recommended to base the regulatory oversight of the EA-SA-IO Electricity Market on the institutional structure and approach that is described below. The recommended institutional structure and approach are regarded as the most realistic way forward for establishing an effective institutional structure for regulatory oversight of the EA-SA-IO Electricity Market. In particular it seeks to reflect and balance the regional regulatory institutional needs with the existing regional regulatory institutional framework conditions and other specific regional characteristics and challenges that were identified during the previous phase of this project. In this respect the recommended institutional structure amongst other things considers that the EA-SA-IO electricity sector is characterised by:

- a challenging regional scope as it covers 29 African countries with different legal and regulatory frameworks, stretching from South Africa to Egypt, comprising four island states and different official languages (English, Arabic, French, Portuguese);
- differences in regulatory needs between the interconnected EA-SA states and the IO region states that are neither connected to the EA – SA states nor between each other;
- varying levels of regional electricity system integration:
    - significant level of regional integration in Southern Africa region with the SAPP already functioning for many years;
    - early stages of regional integration in Eastern Africa with EAPP established but not yet operational;
- one already existing regional regulatory authority, the IRB for the EAPP;
- various other organisations already dealing with regional regulatory matters (RERA, RAERESA, AFUR, EREA);
- different regional governmental organisations with different regional scopes and mandates (SADC, EAC, COMESA, IOC).

5.1.2 Recommended Starting Point: different regulatory regions and regional regulatory authorities supported by regional regulatory capacity building organisations

In order to align the future institutional framework for regulatory oversight of the EA-SA-IO Electricity Market to the maximum degree with the outlined, already existing regional regulatory institutional framework conditions and other specific regional characteristics and challenges it is recommended as a starting point to:

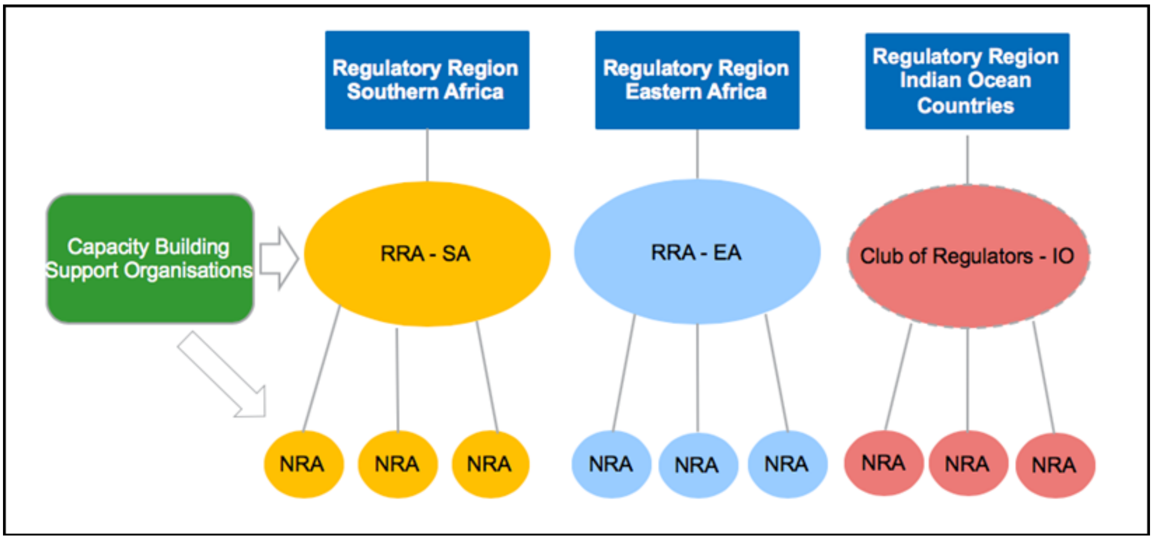
- split the countries covered by the present study into three different regulatory regions, comprising
    - a regulatory region for Southern Africa comprising Angola, Botswana, the Democratic Republic of Congo (DRC), Eswatini, Lesotho, Malawi, Mozambique, Namibia, South Africa, Tanzania, Zambia, Zimbabwe duly reflecting the already existing regional pre-conditions, in particular the SAPP regional scope and already existing advanced regional integration across SAPP;
    - a regulatory region for Eastern Africa comprising Burundi, the Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Libya, Rwanda, South Sudan, Sudan, Tanzania, Tunisia and Uganda duly reflecting the already existing regional pre-conditions, in particular the EAPP regional scope and present status made in the EAPP in terms of regional integration;
    - Note that DRC and Tanzania are members of both regulatory regions, recognising their participation in both regional markets currently; and
    - a regulatory region for the Indian Ocean countries comprising the Comoros, Madagascar, Mauritius, the Seychelles and duly reflecting the different regulatory needs of the island

states of the Indian Ocean region in comparison to the regulatory needs of the continental African countries.

- establish a single regulatory institution for each of the three regulatory regions, comprising
  - an independent regional regulatory authority for the regulatory region for Southern Africa;
  - an independent regional regulatory authority for the regulatory region for Eastern Africa;
  - a regional regulatory association, i.e. a Club of Regulators for the regulatory region for the Indian Ocean countries, building on the "Club of Regulators" model that is currently in use.
- establish an effective framework for capacity building support for the entire EA-SA-IO region that enables the three established regional regulatory institutions as well as the national regulatory authorities across the EA-SA-IO region to train their staff in all regulatory matter that are required in order to enable them to effectively and coherently exercise their respective regulatory powers and responsibilities.

This recommended general approach for establishing an effective institutional framework for regulatory oversight in the EA-SA-IO region is comprehensively illustrated by the following chart.

Figure 5: Recommended institutional framework for regulatory oversight



5.1.3 Recommended Division of Tasks between Regional and National Regulatory Institutions

One of the key aspects that needs to be clearly determined in order to establish an effective institutional structure for regulatory oversight of the EA-SA-IO Electricity Market is the division of responsibilities between the three established regional regulatory authorities and the national regulatory authorities across the three regulatory regions. As a general rule, the regional regulatory authorities should only exercise such responsibilities that have been attributed to them by the relevant enabling legal documents. In line with the principle of subsidiarity any other responsibility should remain the exclusive responsibility of the national regulatory authorities. In line with this general rule it is recommended to divide the responsibilities between regional and national regulatory institutions as follows in order to ensure an effective institutional structure for regulatory oversight of the EA-SA-IO Electricity Market:

- Responsibilities of Regional Regulatory Authorities and the Club of Regulators:
  - development and adoption of common mandatory regional regulatory rules and standards documents applicable to entire regional system development and operation, in particular:
    - Regional Grid Code;
    - Transmission Charges;

  - Common standards for Wheeling Agreements (including Wheeling Charges);
  - Common Standards for PPA;
  - Licensing Rules and Licence Templates for Regional Electricity Activities etc.; and
  - Development of recommended common regional regulatory rules and standard documents for entire region with support of other relevant regional organisations.
- Regulatory decisions on compliance with mandatory regional regulatory rules and documents.

- Responsibilities of National Regulatory Authorities:
  - enforcement of regional regulatory decisions by the regional regulatory authorities;
  - transposition of regional regulatory rules, guidelines and decisions into national regulatory rules and guidelines.

The scope of potential general key responsibilities for the recommended regional regulatory institutions for the EA-SA-IO regions is comprehensively illustrated by the following table.

Table 10: Key responsibilities for recommended regulatory institutions

Regional Regulatory Authorities EA-SA	Regional Advisory Body IO
Development of mandatory harmonised regional regulatory rules and documents • Licensing Rules for Regional Market Participants • Regional Grid Code • Grid Connection Rules	Development of recommended harmonised regulatory rules and documents • Licensing Rules • Transmission and Distribution Grid Code • Grid Connection Rules
Regional Grid Development Planning	
Development of recommended model regulatory documents and commercial agreements for regional power trade: • Model Licenses • Model PPA • Model Wheeling Agreement • Model Connection Agreement • Other Standard Market Agreements	Development of recommended model regulatory documents and commercial agreements: • Model Licenses • Model PPA • Model Connection Agreement • Model RE Procurement Guidance etc.
Regulatory Decisions regarding compliance with mandatory regional regulatory rules	
Communication of Regulatory Decision to National Regulatory Authorities (responsible for enforcement)	
Regional Market Surveillance Rules and Regional Market Surveillance	

5.1.4 Recommendations regarding capacity building support framework

As mentioned above it is recommended to complement the recommended regional regulatory institutional framework by an adequate capacity building framework that that enables the three established regional regulatory institutions as well as the national regulatory authorities across the EA-SA-IO region to train their staff adequately in all regulatory matter that are required in order to enable them to effectively and coherently exercise their respective regulatory powers and responsibilities.

Two principal options are available to create the respective capacity building mechanisms:

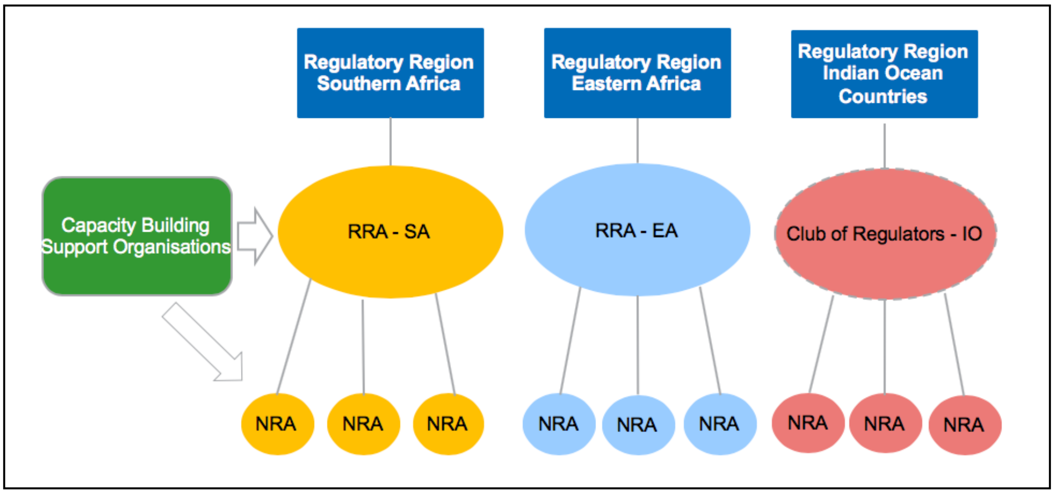
- establish and mandate a new single regional regulatory capacity building organisation to provide training to the regional and national regulatory authorities across the EA-SA-IO region; or
- mandate one or more of the regional organisations with knowledge and capacity in regional and national regulatory matters that already exist in the EA-SA-IO region to provide training to the regional and national regulatory authorities across the EA-SA-IO region.

While in principle, the first option is regarded as more desirable in terms of coherence and resource efficiency, it is, in line with the general intention of the consultants to build the recommended regional regulatory framework for the EA-SA-IO region to the to the maximum extent possible and useful upon the already pre-existing institutional and organisation regulatory framework, recommended to base the envisaged capacity building framework on the second option in its first phase. In this respect, as has been outlined previously, a series of organisations with proven in-depth understanding and knowledge of regional and national regulatory matters in the field of electricity already exist in EA-SA-IO.

5.1.5 Summary Overview of proposed Institutional Structure for regulatory oversight of EA-SA-IO Electricity Market

The proposed institutional structure for regulatory oversight of the EA-SA-IO Electricity Market is illustrated by the below chart.

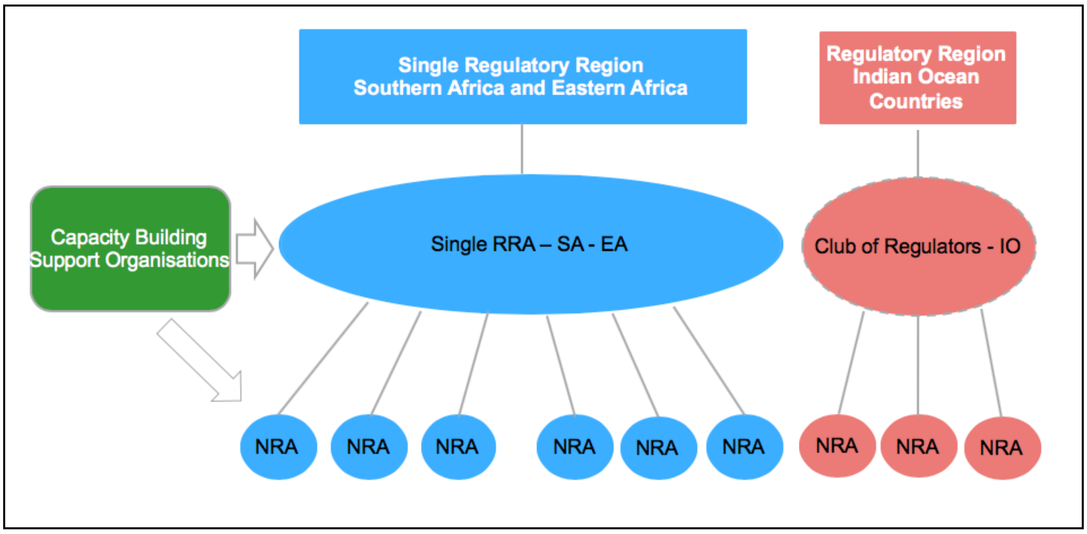
Figure 6: Proposed institutional structure for regulatory oversight of the EA-SA-IO Electricity Market



5.1.6 Long-Term Objective: towards a Single SA-EA Regional Regulatory Authority supported by a Single Regional Regulatory Capacity Building Organisation

While the approach outlined above presents a realistic starting point for establishing an effective institutional structure for regulatory oversight of the EA-SA-IO Electricity Market, the proposed has been designed taking into consideration the factually existing limitations that are imposed by the existing regional pre-conditions. It thus presents a compromise that aims to establish the most effective institutional framework for regulatory oversight in the EA-SA-IO Electricity Market that can be achieved under the presently existing pre-conditions. However, it is recommended to have a more ambitious vision for the medium to long-term future. In this respect, it is recommended to gradually merge the proposed parallel regulatory regions and regulatory institutions for Southern and Eastern Africa in the medium-term future, in order to maximise the coherence and effectiveness of the regional regulatory institutional framework for these regions. The long-term institutional structure for regulatory oversight of the EA-SA-IO Electricity Market that would emerge from this institutional merging process is illustrated by the below chart.

Figure 7: Proposed long-term institutional structure for regulatory oversight of the EA-SA-IO Electricity Market



5.1.7 Cross-regional regulatory coherence and co-operation as key success factor for the proposed way forward

The long-term success of the recommended institutional structure for regulatory oversight of the EA-SA-IO Electricity Market, amongst other factors, in particular depends on the level of cross-regional regulatory coherency between the Southern African and Eastern African regulatory regions. Ultimately the evolution towards a single regulatory region will only be smooth if both zones are regulatory coherent to the maximum degree possible, both in terms of institutional set-up and in terms of regulatory standards and practice. Non-coherency in these respects would lead to fragmented regulatory practice across the two regional regulatory zones and would jeopardise a smooth gradual transition toward a single regulatory region for Southern and Eastern Africa. In this respect, it is recommended to ensure in particular from the onset that

- the enabling legal documents for both regional regulatory authorities are coherent to the maximum degree possible in terms of governance, organisational structure, regulatory functions, regulatory responsibilities, regulatory instruments;
- both entities adopt coherent mandatory regional regulatory rules, standards and documents; and
- both entities coherently apply the common mandatory and recommended regional regulatory rules, standards and documents.

Beyond that, it is of vital importance for the success of the proposed approach that the national regulatory authorities coherently and consistently enforce the regional regulatory rules, standards and decisions that are adopted by the two regional regulatory authorities.

In addition to the outside long-term success factors, it is of vital short-term importance to ensure a high level of co-operation between the two regulatory authorities for the Southern and Eastern African region regarding cross regional regulatory issues, i.e. cross regional interconnection planning, cross regional electricity transfers, etc.

5.2 Licensing regimes

5.2.1 Overview

An important area of oversight in the EA-SA-IO Electricity Market concerns the development of a harmonised regime for the licensing of power sector activities.

We propose that harmonised arrangements are required that address the following range of regulatory activities:

- Harmonised Licensing Guidelines, which set down the principles of electricity sector licensing, which activities should require licences and any restrictions on the nature of the organisations or individuals that are permitted to hold licences;
- Common procedures for lodging licence applications and the processing of these by national regulatory authorities – we propose that licences should be issued by NRAs but that the

application and approval process should be harmonised as far as possible to ensure that there is a level playing field for potential electricity market participants across the different national jurisdictions;

- Standard licence conditions in core areas of the electricity supply chain, including:
  - Generation;
  - Transmission (especially guaranteeing third-party access to national transmission networks for the purposes of power import and export);
  - Distribution (especially rights for embedded generation used for exports and customers seeking to import from the regional markets);
  - Interconnection (focusing on licence requirements for independent developers of international interconnectors and their obligations in respect of interconnector planning, operation and availability);
  - System Operation (to the extent that this is licensed separately from transmission ownership); and
  - Import and Export (containing the minimum conditions that generators and consumers need to comply with in order to access and participate in regional markets).

From the work carried out reviewing sample countries across the region, it is clear that most jurisdictions have in place a licensing regime that covers the key elements of the electricity supply chain. Licences are typically required for the following activities:

- Generation;
- Transmission;
- Distribution; and
- Electricity supply/retailing.

noting that the supply/retailing activity is often combined with the distribution function. The need for a generation licence typically varies according to the size of the generating plant, and whether the plant is being used for self-generation or for power purchase by third parties.

Primary electricity legislation often refers to the need for licences for the above activities as clearly separated functions. Given the dominance of vertically integrated power utilities within the region, however, the same organisation can hold licences for a number of different activities.

The objective of harmonising the approach to electricity licensing should be to align the behaviours of those organisations undertaking different activities in the supply chain irrespective of the nature of the ownership of these organisations.

We noted from our review of current practices the general absence of import and export licences, even though these may be permitted under the high-level legislation in some countries. Whilst the right to import and export is given in some of the legislation, it is often only allowed with express permission of the Ministry of Energy or equivalent, and there is a concern that this could lead to undue delays for IPP developers in being granted the legal right to export power into the international markets. Import and export licences should therefore become a core part of the regulatory structure in each of countries that are able to trade in the EAPP and SAPP markets.

We note that in the region currently, system operation is not regarded as a separately licensed activity. The requirement for a specific System Operator licence becomes relevant when the unbundling of the electricity sector has been progressed to a point where system operation has become functionally separated from transmission network ownership. This can be a valuable step in assisting the process of open access to the transmission network for generation and large consumers, however it is not a prerequisite for the development of a regional electricity market. Nevertheless, within the SAPP/EAPP region there is an emerging role for private sector developers of transmission that is likely to expand as the requirements for new infrastructure investment grow. Consequently, we are recommending separate licence conditions for transmission companies and system operators, to give a clear separation of roles and responsibilities.

The key requirements that should be addressed in harmonised licences across the SA-EA-IO region are noted in the following sections.

5.2.2 Generation licences

Most electricity jurisdictions internationally adopt an approach to generation licensing based on:

- All generators above a certain minimum size threshold requiring licences;
- Licence exemptions being granted below this threshold; and
- Exceptions being allowed in some situations for self-generation, i.e. generation located at a consumer's premises or that is dedicated to the supply of load on the same industrial/commercial site or within a limited geographical area at which the generator has its own industrial demand.

The diverse nature of the power systems in Eastern and Southern Africa is such that it would not be appropriate to propose common size thresholds for licensing – the potential impact of a generator of a particular size on one of the smaller networks or on an island would be significantly different from that on a major interconnected power system.

Generation licences should be structured to include the following core requirements.

Topic	Key provisions
Right to generate electricity	The basic right to generate electricity from the nominated power station site specified in the agreement should be granted.
Right to sell electricity	The right to sell electricity should be specified, detailing any restrictions that apply and noting that reference may be required to a separate Export Licence to permit participation in regional power trading.
Licence fees	The fees payable on an annual basis for maintaining the generation licence should be specified.
Compliance with National and Regional Grid Codes	Generators should be required to comply with the terms of the grid codes that apply in each country. These may contain planning, connection, operation, market, information exchange and other codes that are relevant to the generator. The Regional Grid Code, referred to elsewhere in this report, will seek to harmonise the technical requirements for generators such that the interconnected operation of the power networks can be achieved safely and reliably.
Compliance with Distribution Code	Where generators are connected to distribution networks (however these are defined in each jurisdiction) they should comply with the requirements of the national code that is specifically relevant to the distribution network. This may be expected to cover broadly the same headings as the Grid Code, but adapted for lower voltage levels of connection and operation.
Scheduling and dispatch	The generator should be required to comply with instructions issued by the national Transmission System Operator – this provision could include a cross-reference to the Grid Code.
Ancillary services	In order to secure the operation of the national and regional transmission networks, generators should be required to provide ancillary services, either as a mandatory requirement or on a commercial basis, according to common service definitions across the region.
Prohibition of cross-subsidies	It is particularly important in the case of generation companies that are either part of vertically integrated utilities or that are part of corporate organisations with multiple electricity sector interests that cross-subsidies between one business area and another are prevented. This will help to ensure that fair competition between generators is achieved within the national and regional electricity markets.
Transfer and assignment of licences	Any restrictions on the transferability of licences between corporate entities or the assignment of licences by one company to another (e.g. in

	the event of corporate restructuring, takeover etc.) should be clearly stated.
Regulatory accounts/financial reporting	All generators should be required to submit accounts in a prescribed format and at an agreed frequency to the relevant NRA.
Suspension and revocation	The conditions under which licences can be suspended or revoked should be specified.

5.2.3 Transmission/Interconnection licences

Transmission licences are key documents in the regulatory structure that are critical to ensuring the development of the regional electricity markets and the promotion of new investment. These licences fulfil a number of key functions:

- They permit the construction and ownership of assets by incumbent national utilities and by new entrants who could be private developers of transmission. In a situation where substantial new investment in network infrastructure is required to increase the penetration of new generation (particularly renewable IPPs) and to increase international interconnector capacity, it is important that licences are granted on a transparent basis and that these incorporate common conditions that will protect network users and contribute to the maintenance network security. This aspect of the licence is equally applicable to the large interconnected networks and the island networks;
- They require transmission companies to promote third-party access to the transmission system. This is the means by which IPPs gain access to the transmission network to use the network either for supplying consumers within the national electricity market, or for transporting power to the borders of the national network for onward delivery into the regional market. The ability for IPPs to supply national consumers could be equally applicable to the interconnected countries and the island systems; transfer of power for export is only applicable to the SAPP and EAPP countries; and
- Where applicable, the licence could also require transmission companies to make their networks available for power wheeling. This is a key aspect of the operation of the interconnected SAPP market, and will become a feature of EAPP as well, since trading power internationally under PPAs or though the short-term market platforms could be dependent on the ability to deliver power via third-country systems.

We propose that common guidelines for transmission licensing are developed across the EA-SA-IO region and that these are developed and promulgated by the Regional Regulatory Authorities (RRAs). The licences themselves should be issued by NRAs within their national jurisdictions. If existing licences deviate from the recommendations in the guidelines, it is recommended that licence modifications are implemented by the NRAs that will ensure that all transmission licences are aligned with the guidelines.

The key terms to be covered in the transmission licence are summarised below. An interface is needed between transmission owners (TOs) and SOs when it comes to offering accepting requests for new connections to the network and/or granting third-party access. For example, the system operator may be the party receiving applications for connection and use of the transmission system, and will then be responsible for coordinating with the TO. In many cases these functions will be handled by a combined TSO, but the licensing guidelines should assume the most general case. Consequently, the licence obligations on TOs proposed below should be read in conjunction with those applying to system operators.

Topic	Key provisions
Obligation to provide transmission services	The transmission licensee has a fundamental obligation to make the transmission system available to the System Operator (SO), to enable the SO to take control of system and to allow the SO access to system data.
System security standard and quality of standard	The transmission licensee is required to adhere to the Grid Code system security and quality standards in relation to the planning and design of the transmission network.

Obligation in relation to offers for connection	This is the key requirement for giving third-party access to the transmission network. The transmission licensee should liaise with SO (if the SO is the recipient for requests for new connections). A clear process should be defined for analysing connections requests, and the grounds on which connection offers can be refused should be set down.
Non-discrimination	Also core to the provision of third-party access is the providing assurance to network users that there will be no discrimination in favour of one user over another. This is particularly important to ensure that new generation being developed by a vertically integrated utility is not granted access to the network ahead of IPPs, either through the connection and planning process, operational planning (including outage scheduling) or in real-time system operation.
Prohibition from selling electricity	International best practice suggests that transmission utilities should not be able to sell electricity in their own right. This is linked with the condition of non-discrimination, to avoid transmission utilities favouring supplies to customers from which the they themselves will profit in planning and operating the network.
Transmission owner – system operator interface	It is important that the transmission licensee is required to liaise with the SO on key issues affecting the performance of the transmission system. As independent TOs evolve, the need for coordination between multiple parties in the operation of the network assets will increase.
Regulatory accounts	Harmonised provisions are required dealing with the preparation, auditing, and publication of accounts, to aid the transparency inherent in the transmission licensee's business.
Disposal of assets	It is good practice to have in place provisions that restrict the circumstances in which TOs are permitted to dispose of their assets, given the supply reliability and security issues associated with network ownership.
Provision of information to National and Regional Regulatory Authorities	Licensees should be obliged to provide reports to NRAs and RRAs regarding the networks for which they are responsible.
Availability of resources	It is important that the transmission licensee maintains sufficient resources in terms of staff and financial capability to fulfil its obligations, and this should be a harmonised condition across the region.

5.2.4 System operator licences

As noted in Section 5.2.3, there is an important interface between the transmission owner and the system operator that needs to be recognised in each national jurisdiction. In addition, SOs are required to work together to maintain a harmonised approach to the operation of interconnected systems and to facilitate cross-border trading of electricity.

The core provisions of the SO licence that should be considered for harmonisation across the region are the following:

Topic	Key provisions
Requirement to offer terms for connection and use of system	It should be mandatory for SOs to offer terms for connection and use of system agreements to generators and consumers seeking connection to the national transmission networks. In addition, it should be a responsibility of the SO to cooperate with neighbouring SOs for the purposes of developing interconnections in the EA-SA-IO region.

Use of system charges	The SO should be required to develop a transparent method for charging generators and consumers for use of the transmission network. Charges should be calculated and published, and updated on an annual basis to reflect changes in network configurations. Charges should be cost-reflective and avoid over-remunerating those TOs that also provide wheeling services. A common transmission charging methodology is recommended that would be proposed by the RRAs, overseen by the NRAs and applied by the national SOs, with revenues passed to transmission licensees as appropriate.
Connection charges	Connection charges should be developed in a transparent way by the SO in conjunction with the transmission licensees. A common methodology should be adopted for the definition of the assets that are included in connections and are charged for separately from the use of system methodology. A “shallow connection charging” policy could be adopted regionally that would ensure that the costs of shared transmission lines and substations are recovered through use of system charges, whereas the costs of assets used solely by one generator or consumer are recovered as part of the connection cost.
Non-discrimination	It is fundamental to the provision of third-party access that non-discrimination between network users is achieved in system operation and well as in network ownership. The SO should be required to demonstrate non-discrimination in all aspects of system operation, taking responsibility for dispatching generation in accordance with the relevant national and regional electricity market rules, together with the national and regional Grid Codes.
Connection and use of system agreements	The SO should enter into connection and use of system agreements with all parties who are using the national transmission networks. The terms of these agreements should be harmonised and could be simplified by reference to a standard code of practice to be adhered to in all connection and use of system agreements across the interconnected systems and the island networks. This could assist the process of promoting investment in new generation and the integration of new generation into the existing networks.
National and Regional Grid Codes	The SO should draft and maintain a National Grid Code, in consultation with the NRA, the transmission licensee and users of the national transmission system (generators and consumers). In addition, the SO should be required to participate in forums supporting the drafting and maintenance of a Regional Grid Code, working in conjunction with other national SOs, transmission licences, generator and consumer representatives and RRAs.
Provision of information	The SO should be responsible for publishing information that supports current and potential future transmission users and network developers as to the opportunities that exist for new connections, the construction of additional transmission assets and the development of international interconnections. These should be developed in conjunction with existing transmission licensees and system users. Annual reports on system performance should also be provided to the NRAs and also, if required, to the RRAs.
Cooperation with other parties	Many aspects of successful national and regional system planning and operation are dependent on interactions between national SOs. It should be a requirement of the SO licence that the SO interacts with national and international stakeholders including its own NRA and the relevant RRA(s) to ensure that networks are developed and operated economically and in technical robust ways.

Economic system operation	The SO should be required to operate the power systems economically, seeking to minimise the costs of providing services such as system balancing and ancillary services (including frequency control, voltage control and system restart services). This requirement should be linked with developments in regional balancing market arrangements.
Prudent system operation	The SO is responsible for operating network assets within their normal or contingency technical limits and for operating systems and assets in line with prudent operating practice. This is important to avoid the risk of transmission licensees' network asset health being compromised.
Regulatory accounts	The SO should prepare accounts in a prescribed format and issue these to the relevant NRA and RRA(s) as required.
Provision of information to National and Regional Regulatory Authorities	SOs should be obliged to provide reports to NRAs and RRAs regarding the performance of the systems for which they are responsible. This should include reporting on the performance of the integrated transmission networks, for those operators responsible for power imports and exports.
Availability of resources	It is important that the SO maintains sufficient resources to fulfil its obligations and deliver on its responsibilities as a prudent system operator.

5.2.5 Import and export licences

Import and export licences should be introduced to give generators and consumers connected to the interconnected power systems of Southern and Eastern Africa the right to buy and sell electricity from the regional markets. These should give the right to power purchasers and sellers to access a future integrated market, i.e. be non-specific as to the market in which exported and imported power are traded. Holding the relevant import/export licence should be a condition of membership of EAPP and SAPP or of a future integrated market. It is important to note that until such time as any form of interconnection between any of the island nations of the Indian Ocean is contemplated, the creation of import and export licences should not be a requirement in the IO countries.

Export and import licences should be issued by the NRA in each country. The market rules in SAPP, EAPP and any future integrated market should contain a requirement that for continued membership trading parties must have the relevant import or export licence in full force and effect within their own national jurisdiction.

The core contents of licences for exporting electricity that should be harmonised across the region are proposed to include the following:

Topic	Key provisions
Right to export electricity	The licence should give the Licensee the right to export electricity generated by identified power plants under its ownership to customers and/or power markets located outside the holder's own country. The details of the relevant generating plants should be provided in an annex to the Licence.
Commercial agreements	The Licensee should be required to enter into PPAs or other sales contracts that are compatible with the regional Market Rules. It should also enter into agreements that give it access to the national transmission network and the necessary wheeling rights to export energy from its generation facilities. Copies of these agreements should be lodged with the NRA and the RRA.
Market membership	The Licensee should be required to obtain membership of the regional market through which it will be trading its energy. Market membership

	should be a requirement parties who are trading bilaterally as well as those using the short-term market platforms.
Regulatory accounts	Separate accounts should be required maintained for generation and export activities in the manner stipulated by the relevant RRA and NRA.
Prohibition of cross-subsidies	Cross-subsidies between business activities within the Licensee's organisation should be prevented.
Provision of information to authority	The Licensee should provide reports to the RRA responsible for the market of which it is a member and to the relevant NRA confirming its compliance with the terms of the licence, providing information about [annual] trading statistics and such other information as the RRA or NRA may reasonably require.
Transfer and assignment of licence	The transfer or assignment of the rights and obligations of the Licence to another organisation should only be permissible with the approval of the NRA.
Term of the licence	Consideration should be given to linking the term of the licence to other conditions, e.g. the term of market membership agreements, if these are limited and subject to periodic renewal.
Suspension	The NRA should have the power to suspend the licence, and should exercise this in consultation with other NRAs and the RRA(s) such that a breach of the licence conditions (e.g. through non-compliance with regional market rules) arising in any country in the region may result in suspension of the Licence until such time as the breach is remedied. Specific events should be defined that could lead to suspension.
Revocation	The NRA should have the power to revoke the licence following a suspension in the event that persistent breaches of the licence conditions are unremedied. The precise circumstances in which the licence could be revoked should be defined.

5.3 Market monitoring and surveillance

5.3.1 SAPP Market Surveillance

There are two main approaches that can be adopted to market monitoring and surveillance in international electricity markets:

1. Markets can be essentially "self-regulating", where it is the responsibility of committees created with representation from the market members themselves to investigate disputes arising over specific transactions or market behaviours; and
2. External regulatory bodies can be involved in the oversight of the market and be given powers to intervene in the investigation of allegations of market manipulation or abuse.

SAPP is currently investigating how best to approach this issue, and is planning to establish a Market Surveillance Unit that will operate within the market and report to the SAPP Coordination Centre Manager. A project is underway to make this operational by the end of 2020. Key aspects of the work to be completed include:

- Establishing the SAPP Market Surveillance Unit and the appropriate systems to enable it to function effectively;
- The development of data collection and evaluation processes and systems to enable the evaluation of market participants' behaviour in accordance with agreed guidelines;
- The definition of templates for market surveillance reporting so that information is presented to the SAPP Coordination Centre Manager in a consistent format; and
- Guidelines for the process of investigating possible breaches of the rules and regulations governing SAPP operation.

It is proposed that a Market Surveillance and Monitoring Handbook will be developed which will be based on international best practice for market surveillance.

5.3.2 Relationship between SAPP and RERA

A key issue concerns the relationship that will be established between RERA as the RRA for SAPP and the internal Market Surveillance Unit. It is important here to note the recommendations contained in the report prepared by Economic Consulting Associates (ECA) on the "Development of a framework and roadmap for the establishment of a Regional Energy Regulatory Authority for SADC"[6]. This report notes that in its current form, RERA "does not have a mandate to exercise the power of regulatory oversight over the regional energy market in SADC." The proposed transformation of RERA from a regulatory association to a regulatory authority would strengthen the organisation's mandate. Its functions and powers to fulfil its mandate then flow from this fundamental definition.

One of the three key elements of RERA's proposed mandate for the future as a regulatory authority, defined in ECA's work, is "Regulation of cross border energy trade". Related to this mandate it is proposed that the SADC Regional Energy Regulatory Authority (SARERA) - the working name for the new authority) has a series of regulatory functions, which may be summarised as follows:

- Issuing regulations governing wheeling charges and allocation of transmission capacity in the SAPP region, including charges applicable in "entry" and "exit" countries;
- Issuing regulations governing access to and use of national networks – "third-party access";
- Regulating access to cross-border interconnectors;
- Regulating technical standards associated with electricity trading (including delegation of responsibilities where appropriate to SAPP);
- Participating in the governance of Market Rules – here the ECA study proposes that SARERA will have the right to approve energy market rules and future rule changes, and to instigate the process of modifying rules (in accordance with the relevant market governance procedures) "where this is necessary to promote competition or avoid anti-competitive behaviour"; and
- SARERA will also have a role in "monitor[ing] cross-border trade in order to identify anti-competitive behaviour in the wholesale energy markets. SARERA shall be granted the power to apply appropriate sanctions (financial penalties, changes to the Market Rules, obligations to dispose of certain businesses) against market participants who are found to be engaging in anti-competitive behaviour."

The last two of these functions in particular – governance of market rules and the identification of anti-competitive behaviour – are areas where the SAPP Market Surveillance Unit may be expected to be particularly active, and it will be important therefore to draw a clear distinction between the responsibilities of SAPP and those of SARERA in undertaking market surveillance activities.

The recommendation of the ECA study is that across a range of regulatory instruments associated with network access, wheeling charges, anti-competitive behaviour and the governance of SAPP market rule development, SARERA will have oversight responsibility and the power to action over non-compliance. These are the areas where interfaces between SAPP and SARERA need to be clearly defined. The ECA recommendation is that the market monitoring role should be fulfilled by the SAPP Coordination Centre – in the light of SAPP's current initiative on market surveillance, this would be a function fulfilled by the SAPP Market Surveillance Unit, reporting to the SAPP CC. The ECA recommendation is that the results of SAPP's market surveillance activities would be reported to SARERA, and SARERA would have the responsibility for taking action in response to any issues that have been detected and reported on by SAPP.

This division of responsibility is an appropriate one in that it ensures that responsibility for acting on information relating to potential breaches of market rules is decided by an organisation that is independent of the market itself. In the SAPP organisation structure, the Coordination Centre reports to the SAPP Management Committee, which comprises representatives of the SAPP members – consequently it is not able to make decisions that are fully independent of the market members themselves.

[6] Development of a framework and roadmap for the establishment of a Regional Energy Regulatory Authority for SADC, Draft Final Report, Economic Consulting Associates, 24/02/2020

We therefore recommend that the approach proposed in the ECA study that gives SARERA the ability to enforce sanctions in response to breaches of the market rules is adopted for the Southern African market, and that a similar approach is taken in the Eastern African Power Pool – see below.

5.3.3 IRB's role in relation to EAPP

We have noted the intention within EAPP for IRB as the regulatory board for the market to be made into an independent regulatory body that sits outside the EAPP structure. This would be a positive development in that it would allow IRB to be given a similar mandate to SARERA as an RRA. It would then be possible for EAPP to develop an internal Market Surveillance Unit that would take responsibility for the collection of information relating to market operation and potential breaches of the market rules. This would report its findings to IRB and any resulting sanctions could be imposed by IRB on defaulting EAPP members.

We recognise that this requires a number of changes to be made to the IRB's organisation and mandate. However, harmonising the roles and responsibilities of SARERA and IRB in relation to market surveillance and overall market monitoring and regulation would be highly desirable as a step on the trajectory towards a single Pan-African regulatory body.

5.3.4 Market Surveillance in the IO region

The need for electricity market surveillance in the IO region is primarily focused around national electricity markets and is therefore a function that should be fulfilled predominantly by the NRAs. The role of the proposed Club of Regulators for the IO region would be an advisory one, helping each of the NRAs to formulate policies and regulatory instruments that enable an appropriate level of intervention in their national markets to protect customers' interests. This would include a role for the Club of Regulators in reviewing international best practice and issuing guidance notes on good practice in market regulation that can be built on by the individual NRAs.

5.4 Incentivising investments in regional transmission infrastructure

5.4.1 Introduction

There are a number of issues affecting investment in regional transmission infrastructure that require a consistent set of regulatory arrangements to address. Specifically, regulation at the regional level that needs to support regulation at the national level if it is going to be fully effective.

The principle of subsidiarity is important here, in the sense that centralised (regional) regulatory authorities should have a subsidiary role to the national regulators, ensuring that only those tasks that cannot be performed nationally are dealt with at a regional level. As shown in Figure 8, this will mean that the RRAs take responsibility for interactions with the Power Pools themselves, focusing on:

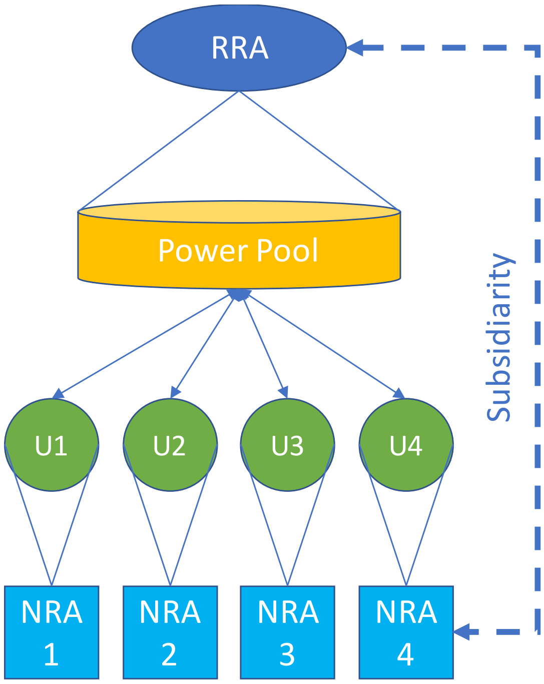
- the regulation of market operation;
- the approval of transmission wheeling charges (both the overall methodology and the levels of charges);
- harmonising technical standards and the regional Grid Code;
- coordinating with NRAs as appropriate on issues of dispute resolution and imposition of sanctions.

NRAs will be responsible for regulating the national power utilities and transmission system operators (TSOs), which may in turn be members of the regional power pools and/or have responsibilities for the development of regional transmission infrastructure. The role of the NRAs will include:

- regulating the arrangements that will apply for Third-Party Access to the national transmission networks, to facilitate regional power trading;
- approving national transmission charges;
- approving national Grid Codes and working with the RRA on the harmonisation of regional Grid Code documentation;
- having regulatory oversight of national electricity markets; and

- liaising with the RRA regarding issues of non-compliance with regional market rules, dispute resolution and the imposition of sanctions.

Figure 8: Relationship between RRA and NRAs in regulating power pools and utilities



5.4.2 Regulatory issues in transmission investment

In order to enhance investment in regional transmission infrastructure, an enabling environment is required that will provide both regulatory and commercial assurance to the developers of transmission infrastructure. This needs to cover the following:

- A clear **licensing structure** to ensure that transmission infrastructure can be developed by other than the vertically integrated power utilities – see Section 5.2;
- **Template agreements** and **standard conditions** for the core agreements that are needed by TOs:
  a. A **Transmission Connection Agreement** that covers the technical and commercial arrangements for connecting new generation and consumer sites to the transmission network;
  b. A **Transmission Use of System Agreement** that defines the rights of transmission users to be, and to remain, connected to the new assets;
  c. An **Interconnector Agreement** that deals with specific connection and operational issues at the point of connection between new interconnector assets developed by independent companies and the existing national transmission networks; and
  d. A **Wheeling Agreement** that sets down the rights and obligations of TOs in relation to international power transfers between countries in the SAPP and EAPP markets.

  A combined Transmission Services Agreement could cover the requirements of a, b and c in one document. This could also make reference to a stand-alone Transmission Services Code that would contain standard conditions to be complied by all TOs.

  Further details of the recommended coverage of these agreements are provided in Section 5.5, because these agreements also support the concept of open access ("third-party access" to the transmission networks – for this to be successful requires clearly defined technical and commercial interfaces between the transmission owners, the network operators and the connected parties (generators and consumers);

- An agreed approach to calculating **national transmission charges** that includes both connection and use of system charges, and ensures that investors in transmission assets can receive a suitable return on the costs of their assets, including allowances for investment costs and operations and maintenance costs;
- A published methodology for the calculation of **wheeling charges** that will include revenue recovery for international interconnectors. It is possible that in the future private developers will build and own transmission lines that will interconnect countries within the SAPP and EAPP markets. This would have the combined effect of increasing interconnector capacity and the potential for regional trade, whilst also reducing the requirement for government funding of interconnectors. In order for private sector developers to obtain funding for transmission projects, however, the revenue stream associated with these will need to be clearly defined. Having a robust methodology for calculating wheeling charges will be an important part of this; and
- As a further extension of national transmission charges and international wheeling charges, the possibility of region-wide commercial arrangements for remunerating **ancillary services** providers could be considered. Of particular relevance to transmission investors is the question of payments for reactive power from compensation equipment and the possibility of network-connected storage devices being paid for the provision of reserves.

5.4.3 National transmission charges

In order to encourage investment in regional transmission infrastructure, a consistent approach to transmission charging is needed that will ensure that investors can receive an adequate return on the investment they make in transmission infrastructure. New transmission lines will be required across the EA-SA-IO region to reinforce networks in order to accommodate new generation and demand. In the integrated power systems of EA and SA, however, new interconnectors will be built either by the existing power utilities or by private investors. Transmission tariffs are the main mechanism whereby transmission owners receive the revenue required by their businesses. The primary objective should be to ensure that transmission charges are:

- Stable;
- Predictable;
- Cost-reflective; and
- Transparent.

in order that both investors and system users gain confidence in the charging regime and their finance plans can be based on a sound knowledge of future revenue streams.

The ability to identify transmission costs separately from the other components of energy costs is closely linked with the need for tariffs to be unbundled. Once this has been achieved, it should be the responsibility of the NRAs and the transmission companies to agree the approach that is to be taken to transmission tariff design. The methodology to be used for national transmission charges could potentially be common to all the interconnected countries and the Indian Ocean networks, ensuring that the NRAs and RRAs are agreed on the principles to be applied. It is not essential that each country adopts the same approach to national pricing, however: countries at different stages of electricity market development may wish to employ different approaches. This can influence the choice of pricing models between the three major types of methodology:

- **"postage stamp" charges**, in which a flat rate charge per MW or capacity or MWh of energy consumption is applied to consumers at the bulk supply level and passed down to smaller domestic/commercial customers through the retail energy tariff;
- **locationally varying zonal charges**, which seek to send signals to network users indicating the impact of their demand and generation on the costs of network infrastructure reinforcement. The locational charges may be developed by considering the use of the transmission network made by each electricity trade. This can be assessed by methods such as:
    - a contract path approach, in which a set of assets deemed to be used by an individual transaction is identified and the costs of these allocated to the transaction by an administrative method;
    - a flow-based MW-km method, which seeks to allocate to the trade a proportion of the costs of the network assets that are actually used to carry power from the seller to the buyer. The charge will therefore reflect the extent of the network utilised by the

transaction, and draws upon the proportional utilisation of each of the network assets by each trade, identified from a load flow study, to determine the level of cost recovery for each asset attributable to the transaction;

- **nodal charges**, which may vary in real time and indicate the short-run marginal costs of network operation, including the impact of losses. This approach, whilst being good for capturing the incremental impact of electricity trades on the network, is less suited to the recovery of transmission investment costs, which is a key consideration.

Postage stamp and zonal charges may be based on long-run marginal costs or average incremental costs for network assets, and derived from historical or forward-looking cost data. Zonal charges are typically developed from a statistical analysis of generation and demand charges calculated at each substation on the network, which are then averaged across regions of broadly similar charges.

There are trade-offs between all of the above methods in terms of economic efficiency and complexity to implement. Postage stamp methods are the easiest to apply, but offer a low level of economic efficiency as they fail to distinguish the impact that different transactions place on the networks. Short-run marginal cost based nodal charges are complex to calculate but send accurate signals of the incremental impact of transactions on the operating costs of the system. Locationally varying zonal charges, using average incremental costs or long-run marginal costs, lie somewhere in the middle of the complexity/efficiency trade-off and for this reason are often adopted for network pricing in electricity markets. It is recommended that NRAs seek to define the principles on which network charges are derived nationally, and monitor the levels of revenue that are achieved by utilities through network charges to ensure that these are adequate to fund the transmission companies without leading to excessive profits.

5.4.4 Regional transmission wheeling charges

Similar considerations apply to wheeling charges as to national transmission charges in terms of the underlying objectives and required characteristics of the charges themselves. In particular it is important that wheeling charges are cost-reflective, and take account of the impact of wheeling flows through third countries on the transmission networks within those countries. The method used to define calculate the wheeling charges needs to be transparent and result in charges that are stable and predictable, to benefit both the transmission utilities providing wheeling services and the countries seeking to import and export power.

We note that considerable work has been undertaken in recent years to define wheeling charge methodologies that can be appropriate for application in interconnected regional markets. Wheeling charges in SAPP have evolved from early experience with a form of postage-stamp charging that applied a fixed percentage uplift to the prices in bilateral energy contracts to account for wheeling costs through to the development of charges based on point-to-point MW-km calculations. The latter method takes account of the utilisation of each transmission network asset on the wheeling path and allocates a proportion of the annuitised cost of each asset to the wheeling trade annually.

A report produced by consultants for the African Union Commission under the EU Technical Assistance Facility for the "Sustainable Energy for All" Initiative (SE4ALL)[7] has recommended the establishment of a Continental Transmission Tariff Methodology for Africa that will facilitate the development of a harmonised and integrated competitive electricity market by ensuring the coordination of transmission tariff methodologies and structures. The project report states that "[This] will eliminate the problem of transmission tariff "pancaking" whereby cross border power exchanges are subjected to a number of tariffs or charges which do not reflect the actual cost of assets used for transmission transactions or wheeling charges." The methodology is based on a point-to-point MW-km method similar to that used by SAPP. This is also the basis of the transmission charging methodology that has been adopted in the West African Power Pool (WAPP)[8].

We therefore recommend that the RRAs work with the NRAs and the national transmission utilities to implement a point-to-point MW-km method for transmission wheeling charges in the integrated SAPP/EAPP market. This would provide a basis for recovering the capital and operations and maintenance costs associated with the use of interconnected network assets and international interconnectors for wheeling. We note that the definition of "point to point" could include the definition of

[7] "Pilot Phase Implementation of Continental Transmission Tariff Methodology for International Bilateral Transactions: Tariff Computational Model – Final Report", Atkins, March 2019

[8] ECOWAS Regional Electricity Regulatory Authority Resolution No. 006/ERERA/15 Adoption of the Tariff Methodology for Regional transmission Cost and Tariff, available from https://erera.arrec.org/wp-content/uploads/2016/08/Transmission-Tariff-Methodology-August-2015-V4_signed.pdf

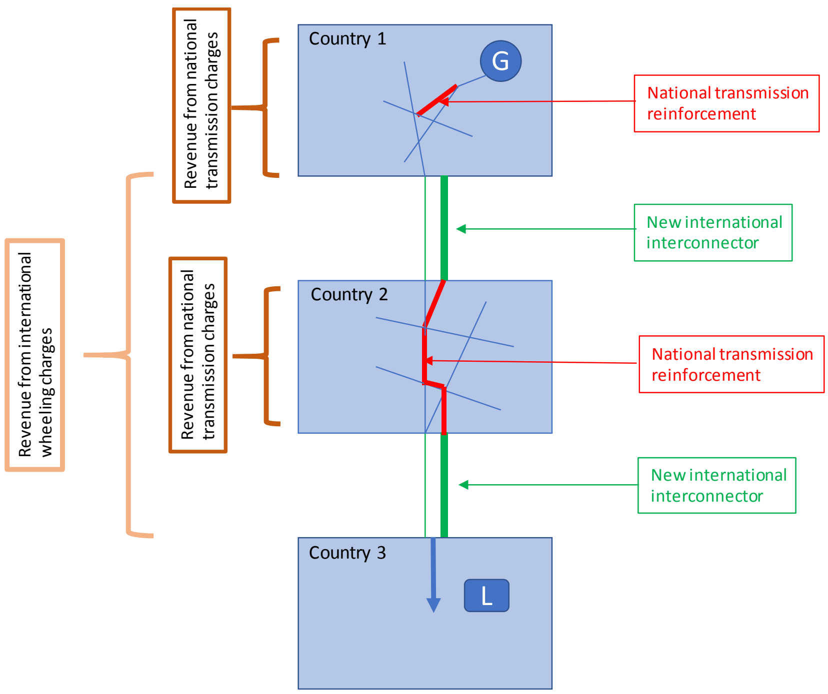
charges that are the same for all demand or generation in any one country that is trading internationally in the market – so charges can be applied "zonally".

The marginal transmission losses associated with wheeling can readily be calculated from load-flow analysis of network flows "with and without" each wheeling transaction. These can then either be remunerated at an appropriate energy cost (e.g. a weighted average cost of generation, as per the proposed Continental Transmission Tariff Methodology) or be settled "in-kind" by energy transfers between buyers, sellers and the wheeling utility.

The methodology itself should be developed by the transmission utilities working under the oversight of the SAPP and EAPP Co-ordination Centres. The role of the RRAs will be to approve the wheeling charge methodology and to ensure the harmonisation of the methods applicable in SAPP and EAPP. In addition, they will need to ensure that the methodology can be applied seamlessly to trades taking place between members of SAPP and members of EAPP, without introducing distortions or acting as a barrier to new trades taking place. The RRAs will be responsible for enforcing the application of the wheeling charge methodology and implementing sanctions for non-compliance.

Figure 9 shows the relationship between national transmission charges and regional wheeling charges in remunerating investments at different levels in the regional transmission network. Ensuring that the combination of revenues from international wheeling charges and national transmission charges is adequate to meet cost recovery requirements for the transmission utilities, will require oversight by the NRAs and reporting to the RRA regarding any changes that may be required to the international wheeling charge methodology.

Figure 9: Relationship between national and regional wheeling charges in remunerating investments



5.5 Promoting open access to the regional transmission network

5.5.1 Overview

Open access to the regional transmission networks in EA-SA-IO is a key requirement to enable the maximum degree of participation in the regional electricity markets. At the national level, ensuring that third-parties can gain access to the transmission network either to supply energy to customers within the country or to transmit energy to the border, for subsequent trading in the regional market, is critical to increasing national and regional access. Third-parties could include IPPs, using renewable or conventional generation technologies, and large consumers. As businesses independent from the network owner/operator, which in the context of the EA-SA-IO region is typically a state-owned vertically integrated utility, there is a need for commercial agreements and robust regulation ensure that they are not discriminated against in the planning and operation of the power systems.

The core coverage of the transmission agreements that are needed relates to:

- the connection of IPP and consumer assets to the national transmission network;
- "use of system" rights for IPPs and consumers to utilise the national transmission network for trading electricity in the national and regional markets; and
- wheeling rights to access the networks of third-countries in order to sell power either via long-term bilateral contracts or shorter-term market platforms in SAPP and EAPP.

In addition, we recommend that bilateral agreements are entered into between the owners of international interconnectors, if these are developed by parties other than national transmission utilities. International Interconnector Agreements would cover connection and use of system issues that recognise the particular nature of connecting and operating interconnector assets.

We propose that as far as possible the terms of Transmission Connection Agreements and Transmission Use of System Agreements should be harmonised across the EA-SA-IO region, since the principles of these can be defined independently of whether the national networks are part of the interconnected Southern African and Eastern African grids or whether they are island systems. The provisions of Wheeling Agreements, which would be applicable within EAPP and SAPP and, in future, between the two markets, should also be aligned.

We summarise below the key principles that should be harmonised in model agreements that could be developed and maintained by the RRAs and the Club of Regulators and implemented by the NRAs.

5.5.2 Transmission Connection Agreement

All potential users of the transmission network seeking connection to the national transmission system in any of the EA-SA-IO countries should be required to enter into Transmission Connection Agreement (TCA) with the owner of the transmission assets to which the user is going to connect. This agreement should establish the ownership boundary between the assets of the two organisations, and in addition will require:

(a) technical compatibility of the user's connection (whether this is a generation site or a consumption site) with the main system assets. This will require cross-referencing to the relevant national Grid Codes and the Regional Grid Code;

(b) the payment of connection costs in respect of any assets that have been provided and installed by the TO. Note that under the terms of the licences referred to in Section 5.2, these charges may be levied by the System Operator in any of the national networks, but they should be calculated according to a standard methodology. National regulations may also permit an IPP or consumer to construct a portion of the connection itself, or using its own contractors. In this case, clear arrangements for the testing and potential adoption of these assets by the TO would be required;

(c) the transfer of connection assets to the TO if they become shared with one more or more additional users. When assets that were formerly associated with one specific IPP are transferred to a TO in this way, they should be reclassified as main system assets. A transparent process for agreeing the valuation of the assets and the amount payable by the TO to the former asset owner should be defined; and

(d) references to be included to the responsibility of the SO in relation to the operation of the connection.

Reference should be made to a separate Connection Construction Agreement if necessary, setting down the detailed arrangements for the construction of specific assets by the TO on behalf of the IPP, together with the associated payments.

Specific issues that should be covered by the TCA include:

- a clear specification of the maximum export capacity maximum export capacity from the IPP that will be delivered to the network (or the maximum import capacity required for a demand connection or to support auxiliary power supplies in the case of an IPP);
- maintenance of the connection assets;
- the planning and notice periods for equipment outages;

- safety rules to be adhered to by SO, TO and IPP/consumer staff;
- the connection charges to be paid by the IPP/consumer; and
- data exchange requirements between by the IPP/consumer and the TO/SO.

5.5.3 Transmission Use of System Agreement

A model Transmission Use of System Agreement (TUOSA) is required that will define the basis on which parties are allowed to utilise the transmission network. The TUOSA will be entered into between connecting organisation (an IPP or a consumer) and the SO, and will cover three key rights and obligations:

1. **Ensuring the availability of the transmission network**. This will create the requirement for the SO and the TO to plan, build, operate and maintain their networks in accordance with the procedures and standards specified in the Grid Code;
2. **Giving the IPP/connected customer the right to be and remain connected and operational**, all the while that they comply with the Grid Code and make the appropriate payments under the terms of the TUOSA; and
3. **Use of System Payments**. This section should set out the payment to be made for the use of system by the IPP/consumer. These payments should be structured according to the charging methodology defined in the SO's Licence.

Specific points that should be covered within the TUOSA include:

- data to be submitted to the SO to enable Use of System charges to be calculated;
- cross-references to the use of system charging methodology;
- details of the billing and settlement arrangements for use of system charges;
- forecasts of demand and generation output to assist system operational planning;
- references to the Grid Code to define system dispatch processes;
- conditions when the SO may restrict the right of an IPP/consumer to use the network; and
- the procedures that will apply in the event of default, which could result in the IPP or consumer being disconnected from the network permanently.

The TUOSA needs also to make reference to the way in which congestion on the transmission network will be handled. This is closely linked with the electricity trading arrangements that are applicable in each country, since the TUOSA only covers the rights of access to the network at a generic level. Whether generation can be accepted onto the national transmission system in all loading conditions and irrespective of the dispatch of other generation on the system is highly dependent on the design of the network.

5.5.4 Wheeling Agreements

A specific requirement for the development of cross-border trading in the interconnected EA-SA market concerns the development of wheeling arrangements such that power generated in one country can be transmitted to demand in a second country through the transmission network of a third country.

A clear precedent has been set in the Southern African Power Pool for wheeling, associated with bilateral contracts and the operation of the Day Ahead Market (DAM). It would be desirable to build on these contractual arrangements and to harmonise wheeling charging methods and contractual arrangements across the region. This would also have the advantage of building on the recommendation contained in the Final Report on the "Strategy for the Development of a Harmonised Regulatory Framework for the Electricity Market in Africa" study carried out under the umbrella of the EU Technical Assistance Facility for the Sustainable Energy for All Initiative[9], which recommended the development of regional transmission pricing guidelines, including principles for determining wheeling charges and the allocation of the costs of network losses.

A number of key contractual provisions are needed to support these arrangements, which will typically be set down in a Wheeling Agreement. This will exist alongside the contracts referred to above, which ensure that generators and consumers can gain access to their national electricity networks.

[9] "Strategy for the Development of a Harmonised Regulatory Framework for the Electricity Market in Africa", report for the African Union Commission, Atkins

Typical requirements of the Wheeling Agreement include the following:

1. **The period of the Wheeling Agreement** – this may be a long term contract running over a period of years, or a short term contract subject to renewal. The period should be aligned with bilateral agreement entered into between the exporting generator or utility and the load or importing utility;
2. **The wheeling capacity required**. This will define the maximum load that the wheeling trade is going to impose on the network of the third country not directly involved in the trade;
3. **The wheeling charge** that will be levied on the transaction by the utility or utilities in the transit countries providing wheeling services. This should be calculated based on a published methodology. We recommend that this methodology should be defined at a regional level, so that there is transparency and equity in the charging method and trades that take place throughout the EA-SA region attract wheeling charges calculated on the same basis;
4. **The defined entry and exit points** on the network(s) providing the wheeling service;
5. Clarity as to whether the wheeling arrangement is **firm or non-firm**. A firm wheeling agreement would require the SO to prioritise the scheduling of the wheeling transaction and not to curtail this without incurring penalties under the contract;
6. Cross references to the relevant **quality of supply standards/Grid Code** requirements to be complied with by all parties;
7. **Metering arrangements** on the boundaries between the relevant electricity networks; and
8. Conditions for **terminating** the agreement, e.g. in the event of non-payment of wheeling charges or technical infringements by the wheeling parties.

5.5.5 International Interconnector Agreements

We recommend the development of standard International Interconnector Agreements that will address specifically the issues that are relevant for the connection and operation of interconnectors developed by third parties. These should include the following basic provisions:

1. The **right to remain connected.** This should be specific that the interconnector owner has the right to remain connected to the relevant national transmission system, subject to compliance with the agreement and relevant regulations;
2. The **right to remain energised and operational**, from the time the interconnector is commissioned for a defined period, subject to the relevant regulations;
3. **Export and import** provisions allowing the transfer of power across the interconnector up to an agreed entry capacity and export capacity on the national network;
4. Requirements for the interconnector owner to carry out **maintenance** and for the parties to agree **outages** to enable maintenance to take place;
5. A section detailing the **connection charges** that will be payable by the interconnector owner for its interconnector to be connected to the relevant national system;
6. Other **site-specific technical conditions** that may be relevant; and
7. Requirements to address **safety issues and site interfaces** relating to the equipment owned by the interconnector owner and the relevant national utility.

5.5.6 Other provisions

Somewhere in the structure of commercial agreements that are required to support open access to the regional transmission there should be standard provisions for addressing the following important aspects of the electricity trading arrangements. These could be covered either in the wheeling agreement or in the PPAs entered into between the buyer and seller of the energy. The market rules governing the operation of the shorter-term market platforms may also specify how these issues will be handled.

- Arrangements for dealing with **transmission losses** arising from the wheeling transaction. Calculations or estimates of the losses incurred as a result of the wheeling of power through the transit networks should be undertaken, and the cost of losses should be recoverable from the wheeling parties. Cost recovery should be based on the costs actually incurred by the SOs providing the wheeling services – alternatively, the in-kind repayment of loss energy could be considered;

- The **balancing arrangements** that will be applicable in the event that a scheduled wheeling transaction is not fulfilled in practice. A mechanism for settling these deviations is required – at present SAPP is developing a Balancing Market for this purpose, and this may be expected to be a core part of the regional trading arrangements in the future; and
- Provisions for **ancillary services**, such as reactive power and frequency response services, which could be provided by generators, transmission utilities or specialist service providers. These arrangements could in future be procured on a market basis, but arrangements are required to cover the costs incurred by the providers of wheeling services in maintaining these aspects of network operation.

5.6 Promoting market access for IPPs

5.6.1 Regulatory arrangements

Many of the requirements for promoting access for IPPs to the national and regional markets of the EA-SA-IO region are addressed by:

- ensuring that primary legislation permits the participation of IPPs in the national electricity market; and
- through the structure of licences and agreements referred to in Sections 5.2 and 5.5.

In order to encourage IPPs to participate in the markets, the licensing regimes and commercial structures put in place should be as transparent as possible. NRAs and RRAs should take responsibility for publishing guidance to IPPs to enable them easily to navigate steps required to become licensed and operational in the national and/or regional electricity sector.

5.6.2 Market entry

There are several levels of electricity market entry possible for IPPs, and these should be clearly outlined at both the national and regional level to ensure that the opportunities for market participation are visible to potential developers. The options that should be developed can be envisaged in five stages:

1. Stage 1: the encouragement of self-generation schemes, whereby the same business is engaged in generation and consumption at an industrial or commercial site, or at two more sites where dedicated power wheeling arrangements are entered into across the national distribution or transmission network;
2. Stage 2: net-metering schemes, either small- or large-scale projects “behind the meter”, i.e. on the customer side of the meter, facilitating self-generation and permitting the banking of excess energy in the system;
3. Stage 3: structured programmes such as tender rounds for new generation from conventional or renewable sources – this is an established way of promoting private investment in generation, and enables government energy ministries to set policy for the future direction of the power sector and invite offers for power plants that fit with broad technological and siting criteria that may be defined at a policy level. In these procurement programmes, the utility acting as the Single Buyer would typically be the offtaker under the PPA;
4. Stage 4: participation by the generator in a competitive national market, involving connection to and use of the national power systems and membership of a national market body – this could include bilateral transactions between IPPs and large consumers with wheeling through the national network; and
5. Stage 5: participation by the generator as a member of the SAPP or EAPP regional markets.

The above market entry stages can of course only be enabled through an underlying regulatory framework that creates an enabling environment for IPP entry. The regulatory framework must be aligned with the approved market structure of the country in question. Many countries have adopted a Single Buyer market structure which, in its pure form, provides for a very specific IPP entry path via the electric utility. For many reasons this creates a “bottleneck” situation which slows down the introduction of new IPPs. These reasons include:

- The utility not being a credit worthy off-taker resulting in projects not reaching financial close.
- Due to the poor financial standing of the utility many IPP developers seek recourse via expensive and onerous utility and IPP guarantees.

- Utilities not wanting IPPs in their service territories
- Utilities slow in embracing new technologies and not appreciating changing customer requirements such as the need to move away from fossil fuels.
- Utilities being inundated with unsolicited project proposals which are often expensive and/or politically well-connected companies. It often takes significant company resources to deal with these projects.

In response to these shortcomings many policy-makers and regulators are exploring market models which allow for a more inclusive arrangement of IPPs. Namibia is one of the first countries that recognised the need to transform the market structure to allow more entry paths for IPPs. The country adopted a “Modified single Buyer” market model which not only allows IPPs to sell electricity to the utility but also directly to end user customers. To enable the new market structure the regulator had to create an enabling regulatory framework which formally addressed the following aspects:

- Review generation license conditions including the development of new licenses (such as traders, exporters and importers).
- Definition and registration of contestable customers
- Unbundling of the tariff to better differentiate between the various services being provided. See explanation below.
- Market rules to spell out the processes and arrangements if an IPP wants to sell to a customer.
- A balancing mechanism to deal with any over/under production and consumption.
- A wheeling framework to enable seamless transactions between IPPs and contestable customers.

Tariff reforms are proposed in order to unbundle services and charges so that transmission and distribution charges are visible to IPPs and their customers. Charges should include the following elements:

- Connection charges;
- Network access charges;
- Network usage charges;
- TOU energy charges;
- Losses charges;
- Wheeling charges;
- Balancing charges;
- Ancillary service charges;
- Levies and cross-subsidies; and
- Customer service charges

Clear differentiation is required between those charges that can be avoided by generators and consumers (e.g. when self-generating, utilising net-metering services and wheeling energy outside the national network) and those charges that are fully applicable. The NRAs will have a role in reviewing and approving the tariffs that are calculated in the above categories.

5.7 Promoting regional and intra-regional trade

5.7.1 Trading Context

Cross-border power trading is at different stages of development in SAPP and EAPP, and this requires consideration in the development of appropriate approaches to market regulation.

In SAPP, trading is taking place using a number of different market platforms, which permit the optimisation of trading parties’ positions over a range of time frames. Long-term trades are conducted through bilateral contracts that may run over periods of several years. In addition, however, four shorter term market platforms are in place, comprising:

- the Forward Physical Market – monthly;
- the Forward Physical Market – weekly;

- the Day-Ahead Market; and
- the Intra-day Market.

In addition to the above, a Balancing Market is currently being implemented, which will give those parties who are responsible for balancing supply and demand in real time access to sources of balancing energy from generation and demand across the SAPP member countries.

In EAPP, trading is currently very limited and is focused on bilateral contracts, although there is no formal trading platform yet in place. Simulated trading has taken place but this has yet to be backed by physical delivery of energy.

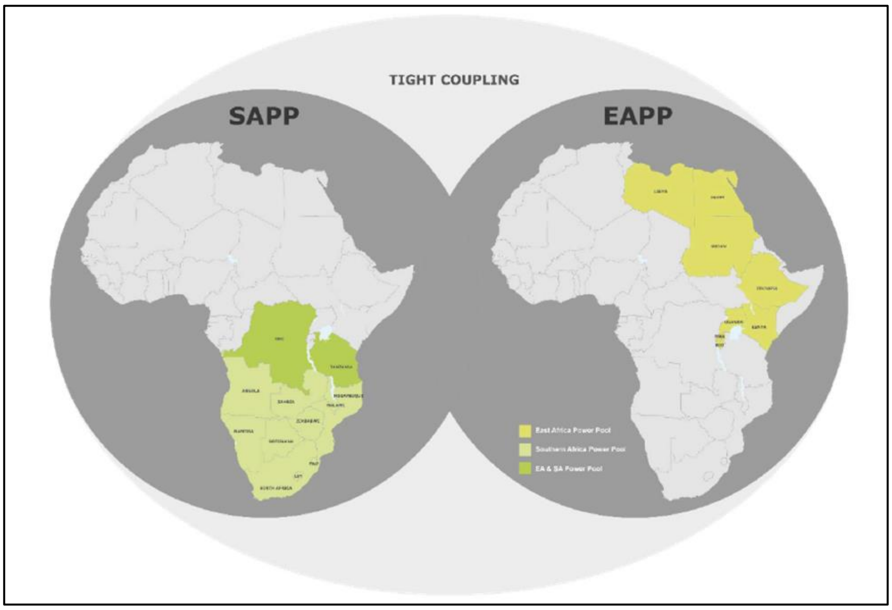
The critical requirements for successful market trading include:

- sufficient **market liquidity**, which requires both sufficient market entrants and the willingness to trade volumes of energy that can create a market in which competition is visible;
- clear, stable and transparent **market rules** which will give power utilities and IPP investors confidence in the market;
- the availability of a **range of market platforms** enabling participants to optimise their commercial position over a range of timeframes; and
- robust **market surveillance,** again to give confidence to market participants that the market will be secure and that anti-competitive behaviour will be penalised.

The experience with SAPP to date has indicated that addressing these issues enables electricity trading to be developed successfully independently of the degree of unbundling that has been undertaken in the power sector. Single buyer entities can still be effective in creating international trading opportunities between themselves, and this can be expected still to be the case when the EAPP and SAPP markets combine. However, specific regulatory arrangements are also required to enable IPPs to sell into the international market directly if market liquidity is to be maximised. Revisions that have been made to the trading arrangements in Namibia to permit IPPs to trade independently of the single buyer (under so-called Modified Single Buyer arrangements) are an important example of this.

The intention described in the SAPP-EAPP Interconnector Impact Study[10] is for the integration of the regional electricity markets of SAPP and EAPP to take place base on the assumption that the SAPP market platforms will become the dominant model for the combined market. The recommendations of the study include defining a target model for market interaction that will consist of "Tight Market Coupling". This is shown schematically in Figure 10.

Figure 10: SAPP-EAPP Tight Market Coupling – Schematic Representation. ***Source: Aurecon AMEI Limited.***



[10] SAPP-EAPP Interconnector Impact Study – Final Report – Aurecon AMEI Limited, October 2018

The key features of the tight market coupling model proposed are as follows:

- SAPP and EAPP will base their market operation on the current SAPP trading platform;
- A methodology will be required for calculating the interconnector capacity between the two markets and for allocating this capacity in market operation;
- Harmonisation will be required between the operational procedures used in the two markets – we note that the study stresses that this does not require both markets to adopt identical procedures but that there will need to be a harmonised Book of Rules governing core aspects of the market interaction;
- The point of interface between the integrated market and the market participants in each region (SAPP and EAPP) will be the regional markets themselves – so membership of SAPP and EAPP will be the gateway into a combined regional market, rather than a new combined market entity being created which IPPs and large consumers are required to join; and
- SAPP and EAPP will continue to be responsible for operating their own markets and managing their market participants. Each market will retain its own "look and feel", and so market participants will identify with their local regional market initially. Settlement processes will be aligned using the common market platform, but the confidentially of data will be retained and separate interfaces used.

The Aurecon report emphasises that both SAPP and EAPP need to work together closely with immediate effect to ensure that combined market operation is possible once the two pools are physically interconnected in 2021.

In order to promote inter-regional trade, a number of strategies are required in parallel with the development of coupling the EA and SA markets.

1. It will be important that EAPP continues its development path along a similar trajectory to that of SAPP, and that EAPP is in a position to "go live" ahead of the coupling of the market with SAPP. This will ensure that the new combined market is seen as a trading platform offering advantages to registered participants in both of the existing intra-regional markets, and that EAPP members gain experience in international trading that can be extended into the wider regional trading;
2. A key requirement for successful market trading is to have sufficient market liquidity in terms of the number of market participants and the volumes of trade involved. SAPP has recently extended its membership categories to broaden the definition of market participants as follows:

   Market Participants (MP) operate or contract generation capacity or load of at least 5MW which is connected at 110kV or above. They have to comply with their national legislation on cross-border trading and they must not be tied to a single buyer contract unless they have consent from the counter party to trade. They must be able to balance agreed schedules or they must have a contract for balancing agreed schedules with a SAPP operating member.

   This will therefore make it possible for both generators and large consumers to participate in the SAPP market, subject to the requirement that the MP must be able to trade independently, i.e. not through a single buyer organisation. It would be highly desirable for EAPP to have a similar broadly-based membership criterion in place to broaden participation in the consolidated regional market. The ability to achieve this within both SAPP and EAPP will be dependent on national utilities and NRAs implementing changes that make it possible for IPPs and large consumers to trade independently of the single buyer in their own countries. This requires changes to the national legal and regulatory regime, including the terms of licences, to ensure that IPPs have the right both to sell energy to parties other than the single buyer and to export energy across the international border, and that large consumers can purchase power from parties other than the single buyer;
3. Associated with the membership changes in point 2 above, streamlining membership applications and the process whereby new members can join the existing markets would be valuable step in increasing regional participation;
4. Both EAPP and SAPP should make a broader range of governance documents available in the public domain (e.g. Market Rules, agreements, minutes of meetings, etc.) so that it becomes easier for potential new market entrants to assess the implications of joining the markets;

5. In order to maximise the level of confidence that current and potential future market participants have in the integrity of the regional and intra-regional markets, it is desirable that market surveillance is separated from market operation as far as possible. We note in Section 5.3 our recommendations in this area, and the importance of the RRAs being the bodies with decision-making responsibilities and enforcing powers in determining sanctions on market participants for breaches of the rules, even if the SAPP and EAPP as the market operators take responsibility for monitoring the activities of market members and passing the relevant reports to the RRAs;
6. A process of running workshops in the Southern and Eastern African regions to give potential market participants insight into the opportunities that exist for intra-regional and regional trading on the SAPP and EAPP market platforms and in the coupled SAPP-EAPP market. This could take the form of "roadshows" for potential IPP developers and industrial customers who could be interested in participating in the regional electricity market. As an extension of this, it is possible that the financial services industry in the IO countries could also be interested in future participation in the mainland electricity markets as electricity traders. Experience with energy market operation internationally suggests that there is significant potential for commodity traders to enter the energy market, and as the regional market grows and matures it may be expected that new entrants will see the possibilities; and
7. One of the primary reasons for trading energy regionally is to give electricity suppliers access to cheaper sources of energy. In addition, in Sub-Saharan Africa the regional markets play a substantial role in resource sharing. Both of these outcomes can lead to economic benefits for the countries in the EA-SA region, and it could be useful for SAPP and WAPP, or for the higher level regional economic community organisations (SADC, EAC, COMESA) to commission studies demonstrating to governments and utilities the potential economic and financial benefits of increased regional trading. We recommended that the results of studies that have already been carried out investigating the future benefits of an integrated market be brought together and circulated to representatives of the member countries of EAPP and SAPP to ensure that the benefits of expanded trading are fully understood.

5.7.2 Implications for Regulatory Framework

An important question arising from the integration of the SAPP and EAPP electricity markets is what role the regional and national electricity regulators will play in regulating the individual regional markets and the integrated market. There are several areas of market operation that require regulatory oversight to ensure that competition is maximised. In addition, ensuring transparency in market operation is essential if the benefits of a move away from long-term bilateral contracts towards the use of more flexible, shorter-term trading platforms, as currently used in SAPP, is to be encouraged.

The main areas in which regulation of the market will be required are:

- Regulating access to international interconnectors – this will include the key interconnectors linking the SAPP and EAPP markets;
- Ensuring that third-party access provisions are upheld within each of the SAPP and EAPP member countries;
- Approving the methodologies that are to be used in calculating wheeling charges between the member countries of SAPP and EAPP;
- Approving the Market Rules that are to be adopted for trading within SAPP and EAPP, and between the two markets – this is a specific area that is applicable as the market trading platforms evolve from facilitating trade via bilateral contracts towards a more sophisticated set of auction-based platforms as has already happened in SAPP.
- Monitoring the competitiveness of the regional markets and advising the market operators of the trends in market liquidity and levels of participation.

As the sophistication of the regional power markets increases so the need for market surveillance and the potential intervention of regional regulatory bodies to assist with dispute resolution, imposition of sanctions and overall monitoring and harmonisation activities is likely to increase. The work that has been carried out in the parallel study to this one looking at the transformation of RERA into an authority[11]

[11] Development of a framework and roadmap for the establishment of a Regional Energy Regulatory Authority for SADC, Draft Final Report, Economic Consulting Associates, 24/02/2020

has identified a range of activities in these areas that will be equally applicable to EAPP and the wider integrated market.

5.8 Enhancing energy security and competitiveness of industries

5.8.1 Introduction

There is a need for a regional grid code that can be used for Southern and Eastern Africa to enhance security and competitiveness of industries. Security is enhanced as an interconnection when security of supply burden is shared across all the entities in the interconnection. Entities include generators, customers, transmission companies and system operators. The regional grid code which provides common set of internationally acceptable technical rules creating a level playing field for trading electricity and security of supply services. This in turn provides investors with surety that their assets will be protected making their investment decision easier and borrowing money cheaper from lending agencies. Enhanced trading lowers regional energy prices and the benefits are shared by all participants. Enhanced security improves reliability of supply with less blackouts and interruptions of supply with major benefits to all consumers.

It is understood that RERA intends to develop a regional grid code in the near future, EAPP has a regional grid code which requires updating and West Africa has just issued Terms of Reference to develop a regional grid code. These efforts should be coordinated to ensure consistency of the African Grid Codes specifically where there is planned synchronous connection between regions. The Indian Ocean nations also should have a ‘reference’ grid code for each of the islands to adopt with minimal tailoring for local conditions. This reference code can also be used by EA-SA-IO countries as an off-grid ‘reference’ grid code.

Regional planning regulations for increasing transmission capacity are required to ensure transmission regional projects are identified, ranked and implemented. Regional transmission planning regulations have recently been introduced to Europe and USA to ensure transmission corridors are developed.

5.8.2 East and Southern African Regional Grid Code

5.8.2.1 Definition

The term Regional Grid Code is widely used to refer to a document (or set of documents) that legally establishes technical and other requirements for the connection to and use of an electrical system by parties other than the owning electric utility in a manner that will ensure reliable, efficient, and safe operation.

5.8.2.2 Need for a Grid Code

The Regional Grid Code is one of a number of regulatory instruments required to support the pursuit of the energy sector policy objectives for Eastern and Southern Africa.

The Southern African Development Community (SADC) Protocol on Energy dated 23 June 2006[12] Appendix 1 Guidelines for Co-operation in Electricity paragraph 1d) states the goal to ‘Promote the evolution of common regional standards, rules and procedures relevant to the generation, transmission and distribution of electricity, including the standardisation of electrical manufacturing facilities, particularly in areas in which the Region holds a comparative advantage’. The Regional Grid Code is clearly one of the documents intended to be developed in this context. This was further ratified in August 2012 when SADC approved the Regional Infrastructure Development Master Plan (RIDMP)[13]. The RIDMP defines regional infrastructure requirements and conditions to facilitate the realisation of key infrastructure in the energy, water, transport, tourism, meteorology and telecommunications sectors by 2027. The master plan is based on the SADC Vision 2027, which includes inter-alia “Soft” interventions entail the required policies/strategies and regulatory frameworks, institutional frameworks and capacity building, financing and cooperation/collaboration arrangements that enable transmission and generation development.

The EAPP has already developed a Regional Grid Code that was drafted in 2011 by SNC Lavalin but this is still to be ratified. IRB is mandated to inter-alia issue licences, recommend changes, approve

[12] The Southern African Development Community (SADC) Protocol on Energy, 23 June 2006, 20060623_protocol_energy.pdf, www.sadc.int
[13] SADC Energy Monitor 2016: Baseline Study of the SADC Energy Sector, 2016, SADC_Energy_Monitor_2016.pdf, www.sadc.int

modifications, impose penalties and sanctions on the East African Regional Grid Code[14]. The EAPP Grid Code requires updating specifically the sections on market operations, the inclusion of variable renewable power plants and alignment with international codes.

With the introduction of bilateral and electricity market transactions that require third party access to and use of the transmission networks, rules need to be formalised.

Bilateral trading and electricity market parties require formal and transparent mechanisms to describe how the provision of a safe, reliable, economic planning and operation of the system will be achieved. There are at least two ways to structure the formal arrangements parties:

- Write all the necessary rules and operations into bilateral agreements and market rules between the parties including third-party parties; and
- Develop a Regional Grid Code to define all the common codes and standards that are needed to operate a safe, reliable and economic Transmission System.

There are a number of important advantages that a well-designed and transparent Regional Grid Code helps to bring to the fore:

- The Grid Code is applicable to all Participants without favour or discrimination thus promoting a level playing field between the Participants;
- Changes to the Grid Code are facilitated through a transparent process, which allows for input by all the Participants; and
- The above features help to reduce investor risks resulting in lower barriers to entry and ultimately to better prices.

A Regional Grid Code therefore provides the rules and procedures that enable the power system to be planned and operated reliably. Each synchronous area should have a single regional grid code. It is also a more effective instrument than bilateral agreements, particularly when more independent players are introduced and when further reforms are undertaken.

Each Regional Grid Code needs to be consistent with another regions grid code covering another synchronous area. The easiest is to have a single grid code that covers all regions. The EU grid code is such an example as it covers Central Europe, Northern Europe, Great Britain and Ireland. A single East and Southern African Regional Grid Code is proposed.

5.8.2.3 Objectives

The fundamental function of a Regional Grid Code is to establish the rules and procedures that allow Eastern and Southern Africa parties to use the power system and to permit the power system to be planned and operated:

1. Safely;
2. Reliably;
3. Efficiently; and
4. Economically.

In order to achieve this goal, the Regional Grid Code must:

- Be objective;
- Be transparent;
- Be non-discriminatory;
- Be consistent with Eastern and Southern Africa policies;
- Define the obligations and accountabilities of all the Eastern and Southern Africa parties;
- Specify minimum technical requirements for the Regional Transmission System; and
- Ensure that the relevant information is made available.

The Regional Grid Code will provide the following assurances:

- To the Regional Regulators and Power Pools, the assurance that the Eastern and Southern Africa Parties operate according to the respective Regulatory conditions;

[14] Source: http://eappool.org/independent-regulatory-board/

- To parties, the assurance that service-providers operate transparently and provide non-discriminatory access to their defined services; and
- To service-providers, the assurance that parties will honour their mutual Grid Code obligations and that there is Regional agreement on these.

5.8.2.4 Grid Code Overview

(1) **Preamble**: This document provides the context for the Regional Grid Code and its various sub-sections. It also contains detailed definitions and abbreviations of the terms used in the Regional Grid Code.

(2) **The Governance Code (GC):** This document sets out how the Regional Grid Code will be maintained. It describes the process that will be followed to update the Regional Grid Code to improve safety, reliability and operational standards. It sets out how parties can influence the amendment process and defines who has the Authority to recommend and ultimately approve and enforce the changes. In addition, the document will also explain oversight and compliance requirements that need to be observed by all parties. The Governance Code also sets out dispute management procedures.

(3) **The Network Code - Requirements for Generators, High Voltage Direct Current Connections (HVDC) and Demand Connection:** This document provides network requirements for grid connection of generators (of all sizes), HVDC connections including Direct Current connected generators and demand connections. It is broken down into sections defining the requirements in terms of:

a. Frequency tolerance, active power and frequency control requirements;
b. Voltage tolerance, voltage control and reactive power provision;
c. Fault ride through capability;
d. Protection requirements;
e. System Restoration, Islanding and Black start capability;
f. Information requirements; and
g. Connection and testing requirements.

(4) **The Planning Code:** this code specifies the minimum technical and design criteria, principles and procedures:

- In the planning and in the medium and long term development of the Interconnected Transmission System of Eastern and Southern Africa; and
- To specify the planning data required to be exchanged by parties and Planning Sub-Committee on planning to enable the Interconnected Transmission System to be planned in accordance with the planning standards.

(5) **The Operation Code (OC):** The OC set out the data exchange between and responsibilities of Power Pools and the TSOs in operating the Interconnected Transmission System. The OCs deal with the criteria and procedures which will be required to facilitate efficient, safe, reliable and coordinated system operation of the Interconnected Transmission System. The OCs are divided into a number of sub-codes covering different operational aspects:

a. Operational Security;
b. Operational Planning & Scheduling; and
c. Load Frequency Control and Operating Reserves.

(6) **The Metering Code (MC):** The MC specifies the minimum technical, design and operational criteria to be complied with for the metering of each point of interchange of energy between parties, Control Areas and TSO's. The MC also specifies the associated data collection equipment and the related metering procedures required for the operation of the Interconnected Transmission System. The code sets out provisions relating:

a. Main Metering Installations and check Metering Installations used for the measurement of active and reactive energy;
b. The collection of Metering data;

c. The provision, installation and maintenance of equipment;
d. The accuracy of all equipment used in the process of electricity Metering;
e. Testing procedures to be adhered to;
f. Storage requirements for Metering data;
g. Competencies and standards of performance; and
h. The relationship of entities involved in the electricity Metering industry.

(7) **The Information Exchange Code (IEC):** The IEC defines the obligations of parties with regard to the provision of Information for the implementation of the Regional Grid Code. The IEC also defines the data to be exchanged between TSOs and Sub-Committees on Planning and Operations for the purpose of the modelling and analysis of steady-state and dynamic conditions for the Interconnected Transmission System. The Information requirements are divided into:

a. Planning Information;
b. Operational Information; and
c. Post-dispatch Information.

(8) **The System Operator Training Code (SOTC):** The SOTC sets out the responsibilities and the minimum acceptable requirements for the development and implementation of System Operator Training and Authorisation programmes. This Code shall ensure that System Operators throughout Eastern and Southern Africa Region are provided with continuous and coordinated operational training in order to promote the reliability and security of the Interconnected Transmission System.

5.8.3 Indian Ocean Islands and off-grid ‘reference’ grid code

5.8.3.1 Definition

The term ‘reference’ Grid Code is widely used to refer to a document (or set of documents) is available to Indian Ocean countries and provides typical technical and other requirements for the connection to and use of an electrical system by parties other than the owning electric utility in a manner that will ensure reliable, efficient, and safe operation of a typical Indian Ocean Island or any off-grid system in the EA-SA-IO region.

5.8.3.2 Need for a Grid Code

The reference Grid Code is one of a number of regulatory instruments required to support the pursuit of the energy sector policy objectives for each Indian Ocean Island or any off-grid system in the EA-SA-IO region.

The reference Grid Code specifically is required for inclusion of IPP’s including variable renewable power plants and alignment with international codes.

The reference grid code prevents duplication of effort by each Indian Ocean Island and ensures consistency of technical requirements.

There are a number of important advantages that a well-designed and transparent reference Grid Code helps to bring to the fore:

- The Grid Code is applicable to all Participants regardless which Island they are on without favour or discrimination thus promoting a level playing field between the Participants;
- Changes to the Grid Code are facilitated through a transparent process, which allows for input by all the Participants; and
- The above features help to reduce investor risks resulting in lower barriers to entry and ultimately to better prices.

A reference Grid Code therefore provides the proposed rules and procedures that enable the power system to be planned and operated reliably.

5.8.3.3 Objectives

The fundamental function of a Grid Code is to establish the rules and procedures that allow parties to use the power system and to permit the power system to be planned and operated:

a. Safely;
b. Reliably;

c. Efficiently; and
d. Economically.

In order to achieve this goal, the Grid Code must:

- Be objective;
- Be transparent;
- Be non-discriminatory;
- Be consistent with Indian Ocean policies;
- Define the obligations and accountabilities of all parties;
- Specify minimum technical requirements for the network; and
- Ensure that the relevant information is made available.

The Grid Code will provide the following assurances:

- To parties, the assurance that service-providers operate transparently and provide non-discriminatory access to their defined services; and
- To service-providers, the assurance that parties will honour their mutual Grid Code obligations.

5.8.3.4 Grid Code Overview

(1) **Preamble:** This document provides the context for the reference Grid Code and its various sub-sections. It also contains detailed definitions and abbreviations of the terms used in the Grid Code

(2) **The Governance Code:** This document sets out how the reference Grid Code will be maintained. It describes the process that will be followed to update the reference Grid Code to improve safety, reliability and operational standards. It sets out how parties can influence the amendment process and defines who has the Authority to recommend and ultimately approve and enforce the changes. In addition, the document will also explain oversight and compliance requirements that need to be observed by all parties. The Governance Code also sets out dispute management procedures.

(3) **The Network Code - Requirements for Generators, High Voltage Direct Current Connections and Demand Connection:** This document provides network requirements for grid connection of generators (of all sizes), DC connections including Direct Current connected generators and demand connections. It is broken down into sections defining the requirements in terms of:

a. Frequency tolerance, active power and frequency control requirements;
b. Voltage tolerance, voltage control and reactive power provision;
c. Fault ride through capability;
d. Protection requirements;
e. System Restoration, Islanding and Black start capability;
f. Information requirements; and
g. Connection and testing requirements.

(4) **The Operation Code:** The OC set out the data exchange between and responsibilities of System Operator in operating the network. The OCs deal with the criteria and procedures which will be required to facilitate efficient, safe, reliable and coordinated system operation of the network. The OCs are divided into a number of sub-codes covering different operational aspects:

a. Operational Security;
b. Operational Planning & Scheduling; and
c. Load Frequency Control and Operating Reserves;

(5) **The Metering Code:** The MC specifies the minimum technical, design and operational criteria to be complied with for the metering of each point of interchange of energy between parties. The MC also specifies the associated data collection equipment and the related metering procedures required for the operation of the network. This could be a metering standard rather than a code.

(6) **The Information Exchange Code** : The IEC defines the data to be exchanged between parties for the purpose of the modelling and analysis of steady-state and dynamic conditions of the network. The Information requirements are divided into:

a. Planning Information;
b. Operational Information; and
c. Post-dispatch Information.

5.8.4 Regional planning regulations for increasing transmission capacity

International regional planning codes are a recent development in Europe and USA. There the development has been pursued in order to ensure that regional transmission plans are established to ensure an increase in VRE and enhanced trade through third-party countries.

These codes set out the principles for planning and cover the following:

- Planning process
- Data and confidentiality thereof
- Economic and security criteria
- Project selection process

The examples of international regional planning codes in this report are the following:

- ENTSO-e / ACER - Regulation No 347/2013
- USA Regional Transmission Operator's – Federal Energy Regulatory Commission (FERC) Order 1000
- East African Power Pool – Regional Grid Code

5.8.4.1 Europe

Regulation No 347/2013 lays down guidelines for the timely development and interoperability of priority corridors and areas of trans-European energy infrastructure

In particular, Regulation:

(a) addresses the **identification of projects of common interest** necessary to implement priority corridors and areas falling under the energy infrastructure categories in electricity, gas, oil, and carbon dioxide;

(b) facilitates the **timely implementation of projects of common interest** by streamlining, coordinating more closely, and accelerating permit granting processes and by enhancing public participation;

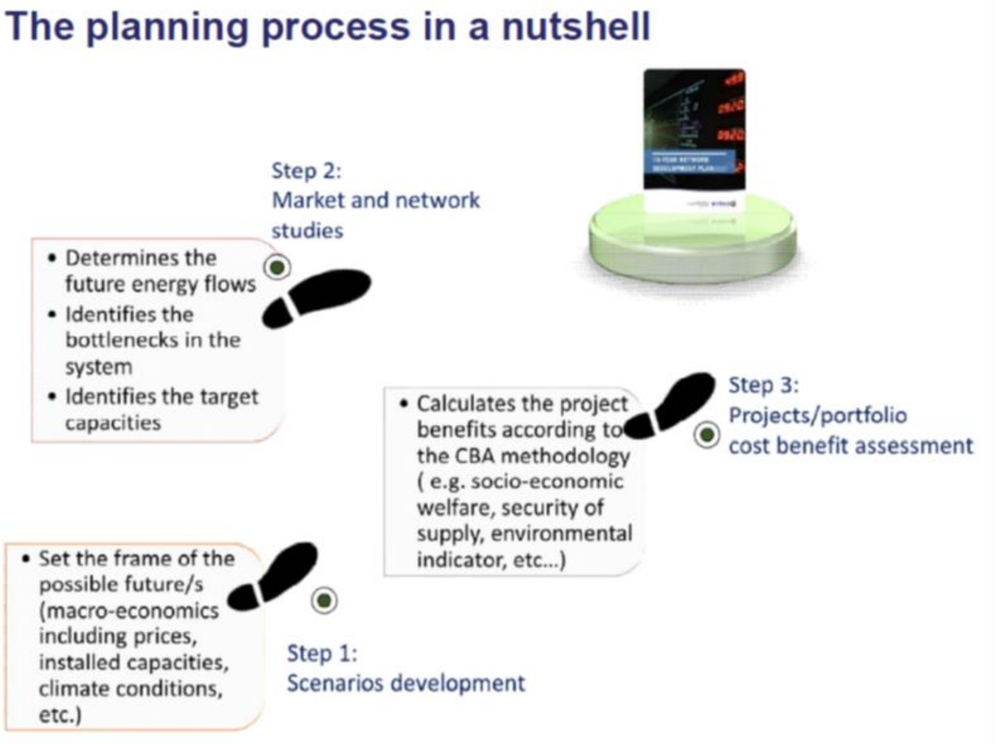
(c) provides **rules and guidance** for the cross-border allocation of costs and risk-related incentives for projects of common interest;

(d) determines the **conditions for eligibility of projects** of common interest for Union financial assistance.

Since 2009 the European legislator has tasked ENTSO-E with the delivery of a European network development plan which builds on national plans and includes specific regional investment plans. Each Ten-Year Network Development Plan (TYNDP) takes two years to complete. The first edition was issued in 2010. The latest available one is the TYNDP 2018[15].

[15] See https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/TYNDP2018/consultation/Main%20Report/TYNDP2018_Executive%20Report.pdf

Figure 11: The planning process on how ENTSO-E implement the planning studies



Step 1 – Develop scenarios for the future

To identify what Europe needs in terms of electricity transmission infrastructure, one needs to first analyse how the energy landscape will evolve. Some political objectives are set until 2030 but there are a lot of uncertainties about generation investments, demand evolution and market developments to name a few. The TYNDP scenario development is about framing uncertainties. It is not about predicting the future. Stakeholders are strongly and formally invited to participate to the scenario building.

Step 2 – Planning Studies

The TYNDP has four scenarios for the development of the power system. Some have high objectives in terms of renewables, some envisage a more decentralised power system, and some envisage a strong European framework. Based on these scenarios, 200 experts of 41 TSOs in 34 European countries carry out common planning studies.

Using common methodologies and tools, these experts look at how power will flow in Europe in 2030 taking into account the different scenarios. This allows them to see where bottlenecks will be and how much transmission capacity is needed at borders to manage these flows.

The result of the planning studies is a series of infrastructure projects. These are only one part of the whole TYNDP projects. The other part is constituted of projects that are not coming from ENTSO-E members and that meet the criteria for inclusion in the TYNDP set by the European Commission.

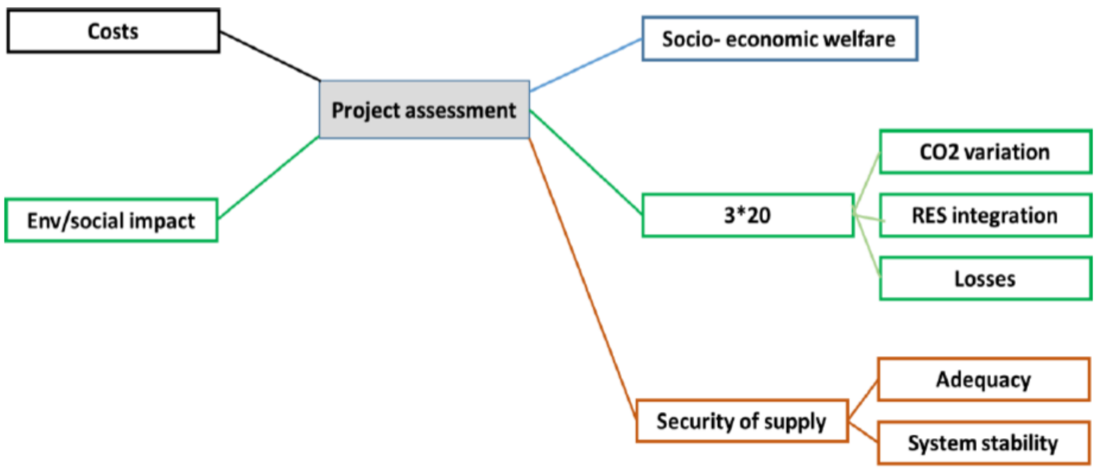
The projects resulting from the planning studies take into account the constraints identified in the 6 Regional Investment Plans which are published together with the list of projects. As for the scenarios, the list of projects and regional investment plans are open to public consultation before being finalised.

Step 3 – Projects assessments

The last phase of the planning process in the TYNDP is the assessment of projects. This is done using a European approved methodology to assess the costs and benefits of projects. This assessment is not just a purely economic assessment. It also considers how projects support the environment, the welfare in Europe and the security of supply among others. The results of this cost-benefit assessment of projects forms the core of the TYNDP report.

By reading the TYNDP report, everyone can see the value of each infrastructure project. The TYNDP is providing decision-makers with a robust and detailed analysis of transmission infrastructure projects on which to base their decisions. One illustration of this is the fact that TYNDP projects and their assessment is used in a European Commission-led process the Projects of Common Interests.

Figure 12: Cost Benefit Analysis Methodology (CBA) for TYNDP Project Assessment[16]



The CBA was drafted by ENTSO-E after consultation with stakeholders. It was then sent to ACER and the European Commission for opinion and to member states for information. Following the opinions received, the CBA methodology was revised and finally adopted by the Commission early 2015.

Each project included in the TYNDP is assessed using the pan-European CBA methodology. As such, the benefit of each TYNDP project is assessed against nine indicators ranging from socio-economic welfare to environmental impact.

Data models and confidentiality

Regulation No 347/2013 key statements on models and confidentiality in Article 11 Energy system wide cost-benefit analysis paragraph 6 requires models to be provided and confidentiality agreements to be signed:

Within two weeks of the approval by the Commission, the ENTSO for Electricity and the ENTSO for Gas shall publish their respective methodologies on their websites. They shall transmit the corresponding input data sets as defined in Annex V.1 and other relevant network, load flow and market data in a sufficiently accurate form according to national law and relevant confidentiality agreements to the Commission and the Agency, upon request. The data shall be valid at the date of the request. The Commission and the Agency shall ensure the confidential treatment of the data received, by themselves and by any party carrying out analytical work for them on the basis of those data.

5.8.4.2 USA

Prior to the emergence of Regional Transmission Organisations (RTOs) and Independent System operators (ISOs)[17]:

- regional transmission planning activities generally involved coordination by utilities through **the regional reliability entity** and joint planning at interfaces;
- The development of regional transmission projects tended to be **location-specific arrangements** involving the utilities involved in developing the projects; and

[16] CBA 2.0 Improving the pan-European cost-benefit analysis methodology, ACER Workshop K Wewering, May 2016
[17] U.S. Department of Energy (DOE), Annual U.S. Transmission Data Review, March 2018

- A **"regional"** project, in this context, simply meant that there was a **bi- or multilateral agreement among two or more parties** (typically, incumbent transmission owners adjacent to one another) to share in developing a project.

Following the emergence of Regional Transmission Organisations (RTOs) and Independent System operators (ISOs):

- Transmission planning activities in RTO/ISOs regions took on a more public character;
- Approval of regional cost allocation for certain transmission projects also emerged as an outcome of these regional transmission planning activities;
- The standards used to judge or select these projects, consequently, varied by region. The outcomes also varied. Some regions' plans identified projects for regional cost allocation; other regions' plans did not; and
- Interregional coordination in the form of information exchange also took place to varying degrees.

To address the lack of coordination for regional transmission planning and actual regional transmission projects being developed FREC issued FERC Order Nos. 890 and 1000*

- Order No. 890, issued in 2007, outlined general requirements for local as well as regional transmission planning practices and procedures.
- Order No. 1000, issued in 2011, laid out specific requirements for:

  (1) regional transmission planning;

  (2) consideration of transmission needs driven by public policy requirements;

  (3) non-incumbent transmission development;

  (4) interregional transmission coordination; and

  (5) cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation.

5.8.4.3 Eastern African Power Pool (EAPP)

The Planning Code (PC) specifies the minimum technical and design criteria, principles and procedures:

- To be used within EAPP in the planning and in the medium and long term development of the Interconnected Transmission System of Eastern Africa;
- To be taken into account by Member Utilities on a coordinated basis, and
- To specify the planning data required to be exchanged by Member Utilities and EAPP Sub-Committee on Planning to enable the EAPP Interconnected Transmission System to be planned in accordance with the planning standards.

The EAPP PC contains the following requirements:

Principles of the Planning Code

The planning principles are concerned with planning of the interconnection between National Systems, connections with External Systems and with those facilities within National Systems which have, or could have, an impact on the reliability of the EAPP Interconnected Transmission System.

Reliability Criteria

N-1 (similar to system operations code) – no economic criteria specified

The Planning Process

10 year plan updated every 5 years which contains:

- Power Balance Statement - A forecast, the Power Balance Statement, by TSOs for each National System of their expected demand and generation over the planning horizon. This forecast will define the requirements for generation support from the EAPP. Interconnected Transmission System for individual National Systems, and
- Transmission System Capability Statement - An assessment, the Transmission System Capability Statement by EAPP Sub-committee on Planning and TSOs of the capability of the EAPP

Interconnected Transmission System to support the required energy flows across both National Systems and cross-border interconnections.

EAPP Power System Modelling

Responsibilities - system studies will be carried out by both the EAPP Sub-committee on Planning and the TSOs and shall be performed using a **common set of principles and a common database** … the EAPP Sub-committee on Planning shall establish a set of common objectives for the development and submission of system data for EAPP power system modelling.

Planning Data Confidentiality

System planning data shall be treated as **non-confidential** when the EAPP Sub-Committees on Planning and Operations and TSOs use such data:

- In the preparation of forecasts, Power Balance Statements and Transmission
- System Capability Statements;
- For the planning of the EAPP Interconnected Transmission System;
- To consider a Connection Application or provide advice to a User;
- Under the terms of an Interconnection Agreement with an External System

5.8.4.4 Establishment of a SAPP Regional Transmission Infrastructure Financing Facility

The project's primary objective is to establish a regional facility, known as the Regional Transmission Infrastructure Financing Facility (RTIFF), that will unlock funding for regional transmission infrastructure. The aim of the Facility is ultimately to enable SAPP to increase and improve trading volumes, alleviate congestion on the existing network, improve reliability and create adequate redundancy in the regional system. In doing so SAPP has asked the Consultant Team to review international best practice and explore mechanisms that could address a series of financial barriers, namely:

- the credit quality of regional utilities and their ability to raise funding for transmission projects;
- the fiscal constraints of SAPP's member states and their ability to issue guarantees;
- the lack of long-term PPA's with credit worthy off-takers; and
- a lack of predictable revenue streams that can be ring-fenced to repay debt.

The main content is:

- Establishing a robust strategic case for RTIFF including careful examination of the barriers to regional transmission infrastructure, as well as quantifying the financial and economic benefits that could be unlocked by delivering new projects;
- A considered approach to reviewing international best practice and taking an innovation mind-set to conceptualise a set of viable options for the Facility's function and form; and
- Ensuring effective validation of the preferred Facility model and engagement with stakeholders before moving towards operationalisation.

5.8.4.5 Recommendations for EA-SA

There should be a similar regulation set up for the EA-SA region as the EU Regulation No 347/2013 to mandate regional co-ordination for interconnector projects. These projects are required to enhance VRE penetration and increase regional trading. Countries who do not directly benefit from such projects have no interest in including these projects in their local transmission expansion plans.

The key issues the regulation should address are:

- Planning process and time frames;
- Cost Benefit Analysis Methodology;
- Ranking of regional based on Cost Benefit Analysis results;
- Funding model for top ranked regional interconnection projects; and
- Data model provision and confidentiality

5.9 Addressing environmental sustainability

5.9.1 Overview

Addressing environmental sustainability through the regulation of the regional energy market in EA-SA-IO is most directly achieved through the measures that are put in place to encourage three key elements:

1. the increased penetration of renewable generation in the region;
2. facilitating interconnection within the region so that the most sustainable forms of energy generation can be traded regionally; and
3. an increased focus on energy efficiency on both the supply side and the demand side.

The measures that have been developed throughout Workstream A are focused on facilitating access to the integrated regional markets of Southern Africa and Eastern Africa for, particularly, IPPs, and also creating a level playing field across the EA-SA-IO region for potential new entrants to the market in terms of the regulations that will apply.

The provisions that are focused on encouraging investment in transmission, through the harmonisation of the relevant agreements and the creation of a standardised wheeling methodology, will contribute to the second of the above objectives by seeking to ensure that:

- transmission utilities are incentivised to provide wheeling services that will enable energy from renewable sources to participate in the regional markets; and
- new developers of transmission infrastructure can see a route to recovering the costs of the associated investments and to make a regulated return on their investments.

In order to link together the different elements of the approach to achieving environmental sustainability across the region, RRAs and NRAs could take a more active role in the supervision of planning processes, in particular the approach that is taken to Integrated Resource Planning (IRP) in the region.

5.9.2 Integrated Resource Planning

Energy Efficiency (EE), RE, integrating RE into network operation and development, and accounting for externalities in evaluating power sector expansion plans are key components of an IRP approach. Regulations could therefore be developed regionally and nationally that require utilities to consider these aspects in their IRPs, with regulators taking a key role in the approval of plans prior to their adoption.

Promoting EE is widely regarded internationally as a cost-effective option for managing energy demand, and this requires a joined-up approach to legislation, regulation and the development and application of standards for electrical equipment. The role of the RRAs and NRAs should be to encourage utilities to build the necessary skills into their organisations and develop planning procedures to investigate the potential for EE alongside increased RE penetration and greater levels of interconnection as an integral part of the IRP process.

Ensuring that the potential contribution of power generation from renewable energy sources is fully recognised in the planning process is one of the key challenges facing the power sector in most countries. The regulatory recommendations cover key issues in connection codes, including the need for a Regional Grid Code, and the relevant transmission agreements, which will assist the connection of RE generation throughout the region. The RRAs and NRAs also have a role to play, however, in reviewing national expansion plans to ensure that the modelling of renewables has used appropriate generation forecasting methods and has analysed the potential for reserve sharing and other means of balancing the intermittency of RE generation. The ongoing studies in SAPP under the World Bank-funded project "Assessment of the Impact of Renewable Energy Technologies on the Operations in the Southern African Power Pool" are an example of best practice being applied to the technical assessment of the effect of increase RE penetration on the interconnected networks. There is also a large body of growing experience internationally in studying the impact of high penetrations of renewables in island systems and developing appropriate technical strategies to manage these. This again could be reflected in optimised planning processes, and the Club of Regulators for the IO countries could have an important role in promoting best practice in this area.

5.9.3 Transmission expansion planning

A key constraint in the integration of RE generation relates to the lead-time that is needed to develop new transmission lines and substations in order to reinforce existing networks adequately to accommodate the additional generation. Planning and constructing new transmission infrastructure can frequently require lead-times in excess of five years, which is substantially longer than the two to three years typically required to build new renewable generation. It is therefore important in the planning process to ensure that transmission infrastructure requirements are being recognised and brought forward in utilities' investment programmes ahead of the time when they will be required to enable new RE to connect. Given the variability in RE output and the seasonal variations in solar and wind resources, it is also important that probabilistic modelling of generation is included when assessing the overall optimisation of the power system.

Running throughout our work is the assumption that cross-border interconnection capacity will need to increase in order to provide the maximum level of electricity market access in Southern and Eastern Africa, and to unlock the full range of benefits of cross-border trading. From the viewpoint of environmental sustainability, interconnections are key to ensuring that renewable resources in different parts of the interconnected international networks can be fully utilised.

5.9.4 Costing externalities

It is recommended that RRAs and NRAs, supported by the regional regulatory advisory bodies, develop guidelines for the costing of externalities into resources plans. This is a complex area, but examples of good practice do exist, such as that taken by the Arizona Public Service (APS). APS takes environmental costs into account when evaluating its resource plans by using a 'CO2 adder', in anticipation that federal regulation of CO2 will be introduced over the 15-year planning horizon of the IRP. APS also uses adders for SO2, NOX, particulate matter (PM) and water, the latter being of particular relevance in an arid state such as Arizona.[18]

5.9.5 Strategic Environmental Assessment

There is wide international experience in the application of Environmental Impact Assessment (EIA) to projects, and this includes experience gained across the EA-SA-IO region. Whilst EIAs are successful in providing basic safeguards against social and environmental impacts of major projects, they are usually developed at a relatively late stage in the project development cycle, and key findings may only emerge at a late stage, either due to changing policy landscapes or the emergence of important data on environmental impacts during the development of the project.

There is an important discipline in international planning of Strategic Environmental Assessment (SEA), which seeks to develop evidence-based analysis of social and environmental factors in the context of the overall strategic plan for the power sector. The key features of an SEA is a process of evidence-based analysis of social and environmental issues within the context of strategic planning. The basic concepts of SEA include:

- Seeking to develop a balanced analysis that builds consensus amongst stakeholders and ensures that power sector goals are fully aligned with national development priorities;
- Ensuring that the analysis undertaken is both objective and unbiased, and that there are no preconceived ideas as to what a desirable outcome looks like; and
- The importance of fully integrating SEA into the planning process, so that options are revised in the light of SEA outcomes, rather than carrying out the SEA as a separate exercise.

Of particular importance is the legal status of SEA – RRAs and NRAs should seek to play their part in enforcing legislation where this exists in the power sector requiring SEA to be carried out within IRPs. In those countries where SEA is not yet a legal requirement, RRAs and NRAs should nevertheless seek to influence power utilities to accommodate this as good practice in the development of sector plans.

5.10 Promoting gender issues

There is a noticeable gender imbalance when visiting regulators in Africa. Senior and professional positions are generally dominated by male employees. Section 7.5 of this report presents a baseline for Women in Energy and supports the observation that females are under-represented at senior and

[18] R Wilson and B Biewald, June 2013, *Best Practices in Electric Utility Integrated Resource Planning*: Examples of State Regulations and Recent Utility Plans. Synapse Energy Economics, INC.

professional levels. This gender imbalance is not only limited to regulators in Africa but can be found in many organisations around the world.

This gender gap exists despite a growing body of evidence showing that gender-balanced organisations achieve higher levels of performance and productivity[19,20]. There are many reasons why this is the case and some of the reasons are summarised in the table below.

Table 11: Reasons why gender balanced organisations perform better

Reason	Description
A wider talent pool	Companies that do not encourage women to join them are missing out on the talents and abilities of half the population. Tapping into these can make a huge difference to your productivity and your bottom line.
A better reflection of your customers	Customers come from all walks of life. The more the make-up of your organisation reflects your customers the more likely it is you will communicate effectively with them.
Different perspectives	Having both women and men in your teams means you benefit from the different points of view and approaches that come from different life experiences.
Improved staff retention	Having an inclusive culture in your workplace boosts morale and opportunity. Inclusive workplaces tend to have lower employee churn rates – which represents big savings in terms of time and money spent on recruitment.
Improved recruitment and reputation	Having an inclusive workplace is a powerful recruiting tool. Female millennials look for employers with a strong record on diversity, according to research by PwC, with 85% saying it is important to them.
Greater profitability	Evidence supports the theory that gender diversity has a positive impact on the bottom line. According to McKinsey, the most gender-diverse companies are 21% more like to experience above-average profitability.

In addition to the benefits of a diverse and gender balanced organisation many governments have a constitutional responsibility to ensure that their societies are free from gender-based discrimination. This responsibility is often discharged through various polices and legislations. Kenya is a case in point. In 2019, The Government of Kenya published its revision of the “National Policy on Gender and Development”. The revision became necessary because the pace at which gender equality were realised was not in keeping with the expectations. It is clear from this revised policy that Kenya is stepping up its efforts “Towards creating a just, fair and transformed society free from gender-based discrimination in all spheres of life practices” as stated on the front page of the policy.

Numerous studies have been undertaken to identify the reasons for the lack of women in the work place especially at senior and professional levels. A good reference document is a “Practical Guide to Women In Energy Regulation” which was commissioned by National Association of Regulatory Utility Commissioners (NARUC) and sponsored by United States Agency for International Development (USAID)[21]. What is interesting from all this body of work is that there is a common set of solutions and actions that will assist organisations in increasing the number of women at senior and professional levels. The table below summarises the recommendations from a report titled “Women In Energy - Gender Diversity In The CEE-SEE Energy Sector” by Boston Consulting Group in collaboration with the Women in Energy Association[22].

[19]See the following Harvard Business Review article with further references: https://hbr.org/2019/02/research-when-gender-diversity-makes-firms-more-productive
[20] See the following McKinsey article: https://www.mckinsey.com/featured-insights/leadership/gender-balance-and-the-link-to-performance
[21] Website address: https://www.usaid.gov/sites/default/files/documents/1865/2018-Cadmus-NARUC_Practical-Guide-Women-Energy-Regulation.pdf
[22] Website address: https://www.womeninenergy.eu/wp-content/uploads/2018/12/Women_in_Energy_in_the_CEE-SEE_Region_Dec2018_final.pdf

Table 12: Recommendations to improve the gender balance of an organisation

Objective	Recommendations
Increase the number of female applicants to job offers in the energy sector	• Raising awareness of what it is like to work in the energy sector • Organising events in order to promote the energy sector • Promoting engineering programs among girls and women • Creating male-female recruiting targets
Create a family-friendly working environment and provide more and clear career progression opportunities for women	• Maternity and paternity leave • Paid and/or unpaid leave • Childcare at work • Create more flexible career paths and help with career planning • Discourage gender-based stereotypes, and encourage a positive corporate culture • Provide training courses and learning opportunities • Female mentorship and sponsorship programs • Robust anti-discrimination policies
Increase female participation in senior leadership	• Offer help and support to women seeking career advice • Provide visibility into available opportunities • Create a fair and objective system for evaluations and promotions • Focus on both male-and female-related skills in job descriptions • Expand the pool of candidates for promotions • Measure and track progress

The above set of recommendations formed the basis of questions on Women in Energy in the survey that was conducted to conduct skills assessment and identify training opportunities. The questions and responses are discussed in more detail in Section 7.5.

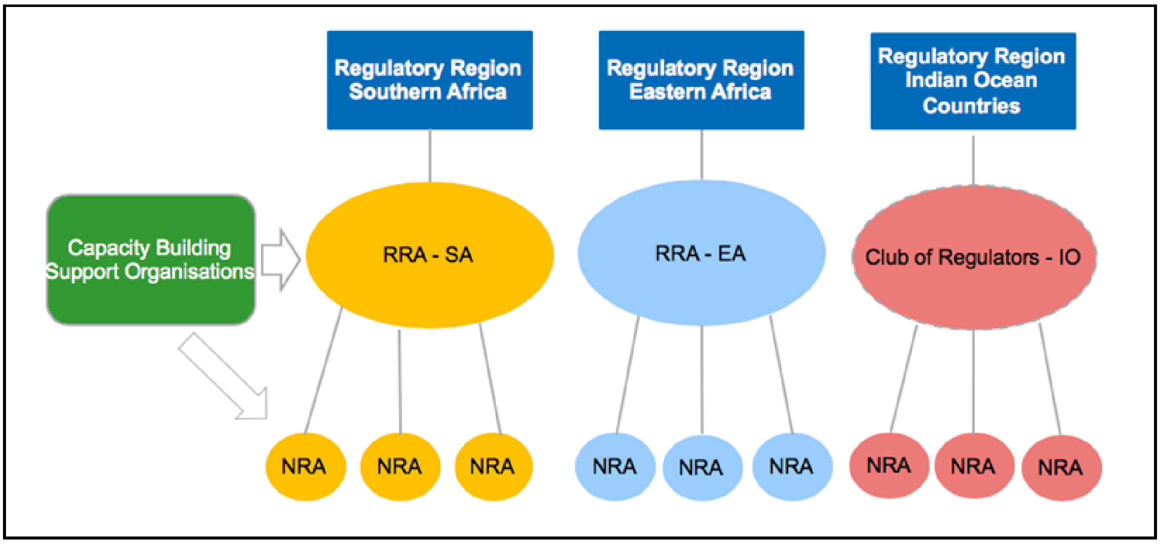
6 Implications of key recommendations and budgetary requirements

6.1 Institutional issues

6.1.1 Recommended Regional Regulatory Institutions

In Section 5 the recommended approach for establishing an effective institutional structure for regulatory oversight of the EA-SA-IO Electricity Market has been described. In this respect it has, as summarised again by the below chart, been recommended to group the countries into three different regulatory regions and establish a regulatory authority for Southern Africa, a regulatory authority for Eastern Africa and a regulatory advisory body for the island states of the Indian Ocean region.

Figure 13: Recommended regulatory regions



Two basic options exist to implement the recommended institutional framework.

1. The recommended institutional framework may be implemented by creating entirely new regional regulatory institutions; or
2. The recommended institutional framework may be implemented based, to the degree possible, on the already existing framework of regional regulatory organisations that has been identified and analysed in the desk study report, namely in particular comprised by the Regional Electricity Regulators Association of Southern Africa (RERA), the EAPP Independent Regulatory Board (EAPP IRB), the Regional Association of Energy Regulators for Eastern and Southern Africa (RAERESA) and the Energy Regulators Association of East Africa (EREA) and the Indian Ocean Club of Regulators.

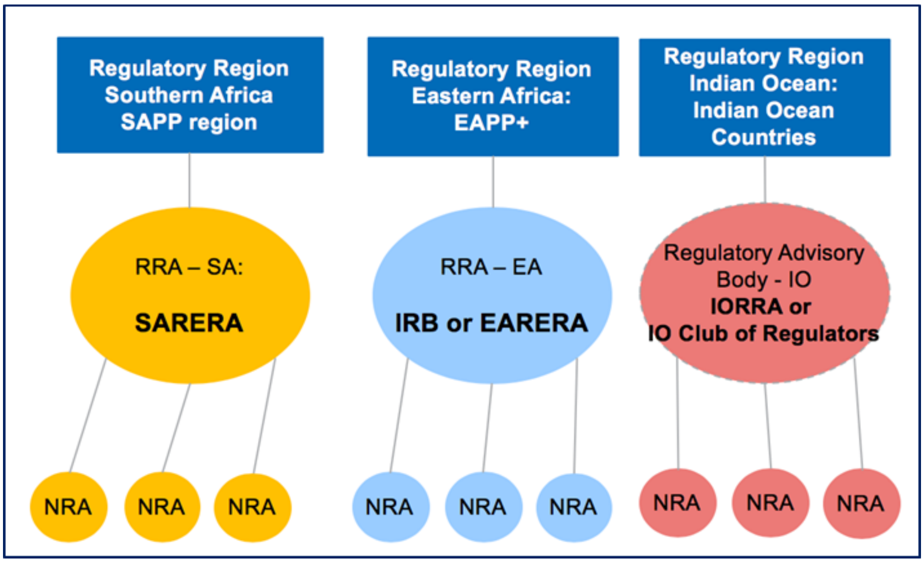
Bearing in mind the outlined findings regarding the existing regional regulatory institutions and organisations, their existing mandates and our intention to integrate these institutions and organisations to the maximum degree possible into the recommended regional regulatory institutional framework, we recommend the following regional regulatory institutional framework for regional regulatory oversight in the EA-SA-IO region:

- the IRB assumes, with an amended and extended mandate and potentially denominated EARERA instead of IRB, the role as competent common independent regional regulatory authority for the entire regulatory region of Eastern Africa. In this respect, the IRB has already been established as regional regulatory authority for the EAPP by the Council of Ministers of the member states of the EAPP. It is therefore not required to establish a new regional regulatory authority for EA. Its mandate is to conduct regulatory oversight of the EAPP power market in an efficient, transparent and non-discriminatory manner and thereby contribute to the regional market's sustainable development. The IRB is formally already mandated as regional regulatory authority and, consequently, the scope of amendments that are required to the enabling legal documents of the IRB are limited.

- a newly created independent regional regulatory authority, i.e. denominated SARERA, assumes the role of a common independent regional regulatory authority for the entire regulatory region of Southern Africa. In difference to Eastern Africa, none of the existing organisations that deal with regional regulatory issues in the SA region (RERA, RAERESA, EREA, AFUR), has a regulatory mandate or regulatory powers. For Southern Africa it is therefore imperative to establish a new legal entity with a common regional regulatory mandate for SA. In line with our approach to build upon already existing regional regulatory capacity to the maximum degree possible we recommend to build SARERA, to the maximum degree possible, on existing RERA human resources, thereby enabling to streamline the exhaustive preparatory work and in depth understanding regarding SA/SAPP regional regulatory issues of RERA into the future regional regulatory authority for Southern Africa; and
- a newly created regional regulatory advisory association for the Indian Ocean region (i.e. denominated IO Club of Regulators) assumes the role as common regulatory advisory body for the island states of the Indian Ocean region.

The recommended institutional framework for regional regulatory oversight in the EA-SA-IO region is illustrated by the chart below.

Figure 14: Recommended regional regulatory institutional structure



As outlined in Section 5 of this report, the long-term success of the recommended institutional structure for regulatory oversight of the EA-SA-IO Electricity Market, amongst other factors, depends on the level of cross-regional regulatory coherency between the Southern African and Eastern African regulatory regions. In order to secure the maximum level cross-regional regulatory coherence it must be ensured from the onset that:

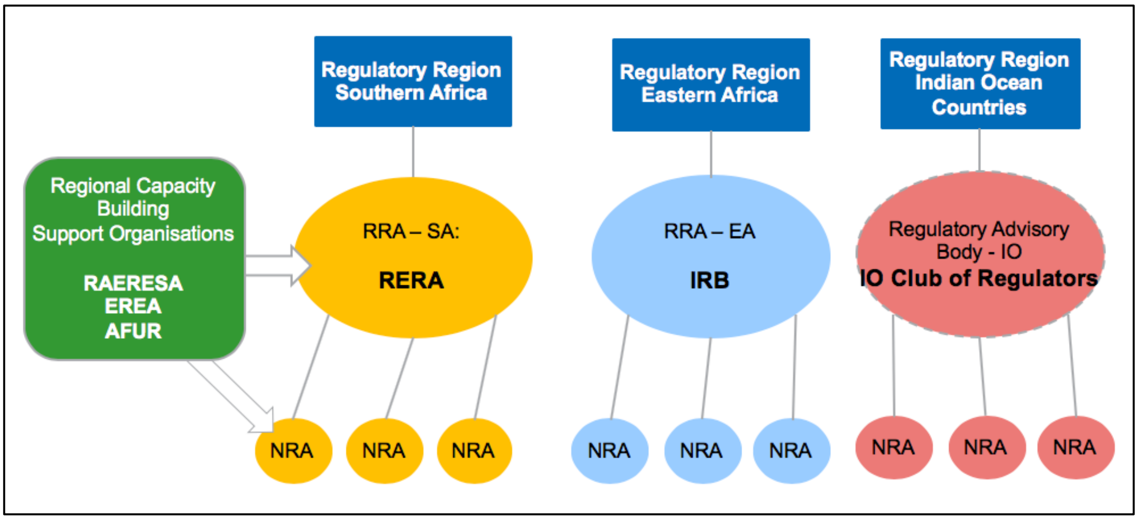
- the enabling legal documents for the two mandated regional regulatory authorities for Southern and Eastern Africa are coherent to the maximum degree possible in terms of governance, organisational structure, regulatory functions, regulatory responsibilities, regulatory instruments;
- both entities are mandated and obliged to adopt coherent mandatory regional regulatory rules, standards and documents;
- both entities are mandated to coherently apply the common mandatory and recommended regional regulatory rules, standards and documents; and
- national regulatory authorities coherently and consistently are mandated and obliged to enforce the regional regulatory rules, standards and decisions that are adopted by the two regional regulatory authorities.

Beyond the highlighted long-term success factors the importance of complementing the recommended regional regulatory institutional framework by an adequate capacity building framework was mentioned in Section 5 of the present report. This capacity building framework will significantly contribute to enable the three established regional regulatory institutions as well as the national regulatory authorities across the EA-SA-IO to exercise their respective regulatory responsibilities and tasks in an effectively and coherent manner.Two principal options exist to create the respective capacity building mechanisms:

- establish and mandate a new single regional regulatory capacity building organisation to provide training to the regional and national regulatory authorities across the EA-SA-IO region; or
- mandate one or more of the regional organisations with knowledge and capacity in regional and national regulatory matters that already exist in the EA-SA-IO region (RAERESA, RERA, AFUR) to provide training to the regional and national regulatory authorities across the EA-SA-IO region.

While in principle, the first option is regarded as more desirable in terms of coherence and resource efficiency, it is in line with the general intention of the consultants to build the recommended regional regulatory framework for the EA-SA-IO region to the to the maximum extent possible and useful upon the already pre-existing institutional and organisation regulatory framework recommended to base the envisaged capacity building framework on the second option in its first phase.
The recommended institutional framework for regional regulatory oversight in the EA-SA-IO region including capacity building support is illustrated by the chart below.

Figure 15: Recommended regional regulatory institutional structure including capacity building organisations



6.1.2 Organisational structure and evolution of recommended regional regulatory institutional framework

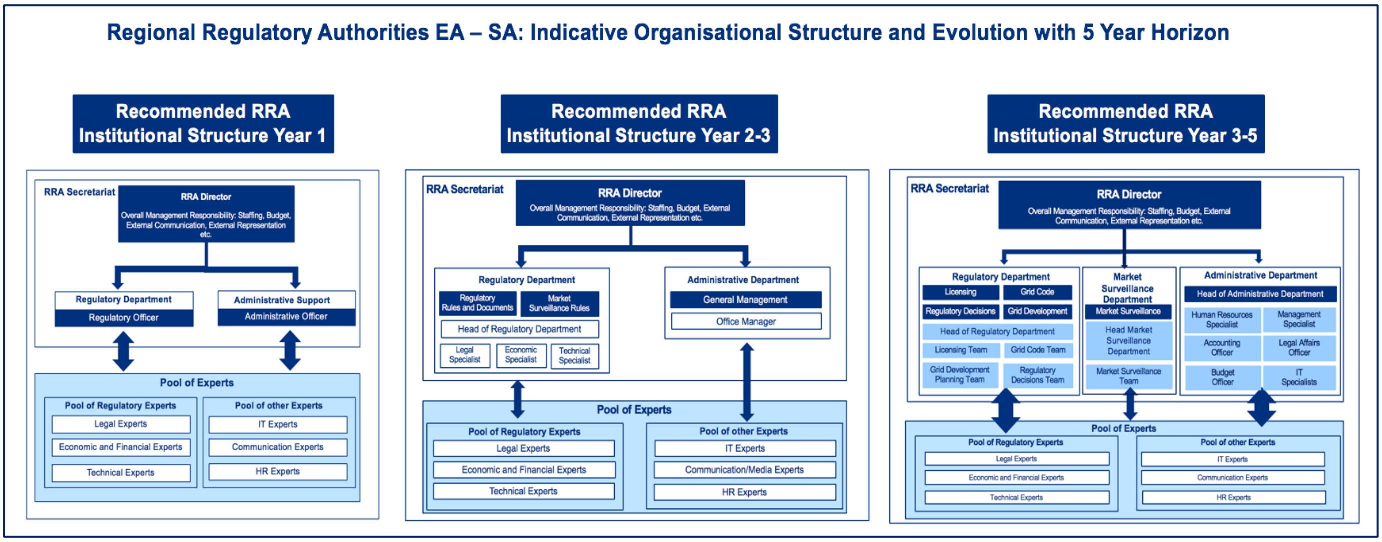
6.1.2.1 Recommended Organisational Structure and Evolution of EA-SA RRAs

As illustrated by the below chart, it is generally envisaged that, during the first 5 years, the two regional regulatory authorities will exercise their tasks through a Secretariat that is composed by a Director and specialised regulatory and administrative support units. In terms of staffing, it is envisaged that the basic organisational structure will in the initial stages only comprise three full time positions which will, over the subsequent years, gradually develop towards a fully operational structure with different departments and a variety of full-time positions.

In terms of staffing, it is, in order to achieve the maximum organisational efficiency, recommended as a general principle that both authorities only exercise their respective regulatory and administrative tasks through their own staff if this is duly justified by the respective regulatory or administrative workload. Especially in the early stages of development of the regulatory authorities, many regulatory and administrative tasks will not justify the creation of internal positions and should, in line with the principle of administrative efficiency, be exercised through specialised external support to be provided from a pool of independent experts rather than through internal staff. While independently of this recommendation, it is envisaged that the organisational structure will gradually grow as illustrated below, it is strongly recommended to maintain the reliance on specialised external support also beyond the indicated 5 year horizon. The ample range of regulatory tasks and varying degrees of workload can be expected to generate continuous need for highly specialised external regulatory expertise that on many occasions will not be available to the regulatory authorities internally.

An indication of a potential general organisational structure of the two regulatory authorities for the EA-SA region and their potential evolution over the first five years is provided by the chart below.

Figure 16: Indicative organisational structures for EA-SA Regional Regulatory Authorities



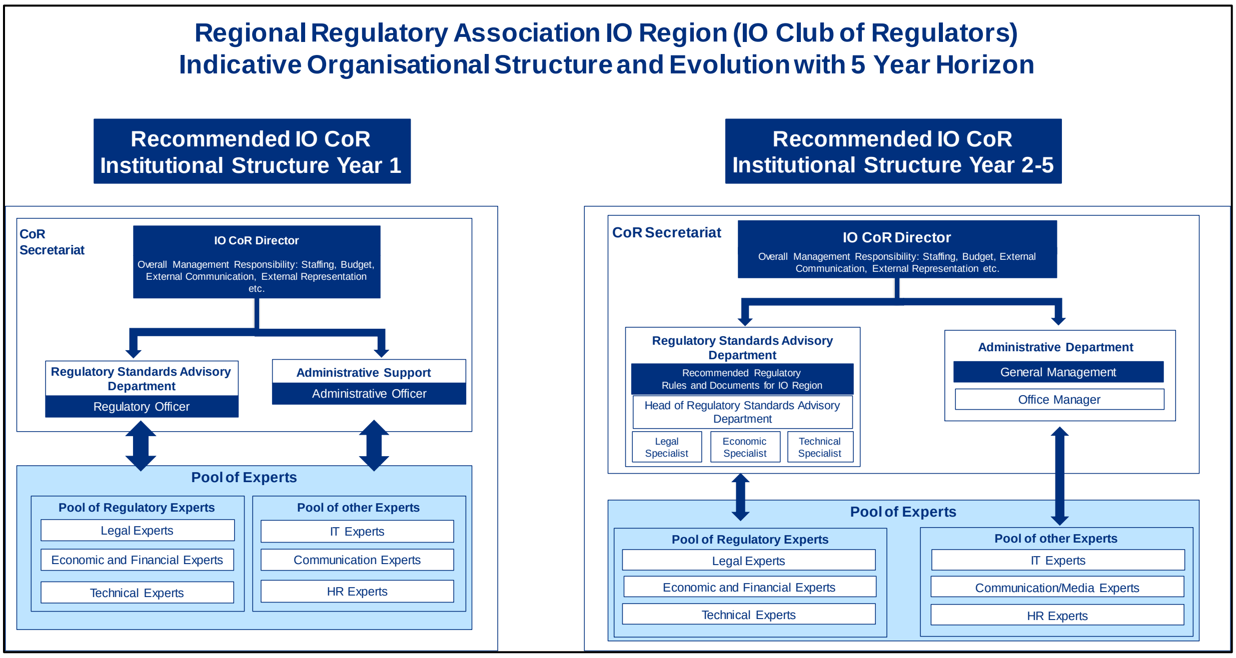
6.1.2.2 Recommended Organisational Structure of IO Regulatory Association

Generally, the organisational structure of the Indian Ocean Regional Regulatory Association, or Indian Ocean Club of Regulators, is aligned with what has been outlined above regarding the two regional regulatory authorities. It is thus envisaged that the respective association exercises its tasks through a Secretariat that is headed by a Director who is supported by a specialised regulatory unit and administrative support unit. While a certain level of gradual organisational development and increase of human resources is also envisaged for the Indian Ocean Regulatory Association or Club of Regulators, the level of development is, in comparison to the regional regulatory authorities, expected to be limited in compliance with its narrower range of tasks.

Beyond this, it is recommended to that the regulatory association for the IO region follows the same staffing principles as recommended for the EA-SA regional regulatory authorities that has been described further above. Thus, as a general principle, regulatory and administrative tasks should only be performed through its own staff if this is duly justified by the respective regulatory or administrative workload. Beyond that, the Indian Club of regulators should rely, to the degree possible, on specialised support from a pool of independent external experts.

An indication of a potential general organisational structure of the Indian Ocean Regulatory Association or Club of Regulators and its potential evolution over the first five years is provided by the chart below.

Figure 17: Indicative organisational structure for Indian Ocean Club of Regulators



6.1.3 Budgetary Sources

While budgetary sources are analysed and illustrated in more detail in subsequent sections of the present report, the potential budgetary sources for the recommended regional regulatory institutional framework in the EA-SA-IO region are briefly presented in this section. Generally, the budgetary sources are similar to those of national regulatory authorities. In particular, the potential sources of income comprise the following four sources:

- contributions from the national budgets of those states that subject their national energy systems to the different types of regional regulatory oversight recommended by this report;
- contributions from national regulatory authorities of those states that subject their national energy systems to the different types of regional regulatory oversight recommended by this report;
- tariffs, fees and levies generated by the regulatory services of the regional regulatory institutions, in particular, comprising fees for regulatory decisions;
- contributions from international and regional donor institutions like the World Bank, AfDB, EC and other potential international and regional donors.

In the early stages it is recommended to cover budgets through national budgets or through contributions by NRAs with additional support by international donors. In the medium-term, the share of the budget covered by tariffs, fees and levies from TSOs and market participants should be gradually increased.

6.2 Regulatory harmonisation

Harmonisation of regulations across the EA-SA-IO region has been proposed in three core areas of activity, relating to:

- Licensing of electricity sector participants;
- Network regulations (including the development of a Regional Grid Codes for the combined Southern African and Eastern African region and a “Reference” Grid Code for the IO countries; and
- Market regulations, focusing on Market Surveillance and Dispute Resolution.

In addition, proposals have been outlined for the RRAs and NRAs to work together to promote good practice in the implementation of Strategic Environmental Assessment as part of the power sector planning process regionally.

A key issue that arises from the harmonisation of regulations is the precedence that will apply to regional regulations versus national regulations. Proposals for addressing these points are as follows.

- National Grid Codes should over time be adapted to align with the Regional Grid Code and the "Reference" Grid Code for the IO countries. We recognise however that in the short to medium term, derogations may be required in respect of particular technical conditions that some national networks may not be able to comply with. Once the RRAs are in place, as defined in Section 6.1, they should take responsibility for assessing the compliance of national Grid Codes in the countries under their jurisdiction, and agreeing with the NRAs and the power utilities the process whereby compliance with the Regional Grid Code will be achieved. In the IO countries, the Club of Regulators should work with the individual countries in the region to help them to align their Grid Codes with the "Reference" code. There would not need to be a process of formally agreeing derogations with the IO countries;
- We propose that the template licences and agreements we have recommended be developed and adopted by the RRAs and be implemented by the NRAs under the principle of subsidiarity. In the IO countries, the Club of Regulators should again work with the NRAs to align their licensing regimes and agreements with best practice, without this being a mandatory requirement;
- Regarding Market Surveillance, we note that SAPP is in the process of creating a Market Surveillance Unit to address market integrity issues. This potentially creates a conflict with the proposed role of the RRA for Southern Africa (the RERA body in its revised role as a regulatory authority) that would have the power to define and enforce sanctions for breaches in regional market rules. Furthermore, we noted during discussions in the Validation Workshop that to enforce regulatory sanctions associated with regional trading requires interlocking actions from NRAs as well as the RRAs for full effect. We therefore propose that:
  a) until such time as the RRAs are fully established it should be the NRAs that take responsibility for enforcing sanctions that have been agreed between SAPP and RERA, in Southern Africa, and between EAPP and IRB, in Eastern Africa; and
  b) in the future, however, the role of the power pools should be to monitor market participants' behaviour and report to the relevant RRA. The RRA would then have the responsibility of deciding and enforcing sanctions.

6.3 Changes to regional MOUs and Agreements

In order to implement the recommended institutional structure for regulatory oversight of the EA-SA-IO Electricity Market the relevant regional organisations, the SADC in Southern Africa, COMESA in Eastern Africa, and the Indian Ocean Commission (IOC) in the Indian Ocean region, will have to make some amendments to create an adequate enabling legal framework that allows each of the proposed regional regulatory institutions to effectively exercise its mandate.

The implementation of the recommended institutional structure for regulatory oversight of the EA-SA-IO Electricity Market requires an adequate enabling legal framework that allows each of the proposed regional regulatory institutions to effectively exercise its mandate.

6.3.1 Decisions and Amendments required to establish the IRB as Regional Regulatory Authority

For Eastern Africa, as previously described, the IRB has already been established as regulatory authority for the EAPP by the Council of Ministers of the member states of the EAPP. Its mandate is to conduct regulatory oversight of the EAPP power market in an efficient, transparent and non-discriminatory manner and thereby contribute to the regional market's sustainable development. The IRB is thereby formally already mandated as regional regulatory authority and, consequently, the scope of amendments that are required to the enabling legal documents of the IRB are limited. Nevertheless, some changes need to be made in order to enable the IRB to function as a fully independent regulatory authority and to exercise its regulatory tasks across the entire EA regulatory region. Its existing enabling documents must be amended in two respects: firstly, the existing mandate must be amended by the EAPP Council of Ministers as required in order to make it fully independent from the EAPP. Secondly, its mandate must be amended in terms of regional scope beyond the scope of the EAPP. In particular, the IRB must be enabled also to serve as a regional regulatory authority for those states that are presently not members of the EAPP but are willing to subject their national energy sectors to regional regulatory oversight by the IRB. In this respect, the existing IRB mandate must be amended by the existing Council of Ministers that is competent for making decisions regarding the mandate of the IRB to enable the IRB to exercise regulatory oversight in any EA state that is willing to subject its national energy sector to regional regulatory oversight by the IRB. In addition, the respective states must be invited by the Council of Ministers to ratify the amended enabling legal documents of the IRB, thereby enabling the IRB to exercise its regional regulatory functions also in these countries and not only within the EAPP. Beyond the outlined changes it is recommended to review the enabling legal documents of the IRB and make such changes to them as required in order to enable the IRB to effectively and independently exercise its regulatory functions and responsibilities (see list of key issues to be verified further below for details).

6.3.2 Decisions and Amendments required to establish a Regional Regulatory Authority for SA

As outlined further above, presently no institution or organisation with a regional mandate or regional regulatory powers in the field of energy, that could be transposed into a regional regulatory authority for Southern Africa by amending its existing mandate, exists in Southern Africa. Therefore, a new independent common regional regulatory authority for Southern Africa must be established. In Southern Africa, the competent regional organisation for establishing an independent regional energy regulatory authority is SADC. Based on the SADC Treaty, the SADC may create new institutions. The correct legal instrument to establish an institution according to existing SADC practice is a Charter. Through the Charter the SADC would need to determine all the key powers required by SARERA to effectively and independently exercise its regulatory functions and responsibilities (see further below for details).

Nevertheless, although as outlined SARERA will have to be established as an entirely new legal entity, in line with our approach to maximise the use of already existing regional regulatory capacity in the establishment of the recommended institutional framework, we recommend to draw upon RERA human resources in order to streamline the exhaustive preparatory work and in depth understanding regarding SA/SAPP regional regulatory issues that RERA has built over the last decade directly into the future regional regulatory authority for Southern Africa. Prior to winding up RERA, RERA should thus be tasked by SADC to support SADC with the preparation of the enabling legal documents of SARERA. Subject to the discretion of SADC, it is also recommended to directly streamline the existing human resources of RERA into SARERA following the formal establishment thereof.

6.3.3 Decisions and Amendments required to establish IO Club of Regulators

As outlined further above, presently no regional institution or organisation exists with an advisory mandate in regulatory matters that are relevant to the IOC member states. Therefore, a new legal entity must be established. In comparison with Southern and Eastern Africa, the creation of a regional regulatory advisory organisation for the Indian Ocean region presents a less complex task. In this respect, unlike in Eastern and Southern Africa, the establishment of the proposed advisory organisation does not require the IOC states to transfer any national powers to the regional level and therefore does not require any formal governmental intervention but can be based on a formal co-operation through a Memorandum of Understanding (MoU) between the national regulatory authorities of the Indian Ocean Region. This MoU Charter would need to determine all key issues required by IORRA or the IO Club of Regulators to effectively and independently exercise its functions and responsibilities (see further below for details).

6.3.4 Summary Overview of Key Issues regarding enabling legal framework for recommended regional regulatory institutions

The following provides a brief overview of the key findings and the key scope of decisions and amendments that need to be addressed in order to establish the recommended institutional structure for regulatory oversight in the EA-SA-IO region.

Figure 18: Summary of key findings and scope of amendments to mandate of existing institutions

	IRB	RRA SA / RERA SA	CoR
Existing form	Established as regulatory authority by Council of Ministers of EAPP member countries	Association or Company without commercial objective established under Namibian Law by the SADC Energy Ministers	Non existing
Existing mandate	Regulatory Authority for EAPP	Regional association with mandate to promote regional regulatory harmonisation	Non existing
Adequacy of existing mandate	Partially adequate: • the existing IRB mandate provides an adequate enabling legal basis for the IRB to function as regulatory authority • However, the IRB is not established as independent regulatory authority but as part of the EAPP and its mandate is limited to EAPP countries	• Existing legal form and mandate are not adequate to enable RERA to function as regulatory authority	Non existing
General Scope of legal changes required	• Existing IRB mandate needs to be amended: IRB needs to be established as fully independent authority outside the EAPP structure, enabling it to exercise regulatory oversight for all countries that are intending to join the common EA regulatory region • IRB precise functions and responsibilities should be aligned with the recommendations of the study	• Due to the inadequacy of the existing RERA mandate a new RRA for SA will need to be established • while formally this requires closure of the existing RERA it is recommended to fully integrate the existing secretariat of RERA into the new RRA for SA, thus building on its extensive regulatory knowledge built over the last decade • RRA for SA precise functions and responsibilities should be aligned with the recommendations of the study	• CoR to be established as association under the laws of one of the IOC Member States • CoR precise functions and responsibilities should be aligned with the recommendations of the study
Competent Authority/Legal Instrument	• CoM Decision of EAPP Countries must revise and amend existing IRB mandate to enable it to function as fully independent RRA for EA • additional countries wishing to provide IRB with regulatory powers to ratify CoM decision in adequate legal instrument (i.e. protocol to CoM decision)	• SADC Council of Energy Ministers to establish RRA for SA based on SADC legal instruments and protocols duly integrating existing RERA secretariat	• as IO CoR does not require regulatory powers IO CoR should be formally established based on MoU by IO NRAs

6.3.5 Scope of Key Issues for enabling Documents

6.3.5.1 Scope of Key Issues for enabling documents of IRB/EARERA and SARERA

While further above the general enabling legal framework for establishing the IRB/EARERA and the SARERA as independent regional regulatory authorities for Eastern and Southern Africa has been determined, this section expands on the specific content of the enabling legal documents in more detail. In this respect, the enabling legal documents, independent of their precise legal form, must, amongst other things, determine the following issues for IRB/EARERA and SARERA:

- siting of the regulatory authority;
- legal status of the regulatory authority;
- governance structure of the regulatory authority;
- financial provisions including financial sources, budget establishment rules and rules for budgetary control of the regulatory authority;
- regulatory tasks, responsibilities and instruments and powers of the regulatory authority, including in particular:
    - development and adoption of common mandatory regional regulatory rules and standards documents applicable to entire regional system development and operation such as
        - Regional Grid Code;
        - Transmission Charges;
        - Wheeling Charges;
        - Common Standards for PPAs; and
        - Licensing Rules and Licence Templates for Regional Electricity Activities etc.
    - regulatory decisions on compliance with mandatory regional regulatory rules and documents;
    - regional market monitoring and market surveillance;
    - regional capacity building and training of national regulatory authority officers; and
    - development of recommended common regional regulatory rules and standard documents for entire region with support of other relevant regional organisations.
- the framework rules for co-operation between regional and national regulatory authorities, in particular, the obligations of the national regulatory authorities, including:

- the general obligation to co-operate with the regional regulatory authorities as required by them to implement their responsibilities;
- the obligation to co-operate with the regional regulatory authorities for the purpose of development of mandatory and recommended regional regulatory rules, standards and documents; and
- the obligation to transpose (to the degree required) and apply mandatory regional regulatory rules, standards and documents adopted by the regional regulatory authorities into national legal and regulatory rules.

- the framework rules for co-operation between regional regulatory authorities and the regional capacity building support organisations that are designated to provide institutional support to the regional regulatory institutions across the three regulatory regions; and
- the obligation to enforce regulatory decisions taken by the regional regulatory authorities at national level and the remedies available to the regional regulatory authorities in case a national regulatory authority fails to enforce a decision by the regional regulatory authority.

6.3.5.2 Scope of Key Issues for enabling documents of IO Club or Regulators

In the Indian Ocean region, the Indian Ocean Commission would need to take a formal decision to establish Indian Ocean Club of Regulators as regional advisory body for regional regulatory issues. Given the advisory nature of the Indian Ocean Club of Regulators, it would appear recommendable to establish the Club of Regulators based on a simple Memorandum of Understanding between the different national regulatory authorities in the Indian Ocean region. This Memorandum of Understanding would need to determine in particular:

- Siting;
- Legal status;
- Governance structure;
- Financial provisions including financial sources, budget establishment rules and rules for budgetary control;
- advisory regulatory tasks, responsibilities and instruments including:
  - development and adoption of recommended regional regulatory rules and standards documents applicable to entire regional system development and operation such as:
    - Common Connection Rules;
    - Common Standards for PPA; and
    - Common Licensing Rules and Licence Templates.

6.3.6 Decisions and Amendments required to establish a capacity building support framework

Finally, as mentioned further above, it is regarded to be of key importance for the effective functioning of the regional institutional framework for regulatory oversight in the EA-SA-IO region that the recommended institutional framework is duly supported by an effective capacity building framework. This capacity building framework will significantly contribute to enable the three established regional regulatory institutions as well as the national regulatory authorities across the EA-SA-IO to exercise their respective regulatory responsibilities and tasks in an effective and coherent manner. While the capacity building framework is outside the scope of the present study, in line with the recommendation to base the capacity building framework on the existing institutions, it is recommended, in line with the recommendation to base the capacity building framework on the existing institutions, to also establish an adequate legal framework (i.e based on an MoU or a Framework Agreement for Provision of Training) that will enable the existing regional capacity building organisations (i.e. RAERESA, EREA, AFUR, details subject to decision) or an entirely new capacity building organisation (i.e. an African School of Regulation) to provide, on an ongoing basis, targeted training to the relevant regional and national regulatory organisations.

6.4 Budgetary requirements

6.4.1 Budget estimate

The Consultant requested the participants, via the questionnaire process as well as during the country visits, to submit their annual budget information. In the end nine regulators submitted their financial results. These returns formed the basis of establishing budgetary benchmarks and requirements.

In reviewing the budgets, it became clear that various regulators use different reporting standards. This is to be expected but it does make it very hard to make a fair comparison between the different institutions and to recommend appropriate norms and standards. The challenge is made more complex in that regulatory responsibilities vary with some regulators being responsible for electricity only while others have additional responsibilities such as: gas, liquid fuels, water and sanitation. The currency difference between the regions adds another layer of complexity.

In order to establish an approach which could be used across all regulators, currencies and regions we have developed a simplified cost framework. The high-level framework serves to counter for differences in reporting formats and business approaches (e.g. renting versus owning of buildings). This framework groups the various expenses into four main categories namely:

1. Total cost-to-company staff costs;
2. Depreciation (e.g. vehicles, equipment, it, etc.);
3. Professional fees (e.g. accounting, consulting & legal fees); and
4. Other General Expenses (buildings, rent, subscriptions, transport, training, workshops, etc.).

By expressing the expense categories as percentages of the total budget It is possible to establish a reference budget which could be used across currency zones. The table below shows the typical benchmark ranges for the four expense categories:

Table 13: Benchmark expense category ranges

Expense Category	Minimum	Expected	Maximum
Staff costs	45%	55%	65%
Depreciation	3%	5%	7%
Professional fees	5%	10%	15%
Other expenses	20%	30%	45%

Note: The only set of results that laid outside the benchmark values was that from Mauritius. It was noted that it has the lowest percentage of employee costs (5%) and unusually high professional fees (63%).

As noted above due the big difference in roles and responsibilities between organisations care should be taken when using the benchmarks. Nevertheless, it is worth mentioning that SAPP expenses also fall within the above benchmark ranges if unique power related costs such as 'Market Administration Expenses' and 'Surplus' are excluded. The SAPP Annual report for 2019 indicates that 'Market Administration' and 'Surplus' represent approximately 52.6% and 32.8% of total costs respectively.

It is interesting, but not surprising, to note that staff costs usually represents the single biggest expense item in the budget. It also represents a very useful starting point for defining the budget for a typical regulator. The analysis shows that the average total cost to company for a regulatory employee varies between USD40,000 and USD80,000 with an expected value of USD60,000.

Using the above approach and results it is possible to construct an average budget for a typical regulator. For example, assume a regulator has a staff complement of 53 (which is the average staff complement of all the regulators that participated in the survey) and that the average cost to company is USD60,000 per year. The total staff cost to the company will therefore be USD3,180,000 per year. Based on this result, and using the expected benchmark values for the high-level expense categories, the estimated budget will be as follows.

Table 14: Indicative budget for a typical regulator

Expense Category	Benchmark	Expense (USD)
Staff costs	55%	3,180,000
Depreciation	5%	289,091
Professional fees	10%	578,182
Other expenses	25%	1,734,545
Total	100%	5,781,817

6.4.2 Financing modalities

The mechanism and source of regulatory authorities funding directly impacts the sustainability, independence, and efficiency of regulation. Energy regulators often use a mix of funding mechanisms, with some of the more common options described in Table 15.

Table 15 Common Regulatory Funding Mechanisms

Funding Category	Funding Mechanism	Brief Description
Support Based	Government Funding	Typically, a fixed amount set aside in a budget allocation to fund regulatory activities
	Grant/Donation (3rd Party)	Funding from a 3rd party for a specific activity or task to be carried out by the regulator (e.g. Development Finance Institute grant)
Trading Based	Levies	Tax on relevant customer transactions through quantity consumed or fixed cost (e.g. electricity cents/kWh, cents /litre of petroleum, cents/gigajoules of gas)
Transaction Based	Licence Fees	Cost-recovery for ongoing administration associated with licensing for regulated entities (e.g. annual renewal fee)
	Application Fees	Cost-recovery for processing applications for regulated entities (e.g. licence application fee)
Ad Hoc Based	Dispute Resolution Charges	Cost-recovery associated with addressing formal complaints or potential litigation
	Penalties and Fines	Extra revenue source and incentive for regulated entities to comply with rules
Other	Interest Earned	Rate of return earned on the regulators savings accounts (e.g. Trust Fund Interest)
	Rental Income	Payment from potential tenants using premises owned by the regulator (e.g. subletting extra office space)

Each funding mechanism has potential benefits and challenges. In general, regulatory funding sourced directly from industry i.e. through cost recovery via user charges (such as levies or application and renewal fees), tends to be more economically efficient than revenue from general support-based sources like the fiscus or third-party grants. Table 16 provides more detail on other benefits and challenges associated with each funding mechanism.

Table 16 Pros and Cons of Regulatory Funding Mechanisms

Funding Mechanism	Benefits	Challenges
Government Funding	• Simple collection for regulator • Transparent budget forecast	• Less independence • Not cost-reflective • Potential political influence
Grant/Donation (3rd Party)	• No cost to customer or government	• Less independence • Unreliable funding source
Levies	• Economically efficient • Fair allocation of cost • Encourages conservation • Scales with industry growth	• Reduced demand reduces funding • Challenge to forecast revenue • Increased cost to customers
Licence Fees	• Economically efficient • Fair allocation of cost • Scales with industry growth	• Increased cost to businesses
Application Fees	• Economically efficient • Fair allocation of cost	• May discourage applicants if too high
Dispute Resolution Charges	• Maintains independence of regulator	• Difficult to estimate in advance • Compromised independence if government approval needed
Penalties and Fines	• Incentive to follow rules	• Requires enforcement
Interest Earned	• Recovers cost of unused assets	• Surplus suggests inefficiency
Rental Income	• Recovers cost of unused assets	• Suggests assets sized inefficiently • Outside of regulatory mandate

As a general best practice, a regulator's funding should be sourced from functions its required to perform in an efficient manner. For example, the licensing fee amount should accurately recover the amount of time and resources required by the regulator to process the licence. Figure 19 outlines a number of additional useful principles for regulators.

In reviewing the revenue modalities of the various regulators, it became clear that the most dominant form of revenue collection is based in energy unit sales (e.g. $/kWh). Another observation is that many regulators charge low licensing fees which are likely below the cost of managing and maintaining licences. This may not be a problem while there are only a few players in the market but this could become a significant issue when more private players enter the market. Licence applications and maintenance processes can take up a huge amount of time and resources which will drive up costs. It is therefore important that regulators put the correct charge on the application, approval and renewal of licences.

Figure 19: Regulatory Funding Principles[23]

Supports outcomes efficiently
1. Funding levels should be adequate to enable the regulator, operating efficiently, to effectively fulfil the objectives set by government, including obligations imposed by other legislation. 2. Funding processes should be transparent, efficient and as simple as possible.
Regulatory cost recovery
3. Regulators should not set the level of their cost recovery fees, or the scope of activities that incur fees, without arm's-length oversight. These fees and the scope of activities subject to fees should be in accordance with the policy objectives and fees guidance set by government or, where these are not in place, the OECD's *Best Practice Guidelines for User Charging for Government Services*. 4. Where cost recovery is required, the regulator should not be at risk of setting unnecessary or inefficient administrative burdens or compliance costs on regulated entities.
Litigation and enforcement costs
5. Because of the significant and unpredictable costs involved, regulators should follow a defined process to obtain funding for major unanticipated court actions in the public interest that is consistent with the degree of independence of the regulator.
Funding of external entities by a regulator
6. A regulator should only fund other entities to deliver activities where they are directly related to the regulator's objectives, such as information and education about how to comply with regulation, or research to inform the regulator's priorities. Any funding of representative or policy advocacy organisations should be the responsibility of the relevant Ministry, not the regulator.

6.4.3 Staffing Levels

The Consultant collected a fair amount of data on the staffing complement of the various regulators. The data was very useful in establish baselines for the Women in Energy task which is discussed in more detail in section 7.5. However, due to the different areas of regulation as well as the different division of responsibilities between Ministries, Regulators and Utilities, it became clear that establishing staffing benchmarks would not be very useful. Nevertheless, and while keeping this caution into account, the Consultant used the available data to establish a high-level benchmark for regulatory staffing. The results are presented below.

Table 17: High-Level Benchmark ranges for Staffing (% of Total Staff Complement)

Staffing Category	Minimum	Expected	Maximum
Policy	2.4%	4.1%	7.6%
Economic	5.5%	8.7%	12.6%
Technical	11.8%	14.3%	22.4%
Legal	4.7%	5.5%	15.5%
Consumer	8.3%	7.8%	12.1%
Oversight/Compliance	6.1%	8.5%	13.5%
General Managerial	10.5%	11.7%	16.3%
Other	28.2%	39.4%	63.7%

23 Source: (OECD, 2013)

Total	77.5%	100.0%	163.6%

Using the benchmarks presented above, the table below shows the staffing complement of an average regulator noting that the staff numbers have been rounded. Again the user is cautioned about these results as they do not take into account the major differences between regulators including responsibilities and tasks.

Table 18: Example staffing for an average regulator

Staffing Category	Expected Benchmark	Staff Complement
Policy	4.1%	2
Economic	8.7%	5
Technical	14.3%	8
Legal	5.5%	3
Consumer	7.8%	4
Oversight/Compliance	8.5%	5
General Managerial	11.7%	6
Other	39.4%	21
Total	100.0%	54

7 Workstream B: Skills Assessment

7.1 Competency Matrix

Under Workstream B, the Consultant developed a competency matrix to assess the competencies of the participants across a broad range of typical regulatory functions, roles and responsibilities. The matrix was converted in a series of questions which formed the foundation of a skills assessment methodology which guided the development of a questionnaire-based survey.

The survey was expanded to also assess the staffing levels and profiles of the participants with a view to establish a baseline at various seniority levels for the number of women involved in the regulatory industry. The questionnaire also requested the participants to indicate their views on:

1. The need for training as well as the areas in which training is needed;
2. Training organisations and institutions being used to provide the training; and
3. Preferred training methods.

7.2 Questionnaire Structure

The responsive training programme was designed around the questions and answers from the skills assessment questionnaire. The questionnaire was sent to 29 regulators (or ministries if no regulators exists), as well as SAPP and EAPP, who were asked to complete and return the forms.[24]

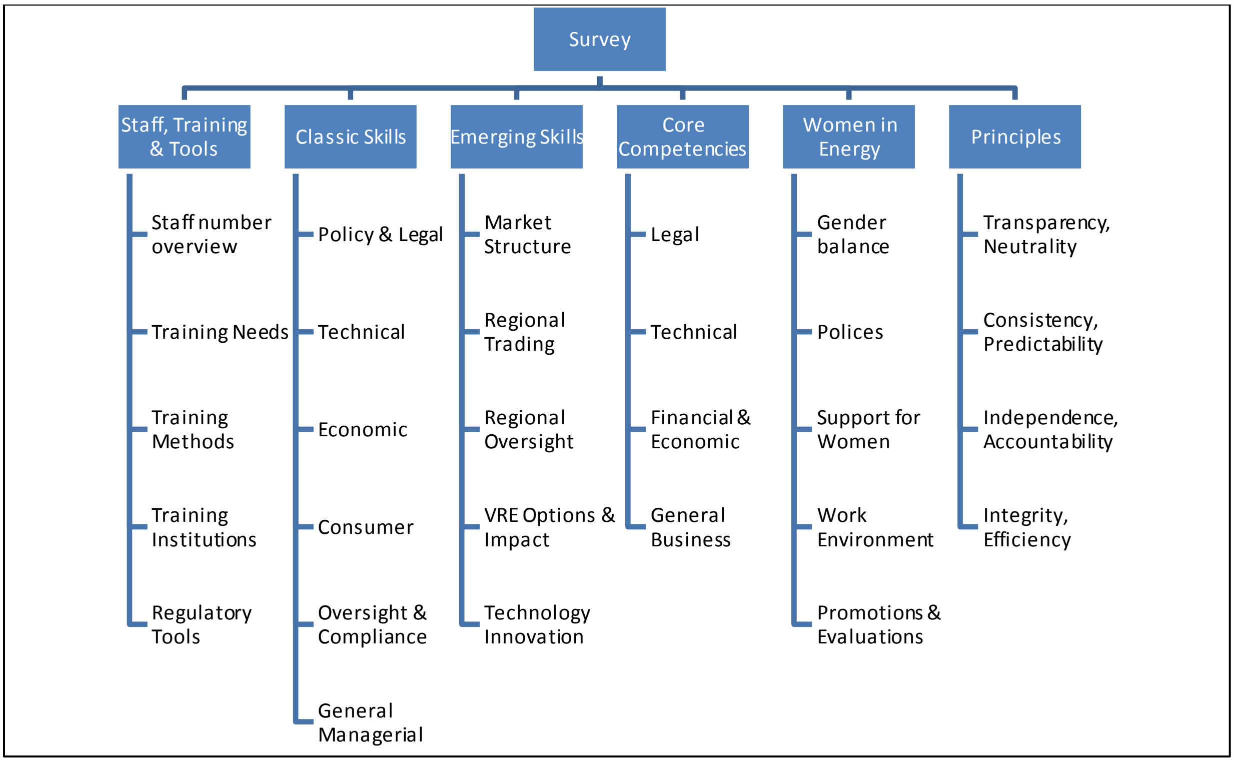
The main objectives of the survey were to:

1. Conduct a skills assessment by answering various questions;
2. Identify the training needs amongst the regulators using the responses to the questions as well as the regulators own identified training needs; and
3. Capture regulatory staffing levels with a view to establish a "baseline" (as-is situation) for Women in the regulatory sector.

The survey structure is shown in the figure below:

[24] A total of 31 potential respondents

Figure 20: Survey Structure



The initial responses, summarised below, provide insight into:

1. Staff, Training & Tools;
2. Classic Skills;
3. Emerging Skills; and
4. Women in Energy.

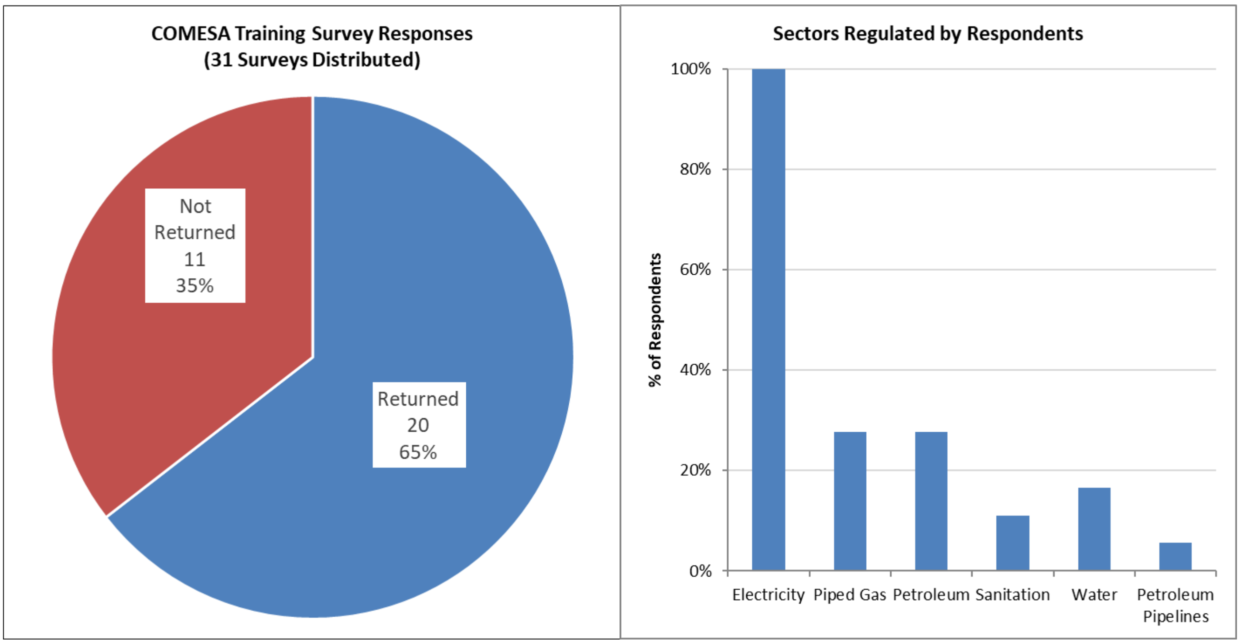
The survey respondents, are shown in the table below:

Figure 21: Regional survey respondents

Respondents (20)		
Southern Africa (9)	Eastern Africa (8)	Indian Ocean (3)
Botswana DRC Eswatini Lesotho Malawi Mozambique Namibia South Africa Zimbabwe	EAPP Egypt Ethiopia Kenya South Sudan Tanzania Tunisia Uganda	Madagascar Mauritius Seychelles

The figures below show the survey response rate as well as providing some insight into the response rates per regulated sector (e.g. electricity, water, gas etc.):

Figure 22: Regional survey response rates comparison



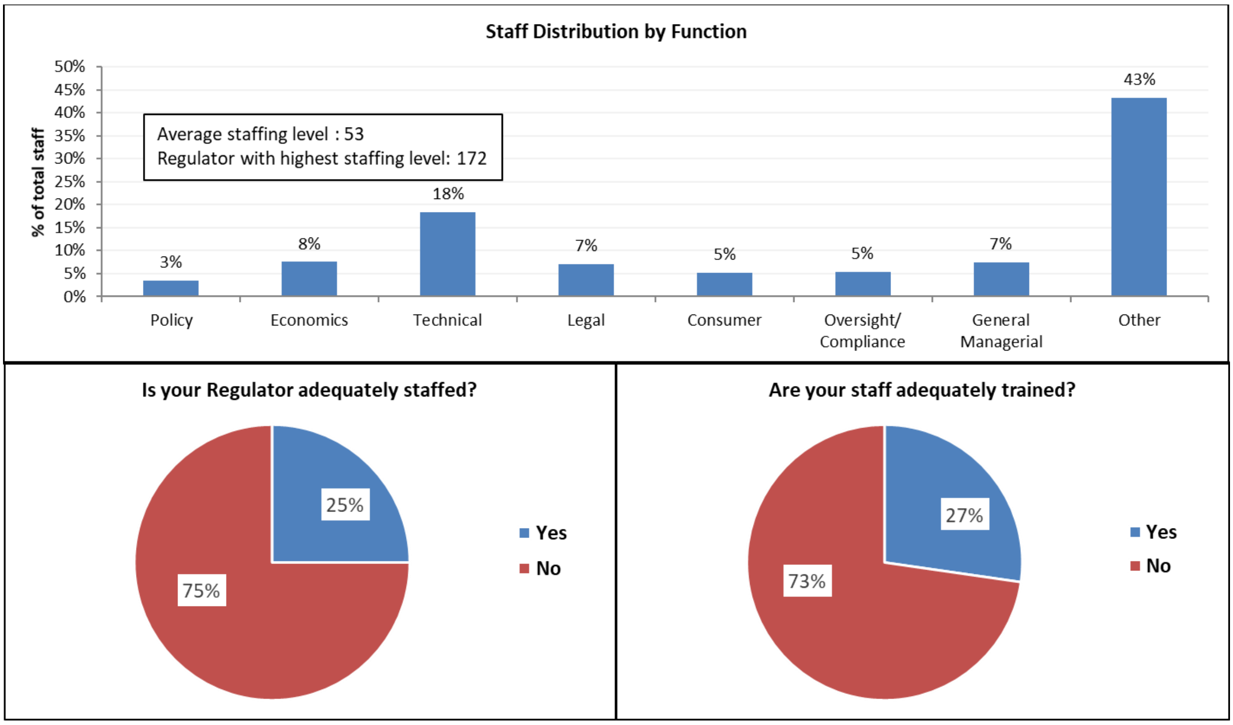
The figure shows that the survey had a total response rate of 65% i.e. 20 out of 31.

It is interesting to note that 100% of the respondents regulate their electricity sector, with some also responsible for piped gas, petroleum, water and sanitation. Whilst some of the survey questions relate to generic regulatory skills, there are several which deals specifically with issues that are only relevant to the electricity industry.

7.3 Responses: Staffing Overview

The initial portion of the survey is dedicated to determining the type of staffing levels that can be found in the respondents' organisations. The key results are summarised below.

Figure 23: Staff levels and skills analysis

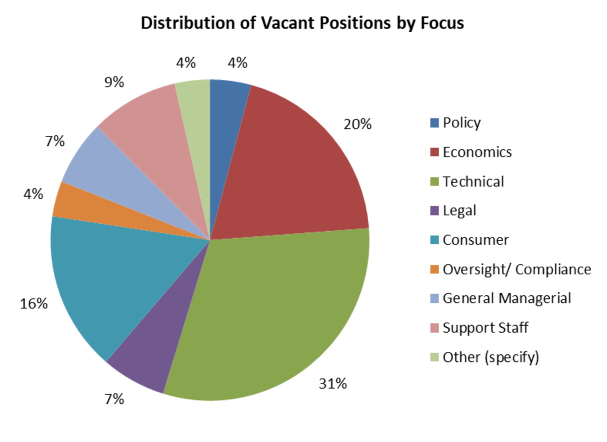


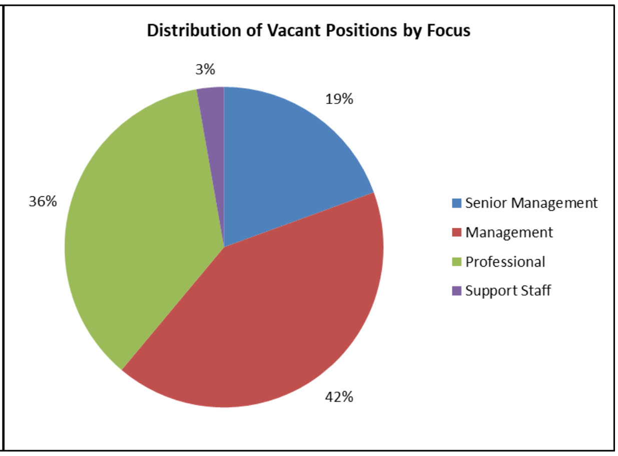
The figures above show:

1. The highest staff complement amongst the 13 respondents for this section of the survey was 172 and the average number of staff was 53. These values exclude staff vacancies. Including vacancies, the average staff complement was 65.
2. Staff with a technical role, made up the largest component (at 18%) of total staff, followed by economics, legal and general managerial (all 7%) – there was a large number of staff (43%) that had functions which fell outside of the categories listed above. These 'other functions' include finance, procurement, audit, risk and corporate planning and human resources which could be seen as part of Support Functions.
3. A critical finding of this section of the survey is that the majority of respondents felt that their organisations were neither adequately staffed, nor appropriately trained.

Respondents also provided some information on the staff vacancies as shown in the figures below:

Figure 24: Staff Vacancy Analysis





The responses show that:

1. The majority of vacancies are for management and professional staff – a total of 78% of total vacancies.
2. An assessment of the distribution of vacancies by focus, reflects that technical support staff have the most vacancies at 31%, closely followed by vacancies for economics and consumer related affairs – these three areas comprise 67% of total vacancies by focus.
3. The remaining 33% of vacancies are fairly evenly distributed amongst the other staff functions.
4. Staff vacancies have a serious impact on organisations and prevent them from discharging all their duties and responsibilities within acceptable time periods and the appropriate quality standard. It also places additional workload on the remaining staff resulting in an overworked and stressed workforce and an unhappy and unhealthy work environment.

7.4 Responses: Skills Assessment

7.4.1 Skills Assessment Approach

The overall skills level assessment[25] was conducted by checking the respondent's abilities across four key domains, as shown in the table below:

[25] As the average score across the four domains

Understanding	The regulator's theoretical understanding of the topics and issues; the regulator's ability to assess and suggest the most effective options given local requirements
Development	The regulator's ability to develop and apply their knowledge and experience in this area to specific relevant regulatory issues; provide input to frameworks, processes, methodologies, rules, policy and planning; assess and report on the impact of regulatory and policy decisions
Maintenance	The regulator's ability to maintain and adjust regulatory frameworks, processes, methodologies, rules, policy, planning and decisions in line with evolving global and local standards and requirements
Monitoring & Measuring	The regulator's ability to consistently monitor and report on frameworks, processes, methodologies, rules, policy, planning and decisions in order to inform and support the understanding, development and maintenance processes.

The scale and scoring system, had four levels as shown below:

Minimal skill	0	Respondent is a novice and requires significant training before he/she is able to function and perform at an acceptable level.
Some skill	1	Respondent has limited but insufficient skills to fulfil the tasks expected by the job.
Adequate skill	2	Respondent holds sufficient skills to undertake typical and routine tasks required by the function and position.
Expert skill	3	Respondent possesses and is able to apply highly proficient and specialised skills to tasks that are varied, complex, and/or non-routine.

Finally, the skills development needs are then based on the scores shown below. For the purpose of this skills assessment exercise the absolute score is not important, what matters is the relative score. Put differently, a lower score is an indication of a higher need for training. Lower scores are therefore an indication of a potential training area:

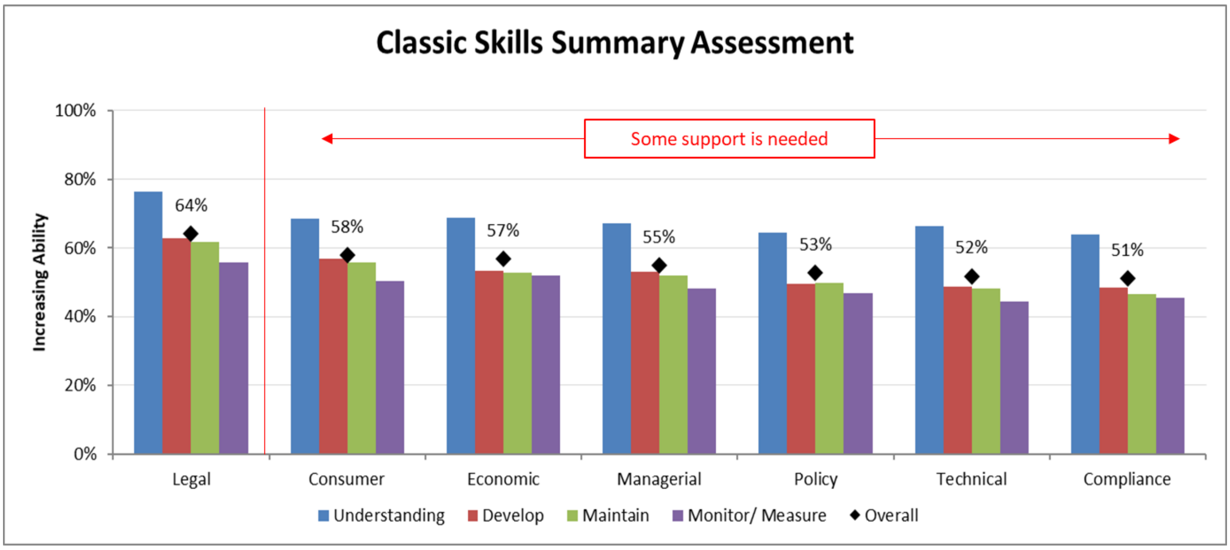
- <u>> 60% Ability score:</u> Limited training required
- <u>50% - 60% Ability score:</u> Training is required
- <u>< 50% Ability score:</u> Significant training is required

7.4.2 Classic Skills

The Classic regulatory skills assessment results show that respondents, on the average, believe they have adequate skills to meet the demands of most "classic" regulatory requirements. Classic skills include those areas in which regulators have traditionally been required to demonstrate competence: the roles of various stakeholders, policy impact, competition vs. regulation etc.

On average one would expect regulators to demonstrate relatively higher skills in these areas, when compared with those skills required in "emerging" or new regulatory areas. In this section, when their skills levels are broken down further (i.e. beyond the average), it becomes clear that most of the staff have a good understanding of the concepts being assessed. However, they felt that their ability to develop, maintain and monitor each area, required further training and support.

Figure 25: Classic skills summary assessment

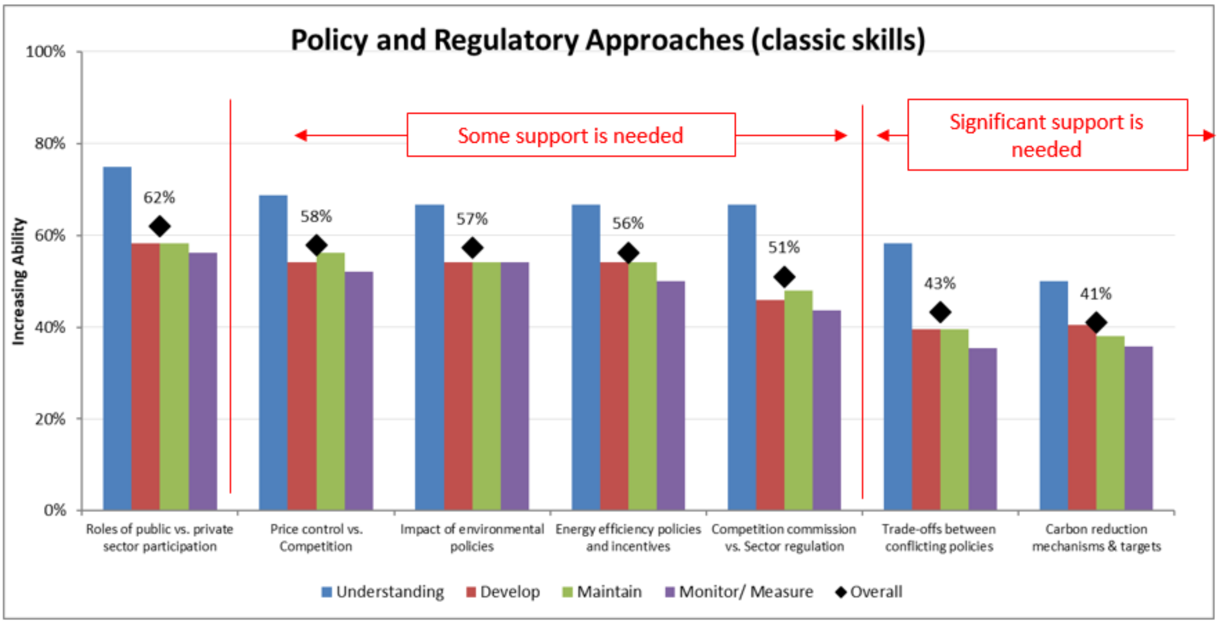


A summary assessment of all the classic skills surveyed, shows that:

1. On average, regulators feel that their legal skills are strongest and only limited training is needed for this skill;
2. All other classic skills require further training support (50% - 60% ability score); and
3. Classic "compliance" and "technical" skills received the lowest scores and require the most training support – this also aligns with regulators initial assessment of those areas which require the most support, as indicated above in Section 7.3.

Below follows a review and assessment of the detailed responses underpinning the Classic Skills Summary Assessment.

Figure 26: Survey responses: classic policy & regulatory skills



For policy and regulatory approach skills:

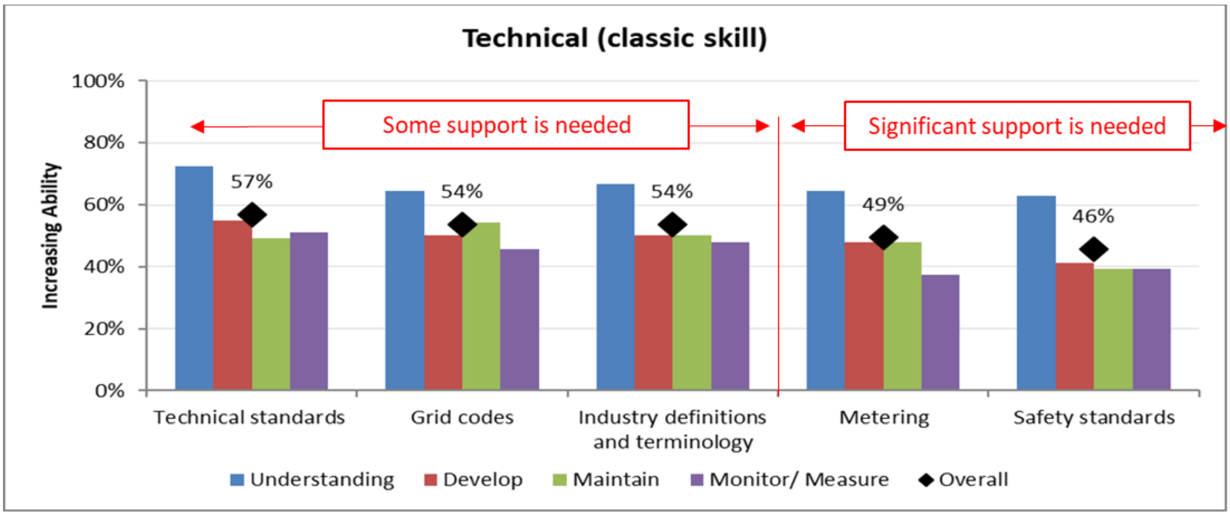
1. On average, respondents felt most comfortable with the differing roles of the public and private sector in their electricity service industry (left hand side of the figure above);
2. However, they were much less comfortable with managing trade-offs between conflicting policies and carbon reduction mechanisms (right hand side of the figure above) – these skills require significant training support; and
3. As noted above, a score of between 50%-60% indicates that some further training is required – the figure above indicates that most of the areas assessed require some training including: environmental policies; price control vs. competition; energy efficiency and the benefits of competition vs. regulation.

The skills breakdown analysis also shows the disconnect between the skills of understanding and application (i.e. develop, maintain and monitor). The black diamond in each bar graph represents the average skill level. The highest average skill on the left of the graph has an average skill level of 62%. It is clear that regulators' "understanding" of the issues is well above the 62%; however, their "development" and "maintenance" is at 58% and their ability to "monitor" is at 51%, well below the average.

This pattern is reflected across all of the "classic" skills areas assessed, with "understanding" consistently above the average and the other three areas below the average. It is important to note that the results presented in this section reflects the skills assessment and hence training needs, for an "average" regulator - the skills assessment and training needs for an individual regulator may differ substantially from the "average". However, it is surprising that on average, regulators self-assessment indicates that they would benefit from training across all of the skills areas surveyed.

Regulators' responses to the survey on "classic technical" skills, is shown in the figure below:

Figure 27: Survey responses: classic technical skills

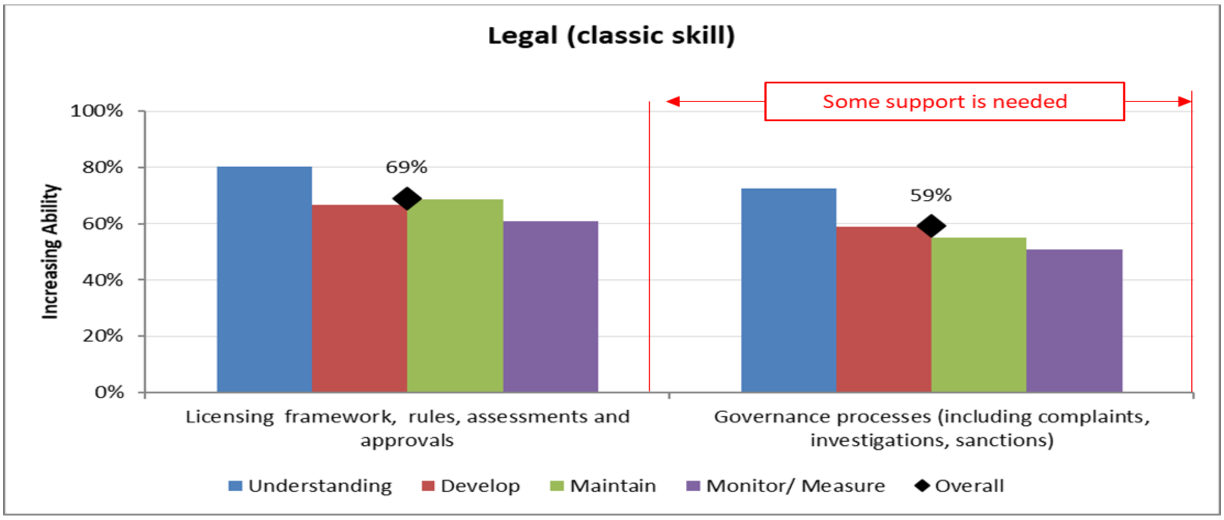


As has been discussed above, technical skills are considered one of the weakest of all the classic skills surveyed.

1. A surprising result from the survey is the need for significant support with metering and safety standards - this could be linked to the introduction of new VRE technology, pre-pay and smart meters, as well as issues around net-metering and net-billing for rooftop PV systems;
2. Another technical area in need of significant training is "Safety standards". Setting appropriate safety standards is of course fundamental to the key responsibilities of regulators. This together with the deployment of new distributed generation technologies in general and "behind the meter" generation in particular the need for training in safety standards are understandable;
3. As with the policy and regulatory approach skills above, technical understanding is consistently higher than development, maintenance, and monitoring; and
4. The one exception is that on average, regulators feel that they are better able to maintain grid codes, than they are able to develop them or monitor gird code compliance. Grid codes are

relatively well-developed regulatory rules in most of the markets surveyed, which could explain the response.

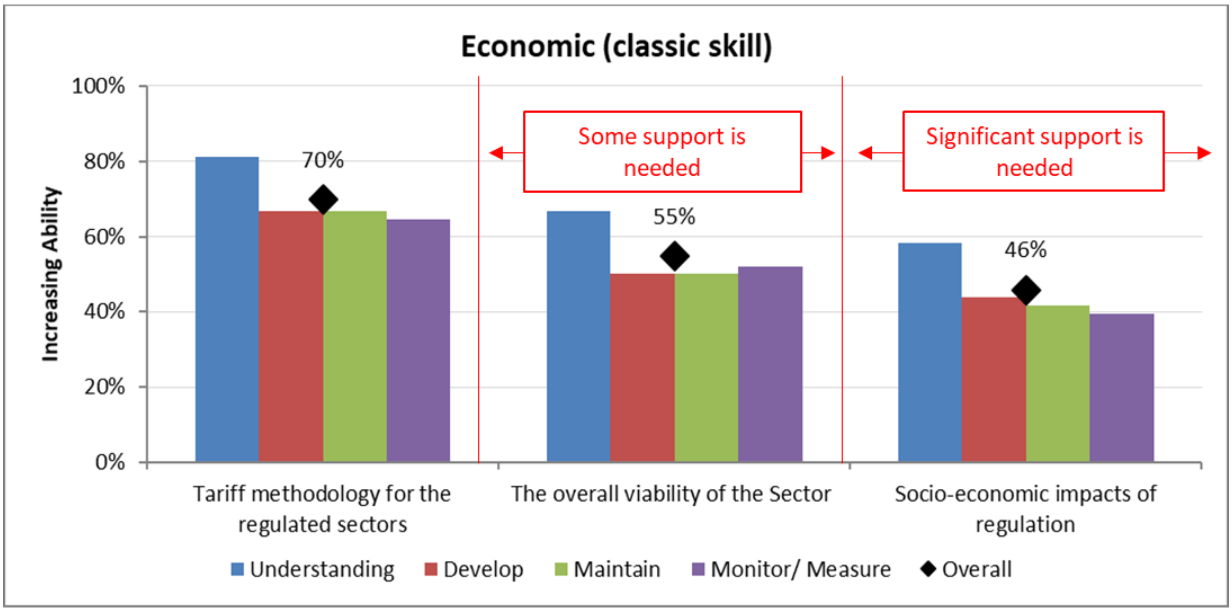
Figure 28: Survey responses: classic legal skills



The results show that overall “classic legal” skills seem adequate and only limited training is needed on governance processes.

Classic economic skills survey responses are shown in the figure below.

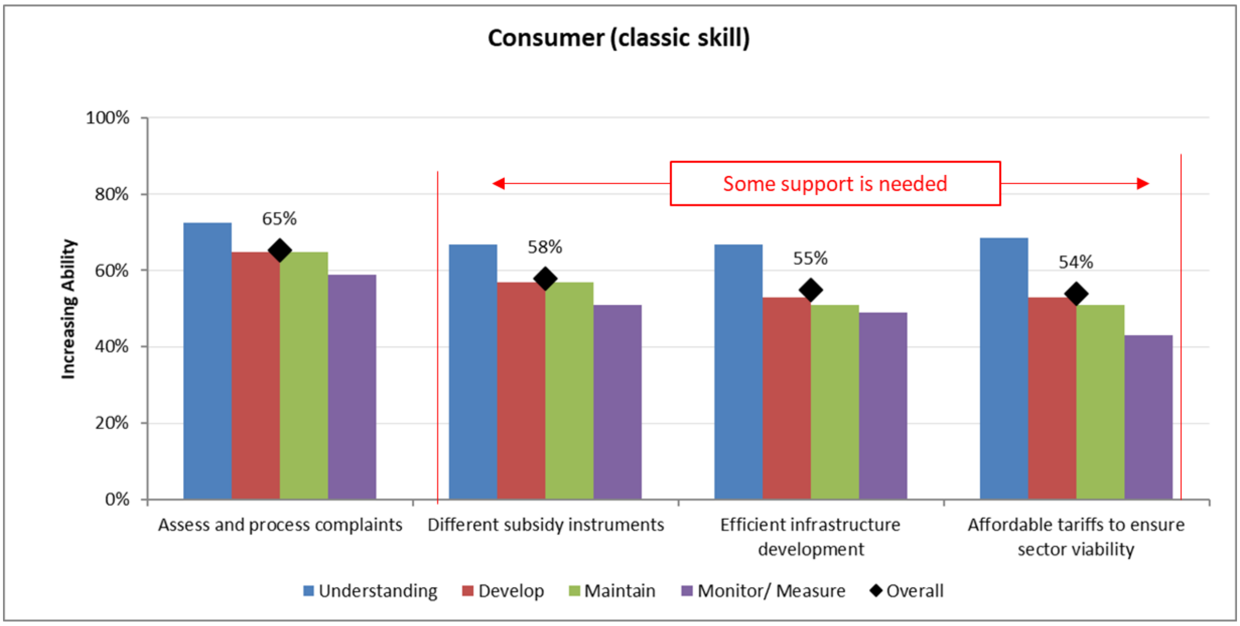
Figure 29: Survey responses: classic economic skills



Of all the classic regulatory skills assessed, regulators are most comfortable with tariff methodologies.

1. Historically, this has been one of the key functions of regulators in the electricity supply industry and it is therefore not surprising that tariff skills levels are the highest of all the classic skills areas; and
2. Some training support is required for ensuring the overall viability of the sector and significant support is required for improving skills on quantifying socio-economic impacts of regulation. The latter is arguably one of the more difficult areas of regulation as it requires a solid understanding of economics and econometric modelling.

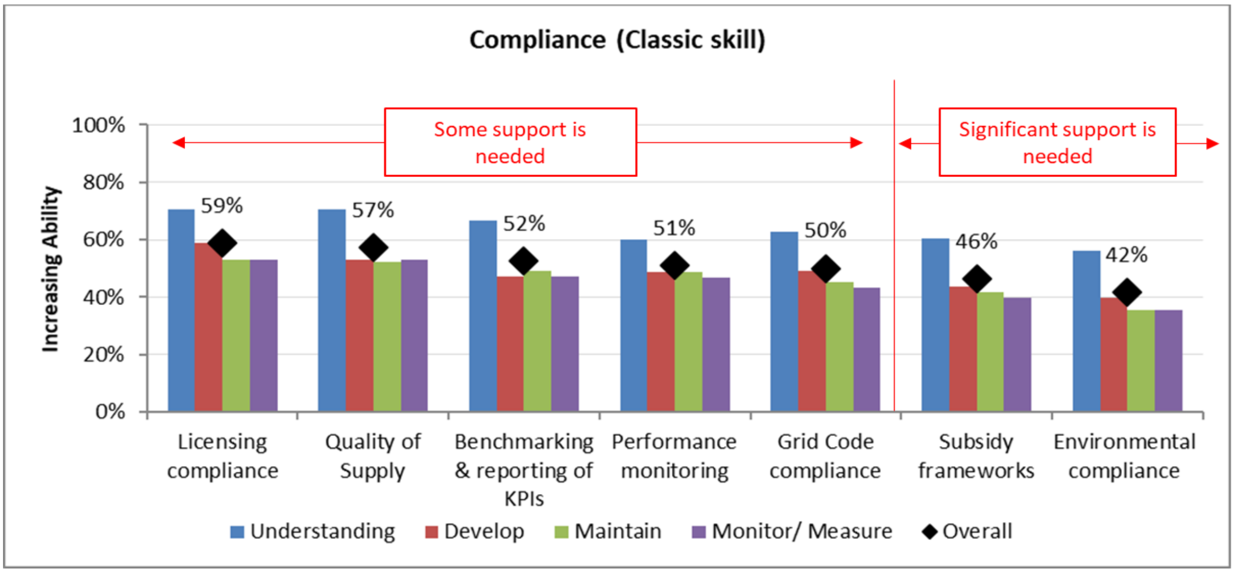
Figure 30: Survey responses: classic consumer skills



The Consumer skills assessment shows that:

1. Some training is required on subsidy instruments, efficient infrastructure development and affordable tariffs; and
2. On average regulators indicated that they were most comfortable with assessing and processing of complaints.

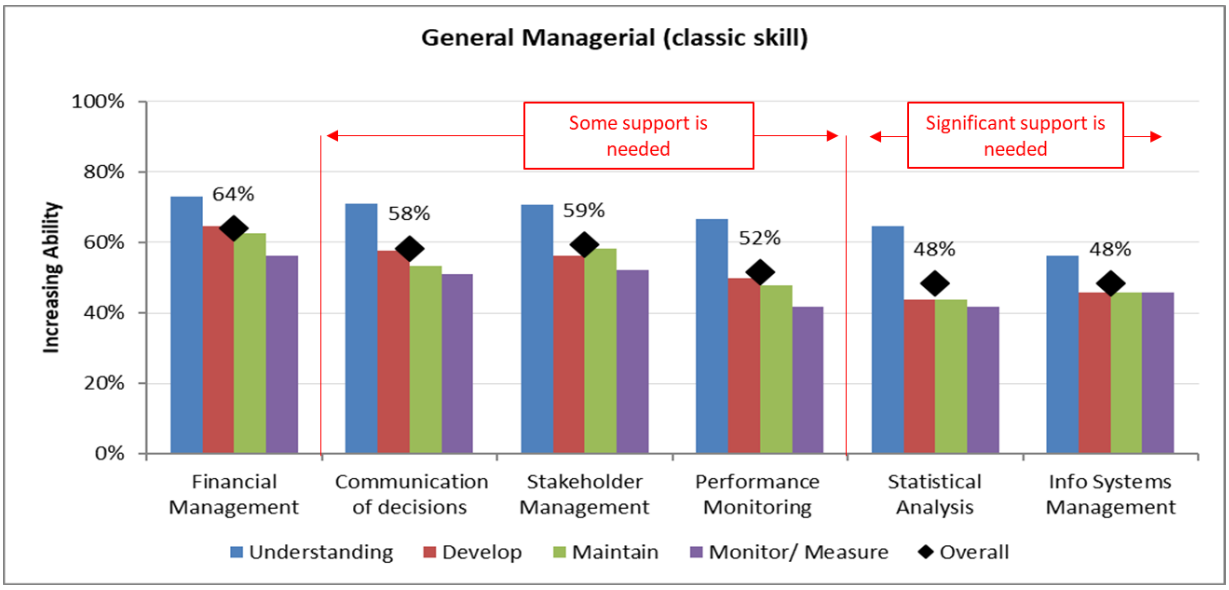
Figure 31: Survey responses: classic oversight & compliance skills



The oversight and compliance assessment shows that:

1. On average, regulators believe that they would benefit from training across all skills areas;
2. The skills which require the most training support include subsidy frameworks, grid code compliance and environmental compliance; and
3. Although regulators felt that they understood the impact on environmental policies, the two skills areas which have scored the lowest of all the skills assessed, are environmental compliance and emissions reductions mechanisms. Environmental issues are becoming increasingly important to all stakeholders in the electricity industry and this is also reflected in the emerging skills survey on the area of VRE.

Figure 32: Survey responses: classic general managerial skills



General managerial skills were the final area surveyed in the classic skills assessment. The survey shows that:

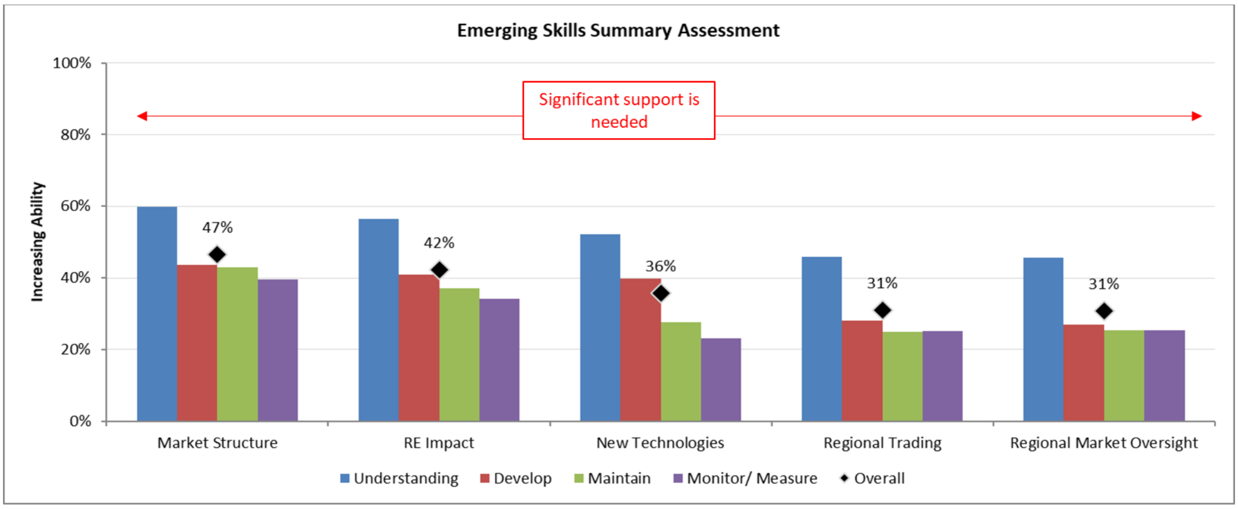
1. Only financial management requires limited training support;
2. Communications, stakeholder management and performance monitoring would benefit from some further training support; and
3. The skills areas which require the most significant support are statistical analysis and information systems management.

7.4.3 Emerging Skills

The demand for regulatory skills is constantly evolving in response to a changing external environment. Market reforms, and the availability of new generation resources, including low cost solar PV and wind, are changing the way electricity is generated, transported and traded. The increase in cross-border trade and the expanding footprint of regional markets are also placing new demand on regulators. This section therefore assesses the regulators' ability to respond to these new and "emerging" market challenges. This section of the survey followed the same evaluation approach as outlined in the previous section on "classic" skills assessment.

This section begins by presenting the emerging skills summary assessment it then follows up with a detailed assessment of the underlying results.

Figure 33: Survey responses: emerging skills summary assessment

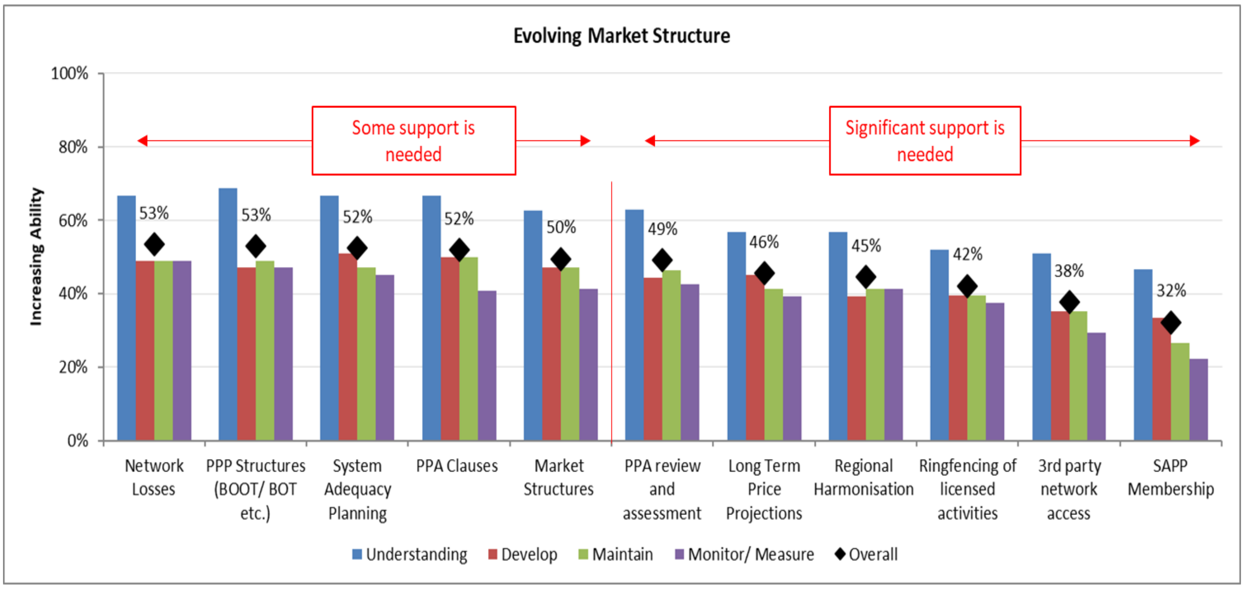


The summary assessment shows that:

1. Overall the average skills are significantly lower than in the classic skills assessment;
2. Trading and market oversight skills have the lowest overall score and require the most training support; and
3. Market structure is the area with the highest average skills assessment.

The detailed responses and analysis of the results from the emerging skills section of the survey, are shown in the figures below.

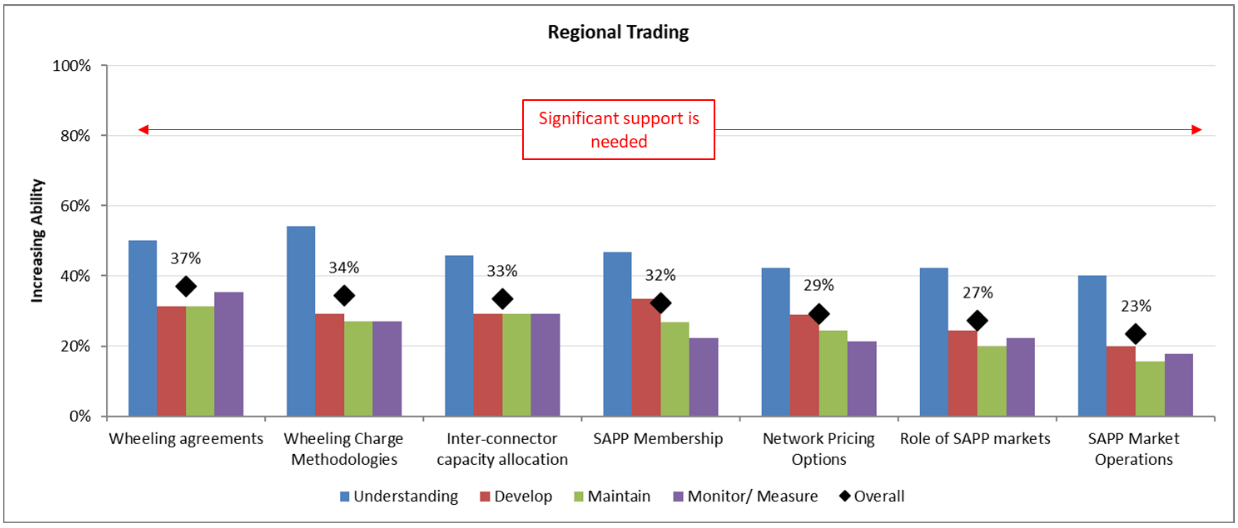
Figure 34: Survey responses: emerging market structure skills



The figure shows that:

1. The overall ability across all the dimensions are relatively low with no score over 55% - this is to be expected as regulators have had less time to develop these skills compared with the "classic" regulatory skills;
2. Many of the regulators have a reasonable understanding of the issues but few are able to develop, maintain and monitor; and
3. All areas require support with several areas that require significant support – skills relating to wheeling and SAPP membership have the lowest rating, below 40%.

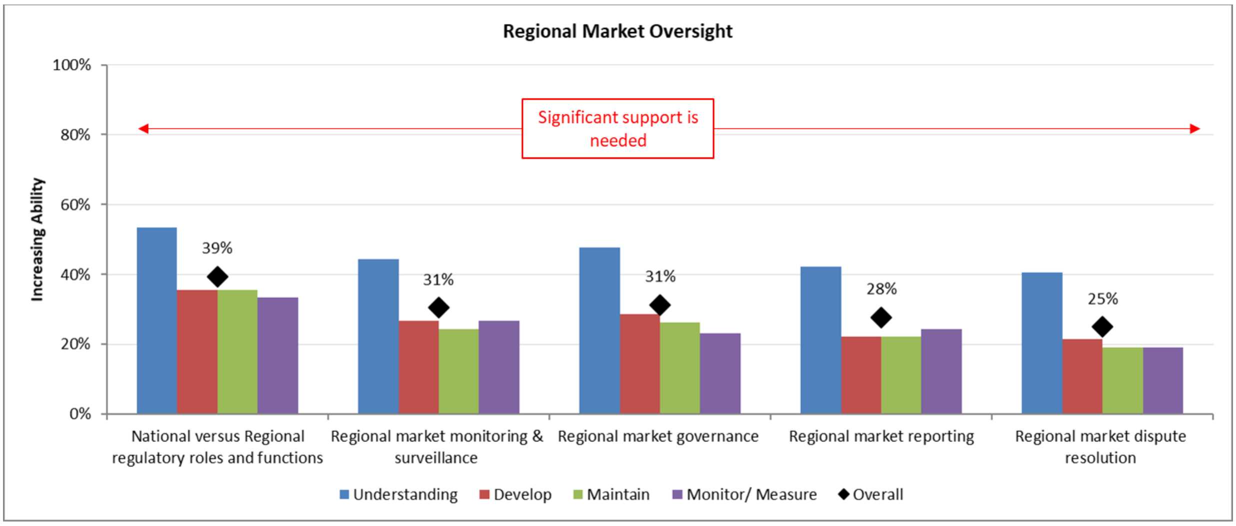
Figure 35: Survey responses: emerging regional trading skills



The figure shows that:

1. This is an area that requires significant training support as evidenced by the low average overall scores (23% to 37%);
2. Of the skills surveyed, on average, understanding of wheeling methodologies has the highest score with 54%;
3. It is interesting to note, that in some instances, regulators are more confident in monitoring key issues, than in developing or maintaining them – this is different to the classic skills where monitoring/measure was consistently lower than other skills;
4. Although not all countries surveyed are connected to the SAPP, many of the surveyed countries are - the low skills levels are therefore surprising given that SAPP is expanding with Tanzania and Kenya becoming interconnected into the SAPP the near future; and
5. Regional markets can play an important role not only in reducing cost but can assist in improving security of supply and reduce load-shedding.

Figure 36: Survey responses: emerging regional market oversight skills

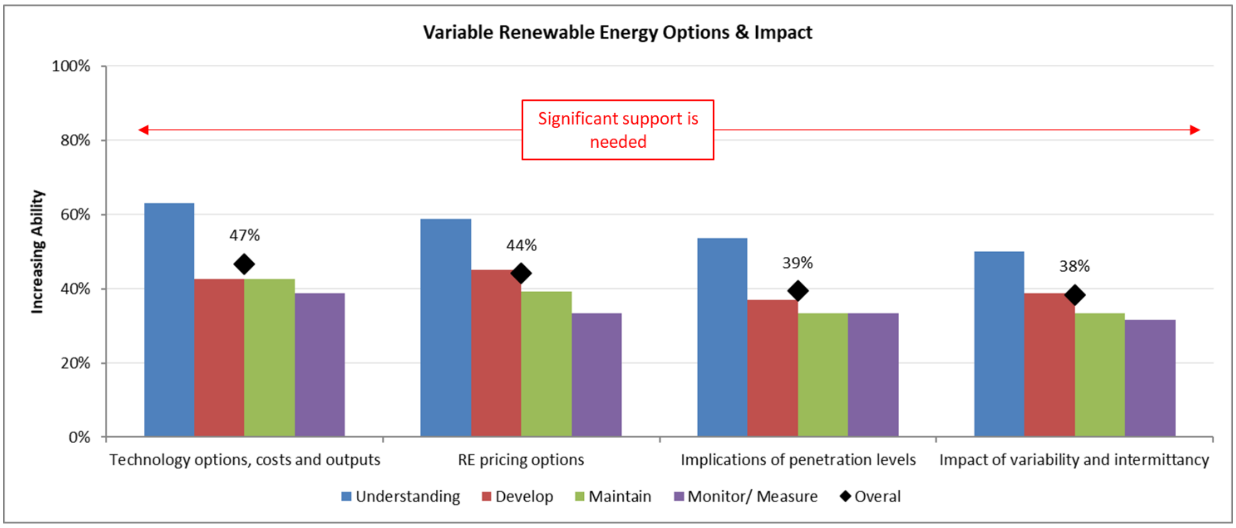


The responses show that:

1. As with the regional trading skills, regional market oversight skills require significant training support;
2. None of the skills show and average level greater that 40%; and

3. Market reporting and dispute resolution require the greatest support.

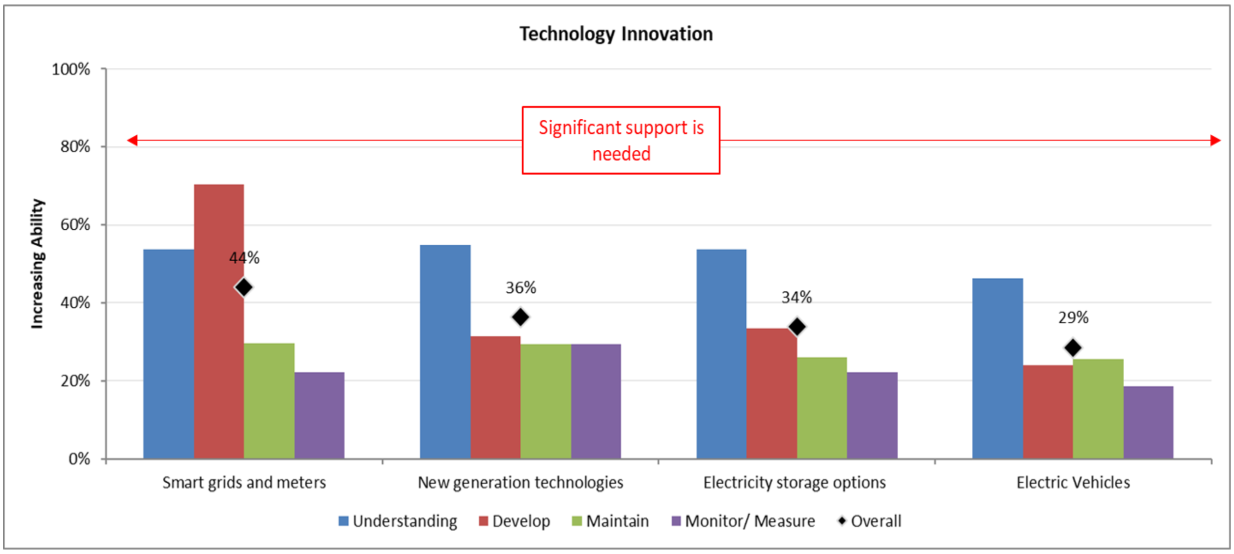
Figure 37: Survey responses: emerging VRE skills



It is clear from the results that:

1. Regulators need significant support to deal with the introduction of VRE sources; and
2. VRE are excellent resources but large deployment poses certain technical, commercial and tariff challenges to regulators.

Figure 38: Survey responses: emerging technology innovation skills



The survey results show that:

1. Smart grids and smart metering have the highest skill level in this section;
2. Regulators have indicated that they are better able to develop smart grids and metering regulation, than they are to understand these issues – this is counter-intuitive and may be due to support from external sources (e.g. consultants, development agencies etc.);
3. The emerging phenomenon of electric vehicles shows the poorest average skills level across all skills areas.

These survey results overwhelmingly suggest that the majority of regulators need to improve their skills and abilities to deal with emerging requirements. Skills in respect of regional trading and new technologies are particularly low and will require urgent attention if countries want to responsibly harness the benefits of regional trading opportunities and new technologies that can reduce costs and tariffs, and accelerate electrification.

7.4.4 Core Competencies

The survey contained an assessment of core competencies that are generally required by regulators. These include:

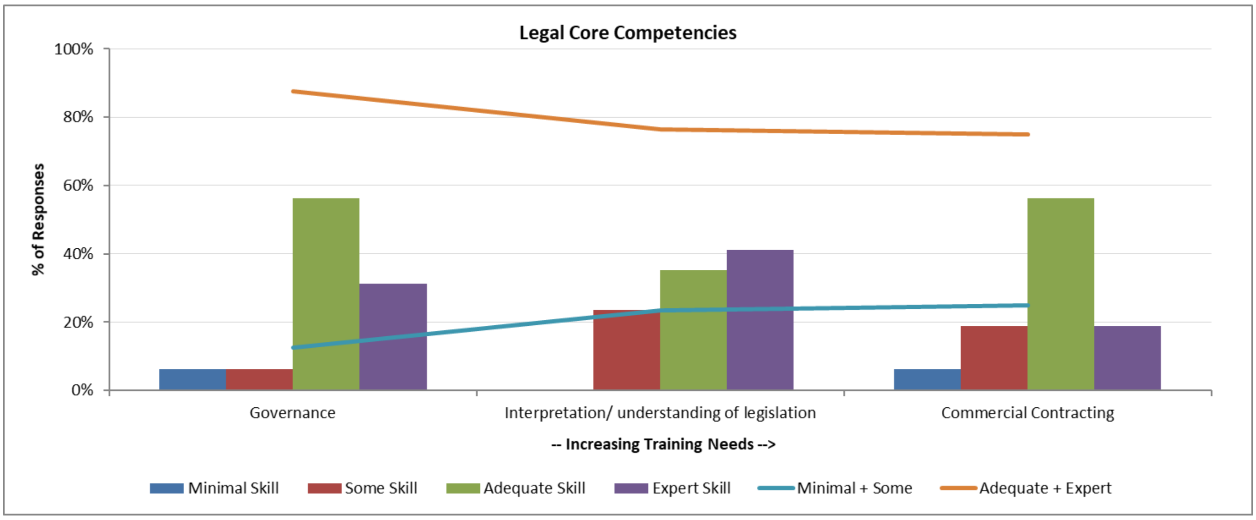
1. Legal;
2. Technical;
3. Financial & Economic; and
4. General Business.

Core competencies relate to skills that are not subject specific e.g. a legal core competency may be described as "Commercial Contracting', which is a skill which could be applied to many different aspects of a regulator's business. This is in contrast to the subject specific "classic" and "emerging" skills assessment shown above.

For each of the competencies, regulators were asked to assess their skills as:

1. Minimal (the lowest);
2. Some;
3. Adequate; and
4. Expert (the highest).

Figure 39: Legal Core Competencies

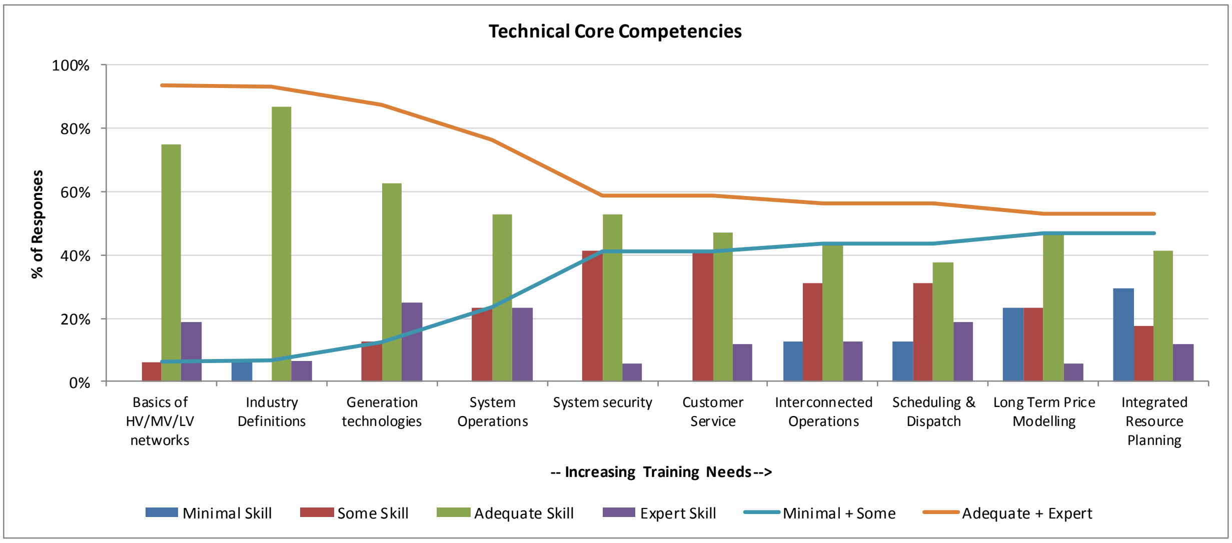


For the figure above:

1. The bar graphs represent the percentage response by skill level for each competency;
2. The brown line shows the total score for the "adequate + expert" skills assessment while the blue line shows the total score for the "minimal + some" skills assessments. The two lines always add up to 100%. The lines therefore provide an overall reference for the training requirements of each competency with the bars showing the detailed results;
3. In the figure above for the "governance" competency on the left, the majority of regulators felt they had adequate (green bar) or expert skills (purple bar) – they therefore need the least training on governance issues in this competency;
4. As one moves across the x-axis from left to right, training needs increase as reflected by the blue line;
5. The higher the "adequate + expert" skill, the less training support is required – in the figure above, the "adequate + expert" line is over 80% for governance, whilst the "minimal + some" line is under 20%;
6. In general, as the lines converge towards the middle of the graph, more training is required – one can therefore observe that interpretation of legislation and commercial contracting require more training than governance;

7. The legal core competencies responses show that the lines only converge slightly and therefore less overall training is required; and
8. Commercial contracting on the right of the x-axis requires the most training support in this competency.

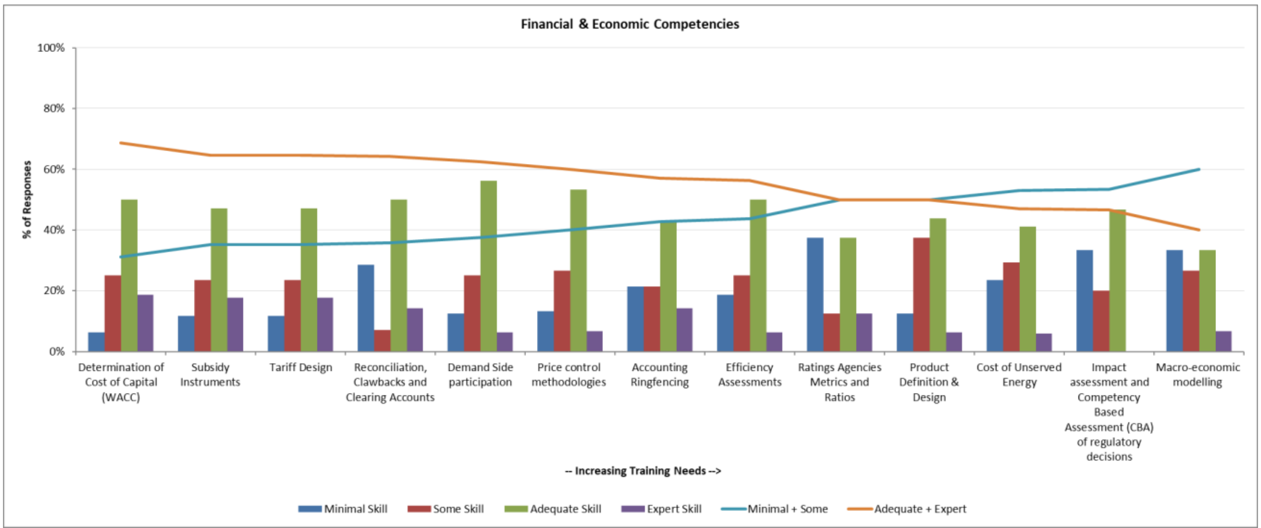
Figure 40: Technical Core Competencies



The technical cost competency survey shows:

1. There is a basic level of competence regarding some of the more fundamental technical skills, however as the competencies become more complex, more training is clearly required;
2. From the middle of the x-axis in the figure above (Long Term Price Modelling) to the right of the figure, the lines converge, indicating a significant requirement for training in those core competencies; and
3. The top three competencies requiring further training are interconnected operations, scheduling & dispatch, and integrated resource planning.

Figure 41: Financial & Economic Core Competencies

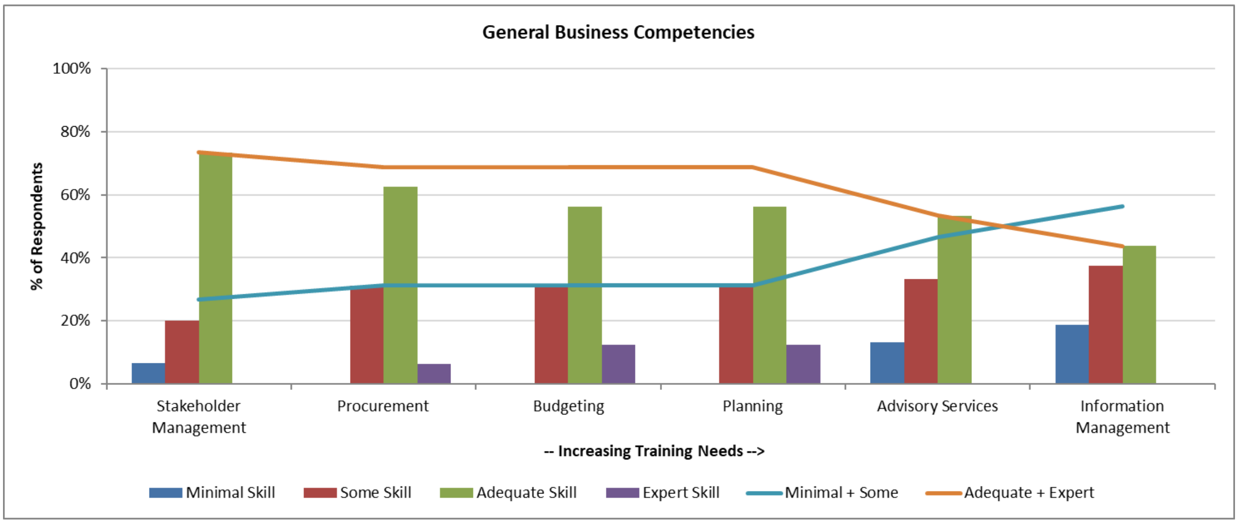


The financial and economic competency assessment showed that:

1. There are a wide range of economic and financial skills that require competencies in regulators;

2. In general, most of the competencies require further training support – showed by the converging and eventual cross-over of the lines in the figure - the most competence was shown around price control methodologies and even this skills area had a 60% to 40% split between adequate/expert and minimal/some; and
3. Economic impact assessment and modelling competencies generally require the most training support.

Figure 42: General Business Competencies



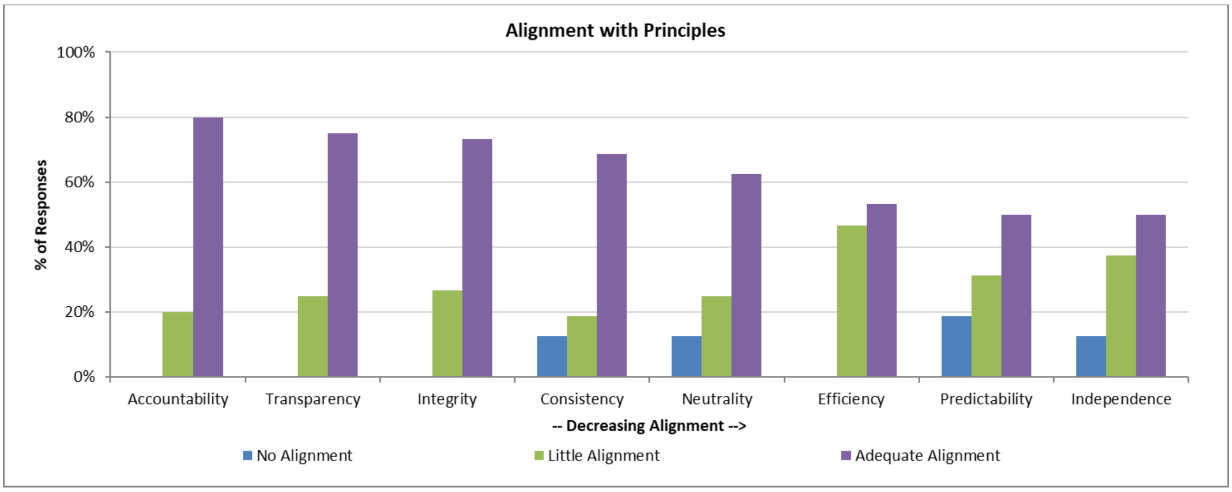
The general business competency shows that:

1. In general, regulators feel comfortable with their level of general business skills; and
2. Two areas that require significant support are advisory services and information management, which shows the highest requirement for training of all the core competencies measured.

7.4.5 Alignment with Principles

Many regulators subscribe to specific principles which define their objectives, approach and their methods of regulation. The principles shown in the figure below are widely acknowledged as guiding the actions of regulators:

Figure 43: Alignment with regulatory principles



The figure shows that:

1. In general, regulators believe that on average, the majority of their organisations are adequately aligned with the principles of transparency; accountability; consistency, integrity, and neutrality;

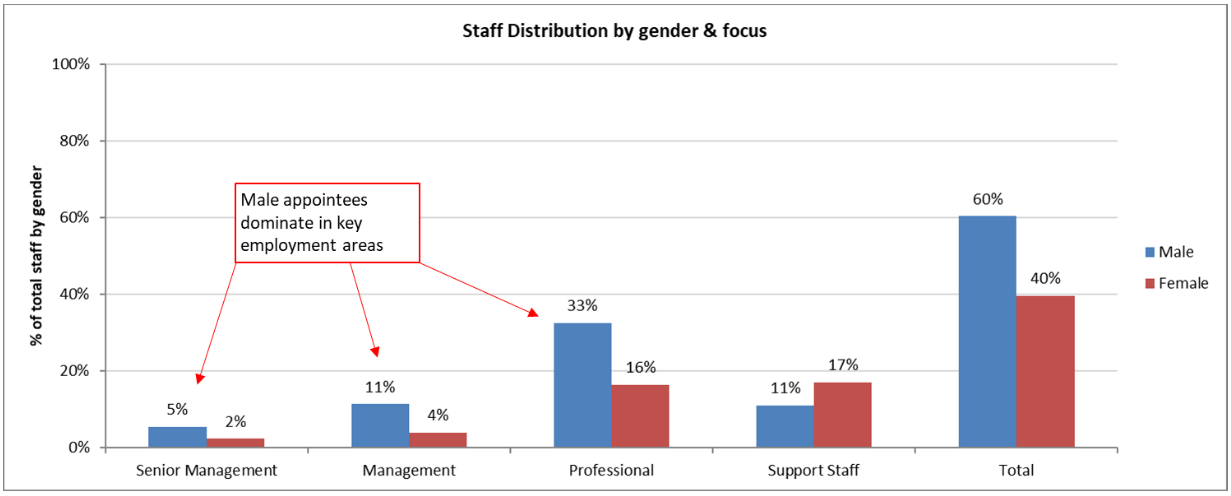
2. It is interesting to note that approximately half believe that they are adequately aligned with the principles of efficiency, predictability and independence;
3. It is somewhat concerning that some regulators feel their organisations are not aligned with the principles of: consistence, predictability and independence; and
4. Not surprising is the principle where regulators feel they are least aligned to is independence followed by predictability.

7.5 Responses: Women in Energy

7.5.1 Baseline for Women in Energy

It is widely acknowledged that women can add considerable value to the energy sector but that they are currently under-represented at many levels but particularly at senior levels. The objective of this section of the survey is to develop a benchmark or reference which reflects the current role of women in the energy regulatory environment. The results are shown below and are based on the responses from 13 regulators with a combined staff complement of 689.

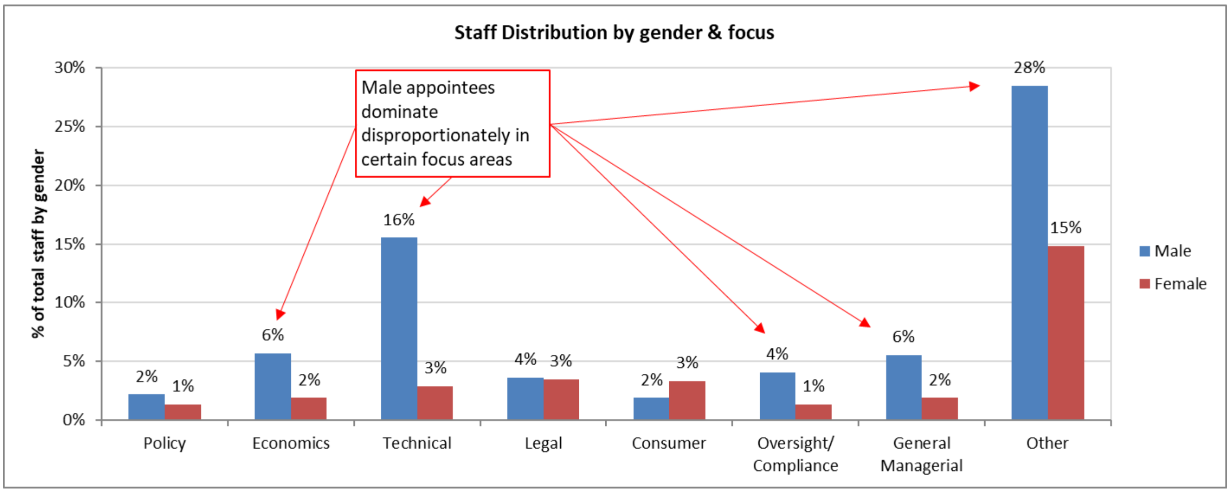
Figure 44: Survey responses: women in energy staff gender distribution & role



The results show that:

1. Male employees far outweigh (more than double) the number of female employees in key employment areas such as Senior Management, Management and Professionals;
2. It is only in the area of Support Staff where the number of female employees exceed the number of males;
3. Overall females only represent 40% of the workforce; and
4. The above results confirm the perception that female employees are under-represented in key positions.

Figure 45: Survey responses: women in energy staff gender distribution & focus



A detailed assessment at the gender distribution by focus area shows that:

1. Male staff are disproportionately represented in certain areas, with notable differences in economics, technical, oversight, general managerial and other; and
2. Female staff only exceed male staff in consumer related roles.

7.5.2 Organisation Readiness Assessment

A significant body of international research exists on the promotion of Women in Energy. This research formed the basis of the assessment of Women in Energy amongst the regulators that took part in the survey. Below is a brief outline of the assessment areas that formed the foundation of the assessment.

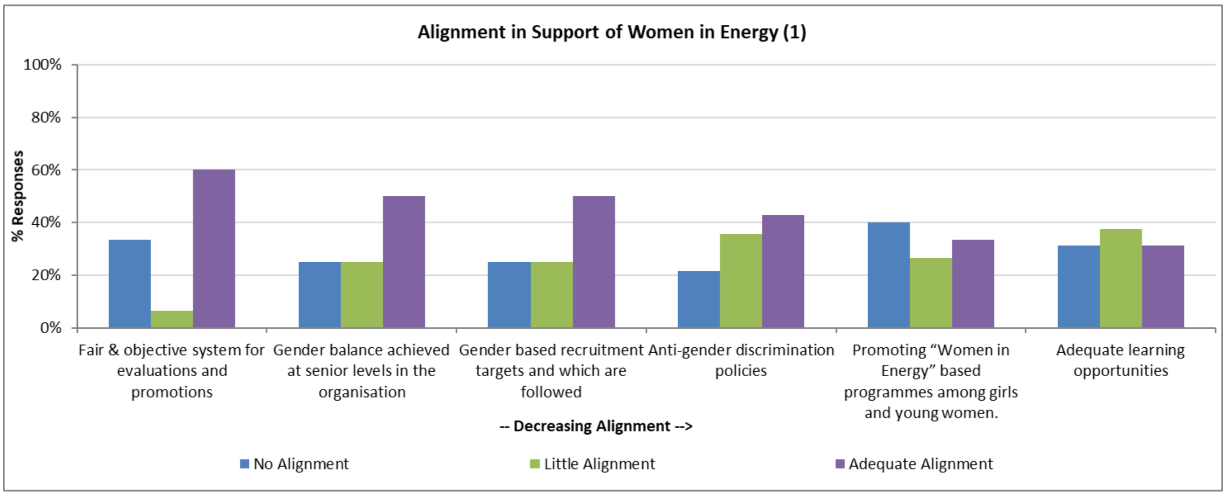
1. Does your organisation have a fair & objective system for evaluations and promotions?
2. Has your organisation achieved gender balance at senior staffing levels?
3. Has your organisation set gender-based recruitment targets and are they followed?
4. Has your organisation developed and implemented anti-gender discrimination policies?
5. Has your organisation adopted specific “Promoting Women in Energy” based type programmes among girls and young women?
6. Does your organisation offer adequate learning opportunities?
7. Have your organisation put in place female mentorship and sponsorship programs?
8. Does your organisation offer bias awareness training?
9. Does your organisation provide support to women seeking career advice?
10. Has your organisation adopted flexi-time and/or part-time employment practices?
11. Has your organisation adopted performance linked KPIs to measure progress of women?
12. Does your organisation offer gender-based bursary opportunities, have targets been set and are these targets followed during bursary awarding process?

The responses to these questions were provided as:

1. No alignment;
2. Little Alignment; and
3. Adequate alignment.

The regulators’ responses are shown below in two separate figures, for ease of reference.

Figure 46: Survey results: women in energy (1)

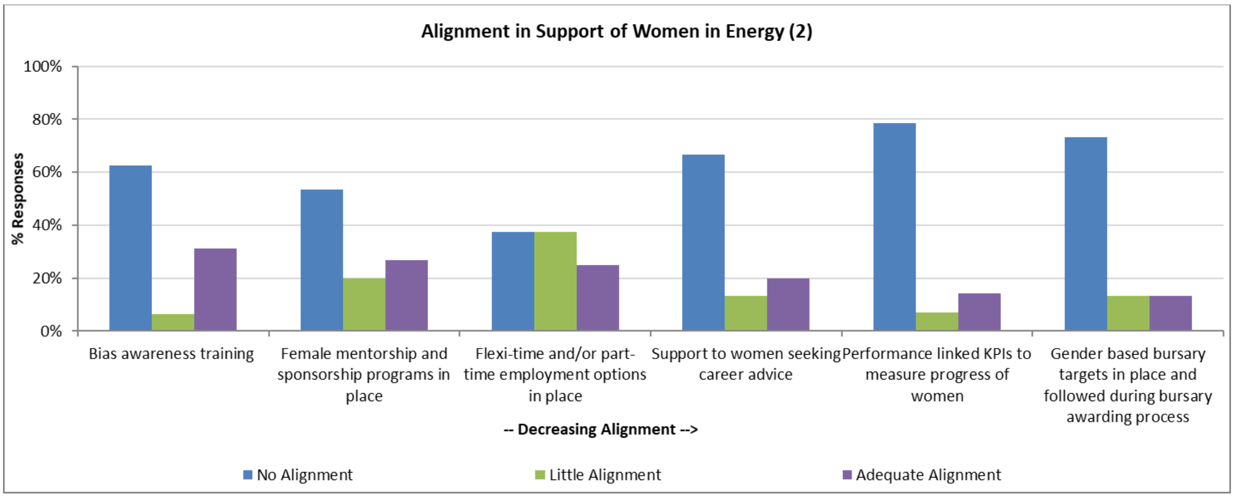


The survey responses show that:

1. For many of the queries, there was a wide distribution of responses, indicating that alignment on issues is not consistent amongst regulators e.g. the question on "objective systems for evaluation and promotion", recorded the highest adequate alignment at 60%; however, 40% also felt that there was little or no alignment; and
2. The areas which reflected the lowest levels of alignment include:
    a. Anti-gender discrimination policies.
    b. Programmes promoting "Women in energy".
    c. Adequate learning opportunities.

The second set of responses are shown in the second figure below. Overall, the queries below show less alignment than the first set of queries in the figure above.

Figure 47: Survey results: women in energy (2)



The figure shows that:

1. In all of the responses in Figure 47 above, there is clearly less adequate alignment on the issues; and
2. There is less than 20% adequate alignment for: women seeking career advice; performance KPIs to measure progress of women; gender-based bursary targets.

The overall results of the survey provide an indicative benchmark for the current status of women in energy. The overall results of the survey indicate that:

1. The ratio of male staff to female staff is 3:2;

2. Male staff are disproportionately represented in certain functional areas including technical and senior management staff; and
3. There is considerable mis-alignment within regulators on practices or objectives aimed at supporting the development of women in energy – the issue showing the highest alignment (fair and objective system for evaluations and promotions) only showed 60% “adequate” alignment with 40% stating that on this issue, their regulator has “little” or no “alignment”.

Given the overall level of misalignment in this benchmark study, it can be concluded that there is a significant opportunity within COMESA to address these issues for the future.

During the Validation Workshop with the stakeholders on this project, one of the delegates noted that: a) women are often prevented (or excluded) from doing certain types of work or that b) women are being harassed in the workplace. The first obstacle is a good example of gender bias in that some male workers are of the view that women are not able to do certain types of work. If men in senior and management positions hold this view they will consciously (or unconsciously) exclude women for doing certain work. This is a serious obstacle to the advancement of women in the workplace. There are multiple ways to deal with this starting with ‘bias-awareness training’. Another way is to put in place various checks and balances in the organisation that will flag if there is inadequate women representation in certain job types.

The harassment of women in the workplace is another obstacle noted by the delegates. It goes without saying that harassment of any kind has no place in the work environment. Harassment is verbal or physical conduct that denigrates an individual because of that person’s race, skin colour, religion, gender, national origin, age, or disability. The organisation must have a ‘zero-tolerance’ towards gender-based and sexual harassment. There many ways to prevent and handle harassment including:

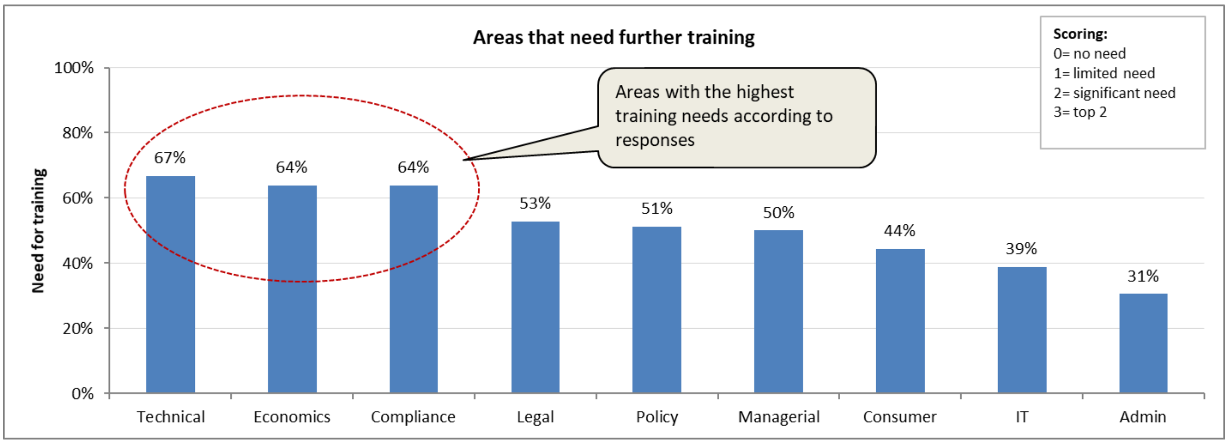
1. Create and communicate your anti-harassment policy;
2. Establish an effective complaint procedure;
3. Take every complaint seriously;
4. Don't leave it to the parties involved to work it out;
5. Investigate every complaint; and
6. Discipline the person who committed the harassment.

7.6 Training Needs Assessment

In addition to the detailed ‘bottom-up’ skills-and-training-needs-assessment-process presented in the preceding sections; the questionnaire also directly asked the respondents to rank their training needs. The self-ranking can be loosely interpreted as a high-level ‘top-down’ process. These results from the ‘top-down and ‘bottom-up’ approaches can be combined to identify the training areas that will have the biggest impact on the regulator.

The respondents were asked to rank their training needs in selected areas using the following scoring approach: 0=no need, 1= limited need, 2=significant need and 3= high need. The results are shown below.

Figure 48: Respondents’ views of areas that need further training



Technical, economics and compliance training scored the highest on the 'top-down' needs assessment. The areas that require the least training support are consumer related issues, IT and Admin. These results are generally consistent with the detailed 'bottom-up' assessment process which forms the basis of the recommended capacity building programme.

7.7 Supply side energy efficiency training, case studies and training providers

Supply side energy efficiency options available include:

- improved economic dispatch within a country and in regional trading;
- improved plant efficiency; and
- reduction in real time losses.

The focus in this section is case studies for improving dispatching of generation, energy trading, power plant rehabilitation, demand side participation in operating reserves, secondary frequency control optimisation and optimal power flow.

Each of these topics has already realised benefits in EA-SA-IO region and elsewhere in the world. Where possible practical cases are provided.

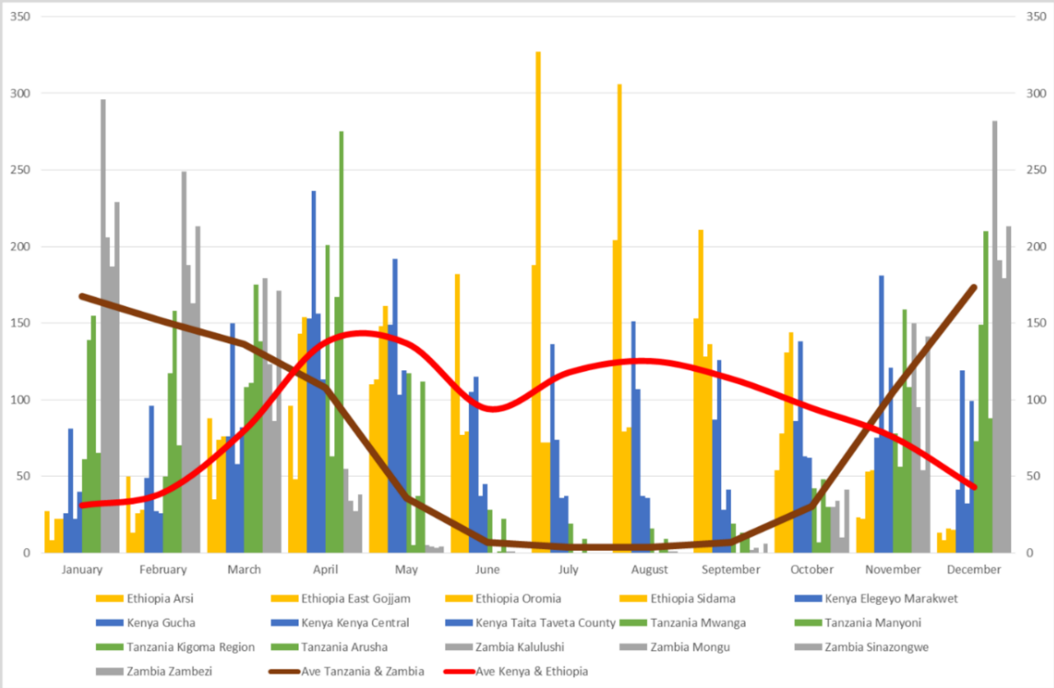
The training requirements for each broad topic is very specific and possible training providers are identified in the final section.

7.7.1 Optimise generation dispatch

Optimising hydro and thermal power plant dispatch in the EAPP / SAPP interconnected system is desired to ensure that power stations are run in an optimal manner.

North / South hydro coordination benefits can be realised in the different rainfall patterns in Northern and Southern hemisphere countries. The rainfall in 4 regions in each country for Ethiopia, Kenya, Tanzania and Zambia is shown in **Figure 49**. The Northern hemisphere countries have rainfall in period April to October and Southern hemisphere countries have rain fall from November to April. When North has a surplus of hydro power and South has a deficit of hydro power and vice versa. There is potential to sell surplus power on a seasonal basis between North and Southern hemisphere countries either through energy banking, short term bilateral trades or SAPP / EAPP market platforms.

Figure 49: Rainfall in 4 regions in each country for Ethiopia, Kenya, Tanzania and Zambia[26]



7.7.2 Optimise energy trading in EAPP / SAPP

Optimise dispatch through vibrant market interaction between the member utilities and other trading members. The day-ahead market, intraday and balancing market platforms needs to be started in EAPP to allow for vibrant trading. EAPP already has done shadow trading showing the benefits of US$ 23m in the pilot project April 8th to July 31st 2014[27]**.**

Most of the energy trading in SAPP and EAPP is under physical bilateral agreements but these could be converted to financial bilateral agreements, for example contracts for differences. Long term physical bilateral contracts can lose their initial proposed value as other generation options come online and as the environment changes. E.g. variable renewable energy requires different operating regimes. Converting a physical bilateral to a financial bilateral contract benefits both the buyer and the seller. The Nordic region has already realised these benefits and most long-term bilateral contracts have been converted to financial contracts which are more economically traded on the Nordic market platforms.

New SAPP rules to allow participants of 50 MW or greater plus recent changes in Namibia and Zambia to allow IPP's to participate in SAPP trading creates opportunities for smaller participants to actively participate in energy optimisation through vibrant market trading. The new rules in the region create a viable market trading platform for merchant variable renewable energy power plants.

SAPP balancing market which will go live in late 2020 which will improve real-time energy optimisation through more vibrant trading of electricity near to real-time and increase VRE penetration.

Trading between EAPP and SAPP markets will result in further supply side efficiency and savings to all participating parties.

7.7.3 Generation rehabilitation – Hydro plant

Rehabilitation of hydro generating plant in order to improve generation efficiency, i.e. increase the energy produced for the same water intake. Rehabilitation measures can include civil works (e.g. repair tunnels and shafts, removal of sediment deposits, removal of aquatic reeds) and electromechanical rehabilitation (e.g. refurbish turbines, valves and generators, replace transformers). Rehabilitation projects can result

26 http://www.samsamwater.com/climate/

27 EAPP short term market and update of market road map, Energinet.dk Energy Consultancy, December 2014.

in the restoration of hydro plant to their original capacity or even a slightly higher capacity than in the original.

Energy Efficiency rehabilitation projects undertaken in Zambia, Zimbabwe and Tanzania have resulted in an increase in generation capacity and improved power plant efficiency, **Table 19**.

Table 19 Energy Efficiency rehabilitation projects undertaken in Zambia, Zimbabwe and Tanzania[28]

Country	Date started	Scale	Cost	Timescale	Expected impact
Zambia	2000 2002	3 Hydro Power Plants (1600 MW)	US$275 million in total	4 to 10 yrs	10 to 20% gain in generating capacity
Generation rehabilitation	1987	1 Hydropower station (750MW)	US$40 million (1994 prices)	16 yrs	Increase in capacity by 84 MW
Tanzania	1999 to 2003	Kidatu Power Plant (204MW)	US$13 million	1993-2003	Available capacity from 175MW to 200MW, Improved efficiency of 2% (24GWh annually, improved reliability)

7.7.4 Generation rehabilitation – Coal plant

Refurbish or upgrade coal-fired generating plant in order to improve generation efficiency and decrease auxiliary consumption, i.e. increase the electricity produced for the same fuel intake. Measures taken to improve efficiency can be minor or major. Minor measures can include upgrading control systems, reduction of steam side losses and combustion tuning. Major measures can include upgrading boilers and turbine blades, coal mill replacement and cooling tower optimisation. Parts of the plant can be refurbished, replaced or upgraded when replaced, and operation and maintenance practices can be improved.

A key measure for reducing auxiliary consumption is to replace existing motors with properly sized and/or energy efficient motors, as most auxiliary loads are powered by electric motor drives (e.g. feed-water system, cooling water system). More efficient variable-speed drives can also be used for large fans and pumps.

7.7.5 Provision of operating reserves and balancing services by consumers

There are consumers who are prepared to reduce consumption for the provision of operating reserves and balancing, where such consumers will either be compensated as an ancillary service or save energy consumed and thereby provide increased generation production / efficiency.

South Africa has primary and tertiary frequency control reserves predominantly provided by consumers. This allows power stations to operate more efficiently (estimated gain of at least 0.5%) and with less wear and tear. The actual expenditure in 2017/18 was Rm 184 with budgeted increase to Rm 319 for 2019/19. Provision of these reserves is more cost effective than procuring from generation resources.

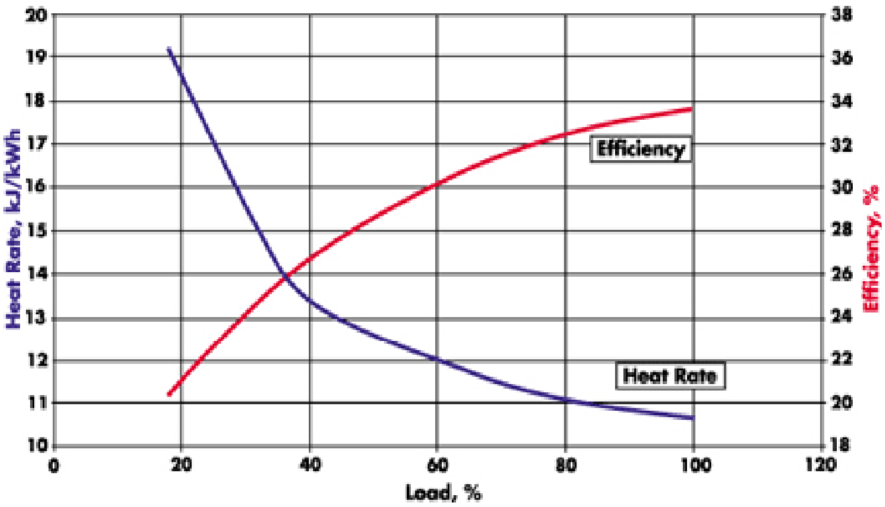
[28] Needs Assessment Study on Energy Efficiency in the Southern African Power Pool, PPA Energy, June 2012

Table 20 Eskom Transmission Ancillary Service requirements from Multi-Year Price Determination (MYPD 4)[29]

Transmission: Ancillary Services	Actuals 2017/18	Projection 2018/19	Application 2019/20	Application 2020/21	Application 2021/22	Forecast 2022/23	Forecast 2023/24
Reserves Total	201	339	359	380	403	428	453
Supply Side	17	20	21	22	23	24	26
Demand Response	184	319	339	359	381	403	428
Reactive Power	301	296	329	347	369	390	411
Black Start & Islanding	41	45	47	48	49	52	51
Constrained Generation	31	302	153	35	84	25	57
Total	**574**	**982**	**889**	**811**	**905**	**895**	**972**

The efficiency curve of a Siemens SGT-600 Industrial Gas Turbine - 25 MW, shows a 1.5% efficiency drop from operating at 90% compared to operating at 100% generation output. A similar efficiency curve applies to coal fired, hydro and other thermal generation.

Figure 50 Siemens SGT-600 Industrial Gas Turbine - 25 MW[30]



7.7.6 Sharing of operating reserves and balancing services by Control Areas

Cooperation between Control Areas in Germany and Netherlands for sharing balancing services and secondary frequency has improved energy efficiency. ACER recognising the supply side efficiency gains is proposing further widening the cooperation to the whole of Europe and is targeting a single balancing and secondary frequency control market.

[29] http://www.nersa.org.za/Admin/Document/Editor/file/Consultations/Electricity/Notices/3Transmission_MYPD%204%20Sept%202018.pdf
[30] https://new.siemens.com/global/en/products/energy/power-generation/gas-turbines/sgt-600.html

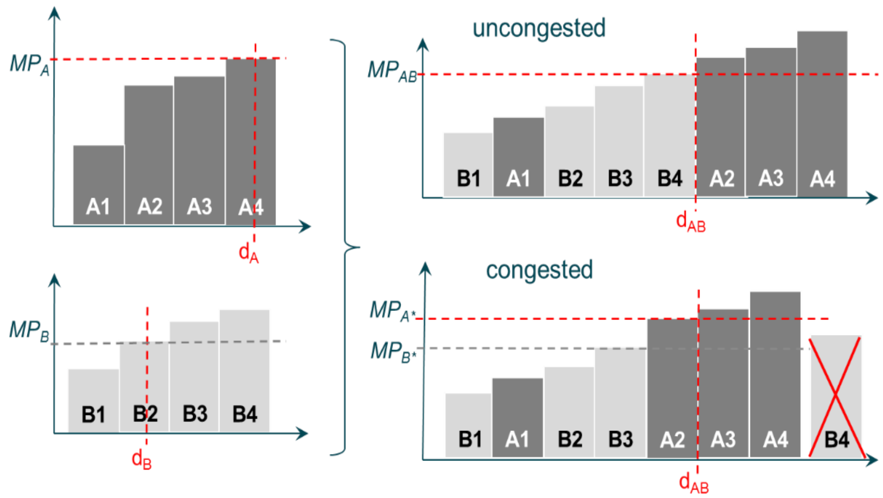


Figure 51 Example of economic benefit in balancing between control areas even with congestion

Supply side energy efficiency benefits could be gained by similar cooperating of Control Areas in SAPP / EAPP and increasing participation of TSO's inside existing Control Areas.

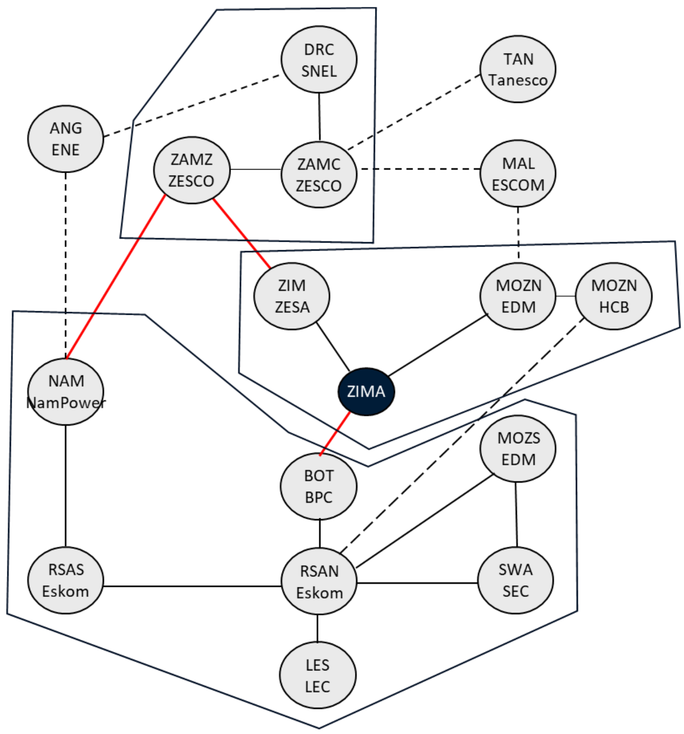


Figure 52 SAPP bid areas and Control Areas

7.7.7 Network enhancements to reduce losses

Network losses can be reduced through network strengthening, increasing line voltages and optimising reactive power flows. Transmission planning criteria for network strengthening should include the techno-economic justification for network enhancements which have a net positive benefit. Some of the obstacles to network improvements to reduce losses can be that these projects do not have a direct benefit to the important criteria of network security and reliability and hence get a low-level prioritisation.

This is an easy supply-side option to reduce overall cost, but the reality is that the implementation is often not realised due to other more pressing matters of network expansion for improved system security and reliability.

7.7.8 Optimising power flow reducing real time losses

Optimal Power Flow (OPF) is provided by SCADA/EMS suppliers which is designed to optimise voltage profiles, thereby reducing transmission system losses, whilst maintaining system security of supply. One of the main targets is to minimise system real and reactive power losses, proposing optimised voltage profiles, generation voltage, transformer taps, switching in and out of capacitive and inductive devices and minimising system energy costs.

This is a supply side energy efficiency option which requires skilled engineers in the TSO's control room to run OPF, analyse results and determine corrective actions to minimising system energy costs whilst maintaining system security.

7.7.9 Training providers for supply side energy efficiency

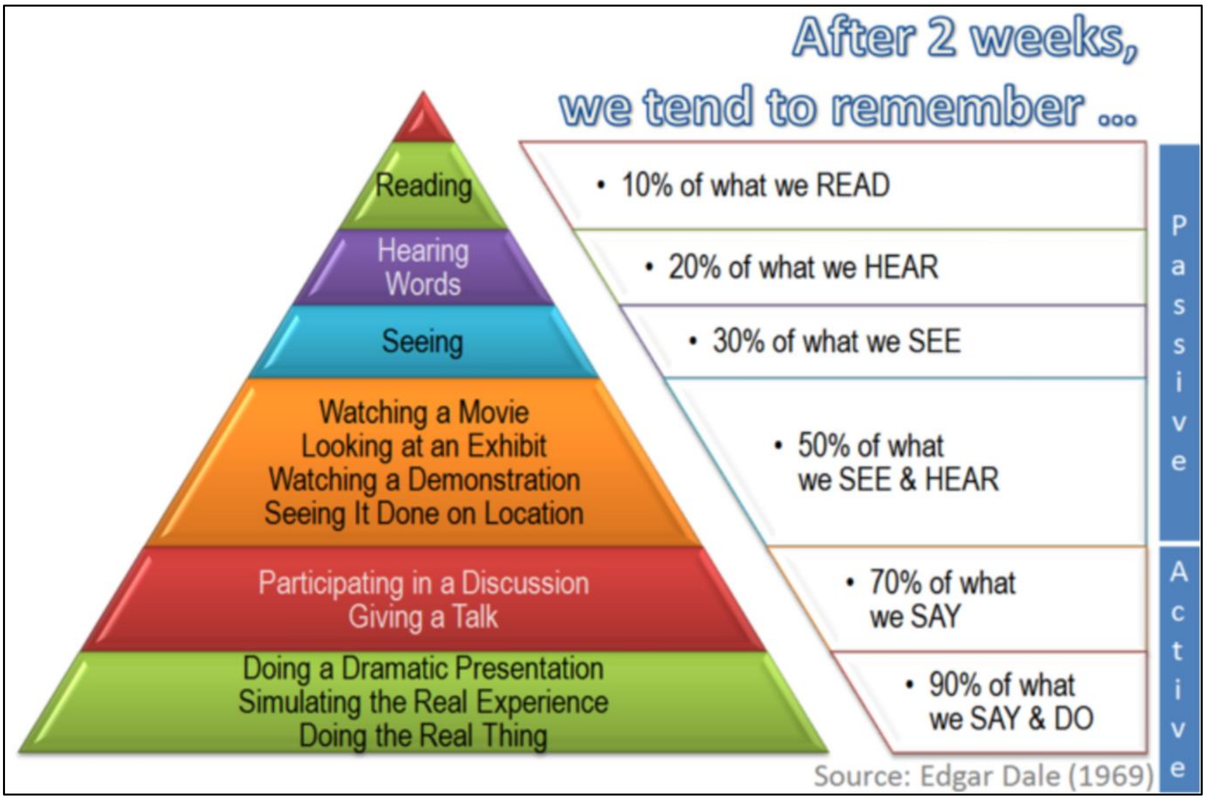
1) Optimise generation dispatch, optimise energy trading control area and reserve optimisation training providers are from Europe and USA who have gone through these exercises and continue to improve hydro-thermal co-ordination. Training is provided by Nord Pool and Manitoba hydro. Ricardo has also provided this training in this area.
2) Generation rehabilitation is very specific to each power plant and training would be best done by the Original Equipment Manufacturer.
3) Transmission planners can be trained to identify transmission loss gains through network strengthening. Training can be provided by suppliers of planning software and there are many consulting firms that provide this training.
4) Training in optimising power flows to reduce real time losses can be done by universities, simulation software providers, consultants and SCADA EMS providers. The training should be done on each system operator's system. Generic training will not realise results as there are pros and cons to optimal power flow and each optimisation opportunity has a real possibility of decreasing system security.

7.8 Training Methods and Institutions

7.8.1 Background

All forms of training are better than no training but some training methods result in better knowledge retention. This figure below, commonly referred to as Edgar Dale's "cone of experience" provides a visual illustration of the contribution of different training methods to the process of learning.

Figure 53: Training method evaluations



The figure shows:

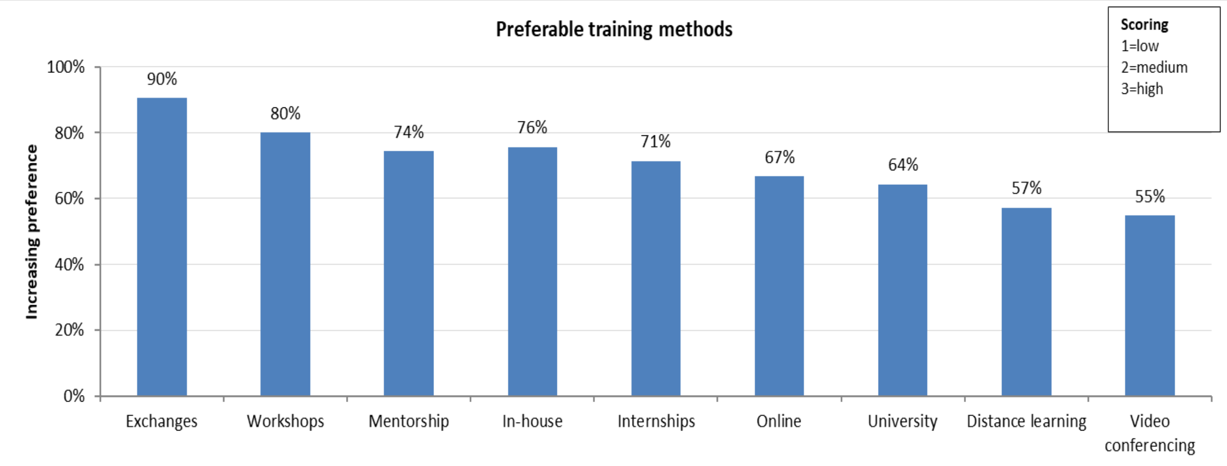
1. At the bottom of the cone or pyramid learning takes place through direct, purposeful experiences. Towards the top of the pyramid learning increasingly takes place through observation and abstraction (symbols). As a result, learners become spectators rather than participants; and
2. Dale wrote that the bottom of the Cone represented "*purposeful experience that is seen, handled, tasted, touched, felt, and smelled*". By contrast, at the top of the Cone, verbal symbols (i.e., words) and messages are highly abstract. They do not have physical resemblance to the objects or ideas. As Dale wrote, "*The word horse as we write it does not look like a horse or sound like a horse or feel like a horse*"[31].

7.8.2 Training Methods

With the Edgar Dale "cone of experience" in mind respondents were asked to rank a list of learning experiences. The results from 13 respondents are summarised in the figure below.

[31] https://lidtfoundations.pressbooks.com/chapter/edgar-dale-and-the-cone-of-experience/

Figure 54: Training method evaluations



The evaluation shows that:

1. The top three training methods included exchanges, workshops and 'in-house' mentorship;
2. Formal instruction via online, university or distance learning courses are amongst the least favoured; and
3. The least favoured training method approach is via video conferencing.

Although not unexpected, it is interesting to note that the results are fully aligned with the "cone of experiences" in that learning opportunities consisting of "purposeful experience that is seen, handled, tasted, touched, felt, and smelled" are preferred which are to the left of the figure are preferred over experiences that are more abstract and which are toward the right.

An interesting observation is that since the spread of the COVID-19 virus and the requirement to keep social distancing many organisations have embraced Video-Conferencing not only as a medium to conduct meetings but also as a recognised and valuable tool in making presentations and presenting courses. It is expected that trainers and trainees will increasingly accept 'video-conferencing', 'distant learning' and 'online' courses as effective means to build capacity.

7.8.3 Training Institutions

The survey requested information on training institutions used in the past. A full list of these institutions and organisations are included below for easy reference.

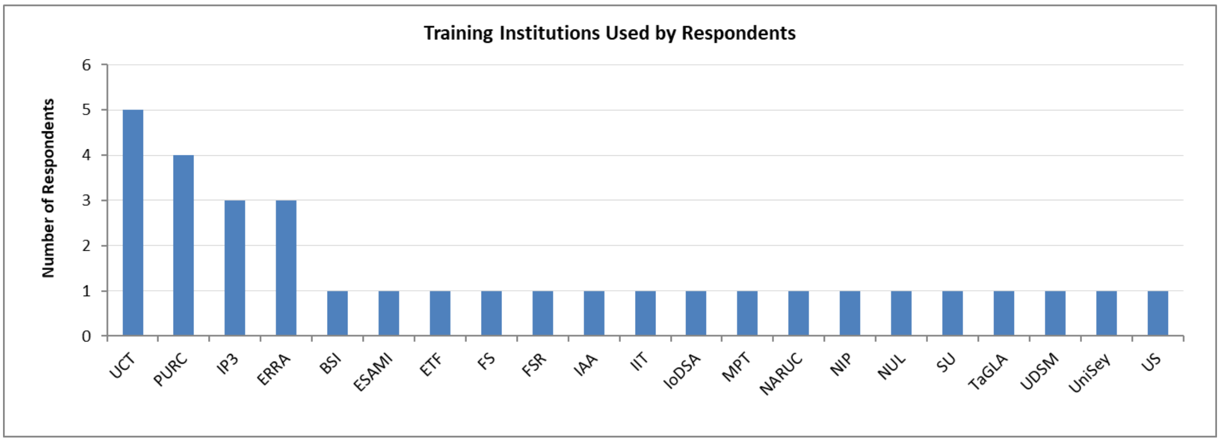
Table 21: Training Institutions previously used by questionnaire respondents

Short Name	Full Name	Website
BSI	Balanced Scorecard Institute	https://balancedscorecard.org/
ERRA	Energy Regulators Regional Association	https://erranet.org
ESAMI	Eastern and Southern African Management Institute	https://esami-africa.org/
ETF	Energy Training Foundation	No website
FS	Frankfurt School of Finance & Management	https://www.frankfurt-school.de/home
FSR	Florence School of Regulation	https://fsr.eui.eu/
IAA	Institute of Accountancy Arusha	https://iaa.ac.tz/
IIT	Indian Institute of Technology, Roorkee, India	https://www.iitr.ac.in/
IoDSA	Institute of Directors in South Africa	https://www.iodsa.co.za/
IP3	Institute for Public Private Partnership	https://www.ip3.org/
MPT	MINES ParisTech	http://www.mines-paristech.eu/

Short Name	Full Name	Website
NARUC	National Association of Regulatory Utility Commissioners, U.S.	https://www.naruc.org/our-programs/overview/
NIP	National Institute of Productivity, Tanzania	https://niptz.org/
NUL	National University of Lesotho	http://www.nul.ls/
PURC	Public Utility Research Center, Florida, U.S.	https://warrington.ufl.edu/public-utility-research-center/
SU	Strathmore University, Nairobi	https://www.strathmore.edu/
TaGLA	Tanzania Global Learning Agency	http://www.tagla.go.tz/en/
UCT	University of Cape Town, South Africa	https://www.gsb.uct.ac.za/
UDSM	University of Dar Es Salaam	https://www.udsm.ac.tz/
UniSey	University of Seychelles	https://unisey.ac.sc/
US	University of Stellenbosch, South Africa	https://usb-ed.com/
AFC	AF Consult	https://www.afconsult.com/en/
IFP	Institut Français du Pétrole	https://www.ifp-school.com/en
CITAC	CITAC Consulting	https://www.citac.com/
IMO	International Maritime Organisation	http://www.imo.org/en
UNCTAD	Virtual Institute	https://vi.unctad.org/

The figure below shows the number of respondents who mentioned the various training institutions. The most frequently mentioned, and presumably the most popular, institutions are shown on the left.

Figure 55: Training institutions used by respondents



The feedback shows that:

1. The majority of institutions[32] have been used by a single respondent only;
2. Only the top four institutions have been used by more than a single respondent;
3. These are:
   a) University of Cape Town Graduate Business School (UCT) = 5 respondents
   b) Public Utility Research Center, Florida, U.S. (PURC) = 4 respondents
   c) The Institute for Public Private Partnerships (IP3) = 3 respondents
   d) Energy Regulators Regional Association (ERRA) = 3 respondents.

[32] A full list of institutions can be found in the Appendices

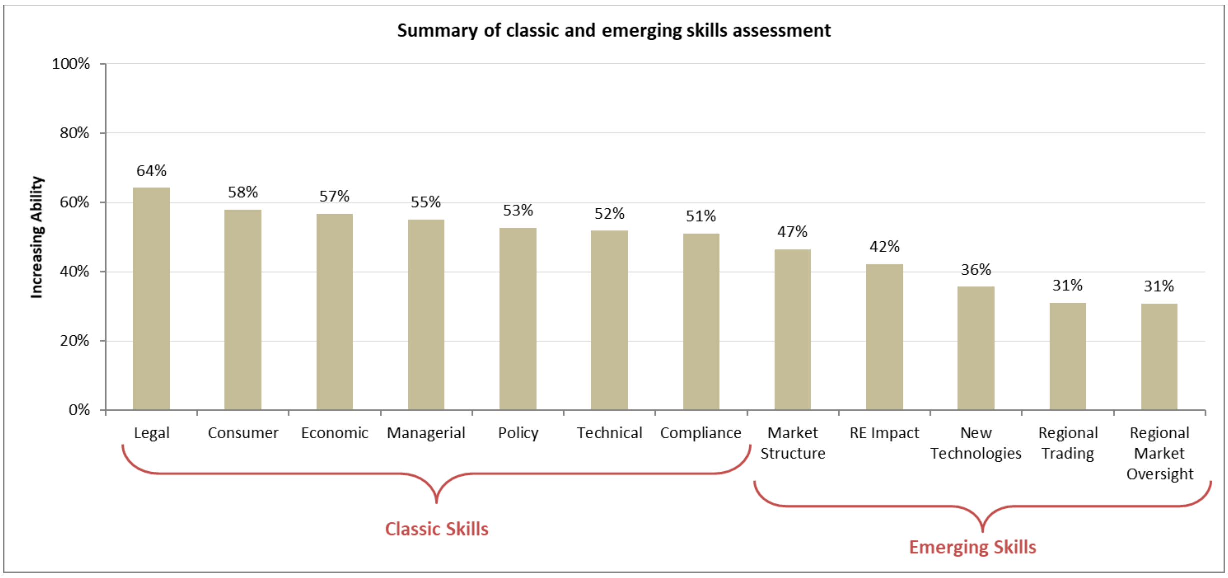
A portion of the survey was dedicated to determining the KPIs used in in each Regulator as a measure of performance.

7.9 Capacity Building Programme

7.9.1 Capacity building design needs

This section uses the observations and results from the skills assessment to construct a responsive capacity building programme to direct the delivery of 'fit-for-purpose' training programmes. The figure below combines the summary results from the "classic" and "emerging" skills assessments.

Figure 56: Training institutions used by respondents



The figure shows:

1. The lowest skills assessment results are for the emerging skills. This is to be expected in that regulators have had less time to build skills and capacities in these areas; and
2. The areas in biggest need of capacity building revolves around the regional energy market and new technologies including renewable energy integration.

In addition to the high-level needs analysis presented above, the detail results under the classic skills assessments also highlighted the following training areas:

1. Trade-off between conflicting policies;
2. Carbon reduction mechanisms and targets;
3. Environmental compliance;
4. Metering;
5. Safety standards;
6. Socio economic impact of regulators;
7. Statistical analysis; and
8. Information systems.

7.9.2 Proposed capacity building programmes

One of the two key outcomes of this project is to: "Design a responsive training programme for strengthening the capacity of national and regional regulatory institutions and Power Pools to proactively influence power trading and developments in the energy sector."

The proposed capacity building programme, presented below, flows from the various results presented in the previous sections as well as the project focus to strengthen and influence power trading and developments in the energy sector.

The recommended program will assist regulators and market operators to build capacity in vital areas needed to address not only today's challenges but also those that regulars will increasing face and the future. A critical follow-on question is who will deliver this programme? In section 7.8.3, the Consultant presented the various formal institutions that are currently being used by regulators to train their staff. These formal training programmes are in addition to the many other forms of training methods discussed in section 7.8.2.

Another option, which was raised during some of the country visits, is whether there should not be a dedicated single entity (Centre of Excellence) charged with the responsibility to "deliver" on the recommended training programme. Delivery could take different forms, including for example a coordination role. On the other hand, it could act as a training institution and be responsible for presenting some of the training programmes. There are many reasons in support of such an initiative including:

1. Many regulators have the same training requirements which creates an opportunity to pool training needs. This will allow the single "Africa Regulatory Training Institution" to negotiate with formal institutions on behalf of national and regional Africa regulators to lower training costs and to influence over the curriculum and content;
2. Cost could be reduced even further and training content could be made even more focused if the single institution designed and delivered training programmes; and
3. Another option could be to find the "best-in-field" lecturers and bring them to training venues in across Africa. This option might be cheaper and deliver world-class training on the doorstep of regulators across Africa. This will be difficult to achieve by a single regulator but as a collective, speaking through one voice, Africa regulators could accelerate quality training at a low cost and quickly build and large numbers of quality regulatory staff.

There are of cause also arguments against such an initiative, such as:

1. The quality and level of training might not be on a par with what is expected.
2. What will be the benefits and costs and will the benefits outweigh the costs?
3. How will it be funded?
4. Who will be take on the responsible?

Working out the details of such a single "Africa Regulatory Training Institution" is beyond the scope of this project but the idea seems deserving enough to warrant further consideration. It is understood that EREA has already advanced plans which could be used as a springboard towards the establishment of a "Centre of Excellence".

Capacity Building Programmes			
Area	Objective	Content	Method(s)
Regional Market	Improve knowledge of regional trading, and how to benefit from participation	• Membership • Governance • Role of markets • Market operations including trading systems • Wheeling & network pricing • Network capacity allocation • Billing & Settlement • Monitoring, oversight & disputes	• Workshops • Conferences • Exchanges

Capacity Building Programmes			
Area	Objective	Content	Method(s)
		• Strengths, Weaknesses, Opportunities, Threats analysis (SWOT) • Risks & Benefits	
Market Reforms	Examine recent developments and experiences with opening energy markets (focus on imports/exports by utilities, IPPs and large customers)	• Options • Advantages and disadvantages • SWOT • Role of prosumers (customers that also feed power into the grid) • Potential benefits and risks	• Training courses • Workshops • Exchanges (country visits)
Licensing Framework	Update licensing framework to align with market reforms	• Updated licensing framework taking into account: • Net-metering, storage • Trading • Imports & Exports	• Exchanges (country visits) • In-house discussions
Technical Framework	Facilitate access to the network by setting standards	• Update grid code requirements to address new technologies and align with market reforms • Develop connection and transmission service needs • Promote 3rd party network access	• Exchanges (country visits) • Workshops
Planning	Develop skills in system planning	• Methods of planning • Planning tools • System adequacy criteria • Dealing with multiple objectives • Long term price projections	• Online • Video conferencing • Internships

Capacity Building Programmes			
Area	Objective	Content	Method(s)
Renewable Energy	Study impact of large-scale penetration of RE capacity	• Cost trends • Technical and commercial impact of small & utility scale PV, and wind • Variability vs. intermittency • How to increase RE integration	• Training courses • Workshops • In house discussions • Visits to learn how other countries have dealt with integration of VRE
Economic Framework	Develop skills for tariff setting and unbundling	• Tariff unbundling to support market reforms • Differentiate between various products including energy, networks, ancillary services, balancing, etc.	• Training courses • Online • Exchanges
Market Governance	Develop skills in regional market governance	• Governance options • SWOT • Monitoring & Surveillance • Rule making • Dispute resolution	• Workshops • Visits • Video conferencing
Economic Regulatory framework	Develop skills in regional market pricing	• Transmission system and wheeling charge pricing • Network losses charges • Balancing service charges • Ancillary service charges	• Workshops • Visits
Women in Energy	Anti-gender discrimination and anti-bias training particularly for senior management	• Gender stereotyping • "Like me" bias • Double standards • Unconscious bias	• Workshops • Conferences

Capacity Building Programmes			
Area	Objective	Content	Method(s)
Women in Energy	Develop access to support structures to help women address business challenges as they arise.	• Assign coaches/mentors to women • Access to networking opportunities through inclusion in business activities	• Coaching • Mentoring • Networking
Women in Energy	Review recruitment policies	• Remove unnecessary and unintended requirements & biases. • Consider gender-based bursary targets	• Workshops • In-house • Exchanges
Women in Energy	Review monitoring and evaluation framework to include gender indicators	• Define indicators • Set targets • Monitor & report progress • Make adjustments where needed	• Workshops • Conferences • Exchanges
Women in Energy	Create learning opportunities	• Meaningful assignments to develop specialist knowledge • Access to training opportunities	• Internships
Women in Energy	Review conditions of employment and work environment	• Make provision for more flexible employer/employee relationships	• Workshops • In-house • Exchanges

8 Conclusions and recommendations

8.1 Workstream A: Institutional issues

The recommended approach for establishing an effective institutional structure for regulatory oversight of the EA-SA-IO Electricity Market is to group the countries into three different regulatory regions and establish a regulatory authority for Southern Africa, a regulatory authority for Eastern Africa and a regulatory advisory body for the island states of the Indian Ocean region.

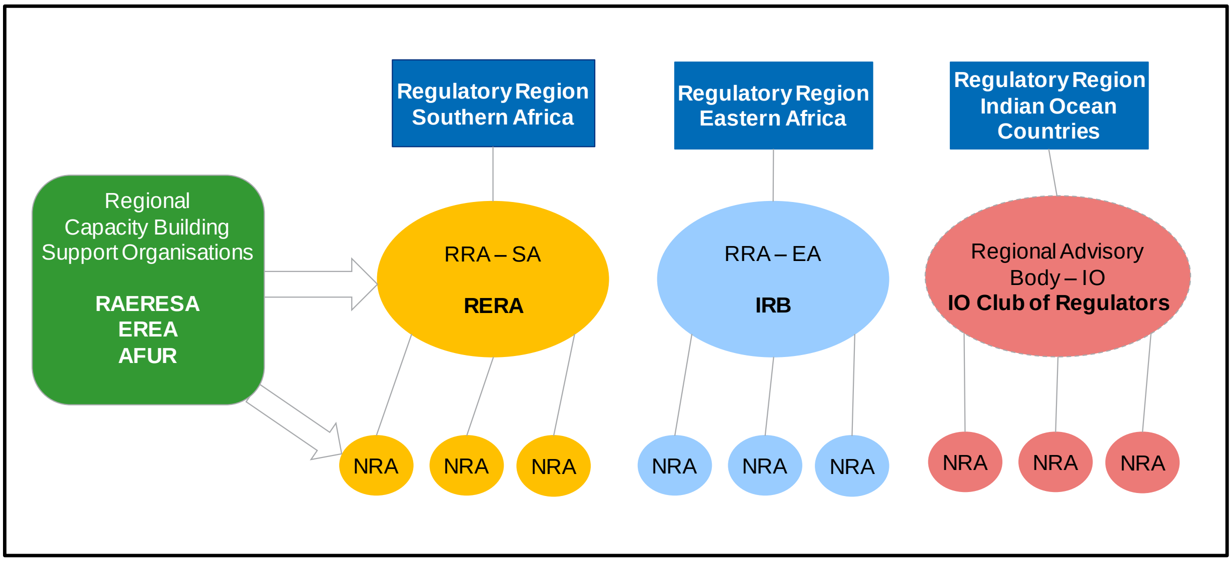
This structure should be established building upon the already existing framework of regulatory organisations that has been identified and analysed in the desk study report. The key existing regional regulatory organisations that already exist and that thus need to be streamlined into the recommended regional regulatory institutional framework, are comprised by the Regional Electricity Regulators Association of Southern Africa (RERA), the EAPP Independent Regulatory Board (EAPP IRB), the Regional Association of Energy Regulators for Eastern and Southern Africa (RAERESA) and the Energy Regulators Association of East Africa (EREA) and the Indian Ocean Club of Regulators.

Bearing in mind the mandates assigned to these organisations by their respective enabling legal documents and having due regard to the regulatory knowledge and capacity already existing within them, it is recommended:

- to establish a new regional regulatory authority for the Southern Africa regulatory region that builds on the knowledge and capacity of RERA;
- to amend the existing IRB mandate in order to establish it as fully independent regional regulatory authority for the regulatory region Eastern Africa;
- to establish regional regulatory advisory association denominated the Indian Ocean Club of Regulators as regulatory advisory body for the island states of the Indian Ocean region; and
- to support the newly created institutional framework for regulatory oversight in EA-SA-IO by an adequate capacity building framework, i.e. through a new African School of Regulation or through the already existing framework of organisations with mandates and knowledge on regional regulatory issues (RAERESA, EREA and AFUR)

The recommended regional regulatory institutional structure is illustrated below.

Figure 57 - Recommended regional regulatory institutional structure



8.2 Workstream A: Regulatory Harmonisation

8.2.1 Licensing

We propose that harmonised arrangements are required that address the following range of regulatory activities:

- Harmonised Licensing Guidelines, which set down the principles of electricity sector licensing, which activities should require licences and any restrictions on the nature of the organisations or individuals that are permitted to hold licences;
- Common procedures for lodging licence applications and the processing of these by national regulatory authorities – we propose that licences should be issued by NRAs but that the application and approval process should be harmonised as far as possible to ensure that there is a level playing field for potential electricity market participants across the different national jurisdictions;
- Standard licence conditions in core areas of the electricity supply chain, including:
  - Generation
  - Transmission (especially guaranteeing third-party access to national transmission networks for the purposes of power import and export)
  - Distribution (especially rights for embedded generation used for exports and customers seeking to import from the regional markets)
  - Interconnection (focusing on licence requirements for independent developers of international interconnectors and their obligations in respect of interconnector planning, operation and availability)
  - System Operation (to the extent that this is licensed separately from transmission ownership)
  - Import and Export (containing the minimum conditions that generators and consumers need to comply with in order to access and participate in regional markets)

Our recommendation is that standard licences be adopted throughout the EA and SA regions, and that the RRAs are responsible for defining the terms of these. NRAs will then be responsible for implementing the licences under the terms of subsidiarity. Licence templates should be adopted by the Club of Regulators in the IO region and the Club of Regulators should work with national regulatory bodies to harmonise licence documents as far as possible.

8.2.2 Market surveillance

SAPP is currently implementing a Market Surveillance Unit, reporting to the SAPP Coordination Centre. We recommend that this unit be required to report on the behaviour of market participants to the RRA for Southern Africa (RERA in its capacity as a regulatory authority), and that ultimately the RRA will be responsible for deciding and enforcing sanctions against market participants where necessary. For a transitional period, however, we propose that until such time as the RRAs are fully established it should be the NRAs that take responsibility for enforcing sanctions that have been agreed between SAPP and RERA, in Southern Africa. The same principle will apply between EAPP and IRB, in Eastern Africa.

The need for electricity market surveillance in the IO region is primarily focused around national electricity markets and is therefore a function that should be fulfilled predominantly by the NRAs. The role of the proposed Club of Regulators for the IO region would be an advisory one, helping each of the NRAs to formulate policies and regulatory instruments that enable an appropriate level of intervention in their national markets to protect customers' interests. This would include a role for the Club of Regulators in reviewing international best practice and issuing guidance notes on good practice in market regulation that can be built on by the individual NRAs.

8.2.3 Incentivising transmission investment

In addition to the licensing arrangements proposed above, we recommend the adoption regionally of a standard set of template agreements to support transmission owners and system operators in the development of the regional networks. We recommend that RRAs develop and apply **Template agreements** and **standard conditions** for the core agreements that are needed by TOs, as follows:

- A **Transmission Connection Agreement** that covers the technical and commercial arrangements for connecting new generation and consumer sites to the transmission network;
- A **Transmission Use of System Agreement** that defines the rights of transmission users to be, and to remain, connected to the new assets;
- An **Interconnector Agreement** that deals with specific connection and operational issues at the point of connection between new interconnector assets developed by independent companies and the existing national transmission networks;
- A **Wheeling Agreement** that sets down the rights and obligations of TOs in relation to international power transfers between countries in the SAPP and EAPP markets.

The template agreements should be implemented by the NRAs under the principle of subsidiarity. In the IO countries, the Club of Regulators should work with the NRAs to align their licensing regimes and agreements with best practice, without this being a mandatory requirement.

8.2.4 Regional Grid Code

There is a need for a regional grid code that can be used for Southern and Eastern Africa to enhance security and competitiveness of industries. Security is enhanced as an interconnection when security of supply burden is shared across all the entities in the interconnection. Entities include generators, customers, transmission companies and system operators. The regional grid code which provides a common set of internationally acceptable technical rules creating a level playing field for trading electricity and security of supply services. This in turn provides investors with surety that their assets will be protected making their investment decision easier and borrowing money cheaper from lending agencies. Enhanced trading lowers regional energy prices and the benefits are shared by all participants. Enhanced security improves reliability of supply with less blackouts and interruptions of supply with major benefits to all consumers.

A Regional Grid Code should be developed that will be common to Southern and Eastern Africa. Compliance with this will be enforced by the RRAs, who will work with the NRAs and national transmission utilities to align national grid codes with the requirements of the regional code. Derogations may be granted where necessary to allow national utilities time to comply with the new requirements.

In the Indian Ocean region, the adoption of a “Reference” Grid Code is recommended, which the Club of Regulators can maintain. The Club of Regulators will then work with the NRAs to help them to align their codes to a common standard, however reflecting the status of the Club of Regulators as an advisory body, this code will not be mandatory in the IO.

8.2.5 Regional planning regulations for increasing transmission capacity

Regional planning regulations for increasing transmission capacity should be set up for the EA-SA region for identifying and supporting transmission projects of common interest. EU Regulation No 347/2013 is a good example that is used to mandate regional co-ordination for interconnector projects and identify projects of common interest. Transmission projects are required to enhance VRE penetration and increase regional trading. Countries that do not directly benefit from such projects have no interest in including these projects in their local transmission expansion plans and the development of a method to have a common regional transmission planning list gives investors and stakeholders confidence in supporting these projects.

The key issues the regulation should address are:

- Planning process and time frames;
- Cost Benefit Analysis Methodology;
- Ranking of regional based on Cost Benefit Analysis results;
- Funding model for top ranked regional interconnection projects; and
- Data model provision and confidentiality

8.2.6 Wheeling charges

In order to encourage the development of a regional market and incentivise investments in transmission infrastructure, we recommend that the RRAs work with the NRAs and the national transmission utilities to implement a point-to-point MW-km method for transmission wheeling charges in the integrated SAPP/EAPP market. This would provide a basis for recovering the capital and operations and maintenance costs associated with the use of interconnected network assets and international interconnectors for wheeling.

The marginal transmission losses associated with wheeling can readily be calculated from load-flow analysis of network flows "with and without" each wheeling transaction. These can then either be remunerated at an appropriate energy cost (e.g. a weighted average cost of generation, as per the proposed Continental Transmission Tariff Methodology) or be settled "in-kind" by energy transfers between buyers, sellers and the wheeling utility.

8.2.7 Environmental sustainability

In order to promote environmental sustainability in the power sector, we recommend that the RRAs develop and implement a standard approach and methodology for the inclusion of Strategic Environmental Assessments in the development of national Integrated Resource Plans. These should assist the process of encouraging energy efficiency measures, increased renewable generation penetration and increased interconnection as integral parts of future national development plans.

8.2.8 Action Plan for Regulatory Harmonisation

All the above measures should be developed into an Action Plan with clearly defined priorities at the regional and national level. Implementing the harmonisation process across the range of regulatory measures that have been identified in this report will require coordinated action between the NRAs and RRAs if this is to prove successful.

The action plan could identify measures over a range of timeframes, which could comprise:

- Short-term actions, to be implemented over a period of 1- 3 years (2021 – 2023);
- Medium-term actions, to be implemented over a period of 4 - 8 years (2024-2028); and
- Long-term actions, to be implemented beyond 8 years (after 2028).

8.2.8.1 Short-term actions

Short-term measures should initially be identified that will assist the alignment of regulation of the electricity markets in EA-SA and the Indian Ocean. We see these as including the implementation of the institutional arrangements, in two key areas:

3. The completion of the creation of national regulatory bodies responsible for the energy sector and the full implementation of their regulatory mandates; and
4. The setting up of the RRAs for EA and SA and the creation of the Club of Regulators for the Indian Ocean.

In parallel with the creation of strong national and regional regulatory bodies, the proposed Centre of Excellence should be created that can act as a focal point for the development of training and capacity building activities in the region.

Alongside the proposed institutional changes, we recommend that work commences on the development of the Regional Grid Code documentation, in order to promote harmonised technical standards that will contribute to the security of the interconnected power systems in SA and EA as the integration of the SAPP and EAPP markets is pursued. The development of a reference Grid Code for the Indian Ocean countries should also be developed over the short-term time horizon, in order that future investors in, particularly, renewable generation technologies, can have confidence that the technical conditions for developing new projects are harmonised across the region.

The development standardised licences and agreements by the RRAs and the Club of Regulators should be undertaken as a short-term priority measure, though we recognise that the ability of the RRAs to promote the adoption of these will depend on the RRAs being set up as effective institutions. Planning and agreeing the content of these documents can be undertaken in the short-term however.

8.2.8.2 Medium-term actions

The development and implementation of a harmonised approach to transmission charging for international wheeling of power across and between the EAPP and SAPP systems is a highly desirable step for ensuring that trading in the integrated markets can be achieved on an equitable basis. Preparatory work on this can be undertaken in the short-term, however the implementation of harmonised transmission pricing across the integrated markets of EAPP and SAPP will be a medium term measure required to accompany a situation when trading across the integrated market is fully established. This in turn requires the completion of key interconnectors in the region and the setting up of the proposed “Tight-coupling” model of market operation between SAPP and EAPP.

The implementation of market surveillance to be undertaken by the RRAs for the combined market is likely to be a medium-term measure. Whilst the RRA for SA can begin its role of market surveillance in SAPP in a shorter-term time frame, given the preparatory work that is currently ongoing within the SAPP market itself and the recommendations that have been prepared for the transformation of RERA into a regulatory authority, co-ordinated market surveillance for the integrated EA-SA market will be medium-term requirement.

The medium-term timeframe will also see the implementation of licences and agreements that are based on the standardised models that will be developed by the RRAs during the first phase of their setting to work. This will include the recommendation of standardised approaches to be adopted by the regulators of the IO countries with advice from the Club of Regulators.

8.2.8.3 Long-term actions

The long-term phase is likely to consist primarily of monitoring and development of the regulatory framework by the RRAs and the NRAs, the basic model of regulatory harmonisation having been defined in the short-term phase and implemented in the medium-term. This will mirror the growing maturity of the integrated EA-SA market and the increase in regional trading activities. In the IO region, monitoring of the national utilities and electricity markets by the national regulators and the sharing of good practice through the Club of Regulators will be established activities.

8.3 Workstream B: Capacity building

The Consultant developed a detailed questionnaire that formed the basis of an interactive skills and competencies assessment process. It is encouraging to note that 20 out of 31 participants (65%) responded to the questionnaire and is an indication of the interest and importance that institutions have in developing their people.

One can clearly conclude that of the 65% of regulators who responded to the survey, the majority felt that they were both understaffed and inadequately trained. Key staffing vacancies were predominantly in professional (technical, economic, consumer and legal) or managerial roles, and it is concerning that the vacancies relate to critical focus areas for regulators. As discussed in Section 7.3, staff vacancies have a serious impact on organisations and prevent them from discharging all their duties and responsibilities within acceptable time periods and the appropriate quality standard.

The classic skills assessment further investigated and built on the issues relating to a lack of training. An overarching finding from the responses, is that regulators have an adequate basic understanding of the skills and abilities required to carry out their duties. However, their ability to develop and apply regulation, maintain and adjust methodologies and frameworks, and monitor and report on outcomes, is limited. The emerging skills assessment additionally reinforced the requirement for further capacity building with lower average skills overall, when compared with the classic skills assessment. It is therefore recommended that capacity building programs factor in not just traditional regulatory skills and techniques, but also focus substantially on developing skills to address emerging trends and issues relating to changes in market structure, renewable energy technologies, trading, market oversight, wheeling, network pricing and market governance and reporting.

The core competency assessment also revealed that whilst there are pockets of excellence, several skills gaps require support. These include legal competencies such as contract drafting, technical competencies such as long-term price modelling and expansion planning and impact assessments. It is recommended that any training programs, therefore also consider competency and skills training, relating to issues which are cross-sectoral, but are also required to support regulation.

A conclusion from the research into “Women in Energy” in Section 7.5, is that certain key employment areas, including technical and managerial roles, are disproportionately dominated by men, given the overall employment split between genders. Furthermore, there is clearly misalignment in the application of policies and programs designed to support the role of women in the energy regulatory environment. It is recommended that further support is given to align regulators on the application of these policies as well as providing increased mentoring and career guidance to women. A clear baseline and KPIs may be developed to measure progress in this respect.

Training in technical, economics and compliance skills received the highest overall requests. The respondents also identified exchanges, workshops and mentorship, as the three key training or capacity building methods they prefer. This provides clear guidance on how to deliver any training courses and it is recommended that any capacity building programs take this into account. Least favoured methods include formal university training and video-conferencing and these should be avoided.

Section 7.9.2 presented a proposed “Capacity Building program” resulting from these findings. It is therefore recommended that this forms the starting point for future training needs, taking into account the issues raised above with regards to training methods and ensuring that further consideration is given to the continued development of the role of women in the energy regulatory environment.

A. Appendix A: Summary of regional and country grid codes

Table 22 Governance Codes

Governance Code Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Board structure	x members from Board chairman rotates	Member from each energy ministry Chairman rotates between countries every 12 months	Members appointed for 3 years by industry and cabinet Minister appoints chairman	Members appointed for 3 years by industry and cabinet Minister appoints chairman	A chairperson appointed by president, 3 principle secretaries, one Director general (CEO), one county executive committee member, 5 members appointed by cabinet secretary. Chairperson's term is 4 years and any other member's term is 3 years	A chairman (non-executive) appointed by President, five non-executive members appointed by the minister and a Director-General	Board consists of one chairman and three commissioners. President shall appoint all these persons on the advice of Prime Minister and upon consulting the opposition	1 chairman, 1 vice-chairman and 3 members; all appointed by the minister for a term of 4 years	3 full time members and 4 part time members; all appointed by the Minister. One of the members shall become chairman and the other shall become vice-chairman	Board shall consist of a minimum of 6 members and a maximum of 9 members, all appointed by the minister with the approval of the President. One of the members shall be Chairman and another be vice-chairman. The Minister shall make these appointments	
Voting majority	51%?	Consensus	51%?	51%?			Consensus	Approval decision lies with Minister		depending upon membership of the board, can be 66% to 55%	
Grid code compliance committee	Yes - all TSO's represented	Independent regulatory board (IRB) is responsible for monitoring the code	NERSA is responsible for ensuring the compliance by	Ethiopian energy regulator is responsible for enforcement	Regulatory authority is responsible for enforcement and	The Energy and Water Utility Regulatory Authority (EWURA) is	No separate committee for compliance monitoring	Regulatory authority is in charge of enforcing the grid code and monitoring	Energy Regulatory Board (ERB) maintains a team of inspectors,	ZERA is responsible for monitoring the compliance of the electricity	

		compliance by market players	all the licensees	and monitoring of compliance by the participants	monitoring of compliance by the participants	the final authority in charge of monitoring the compliance of the participants		market participant's compliance with it	whose task is to inspect the grid connected entity for the compliance	market players	
Non-compliance penalties			Actions in terms of procedures for handling licensing contravention s (may be licence specific)	Imprisonment of up to 3 years or fine up to Birr 15,000	Regulatory Authority can decide and levy a monetary penalty on the non-compliant party. In case of violation of licence condition, the authority can revoke the licence	No exclusive penalties are listed out in the grid code	1) Electricity Act limits the penalty at 1,00,000 Rupees or 5 years of imprisonment 2) Authority has the power to decide the quantum of penalty for non-compliance	**Penalties by The Electricity Act 2007:** 1) Maximum of N$ 16,000 or 2 years imprisonment **Penalties by the grid code:** 1) Resolve through negotiation 2) Actions in terms of procedures for handling licensing contravention s	ERB is empowered by the law to award monetary penalties up to 100,000 penalty units and imprisonment up to 5 years	Energy Regulatory Authority Act contains provision of fine not more than level 14 or imprisonment not more than 5 years or both ZERA shall decide penalties for various issues within in framework laid down by the law	
Derogations allowed		Upon request, Independent regulatory board can allow derogations suspending certain obligations	Upon request, NERSA may approve the derogation, based on the recommendat ion received from Grid code advisory committee (GCAC)	Ethiopian Energy Regulator is in charge of granting derogations for individual participant. It may seek advice of an independent expert while	Upon the request from a market participant for an exemption from a particular grid code obligation, Regulator Authority can grant a derogation. It	**Step1:** participant shall apply to Grid code secretariat (GCS) with full details of derogation **Step2:** GCS refers the application to Grid code advisory	**Step1:** participant shall apply to Utility Regulatory Authority (URA) with full details of derogation **Step2:** Authority may consult system	Derogations are allowed to make it possible for market players that are in transition phase. The application process is similar to the process for	1) concerned party seeking the derogation shall write directly to Energy regulation board giving full details. DNSP (secretariat) shall be	**Step1:** participant shall apply to Grid code secretariat (GCS) with full details of derogation required. Zimbabwe Electricity Transmission and	**Step 1:** Any party that requires derogations from certain provision of the grid code shall make a written application to Grid code development committee

				granting such exemptions	can consult an expert for opinion during the review of the derogation application	committee (GCAC) for its expert advice **Step3:** Regulatory authority takes the final decision upon the comments received from the GCAC	operator before deciding on a request **Step3:** In case of approval, depending upon the type of derogation, authority may approve derogation for individual entity or entire market players who are fit for the derogation	amendment proposal	provided with a copy 2) DNSP shall liaise with TSO before submitting the assessment of the derogation to ERB 2) Upon approval from ERB, secretariat shall update the register with the details of the derogation	Distribution Company (ZETDC) shall act as GCS **Step2:** GCS refers the application to Grid code Review Panel (GCRP) for its expert advice **Step3:** Regulatory authority takes the final decision upon the comments received from the GCRP	**Step 2:** GCDC shall review the application, involving experts if required, and make recommendations to regulator **Step 3:** Regulator shall take the final decision in relation to the derogation required
Process to change grid code	All ACER members in a synchronous zone must agree on change Change ratified by EU?	corresponding party should approach Independent regulatory Board with the modification proposal. IRB, guided by code review panel, will approve the change	Corresponding party should make an application to Grid code secretariat. Upon the receival of an application, secretariat requests a review by GCAC. After review, NERSA takes the final decision to approve the proposed changes in the grid code	Any market participant may request a change in the grid code. Regulatory authority, as a custodian, is responsible for amendments or changes in the grid code. It can take advice from Ethiopian National Transmission System Grid code Review committee (ENTSGCRC).	Any user of the national grid can make a formal request to modify any aspect of the grid code. Regulatory authority can take help from Grid code review committee; however, authority is not bound by the recommendation made by the committee	**Step1:** participant shall apply to Grid code secretariat (GCS) with full details of amendment proposed **Step2:** GCS refers the application to Grid code advisory committee (GCAC) for its expert advice **Step3:** Regulatory authority takes the final decision upon	**Suo moto changes in grid code:** Authority may revise the grid code every 3 years to make it up to date **Process for individual request:** step1: corresponding party should write to Code review committee step2: Authority, upon recommendation from code	**Step1:** Any participant may make a proposal to amend the grid code. The participant should first write it to Minister followed by another application to Grid code secretariat **Step2:** Secretariat shall forward the proposal to Grid code amendment committee for	**Step 1:** all the request shall be submitted to Distribution grid code review panel **Step 2:** After discussions, DGCRP shall make recommendations to ERB regarding the proposal **Step 3:** ERB shall take the final decision, upon considering the suggestions from DGCRP	**Step1:** participant shall apply to Grid code secretariat (GCS) with full details of amendment proposed. Zimbabwe Electricity Transmission and Distribution Company (ZETDC) shall act as GCS **Step2:** GCS refers the application to Grid code Review Panel	**Step 1:** Any party that proposes modifications to the existing grid code shall make a written application to Grid code development committee **Step 2:** GCDC shall review the application, involving experts if required, and make recommendations to

				However, it is not bound to follow the advice of ENTSGCRC while approving a change.		the comments received from the GCAC	review committee, may forward it to Ministry for final approval	their recommendation **Step3:** GCAC's recommendations are forwarded to the board for their comments **Step4:** The board forwards the proposal to Minister for approval. Minister may or may not approve the request Step5: Secretariat communicates the decision to the corresponding applicant		(GCRP) for its expert advice **Step3:** Regulatory authority takes the final decision upon the comments received from the GCRP	regulator **Step 3:** Regulator shall take the final decision in relation to the proposed amendment to the grid code

Table 23 Synchronous Generation Connection Codes

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Frequency tolerance requirements	**Normal** EU 49.0 - 51.0 Hz UK 49.5 - 50.5 Hz Nordic 49.0 - 51.0 Hz **Extreme** EU 47 - 51.5 Hz	Normal range 49.5 - 50.5 Hz Extreme 47 - 52 Hz	Normal range 49.0 - 51.0 Hz Extreme 47 - 51.5 Hz	Normal range 49.0 - 51.0 Hz Extreme 47 - 51.5 Hz	Normal Range 49.5 - 50.5 Hz under disturbance 49 -52 Hz Max. band under system fault 48.75 Hz - 51.25 Hz Extreme	51 Hz - 51.5 Hz for 10 mins Continuous operation in the range 49 Hz and 51 Hz 48.5 Hz - 49 Hz for 80 mins 48 Hz - 48.5 Hz for 10 mins	51.5 Hz - 52 Hz for at least 15 sec 51 Hz - 51.5 Hz for at least 90 min 49 Hz - 51 Hz continuous operation 47.5 Hz - 49	**High frequency requirements:** f > 52 Hz for at least 1 minute **over life of plant** 51.5 Hz - 52 Hz for at least 10 mins over		Generators shall be capable to work when the frequency momentarily rises to 51.25 Hz or falls to 48.5 Hz	Generators shall remain connected to the system within the frequency range of 48.5 Hz and 51 Hz

	UK 47 - 51 Hz Nordic 47.5 - 51.5 Hz				system operation f<47.5 Hz or f>51.5 Hz for 20 seconds	47.5 Hz - 48 Hz for 1 min 47 Hz - 47.5 Hz for 200 ms	Hz for at least 90 mins 47 Hz - 47.5 Hz for at least 20 sec	**life of plant** f > 51.5 Hz for five mins, trip the plant **Low frequency requirements:** 48 Hz - 48.5 Hz for at least 5 mins 47.5 Hz - 48 Hz for at least 30 sec f < 47.5 Hz at least 6 sec beyond which precautionary action can be taken			
High frequency control requirements	Primary frequency control mandatory Deadband 0.5 Hz & droop 2-12% Secondary and tertiary frequency control an ancillary service	Primary frequency, secondary and tertiary frequency control mandatory	Primary frequency control mandatory Deadband 0.5 Hz & droop 2-12% Additional primary, secondary and tertiary frequency control an ancillary service	Primary frequency, secondary and tertiary frequency control mandatory	Spinning, regulating and tertiary frequency control mandatory	1) The turbo-alternators shall be able to run for at least 10 mins in the frequency above 51 Hz but less than 51.5 Hz 2) In frequency above 51 Hz for more than 5 minutes, units shall trip in a staggered format approved by the TSO 3) In case of frequency	1) In case of unit islanding, the generation unit shall be able to maintain the operating frequency of the island group well below 52 Hz 2) In other instances, response to high frequency shall be implemented within 10 sec and be sustained	1) A requirement of 4% governor droop characteristics or as agreed by the system operator 2) Ability to respond within 10 seconds of excursion and sustainable throughout the excursion period		1) Governor droop characteristics shall be between 4% and 6%	All generators operating at capacity above the minimum generation requirement shall reduce the generation according to the connection agreement. The response shall be active within 10 seconds and shall be sustained until further

						above 51.5 Hz, generators can trip sequentially in a window of 30 seconds 4) the droop of the governor shall be 4%	throughout the duration of the excursion				instruction from the TSO
Low frequency control requirements	Primary frequency control mandatory units > 10-75 MW Deadband 0.5 Hz, response 1.5% & droop 2-12% Secondary and tertiary frequency control an ancillary service	Primary frequency, secondary and tertiary frequency control mandatory	Primary frequency, secondary and tertiary frequency control an ancillary service	Primary frequency, secondary and tertiary frequency control mandatory	Spinning, regulating and tertiary frequency control mandatory	1) All the units shall have a droop characteristic of 4% with a minimum response of 3% of the MCR within 10 seconds of a frequency incident and be sustainable for at least 10 minutes	Generation units shall be capable of a response of a minimum of 3% of registered capacity and the response should be sustainable for 10 minutes	1) A requirement of 4% governor droop characteristics or as agreed by the system operator 2) for hydro generators, all reasonable efforts must be taken to operate the unit under low frequency conditions, provided that system frequency is above 46 Hz		1) Governor droop characteristics shall be between 4% and 6%	All generators must be equipped with governor mechanism to provide primary frequency control response. The amount of active power to be injected by each generator shall be according to connection agreement.
Voltage tolerance requirements	0.85-0.9pu 60min 1.118-1.15pu 20-60min	0.95-1.05 pu (normal condition) 0.9-1.1 pu (single contingency) 0.85-1.2 pu (multiple contingency)	deviation should not be more than 5% of declared voltage in two periods of 10 minutes each	Voltage limitations of any generation unit shall not create variation in excess of +/-	Voltage limitations of any generation unit shall not create variation in excess of +/-	continuous operation in 0.9 pu - 1.1 pu range	Generator shall remain connected to the grid within the tolerance limits of +/- 10% from the nominal value	1) Normal operation between 0.9 pu - 1.10 pu 2) 0.2 sec of 0 pu voltage 3) 2 sec of 0.75 pu voltage	1) for connection of voltages less than 11kV, tolerance is +/-10% 2) for connection of voltages		Active and reactive power generated by the unit shall not be affected by voltage variation

				10% of nominal value	10% of nominal value			4) 60 sec of 0.85 pu voltage 5) voltage of one phase is not less than 5% of any of the other two phases	greater than 11kV, tolerance is +/-5%		between +/- 5 % of nominal value
Fault ride through	Fault voltage 0.05-0.3 Fault duration 0.15s Recovery voltage 0.85 Recovery time 1.5-3s	Fault clearance time: 80ms (400kV,500kV) 100ms (220kV -230kV) 120ms (<=132kV)		Fault clearance time: 80ms for 220kV and above 100ms for 132kV and below		Voltage drop to 0 for 0.2 sec 0.75 pu for 2 sec and 0.85 pu for 60 sec	**Low voltage ride through:** Generating units should be able to sustain low voltages as low as 0.05 pu and for a period of 1.12 sec before the voltage restores to original nominal value **High voltage ride through:** Generator shall sustain voltage of 1.2 pu for 0.2 sec and 1.15 pu for 1 sec				

Table 24 Nonsynchronous Generation Connection Codes

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Frequency tolerance requirements	Normal EU 49.0 - 51.0 Hz UK 49.5 - 50.5 Hz	Normal range 49.5 - 50.5 Hz Extreme 47 - 52 Hz	Normal range 49.0 - 51.0 Hz Extreme 47 - 51.5 Hz	Normal range 49.0 - 51.0 Hz Extreme 47 - 51.5 Hz	49.5 - 50.5 Hz continuous operation 49 - 50 Hz at least 60 mins	47.5 Hz - 50.5 Hz	51.5 Hz - 52 Hz for at least 15 sec 51 Hz - 51.5 Hz for at least	a steady state operation between 49 Hz and 51 Hz		No renewable energy specific requirements. Conditions for	Generation unit shall remain connected to the grid in the

	Nordic 49.0 - 51.0 Hz Extreme EU 47 - 51.5 Hz UK 47 - 51 Hz Nordic 47.5 - 51.5 Hz				48 - 51.5 Hz At least 30 mins 47.5 - 51.5 Hz at least 3 mins <41.75 or >51.5 Hz at least 20 seconds <47 Hz for more than 0.2 sec, may disconnect >52 Hz for more than 4 sec, must disconnect		90 min 49 Hz - 51 Hz continuous operation 47.5 Hz - 49 Hz for at least 90 mins 47 Hz - 47.5 Hz for at least 20 sec			synchronous generation shall be used	range of 48.5 Hz and 51 Hz for 47.5 Hz < f < 48 Hz, for not more than 10 mins for 48 Hz < f < 48.5 Hz, for not more than 20 mins for 48.5 Hz < f < 49 Hz, for not more than 30 mins for 50.2 Hz < f < 51.5 Hz, for not more than 30 mins
High frequency control requirements	Primary frequency control mandatory Deadband 0.5 Hz & droop 2-12% Secondary and tertiary frequency control an ancillary service	Generating units must have capabilities set out in the power frequency curve agreed with the TSO	Primary frequency above 50.5 Hz mandatory any additional primary, secondary and tertiary frequency control an ancillary service	1) Ability to Operate at level below its instantaneous capacity	1) Ability to Operate at level below its instantaneous capacity	Units shall be capable of running in limited frequency sensitive mode in case of over frequencies (LFSM-OF). This is also called as "power curtailment during over frequency" in some African countries	**Power park stations are not expected to participate in frequency control until instructed by the TSO** 1) Generating units shall activate frequency control mechanism as soon as technically possible and no later than 2 seconds. Response shall be fully achieved in 10 seconds and	1) A capability to ramp down the output of the generating unit in the band set by SO and with a droop decided by it 2) Ability to implement different droop in a range of values set by SO	1) If frequency is more than 52.5 Hz, current shall be reduced till the frequency reaches 51.5 Hz. If the situation continues for 10 mins, system shall disconnect within 3 sec 2) Power plants shall be able to receive a set point corresponding to active power output from the SO	No renewable energy specific requirements. Conditions for synchronous generation shall be used	1) Step change of 10 % of rated power output is allowed at maximum 2) The ramp rate shall be 20% of rated power / min

							be sustainable throughout the excursion 2) Output shall be reduced in case of high frequencies and allowed to increase only when the frequency touches 50.05 Hz		and implement it		
Low frequency control requirements	Primary frequency control mandatory units > 10-75 MW Deadband 0.5 Hz, response 1.5% & droop 2-12% Secondary and tertiary frequency control an ancillary service	Generating units must have capabilities set out in the power frequency curve agreed with the TSO	Primary frequency, secondary and tertiary frequency control an ancillary service	1) Ability to Operate at level below its instantaneous capacity	1) Ability to Operate at level below its instantaneous capacity	1) Only the new generators, where proportion of non-synchronous generation reaches 30% at PoC, have to participate in full active frequency response 2) response shall be activated within 2 seconds and shall reach 3% of maximum rating in 10 seconds. The response shall be sustainable for 10 minutes	Generation units shall be capable of a response of a minimum of 3% of available active power and the response should be sustainable for 10 minutes	1) Ability to ramp up the power output by a % decided by the SO, if there is a overloading capability inherent to the unit. This ramping has to be done with a droop set by the SO		No renewable energy specific requirements. Conditions for synchronous generation shall be used	

Voltage tolerance requirements	0.85-0.9pu 60min 1.118-1.15pu 20-60min	0.95-1.05 pu (normal condition) 0.9-1.1 pu (single contingency) 0.85-1.2 pu (multiple contingency)	deviation should not be more than 5% of declared voltage in two periods of 10 minutes each	Voltage limitations of any generation unit shall not create variation in excess of +/- 10% of nominal value	Voltage limitations of any generation unit shall not create variation in excess of +/- 10% of nominal value	0.9 pu - 1.1 pu	Generator shall remain connected to the grid within the tolerance limits of +/- 10% from the nominal value	1) Units shall be able to remain connected to the grid between the voltage levels of 0.9 pu and 1.1 pu 2) A settable ramp rate between 1 kV/min and 100 kV/min 3) Capability to regulate voltage within a set point with resolution of 0.01 pu	1) for connection of voltages less than 11kV, tolerance is +/-10% 2) for connection of voltages greater than 11kV, tolerance is +/-5% 3) Inverter shall disconnect within 3 seconds in the event of average voltage is greater than nominal operating voltages for continuous 10 mins 4) Shall tolerate voltage unbalances resulting from system disturbances	No renewable energy specific requirements. Conditions for synchronous generation shall be used	1) Wind power generation units shall remain connected to the grid between the voltage range of 0.85 pu and 1.15 pu. 2) If the voltage level is between 1.10 pu and 1.15 pu for more than 30 minutes, the unit shall disconnect
Fault ride through	Fault voltage 0.05-0.3 Fault duration 0.15s Recovery voltage 0.85	The fault ride through conditions are to be agreed between the corresponding TSO and the	**For Solar/Wind plants** Continuous connection between 0.9 and 1.1 pu	**For Solar/Wind plants** Continuous connection between 0.9 and 1.1 pu	**For Solar/Wind plants** Shall remain connected throughout voltage dips	1.2 pu for 2 sec and 1.15 pu for 60 sec	**Low voltage ride through:** Units shall remain connected to grid till voltages as	**Low voltage ride through:** 1) For 0.85 pu < U < 0.9 pu, system shall remain connected for		No renewable energy specific requirements. Conditions for synchronous	1) for 0 pu, remain connected for 150 ms 2) for 0.85 pu, remain connected for

	Recovery time 1.5-3s	Renewable power producer	0 pu for 0.15 sec <0.85 pu for 2 sec 0.85 pu for 3 sec 1.1 < voltage < 1.2pu for 2sec	0 pu for 0.15 sec <0.85 pu for 2 sec 0.85 pu for 3 sec 1.1 < voltage < 1.2pu for 2sec	Continuous connection between 0.9 and 1.1 pu 0 pu for 0.15 sec <0.85 pu for 2 sec 0.85 pu for 3 sec 1.1 < voltage < 1.2pu for 2sec		low as 0.15 pu. At 0.15 pu, the unit shall remain connected for 0.625 sec. For voltages between 0.15 pu and 0.94 pu, unit shall remain connected for 3 sec, beyond which it can disconnect from the system **High voltage ride through:** unit shall remain connect at voltages between 1.1 pu and 1.2 pu for 2 sec	a maximum of 120 sec 2) For 0 pu < U < 0.85 pu, system shall remain connected for a maximum of 2 sec and a minimum of 0.2 sec		generation shall be used	3 sec 3) for any value between 0 pu and 0.85 pu, a linear line connecting 150 ms and 3000 ms 4) Generator shall ride through a voltage drop to 0.3 pu for two successive failure of automatic reclosure
Synthetic inertia	TSO to decide			Requirement of balancing ancillary service from wind plants	Requirement of balancing ancillary service from wind plants	If the power from non-synchronous generation reaches 30% of the total power delivered at the PoC, the new generators that are added shall have the capability to	No exclusive condition related to synthetic inertia. But units are expected to participate in the frequency control programme during both low and high frequency excursions				

						participate in the frequency control of the system					

Table 25 Operations Planning Codes

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Data for operational security analysis in operational planning	Individual grid models for year-ahead, week-ahead, day-ahead and intraday	Each TSO shall ensure data corresponding to generation and transmission reactive power resources like status of transformer taps, voltage regulators and power system stabilisers are available to all TSOs, EAPP CC	National transmission company (NTC) is responsible for modelling during the power system planning	Daily/weekly/ monthly/yearly Demand estimation (MW,Mvar,MWh) combined with system studies by ENTSO	**EAPP requirement:** 1) System frequency 2) Transmission line status 3) Active and reactive power flows 4) Voltages at transmission busbars 5) Dynamic and static reactive power reserves 6) overload and protection alarms **Kenyan requirements:** Hourly/Daily/ monthly load forecast data, and the source of the forecast	TSO is in charge of maintaining the technical database required for this purpose	1) Load forecast from users like bulk suppliers, distribution networks and large users 2) Generation related data like planned outages, maintenance plans, generation capability 3) Power system model, developed in collaboration with various users of the system	1) Data submitted to TSO by users before commissioning of the facility, subject to periodic updates in even of any changes		1) Demand forecast 2) Generation scheduling 3) Demand control procedures 4) Contingency plans	1) Existing technical models of the power system maintained by TSO 2) Models of to be connected or to be expanded systems provided by the users of the grid
Year ahead planning scenarios	(a) electricity demand; (b) the	**Ten Year Ahead plan submitted**	**Five Year ahead plan (published**	**Ten year ahead plan:** 1) load and	**Ten Year ahead plan:** 1) Specific	**Ten Year ahead plan updated**	**1 year ahead planning is called mid-**	1) Generation and import plans			1) Day with highest system

	conditions related to the contribution of renewable energy sources; (c) determined import/export positions, including agreed reference values allowing the merging task; and (d) the generation pattern, with a fully available production park; (e) the year-ahead grid development.	**annually:** 1) Forecast of seasonal minimum and maximum at reference dates set by control centre 2) Amount and nature of generation currently available 3) Generation capacity required to meet operational margins 4) Additional units and upgradation of existing units 5) Power exchange with external systems 6) Transmission system capability	**annually):** 1) Recent data from generators, embedded generators, NTC, TNSPs and distributors 2) Scenarios for growth in demand from consumers 3) Scenarios for growth in generation 4) Committed projects for generation 5) Demand Management programmes 6) Reasonable assumptions related to exports and imports	generation forecasts 2) Equipment performance scenarios	customer information 2) System performance statistics 3) KNTS load and generation forecast 4) Government and customer development plans 5) Equipment performance scenarios	**annually:** 1) 10 years demand forecast of distributors and end users **Annual operations plan:** 1) Adequacy and capability of the generation units to meet the demand for the next 5 years 2) planning and placement of the generator and transmission outages 3) Possible problems that can arise during the planning period and their alternative solutions 4) Adequacy of the emergency procedures in place	**term operational planning** 1) Historic demand data 2) Weather forecast 3) Historic demand trends 4) Incidence of major activities or events 5) Unit power generation forecast or schedule 6) Demand transfers (reconfigurati on) 7) Planned demand shedding	2) load forecast for each substation 3) Thermal limits of the transmission equipment 4) Transient stability 5) Bus bar arrangement 6) Projects initiated by transmission company			demand 2) Day with lowest system demand 3) weather estimates corresponding to the above two days 4) Output from embedded generation 5) Planning of individual distribution companies to manage the increased demand in their control area
Common model development	Defined in Article 17 of Regulation	EAPP sub-committee on planning shall	Generators are responsible	1) ENTSO is responsible for collection	1) KNTSO is responsible for collection	Tanzania Electric supply company	**System operator is responsible**	Transmission company is responsible		ZETDC is responsible for the	Generators are responsible

	(EU) No 2015/1222,	be responsible for co-ordinating the system model development	for provision of following data for purpose of system planning 1) Simulation models of the generation unit 2) information required by the TSO for the operation of the electricity sector	of data from users for planning and system studies 2) Users shall provide updated EMS model data every year in a mutually agreed upon electronic format	of data from users for planning and system studies 2) Users shall provide information requested by TSO for the purpose of planning and monitoring, without delay	(TANESCO) is in charge of keeping an up to date technical database for the purpose of planning and system studies All the electricity supply players shall provide the information requested by TANESCO for this purpose	**for creation and maintenance of models** 1) Generators to provide dynamic models, control systems, power capabilities like rated capacity 2) Transmission to provide transformer and line data 3) Distributors to provide models for complex load and protection relay settings	for building of a technical database of the entire power system. All the users are mandated to share the required information with the company for this purpose This data can be static and recorded during commissionin g or dynamic and updated every year		maintenance of technical data base of the power system for the purpose of modelling and system studying. Co-operation is mandatory from all the connected users for this purpose	for provision of following data for purpose of system planning 1) Simulation models of the generation unit 2) information required by the TSO for the construction and maintenance of such database
Operational security analysis	N-1 All voltage limits and flows adhered to	1) N-1 contingency criterion 2) Interchange scheduling 3) operational reserve 4) Voltage control 5) Fault level control 6) protection co-ordination 7) Remedial	1) N-1 contingency criterion	1) N-1 contingency criterion 2) Interchange scheduling 3) operational reserve 4) Voltage control 5) Fault level control 6) protection co-ordination 7) Remedial	1) N-1 contingency criterion 2) Interchange scheduling 3) operational reserve 4) Voltage control 5) Fault level control 6) protection co-ordination 7) Remedial action	1) Operation within technical standards and equipment ratings 2) Transmission capability of TS under normal and emergency conditions 3) Annual studies	1) Transmission system voltage 2) Transmission system frequency 3) Load power factor 4) Thermal loadings 5) Fault levels 6) System stability	1) Multiple outages of credible nature shall be studied 2) Black start capability of the system 3) Primary and emergency control centre functioning 4) Reliable		1) load flow analysis 2) Fault analysis 3) Stability analysis	1) Load flow Studies 2) Short circuit studies 3) Transient stability studies 4) Steady - state stability studies 5) Voltage collapse analysis 6) Electro-magnetic

		action schemes		action schemes	schemes 8) Auxiliary supply 9) Supply restoration 10) Switch gear operation	related to changes in the bulk system	7) Reliability criteria (N-1)	communicatio n systems			transient analysis 7) Reliability analysis
Regional operational security coordination	TSO must communicate with regional authority Plan to coordinate to be put in place	TSOs are responsible for operational aspects like N-1 criterion, voltage control, operational reserve etc. in their region and notify the EAPP CC	International operator may request SO to take an action to increase/decr ease the power flow. This can be addressed without jeopardising the South African power system	1) participating, as a TSO , in EAPP's automatic load shedding programme, to control frequency and voltage 2) Rota disconnection s for planned outages	1) participating, as a TSO , in EAPP's automatic load shedding programme, to control frequency and voltage 2) Rota disconnection s for planned outages		No discussion related to regional power pool in the grid code	Shall be governed by SAPP agreement			The grid code is drafted so that it refers to only the internal process within Egypt. Relations with neighbouring countries have to be negotiated directly with them
Regional outage coordination	TSO's can combine plans under a single security coordinator	EAPP CC co-ordinates with all the member TSOs and generators to formulate the annual outage plan	NA	The present law stipulates that ENTSO be following the procedure set down by EAPP for regional outage coordination	The present law stipulates that KNTSO be following the procedure set down by EAPP for regional outage coordination		No discussion related to regional power pool in the grid code	Shall be governed by SAPP agreement			The grid code is drafted so that it refers to only the internal process within Egypt. Relations with neighbouring countries have to be negotiated directly with them
Methodology for outage coordination	all TSOs shall jointly develop a	1) Demand forecast for 3 years ahead	1) all the outages involving the	1) Generators/Tr ansmission	1) Each Generating unit has to	**Philosophy:** 1) Customer load shall be	1) Methodology is divided into	1) all the outages involving the		1) All users shall work with ZETDC to	

	methodology at least per synchronous area, for assessing the relevance for the outage coordination of power generating modules, demand facilities, and grid elements located in a transmission system or in a distribution system, including closed distribution systems.	are submitted to EAPP CC 2) Generators submit draft outage plans 3) TSOs submit draft outage plans 4) pre-emptive rights of TSOs are submitted Final plan is published at the end of each year as a result of iterative process by CC	TNSP should be negotiated by the effected customers and noticed at least 14 days in advance 2) TNSP should try to optimise these outages to reduce the risk to the power system 3) Generator outages are to be planned in conjunction with transmission outages, with generator outages given higher priority 4) TNSP has a responsibility to make sure there are not more than one outage in a particular bay during a given period. however it is the system operator who is to take the decision during the	entities shall submit the outage plans for the next fiscal year 2) TSO is responsible for conducting the system studies to ensure there are adequate resources to maintain the grid security 3) TSO can defer outages if it is deemed fit for the operation. 4) An annual outage plan is published after many iterations involving discussions with relevant participants 5) a quarterly review of the outage plan is conducted to make any necessary modifications to the plan depending on the events occurring during the	publish their planned outage plans. 2) TSO shall co-ordinate the annual outage plan ensuring sufficient reserves all the time 3) Generating units are expected to apply before each individual outage with the relevant details 4) upon study, TSO shall give the final approval for the corresponding outage	shed for a reasonable time rather than risking a cascading failure of the power system **Planned outage:** 1)every generator shall publish 52 week ahead outage plan containing the details of the maintenance related outages 2) SO, together with the transmission, shall optimise this plan to ensure minimum disruption to the system **unplanned outage:** 1) outage requester shall apply to transmission outage scheduler for the approval 2) This will be followed by	short term, medium term and long term outage plans. 2) Year ahead plan is expected to be very detailed compared to 2,3 year ahead plans 3) Generators first submit the maintenance outage requirement by November 1 of each year. later SO and generators agree upon a final outage plan 4) This is followed by Transmission or distribution service providers, where they publish their outage plans 5) SO optimises these plans to maximise the system reliability and	TNSP should be negotiated by the effected customers 2) TNSP should try to optimise these outages to reduce the risk to the power system 3) Generator outages are to be planned in conjunction with transmission outages, with generator outages given higher priority 4) TNSP has a responsibility to make sure there are not more than one outage in a particular bay during a given period. However, it is the system operator who is to take the decision during the real time operation		develop an outage plan for the subsequent financial year 2) Each user shall obtain approval from ZETDC prior to availing any outage 3) ZETDC has the authority to reject the outage approval request, if it determines that the outage is detrimental to system stability, reliability and safe operations	

			real time operation	operation 6) the generation and transmission programmes should be as per their latest approved outage plans and approval is required before every outage		an approval from System operator outage scheduler 3) Final approval/rejection is given by the shift controller on the day of execution	security; publishes the final plan 6) planned outages (other than planned maintenance events) can be scheduled with notice of at least 2 days depending upon the duration of the outage and SO is expected to accommodate these request as possible as technically				

Table 26 System Operational Security Codes

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Operational security alert condition	Voltage and power flows within limits Frequency outside limits Reserve reduced > 20% for longer than 30 mins	An occurrence of a contingency together with commitment of all the operation reserves available for balancing of transmission and generation facilities	1) Possibility of unmet demand even after usage of expensive contingency resources 2) ACE deficit exceeding the available resources for 10 mins 3) frequency is less than 49.8 Hz for	**Alert condition of EAPP:** An occurrence of a contingency together with commitment of all the operation reserves available for balancing of transmission and	**Alert condition of EAPP:** An occurrence of a contingency together with commitment of all the operation reserves available for balancing of transmission and	1) Impendable mismatch between supply and demand 2) ACE deficits exceeding the reserves 3) Operating frequency less than 49.8 Hz for more than 10 minutes 4) Frequency out of	A risk of widespread and serious disturbance to the whole or part of the transmission system	1) frequency of the system is out of the range 49.5 Hz to 50.5 Hz 2) possibility of mismatch between the generation and demand for the power 3) Occurrence of any safety related issue		1) Demand-supply mismatch	1) Gross reserve is less than the largest capability of unit or line 2) Generation deficiency exists 3) Voltage exceeds +/-5% but within +/-10% 4) Critical loading of

			more than 10 minutes 4) operating frequency out of limits (<49.5 ,>50.5)	generation facilities **Alert condition of Ethiopia:** 1) a mismatch between the demand and supply of power	generation facilities **Alert condition of Kenya:** 1) a mismatch between the demand and supply of power 2) Cyber security incident related to the communication systems 3) Unauthorised firmware update 4) Trigger of tamper detection mechanism	operating ranges 5) security or safety related issue					transmission line or substation equipment by more than 90% but less than 110% 5) any possible weather disturbance
Operational security emergency condition	Voltage or power flows outside limits Frequency outside limits One measure of defence plan activated TSO Scada/ EMS tools unavailable > 30 mins	Emergency is defined as an unstable operating conditions such as 1) cascade tripping 2) low voltage or frequency 3) loss of synchronism 4) loss of supplies 5) islanding of generating units		**Emergency condition of EAPP:** Emergency is defined as an unstable operating conditions such as 1) cascade tripping 2) low voltage or frequency 3) loss of synchronism 4) loss of supplies	**Emergency condition of EAPP:** Emergency is defined as an unstable operating conditions such as 1) cascade tripping 2) low voltage or frequency 3) loss of synchronism 4) loss of supplies	A situation where Transmission or Distribution licensees have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises their ability to supply their	1) Fault affecting system circuits, plants or apparatus which in turn can affect more than 20% of distribution system customer base 2) Overloading of the systems in excess of	Unplanned loss of facility or situation beyond the control of SO and has potential to jeopardise the system		sudden loss of generation substantially in excess of the spare capacity available	An outage without cascading effects with following conditions 1) voltages more than +/- 10% 2) Overloading by more than 110%

				5) islanding of generating units	5) islanding of generating units **Kenyan definition:** 1) Sudden loss of generation in excess of spare capacity	system demand.	110% of the rated capacity 3) Total or partial blackout 4) system separation				
Operational security blackout state	Loss of > 50% of demand Loss of voltage > 3 mins										
Operational voltage security limits	TSO to decide	EAPP connection code contains the operational voltage limits of the inter connection Normal 0.95-1.05 pu N-1 contingency 0.9-1.1 pu Multiple contingency 0.85-1.2 pu	for voltages >=500V +/-10% for voltages <500V +/-15%	**EAPP requirements:** Normal 0.95-1.05 pu N-1 contingency 0.9-1.1 pu Multiple contingency 0.85-1.2 pu +/-1% of nominal voltage for frequent voltage flicker +/-3% of nominal voltage for infrequent voltage flicker	**EAPP requirements:** Normal 0.95-1.05 pu N-1 contingency 0.9-1.1 pu Multiple contingency 0.85-1.2 pu +/-1% of nominal voltage for frequent voltage flicker +/-3% of nominal voltage for infrequent voltage flicker	A deviation of 10% on either side of the nominal continuous operational voltage is allowed	1) Under normal conditions, there shall not be more than +/-6% deviation in the voltage from the nominal value 2) Under contingency conditions, there shall not be more than +/-10% deviation in the voltage from the nominal value	1) varies as per the voltage of operation of the particular section under study. Allowed deviation Can be as low as 4.58% for 765kV and as high as 13.63 for 88kV	1) for connection of voltages less than 11kV, tolerance is +/-10% 2) for connection of voltages greater than 11kV, tolerance is +/-5%	Deviation shall not be more than +/-5% of the standard value of operation	1) Normal voltage range shall be 0.95 pu - 1.05 pu 2) Voltage can fall between 0.90 pu and 0.95 pu for a maximum of 1 minute 3) Voltage can rise between 1.05 pu and 1.10 pu for a maximum of 1 minute 4) Transient voltages can drop to 0 pu or 1.4 pu for not more than 1 second
Short circuit analysis	TSO must calculate short circuit levels at	TSOs are responsible for calculation of short circuit	National transmission company (NTC) is	Planning and development organisation is responsible			**System operator is responsible for this**			A detailed fault analysis is mandatory during any	A detailed fault analysis is mandatory during any

	interconnection points	currents at each node within its control area, by considering effects of neighbouring control area	responsible for the study of transmission system development options. This study can involve short circuit analysis	for the study of transmission system development options. This study may involve short circuit analysis			1) the short circuit current in event of a fault shall be well within the operating limits of the equipment 2)Short circuit analysis shall identify the circuit elements that can be damaged due to short circuit. new functional settings shall be calculated 3) Alternative circuit configuration shall be selected to avoid this damage and configuration shall be verified for its effect on the system stability			additions or modifications to the grid. During these studies, the short circuit currents are calculated at all the possible fault locations and compared with the standard tolerance values of individual equipment	additions or modifications to the grid. During these studies, the short circuit currents are calculated at all the possible fault locations and compared with the standard tolerance values of individual equipment Alternative circuit or bus bar configurations are identified to keep the fault levels within the acceptable limits of the individual equipment
Power flow limits	Maintain within limits under N-1	Power flow within the EAPP interconnector shall be maintained within the Net transmission	System operator (SO) is responsible for determination of operational limits	the ENTSO is responsible for the load flow studies and setting an operational limits on the system	Thermal ratings of standard transmission lines and transformers are to be updated every	1) Thermal ratings of standard TS lines shall be used as initial check and be updated from time to time.	Power flows due to addition of new generation stations should be well within the	1) Thermal limits of the equipment shall be used as a checklist to verify overloading of the power		1) A detailed load flow analysis is performed to study the effects of any modifications/ additions to	1) A detailed load flow analysis is performed to study the effects of any modifications/ additions to

		capability (NTC) limits		A minimum of offline verification every week and studies using actual data SCADA data wherever possible	year by KNTSO. These ratings are to be used as initial check for line or equipment overloading	The temperatures used are 90°C for firm supply and 75°C for non-firm supply 2) TSO is responsible for studies to determine the system operational limits every year	planning criteria under normal and contingency conditions	system 2) Current flow limits of shunt capacitors, circuit breakers		the grid. 2) Power flow limits used in this analysis are the standard limits stipulated by the manufacturer. 3) Thermal design ratings shall not be exceeded during steady state operations	the grid. 2) Power flow limits used in this analysis are the standard limits stipulated by the manufacturer. 3) Thermal design ratings shall not be exceeded during steady state operations
Contingency analysis	If non-compliance N-1 determined the remedial action must be immediately taken	N-1 contingency with following contingency 1) a single transmission line 2) A single or combination of generating units 3) A single transformer 4) A voltage compensation installation 5) A HVDC link Multiple contingency: 1) A double circuit line 2) A single busbar	N-1 (or N-2) contingency criteria is used for long term planning purpose	N-1 contingency with following contingency 1) a single transmission line 2) A single or combination of generating units 3) A single transformer 4) A voltage compensation installation 5) A HVDC link **Multiple contingency:** 1) A double circuit line 2) A single busbar	**EAPP definition of contingency:** N-1 contingency with following contingency 1) a single transmission line 2) A single or combination of generating units 3) A single transformer 4) A voltage compensation installation 5) A HVDC link Multiple contingency: 1) A double circuit line	N-1 contingency is used for long term planning purpose	1) Electrical lines shall withstand loading up to 110% for at least 30 minutes 2) Transmission system shall remain stable in the event of a trip of large generator station or short circuit of an electric line (N-1 criterion)	1) N-1 criterion with most unfavourable generation pattern shall be used for contingency analysis 2) N-2 criterion with average generation pattern shall be used		1) N-1 criterion shall be used for contingency analysis 2) Voltage shall remain within 0.9 pu and 1.10 pu in the event of a single contingency 3) transient voltages during a disturbance shall not be out of the range 0.8 pu - 1.2 pu for more than 500 milli seconds	1) N - 1 criterion for transmission lines working at 400 kV and 500 kV voltages. N-2 criterion for lines working at 220 kV, 132 kV and 66 kV

		3) More than one generation unit		3) More than one generation unit	2) A single busbar 3) More than one generation unit **KNTS requirement:** 1) a single contingency in busbars should not affect more than 100MW of supply **(at generation level)**						
Protection	Main and back-up protection mandatory on transmission system	Mandatory equipment of two fully redundant protection systems from two different suppliers. In addition, a separate backup protection is also provided	**System protection:** 1) Under-frequency load shedding 2) out of step tripping 3) Under voltage load shedding 4) sub synchronous resonance protection	1) Fault clearance times 2) Circuit breaker fail protection 3) reliability of protection systems (99.5%) 4) 2 redundant main protection system for transmission facilities 5) Technical requirements for generation units and their connection 6) Technical criterial for	1) Fault clearance times 2) Circuit breaker fail protection 3) reliability of protection systems (99.5%) 4) 2 redundant main protection system for transmission facilities 5) Technical requirements for generation units and their connection 6) Technical criterial for	1) all the generators shall comply with the technical and operational requirements of the protection system. 2) protection setting of the individual units shall be co-ordinated with the setting of transmission protection 3) Automatic voltage regulator (AVR) is mandatory for	1) All the users of transmission system shall implement minimum protection scheme 2) the design of protection systems by the users shall be as per the approved standards 3) Reliability of all the protection equipment shall be as per prudent utility practices 4)Protection schemes by	1) under frequency load shedding 2) out of step tripping 3) Under voltage load shedding 4) Sub - synchronous load shedding 5) Protection against near 50 Hz resonance	**System protection:** 1) Under frequency load shedding 2) Prevention of voltages sliding 3) Forced outages 4) Ensuring continuous power supply to power station auxiliary system	**Equipment protection:** 1) All the switches shall operate as per the accepted fault clearance time 2) Generators shall be protected by adequate protection system 3) Transmission lines shall have main and backup protection system System protection:	**Equipment protection:** 1) All the equipment required for safe and reliable operation of the grid shall be having two separate and independent protection systems 2) All circuit breakers shall have two independent trip coils 3) Protection system shall not trip during routine power swings

				communication 7) Transmission system performance indicators	communication 7) Transmission system performance indicators	the units 4) Under-frequency load shedding 6) out of step tripping 7) Under voltage load shedding 8) sub synchronous resonance protection	the transmission system is mainly for the security of the transmission system. users are responsible for protection of their assets 5)Protection relay setting shall be co-ordinated with the system operator			1) Under frequency load shedding	decided by the TSO 4) All circuit breakers shall have fail protection 5) Fault clearance times of all the protection systems shall be as per the standard time limits 6) All protection systems shall have "system dependability index" of not less than 98%
Protection review	Review every 5 years including dynamic stability	Mandatory calibration of equipment at least once a year. Review of protection system whenever there is an expansion or modification to the transmission and generation facilities	1) To ensure high level of protection performance and sustainability, TNSP shall monitor the protection performance of TS 2) All generators to confirm protection compliance every 6 years	1) Annual Recalibration of every protection equipment and review of relay settings 2) Review of schemes during every expansion or changes of generators	**EAPP requirements:** 1) TSO and EAPP shall review the under and over frequency settings of the relays every year 2) Each protection device must be tested and re-calibrated at least once a year 3) A review of protection	1) Distribution shall submit report of periodic testing of the load tripping relays in its network 2) generators shall conduct a routine testing of protection settings by a competent persons 3) transmission systems shall conduct a	1) Protection system settings shall be reviewed during every event of changes or expansion on the generation/transmission facilities	1) Periodic testing of protection equipment and system to ensure a performance as per the design standards 2) continuous monitoring of the protection system's performance	1) Emergency plans intended to protect the system in emergency conditions shall be reviewed every 2 years	1) Protection equipment shall be tested every two years	1) Periodic review meetings by the TSO to co-ordinate the system protection 2) Periodic testing and maintenance of the protection system equipment 3) Periodic testing of the communication channels 4) Digital protection

					settings shall be carried in the event of any design changes or expansion of the facilities **KNTS requirements:** 1) Periodic review of list of the critical resources and the authorised persons with access to these resources (cyber security) 2) bi-annual review of generation compliance by all the generation licensees	periodic testing of protection systems and their settings 4) Transmission shall monitor the performance of the protection systems 5) System operator shall review the relay settings for main and back up protection of the TS					system shall be verified every 4 years 5) Static protection system shall be verified every 2 years 6) Electro-mechanical protection shall be verified every 6 months
Special protection schemes	Allowed but must be coordinated with affected TSO's	SPS called Remedial Action Scheme (RAS) is allowed. Depending on the effect of automatic actions, an agreement is needed between the implementing		Remedial Action Scheme (RAS) stipulated by EAPP requirements	Remedial Action Scheme (RAS) stipulated by EAPP requirements		1) System operator may require protection scheme other than the standard requirements for system stability and protection			Any protection scheme that can increase the utilisation of the investment already made like automatic shedding of generation	

		TSO and affect parties like EAPP, users, neighbouring TSOs									

Table 27 System Operations Codes

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Primary frequency control reserves	Dimensioning for FCR (primary reserves) must be coordinated per synchronous area	Primary reserve to be provided by EAPP is equal to the size of the largest generator connected to the system	Instantaneous reserve that is fully activated in 10 seconds and sustained for 10 minutes is equivalent to the primary reserve of the power pools	**EAPP requirement:** The amount of primary reserve should be equal to the size of the largest single generating unit connected to the system	**EAPP requirement:** The amount of primary reserve should be equal to the size of the largest single generating unit connected to the system	called regulating reserve. It is activated within 10 seconds and fully available within 10 minutes. Used to match second by second matching of the demand and supply. Objective is to maintain the system frequency within +/- 0.5 Hz	Spinning reserves, already synchronised to the power grid, are the reserves that provide primary response to the real time changes in demand. Followed by a 10-minute reserve, that can be fully activated well within 10 minutes	Regulating reserve, which are used to match the second by second demand and supply are equivalent to primary control reserves			All generators must be equipped with governor mechanism to provide primary frequency control response. The amount of active power to be injected by each generator shall be according to connection agreement.
Control area agreements	TSO can agree to combine to single control area	EAPP is divided into control areas. One of the TSOs in the control area becomes the operator. This requires	If a participant is in emergency, other participants should support to the extent necessary for	As per EAPP regulations, ENTSO has to be a part of a control area led by one of the participating TSO	As per EAPP regulations, ENTSO has to be a part of a control area led by one of the participating TSO	System operation shall be co-ordinated between system and the control areas. This includes co-ordination of				ZETDC is one of the control areas within SAPP. ZETDC shall employ AGC and manual frequency control as per the	The grid code is drafted so that it refers to only the internal process within Egypt. Relations with neighbouring countries have to be negotiated directly with them

		agreement between the TSOs of a control area	safe operation of the power system			outages, voltage levels, MW and MVAR flows and switching that affect two or more components of the system				agreement between ZETDC and SAPP	
Cross border reserve activation	FCR allowed but limited to 50% for security Regulation reserve allowed as long as there is sufficient transfer capacity Replacement reserve allowed as long as there is sufficient transfer capacity		SAPP agreement shall apply for operational liaison with all international power systems connected to the TS			From Tanzania's side, TSO shall co-ordinate the operation of international tie-lines		shall be governed by SAPP agreement			The grid code is drafted so that it refers to only the internal process within Egypt. Relations with neighbouring countries have to be negotiated directly with them
Frequency control targets	Each synchronous area to decide	calculated by Control area contribution co-efficient. It is the ratio of total annual energy in a control area to annual energy generated in EAPP	Quality control criteria defined by NRS 048 and south African power pool requirement	1) frequency not less than 49.8 Hz for more than 10 minutes 2) frequency of operation is within 49.5 Hz and 50.5 Hz 3) EAPP mandated control	49.7 Hz < f < 50.2 Hz	1) Spinning reserve have target of maintaining the frequency above 49 Hz 2) Regulating reserves have the target of maintaining the	Under normal operations 50 Hz +/- 0.75 Hz Under exceptional circumstances 47 Hz - 52 Hz	1) for islanded systems, target is to maintain the system frequency between 49 Hz and 51 Hz 2) Normal frequency of operation is between	For grid networks normal operations shall be within 49 Hz to 51 Hz For island networks normal operations shall be	Normal range 49.85 Hz - 50.15 Hz During disturbance 48.5 Hz - 51.25 Hz Exceptional disturbance 47.5 Hz - 52.5 Hz	normal range - 49.95 Hz - 50.05 Hz

		connected power systems		targets as per the total installed capacity		frequency within +/- 0.5 Hz from 50 Hz		49.5 Hz and 50.5 Hz	within 47.5 Hz to 52.5 Hz		
Ramping restrictions	TSO 's in a synchronous area must calculate HVDC ramping limits to be agreed between two synchronous areas	1) Wind/solar plants should be capable of controlling the ramp rate at the maximum set point sent by the respective TSO 2) Range of possible ramp rate should be between 1MW/min and 30MW/min		1) Wind/solar plants should be capable of controlling the ramp rate at the maximum set point sent by the ENTSO 2) Range of possible ramp rate should be between 1MW/min and 30MW/min	1) Wind/solar plants should be capable of controlling the ramp rate at the maximum set point sent by the ENTSO 2) Range of possible ramp rate should be between 1MW/min and 30MW/min		Not less than 1.5% of registered capacity per minute	1) A voltage control ramping between 1kV/min and 100kV/min is mandatory for renewable power plants 2) Active power ramping of renewable power plants shall be between 1% of total capacity/min and 50 MW/min and this rate shall be settable by SO	1) Renewable power plants shall follow the ramping restrictions laid down by the system operator during the start, output change and controlled shut down of the plant	1) Ramp rate of generators shall be within +/- 10% of the registered ramp rate and as per the instructions received from the system operators unless otherwise stated	TSO shall instruct the generator with required ramp rate. In any case, limiting ramp rate shall not exceed 10% of rated power
Reserve dimensioning	FRR and RR is sufficient to cover the positive LFC block imbalances for at least 99 % of the time	frequency control target of each control area is converted into primary reserve using demand-frequency response curve of the control area	1) for maintaining frequency above 49.5 Hz, single largest contingency is Koeberg unit of 920MW. 2) For maintaining frequency			1) TSO calculates the Reserve margin of each generating unit with due consideration to start-up price, response characteristic s, system	CEB shall calculate the quantum of operating reserves noting the following aspects and get authority's approval 1)Magnitude of largest	The quantum of various reserves is government by the agreement made between Namibia and other participants of SAPP		the minimum reserve dimension shall be 10.6% for thermal power stations and 7.6% for hydro power station (for planning)	Value of primary reserve to be provided by each generator will be stated in the connection agreement

			above 49 Hz under credible multiple contingency is 1800 MW (equivalent to 3 units of Cahora Bassa)			constraints, availability of generating units, hydro dam levels and lake inflow rates in its weekly plans 2) Single largest contingency is Kihansi with 60 MW capacity	generation infeed 2) Predicted frequency drop due to loss of largest infeed 3) possibility of demand control 4) cost of operating reserves 5) Ambient weather conditions 6) Availability of water in hydro power plants				

Table 28 Information Exchange Codes

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Mandatory information monitoring	(a) generation; (b) consumption; (c) schedules; (d) balance positions; (e) planned outages and substation topologies; and (f) forecasts	1) Active power flows on transmission circuits and from generation stations (MW) 2) Reactive power flows on transmission circuits and from generation stations (MVArs)	1) Energy accounting information 2) TS time lagged Status information 3) Monthly generator performance indicators 4) Significant events such as catastrophic failures 5) performance of distributors	**Operational Planning:** 1) a detailed list of static and dynamic information from users, generators, TNSP, Distributors used for operational planning, facility initiation **Post-dispatch information**	**Operational Planning:** 1) a detailed list of static and dynamic information from users, generators, TNSP, Distributors used for operational planning, facility initiation **Post-dispatch information**	**Operational planning:** 1) Mandatory weekly maintenance planning update by the generators to Transmission and system operator 2) 24 hours day ahead ancillary service schedule 3) Monthly	1) Performance of grid users on power quality standards 2) Maintenance and system logs of system operator and users	1) Mandatory monthly and annual performance of the users connected to the grid according to the standard indicators in the grid code and negotiated indicators in the agreements 2) Hourly	1) Monthly performance reports by the generators	1) Actual generation sent out power 2) Actual active power drawn by grid users 3) Tie line interchange 4) Reactive power flow into and out of grid 5) System frequency 6) Voltage	1) Bi-annual reliability reports by the generators 2) quarterly performance reports by TSO

		3) Voltages at generators bus bars and transmission lines (kV) 4) MWh 5) MVArh 6) Amps 7) System frequency (Hz) 8) Transmission line status 9) static and dynamic reactive power reserve 10) appropriate alarms including overload and protection alarms	and end-users 6) Monthly TS performance indicators 7) Monthly and annual system operation performance information (imports, exports, MW etc) 8) Distributor and end user data 9) bi-annual unit compliance/non-compliance reports by generators	**to be provided by TSO:** 1) a detailed system and generation unit information 2) Operational information of each unit dispatched 3) Operational information about overall dispatch **Performance data:** 1) Monthly performance report of generators 2) Monthly performance report of TSO 3) Monthly performance report of distributors	**to be provided by TSO:** 1) a detailed system and generation unit information 2) Operational information of each unit dispatched 3) Operational information about overall dispatch **Performance data:** 1) Monthly performance report of generators 2) Monthly performance report of TSO 3) Monthly performance report of distributors	performance data by generators, transmission system, system operator and distribution companies 4) a detailed list of static and dynamic information from users, generators, TNSP, Distributors used for operational planning, facility initiation 5) A mandatory bi-annual compliance report by every generator 5) Mandatory power quality monitor and fault recorder by the non-synchronous generators at the PoC		demand for each day, maximum and minimum demand in a year along with the time of their occurrence; SO is in charge of this 3) Bi-annual compliance report by the generators 4) Bi-annual fault level report by transmission company		profiles of all stations and point of connection 7) Equipment loading 8) Generator's performances on monthly and annual basis 9) Distributors and large consumers performance on annual basis	
Forecast Data exchange between TSOs	(a) the regular topology of substations and other	1) Ratings of transmission system facilities	1) Generation plan (New addition and expansion	**Between ENTSO and participants:** 1) Generation		**Between TANESCO and participants:** 1) Generation		**Data exchange between TSO and users:**		1) all users shall submit forecast of monthly	**data to be exchanged between TSO and users:**

	relevant data, by voltage level; (b) technical data on transmission lines; (c) technical data on transformers connecting the DSOs, SGUs which are demand facilities and generators' block-transformers of SGUs which are power generating facilities; (d) the maximum and minimum active and reactive power of SGUs which are power generating modules; (e) technical data on phase-shifting transformers; (f) technical data on HVDC systems; (g) technical data on	based upon appropriate ambient conditions 2) Demand on EAPP interconnected transmission system and its distribution on various nodes 3) Transmission system capability 4) Interchange with external systems 5) Timing of new facilities 6) outage schedule of existing facilities 7) list of contingencies to be considered during program execution 8) Generation indicative of the conditions under study	included) 2) Export and import plan 3) Distributor and customer load forecast data (10 years ahead load forecast) 4) Load forecast for each node in the Power system	plan (New addition and expansion included) 2) Export and import plan 3) Distributor and customer load forecast data (10 years ahead load forecast) 4) Load forecast for each node in the Power system		and import capacity plans shall be used to obtain the generation pattern 2) Forecast of demand at each substation by referring to the distributors and end users connected		1) Generation and import plans for determination of generation pattern 2) Distributor and end-user load forecast		demand for the year ahead, at all points of connection, to ZETDC 2) All users shall submit forecast of daily demand for the month ahead, at all points of connection, to ZETDC	1) Demand profile of individual user on the day of peak system demand (at each of the connection points) 2) Demand profile of individual user on the day of minimum system demand (at each of the connection points) 3) Demand profile of individual user on the day of local peak demand (at each of the connection points) 4) Annual forecast of energy for each connection point 5) Forecast of embedded generation of each user 6) Amount of demand reduction

	reactors, capacitors and static VAR compensators ; and (h) operational security limits defined by each TSO TSO SCADA/ EMS tools unavailable > 30 mins										available with each user for the purpose of demand management
Real-time data exchange between TSOs	(a) frequency; (b) frequency restoration control error; (c) measured active power exchanges between LFC areas; (d) aggregated generation infeed; (e) system state in accordance with Article 18; (f) setpoint of the load-frequency controller; and (g) power exchange via virtual tie-lines.	EAPP CC and TSOs shall agree on the type of operational data to be exchanged on real time basis and shall ensure that appropriate systems are in place	1) Frequency 2) Gross MW 3) Gross Mvar 4) net MW 5) net Mvar 6) Rotor RPM 7) Stator kV (real time data to be shared between generator and operator)	**Users shall exchange the following SCADA data:** 1) Breaker status 2) Analog measurements (voltage and flows) 3) Generation MW and Mvar 4) Load MW and Mvar 5) Balancing area net interchange 6) operating reserve 7) Instantaneous demand	**Users shall exchange the following SCADA data:** 1) Breaker status 2) Analog measurements (voltage and flows) 3) Generation MW and Mvar 4) Load MW and Mvar 5) Balancing area net interchange 6) operating reserve 7) Instantaneous demand	**Users shall share the below SCADA data with TSO:** 1) Frequency 2) Gross MW 3) Gross Mvar 4) Net MW 5) Net Mvar 6) Stator kV 7) Rotor RPM 8) list of status indicators	1) Voltage 2) Current 3) frequency 4) Active and reactive power 5) Plant status indicators 6) Alarm indicators	**Users shall exchange the following SCADA data with TSO:** 1) Breakers status 2) Analog measurements (voltage and flows) 3) Generation MW and Mvar 4) Load MW and Mvar 5) Balancing area net interchange 6) operating reserve 7) Instantaneous demand	1) MW 2) Mvar 3) MWh 4) frequency 5) Voltage	**Generation SCADA requirements:** 1) MWh 2) Voltage 3) Frequency 4) MW 5) Mvar **Transmission SCADA requirements:** 1) Voltage 2) Frequency 3) MW 4) Mvar 5) Current	**Between TSO and generators:** 1) Generating units status 2) Circuit breaker status 3) status of various switches 4) various alarm status 5) protection system signals 6) Bus and line voltage 7) Real and reactive power 8) Frequency 9) Transformer tap change position

Generation data to TSO	Long list of planning and operational data		1) Generator planning data (one time before connection) 2) Maintenance plan (annual) 3) operational data (real time Exchange)	1) list of information corresponding to operational planning 2) list of real time SCADA data	1) list of information corresponding to operational planning 2) list of real time SCADA data	1) Monthly performance data listing the indicators required by the authority 2) Maintenance plan for 3 years, updated every week 3) static information related to the individual generating units for the purpose of system studies and database updating	1) static data corresponding to the active and reactive capabilities of generators, requiring an update in the event of any changes to the unit	1) Generators shall provide a monthly review of performance indicators listed in the grid code		1) Declared available capacity 2) reduction or re-establishment of the declared available capacity 3) Yearly maintenance requirements in the form of weeks of outage time required per year	1) Generation unit technical data 2) Generation unit outage data 3) Operational planning data 4) Scheduling and dispatch data
Demand data to TSO	Long list of planning and operational data		1) Day-ahead energy schedule 2) Day-ahead ancillary service schedule 5) Hourly system total MW loading 6) Hourly system market prices 7) hourly power station MW sent out 8) Hourly constrained	1) hourly/daily/ monthly load forecast data and the source of forecast 2) Transmission system loss to be included in the demand forecast 3) Demand response resources 4) Non-confirming	1) hourly/daily/ monthly load forecast data and the source of forecast 2) Transmission system loss to be included in the demand forecast 3) Demand response resources 4) Non-confirming	1) 5 year ahead load forecast data 2) an estimate of 10 years ahead demand	1) Yearly submission of active and reactive power consumption forecast by distribution licensee, bulk supplier and large user connected to TS 2) Every large consumer that requires a connection to HV line or a	Each distributor and large end-user are required to submit the following load forecast related data to TSO 1) 5 year ahead load forecast data 2) an estimate of 10 years ahead demand		1) a forecast of demand for 10 years at each point of supply	1) connection point data corresponding to demand and demand transfer capability 2) Demand control data 3) Load characteristic data 4) User demand profiles and active energy data

			generation 9) Hourly international tie-line power flow 10) pre-determined system load flow data	load data and long list of other items	load data and long list of other items		modification to existing lines shall provide the System operator with 5-year demand estimate				
Communication protocol	ICCP	ICCP or as agreed between TSOs and EAPP CC	IEC standard for SCADA and communication	IEC standard for SCADA and communication	IEC standard for SCADA and communication	IEC standards for SCADA		IEC standard for SCADA and communication		As specified by ZETDC	As per the connection agreement between generator and TSO

Table 29 Metering Code

Criteria	ACER	EAPP	South Africa	Ethiopia	Kenya	Tanzania	Mauritius	Namibia	Zambia	Zimbabwe	Egypt
Meter period		1 hour	30 minutes	1 hour (for inter connection meters)	**EAPP requirement:** hourly active and reactive power and energy	Half hour (30 minutes)	15 minutes	30 minutes		Integrating pulse meter shall be able record pulses that is adjustable between 15 minutes and 60 minutes	Meters shall be capable of integrating over time period of 15 , 30 and 60 minutes
Meter accuracy		Accuracy class of 0.2 or better (0.2%)	ranges from class 0.2 to class 2, Depending on the load	class 0.2 to class 1 depending on the voltage of the connection class 0.2 or better (for interconnections)	**EAPP requirement:** Accuracy class of 0.2 or better (0.2%) **KNTGC requirement:** As per IEC standards	As per NRS 057 (South African standard). ranges from class 0.2 to class 2, Depending on the load	Class 0.2 with accuracy of +/- 0.5%	As per NRS 057 (South African standard). ranges from class 0.2 to class 2, Depending on the load		Accuracy Class 0.2 or equivalent	Accuracy class 0.2

Calibration and inspection		Calibration a least every 3 years	5 years for Larger capacity meter, 10 years for smaller ones	Calibration a least every 3 years (for inter connection meters)	**EAPP requirement:** Mandatory calibration every 3 years Mandatory connection checking every 5 years	NRS 057-4 dictates the process of testing the metering installations	1) System operator is responsible only for electro-mechanical meters 2) Electronic meters shall be calibrated at factory with for guaranteed calibration period 3) Meters shall be recalibrated only at factories after the expiry of guaranteed calibration period or before this period in case of any drift in readings	Recalibration procedure shall be as per NRS 057:2001. Apart from periodic recalibration of the metering systems, a verification is mandatory at least once a year where values from database is compared to the meter readings	as per the standard ZS 647	1) instrument transformers shall be tested for their accuracy at least once in 5 years or whenever accuracy of the equipment is in doubt 2) Electricity meters shall be tested every year and recalibrated during these tests if necessary	Meter inspection and testing shall be done at least once a year
Security		Meters must be sealed and physical checks every 3 months	Access to meters is only to authorised personnel	Meters must be sealed and physical checks every 3 months (for inter connection meters)	Meters must be visible but the Access to meters is only to authorised personnel	1) No Electronic access to meters to any users, except under authority granted permission 2) Access to meters to	1) Sealing of the meters with recalibration date marked on the seals along with the marks that identify person in	1) No Electronic access to meters to any users, except under authority granted permission 2) Access to meters to	1) No Electronic access to meters to any users, except under authority granted permission 2) Access to meters to	1) Meters are sealed every time they are tested 2) Meter cubicles are completely closed, provided any register on the	1) Both TSO and user shall use their own seal to securely seal the meter 2) Meter cubicles are completely closed, provided any register on the equipment is visible

						only authorised personnel	charge of sealing	only authorised personnel	only authorised personnel	equipment is visible	
Disputes		Dispute procedure in general conditions	First step is incident reporting. Then escalated to non-conformance . Final step is mediation/arbitration by NERSA	1) Issuance of notice by the effected party to the party responsible for issue and resolve with discussion 2) in case of failed discussion, Regulatory authority can be requested to resolve the dispute	1) Issuance of notice by the effected party to the party responsible for issue and resolve with discussion 2) in case of failed discussion, Regulatory authority can be requested to resolve the dispute	**Step1:** affected party issues an incident report to the affecting party **Step2:** if not resolved, a non-confirmation report is issued to the management **Step3:** if step 2 fails, matter is referred to authority for mediation/arbitration	**Step1:** if the metering system is found to be inaccurate by more than allowed by the standard, parties shall decide on an estimated value of the consumption **Step2:** if both the parties fail to agree on a single estimate within the reasonable time (PPA, IA etc.), they may request arbitration as per the agreement between both the parties	**Step1:** affected party issues an incident report to the affecting party **Step2:** if not resolved, a non-confirmation report is issued to the management **Step3:** if step 2 fails, matter is referred to authority for mediation/arbitration		Resolution is as per the governance code	**Step 1:** concerned parties shall try to resolve the disputes amicably through discussions **Step 2:** Failed discussions eventually leads the matter being referred to regulator
Meter data confidentiality		No third party access allowed	Confidential information. Treated as per info exchange code	All data exchanged between parties in relation to ENTS is considered confidential	Meter data and passwords are confidential. As such they are treated accordingly	Meter data and passwords are confidential. As such they are treated accordingly		Metering data is considered confidential by the code	Billing related data is confidential information and shall be treated as per information	Metering data is considered confidential by the code	unless otherwise specified, all the data exchanged between the users and TSO is considered confidential by the grid code

									exchange code			
Operational metering		Operational metering to meet real-time operation requirements		**EAPP requirement:** 1) MW, MWh, Mvar, Mvarh, cumulative demand. Additionally, time of use, power quality monitoring (for inter connection meter) **ENTGC requirement:** 1) ENTSO and Users shall agree on the format of the indicators to be measured	**EAPP requirement:** 1) MW 2) MWh 3)Mwvar 4)Mwvarh 5) time of use 6) Power quality indicators in both export and import directions **KNTGC requirement:** 1) meters should record both active and reactive energy consumed, in both ways	1) both active and reactive power measurement in both directions	**The parameters to be metered are subject to PPA:** Following list is a possible but not an exhaustive 1)Active energy (MWh) OUT & IN 2) Reactive energy (Mvarh) first quadrant 3) Reactive energy (Mvarh) fourth quadrant 4) Active power demand (MW) OUT & IN 5) Reactive power demand (Mvar) first quadrant 6) Reactive power demand (Mvar) second quadrant	1) both active and reactive power measurement in both directions	1) both active and reactive power measurement in both directions	1) kW 2) kWh 3) kVar 4) kVarh 5) Cumulative demand 6) time of use 7) pulse output	**Meters shall measure the following quantities in both directions** 1) kW 2) kWh 3) kVar 4) kVarh **Additionally following items are required** 5) Cumulative demand 6) time of use 7) pulse output

							7) Apparent power (MVA) OUT & IN 8) Total harmonic distortion 9) power factor				

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