Milestone 4 Report:
Market Operator (MO) and Market Procedures

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Initiative of
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1.0 Executive Summary

1.1. Introduction

For over a decade the Government of Nigeria has been moving towards establishing a competitive electricity sector. Having unbundled the industry from a vertically integrated monopoly into three separate sectors – generation, transmission and distribution/retailing – it is appropriate for the country to begin the next logical step in the evolution of the industry and initiate the process of allowing competition in the generation sector. To facilitate a competitive generation sector The *Market Rules for Transitional and Medium Term Stages of the Nigerian Electricity Power Sector* (MRTS), have been developed and approved.

A competitive generation sector requires not only unbundling but also equal and non-discriminatory access to both the capacity of the transmission system as well as system operation. The latter activity involves the simultaneous coordination of (1) supply (*i.e.,* the output from competitive generators) and (2) demand using the (3) transmission network. When electricity is flowing, *i.e.,* being produced, transmitted across the network and consumed, these three components must be operated like a single integrated "machine."

Seamless integration of the three components requires that the choices made by the participants are consistent (*i.e.,* aligned) with reliable operation of the grid. Because the electricity "machine" runs so quickly we require an "air traffic controller" or system operator who has been granted unilateral authority over the actions of the participants and their assets for short intervals of time.

In order for this "machine" to work efficiently, transparently and reliably we need to ensure there is precise coordination among the participants and the system operator. This is accomplished by defining and then assigning the necessary responsibilities of the participants and the system operator through an agreed upon set of rules. In addition to assigning responsibilities, the rules also need to define how these obligations are carried out.

Reliable operation of the electricity "machine" requires that all the identified tasks must be performed. Thus, if a market participant does not perform a specific task, then it *must* be done by the system operator and vice versa – failure to successfully carry out a given task can result in the failure of the machine. One of the most important aspects of electricity market design is deciding the right balance between the tasks that are to be performed by the system operator and those to be performed by the market participants. At one extreme, if the rules assign all the responsibilities to the system operator, then there will be little or no ability for the generators to compete with each other. In effect, the rules will have unwittingly re-constituted the monopoly generator. While we know there will be a system operator, one of the crucial tasks of the market design exercise is to achieve the appropriate balance that maximizes both reliable operation of the grid and the ability for generators to compete.

The contractual environment prior to the imposition of competition an open access is fairly simple. The vertically integrated monopolist has unilateral control over both generation and transmission and internalizes the complexity of grid operations. Reliable operations can be almost entirely defined and determined unilaterally by the vertically integrated monopolist.

In this environment it is appropriate to think of the monopolist as supplying "delivered energy" to a customer at a specified off-take point. Because the monopolist owns and controls the entire "machine" right up to the customer's off-take point, power purchase agreements can transfer ownership at the off-take point. The monopolist is able to write these types of contracts because unilateral control from the generation to the exit point means they are able to internally manage most of the risk of producing and transporting the electricity. However, disaggregating generation from transmission capacity and system operation necessarily means the generation company can no longer manage any of the risks associated with transport or dispatch. This must have an effect on the ensuing structure of power purchase agreements.

When the electricity "machine" is owned and operated by a single company or government agency no other entity had access to the transmission system. In this situation there is no need to define and determine a "transmission right" because no generator other than the monopolist could access the grid. A "transmission right" is a "right" to use the transmission system. Where use of the system constitute access to the transmission capacity and access to the dispatch process. We can use an airport as an analogy. If an airline company wants to use the airport they need to have "landing strip capacity", *i.e.,* they need to own, rent, or lease some amount of the physical capacity of the landing strip, and they also need the air traffic controller to allow them to take off and land their planes. A user of the electricity grid has the same requirements.

Defining and allocating transmission rights is a necessary step in implementing competition and open access. As a result this issue has been dealt with in other areas. Two distinct methodologies have been developed:

1. The "physical rights" model whereby a transmission right has a physical interpretation. Specifically a participant must have the right to the transmission capacity they use to transport power from a source to a sink.

2. The "financial rights" model whereby a transmission right has no physical interpretation; rather it is purely a financial right to revenue streams (positive or negative) that arise from using the transmission system.

Neither is without problems, though international experience has shown that the physical rights model has far greater limitations.

Thus, the central issue of electricity market design is to develop non-discriminatory mechanisms for allocating transmission capacity while maintaining reliability and allowing competition between generators and different technologies (*i.e.,* generation technologies as well as demand side response).

The fundamental characteristic of the proposed market is the separation of the physical and financial aspects of electricity. Specifically, the market underpinned by the MRTS is based on:

- The assumption that the frequency and cost of transmission constraints are both insignificant.

- This assumption then allows for an electricity pricing structure that is, by design, largely unrelated to actual decisions made by the System Operator.

- Since the grid is assumed not to suffer constraints, the Rules provide little guidance to the System Operator during times when the grid is constrained.

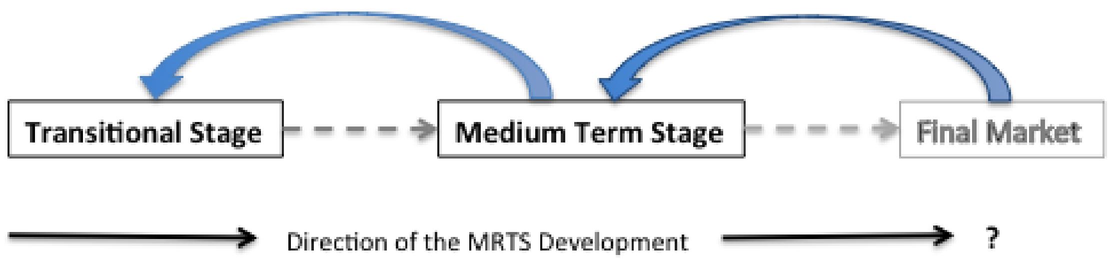
- The fundamental tool provided by the MRTS to the System Operator to manage real time supply and demand balancing is Operating Reserve.

To the extent that transmission constraints are more, rather than less prevalent, the market design will face problems. Moreover, a constraint-free electricity grid, as is present in Singapore, does not represent an optimal situation. Investment in transmission infrastructure should only take place up to the point where the marginal benefit (i.e. the reduction in the costs caused by constraints) of additional transmission capacity equals the marginal cost of the investment. This criteria implies that the complete elimination of constraints is rarely, if ever, economically optimal.

1.2. *Conclusions and Recommendations*

Regarding the creation and operation of an electricity market, the Government of Nigeria has stated that its objective of the "Rules are to establish and govern an efficient, competitive, transparent and reliable market for the sale and purchase of wholesale electricity."[1] In their current form the structure defined by the MRTS will not achieve these objectives.

- As depicted in the following diagram, the process for creating a competitive electricity market in Nigeria envisions a staged approach in which a Transitional Phase is followed by a Medium Term Stage and then a the Final Market. The MRTS are primarily focused on the Transitional and Medium Term Stages. In fact the MRTS provides no description or detail regarding the Final Market design. Moreover, there is little in the way of detail on the transition from one stage to the next.



The Underlying Development Process of the MRTS and the Market

There is a fundamental problem with this approach because there is no vision regarding the end state, *i.e.,* what will the Final Market look like, how will it work, what components will it have, will it be based on physical/financial transmission rights, how will prices be determined, etc.?

The need to understand the end state is not a luxury and its omission will have significant consequences. To the greatest extent possible the evolution of the market should be incremental. Because poor market design forces structural changes, the evolution will be more costly to implement and will cause dislocation in the industry/economy as well. For example, there is no doubt whatsoever the costly disaster that occurred with the California electricity market was completely avoidable.[2] The effects of a poorly designed market are wide ranging. They include but are not limited to: high costs to end users, uncertain and inefficient contracting, inefficient infrastructure investment, costly and time consuming market re-design and implementation, etc. The crisis that occurred in the California electricity market was directly related to a poorly thought out final market design and was completely avoidable.

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[1] Section 2.1 of the *Market Rules for Transitional and Medium Term Stages of the Nigerian Electricity Power Sector.*
[2] The aggregate cost has been estimated at US$40-$45 billion (see http://en.wikipedia.org/wiki/California_electricity_crisis)

We therefore recommend that a White Paper describing the basic cornerstones of the Final Market be written, vetted through the industry and stakeholders and eventually adopted. The purpose of the White Paper is to connect or bridge the language and objectives of the EPSR Act 2005 to the market design process and then to the eventual market rules and finally to the operation of the market. The EPSR Act 2005 provides the government's objectives but it (correctly) does not provide the answer to "how" the objectives will be achieved nor does it address "why" a specific design is to be chosen. There are four discernible parts to the market design process and each has a deliverable:

(1) The underlying legislative or regulatory authority,

(2) The design process itself,

(3) The creation of the market rules, and

(4) The approval process.

The Final Market Design White Paper is, in essence, the deliverable for the second part.

Even though the MRTS, i.e. the market rules, have been created and approved does not change the need to address the second "part" of the process. The four components are integrated as well as integral for the design and operation of a successful market. Each step cannot be ignored or short-changed. The MRTS are by definition the interim and not the final rules and much debate, indeed most of the discussion on market design, implementation and operation within the Nigerian electricity sector still needs to take place. This is manifested in the MRTS through the lack of detail contained in the rules and the problematic rules provided for dispatch.

We firmly believe that at the end of the process of developing the White Paper, certain aspects of the existing MRTS will need to be rewritten as a result of better understanding of how electricity markets actually function. This entire process, from drafting the White Paper to incorporating comment and to making any necessary changes to the MRTS should take no more than 9-12 months if managed properly. This time frame is entirely reasonable given the state of the electricity industry in Nigeria.

We would have preferred that the basic elements - no substantial or specific detail is needed - regarding the final market had been worked out prior to the development of the medium term market rules. That is we would have preferred for the process to work backwards from the basic high level design concepts contained in the White Paper rather than incrementally towards an unknown target. The industry needs to fully understand and appreciate the importance of: the dispatch function, different mechanisms for allocating transmission capacity, the effect of unconstrained energy-only pricing, self-commitment of generation compared to centralized commitment, etc., in order to move to the final market design.

It is crucially important for the White Paper to reflect the input and eventually the support of the stakeholders. As such, we recommend that a formal stakeholder process under the direction of the System and Market Operators be tasked with this project.

- Our second recommendation is that the consequences of the implicit assumption that the transmission grid is largely unconstrained should be verified. As discussed in the body of this report, the success of the market created by the MRTS is directly related to this assumption. The greater the significance - both financially and number of occurrences - of transmission constraints, the more likely the market will fail. Therefore, before any material work begins on implementing the Medium Term market, an analysis of the transmission grid should be conducted to validate the appropriateness of this assumption.

- Contingent on the findings with respect to the transmission constraints, our third recommendation is to evaluate the quantity, cost and availability of operating reserves that will be necessary to balance real time supply and demand.[3]

- The MRTS dictates there will be a single unconstrained price for imbalance energy regardless of the location on the grid. To the extent there are transmission constraints this necessarily means the "energy" price will not be cost reflective. Specifically, some load will pay far less than their true marginal cost while others will pay far more. This pricing is neither fair nor non-discriminatory and will reduce or eliminate the transparency of the dispatch process. It may also risk the reliability of the system because the pricing signals are in direct opposition to the needs of dispatcher in ensuring system reliability, i.e. at locations where the dispatcher would like *greater* load, the price is artificially increased by the pricing rule, thereby *reducing* the quantity of electricity demanded, while at the same time, at locations where the dispatcher would like *less* load the pricing rule *encourages* consumption by artificially reducing the price. Therefore, our fourth recommendation is to eliminate the unconstrained price in favor of a price signal that is more reflective of cost causation.

- The fifth recommendation is to provide additional specificity to the Market Monitoring rules with respect to how market power will be defined, the methodology by which the potential abuse of market power will be determined by the Market Monitor and what procedures will be used to mitigate the use of market power.

- Related to the previous recommendation, regarding price offers made by generators, it is not clear whether the rules envision that the offer is supposed to be a single price offer (i.e., the offer includes the return to capital and the marginal cost of producing) or simply the marginal cost of producing the electricity.

- It is not clear whether transmission losses will be priced according to marginal or average losses. While either can be used, economic efficiency is obtained by using marginal losses, especially on a transmission system where line losses are significant.

- Both the MRTS and the Grid Code are silent with respect to how integration with the West Africa Power Pool and the adjacent electricity systems will take place. This

[3] We note that the *Draft Electricity Market Rules* for Ghana specifies that generators must set aside an exorbitant 20% of their capacity to serve as Operating Reserves.

becomes increasingly relevant as the ECOWAS Master Plan for WAPP is implemented. The rules should describe how the seams will be managed.

- We higher costs and no commensurate benefit from separating the System and Market Operators.

2.0 Section A: Introductory Comments and Background Material

2.1. Introduction and Objective

For over a decade the Government of Nigeria has been moving towards establishing a competitive electricity sector. Until the latter part of the 1990's the technological base of electricity production exhibited economies of scale, *i.e.,* the average cost of producing a megawatt of electricity declined the larger the scale of the operation. This necessarily meant that larger generator plants produced electricity on a per unit basis more cheaply than smaller plants. Thus it was economically efficient to have one large plant rather than several smaller, more expensive units, *i.e.,* a single regulated monopoly (either by government ownership or explicit regulation) was economically preferred to competition between several smaller units. Figure 1 details how the underlying technology led to a specific market structure and then to a specific commercial environment.

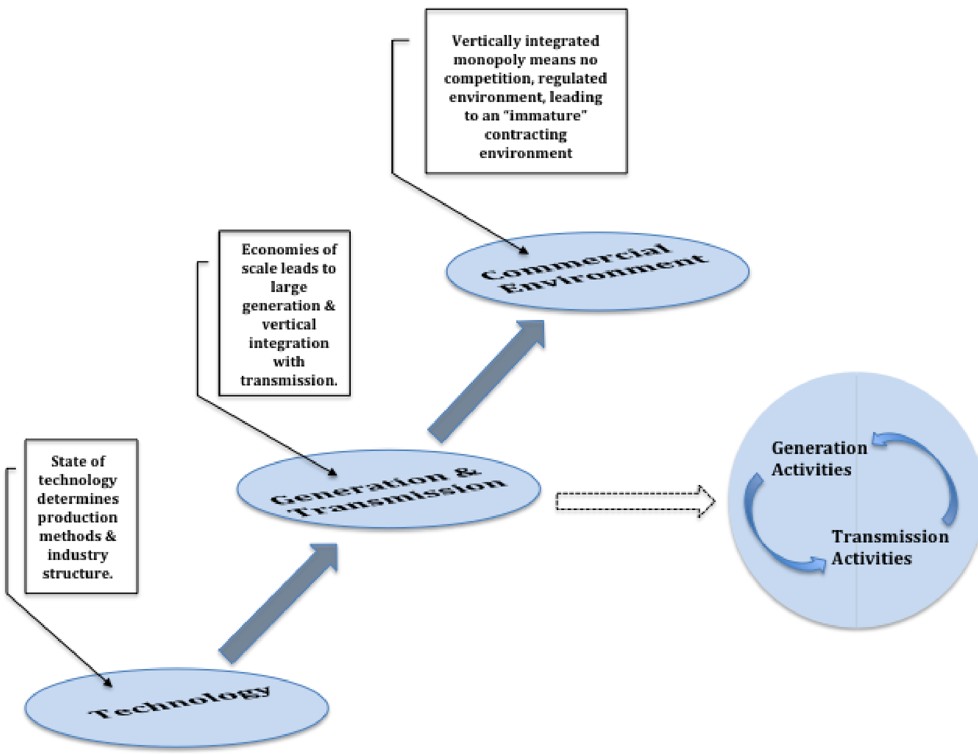

Figure 1: Relationship between technology, production and transport and the commercial environment in the electricity sector.

While, electricity transmission, with high capital costs relative to variable costs, was also most efficiently organized as a monopoly, vertical integration of generation and transmission was the byproduct of the underlying technology in generation. Since larger generation was more efficient, the key investment decision was related to location. Was it more efficient to build a large plant close to input fuel sources and most likely away from the load and transport the finished electricity to the load? Or, alternatively, was it more efficient to build (usually smaller) plants closer to the load and transport the input fuel to the plant? Optimal decision-making required an integrated approach that resulted in the aggregation of generation and transmission into a single vertically integrated monopolist. With a single integrated monopoly supplying electricity, there was no need for a robust commercial environment. Regulation or similar government-based processes set prices and contracts were limited and relatively simple. Importantly the complexity of producing and transmitting electricity was subsumed within the operations of the monopoly.

As will be discussed in Section B, technological advances over the past 20 years have eroded the efficiencies arising from large-scale generation. As a result, smaller scale generation plants can now compete effectively on a per unit cost basis with their larger counterparts. The consequence of the new state of technology is that there is no longer any justification for generation to be organized as a monopoly. Nor is there any economic justification for the integration of generation and transmission into a vertically integrated entity.

Because of the technological changes, Nigeria, like many other countries, has unbundled the vertically integrated monopoly into two separate sectors – generation and transmission.[4] It is now appropriate for the country to begin the next logical step in the evolution of the industry and initiate the process of

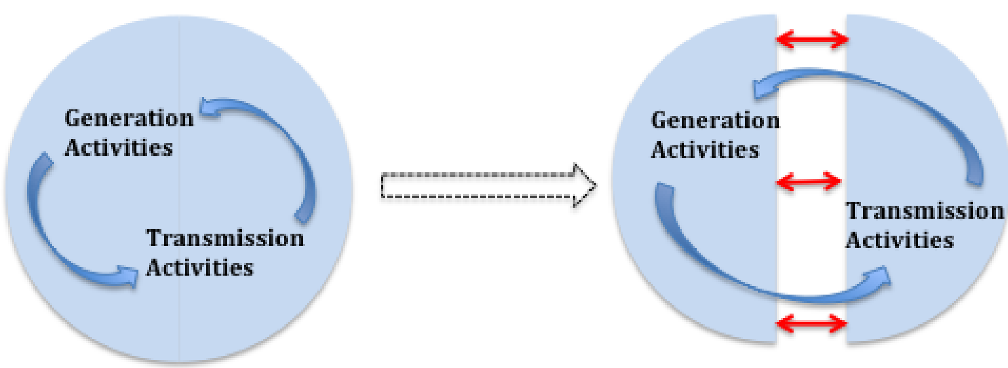

Figure 2: Unbundling Generation from Transmission.

allowing competition in the generation sector. In Figure 2 we show the effect of introducing competition and open access into the industry – the previously vertically integrated monopoly that was responsible for both generation and transmission activities is separated into two entities.

Introducing competition will leave some things unchanged – the laws of physics cannot be changed by legislation, regulation or contracts – but in many other areas it will result in fundamental changes. In particular under a vertically integrated monopoly (*i.e.,* where generation and transmission activities are housed within a single firm) structure, there is no need to define or

[4] We abstract from the situation where the initial monopoly also contained the distribution/retailing function because the focus of this analysis and the MRTS is a review of the wholesale market rules.

grant access to the transmission grid since competition is prevented. Neither is there any need to explain how the system is being operated on a minute-to-minute basis. This information is relevant only to the monopolist since there are no other generators connected to the grid.

However, once competitive generators are allowed to connect to the grid, then ownership (*i.e.,* access) and operation of the transmission grid must be completely separated from any and all generators. Furthermore, all generators must have equal and non-discriminatory access to the transmission system as well as to system operation function. The latter activity involves the simultaneous coordination of (1) supply (*i.e.,* the output from competitive generators) and (2) demand using the (3) transmission network. When electricity is flowing, *i.e.,* being produced, transmitted across the network and consumed, these three components must be operated like a single integrated "machine." Figure 3 provides the complete picture of what must take place with the previously vertically integrated monopolist in order to implement open access and allow competition to take place.

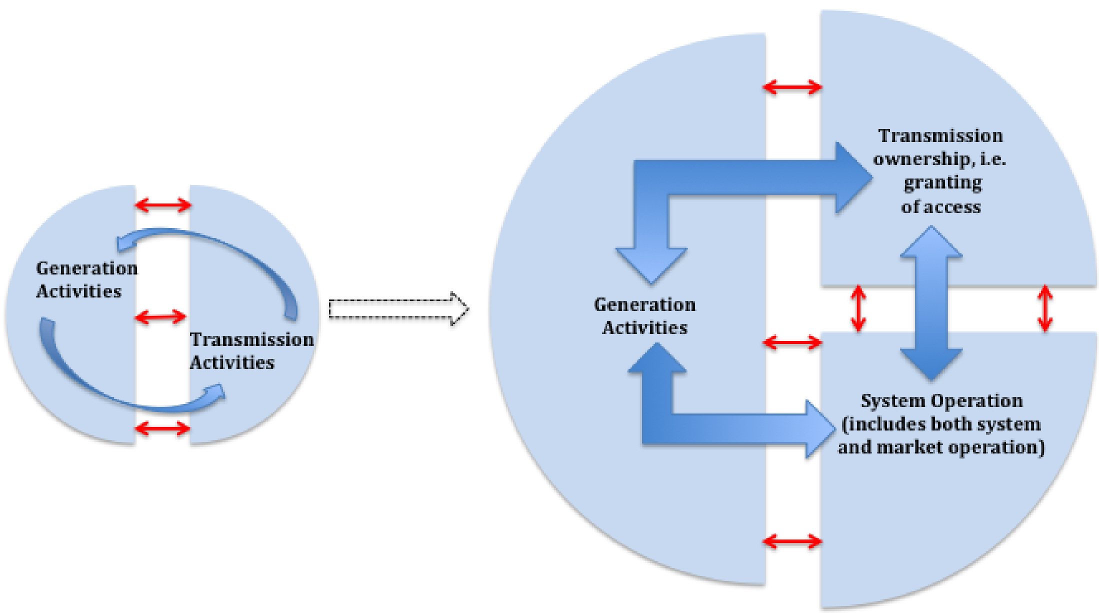

Figure 3: Separating Transmission into ownership and system operation.

Unbundling has no effect on the physics so the generation and transmission activities that had previously been performed within a single firm must still be completed albeit now by independent and competitive entities. Moreover, these tasks must still be completed as seamlessly and efficiently as they had been.

In Figure 3, the integration of the three components requires that the choices made by the participants are consistent (*i.e.,* aligned) with reliable operation of the grid. Because the electricity "machine" runs so quickly, to ensure reliable operation of the system we require an "air traffic controller" or system operator who has been granted unilateral authority over the actions of the participants and their assets for short intervals of time.

In order for this "machine" to work efficiently, transparently and reliably we need to ensure there is precise coordination among the participants and the system operator. In other words we need to replace the internal operating procedures of the monopolist with rules and contracts such that we are able to operate the "machine" while (1) providing non-discriminatory access to the transmission grid and the system operation function and (2) providing generators the opportunity to compete with each other.

In order for this to happen, the commercial environment will need to become much more robust than it was under the vertically integrated monopoly structure. Under the monopolist, there was no need (1) for an Interconnection Agreement that defined the terms and conditions of connecting to the network,

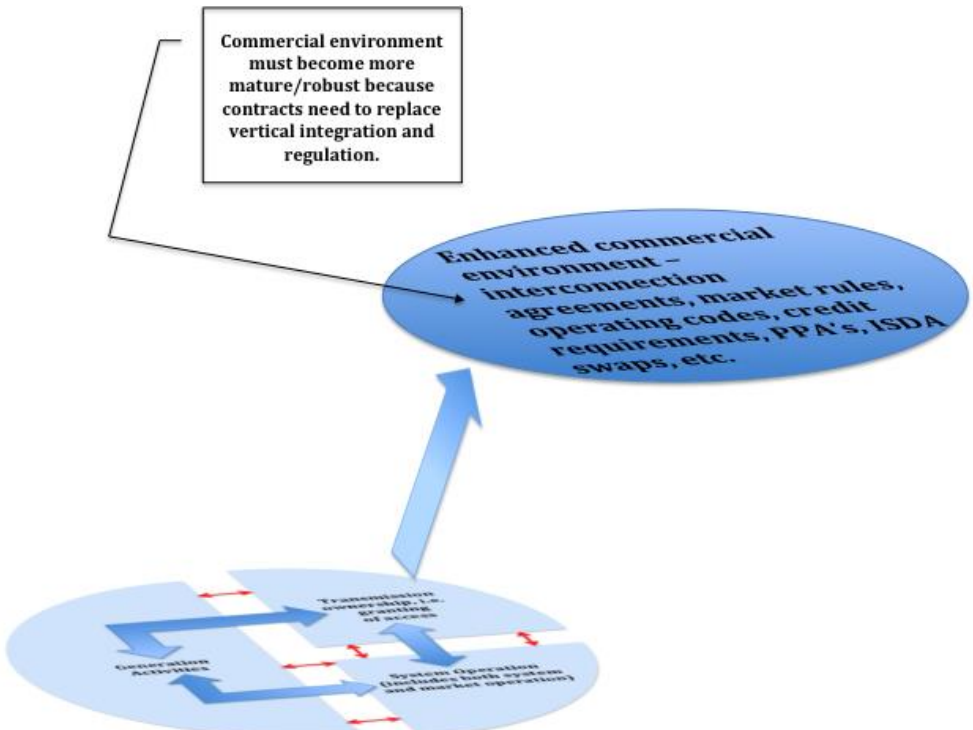

Figure 4: Unbundling requires a more robust commercial environment.

(2) for a set of rules and codes to define how system operations was carried out, (3) to define transmission rights (either physical or financial), since no entity other than the monopolist could use the grid, etc. Furthermore, power purchase agreements – if they were needed at all – could be very could be simple because the monopolist controlled all aspects of producing and transporting the power. In Figure 4, we highlight the fact that the changes in the wholesale market will bring about changes in the commercial environment as well.

In order to achieve the necessary level of co-ordination we first need to identify/define all the tasks that had been previously accomplished under monopoly provision. Once that is completed we then assign through some means (rules, standards, contracts, etc.), the responsibility for performing those tasks to either a participant(s) or the system operator. In addition to assigning responsibilities, the rules also need to define how these obligations are to be carried out. For example, the rules may assign a generator the responsibility to submit a supply offer to the System Operator. In all likelihood we also want the rules to define the deadline for submission, the frequency of submission and the form of the offer.

Reliable operation of the electricity "machine" requires that all the identified tasks be performed. Thus, if a market participant does not perform a specific task, then it *must* be done by the system operator and vice versa – failure to successfully carry out a given task can result in the failure of the machine. One of the most important aspects of electricity market design is deciding the right balance between the tasks that are to be performed by the system operator and those to be performed by the market participants. At one extreme, if the rules assign all the responsibilities to the system operator, then there will be little or no ability for the generators to compete with each other. In effect, the rules will have unwittingly re-constituted the monopoly generator. While we know there will be a system operator, one of the crucial tasks of the market design exercise is to achieve the appropriate balance that maximizes both reliable operation of the grid and the ability for generators to compete.

In the Nigerian context, these rules are contained in the *Market Rules For Transitional and Medium Term Stages of the Nigerian Electricity Power Sector*[5,6] and the purpose of this report/analysis is to review these rules and then comment and where appropriate or necessary, make recommendations for improving the proposed electricity market design contained in the MRTS. Our primary focus will involve analyzing not so much the rules of the market but rather whether the rules themselves are complete.

2.1.1. Competition necessarily changes the commercial environment

Sally Hunt and Graham Shuttleworth recall a conversation with a utility regulator that summarizes the effect of introducing competition into the previously monopolized structure of electricity:

> *"I grew up in a world of planning and marginal cost pricing. I know how to make tariffs and calculate rates of return…I know how to choose the next supply source and how to estimate demand…I can do cost allocations…But in this new world of competition, I seem to need to know about markets and contracts and risk allocation…"*[7]

Introducing competition has no effect on physical electricity – the laws of physics are immune to the structure of the industry – but it fundamentally alters the commercial relationships in the industry.

As was mentioned in the previous section, the contractual environment prior to the imposition of competition and open access is fairly simple. The vertically integrated monopolist had unilateral control over both generation and transmission and internalized the complexity of grid operations.

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[5] February 2009.
[6] As will be shown below this necessarily also implies at least a partial review of *The Grid Code for the Nigeria Electricity Transmission System*.
[7] Sally Hunt and Graham Shuttleworth, *Competition and Choice in Electricity* (John Wiley & Sons, UK, 1996). P xi. 1996.

Reliable operations can be almost entirely defined and determined unilaterally by the vertically integrated monopolist.

In this environment it is appropriate to think of the monopolist as supplying "delivered energy" to a customer at a specified off-take point. Because the monopolist owns and controls the entire "machine" right up to the customer's off-take point, power purchase agreements can transfer ownership at the off-take point. The monopolist is able to write these types of contracts because unilateral control from the generation to the exit point means they are able to internally manage most of the risk of producing and transporting the electricity. However, disaggregating generation from transmission capacity and system operation necessarily means the generation company can no longer manage any of the risks associated with transport or dispatch. This must have an effect on the ensuing structure of power purchase agreements.

2.1.2. Transmission Rights

When the electricity "machine" is owned and operated by a single company or government agency no other entity had access to the transmission system. In this situation there is no need to define and determine a "transmission right" because no generator other than the monopolist could access the grid. A "transmission right" is a "right" to use the transmission system; where use of the system constitutes access to the transmission capacity and access to the dispatch process. We can use an airport as an analogy. If an airline company wants to use the airport they need to have "landing strip capacity", *i.e.,* they need to own, rent, or lease some amount of the physical capacity of the landing strip, and they also need the air traffic controller to allow them to take off and land their planes. A user of the electricity grid has the same requirements.

The fundamental issue, *i.e.,* establishing transmission rights, was not created by competition of open access. Rather the vertically integrated monopolist previously dealt it with internally and informally. Competition merely brings the complexity out in the open and mandates an explicit/formal solution.

Defining and allocating transmission rights is a necessary step in implementing competition and open access. As a result this issue has been dealt with in other areas. Two distinct methodologies have been developed:

1. The "physical rights" model whereby a transmission right has a physical interpretation. Specifically a participant must have the right to the transmission capacity they use to transport power from a source to a sink.

2. The "financial rights" model whereby a transmission right has no physical interpretation; rather it is purely a financial right to revenue streams (positive or negative) that arise from using the transmission system.

Neither is without problems, though international experience has shown that the physical rights model has far greater limitations.

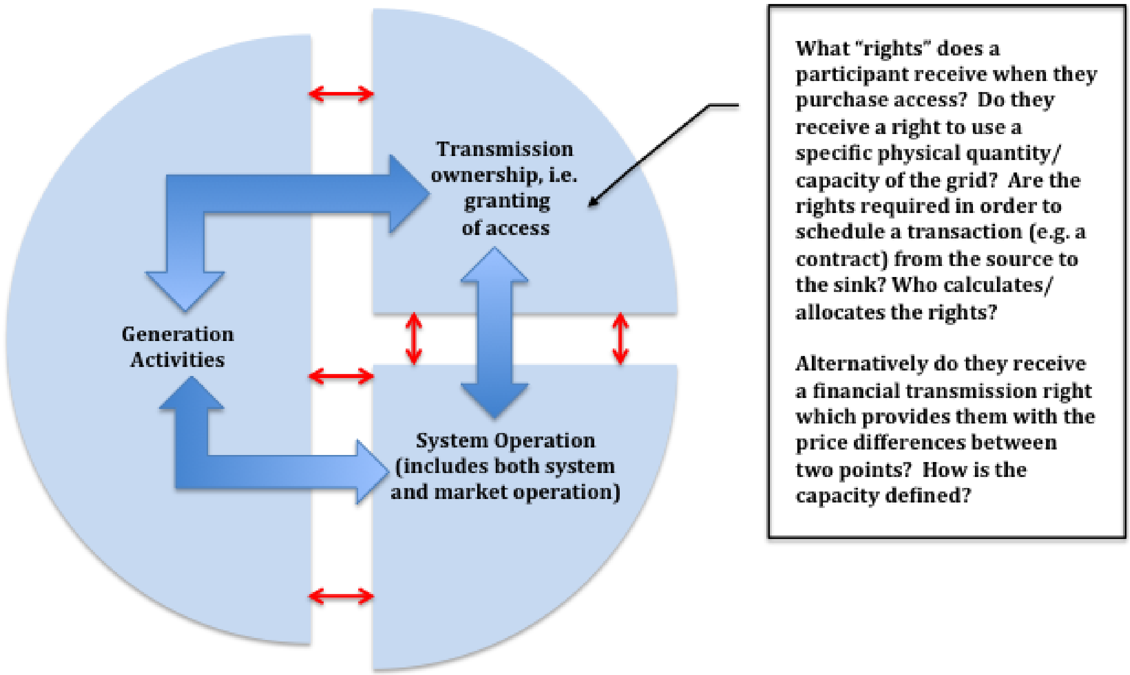

Figure 5: How are transmission rights defined and how are they used?

2.1.3. Scope of the "Rules"

In Section 1.0 we discussed the fact in order to ensure the "machine" works as well or better than it had under the monopoly we need to ensure precise coordination between the participants and the system operator. We also noted that the way we accomplish this by replacing the internal operating procedures of the monopolist with a new set of rules, standards and contracts.

The MRTS are just such a set of rules. In particular they establish responsibilities for the Market Participants and the Market Operator in running the Transitional and Medium Term stages of the Nigerian electricity market.

Rule 1.2 of the MRTS sets out the rules for two separable but sequentially interdependent "electricity trading systems":

1.2 Establishment of electricity trading system

These Rules have been framed by the Market Operator in order to establish the electricity trading system for the Nigerian Electricity Power Sector and to make provisions for the following:

1.2.1 During the Transitional Stage:

(a) Energy procurement and contracting;

(b) Energy metering and settlement of contracts; and

(c) Collection by the Market Operator of the System Operation and Market Administration Charge;

1.2.2 During the Medium Term Market:

(a) Trading in Imbalance Energy;

(b) settlement of charges and payments relating to Energy, Ancillary Services and usage of the Transmission System; and

(c) collection by the Market Operator of the System Operation and Market Administration Charge and the Cost of Imbalance Energy;

1.2.3 A system for the administration and enforcement of these Rules.

Additionally, Rule 1.5 tells us that in order to fully understand the rules we need also to incorporate The Grid Code for the Nigeria Electricity System:[8]

1.5 Relationship with the Grid Code and the Operating and Market Procedures

1.5.1 These Rules complement and supplement the Grid Code and should be read in conjunction therewith. Together the two documents constitute these Rules for the planning, dispatch and operation of the system and the administration of the wholesale electricity market in Nigeria.

1.5.2 These Rules shall be interpreted so as to avoid, to the extent reasonably possible, findings of inconsistency between these Rules and the Grid Code.

1.5.3 Operating Procedures and Market Procedures complement and supplement these Rules. General provisions relating to Operating Procedures and Market Procedures are made in Rule 4.

Thus both the transitional phase and the medium term market rules need to be interpreted within the context of the Grid Code. Rule 1.3 of the Grid Code provides the purview of these rules:

1.3 The Grid Code

1.3.1 The Grid Code contains the ***day-to-day operating procedures and principles governing the development, maintenance and operation of an effective, well-coordinated and economic Transmission System for the electricity sector in Nigeria.*** (Emphasis added)

1.3.2 The code is designed to:

[8] The Grid Code for the Nigeria Electricity Transmission System, Version 01. Hereafter referred to as the "Grid Code."

(a) *Facilitate an efficient production and supply of electricity for all Users of the Transmission System and TCN itself, without any act of discrimination between Users or class of Users.*

(b) *Facilitate competition in the generation and supply of electricity in the country.*

1.3.3 For complete understanding of the operation of the Nigeria Electricity industry post de-regulation, this document have (sic) to be read in conjunction with the Market Rules, Distribution Code and other documents relating to other operational aspects of the industry.

Rules 1.5.1 (b) (i) – (v) provide further guidance for the activity of the system operator:

1.5.1 TCN shall perform two different group of functions in relation to network and system operation activities:

(b) As System Operator

(i) dispatch Generating Units in accordance with this Code at least cost, on the basis of Nominations by Generators;

(ii) procure Ancillary Services and recover the costs of procuring Ancillary Services;

(iii) handle Power System emergencies and restore the Power System;

(iv) perform demand forecasting;

(v) coordinate Generation and Transmission outages.

These sections provide a very clear description of the scope of the Grid Code as it pertains to system dispatch. Unfortunately no such precision is found in the MRTS as to the exact scope of those rules.

We know from Rule 1.3.1, the Grid Code pertains to the physical operation of the electricity system, but with no symmetrical language in the MRTS we can only assume these rules refer to the "financial" operation of the market.

What are missing in both the Grid Code and the MRTS are an explanation of the market design philosophy and the resulting underlying elements of the desired market.

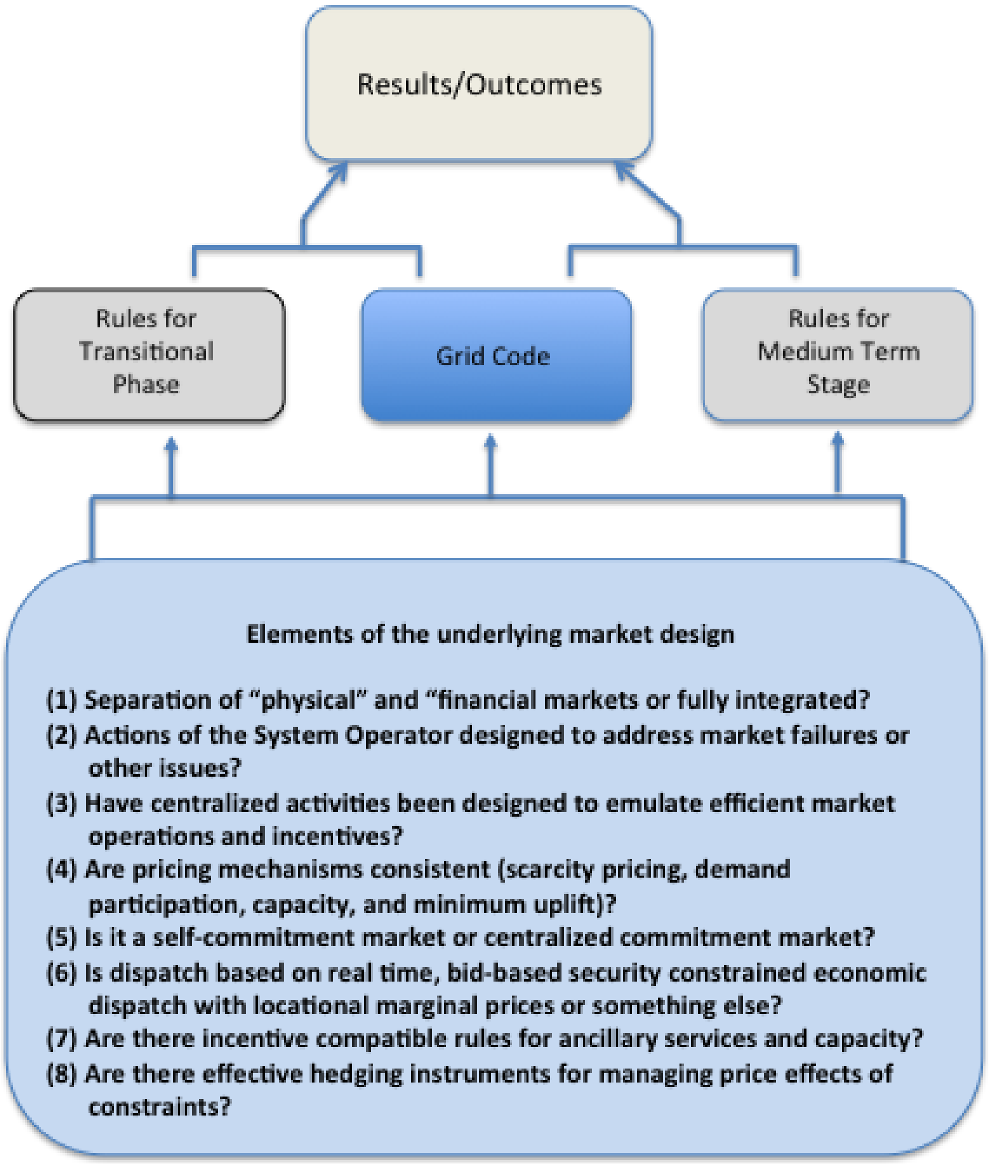

Figure 6: Relationship between the underlying market design philosophy and both the Grid Code and the MRTS.

Put differently the Grid Code and the MRTS in combination form the rules for a market, yet we are not provided with the basic philosophical building blocks of the market.

For example, with respect to the commitment of generation, the market design can either be based on self-commitment (as in New Zealand) or centralized commitment (as in the North American markets). In a self-commitment market, the system operator has **not** been granted the authority to order a generator on. In comparison, in a centralized commitment market, the rules provide the system operator with the ability to order a unit on.

Either market design can and has worked, so both are in some sense "correct", it simply depends on what kind of market is desired. A self-commitment market minimizes the role of the system operator, whereas a centralized commitment market maximizes the involvement of the system operator. Additionally there are a myriad of needed rules that are related to this decision. For example, in a centralized commitment market, the rules must allow the system operator to be able to pay for generation they have committed. Which means the rules have to define who pays and how much.

Another example is whether the market will be based on single or three-part offers. Under the former the generator includes fixed costs in his/her offer (including the return on capital). In comparison, under a three-part offer market design an offer consists of startup cost, minimum run time and variable costs. Again, either market design can and has worked it is really a question about what kind of market does the industry want. As with the previous example a number of follow-on rules depend on this assumption.

Once a decision has been made regarding the underlying market philosophy then we can evaluate the rules with regard to whether they are consistent and complete with respect to this market design. It is extremely unfortunate and problematic that the Grid Code and MRTS do not provide the underlying design philosophy because we must infer what was intended from the rules – which raises the very real possibility that the rules may be wrong and we make an incorrect inference regarding the market design philosophy.

2.1.4. Separation of the Grid Code and the Market Rules

From a design perspective the fact that Nigeria has chosen to separate the Grid Code, *i.e.,* the rules pertaining to the physical operation of the system, from the rules dictating behavior in the market is highly indicative of an underlying philosophy regarding the market design.

It is common to separate the rules/standards pertaining to "reliability" from those governing the market. As will be developed below the key questions with respect to market performance pertain to the rules regarding system dispatch, *i.e.,* what the Grid Code calls "the day-to-day operating procedures and principles governing the…operation of an effective well-coordinated and economic Transmission System." These rules are the single most important aspect of the market design. In short, the rules governing dispatch, regardless of where they are located will be the biggest determinant of the success or failure of the MRTS to achieve the objectives of the government.

2.2. Methodology and Background

In order to accomplish the objective, *i.e.,* an evaluation of the MRTS, we first need to add specificity to the objective. In particular we need:

1. To provide a benchmark for evaluating the rules, *i.e.,* what are the metrics for deciding whether the rules are appropriate? What is it that policy makers are expecting of the market described by the MRTS?
   Fortunately the MRTS provides the relevant benchmark in Rules 2.1 and 2.2:

2. OBJECTIVES, CONTENTS AND ADMINISTRATION

2.1 Objectives

The objectives of these Rules are to establish and govern an ***efficient, competitive, transparent and reliable market for the sale and purchase of wholesale electricity and Ancillary Services in Nigeria and to ensure that the Grid Code and the Market Rules work together to secure efficient co-ordination and adequate participation****.*[9]

2.2 Contents

Further to Rule 2.1 above, these Rules:

2.2.1 provide a framework for an efficient, competitive, transparent and reliable wholesale electricity market;

2.2.2 set out the responsibilities of Participants, the TSP, the System Operator and the Market Operator in relation to trading, co-ordination, dispatch and contract nomination, pricing of imbalances and Ancillary Services, metering, settlement and payments;

2.2.3 set out the operation and pricing system of the Balancing Market;

2.2.4 ensure an efficient, transparent and predictable settlement system and set out the payment obligations;

2.2.5 establish a governance mechanism and a market monitoring system;

2.2.6 provide a framework for resolution of disputes amongst Participants or between Participants on one hand and the System Operator or the Market Operator on the other, on matters relating to the Market Rules and the Grid Code; and

2.2.7 provide an efficient and transparent process for amending the Market Rules and the Grid Code.

Similarly Rule 1.3.2 of the Grid Code as previously cited, states that:

1.3.2 The code is designed to:

(a) Facilitate an efficient production and supply of electricity for all Users of the Transmission System and TCN itself, without any act of discrimination between Users or class of Users.

[9] Emphasis added.

(b) *Facilitate competition in the generation and supply of electricity in the country.*

Thus the objective of the MRTS (Rule 2.1) is to create a market that is (1) efficient, (2) competitive, (3) transparent, and (4) reliable. In addition the rules should (per Rule 2.2) define the responsibilities of the Market Participants, Transmission System Provider, the system operator and the Market Operator as their actions pertain to trading, co-ordination, dispatch, contract nomination, pricing of imbalances and Ancillary Services, metering, settlement and payments. The goals listed in Rules 2.1 and 2.2 of the MRTS necessarily include those of Rule 1.3.2 of the Grid Code; they simply increase the requirements in order for the market to be classified as successful.

This language in Rules 2.1 and 2.2 is also consistent with, but much more definitive and, as a result constraining, than that contained in the *Electric Power Sector Reform Act, 2005* (EPSRA). The EPSRA refers only to the development of "competitive electricity markets."[10]

For purposes of this report we will primarily use the principles outlined in Rule 2.1 of the MRTS. Namely that the Rules are to establish and govern an (1) efficient, (2) competitive, (3) transparent and (4) reliable market for the sale and purchase of wholesale electricity and ancillary services.

2. It is important to understand that the objectives outlined in Rules 2.1 and 2.2 of the MRTS are, in large part, *results or outcomes* of the market mechanism. In other words, the objectives apply more accurately to the outcomes of the market rather than to the market itself.
   As shown in Figure 7 below, the MRTS represents one of several factors that, in combination, will determine whether the market produces outcomes that are efficient, competitive, transparent and reliable. For example, the competitiveness of the market will largely be determined not by the market rules but rather by the industry structure, *i.e.,* the ownership structure, the number and size of the competitors, and the regulatory regime.

   This highlights the importance of evaluating the MRTS and Grid Code in the context of the legal, regulatory, and commercial environment in which the market will operate. Thus, while the primary focus of the analysis is on the MRTS and whether or not the proposed design is likely to fulfill the government's objectives as stated in Rule 2.1, these rules are necessary but not sufficient to meet the stated objectives.

[10] From the introduction to the legislation: "An Act…to develop competitive electricity markets."

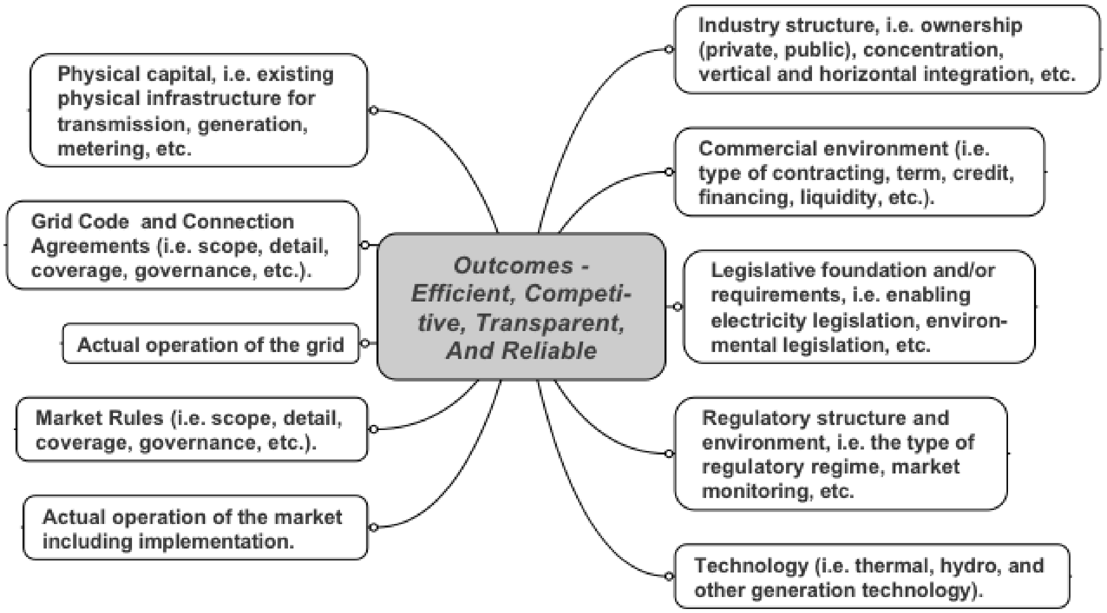

Figure 7: Factors Affecting Market Results.

2.2.1. Legislative Background

The MRTS are among the most recent steps in a process initiated in 1998 when the Electricity (Amendment) Decree and the NEPA (Amendment) Act were both passed terminating the monopoly status of NEPA. In September 2001 the Federal Government adopted the National Electric Power Policy[11] that outlined a number of objectives:

- *to ensure a system of generation, transmission, distribution and marketing that is efficient, safe, affordable and cost-reflective throughout the country;*
- *to ensure that the power sector attracts private investment both from Nigeria and from overseas;*
- *to develop a transparent and effective regulatory framework for the power sector;*
- *to develop and enhance indigenous capacity in electric power sector technology;*
- *to participate effectively in international power sector activities in order to promote electric power development in Nigeria, meet the country's international obligations and derive maximum benefit from international cooperation in these areas;*
- *to ensure that the Government divests its interest in the state-owned entities and entrenches the key principles of restructuring and privatization in the electric power sector;*
- *to promote competition to meet growing demand through the full liberalization of the electricity market; and*

[11] Provide reference

- *to review and update electricity laws in conformity with the need to introduce private sector operation and competition into the sector.*

These objectives were operationalized with the passing of the Electric Power Sector Reform (EPSR) Act in March 2005 that:

1. Unbundled the state-owned entity into generation, transmission and distribution,
2. Provided for the transfer of assets, liabilities and staff of the National Electric Power Authority (NEPA) to the Power Holding Company of Nigeria (PHCN) and then to successor generation, transmission and distribution companies,
3. Called for the creation of a competitive electricity market, and
4. The creation of an independent electricity regulator.

As previously discussed, the aforementioned objectives of the National Electric Power Policy have been formally encoded in the MRTS via Rules 2.1 and 2.2, *i.e.,* to create an efficient, competitive, transparent and reliable electricity market and in the Grid Code via Rule 1.3.2. Also embedded in the EPSR Act is the requirement that the process of moving to a competitive market must entail an interim or transitional market phase.[12] This requirement has been included in the MRTS through Rule 1.2:

1.2 Establishment of electricity trading system

These Rules have been framed by the Market Operator in order to establish the electricity trading system for the Nigerian Electricity Power Sector and to make provisions for the following:

1.2.1 During the Transitional Stage:

(a) Energy procurement and contracting;

(b) Energy metering and settlement of contracts; and

(c) Collection by the Market Operator of the System Operation and Market Administration Charge;

1.2.2 During the Medium Term Market:

(a) trading in Imbalance Energy;

(b) settlement of charges and payments relating to Energy, Ancillary Services and usage of the Transmission System; and

(c) collection by the Market Operator of the System Operation and Market Administration Charge and the Cost of Imbalance Energy;

[12] See specifically Sections 24, 25 and 26 of the ESPR Act.

1.2.3 A system for the administration and enforcement of these Rules.

While the EPSR and the MRTS are consistent in requiring two distinct steps along the evolution to a market – a transitional phase and the implementation and operation of a Medium Term Market – there is no explicit or embedded rationale for why this is needed.

Rules 2.1 and 2.2, when taken together implicitly highlight the two fundamental problems related to implementing a wholesale electricity market in Nigeria:

1. Addressing the issues caused by the current state of the electricity sector in Nigeria.

2. Designing and implementing an appropriate electricity market.

These two Rules when taken together potentially create a conflict – if the market is to meet the requirements of 2.1 then it is not clear why or how it would be a "medium" term market. That is, if the market meets the four criteria listed in Rule 2.1 – as the rules require – then it is not obvious the basis upon which it would be considered a "Medium" Term Market rather than the "Final" Market. Neither the MRTS nor the National Electric Power Policy limits the interpretation of Rule 2.1 to reflect a medium stage. For example, there are no qualifying statements or guidance suggesting the Medium Term Market should be "as efficient as possible given a specific set of constraints or obstacles."

The logical interpretation of the rationale for requiring a medium term market is that there are some concrete impediments (legal, institutional, commercial, etc.) that prevent the implementation of the "final" market. The efficient medium term market is then understood within the context of this obstacle. For example, when New Zealand implemented their wholesale electricity market in the mid-90's, an interim or medium term market had to be developed, implemented and operated until the bilateral contracts – which included provisions that were not consistent with a competitive generation sector – between the Electric Corporation of New Zealand and their customers expired. In this case there was a specific reason why the medium term market was required as well as a defined event that triggered when the "final market could be implemented.

In addition to New Zealand, many other electricity market implementation processes have made use of an interim stage[13] and given the state of the sector in Nigeria this is a beneficial aspect of the process. However it is important to note the MRTS does not provide any description or detail on the design of "Final" as compared to the Medium Term Market. Nor does the MRTS identify design elements that will need to be changed in order to move to the "Final" Market.

When other market implementation processes have included a transitional phase it is common to (1) distinguish what design elements in the interim market have been compromised with respect to the final market design, and (2) to provide either a defined termination date, or a set of agreed

[13] For example, in North America organized electricity markets went through an evolution from individual utility dispatch to what has been termed a "Day 1" market that involved centralized calculation and allocation of transmission capacity to a "Day 2" market that added centralized dispatch.

upon criteria that, once achieved, trigger a move to the next step. Neither of these are the case in the Nigerian process. The importance of this is twofold.

- First, both the Transitional Stage and the Medium Term Market may be very long-lived. In fact, given the state of the sector in Nigeria it is hard to imagine the transitional phase, let alone the medium term market, lasting less than 5 years. In total it is likely that the transitional and medium term markets will be in place for at least 10-15 years.
- Second, since this "interim"[14] structure is likely to be around for quite a while the rules take on added importance. If the interim market was a short-term solution, then any possible market design flaws could be addressed by temporarily implementing so-called "work arounds" until the final solution is able to be put in place. But given the high probability the interim market will last more than a decade the robustness of the "interim" market design is paramount.

In summary, the guiding language of the ESPR as it relates to the objectives of the electricity market has been faithfully reproduced in Rules 2.1 and 2.2. However, this language is largely inconsistent with the notion of an "interim" or "medium" term electricity market. This raises several fundamental and significant issues:

1. If Rules 2.1 and 2.2 are, in a sense, non-negotiable, then the MRTS cannot – by definition – be the rules for an interim market. That is, if the MRTS provides the foundation for a market that is efficient, competitive, transparent and reliable, then there are no reasons to move to a "final" market. In other words a market cannot simultaneously be efficient, competitive, transparent and reliable and at the same time be an interim as opposed to final market.

2. However, if Rules 2.1 and 2.2 are really intended to apply to the "final" market rules then we need to have some agreed upon objective for the MRTS because it is inappropriate to evaluate the MRTS using the metrics for the final market.

Given the obvious need for a long-lived "interim" market the recommended process would be to either: (1) have an overarching or high-level set of objectives the final market was expected to achieve, *i.e.,* those given in Rules 2.1 and 2.2, and then task the MRTS with being consistent with and advancing the industry toward those objectives or (2) writing the final market rules and then include "work arounds" in cases where the final rules could not be implemented.[15] As will be shown in the next section, there are no "interim" market rules that can be implemented that will also achieve the objectives set forth in Rules 2.1 and 2.2.

To further clarify this point:

- Evaluation of the MRTS requires defined metrics/objectives (preferably measurable.

[14] From hereon we use the term "interim" to include both the transitional and medium term markets.
[15] The latter solution was used by the ERCOT (Electricity Reliability Council of Texas) market in the US when the initially implemented their market in 2001.

- The objectives specifically contained in Sections 2.1 and 2.2 of the MRTS as well as those contained in Section 1.3.2 of the Grid Code, while consistent with the enabling legislation, by necessity pertain to the "final" (and not the "interim") market.
- The implication is that either the rules are indeed "final" rules or, if not, then Sections 2.1 and 2.2 are not applicable.
- Since an "interim" market is a necessity in Nigeria, it is safe to assume that the MRTS are not the final rules.
- By definition then, Rules 2.1 and 2.2 do not provide the required metrics to allow evaluation of the "interim" rules.
- There is no documentation on the relationship between the "interim" and "final" rules.
- This represents a fundamental flaw in the process and should be rectified. A high level "policy paper" should be produced and adopted by the government. This position paper should provide the design cornerstones of the final market. Without this linkage any evaluation of the MRTS is necessarily ad hoc due to the lack of a fixed and agreed upon reference point for the interim rather than the final market.
- As it currently stands there are no objective and accepted guidelines to favor one criterion over another. Given that that the interim market will not – again, by definition – be able to meet all the criteria in Rules 2.1 and 2.2, we are left with no ability to favor a set of rules that are, for example, less transparent but more efficient than another set. Or similarly, are we to favor rules that may increase reliability at the expense of transparency? The current paradigm does not assist in making those decisions.
- Establishing a relationship between the "final" design/rules and the "interim" design/rules will lead to better decision-making in the implementation phase (when much of the detail of the market is put into operating procedures and software code) as well as the improving the evolution of the market rules.

For purposes of this report, given the expected duration of the "interim" market we will evaluate the MRTS as if they were the rules for the "final" market, *i.e.,* we will assume that Rules 2.1 and 2.2 provide the relevant objectives and that the MRTS are indeed the rules for the "final" market.

2.2.2. Overview of the current state of the Nigerian wholesale electricity sector: (1) physical generation, (2) physical transmission and (3) commercial arrangements.

With respect to electricity, Nigeria is in an extremely unique position relative to other market implementation processes in that:

- The sector lacks adequate generation capacity:

- As shown in Figure 8, Nigeria has approximately 8,800 MW of installed capacity of which only about 51% is available on average.[16]

Power plant	Installed capacity (MW)	Average availability (MW)
Hydro power plants		
Kainji	760	412,55
Jebba	578.4	431,83
Shiroro	600	390,21
Thermal power plants		
Egbin	1320	819,55
Sapele	720	125,17
Delta II-IV	900	342,95
AfamII,IV,V, VI	1166	457,2
Geregu	414	208,69
Omotosho	335	118
Olorunshogo I,II	710	324
Okpai	480	441,57
Omoku	150	80,18
Ajaokuta G.S	110	0
Ibom G.S	155	82,89
AES	302	208,20
Trans-Amadi	100	32,63
Total	**8800,4**	**4475,87**

Figure 8: Power Generation capacity of the current Nigerian grid.

- As shown in Figure 9, Nigeria lags Brazil, Pakistan, and Bangladesh– the three countries closest in population - in electric power consumption.

16 Faleye, Omobobola Omolola “Modelling Demand Uncertainties in Generation-Transmission Expansion Planning – A case study of the Nigerian Power System” (Master Thesis Project, School of Electrical Engineering, Royal Institute of Technology, 2012).

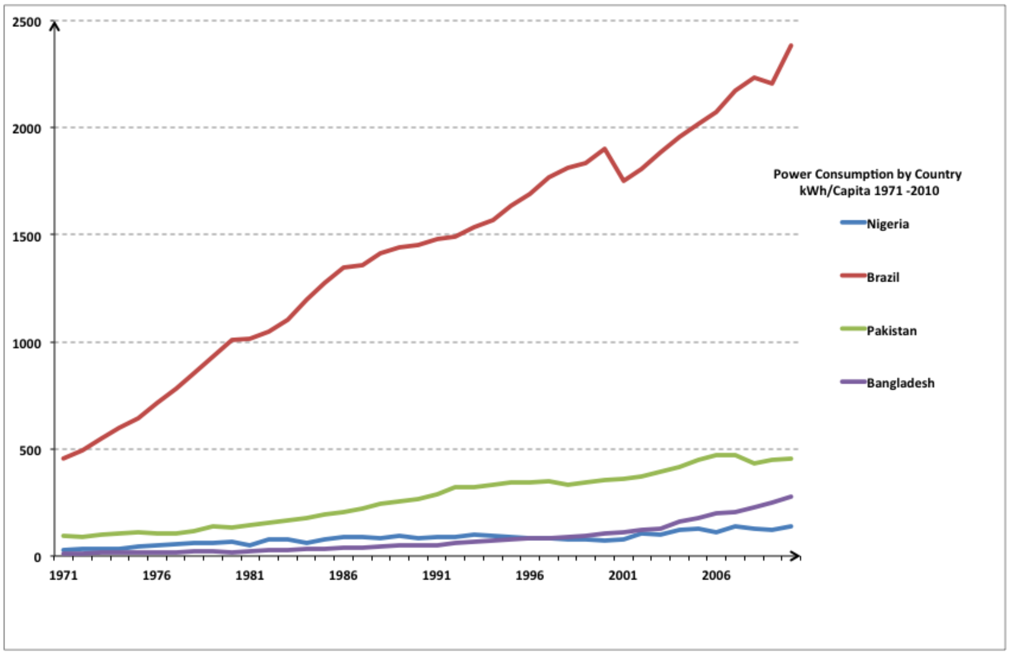

Figure 9: Electric power consumption - kWh per capita for Nigeria, Brazil, Pakistan and Bangladesh.[17]

- Among the ECOWAS Member States for which the World Bank has electricity consumption data, as shown in Figure 10 Nigeria consumes less electricity on a per capita basis than Ghana, Cote d'Ivoire, and Senegal.

[17] Source: http://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC/countries/NG-BR-PK-BD?display=graph.

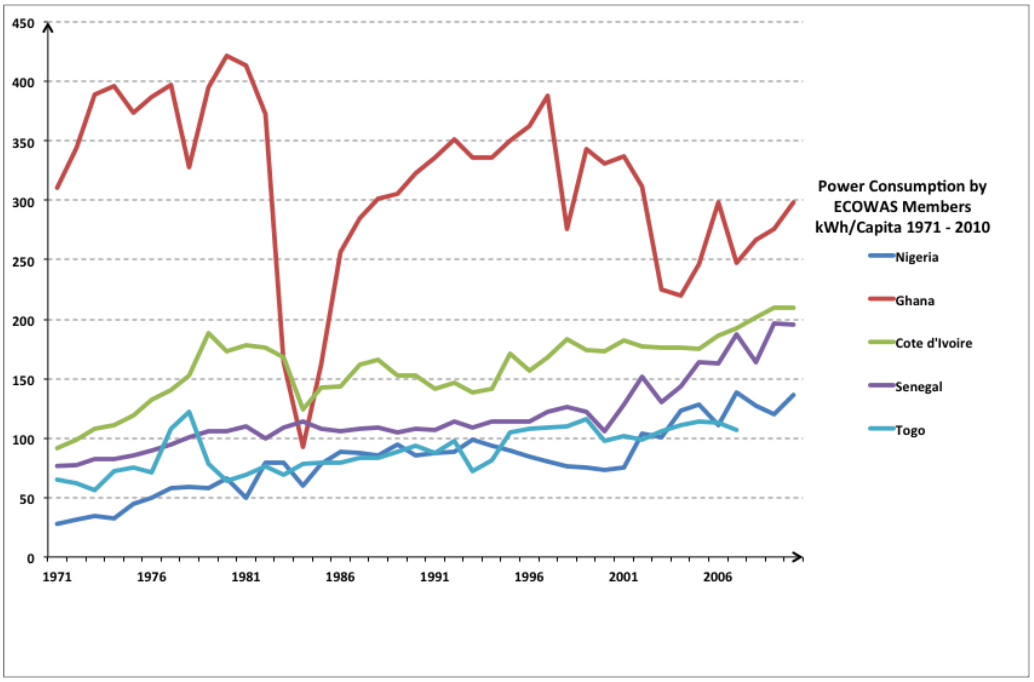

Figure 10: Per capita electric power consumption for ECOWAS Member States.[18]

- Roughly 50% of the population does not have access to electricity.[19]
- Self-generated electricity accounts for 50% of total generation and is twice as expensive as grid-connected generation.

- The sector lacks adequate transmission capacity:
  - *"By 2010, when the last major transmission project was completed in Nigeria, the electric power transmission network consisted of approximately 5000km of 330 kV lines, and around 6000km of 132 kV lines. The 330 kV lines fed a little more than 20 substations of 330/132 kV rating with a combined capacity of more than 7,000 MVA which translates to 5,600 MVA at a utilization factor of 80%. In addition, the 132 kV lines fed a little more than 100 substations of 132/33 kV rating with a combined capacity around 9800 MVA which also translates to 7,350 MVA at a utilization factor of 75% (PHCN 2005)…Statistical explorations reveals a strong correlation of the layout of the transmission line densities and capacity to the industrial and population activity demographic indicators showing that the major towns in the country corresponds with the longer length and higher capacity of the transmission corridors and other important characteristics. This in turn has led to a transmission system that is not oriented with a long term energy*

[18] Source: http://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC/countries/NG-GH-CI-SN?display=graph.
[19] http://www.punchng.com/business/business-economy/51-of-nigerians-lack-access-to-electricity-report/

*policy and obviously a transmission planning that works by "healing through line addition" to solve the arising transportation bottlenecks…This little attention given to the network Grid relative to the other aspects of the Nigerian power sector has led to a decayed infrastructure that performs way below capacity hence, a power sector that can hardly support the population and related activities growth of her people…Subsequently, the major challenges of the Nigerian transmission network are that the design is still radial and currently overloaded…**In addition; it cannot currently wheel more than 4,000 MW and suffers from a poor voltage profile in most parts of the network, especially in the North and lack of evacuation capacity in the eastern part**...Other constraints include the inadequate dispatch and control infrastructure leading to frequent system collapses, high transmission losses of the range of 10-55 % and of course the limited national access to electricity of about 40% for households, made up of 81% urban and 18% rural. All these have culminated to a weak network that is old, with weak capacity utilization and double digit losses over the years"*[20]

- Transfer capability between the regions is limited and there are significant constraints.

  - According to a recent news report: *"Meanwhile, top government sources at the Ministry of Power and the TCN said the neglect for power transmission infrastructure by successive governments led to the weak state of the nation's transmission network. According to them, the quantum of power being generated in the country is far higher than what the transmission capacity can handle. The officials explained that previous administrations had focused on power generation, but relegated transmission to the background. A senior official in the Power ministry, who pleaded not to be named because he was not authorised to speak on the subject, told our correspondent in Abuja. This warranted the poor supply of generated power **for TCN lacked the capacity to fully transmit the quantum of electricity generated**."*[21]

- Finally the robustness of the commercial environment is inadequate:
  - History of chronic underpayment by customers for the electricity consumed with only 30% of the power generated being paid for.
  - Only 60% of customers with access to electricity are currently metered.[22]

[20] Cyrinus, Egeruoh Chigoziri "Long Term Transmission Expansion Planning for Nigerian Deregulated Power System – A systems approach", (Master Thesis, Universidad Pontificia Comillas and Delft University of Technology, 2012). Emphasis added.
[21] Okechukwu Nnodim, "Transmission infrastructure neglect worsens power supply – Investigation," Punch, April 29, 2013. (see: http://www.punchng.com/business/financial-punch/transmission-infrastructure-neglect-worsens-power-supply-investigation/). Emphasis added.
[22] See: http://www.voanews.com/content/nigeria-seeks-to-meter-electricity-boost-output-149354125/369932.html

- Long history of government intervention and subsidization of electricity prices.
- Lack of long-term contracting (necessary to underwrite IPP generation projects) because of non-payment and the poor credit ratings of buyers.

The picture that emerges from this short list of facts is of an industry with widespread and significant issues. This is neither new nor unknown as the situation is well understood both inside and outside of the sector.

We stress though the fact that the transmission network is significantly constrained (*"…it cannot wheel more than 4000 MW…"*[23]). While this situation may be understood at the level of physical capital and required investment, the effects of this very real constraint do not appear to be well appreciated in the underlying design of the MRTS.

Individually as well as collectively, these issues have the potential to affect the design, implementation and operation of the electricity market.

Perhaps the overarching objective of the National Electric Power Policy and the resulting legislation is to attract private financial capital into the sector to address the first two issues, *i.e.,* generation and transmission inadequacy.[24] In this regard, Nigeria is similar to many other countries that began reforming their energy sectors during the 1990's.[25] However, therein lies the problem. There are two fundamental requirements that must be in place that are necessary (but not sufficient) in order to attract private and/or foreign financial capital:

- The sector must exhibit commercial viability, *i.e.,* adequate credit standards must be in place and upheld, contracts must be honored, and customers must pay their bills. Lacking this commercial integrity, financial capital will continue to require government assurance of payment.

- The investors must be reasonably confident that "self-dealing" will not occur, *i.e.,* that there is a level playing field and that specific investors will not have an advantage.

Thus policy makers in Nigeria are dealing with a classic problem. In order to achieve the necessary investment in the electricity sector, they need to attract private/foreign financial capital and in order to attract the capital they need commercial integrity and non-discriminatory access to the transmission system which can only be achieved through the creation of an efficient, competitive, reliable and transparent electricity market. However, for the market to deliver the desired outcomes there needs to be investment in generation and transmission and dramatic improvement in the commercial viability of the electricity sector.

[23] This mirrors statements made by industry participants at a meeting at the Nigerian Electricity Regulator of the XX Committee in Abuja on …
[24] Reference
[25] The UK, Australia, New Zealand, Nordpool (initially Norway and Sweden and then Finland, Western Denmark and finally Eastern Denmark), and sections of the United States are all examples of countries/regions that began reform programs during the 90's.

This is a complex problem and we reiterate that a well-designed, implemented and operated market is a necessary but not sufficient condition in order to achieve the desired outcomes listed in Rule 2.1.

2.3. Introduction to electricity markets

While the term "market" is commonly used, this does not mean there is a common or even correct understanding of either the term or the underlying concepts.

- *The importance of understanding what an electricity market is (or should be) and how it works (or should work) is of fundamental importance to understanding the analysis and recommendations contained in this report.*
- *As currently proposed there are fundamental and fatal flaws in the market design prescribed by the combination of the Grid Code and the MRTS, i.e., the market described by the Grid Code and the MRTS will not achieve the objectives laid out in Rule 2.1. Moreover, in light of the discussion in the previous section, implementing the interim market may actually move the industry in the wrong direction relative to the objectives specified in Rule 2.1. Based on the experience of other markets, if implemented, the "MRTS market" will require a substantial and expensive re-design in order to fix these flaws.[26] As will be shown, the flaws in the design are neither independent nor incremental, i.e., it is not simply a matter of changing "incorrect" rules or sections. Rather the problem – as will be shown in this section – is based on an incorrect and inaccurate paradigm.*
- *The material provided in this section is neither theoretical nor subjective. As such it provides a practical and unbiased framework from which to review the proposed market design.*

[26] In particular, the MRTS exhibits many of the flawed assumptions inherent in the initial California electricity market as well as that of the initial market in the UK. Both of which had to go through a complete re-write of the market rules and a "re-launch" of the market.

2.3.1. Summary of electricity and economics

A market is a specific form of economic organization. Other examples include contracts, vertical and horizontal integration, command-and-control, etc. The choice of which form of organization to adopt depends upon a number of issues, e.g. the difficulty of writing complex contracts, the existence and magnitude of transaction costs, information asymmetries, the prevailing technology, etc. In other words, there is no single "optimal" form of economic organization. Rather the choice depends upon specific institutional and technological characteristics.

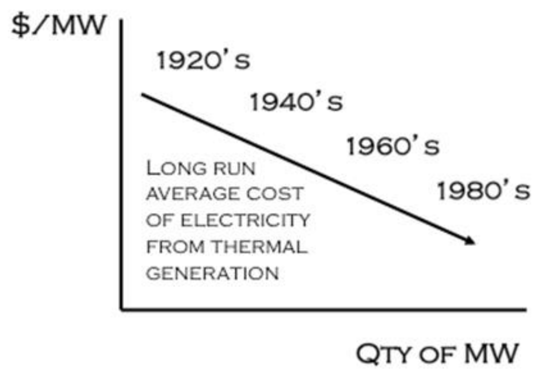

Figure 11: Average Cost of Electricity Produced by Thermal Generation Over Time.

Until the latter part of the last century, the technology underlying generation and transmission necessarily led to the vertical integration of these activities (if not distribution and retailing). Specifically, there were economies of scale present in generation that meant the average per unit cost of producing electricity declined as the size of the plant increased; larger plants produce cheaper electricity.[27] The relationship between plant size and cost per megawatt over time is depicted in Figure 11. With respect to economic organization, the implication of a declining long run average cost curve is that production is optimally carried out by a few large firms, or even a single firm, rather than by a multitude of competitors. The declining cost structure made possible by technology, is characterized as a natural monopoly and explains the rationale behind the optimal form of economic organization within the generation sector, *i.e.,* monopoly production. Moreover, the declining cost structure is not limited to thermal generation. Both hydro and nuclear generation have very high fixed costs relative to the variable costs. This causes a similar downward shaped average cost curve over the relevant range of production and provides an equivalent incentive for only a few large generators rather than a number of smaller competitors.

Thus up until the 1980's there were technological reasons for the industry to have a few large generators supplying the market rather than many smaller generators. The fact that large generation was more efficient than smaller plants also biased the location decision for generation facilities as well.

[27] See for example: Sally Hunt and Graham Shuttleworth, *Competition and Choice in Electricity* (John Wiley & Sons, UK, 1996). Chapter 2. 1996.

Electricity can either be transported as input fuel for the generator by rail, barge, pipeline, and hydro or as the final commodity via transmission lines. In other words, the location decision for a generation facility is to either locate close to the input fuel source (*i.e.,* a coal mine, gas pipeline, river, etc.) which in most cases is far removed from the end use customer and transport the finished commodity, or to locate close to the load center and transport the input fuel to the generator. It is not surprising then that the location decision for generation is interdependent with investment and operating decisions pertaining to the electricity transmission network. Efficient capital investment as well as optimal day-to-day operation required both generation of the commodity and the transport to be materially integrated with each other. In this way the specific economic organization – large vertically integrated (*i.e.,* generation and transmission) – was predetermined by the state of technology.[28]

As shown in Figure 12, in the 1990's technological advances arising initially from the space program led to dramatic improvements in the efficiency of small-scale generation units. In other words, small-scale generation was now capable of producing electricity as efficiently as much larger facilities.

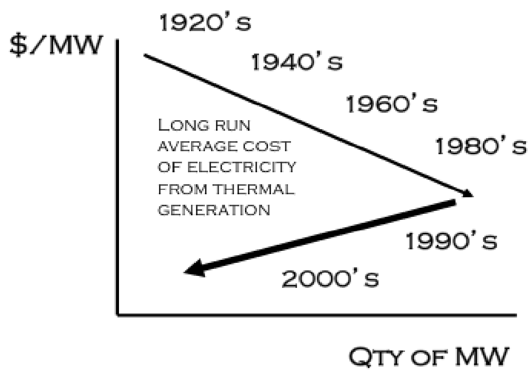

Figure 12: Average Cost of Electricity
Produced by Thermal Generation

The effect of these advancements could not have been more fundamental to the industry. Recall that the entire rationale behind the vertically integrated form of economic organization was because larger generation plants produced cheaper power. With no economic reason for larger plants, there was no longer any reason for monopoly generation. Furthermore, since generation could be competitive, there was no longer a reason for generation to be vertically integrated with transmission.

Once the decision has been made by policy-makers to allow competitive generation then there is a need to separate electricity as a commodity from transmission as a service. Competitive generators require that access to the transmission system is non-discriminatory, *i.e.,* no subset of

[28] The rationale applies regardless of the form of ownership, *i.e.,* it does not matter if the vertically integrated monopoly is owned by the government or private shareholders.

generators can be allowed to have priority access to the transmission system. If non-discriminatory access is not achieved then generators will not compete and the social and economic benefits (greater efficiency, lower prices, etc.) of competition will not be achieved,

It is nearly impossible to overstate both the fundamental importance of the effects of the technological advances as well as the difficulty in disaggregating generation and transmission after 60-90 years of operating as a single vertically integrated monopolist.

Nigeria is no different than any other country with respect to the imperatives caused by these technological changes. There is no longer any economic rationale for monopoly generation and, as a result, no justification for a vertically integrated generation and transmission provider. Nigeria has not only recognized this, but the language contained in the Roadmap for Power Sector Reform is entirely consistent with the required changes.[29]

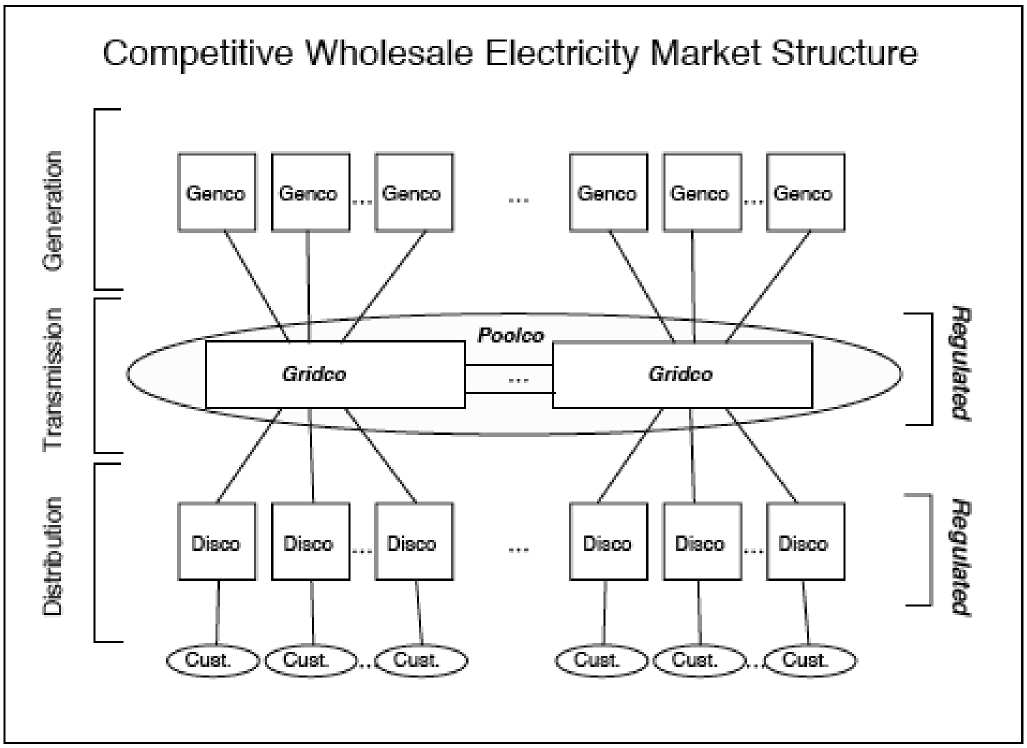

Figure 13: Diagrammatic Representation of a Competitive Electricity

Figure 13 provides a generic diagrammatic representation of what the government is ultimately attempting to accomplish.[30] The diagram shows that, by disaggregating physical electricity

[29] Presidential Task Force on Power (PTFP), Roadmap for Power Sector Reform, 2010.
[30] While the separation of functions shown in this diagram has numerous authors, this particular example is drawn from a presentation by William W. Hogan, "Poolco: What's the trick? Coordination for Competition,

production and consumption into the three primary activities – generation, transmission and distribution/retailing – highlights the importance of the activities of the transmission sector which is comprised of the "Gridco", *i.e.,* the physical transmission network, and the "Poolco", *i.e.,* the agent responsible for coordinating generation in order to meet load by granting access to the transmission network.

There are no inherent ownership assumptions in the diagram, *i.e.,* the "Genco's", or generation companies, could be either State-owned or Independent Power Producers as could be the "Disco's", or Distribution Companies. Moreover, the Disco's may or may not be vertically integrated with a retail business. Neither should it be inferred from the diagram that the activities of the Poolco and the Gridco must be performed by the same entity.

The MRTS and the Grid Code combined are the rules that outline how the "Poolco" will operate. In the proposed Nigerian structure the "Poolco" consists of the system operator and the market operator. ***In this context, "operate", means how the "Poolco" will allocate and price physical transmission capacity in real time so as to match supply and demand***.

At this point it is necessary to discuss three concepts that are fundamental to electricity market design:

- The relevant time frame
  - Electricity generation, consumption and transmission/distribution wires operate like a single integrated machine, *i.e.,* an integrated system. If supply and demand are not kept within close balance of each other at all times then the frequency of the system will rise or fall and the individual components (e.g. generation plants) of the "machine" will most likely be damaged. While storage would eliminate the need for *current* generation to always equal *current* load, the large-scale application of electricity storage is not economically feasible. As a result, the *reliable operation of any electricity system requires that generation is equal to load at every moment in time*.

    This basic fact has a tremendous effect on the design of an electricity market. For most commodities and services, the market mechanism works to coordinate the activities of participants by creating a price that incentivizes behavior on the part of its participants that leads to a balance between supply and demand. For example, when the quantity supplied exceeds the quantity demanded at a given price, the price will fall which induces suppliers to produce less and for consumers to purchase more and the "problem" of excess supply is eliminated. This simple textbook explanation glosses over the fact that, in the real world it takes time for the price mechanism to "work", *i.e.,* it takes time for prices to change and for participants to react to new prices. Unfortunately, when it comes to electricity we do not have the luxury of ignoring time – in the time it takes the price mechanism to work lives could be lost, expensive machines ruined and the

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Transmission Pricing and Open Access in the Restructured Electricity Market." July 18, 1995, p. 7. (see http://www.hks.harvard.edu/fs/whogan/)

system could either go black or burn down. The integrated electrical system operates at a far faster pace than can the market. Although physical demand and supply on an electrical system must be balanced within a narrow band at every instant in time, the price mechanism cannot coordinate buyers and sellers that quickly.

The time frame within which we cannot expect the market to work to allocate resources is called real time[31] or as in the MRTS the "dispatch period" and in some markets is as short as five minutes or as long as sixty minutes. The MRTS defines the Dispatch Period to be thirty minutes.

In essence the "dispatch period" is the time frame within which the market cannot be used to solve supply/demand imbalances. Rather within this time frame the system operator has the authority to direct/order the participants to act in a way that is consistent with reliable operation of the integrated system.

The longer the dispatch period the more authority and autonomy the system operator requires in order to operate the system reliably. For example, compare the very different requirements of 5- and 60-minute dispatch periods. Under the former a price – reflecting supply and demand conditions – is produced every 5 minutes. Both generation and load is expected to respond to that price and, in a majority of scenarios, this response is expected to eliminate supply/demand imbalances. In this case the system operator only needs the tools necessary to get him/her to the next 5-minute interval. Suppose for example the 5-minute load forecast was below the actual level of load. Within the 5-minute interval no new price is being produced to signal generators that more output is needed. Instead the system operator must instruct a generator to increase their production. However, at the start of the next 5-minute interval, prices will rise to reflect the inaccurate load forecast and generation will increase their production in response to this price increase. In contrast, compare what happens under market design based on a 60-minute dispatch interval. In this case the system operator has to wait a much longer time for the price mechanism to work and so will most likely have to order much larger quantities of generation to mitigate the inaccurate load forecast. As a general rule the longer the dispatch period, the more authority that must be granted to the system operator, and the less reliance on market solutions.

While the 30-minute dispatch period is longer than that used in mature markets where 5- or 15-minute intervals is common, the 30-minute period is a good starting point for the Nigerian market. Over time as the operation of the market matures and more generation and transmission capacity is added to the system, then the "non-market" interval can be reduced accordingly.

[31] The time when actual physical generation and physical consumption are taking place.

- The use of the term “electricity market” in the MRTS is at best a misnomer and at worst incorrect.
    - Given the need for a “dispatch interval” during which centralized command-and-control decision-making is used by the system operator to ensure reliable operation of the grid rather than the de-centralized market/price mechanism, it is misleading, confusing and fundamentally incorrect to talk about a real time electricity market.

      Since the time required by the price mechanism to bring about the necessary adjustments in the actions of participants is too great relative to the speed necessary to maintain a reliable electricity system every electricity system requires explicit or direct coordination during the dispatch interval. The relationship between the type of decision-making (*i.e.,* command-and-control compared to the price mechanism) and the relevant time frame is shown in the following diagram.

		Time Frame	
		Dispatch Interval	Prior to Dispatch Interval
Decision Making	Command-and Control	***Yes***	*Some but limited*
	Market/Price	*Some but limited*	***Yes***

Figure 14: Decision Making as a Function of Time in Electricity

Correctly speaking the term “electricity market” refers to the lower right hand quadrant in Figure 14. This represents the space were bilateral power purchase agreements are written, investments are made, maintenance decisions are made, fuel supply arrangements are entered into, generator offers are compiled and given to the system operator, etc. In comparison the quadrant in the upper left is where the system operator makes virtually all decision-making unilaterally. Coincidentally that is also the quadrant that is the rightful home of the MRTS. This is partly the reason why we referred earlier to the MRTS as being necessary but not sufficient for meeting the objectives detailed in Rule 2.1.

The dashed line connecting the upper left and lower right quadrants indicates that a relationship exists between activities that take place in these two very different time frames and decision-making paradigms. As was pointed out earlier, electricity is a “real time” commodity in that current production and consumption must, within a very tight band be equal to each other. Therefore, the “market”, *i.e.,* everything that transpires prior to real time is in part based on an expectation about what will happen in real time. If, for example, what happens in real time is consistently and materially different than what was expected to take place when participants entered into contracts, made investment decisions, scheduled maintenance, etc., then the market will change its expectations. It is therefore, critically important that the unilateral actions/decisions taken by the system operator are (1) transparent, (2) auditable, (3) replicable and (4) consistent. Unfortunately, as will be discussed later neither the Grid Code nor the MRTS provide for any of these conditions.

The primary task of the system operator in performing the required functions in the upper left quadrant is to match real time generation and load. Which amounts to allocating the available real time capacity of the transmission system. A necessary (but not sufficient) requirement to foster competition is to ensure this allocation process is fair and non-discriminatory, *i.e.,* that one or more of the "Genco's" in Figure 8 is not given preferential access rights to the transmission network.[32] *Therefore, with respect to electricity, creating the platform from which a "market" can develop necessarily means ensuring fair and non-discriminatory access to the transmission grid. That is, all parties need to be able to obtain transmission capacity on a fair and non-discriminatory basis.*

However, as we have discussed the physical characteristics of electricity necessarily mean that the transmission system cannot be perfectly "rationed" prior to real time in as much as the capacity of the transmission system at any point in time cannot be known with certainty until power is actually flowing. Moreover, the capacity of the transmission network is not simply a function of the physical infrastructure of generation, and transmission facilities and load[33], but also a result of the decisions made by the Dispatcher in matching supply and demand. As highlighted by Paul Joskow and Richard Schmalensee as far back as 1983:

> *The role of the transmission network in transporting power and in coordinating the efficient supply of electricity in both the short run and the long run is the heart of a modern electric power system. The transmission system is not just a transportation network that moves electricity from individual generating plants to load centers. Transmission plays the most fundamental role in achieving the economies of electric power supply that modern technology makes possible. The practice of ignoring the critical functions played by the transmission system in many discussion of deregulation almost certainly leads to incorrect conclusions about the optimal structure of an electric power system.[34]*

[32] This is required by Rule1.3.2 of the Grid Code that mandates the "efficient production and supply of electricity for all Users of the Transmission System without any act of discrimination between Users or class of Users."
[33] As will be shown in the next section.
[34] Joskow, Paul L. and Richard Schmalensee, Markets for Power: An Analysis of Electrical Utility Deregulation, MIT Press, 1983. P. 63.

In this passage, Joskow and Schmalensee, writing without the benefit of current vernacular on the topic point directly to the importance of the dispatch or coordination function ("…not just a transportation network..."). Creating a market is an exercise in designing rules that provide fair and non-discriminatory access to the dispatch function, which provides the platform from which the market can develop. ***Unless the electrical grid is so "overbuilt" relative to the requirements, including reliability, that transmission capacity need never be rationed; the starting point of good market design is with the dispatch function itself because this is the foundation of all wholesale electricity markets.***

2.3.2. Importance of "Real Time" and the Allocation of Transmission Capacity – dispelling three common myths!

As was stated in the previous section: the physical characteristics of electricity necessarily mean that the transmission system cannot be perfectly "rationed" prior to real time in as much as the capacity of the transmission system at any point in time cannot be known with certainty until power is actually flowing. Moreover, the capacity of the system is not simply a function of the physical infrastructure of generation, and transmission facilities and load, but also a result of the decisions made by the dispatcher in matching supply and demand. Therefore, the starting point of good market design is with the dispatch function itself because this is the foundation of all wholesale electricity markets.

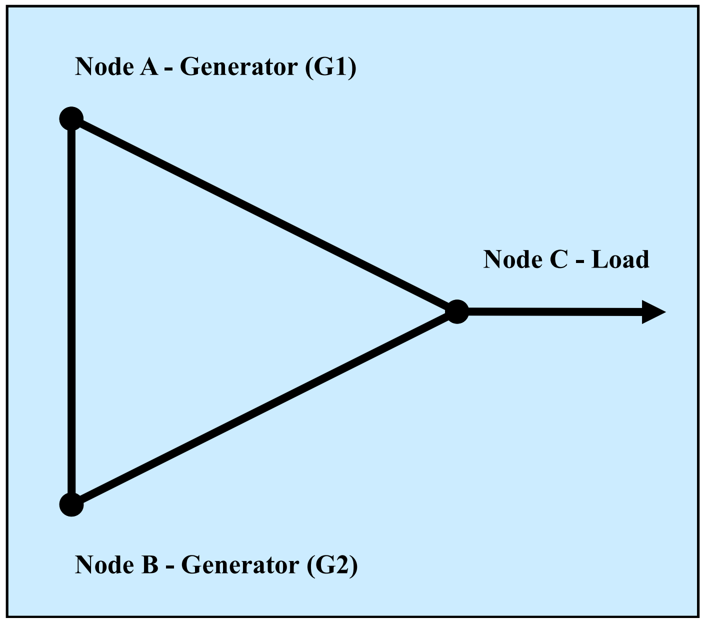

Figure 15: Simple Electrical System – No Transmission Constraints

In effect, the electricity market rules can be thought of as a set of instructions, rules and processes for how the system will be dispatched. ***Every electricity market that has tried to ignore this basic fact has met with failure and the rules have had to be re-written and the market re-built.*** The reason for this importance is due to the unique characteristics of electricity. In particular, electricity cannot be stored in meaningful quantities, which means that current supply must equal current demand, and electricity will always follow the laws of physics. *Market rules that do not reflect these fundamental characteristics have always and will always result in the failure of the market. Since the laws of physics cannot be ignored or altered, market rules that are not firmly based in the reality of electricity cannot support a workably competitive electricity market.* **In other words, good market design begins with reliable *real time* operation of the system. Without a reliable system there can be no market.**

It is useful to develop a context or paradigm to view the rules through. We begin with the simplest possible interconnected system; three nodes connecting two generators and one load. The system is shown in Figure 15. The generators are located at Nodes A and B (G1 and G2 respectively) and the load is located at Node C. To keep things as simple as possible we assume

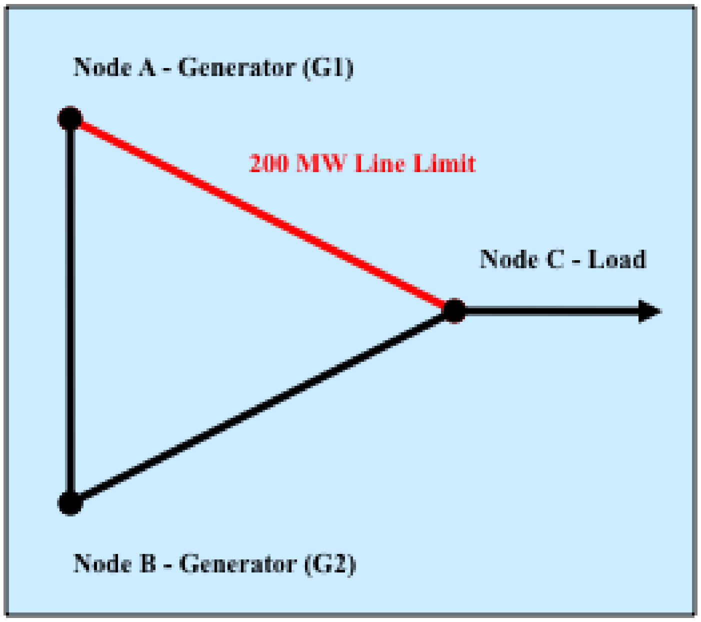

Figure 16: Simple Electrical System – Single Transmission Constraint

the transmission lines, AB, BC, and AC are identical length, size and there are no losses when electricity is flowing.

In this abstract system, with infinite supply and no line losses, load at Node C can be served either from G1 or G2. We can create a supply curve from the Economic Merit Order from the short run marginal costs of each generator.

This simplistic model doesn't really allow for much understanding or analysis of the problems facing the system operator (*i.e.,* Poolco) in real time.

In this hypothetical world the job of the system operator would be pretty easy. Simply choose the cheapest generators required to meet the load.

However, if we relax just a single assumption regarding the transmission system we can start to use this model to help guide us through the proposed rules. Specifically we will assume there is a line limit on the transmission line between A and C. A line limit is an example of a transmission constraint. In reality there are many other transmission constraints that the system operator must take into consideration when matching actual physical supply and demand in real time.

In Figure 16, we relax the assumption of unlimited transmission capacity by introducing a thermal constraint on AC. Specifically the line now has a 200 MW limit, *i.e.,* it cannot transmit more than 200 MW of power from Node A to Node C or vice versa.

We can now use this model to derive some conclusions regarding dispatching the system.

First, if we assume that load at Node C is 300 MW as in Figure 17, then either G1 or G2 is capable of supplying the load.

Figure 17 shows the situation when G1 produces 300 MW. In this case, 200 MW from G1 will flow along AC to the load at Node C, while 100MW will flow along AB and then BC to the load at Node C.

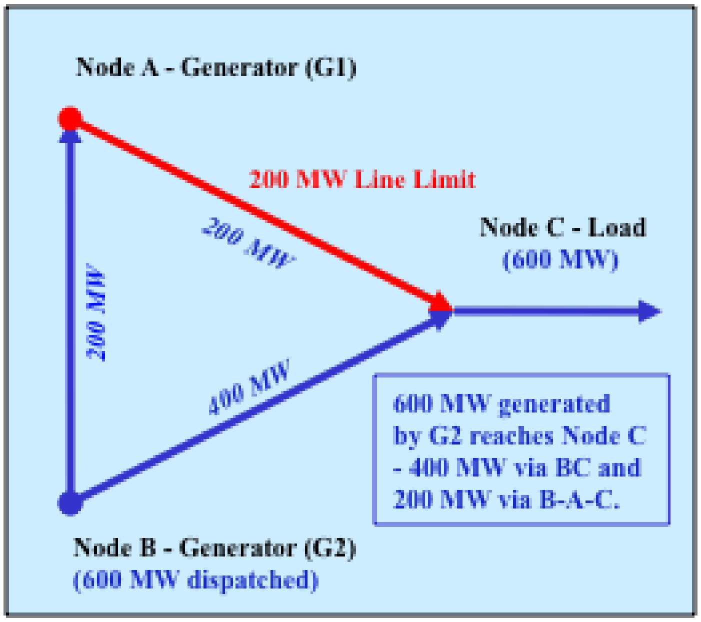

Figure 17: Simple Electrical System – Single Transmission Constraint, 300MW of System Load

Alternatively, assume G2 produced the entire amount. Then 200 MW would flow along BC, with the other 100 MW flowing from BA to BC. The 1/3 "relationship" between the transmission lines is a product of our assumption that the lines are of equal length and Kirchhoff's Law[35].

Now suppose instead that load at Node C was not 300 MW but 600 MW. Note first that G1 cannot supply the entire load. If G1 produces 600 MW, then 2/3 or 400 MW will flow along AC, which will be a violation of the line limit, and AC will burn up. G2 on the other hand, can supply the entire load. As shown in Figure 18, if G2 produces 600 MW, 400 MW will flow along BC and the remaining 200 MW will follow BA to AC without violating the 200 MW line limit.

Figures 17 and 18 can be used to develop some insight into one of the most important aspects of implementing an electricity market – allocating the capacity of the transmission system. When a single entity owns and operates both the generation and the transmission system there is no problem because there is only a single user of the transmission system. But when there are multiple (competing) generators, then more than one

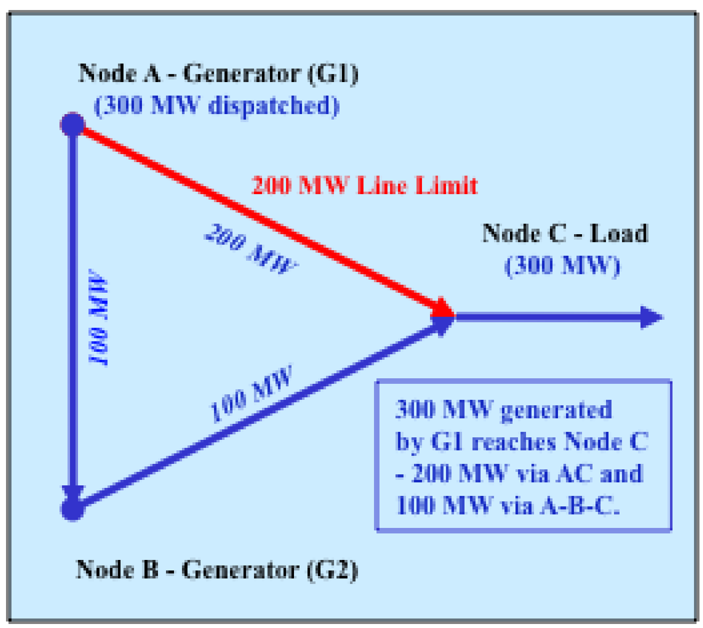

Figure 18: Simple Electrical System – Single Transmission Constraint, 600MW of System Load

[35] Kirchhoff's current law is: $\sum_{k=1}^{n} I_k = 0$, where n is the total number of branches with currents flowing towards or away from the node.

entity would like to use the transmission system to transport their power. *As long as the transmission system has sufficient capacity to meet all the demand for transmission capacity the issue is non-material. But as was discussed above, the Nigerian transmission system currently only has the capacity to wheel approximately 4000 MW of power, i.e., there is not enough capacity on the transmission system to transport all the potential generation in the country*.

One solution to the problem of allocating "space" on the transmission system is to define and allocate so-called physical "rights" to the transmission capacity.[36] In the North American natural gas market, it is normal to purchase pipeline "capacity" in order to move gas from a source to a sink. Typically the producer or shipper will obtain the necessary physical pipeline transmission capacity and then schedule their gas using their physical transmission rights, *i.e.,* they own the right to use a specific portion or amount of the pipeline. The simple model developed here and shown in Figures 17 and 18, highlight the fallacy of this paradigm when applied to electricity. Unlike natural gas, the capacity of the electricity transmission grid depends upon the load and the location of the generation used to meet the load. Imagine if the System Operator had estimated that load at Node C was going to be 300 MW and on that basis provided all the transmission capacity to the generator at Node A (on the expectation they would provide all the required generation)

Now assume that real time load at Node C is actually 600 MW as shown in Figure 13. In this case the Generator at Node A will not be able to produce any amount yet they hold all the transmission capacity while the Generator at Node B will be required to produce all 600 MW yet they will not own any transmission capacity to transport their power.

In Figure 17 the maximum "capacity" of the transmission system was 300 MW if G1 is used to meet the load, while in Figure 18 the "capacity" was 600 MW if G2 is used to meet the load. This example dispels a common myth that transmission capacity determined *ex ante*, *i.e.,* before real time, can be used for purposes of dispatch. In the situation just described the system operator will have to abrogate the transmission rights allocated to G1 and then issue new rights and allocate them to G2. In effect the initial allocation was of no value and the market will quickly factor this in to their expectations commercial arrangements.

We have shown that the available capacity depends upon system load, which generators are used to meet the load, and the location of the load and generation vis-a-vis the topology of the transmission system.

Now let's assume that the short run marginal cost (SRMC) of G1 is $20 and that of G2 is $30 and both have unlimited generating capacity. As shown in Figure 19, if the load at C is 270 MW then the optimal generation dispatch would be for G1 to produce all of the output (total cost would be 270 MW * $20 = $5,400).

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[36] In the United States it was initially assumed, incorrectly, the physical capacity of the transmission system was static and knowable, *i.e.,* like that of a natural gas pipeline network. This led to the creation of "physical transmission rights" for the electricity system that users of the transmission system had to acquire in order to schedule and use the network.

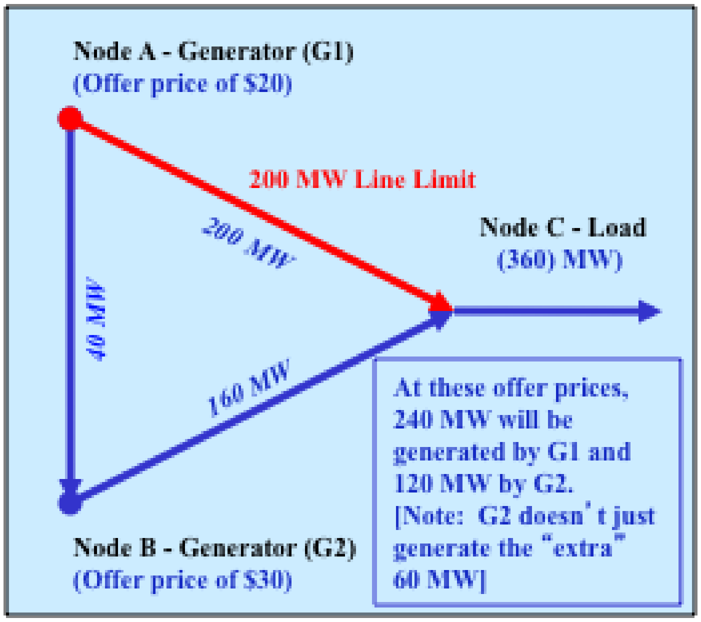

Figure 19: Simple Electrical System – Single Transmission Constraint, 270MW of System Load and SRMC

Figure 19 provides the detail of how the power would actually flow from G1 to Node C. In this case, the *system-wide price* would be $20. That is, everybody on the system would either pay, in the case of load, or be paid, in the case of G1, $20. G2 would receive no revenue since they did not produce any electricity.

But what happens if load rises from 270 MW to 360 MW as is shown in Figure 20. If the transmission system is unconstrained, having G1 produce all 360 MW would be the least cost option. But the existence of the line limit on AC means that the system will have to be **re-dispatched**.

Furthermore, since we saw in Figure 17 the most that G1 can produce is 300 MW, it might *seem* optimal to have G1 produce 300 MW, while G2 produces the remaining 60 MW. Total cost under this scenario would be: (300 MW * $20) + (60 MW * $30) = $7,800. However, if G1 produces 300 MW then there is no available capacity on AC. Thus when G2 produces 60 MW and 1/3 of that output flows on AC; the line limit will have been exceeded (200 W from G1 and 20 MW from G2).

So while this may be a least cost solution, it is not a feasible solution.

Rather than dispatch according to the simple Economic Merit Order, the system operator must ***re-dispatch***, *i.e.,* the dispatcher is going to have to change the least cost level of output because it does not respect the

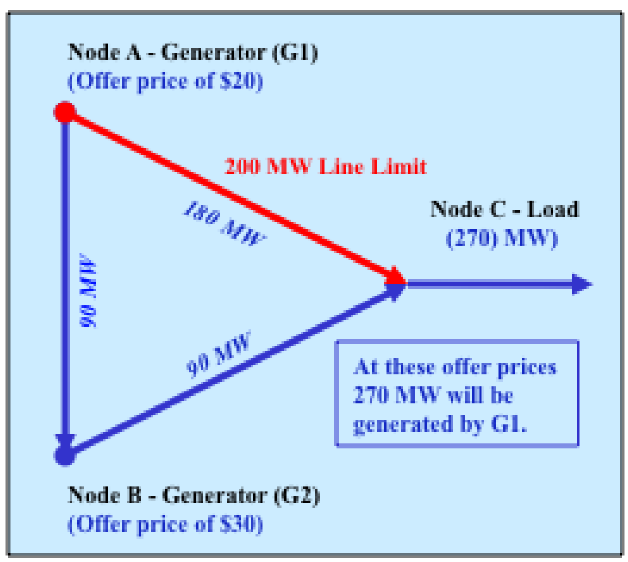

Figure 20: Simple Electrical System – Single Transmission Constraint, 360MW of System Load, Optimal Dispatch

transmission constraints in the system, *i.e.,* it would violate the reliability requirements. Given the offer prices and the system, the least cost solution will be when G1 produces 240 MW and G2 produces 120 MW. The total cost will be (240 MW * $20) + (120 MW * $30) = $8,400, which is $600 more than the "unconstrained" solution. Figure 20 shows the final solution.

Assume the system dispatcher started with the assumption that the cheapest generator (G1) was going to produce all of the power necessary to serve the load, *i.e.,* 360 MW. But he/she knows that will cause AC to have 240 MW of power flowing across it, when the constraint is 200 MW. So the operator has to relieve 40 MW of flow across AC while keeping the lights on at C. Suppose it was possible for the operator to sequentially solve this problem, *i.e.,* they start with the cheapest solution, regardless of constraints, and then find a solution that is least cost while not violating the constraints, *i.e.,* they determine the optimal dispatch solution. For every MW reduction in output by G1, the operator in effect, "buys" 2/3 MW of space on AC, which then allows him to "buy" 2 MW of output from G2. In this way the optimal dispatch will occur when G1 and G2 are producing 240 MW and 120 MW respectively. This solution is "optimal" because it minimizes the cost of meeting the demand without violating the constraint. No other solution will achieve this result. Suppose for example, the dispatcher chose instead to use 238 MW from G1 and 122 MW from G2, then total production costs for this solution would be $20 higher at $8,420. Alternatively, suppose they chose G1 and G2 to produce 241 MW and 119 MW respectively. This would lower production costs to $8,390 but would cause the flow on AC to be 200.33 and would violate the line limit. Figure 21 provides a disaggregated view of the power flows from both G1 and G2 under the optimal solution.

The example dispels a second popular myth – that "energy" and "reliability" can be separated. What this example shows is that the actions of the system operator affect dispatch and prices, *i.e.,* it is not possible to keep the system operator out of the market.

The notion that electricity can be disaggregated into indvidual components may make sense from the perspective of accounting or settlement but it has no meaning when it comes to the physical activites associated with dispatching generation to meet load. This "belief" that electricity is separable causes profound mistakes with respect to electricity market design. If the system operator cannot distinguish "physical" electricity, then how is he/she going to be able to distinguish between electricity that was purchased via contract versus that which was purchased in the spot market?

All electricity is equivalent once it is "on the grid." Thus electricity that is necessary for voltage support is identical to electricity that is being used to turn a motor. Similarly electricity purchased through a long-term contract is identically equivalent to electricity that was purchased yesterday or today. From the perspective of physical dispatch the arrangement under which the electricity was purchased is irrelevant.

2.3.3. Pricing electricity

Given the optimal dispatch shown in Figure 21, we can use the model to evaluate different potential pricing methodologies. Suppose that G1 and G2 were both owned by the same company. Generation would then be a monopoly and presumably regulated and we could use *average cost pricing* and simply divide the total production costs by the number of megawatts to find the average production cost and use that as our price. In this example that would be: $8,400/360 MW = $23.33. In this example, our interest is not in determining a “price” as much as it is to ensure the generator gets cost recovery. However, if a single company does not own G1 and G2, *i.e.,* they are competitors, average cost pricing will not “work.” Under this methodology, the “price” did not cover G2’s marginal cost ($23.33 versus $30), so why would G2 produce any electricity if they knew they were going to lose money on every megawatt.

If the market rules impose an average pricing regime (*i.e.,* the cost recovery mechanism used by regulators in declining cost industries like electricity) in a competitive market, when the system operator calls for G2 to produce they will not respond, and the load will not be served. Thus, in a

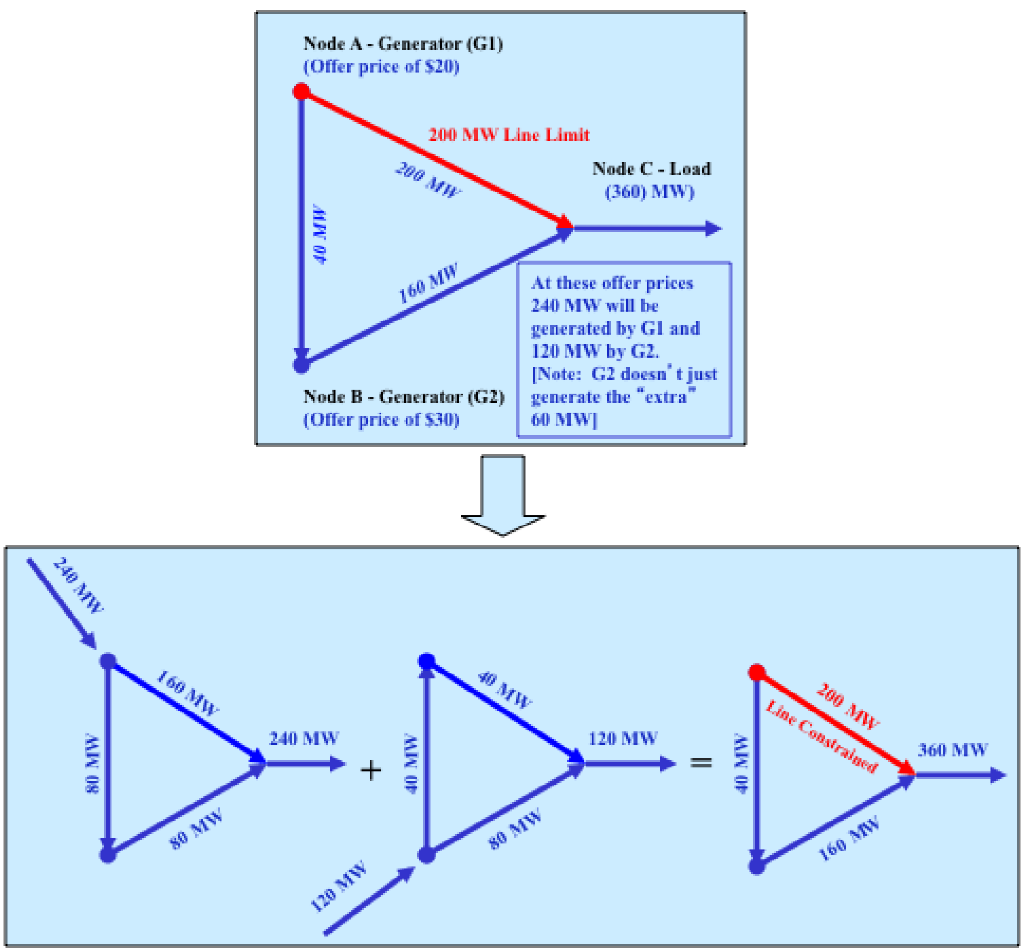

Figure 21: Simple Electrical System – Single Transmission Constraint, 360 MW of System Load, Power Flows Under Optimal Dispatch

competitive market we cannot use average cost pricing without providing an extra payment to G2, the generator whose marginal cost is above the average cost.

Alternatively, we could use a simple Economic Merit Order to determine the highest priced generator needed to satisfy demand and create a system-wide "market" clearing price. This would mean that G2 at $30/MW would set the price. The total cost to consumers would be $30 * 360 MW = $10,800. Like average cost pricing, there is a certain appeal to the simplicity of having a single price. However, as will be shown with the next methodology, that simplicity comes at the cost of masking the complexity of electricity transmission and dispatch.

A third alternative is to find the price that reflects what actually took place including the steps the dispatcher needed to take in order to match supply and demand while recognizing the constraints. This is called *marginal cost pricing* and we need to calculate the *marginal cost of the next megawatt at each node.*

Suppose that load at C was 361MW rather than 360MW. We know how much G1 and G2 produce when load is 360MW, but how would the dispatcher acquire one more MW. He/she would reduce G1 by 1 MW which saves $20 and then increase G2 by 2 MW (1 MW to make up for the reduction in G1's output and 1 MW to meet the added load) which would cost $60, *i.e.,* 2 MW * $30. Thus the marginal price at Node C, when load is 360 is: (-1 * $20) + (2 * $30) = $40. We can do the same analysis at the other two nodes and determine that prices are $20 at A and $30 at B. Thus the price that reflects the actual dispatch is not a simple single, system-wide price but rather three prices, one for each node:

- Price at Node A = $20,
- Price at Node B = $30,
- Price at Node C = $40.

It is useful to reflect on these prices and in particular the information that is being conveyed. For consumers at Node C, an extra MW of demand will require the dispatcher to reduce output from G1 by 1 unit and increase G2 by 2 units. Given the assumed marginal costs of G1 and G2 the cost is $40. Under average cost pricing the price would be $23.33 and under the simple highest generator running approach the price would be $30. In either of these cases, consumers would pay a price that is lower than the actual cost – *given the transmission system!* In other words the latter two pricing mechanisms do not accurately reflect the reality of the transmission system and the required actions of the dispatcher to match supply and demand.

Under the marginal cost pricing example, generators will receive the price at their node times the amount of output they produced or $8,400 in revenue (G1 will receive $20 * 240 MW = $4,800 and G2 will receive $30 * 120 MW = $3,600) and the load will pay $14,400 (360 MW * $40/MW). In this example, the binding transmission constraint leads to three separate and distinct prices and leads to the creation of a $6,000 settlement surplus. It is imperative that neither the Gridco nor the Poolco receive this surplus. The surplus is the direct result of a transmission constraint and the Gridco should not be rewarded for having a highly constrained transmission system.

Likewise the Poolco should not be financially rewarded for using a dispatch that maximizes rather than minimizes the surplus created from transmission constraints.

The surplus should be returned to the customers in some manner. Since the surplus arises from the existence of transmission constraints the usual method for returning the surplus is through financial transmission rights (FTR). An FTR pays the owner the difference in prices between two nodes on the system. Thus in our example, the owner of an FTR from A to C would receive $20 for every 1 MW FTR they owned. There are alternative methods for returning the surplus.

Returning to the different pricing methodologies, notice that under the simple Economic Merit Order pricing methodology, the actions of the dispatcher in recognizing and then managing the constraint is not reflected in the price. The $30 price reflects only the cost of generation. But in reality, the existence of the 200 MW line limit on AC means that an additional megawatt of demand requires ***re-dispatch***. That is, an additional megawatt of demand requires the dispatcher to back G1 down by 1 megawatt and ramp G2 up by 2 megawatts. Thus the true cost of an additional megawatt of load at Node C is not $30, but rather $40. If we adopt the simple Economic Merit Order approach to pricing we will be undervaluing the effect of the constraint and, as a result, over encouraging the use of electricity. Moreover, we will not be sending the appropriate investment or consumption signals to the market.

In conclusion, if a system has no transmission constraints (e.g. thermal, voltage, stability, etc.) then there is no real need for a system operator to coordinate power flows and the market rules can, and should, be quite simple. However, the assumption or the belief that a particular system has no transmission constraints has always turned out to be false in other market design and implementation processes. In many cases, existing constraints are well known and managed prior to real time, *i.e.,* through the scheduling or commitment process. That the constraints in a particular system may not have shown up historically in real time simply means that the behavior of participants has been modified over time because they know the constraints would arise. And because in most cases the participants are either regulated monopolists or government entities the behavior of participants is different than it is in a competitive market.

2.4. Summary

Our purpose for each of the previous sections was as follows:

- Section 1 provided the rationale behind the original structure of the industry. By showing that the structure, including the commercial environment, was largely a function of a given state of technology (e.g. economies of scale in production) it becomes understandable why a change in that technological foundation will necessarily lead to a change in the industry structure and the commercial environment.

  Under monopoly provision, there is no practical or commercial imperative to define the services provided by the transmission grid. Competition and open access changes this dramatically. As a matter of fact, the primary and most important activity in implementing open access is to provide specificity to the services provided by the transmission grid. Specifically, to define what constitutes transmission access and how will system coordination be achieved. The former relates to establishing and allocating transmission rights, while the latter pertains to defining the scope and role for non-market centralized activities carried out by the system operator.

Finally we noted that the Grid Code and MRTS are to be treated as companion sets of rules. However, the overall structure lacks any definition of the underlying market design philosophy. We don't know for example, whether the market design is aimed at minimizing or maximizing the role of the system operator. Both philosophies have been successful and neither is necessarily better than the other. Lacking the underlying market philosophy makes any evaluation of the rule structure necessarily problematic because we cannot determine whether our inference of the design philosophy is at fault or the rules themselves.

- Section 2 is a brief presentation of the facts of the Nigerian system. Starting with the MRTS and the Grid Code we find that the objectives of implementing open access are to create an efficient, competitive, transparent and reliable market. While we completely agree with these objectives, the rules themselves are necessary but not sufficient to achieve the goals. In fact the rules should be thought of as a piece of the platform from which Nigeria can achieve the desired goals.

  Furthermore, the Nigerian situation is extremely unique relative to other open access implementations in that there are significant obstacles with regard to the amount of generation and transmission capacity as well as the robustness of the commercial arrangements. Thus market design and implementation must be accomplished simultaneously alongside significant capital expenditures.

- Finally Section 3 provides a rudimentary introduction into the basic issues facing the system operator, or "Poolco". In particular we explained:

  - The integral importance of the system operator in allocating real time transmission capacity,
  - Why transmission capacity is, to a material extent, neither fixed nor knowable until real time,
  - The effect of transmission constraints on the dispatch of generation,
  - How to correctly price real time electricity,
  - How electricity prices are affected by dispatch decisions, and
  - Why physics dictates the range of responses available to the system operator.

3.0 Section B: Evaluation of the MRTS

Given the background material in the previous section we are now in a position to evaluate whether the MRTS and the Grid Code in combination are likely to meet the government's objectives in establishing a competitive market.

3.1. Introductory comments on the MRTS

It is a gross understatement to say there are significant obstacles along the path to allowing competition and implementing open access in Nigeria:

- Nearly 50% of the population lacks access to electricity.
- The country is seriously deficient in both generation and transmission capacity.
- The commercial environment is immature and unsustainable.
- Industry reform has dragged on for more than a decade.
- The proposed rules are for two interim markets and there is no recommended design for the final market.

Nevertheless, the government has wisely adhered to its reform agenda and is now on track to begin the process of allowing competition and open access. A favorable implementation and successful operation of the market is ultimately critical to improving the social welfare of the country. However, there can be no doubt that this will be a fragile situation for a number of years.

One general comment before starting the review of the rules, the separation of the System and Market Operators into two distinct activities is purely cosmetic. Despite all arguments to the contrary, the distinction is purely ideological and has no meaningful operational justification. From the perspective of efficiency, the distinction should be eliminated and the two functions merged into a "Transmission System Operator."

3.1.1. The Transitional Phase

The MRTS provides for a Transitional Stage to precede the implementation of the Medium Term Market. The Transition Stage is not intended to be a market, but rather more of a necessary administrative step in the process. Rules 1.2.1 and 6.1 – 6.4 define the activities that are to take place in the Transition Stage:

1.2 Establishment of electricity trading system

These Rules have been framed by the Market Operator in order to establish the electricity trading system for the Nigerian Electricity Power Sector and to make provisions for the following:

1.2.1 During the Transitional Stage:

(a) Energy procurement and contracting;

(b) Energy metering and settlement of contracts; and

(c) *collection by the Market Operator of the System Operation and Market Administration Charge;*

6. MARKET DEVELOPMENT

6.1 Market Stages

The competitive market for electricity in Nigeria will evolve through the following stages:

6.1.1 Pre Transitional Stage, during which:

(a) preparation will be made for physical unbundling and future privatisation of PHCN;

(b) performance incentives for distribution and generation activities will be established; and

(c) the Grid Code and these Rules will be implemented and tested

6.1.2 Transitional Stage, characterised by entry of new generation, contract based arrangements for electricity trading and the introduction of competition.

6.1.3 Medium Term Market, with the introduction of generation competition and a centrally administered balancing mechanism for the market.

6.2 Preparations for initiation of the Transitional Stages

6.2.1 During the pre-transitional stage, the System Operator or the department of PHCN responsible for system operation services will:

(a) Commence application and implementation of the draft Grid Code, with a view to:

(i) testing feasibility, coordination, data exchange, reliability and quality parameters and standards;

(ii) Identifying any problems or gaps; and

(iii) drafting such amendments as may be required to the Grid Code;

(b) Develop and implement the initial operating procedures;

(c) Prepare monthly Grid Code Implementation Reports;

(d) Train future Participants on the Grid Code; and

(e) *Not later than [six] months after initial implementation, present the revised Grid Code for Minister approval.*

6.2.2 *During the pre-transitional stage, the Market Operator or the department of PHCN responsible for market administration will:*

(a) *Commence application and implementation of the draft Market Rules to the extent that these Rules apply during the Transitional Stage with a view to:*

(i) *enable it review feasibility, coordination, timing, metering problems or gaps; and*

(ii) *draft such amendments as may be required to the draft Rules;*

(b) *Develop and implement initial Market Procedures;*

(c) *Prepare monthly Market Rules Implementation Reports;*

(d) *Train future Participants on the Market Rules;*

(e) *Not later than [six] months after initial implementation, present the revised draft Market Rules for Minister approval;*

(f) *Implement as a transitional governance system, the Initial Stakeholder Advisory Panel;*

(g) *Implement workable metering arrangements and settlement procedures in order to test existing metering system; and*

(h) *Implement and or maintain adequate data bases and procedures for the settlement process and issuance of Settlement Statements.*

6.3 Transitional Stage

6.3.1 *All electricity trading arrangements during the Transitional Stage will be consummated through contracts, and there will be no centrally administered balancing mechanism for the Transitional Stage Market.*

6.3.2 *The Market Operator shall develop a Market Procedure for the management of inadequate supply and shortage conditions during the Transitional Stage. This Market Procedure will allocate generation shortages proportionally among Loads and will be tested and improved during the Transitional Stages, and shall become part of the Grid Code at the start of the Medium Term Market.*

6.3.3 Not later than [twelve] months after the initiation of the Transitional Stage, the Commission will constitute the initial Market Surveillance Panel.

6.4 Preparations for initiation of the Medium Term Market

6.4.1 Prior to the commencement of the Medium Term Market, the System Operator shall prepare an Operation Procedure to manage shortages due to insufficient generation or transmission congestion. Such Operation Procedure shall be based upon the Market Procedure developed by the Market Operator pursuant to Rule 6.3.2 above.

6.4.2 Prior to the commencement of the Medium Term Market, the Market Operator, shall:

(a) ensure that all necessary arrangements for proper functioning of the Medium Term Market are in place, including the necessary models, settlement software and data bases; and

(b) ensure that all market Connection Points have adequate metering and communication systems.

6.4.3 Prior to the commencement of the Medium Term Market, the Market Operator shall, in consultation with the Stakeholder Advisory Panel, develop and Publish the procedures for the determination of energy prices in the Balancing Market, particularly during shortages or unexpected constraints, provided that the Commission shall give prior approval to the procedures.

6.4.4 Upon the request of Participants, the Market Operator shall organise meetings to explain and demonstrate the software, models and systems for the operation of the Balancing Market, and pricing and settlement therein.

6.4.5 Prior to the scheduled initiation of the Medium Term Market, the Market Operator shall carry out the following activities:

(a) At least [twelve] months prior to the scheduled initiation of the Medium Term Market, develop and implement the requisite software, metering and settlement systems for the for Medium Term Market;

(b) At least [twelve] months prior to the scheduled initiation of the Medium Term Market, publish on the Website, a schedule to dry run and test the operation of the Balancing Market and implement a shadow trial Balancing Market and trial software for the Medium Term Market in order to:

(i) *test the pricing mechanism in the Balancing Market and rules and procedures for settlement therein; and*

(ii) *review feasibility, timing, metering systems, software and identify any problems or gaps therein.*

(c) *As part of the activities in the immediately preceding paragraph (b) above, the Market Operator shall calculate and publish on the Website the prices of the shadow Balancing Market, to show short-term opportunity prices or system marginal prices notwithstanding that Participants have not commenced trading at these prices and:*

(i) *The System Operator shall evaluate the calculated prices and the results of the shadow Balancing Market to identify and implement improvements in the System Operator dispatch software and models; and*

(ii) *The Market Operator shall develop and publish on the Website the preliminary draft of the Market Procedure showing the detailed methodology for the calculation of Balancing Market prices and operation of the Balancing Market, including all aspects on pricing and deviations during shortage periods, load curtailment or emergencies.*

(d) *At least [six] months prior to the scheduled initiation of the Medium Term Market, the Market Operator shall commence training of Participants on the Medium Term Market Rules and procedures, to enable Participants practice and understand the new mechanisms.*

(e) *Commencing [six] months prior to the scheduled initiation of the Medium Term Market, the Market Operator shall prepare and submit monthly Medium Term Market Rules Implementation Reports to the Commission and all Participants, and shall publish same on the Website. The Report shall describe:*

(i) *the tests performed on models, settlement software and data base management and the results thereof in the trial period;*

(ii) *adjustments and corrections implemented in systems, models and software; and.*

(iii) *proposals for any amendments to the Market Rules that may be required.*

(f) *At least [three] months prior to the scheduled initiation of the Medium Term Market, develop and or as the case may be, amend all the necessary Market Procedures for the Medium Term Market in consultation with the Stakeholder Advisory Panel, and conclude preparations for its implementation.*

(g) *At least [one] month prior to the scheduled initiation of the Medium Term Market, prepare a report demonstrating that all systems, software and procedures required for the Medium Term Market are ready and have been adequately tested and that the Market Operator and Participants are ready to commence activities on the Balancing Market.*

The pre-transitional stage and the transitional phase are necessarily a type of "no-man's" land. It is, however, extremely important in the Nigerian context because of what it represents. In particular the introduction of far greater rigor and precision in the industry that will ultimately be necessary for a truly successful commercial sector.

In other market development processes, this stage is similar, but not identical, to what is termed "market trials." In any market implementation there are a series of "trials" that test information exchange, interfacing, software implementation, training, dispatch, settlement, etc. Depending on the scope of the individual trial they can run anywhere from a few hours to several hours or days. The primary difference between this process and the one defined in the MRTS being the length of time and the scope of activities. Unlike other implementation processes the MRTS sets aside a significant amount of time whereby many different aspects of the eventual (medium term) market are developed.

During the Transitional Stage, generation will largely be dispatched as though it was still under monopoly ownership and control and individual generators are paid the "Dispatch Compensation Payment" – a monthly payment for following dispatch instructions. The rules do not describe the calculation of the payment or any the surrounding the details, e.g. how long is the rate set for, can it be adjusted, is it locationally based, etc.

The most significant concern regarding the Transitional Stage is that it becomes a semi-permanent state. This may happen for a number reasons:

- Change can be difficult for Market Participants and consumers.
- The "Dispatch Compensation Payment" is simply a regulated rate and to the extent generators are successful in getting a rate that exceeds what they expect to receive in a competitive environment they will want to continue the Transition Stage.
- The System and Market Operators are responsible for putting new software in place, providing training, develop operating guides, etc. and we can assume they will be risk averse to moving to the Medium Term Market expeditiously.

The Transitional Stage is not designed or intended to be efficient, transparent or foster competition. It may or may not be reliable. Thus the transition stage, by design, will not achieve three of the four objectives listed in Rules 2.1 and 2.2.

Recommendation:

Our preference is that the rules for the Transition Stage contain a hard timeline for moving to the Medium Term Market. Given the initial conditions of the Nigerian electricity sector, it is reasonable that the Transition Stage should not last more than 36 months. Consistent with this recommendation, we would like to see the MRTS disaggregate the Transitional Stage into sub-stages with defined timelines for each sub-stage. This accomplishes two things: (1) it breaks the process down into manageable pieces and prioritizes the work program for the System and Market Operators as well as the Market Participants, and (2) it provides the opportunity for incremental success.

We would also like the Rules to include not just the production

With respect to specific rules we provide the following comments:

1. *New language should be provided for Rule 6.3.1. Of course there will be a centrally administered balancing mechanism, there is no other possible way to manage real time transmission constraints. What will be missing is a "balancing market."*

2. *The following phrase in Rule 6.4.1 "…shortages due to insufficient generation or transmission congestion" is unclear. Is the Rule meant to address insufficient transmission capacity or generation shortages that are exposed by transmission congestion?*

3.1.2. The Medium Term Market

The MRTS provides for a Transitional Stage to precede the implementation of the Medium Term Market. The Transition Stage is not intended to be a market, but rather more of a necessary administrative step in the process. Rules 1.26 and 6.5define the activities that are to take place in the Transition Stage:

1.2 Establishment of electricity trading system

These Rules have been framed by the Market Operator in order to establish the electricity trading system for the Nigerian Electricity Power Sector and to make provisions for the following:

…

1.2.2 During the Medium Term Market:

(a) trading in Imbalance Energy;

(b) settlement of charges and payments relating to Energy, Ancillary Services and usage of the Transmission System; and

(c) collection by the Market Operator of the System Operation and Market Administration Charge and the Cost of Imbalance Energy;

1.2.3 A system for the administration and enforcement of these Rules.

6.5 Medium Term Market:

6.5.1 In the Medium Term Market, the Balancing Market will be a spot market, allowing efficient opportunity trading and efficient contracts to cover and or hedge price risk and while maintaining a security constrained economic merit order dispatch.

6.5.2 The Medium Term Market will, among other things, reflect flexibility in the design of bilateral contracting through the implementation of the Balancing Market where each Participant will be able to buy and sell the difference between Metered Quantities and contracted quantities at fair and efficient market-determined prices. The Balancing Market will be an open and non-discriminatory market of last resort for Participants whose contracts do not cover the electricity that they produce or, as the case may be, consume.

6.5.3 The main features characterising the design and structure of the Medium Term Market are as follows:

(a) several Distributors, each with a monopoly over retail sales to customers within its franchise region;

(b) *each Distributor may enter into bilateral contracts for purchase and or sale of energy;*

(c) *open entry to the market and, subject to technical and environmental obligations, and within the energy policy defined by the Government, investors can decide the timing, location and type of new generation capacity to construct;*

(d) *competition in Dispatch; and*

(e) *flexibility in electricity trading arrangements through the implementation of a Balancing Market.*

As defined in Rules 1.2.2 (a) and 6.5.1 the defining characteristic of the Medium Term Market is the operation of a "Balancing Market."

The term "balancing market" is technically inaccurate and causes a great deal of confusion. In order to keep the lights on, *i.e.,* operate reliably, the system operator will dispatch generation (including "re-dispatch" for transmission constraints), balance supply and demand, keep frequency at 60Hz, maintain voltage, monitor and control grid flows, control transmission, monitor contingencies, manage reserves, handle emergencies, and much more. Most, if not all, of these actions are interdependent and simultaneous. Thus, the system operator does not balance supply and demand independent of re-dispatching or maintaining voltage, etc. The term "balancing market" incorrectly implies the opposite, *i.e.,* that it is possible for the system operator to balance supply and demand independently of the other actions. The casual reader is then left thinking that "balancing" contractual deviations is physically separable from the other activities. It is not. Instead it is best to think of the system operator as potentially taking a myriad of actions that are physically interdependent and inseparable.

Furthermore, the term "market" is misleading as well. In real time, demand is inelastic and the price mechanism cannot work fast enough to direct behavior in the time frame required for reliable grid operation. Rather what happens in electricity is the system operator solves for a price that, based on the information he/she has been given, will cause participants to make choices that are consistent with reliable operation of the system. For example, suppose an unanticipated transmission constraint arises in real time. What needs to happen is for some generators to reduce their desired level of output while others need to increase theirs. The optimization software will identify which generators need to change their output and the system operator will, based on the information the generators provided in their offers in combination with information pertaining to the transmission grid, be able to solve for prices that will cause the necessary reduction in output from one set of generators and the simultaneous increase in output from a different set of generators.

Therefore, rather than starting from the perspective of "market design", it is more accurate and ultimately more efficient for the participants to start with the following paradigm:

- In order to implement open access and allow competition, what tasks must the system operator perform to ensure reliability?
- Are there any other tasks we would like the SO to perform?
- How would we like the SO to perform these tasks?
- What information and tools does the SO need to perform the tasks?
- Where will the information and tools come from and how do we ensure it is accurate?
- How do we best align the needs of the SO in fulfilling his/her obligations with the economic incentives of the participants?

Adherence to this paradigm and, despite all temptation, ignoring a discussion on electricity market design in the process will result in a system operations function that is efficient, transparent and reliable – which will serve as the best platform for competition and the development of a robust electricity market.

The design philosophy inherent in the MRTS

As alluded to in the previous section the MRTS falls victim to the desire to design a market rather than address the needs of the system operator. With that in mind, the overarching design "philosophy" of the MRTS is not, in the first instance, so much a philosophy about "market" design at all but rather a pragmatic response to the (poor) state of physical investment in generation. Specifically the "market" created by the MRTS and the Grid Code both flow directly from the two interrelated premises that explain the proposed market rules/design:

- Nigeria needs more generation, and
- Nigeria requires private capital to build the needed generation.

Nigeria's need for non-government financial capital to build the required generation capacity provides the requirement for open access. Private investors must have assurance their generation will be treated fairly and non-discriminatorily, before they will invest.

Operationally this means the services provided by both "Gridco" and "Poolco" must both meet this standard. Furthermore, because private sponsors of generation projects prefer to use project financing rather than financing from their own balance sheet, there is a need for bilateral contracting. However, the lack of credit worthy counterparties serves as an obstacle to bilateral contracting. To address this issue, the government has created, and financially guarantees, the Nigerian Bulk Electricity Trader (NBET). The NBET is charged with being the "contract market maker" by entering into long-term contracts with buyers and sellers.[37] In effect, the government is recognizing that for a number of reasons the existing commercial environment is not conducive to bilateral contracting.[38] The question at hand is not whether the government should be addressing this situation because it is obvious that they should, but rather what constitutes good market design.

As shown in Figure 22, the market design philosophy underlying the MRTS and the Grid Code is a "top down" approach with the primary focus on putting in place an effective bilateral contracting regime, rather than building an effective platform that is necessary for a robust commercial environment, including bilateral contracting.

By starting with the "market" rather than reliability and the coordination function, the eventual rules will, most likely, to a greater rather than lesser degree, "separate" the physical operation of the grid from the financial market.

The fundamental flaw in this approach is that how participants decide to transact power is irrelevant to the job of the system operator in real time, *i.e.,* whether power is purchased via a

[37] There is nothing wrong with the goal of making the environment for bilateral contracting more robust. Especially given the current situation in Nigeria. But successful contracting requires and, ultimately will flow, from a well-designed and operated real time spot market.

[38] This is a common occurrence in countries where the electricity sector has been under government control and/or ownership.

bilateral contract or through spot market purchases, has no bearing whatsoever on the task of the system operator.

At a high level the resulting market defined by the combination of the MRTS and the Grid Code can be characterized as "zonal" and "physical."

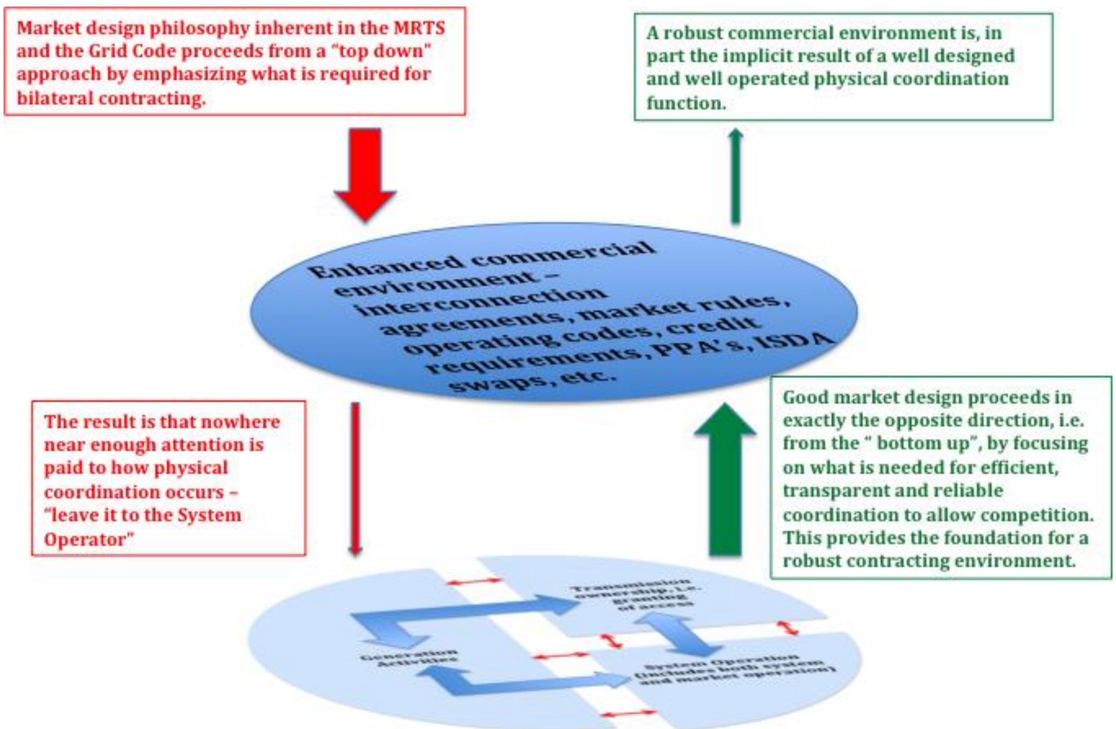

Figure 22: "Top Down" versus "Bottom Up" Market Design

<u>Bilateral contracting under monopoly provision</u>

We can use Figure 15 to explain how contracting changes with the introduction of open access. Assume that initially G1, G2 and the transmission system are all part of an integrated monopoly provider of electricity and transmission, e.g. NEPA.[39] As such NEPA had the ability to make unilateral decisions regarding both generation and transmission. As an integrated monopolist, NEPA had the ability to internalize the production "vs." transport decision, *i.e.,* how best to simultaneously meet load, operate reliably and manage any transmission constraints that arise. Thus NEPA alone decided which facilities would be used to provide energy and ancillary services as well as where generation capacity would be held for reserves.

In its capacity as an integrated monopolist, NEPA was structurally capable of managing a wide range of risks and costs. Indeed, by virtue of the organization of the industry, NEPA was the only entity capable of managing certain costs and risks. As a result NEPA could enter into bilateral

[39] We use NEPA only because it was the former vertically integrated monopoly generation and transmission company.

contracts with their customers for “delivered energy”, *i.e.,* bilateral contracts that obligated NEPA to produce and transport electricity to specific physical locations on the grid. In combination the two aspects – being a monopoly and being vertically integrated – of the industry structure provided NEPA with the ability to internalize all the decisions necessary to fulfill the terms of the physical contracts.

To show why this was possible consider the simplified 3-node electricity network in Figure 15. As the generation owner and transmission system operator, NEPA will decide how much each facility will generate while meeting both the contract requirements and operating reliably.

Since there are no generators other than those owned by NEPA connected to the grid, NEPA’s operational decisions have no effect on any other entity.

In this example the contract price at Node C will reflect the cost to NEPA of (1) producing the energy, (2) managing the transmission constraints and line losses and (3) providing the ancillary services. All of the complexity regarding which facilities are to be used for energy and ancillary services, how transmission constraints are managed, how any outages are handled, etc. remain unseen to the customer. Presumably when they negotiated the contract, NEPA determined the expected costs to deliver the energy to Node C and the contract price reflects these anticipated expenses. Importantly, the complexity of the physical system is not reflected in the pricing structure of the contract. Whereas the power flows and the transmission constraints are changing constantly the price stays fixed.

Under a vertically integrated monopolistic market structure, the structure itself, allows the complexity of the system to be “contained” within a single firm and it does not need to be reflected in the contracts.

Under a monopoly provider, contracts were “physical” in nature in that the commodity being purchased was delivered energy. The monopolist dealt internally with all of the complexity of coordinating production and transport with load.

Bilateral contracting under open access and the creation of transmission rights

Now suppose that in Figure 15, rather than having both generators owned by a single company, we allow two different companies to own/operate the generation plants. As we have discussed there are two broad steps that must be accomplished if there is to be effective competition.

1. All generators must be assured they will have equal and non-discriminatory access to the transmission grid.

    - Within this step we must define and implement access to the transmission capacity as well as access to system operation. We can use an airport as an analogy. Competing airlines need equal and non-discriminatory access to the gates and runways, *i.e.,* the physical capacity of the airport. Additionally they need non-discriminatory access to the services provided by the air traffic controller, *i.e.,* the system operation. Individually, neither is both necessary and sufficient to allow effective competition to take place.[40]

2. The ownership and operation of the grid must be independent of all generation.

    - This requires the separation of transmission ownership and operation from all generation interests. It also requires the separation of transmission asset ownership and operation from system ownership and operation.

These two steps are necessary but not sufficient pre-requisites for the institutional platform from which effective competition between generators can take place.

What may seem to be a relatively simple and innocuous change in corporate structure is, in fact, tremendously significant and ultimately leads to a complete change in the contracting structure. Continuing with the 3-node model from Figure 15, following the divestiture of transmission into "Gridco" and "Poolco", our previously vertically integrated monopoly has now become a pure generation company with no operational control of the transmission grid. Thus "NEPA" no longer determines:

1. The capacity of the transmission system,
2. Which generation plants are dispatched,
3. How to manage transmission constraints, or
4. Maintain frequency and voltage.

Instead of NEPA making these decisions (in conjunction with decisions regarding how to run their generation facilities) they are now made by "Gridco"/"Poolco". The implication of this change is that NEPA no longer controls the "delivery" component of the delivered energy contract.[41] Rather the system operator is in control of managing the transmission system. The generator and/or the load are now subject to transmission risk, *i.e.,* the risk that production from a specific generation facility is unable to be used to fulfill contractual obligations because of conditions on the transmission grid. To overcome this risk the participants need a "transmission right" – one aspect of which will be the right to a specified amount of capacity.

Thus disaggregating generation from transmission and allowing competitive generators to connect necessarily requires that "transmission rights" be defined and determined. Remember, that when NEPA owned and operated both the generation facilities and the transmission grid, no other entity had access to the transmission system. There was no need to define and determine a transmission right because no generator other than NEPA could access the grid. A Transmission Right is a "right" to use the transmission system. Which, as we have seen, has two

[40] This situation occurs in other parts of the world particularly in regions of the United States without organized markets where non-discriminatory access is provided to the transmission capacity but system operation is not necessarily non-discriminatory.

[41] We will ignore for the moment that the generator no longer even controls the "energy" component as was shown by the example presented in Figure 20.

aspects – the "right" to non-discriminatory access to the physical system and the "right" to participate in the non-discriminatory dispatch process.

The reason that transmission rights are required is that whenever the system is constrained, then not all generators are able to access the physical system. That is, when there is a constraint – a bottleneck on the system – then some generators will not be able to use the transmission system to the extent they may want. When the system is constrained the transmission capacity is scarce and there must be a fair, transparent and non-discriminatory mechanism for allocating the scarce resource. If competition is to be effective, establishing transmission rights is not an option it is a requirement.

Defining a transmission right involves addressing a number of questions and issues:

- What "rights" and "obligations" are attached to a transmission right?
- Will either a buyer or seller be required to have a transmission right if they produce or consume power? If so, what requirements must they meet?
- Will there be different levels of rights?
- Will some transmission rights have a higher level of service, e.g. will they receive preferential treatment? For example, suppose a constraint arises and not all capacity is available and some users are not able to use all of their transmission rights, is there some "ranking' as to who gets cut or is it on a pro rata basis?
- Who will be responsible for determining the quantity of transmission rights that are available? Will it be the transmission asset owner (i.e., Gridco), or will it be the system operator (i.e., Poolco)?
- What methodology will be used to determine the quantity of transmission rights? Will the methodology use average or peak demand? How will outages be handled?
- What obligations, i.e., responsibilities and liabilities, are placed on the "creator" of the transmission rights? What if they issue too many or too few?
- Will there be regulatory oversight?
- How will the rights be distributed? Through an auction? An allocation process? If they are allocated, what is the basis for the allocation? Historical usage?
- How will the transmission rights be priced?
- Who receives the revenues?
- What will be the term/duration of a transmission right? If there is going to be more than one period, how will transmission capacity be allocated across the different periods? For example, suppose we decide to create and offer a 1-year transmission right and a 3-year transmission right. How much transmission capacity do we make available for each potential category?
- Does an existing holder of a transmission right receive preferential rights for acquiring them in subsequent periods? That is, are there "rollover rights?"

These are just a few of the issues that must be resolved with any physical rights based market design.

Physical and financial transmission rights

Defining and determining transmission rights is a necessary step in implementing competition. As a result, this issue has been dealt with in other market and two distinct methodologies have been developed:

1. The "physical rights model" whereby a transmission right has a physical interpretation. That is, the holder of a "physical transmission right" is entitled to use that amount of the capacity of the transmission system. Thus in order to fulfill the conditions of a bilateral contract a generator (purchaser) needs to obtain the transmission rights for the amount of power they have sold (bought). They will then need to use this capacity to schedule the transaction. The physical rights model relies on the *ex-ante* calculation of the Available Transfer Capability (ATC) of the transmission system. To the extent the ATC is an accurate representation of the actual capacity that is available in real time then contracts will mirror real time power flows. However, as was shown in Figures 17 and 18, we can calculate differing amounts of transmission capacity depending on the assumptions that we use.

   Suppose for example, we had estimated the ATC to be 300 MW (as in Figure 17). Furthermore, assume that G1 (the generator at Node A) had either purchased or been allocated all 300 MW of transmission capacity and further to acquiring these transmission rights sold 300 MW of power to the load at Node C under a physical delivered energy bilateral contract.[42]

   For a given dispatch interval, G1 notifies the system operator through their day-ahead schedule that they will be supplying 300 MW to the load at Node C by using the equivalent amount of transmission rights.

   As long as the load at Node C is less than or equal to 300 MW for the dispatch interval everything will work, *i.e.,* G1 will be able to produce and transport 300 MW to the load a Node C. In this case the day-ahead schedule will match what happens in real time.

   Now let's assume the real time load is not 300 MW but rather 360 MW as was shown in Figure 20. In this case G1 cannot produce 300 MW, rather they can only produce 240 MW and G2 needs to produce 120 MW to make sure the load at Node C is served. But, not only are there only 300 MW of transmission rights but G2 does not own any, so they are not allowed access to the grid.

   What must happen in this case? Either we let the lights go out because G2 is not allowed to produce, which is nonsensical, or the system operator instantaneously provides G2 with 120 MW of transmission rights. The system operator acquires the 120

[42] A physical delivered energy contract requires physical delivery of the energy to the relevant point on the grid.

MW by simultaneously creating an additional 60 MW and by reallocating 60 MW from G1 to G2.

This example highlights several very important market design considerations.

- How accurately can the TTC be determined?
- How do we clear and settle the 120 MW produced by G2?
- How much does G1 get paid?
- Does the system operator have the tools to create/reallocate transmission rights in real time?

To the extent the transmission grid is unconstrained, the amount of real time intervention by the system operator is minimized. After all, the problem in the previous example was caused by the 200 MW thermal limit on line AC. To the extent the Nigerian transmission system is unconstrained then the physical rights model might provide a solution. However, as was highlighted in Section 2.2 above, the capacity of the transmission system is limited to approximately 4000 MW, *i.e.,* the transmission system cannot transport the existing capacity of the generating facilities, let alone new capacity. The assumption of an unconstrained transmission seem is unwarranted.

The physical rights model suffers from uncorrectable flaws that ultimately prove to be fatal:

- It is fundamentally economically inefficient because costs are not considered in allocating transmission capacity,
- Transmission capacity must be established beforehand. While ex ante estimates of ATC can be used for transmission planning purposes they are not acceptable for system dispatch, where the requirements are much more narrow.
- Once distributed, the transmission rights cannot be exchanged quickly enough to meet the needs of the system operator. This results in the system operator "overriding" transmission rights, *i.e.,* negating some rights and changing the supply of others. Again this is a source of inefficiency because schedules will have to be curtailed by some arbitrary method, e.g. a "pro rata" curtailment.
- When required to alter line flows to avoid overloading a line or violating a contingency, the system operator does not have the granularity necessary and the resulting mechanism can be extremely inefficient (e.g. a pro rate reduction rather than a targeted response by the most effective generator).
- The process of managing transmission constraints is not transparent, *i.e.,* the participants cannot discern why power flows were reduced.
- As a result, every market that has started with physical rights has eliminated them and chosen a different path.

2. To deal with the inherent flaws of the physical rights model the "financial rights model" has been developed and implemented. In this model a transmission right has no physical interpretation, rather it is purely a financial right to revenue streams (positive or negative)

that arise from using the transmission system. In order for this model to be a viable alternative, the MRTS and the Grid Code would need to instruct the system operator to operate a real time spot market using bid based security constrained economic dispatch that produces locational marginal prices at different locations. Neither the MRTS nor the Grid Code specifies the creation of a spot market based on locational marginal prices for the Medium Term Market.

In summary, the physical rights model tries to duplicate, under open access, what was possible under vertical integration. The inherent flaw is that the basic conditions that were present under vertical integration – the internalization of generation and transmission operation by a single firm – cannot be duplicated under open access. In the case of the vertically integrated monopoly if an unanticipated transmission constraint arose in real time, the monopolist had the ability to change the output levels of any facilities that were required and the financial effects of doing so were internalized within a single firm.

The Medium Term market design is based on the zonal application of the physical rights model

Rule 25 of the MRTS details how physical capacity on an Interconnector[43] will be allocated and used by the market participants. It also provides the rules for how the system operator will ration the transmission rights across the interconnector in the event that actual TTC is less than what was created and distributed to the market participants. Importantly, the rules implicitly assume that there is excess transmission capacity, *i.e.,* there is no need to allocate the capacity, on the transmission facilities other than the Interconnectors. Hence the MRTS implicitly divides the Nigerian transmission system into independent "zones" that are connected by Interconnectors.

25. Trade Across the Interconnector

25.1 Purpose and Application

25.1.1 This Rule 25 sets out the arrangements for allocation of capacity on an Interconnector, together with arrangements for dealing with any resulting Imbalance Energy.

25.1.2 Rule 25 shall not apply during the Transitional Stage.

25.2 Contracted Interconnector Capacity Arrangements

25.2.1 A Participant, who intends to Import or Export Energy across an Interconnector shall obtain an Interconnector Capacity Entitlement or a Daily Interconnector Capacity allocation granted pursuant to this Rule 25.

25.2.2 An Interconnector Capacity Entitlement may be procured pursuant to

43 *"Interconnector means Facilities used solely for conveying Energy directly to or from a substation or converter station within Nigeria, from or as the case may be, to Facilities in another Control Area." MRTS Rules Defintions.*

(a) an Interconnector Capacity Entitlement Agreement; or

(b) an assignment from a holder of such Interconnector Capacity Entitlement pursuant to Rule 25.6.

25.2.3 Each Participant possessing Interconnector Capacity Entitlement in accordance with paragraphs (b) (i) and (ii) shall notify the System Operator of the Interconnector Capacity Entitlement no later than 10:00 hours, two days ahead of the Dispatch Day on which it intends to utilise the Interconnector Capacity Entitlement.

25.2.4 In the event a Participant possessing an Interconnector Capacity Entitlement does not intend to utilise the entire Interconnector Capacity Entitlement on the same Dispatch Day, the Participant may assign the rights to unutilised Interconnector Capacity Entitlement in accordance with Rule 25.6 or, in the absence of such assignment, the System Operator may allocate the unutilised Interconnector Capacity Entitlement to any other Participant in accordance with the Interconnector Capacity Entitlement Agreement, or in the event that the Interconnector Capability Entitlement Agreement does not provide for allocation of unutilised capacity to a third party in accordance with the provisions of Rule 25.4.

25.3 Daily Interconnector Capacity Allocations

25.3.1 A Generator not possessing an Interconnector Capacity Entitlement pursuant to an Interconnector Capacity Entitlement Agreement or an assignment in accordance with Rule 25.2.4 may submit to the System Operator, a request for access to the Interconnector in units of 1 MW for a full Dispatch Day.

25.3.2 The request referred to in Rule 25.3.1 shall be submitted to the System operator no later than 10:00 hours, two days ahead of the relevant Dispatch Day.

25.4 Interconnector Capacity Allocation

25.4.1 In respect of each Dispatch Day, the System Operator and the Control Area Operator of the neighbouring Control Area or the operator of a Regional Market as the case may be, shall no later than 12.00 hours, two days prior to the Dispatch Day, agree the Total Interconnector Capacity available to be allocated in respect of the Interconnector in question. The Total Interconnector Capacity so determined shall form the basis of allocation pursuant to this Rule 25.4. The System Operator shall publish on its website the available Interconnector capacity so determined.

25.4.2 In the event that congestion would result from over-subscription in any direction, of the capacity of the Interconnector as determined in accordance with Rule 25.4.1, the System Operator shall allocate the

Interconnector capacity in accordance with Rule 25.4.3 such that the total capacity allocated to all Generators does not exceed the Total Interconnector Capacity.

25.4.3 In cases of over-subscription, the Total Interconnector Capacity shall be distributed amongst the Participants on the basis of the following rules:

(a) The System Operator shall not allocate any Interconnector capacity in response to any request for allocations of Daily Interconnector Capacity pursuant to Rule 25.3 until all the requirements for Interconnector Capacity Entitlement have been fulfilled.

(b) In the event that the Total Interconnector Capacity is insufficient to meet the total requirements for Interconnector Capacity Entitlement that have fulfilled the condition in paragraph (a), the System Operator shall consider the capacity available on the Interconnector, together with each Participant's notification of use of their Interconnector Capacity Entitlements.

(c) On the basis of the factors referred to in paragraph (b), the System Operator shall either:

(i) make a pro-rata allocation of Interconnector Capacity Entitlement to each Participant; or

(ii) allocate to each Participant, such percentage of the Interconnector Capacity Entitlement requested by the Participant, as may be specified by the Commission.

(d) If additional capacity is available on the Interconnector after the System Operator has satisfied all requests for Interconnector Capacity Entitlements, the System Operator shall accept all requests for allocation of Daily Interconnector Capacity, provided that if the capacity available on the Interconnector is insufficient to meet all requests for Daily Interconnector Capacity, the provisions of paragraph (e) shall apply.

(e) In the event that there is insufficient capacity on the Interconnector to meet all requests for allocation of Daily Interconnector Capacity, the System Operator shall consider the capacity available on the Interconnector, together with each Participant's request for Daily Interconnector Capacity, and on the basis of these two factors, shall either:

(i) make a pro-rata allocation of Daily Interconnector Capacity to each Participant; or

(ii) allocate to each Participant, such percentage of the Daily Interconnector Capacity requested by the Participant, as may be specified by the Commission.

(f) In all cases super-positioning will not be considered.

25.5 Confirmation of Access requests

No later than 14:00 hours two days ahead of the relevant Dispatch Day, the System Operator shall notify each Participant to whom capacity on the Interconnector has been granted by virtue of an Interconnector Capacity Entitlement or a Daily Interconnector Capacity, of the extent of the access granted provided that such notification shall be indicative only and shall not bind the System Operator.

25.6 Capacity Assignment

25.6.1 A Participant holding Interconnector Capacity Entitlement pursuant to an Interconnector Capacity Entitlement Agreement may assign all or part of its Interconnector Capacity Entitlement, for a short term not exceeding 10 Dispatch Days by submitting a request in that regard to the System Operator, in the form and manner prescribed by the System Operator, no later than 10:00 hours two days ahead of the Dispatch Day. The System Operator shall take a decision on the request no later than 12:00 hours on the same day.

25.6.2 An assignment an Interconnector Capacity Entitlement for a term which exceeds 10 Dispatch Days may only be made according to the terms of the relevant Interconnector Capacity Entitlement Agreement, provided that such assignment shall not become effective unless and until it is approved by the System Operator.

25.7 Nominations for Import and Export of Energy

25.7.1 A Participant in possession of an Interconnector Capacity Entitlement and Daily Interconnector Capacity Allocation shall submit an Interconnector Energy Trade Nomination in respect of their desired Import or Export of Energy to the System Operator no later than 10:00 hours on the day immediately preceding the Dispatch Day to which the nomination applies. The Interconnector Energy Trade Nomination shall apply to all Dispatch Periods of the Dispatch Day.

25.7.2 A Participant shall submit separate Nominations in respect of Imports and Exports during a Dispatch Day and shall make no more than one Nomination for an Import and one Nomination for an Export in the same Dispatch Day. Where the Interconnector Energy Trade Nomination is made in respect of an Import, the Nomination shall identify the seller and its location in the neighbouring Control Area and where the Nomination is *made in respect of an Export, it shall identify the purchaser and its location in the neighbouring Control Area. The Energy amount nominated in any one Dispatch Period shall be no greater than the total Interconnector capacity allocated to the Participant pursuant to Rule 25.4.*

25.7.3 To the extent applicable, the Interconnector Energy Trade Nomination by a Generator shall comply with the requirements of Rules 23.1.2 and 23.1.3.

25.7.4 In respect of each Interconnector, the System Operator and the Control Area operator in the neighbouring Control Area shall agree an Interconnector Transfer Schedule by 16:00 hours on the day immediately preceding the Dispatch Day. In determining the Interconnector Transfer Schedule, the System Operator and the relevant Control Area operator shall ensure that any Import to one Control Area shall be matched by an Export from the other Control Area. In the event that there is a mismatch, the System Operator and the relevant Control Area Operator shall agree such changes to the Import or Export quantities, or both, as are reasonably necessary to achieve the necessary match.

25.8 Actual Available Transfer Capacity

In the event that in any Dispatch Period the actual Available Transfer Capacity in any direction is less than the total Interconnector Energy Trade Nominations in that direction, the System Operator shall reduce the Interconnector capacity allocated to each Participant pursuant to Rule 25.4 pro-rata on the basis of their individual Interconnector Energy Trade Nominations, until the sum of the revised Interconnector capacities allocated by the System Operator equals the actual Available Transfer Capacity.

25.9 Interconnector Usage Charge

25.9.1 Upon submission of a request for allocation of Daily Interconnector Capacity, a Participant shall pay to the System Operator:

(a) an Interconnector Capacity Charge in respect of actual Interconnector Capacity to which the Participant is entitled; and

(b) an Interconnector Usage Charge on the basis of the metered units of Energy imported or exported across the Interconnector.

25.9.2 Participants who acquire Interconnector capacity by any process other than those specified in these Rules shall pay for that capacity in accordance with an agreement reached with the System Operator in that regard.

Rule 25 provides the description of the “physical rights” model as applied to the MRTS. Summarizing we know the following:

1. A participant obtains the transmission right via an *“Interconnector Capacity Entitlement Agreement”* which is *an agreement between the TSP or the System Operator and a Generator granting Interconnector Capability*[44] *Entitlement to a Generator.*

2. While the rules state they are to be granted by either the TSP or the system operator, no information specific information is provided with respect to:

    i. How the quantity will be determined.

    ii. How the TSP and the system operator will coordinate their actions.

    iii. The duration of the transmission right.

    iv. Whether the rights “rollover” to the original owner.

    v. How competing requests will be handled.

    vi. Whether load growth is to be included.[45]

    vii. Whether there will be different “levels” of service.

    viii. Whether new transmission capacity will be allocated to existing transmission rights.

    ix. Whether there is any liability placed on the issuing entity, *i.e.,* what if they create too few?

3. The transmission rights can be re-assigned from the original owner for periods of less than 10 days upon approval of the system operator.

4. The transmission rights can be re-assigned by the system operator if the original owner does not use them, i.e., the rights have a “use-it-or-lose-it” quality.

5. If the system operator determines a particular Interconnector lacks sufficient capacity to meet all of the transmission rights, then the System Operator can either reduce all relevant participants by a pro rata share or reduce individual participant by an agreed upon amount.

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[44] It appears the word “capability” is a typographical error and should be replaced with “capacity.”

[45] Many long-term bilateral power purchase agreements will accommodate load growth.

6. By 14:00 of the day prior the system operator will notify participants their expected transmission rights allocation for the next day. This is an indicative non-binding forecast.

7. If the real time Interconnector capacity is less than the pre-scheduled amount then the system operator will reduce flows either by a pro rata reduction of all participants or through an agreed up amount.

The structure described in Rule 25 of the MRTS is a basic/standard "physical rights" model. The primary inefficiency that is endemic to any physical rights model is due to the inefficient mechanism for managing real time transmission constraints. Per the Rule 25.8, the primary "tool" granted to the system operator by the rules is the use of a pro rata reduction on the constrained element.

The inefficiency arises because every generator will have a different electrical effect (*i.e.,* shift factor) on a given constraint but the rationing mechanism is simply a pro rata reduction.

Recommendation:

We will discuss alternatives to the physical rights model below; here we offer recommendations for improving the existing rules.

With respect to the allocation of transmission rights, Rule 25 lacks specificity regarding the actual creation of the Interconnector Capacity Entitlement (ICE). In particular the market rules need to provide:

- The methodology by which the quantity will be determined, i.e., load, peaks, outages, etc.
- The effect of a transmission outage on the allocation.
- How new transmission investment will be incorporated in the establishment of transmission rights.
- The duration of the transmission right.
- Whether, upon expiry, the rights "rollover" to the original owner.
- Does the original owner have the right of first refusal?
- How competing requests will be handled, i.e., what if two or more participants want identical rights but there is not enough transmission capacity to meet both demands, what if two or more participants want the rights for the same path but for different lengths of time, etc.
- Will partial path transmission rights be defined, i.e., what if there is not enough available transmission capacity along the entire source-to-sink path to grant on certain portions there is enough capacity?
- Whether load growth is to be included.
- Whether there will be different "levels" of service, i.e., will some Entitlements provide a greater level of service should there be a need to curtail service.
- How an Entitlement is to be scheduled.

Regarding the use of Entitlements to allocate transmission capacity in real time we have previously discussed that they are a “blunt” mechanism at best. In the end, the rules provide the system operator the authority to initiate a pro rata cut of all flows on a constrained path.

Evaluating the Rules for the Medium Term Market

In any market there are six design areas that are critically important, how:

1. Real time power flows are managed, particularly in the presence of transmission constraints.

2. The real time price of electricity is determined.

3. Settlement takes place.

4. The rules for prudential requirements (security) work.

5. The market is governed.

6. Market monitoring takes place.

These six categories actually form three pairs of closely related topics (1) dispatch and pricing, (2) security and settlement and (3) governance and monitoring. We look at each of these pairs in the following sections

Dispatch (and scheduling) and pricing

In this section we evaluate the rules for (1) dispatch (including scheduling) and (2) pricing. The rules for dispatch (and scheduling) are found in the Grid Code while those for pricing are located in the MRTS.

Rule 8 (we exclude Rule 8.5.4 (Reactive Power) of the Grid Code contains the Rules for both scheduling and dispatch:

8. SECTION: SCHEDULING AND DISPATCH

8.1. OBJECTIVE

8.1.1. The objective of this section is to provide Generators with provisional running orders for the Dispatch Day such that Generating Units will be made available in the correct time scale to enable the System Operator to Dispatch them whilst maintaining the required Operating Reserve. In order to achieve the primary objective this section details the time scale for the System Operator to make specific information available to Generators and Users.

8.1.2. A further objective of this section is to establish a framework to enable the System Operator to issue Dispatch Instructions to:

(a) Generators with respect to their Generating Units; and

(b) Users in relation to Ancillary Services.

Dispatch Instructions are issued such that available Generation is matched to Demand with appropriate margin of Operating Reserve whilst maintaining the integrity and security of the Transmission System with acceptable Quality of Supply.

8.2. GENERAL

8.2.1. The System Operator shall dispatch generators according to Market Rules, subject to constraints of safety of personnel, equipment, system security, reliability and the environmental requirements.

8.2.2. The scheduling and Dispatch of Generating Units is necessary to ensure that the most economical combination of Generating Units possible is used for each Dispatch Period. This optimal combination of Generating Units must meet the Demand such that the necessary Frequency Control can be achieved.

8.2.3. In order to achieve this, the System Operator will have to calculate the optimal combination of Generating Units on a continuous basis using specialised software suitable for this. These calculations by the System Operator are based on Day-ahead Nominations by each Generator and the anticipated Demand.

8.3. DATA AND PROCESS

8.3.1. The System Operator shall forecast the Power System Demand in accordance with Condition 7.4.5 that shall be used in the Dispatch process.

8.3.2. System Operator shall set the level of Reserve that shall be used in the Dispatch process.

8.3.3. System Operator shall include in the Dispatch Instructions the Active Power Output level of a Generating Unit, Synchronising or Desynchronising time, if appropriate and Ancillary Service to be provided.

8.3.4. System Operator shall adjust Generation Unit Active Power Output by using a merit order based on the Day-ahead Nominations provided by Generators for each Generating Unit as variations occur due to such factors as Demand or Availability variations.

8.4. DISPATCH SCHEDULING

8.4.1. Production of a Dispatch Schedule

Each day between 13:00 hours and 16:00 hours the System Operator shall produce the two Dispatch Schedules pursuant Conditions 12.4.2 and 12.4.3 for the Dispatch Day. The System Operator may produce the Dispatch Schedule more or less frequently, or reasonably delay its production in response to changes in Availability and other events that may arise. The Dispatch Schedule is utilised by the System Operator in its scheduling and in its preparation for Dispatch of Generating Units.

In preparing the Dispatch Schedule, the System Operator shall schedule Day-ahead Nominations to minimise the offered cost of meeting Load forecast according to the principles set out in section 6.3, taking into account the following factors:

(a) Forecast Demand and geographical Demand distribution;

(b) Generating Units' Registered Information, including operating characteristics, Ancillary Service capability and Availability;

(c) Generator Day-ahead Nominations, including Nominations by Hydro Generating Units;

(d) Declared abnormal risks to Generating Units;

(e) Ancillary Service requirements, including Frequency Control, Operating Reserve and Voltage Control;

(f) Reliability Must-run requirements;

(g) Transmission System constraints, including Network and Generating Unit constraints;

(h) Transmission System losses;

(i) System Operator and Users' monitoring and test requirements;

(j) Transmission System stability implications;

(k) Interconnector Capacity Entitlements and Interconnector Energy Trade Nominations pursuant to Rule 7.10 of the Market Rules;

(l) Interconnection Agreements;

(m) Other factors as may be reasonably considered by the System Operator to be relevant to the Dispatch Schedule.

8.4.2. Pre-dispatch Day constrained Schedule

The System Operator shall produce a Pre-dispatch Day constrained Schedule for each Dispatch Day by 16:00 hours on the Pre-dispatch Day.

The System Operator shall issue provisional running orders based upon the Dispatch Schedule for the Dispatch Day to each Generating Unit by 16:00 hours on the Pre- dispatch Day.

The provisional running orders issued to each Generating Unit by the System Operator, shall indicate the planned Load pattern specifying:

(a) Forecast start-up and shut-down times, if relevant;

(b) Forecast Active Power Dispatch levels for each Dispatch Period; and,

(c) Forecast levels of Operating Reserve provision for each Dispatch Period, if the Generating Unit is contracted for Operating Reserve requirements.

Provisional running orders are indicative only, provided as a guide to the expected output requirements from Generating Units and are not Dispatch Instructions.

8.4.3. Pre-dispatch Day unconstrained Schedule

The System Operator shall produce a Pre-dispatch Day unconstrained Schedule for each Dispatch Day by 16:00 hours on the Pre-dispatch Day. The same principles specified in section 8.4.1 shall be applied with the following change:

(a) The known Transmission System constraints must be excluded.

This Schedule shall be used to forecast the Day-ahead Price consistent with the appropriate Market Rules.

8.4.4. Dispatch Day schedule

If the System Operator forecasts a significant difference between the provisional running orders and anticipated Dispatch Instructions, in the interval between the issue of provisional running orders and the issue of relevant Dispatch Instructions, the System Operator shall endeavour to notify this difference to impacted Generators.

8.4.5. System congestion

System Operator shall install and commission such real time equipment and software as to calculate Transmission System restrictions and Reliability margins per Dispatch Period.

System Operator shall change the Dispatch Schedule of the Generators in order to eliminate transmission congestion and to ensure the security and Reliability of system operation.

System Operator shall reduce the Transmission Services contributing to the congestion if it was not possible to eliminate congestion by changing the scheduling of the Generators.

System Operator shall further instruct all Users, independent of the transmission services, to take specific action in order to avoid more major disturbances in emergency situations.

8.4.6. Ex-post Unconstrained Dispatch Schedule

The System Operator shall produce an Ex-post Unconstrained Dispatch Schedule for each Dispatch Day by no later than 12:00 hours on the Calculation Day. This leaves the System Operator sufficient time to calculate the System Marginal Price for each Dispatch Period pursuant Rule 11.2.1 of the Market Rules. The same principles specified in section 8.4.1 shall be applied with the following two changes:

(a) The actual Load readings must be used; and

(b) The Transmission System constraints must be excluded.

8.5. GENERATION DISPATCH

8.5.1. Dispatch Instructions To Generators

The System Operator shall issue Dispatch Instructions relating to the Dispatch Day at any time during the period beginning immediately after the issue of the Dispatch Schedule in respect of that Dispatch Day.

The System Operator shall give a Dispatch Instruction to a Generator for a specific Generating Unit to change the output of Active Power, Reactive Power or an instruction to provide an Ancillary Service.

The System Operator shall give Dispatch Instructions to a Generator orally, by phone or by electronic means including by means of Automatic Generation Control. The Dispatch Instruction shall identify the relevant Generating Unit by specifying the Generator's and Generating Unit's unique identification number pursuant Rule 4.5.1 of the Market Rules.

A Generator shall immediately and formally acknowledged a Dispatch Instruction in respect of a Generating Unit by telephone, or immediately provide a reason for non- acceptance. The reason for non-acceptance shall only be on safety grounds (relating to personnel or plant) or because the Dispatch Instruction is not in accordance with the Nomination or the Registered Information relevant to the time and period to which the Dispatch Instruction relates.

The System Operator shall be notified without delay by telephone in the event that in carrying out the Dispatch Instruction, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant).

The System Operator shall maintain a record of all daily Dispatch Instructions issued to Generators.

8.5.2 Generation Synchronising and Desynchronising Times

The System Operator shall determine the required Synchronising and Desynchronising times for Generating Units.

The System Operator shall issue Dispatch Instructions to Generators to Synchronise (or Desynchronise) specific Generating Units in accordance with their Registered Information.

If a Dispatch Instruction to a Generator to Synchronise a specific Generating Unit does not also contain an Active Power Output to be achieved then it shall be assumed that the instruction is to increase output (following Synchronisation) up to the level of minimum generation of the Generating Unit as specified in the Registered Information.

The Generator shall immediately (at the time the discrepancy is identified) inform the System Operator of a situation and estimate the new Synchronising time, where Synchronising time issued by the System Operator to a Generator for a specific Generating Unit and the Generator identifies that the Generating Unit will not be Synchronised within ± 10 minutes of the instructed time.

The allowable tolerance appropriate to Synchronising times shall be based on the times set out in the Registered Information.

8.5.3 Generation Active Power Dispatch

Based on the Day-ahead Nominations of the Generators, on System conditions, and on other factors as may arise from time to time. The System Operator shall issue Dispatch Instructions to a Generator in relation to a specific Generation Unit, which has been instructed to be Synchronised, to adjust its Active Power Output.

When a Generator has received and accepted a Dispatch Instruction for a Generating Unit to change the level of Active Power it shall without delay adjust *the level of output of the Generating Unit to achieve the new target in line with its Registered Information and its Quantity Nomination.*

A Generating Unit shall be deemed to have complied with a Dispatch Instruction when it achieves an output within the allowable tolerance as specified in Rule 12.5.1 of the Market Rules. Deviations outside the allowable tolerance band will be treated according to Rule 12.2.1(c) of the Market Rules.

The adjustment of Active Power Output of a Generating Unit operating in a Frequency sensitive mode for System Frequency other than an average of 50Hz, shall be made in accordance with the current registered value of Governor Droop for the Generating Unit.

The System Operator shall be notified immediately by telephone in the event that while carrying out the Dispatch Instruction an unforeseen problem arises caused by safety reasons (relating to personnel or plant).

…

8.5.5. System alerts

The System Operator shall notify Generators, by one of several means, of the existence of a System Emergency Condition.

8.5.6. System Emergency Conditions

The System Operator may instruct Generators to operate outside the limits implied by the then current Registered Information in order to maintain Transmission System integrity under System Emergency Conditions.

Where the System Operator has issued an emergency instruction requiring operation of a Generation Unit outside the limits applied by the then applicable Quantity Nomination and Registered Information, then the Generator shall comply with the emergency instruction if, in the reasonable opinion of the Generator, the safety of personnel, and/or plant is not compromised in complying with the request.

8.5.7. Failure To Comply With A Dispatch Instruction

The Generator shall inform the System Operator by telephone without delay if at any time a Generating Unit is unable to comply with any Dispatch Instruction correctly issued by the System Operator in respect of any Generating Unit.

8.5.8. Constrained Generation

Constrained generation is the service supplied by a Power station to the System Operator by constraining its power output below (alternatively above) the unconstrained schedule level. The service is required to ensure that the

Transmission Network remains between appropriate operational limits (e.g. thermal, voltage or stability limits).

In providing the service, the Power station experiences a financial loss, for which it shall be compensated by the Transmission Network according to the market rules. Constrained generation is required to meet network Reliability as there are no current rules for market splitting across transmission constraints or the handling of units in strategic positions. The identification of the specific Transmission Network constraints applicable at any point in time shall be the responsibility of the System Operator.

We provide for purposes of comparison the rules pertaining to dispatch and pricing for the PJM[46] market in North America.

2.2 General.

The Office of the Interconnection shall determine ***the least cost security-constrained dispatch****, which is the* ***least costly means of serving load at different locations in the PJM Region based on actual operating conditions*** *existing on the power grid (including transmission constraints on external coordinated flow gates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:*

(a) ***To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network****. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time*

[46] PJM is a North American electricity market centered in the mid-Atlantic region. It is the largest market in the world.

schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below ***, every qualified offer for demand reduction and of energy by a Market Seller from resources that are following economic dispatch instructions of the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices****, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets. Offers of demand reduction from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection.*

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real- time dispatch, as applicable. This calculation shall be made by applying an incremental linear optimization method to minimize energy costs, given actual system conditions, a set of energy offers, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection

shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.

(b) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

There are two fundamental problems with the MRTS. First, as shown through the comparison with a sample of rules from PJM, they do not contain anywhere near enough detail and specificity. The following table highlights this point where three examples of rules from PJM and their counterpart from the Grid Code are matched side-by-side. There can be no doubt which set of rules will result in more transparent operations.

PJM	Grid Code
During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program	*The System Operator shall issue Dispatch Instructions relating to the Dispatch Day at any time during the period beginning immediately after the issue of the Dispatch Schedule in respect of that Dispatch Day.*
***To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network**.*	*System Operator shall install and commission such real time equipment and software as to calculate Transmission System restrictions and Reliability margins per Dispatch Period.*
The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are the basis for the Day-ahead Energy Market.	*In order to achieve this, the System Operator will have to calculate the optimal combination of Generating Units on a continuous basis using specialized software suitable for this. These calculations by the System Operator are based on Day-ahead Nominations by each Generator and the anticipated Demand*

The lack of detail and specificity is, in part, due to the "top down" approach and the emphasis on "market design" at the expense of focusing on providing the system operator with the tools needed to manage real time power flows.

The PJM Rules not only define what PJM must do but the manner in which it must be done and the tools that must be used. A market participant in PJM can read these rules and understand how PJM is going to perform the tasks assigned to it. Moreover, to the greatest extent possible the actions taken by PJM in their role as system operator are (1) transparent, (2) auditable, (3) replicable and (4) consistent primarily because PJM would be in violation of their rules if they do not follow them exactly.

While the lack of detail and specificity in the MRTS/Grid Code rules is certainly important, a more significant issue arises from the apparent lack of a coherent process. According to the rules exactly what does the system operator do, and how do they accomplish it?

In particular how is the system operator supposed to integrate physical transmission rights[47] to arrive at a least cost (*i.e.,* efficient) dispatch, *i.e.,* how is it that the system operator is going to simultaneously adhere to the Interconnection Entitlements and, according to Rule 8.4.1 of the Grid Code, "*schedule Day-ahead Nominations to minimize the offered cost of meeting Load forecast according to the principles set out in section 6.3."* While efficiency is explicitly recognized as an objective of the market in Rules 2.1 and 2.2 and Rule 8.4.1 of the Grid Code, the dispatch and scheduling rules provided in the Grid Code neither explain how it is to be done nor ensure that it will occur.

There is no inherent theoretical or practical reason why dispatch based on physical rights will result in an efficient outcome. For example the Market Monitor for the Midwest ISO estimated in 2002, as a result of using the physical rights model, "that, on average, more than three times as many transactions are curtailed as would be required to be redispatched to relieve the constraint."[48] As a result of this inefficiency the Market Monitor strongly supported the move to an LMP-based dispatch process.[49]

The entire real time congestion management scheme in the MRTS/Grid Code – ***the single most importance aspect of the rules*** – is defined by the following (single) sentence contained in Rule 8.4.5:

System Operator shall change the Dispatch Schedule of the Generators in order to eliminate transmission congestion and to ensure the security and Reliability of system operation.

Herein lies the reason why, in Figure 22, we indicated that real time physical coordination was simply "left to the System Operator." Not only is there no specificity as to how System Operator will accomplish real time balancing, we have no idea the basis upon which a generators dispatch schedule will be changed, *i.e.,* is it based on location, ramp rate, offer price, etc. In effect the owner of every generator is required to hand over the operation of their asset to the System Operator.

The *only* mechanism or tool in the rules by which the System Operator can accomplish real time balancing is through the use of Operating Reserves. To the extent that real time actual conditions on the grid differ from what was planned, the System Operator must use Operating Reserves to accomplish the balancing function. The rules around the procurement, deployment and cost recovery of Operating Reserves are, therefore, significantly important. Indeed, they are

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[47] Recall that there was "no least cost dispatch" basis for distributing the Interconnector Capacity Entitlements, *i.e.,* the transmission rights were not granted in relation to a least cost dispatch.

[48] See page 5 at: http://www.potomaceconomics.com/uploads/midwest_presentations/2003%20State%20of%20the%20Market_final%20presentation.pdf

[49] See previous report. The Midwest ISO implemented centralized bid-based security constrained economic dispatch in April 2005.

more important than the actual "dispatch" rules, since these have little bearing on how the system will be balanced in real time. The MRTS are largely silent with respect to Operating Reserves. Instead we need to look at the Grid Code:

> ***2.2. GENERAL***
>
> *...*
>
> ***Operating Reserve is required to secure capacity that will be available for reliable and secure balancing of supply and demand.***[50]
>
> ***2.5. COMPONENTS OF OPERATING RESERVE***
>
> *2.5.1. TherearetwotypesofOperatingReservenamelyQuickReserveandSlowReserve.*
>
> *2.5.2.* ***Quick Reserve*** *is the reserve that can respond within ten seconds and be fully active within 30 minutes of activation. This Reserve is used for second-by-second balancing of supply and demand, and to restore frequency to nominal values following a disturbance. Quick Reserve shall consist of Spinning Reserve and Emergency Reserve*
>
> *(a)* ***Spinning Reserve:*** *Spinning reserve is the additional output from synchronised Generating Unit, which must be realizable to respond to containing and restoring any frequency deviation to an acceptable level in the event of a loss of generation or a mismatch between generation output and demand. The Spinning Reserve from the Generating Unit must be capable of providing response in two distinct ways and time scales: Primary Reserve and Secondary Reserve.*
>
> *(i)* ***Primary Reserve:*** *Primary Reserve is an automatic increase/decrease in Active Power output of a Generation Unit in response to a System frequency fall/rise, in accordance with the primary control capability and additional mechanisms for acquiring active power. This change in active power output must be in accordance with the technical characteristics and loading of the Generation Unit, without any time delays other than those necessarily inherent in the design of the Governor Control System.*
>
> *(ii)* ***Secondary Reserve:*** *Secondary reserve is the automatic response to frequency changes which is fully available by 30 seconds from the time of frequency change to take*

[50] Emphasis added.

over from the Primary Reserve, and which is sustainable for a period of at least 30 minutes.

(b) ***Emergency Reserve:*** *Emergency Reserve is typically made up from contracted interruptible load, gas turbines and emergency generation. Emergency Reserve is a less frequently used reserve and is used when the Transmission Network is not in a normal condition and to return the Transmission Network to normal conditions while slower reserves are being activated. The Reserve can be used by the System Operator for supply and demand balancing, network stability and voltage constraints. This Reserve shall be activated, on request, within ten minutes and shall be sustainable for two hours.*

2.5.3. ***Slow Reserve:*** *Slow Reserve is the component of the Operating Reserve not connected to the Transmission System but capable of serving demand within a specified time. Slow Reserve is used to restore Quick Reserve when required. Slow Reserve shall consist of Hot Standby and Cold Reserve.*

(a) ***Hot Standby:*** *Hot Standby is a condition of readiness in relation to any Generation Unit that is declared available, where it is ready to be synchronise and attain an instructed load within 30 minutes, and subsequently maintained such load continuously.*

(b) ***Cold Standby:*** *Cold Standby is a condition of readiness in relation to any Generation Unit that is declared available, to start, synchronise and attain target loading within a pre-defined period of time, typically within up to 12 hours.*

Under Rule 2.2 the Grid Code specifies that Operating Reserve is required "for reliable and secure balancing of supply and demand." Thus we should expect to see the System Operator use (primarily) Secondary and Slow Reserves to manage real time imbalances. Regarding how much Operating Reserves to procure the Grid Code leaves it up the System Operator:

2.8.4. During the Medium Term and Final Stages: (a) The System Operator shall be responsible for contracting for the required Operating Reserve and shall Dispatch it economically between all the participating Generators, Distributors and Eligible Customers (in the case of Interruptible Load).

The procurement cost for Operating Reserves will be recovered through the Ancillary Services charge.

In review, because the MRTS does not provide a specific mechanism for managing real time imbalances,[51] the System Operator will necessarily use Operating Reserves.

It is again useful to compare the MRTS the rules from other markets to see how other jurisdictions have addressed the issue of real time dispatch. Below are the relevant sections from the Wholesale Electricity Spot Market (WESM) Rules for the Philippines (emphasis added):

3.2.1 Market Network Model

3.2.1. The Market Operator shall maintain and publish a market network model, which will be used for the purpose of central scheduling and dispatch, pricing and settlement.

3.2.1.2 The market network model shall represent fairly, and in a manner which will facilitate consistent and reliable operation of the power system:

(a) The transmission network under the control of the System Operator, and

(b) Such other aspects of the power system which, when connected, may be capable of materially affecting dispatch of scheduled generating units or pricing within the spot market.

3.2.1.3 The simplifications, approximations, equivalencies or adaptations as may facilitate the dispatch, pricing, or settlement processes.

3.2.1.4 Where appropriate, the Market Operator or the System operator may recommend alterations to the market network model, so as to maintain:

(a) The relationship between the market network model and the transmission network; and

(b) Consistency with market requirements, in accordance with clauses 3.2.1.2 and 3.2.1.3.

3.2.1.5 Any alteration recommended under clause 3.2.1.4 shall be approved by the PEM Board.

3.2.1.6 The Market Operator shall continuously adapt or adjust the representation of the market network model to accurately reflect power system conditions, within the relevant market time frames, as advised by the System operator under clause 3.5.3.

…

3.6 MARKET DISPATCH OPTIMIZATION MODEL

[51] In other markets the System Operator dispatches according to Security Constrained Economic Dispatch and the resulting locational marginal price signals are the primary mechanism/tool for real time balancing.

3.6.1 Model Definition

3.6.1.1 ***The market dispatch optimization model simultaneously determines dispatch targets for the end of a trading interval, reserve allocations for the trading interval, associated energy prices at all trading nodes in the power system and when applicable reserve prices for all reserve regions.***

3.6.1.2 The Market Operator shall maintain and publish the formulation of the market dispatch optimization model, and the performance standards, in accordance with the WESM objectives.

3.6.1.3 ***The objective of the market dispatch optimization model shall be to maximize the value of dispatched load based on dispatch bids, minus:***

(a) The cost of dispatched generation based on dispatched offers;

(b) The cost of dispatched reserves based on reserves contracted for or when applicable reserve offers; and

(c) The cost of constraint violation based on the constraint violation coefficients.

3.6.1.4 In formulating the market dispatch optimization model, the Market Operator and System operator shall ensure that the dispatch for each trading interval is made subject to:

(a) Constraints representing limits on generation offer, demand bid and when applicable reserve quantities as specified by Trading Participants in accordance with clause 3.5, except to the extent that as they may be relaxed in accordance with clause 3.5.13;

(b) Constraints representing the technical characteristics of reserve facility categories, including when applicable reserve effectiveness factors initially set at one (1);

(c) Energy balance equations for each node in the market network model ensuring that the net load forecast for the end of the trading interval at each market trading node as determined by the Market Operator is met;

(d) Constraints representing limitations on the ramp rate from the plant status deemed to apply prior to the commencement of the trading interval;

(e) *Constraints defining power system reserve requirements as provided by the System operator under clause 3.5.3;*

(f) *Network constraints, as implied by the market network model provided by the System operator under clause 3.5.3;*

(g) *Loss and impedance characteristics of market network lines, as advised by the System operator under clause 3.5.3, and defined in Appendix A2;*

(h) *Constraints on HVDC link operations, as advised by the System operator under clause 3.5.3, and defined in Appendix A2;*

(i) *Power flow equations, as defined by a DC approximation to an AC power flow within AC sub-systems, or equivalent mathematical representation; (As amended by DOE DC No. 2006-01-0001 dated 10 January 2006)*

(j) *Any overriding constraints imposed on the recommendation of the System operator in accordance with clause 3.5.13; and*

(k) *Any additional constraints due to ancillary services or system security requirements.*

3.6.1.5 The market dispatch optimization model shall be designed so that, subject to the approximations and adjustments provided for by clause 3.6.4:

(a) It will produce an optimal dispatch given the objective defined by clause 3.6.1.3, and the constraint structure defined by clause 3.6.1.4, and specifying dispatch targets for each scheduled generating unit, scheduled load and reserve facility;

(b) It will produce a schedule of flows on each transmission line corresponding to the optimal dispatch determined in accordance with clause 3.6.1.5 (a);

(c) It will produce energy prices for each market trading node, and when applicable reserve price for each reserve region, so that the recommended dispatch targets for each individual Trading Participant would be optimal for that participant at those prices, given their offers and demand bids and after accounting for other constraints which may affect that Trading Participant, and

(d) It will perform its functions in accordance with the performance standards approved by the PEM Board.

3.6.2 Constraint Violation Coefficients

3.6.2.1 The constraint violation coefficients shall:

(a) Be set so as to ensure that the market dispatch model will always find a solution which satisfies all constraints, if such a solution exists;

(b) Be set so as to ensure that binding constraints are prioritized, such that constraints resulting in the lowest reduction in the capability of the network, load or generating units will occur first; and

(c) ***Be set so as to ensure that the prices produced by the market optimization algorithm will be appropriate in all the circumstances, taking into consideration the processes defined in section 3.10 to adjust or override those prices for settlement purposes.***

3.6.2.2 The constraint violation coefficients may:

(a) Vary according to the time of day, or on any other basis as determined by the Market Operator,

(b) Increase progressively as the constraint becomes more severe; and

(c) Increase or decrease as a function of the length of time for which the constraint has been violated.

3.6.2.3 The constraint violation coefficients for the nodal energy balance equations referred to in clause 3.6.1.4 (c):

(a) Will be known as the nodal value of lost load (nodal VoLL); and

(b) May vary from node to node and/or be set so as to reflect load shedding priorities.

3.6.3 Interpretation of Model Outputs

The output of the market dispatch optimization model is to be interpreted as providing energy and when applicable reserve dispatch targets for the end of each trading interval to which the market dispatch optimization model is applied.

3.6.4 Modeling Approximations

3.6.4.1 If the Market Operator deems it to be appropriate in all the circumstances, the market dispatch optimization model may incorporate *reasonable approximations so as to render the optimization problem solvable using an established optimization methodology such as linear programming.*

3.6.4.2 Any approximations introduced in accordance with clause 3.6.4.1:

(a) May involve producing a piece-wise linear approximation to a non-linear function;

(b) May involve producing a convex approximation to a non- convex function;

(c) May include automated procedures to deal with situations in which a choice shall be made to impose or relax certain constraints, as provided for in clause 3.5.13; and

(d) Shall preserve, under all operating conditions, an accuracy which is generally acceptable to all WESM members and particularly to any Trading Participants directly affected by such approximations.

3.6.5 Model Development

From time to time, the System operator and the Market Operator shall investigate the scope for further development of the market dispatch optimization model beyond the minimum requirements specified in clause 3.6.1 and, submit their recommendations in a report to the PEM Board for consultation with WESM members.

(As amended by DOE DC No.2005-11-010 dated 11 November 2005)

3.6.6 Market Settlement

The market shall be cleared, prices determined, and dispatch determined according to the model results for each trading interval, in the form that is written. The model results shall not be challenged ex-post. In the event that Trading Participants identify solution inconsistencies with the stated definition and objectives of the model, the Market Operator will formulate a plan to correct the model.

Notwithstanding such model solution errors, the spot market shall continue to be cleared according to the model results until a model revision is put into service in accordance with clause 3.6.5.

As with the PJM rules we see sufficient detail and specificity to not only provide transparency to the process but also provide guidance to the system/market operator.

It is true that neither PJM nor WESM use physical transmission rights relying instead on a centrally dispatch real time spot market based on security constrained economic dispatch that produces locational marginal prices. Both markets have efficiency, transparency, reliability and fostering competition as their objectives.

We noted earlier that per the definition contained in the MRTS, the market rules provide only for Transmission Entitlements across the Interconnectors. Transmission facilities behind these interconnectors are assumed to have excess capacity such that no capacity need by allocated. The implication of this is that the rules divide the Nigerian transmission network into "zones" that are connected by the Interconnectors. This is similar (but not identical) to the market that was first implemented in California. Alaywan, Wu and Papalexopoulos provide a summary of the zonal California market and the reasons for its failure:[52]

> *Since its establishment, the ISO has been operating a decentralized and zonal-based market system that provides transmission rights with scheduling priority…The current market functions of the ISO include the following:*
>
> - *The Day-Ahead (DA) Markets manage congestion and procure ancillary services.*
> - *The Hour-Ahead (HA) Markets manage congestion and procure ancillary services.*
> - *The Real-Time energy market maintains the power balance of the system…*
>
> *The zonal model is based on the assumption that intra-zonal congestion is infrequent and insignificant (in terms of financial consequences). This assumption turned out to be true only at the beginning of the ISO operation. As the actual dispatch pattern in the market environment evolved and new resources entered the market, intra-zonal congestion became very frequent and significant. At the same time the creation process for new zones lagged behind considerably. The new congestion pattern is caused by new generation in operation outside major load pockets mostly in Southern California coupled with new generation at the California/Arizona/Nevada border. These new, efficient and competitive resources started operation with little or no transmission upgrades to the current transmission system to aid in the transmission of new generation to load pockets.*
>
> *The zonal model is based on the assumption that intra- zonal congestion is infrequent and insignificant (in terms of financial consequences). Once it is identified that a certain intra-zonal constraint becomes congested frequently with*

[52] Alaywan, Ziad, Tong Wu and Alex D. Papalexopoulos, "Transitioning the California Market from a Zonal to a Nodal Framework: An Operational Perspective." *Power Systems and Exposition 2*, pp. 862-867. At: http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=1397468&url=http%3A%2F%2Fieeexplore.ieee.org%2Fiel5%2F9620%2F30397%2F01397468

substantial financial consequences, new zones must be defined. However, the precise definition of "infrequent" and "insignificant" becomes difficult to quantify and its applicability in a stakeholder process with diverse interests and for a meshed physical network difficult to manage. Moreover, the fact that the ISO does not operate (after the energy crisis) a forward energy market fundamentally limits the way new zones can be created.

The specific problems with the zonal model, which is currently in use, are summarized as follows:

- *The zonal model is based on the assumption that intra- zonal congestion is infrequent and insignificant, which has been proven untrue.*
- *The zonal congestion management creates infeasible forward market schedules because it ignores intra-zonal congestion that needs to be dealt with in real-time. As a result, the current market design does not perform a complete reliability evaluation of all scheduled resources in the forward market.*
- *The real-time intra-zonal congestion management that is based on "out of sequence" dispatch not only is inefficient and results in non-optimal solutions, it also unduly places the burden of simultaneously resolving multiple intra-zonal constraints on the real-time operator.*
- *The zonal-based forward market provides the opportunity for exercising the "DEC" game, with onerous financial consequences for the consumers.*
- *Markets cannot allocate resources efficiently when scarce resources are not recognized, and experience has shown vividly that power markets using the zonal model are especially vulnerable to gaming that exploits such deficiencies. The prevalence of these strategies and their severe effects on system reliability, have shown that power systems cannot rely on individual market participants to ensure overall physical feasibility. Indeed, the clear conclusion is that financial incentives and gaming opportunities can easily thwart the engineers' attempts to maintain reliable operations.*

As the authors explain, the success or failure of any zonal-based market design depends on the validity of the assumption that intra-zonal congestion is both "infrequent and insignificant." Moreover, the market design must incorporate an expeditious mechanism for implementing new zones should the need arise.

Recommendations:

Section 8 of the Grid Code does not provide anywhere near the requisite level of detail and specificity that is necessary and has been adopted by diverse markets around the world. As they are currently written the rules maximize the discretion of the system operator; because the rules don't provide guidance, the system operator must fill the vacuum. The rules should be amended to provide ***explicit*** *guidance for:*

- *How the system operator will alleviate real time congestion.*
- *The methodology for pro rata curtailments (reductions).*
- *How the physical transmission rights will be incorporated into the process, per Rule 8.2.3, of finding the "optimal combination of generators."*
- *How Interconnector Entitlements will be related to the methodology the System Operator will use to "change the Dispatch Schedule of the Generators in order to eliminate transmission congestion and to ensure the security and Reliability of system operation" (Rule 8.4.5).*
- *The accepted objective function for the dispatch software.*
- *Various modeling techniques and assumptions.*

We know of no market that has had as an explicit directive efficiency and transparency while at the same time relying on the physical rights model. As will be discussed below, the real question is whether to try and find a solution to the issues raised while maintaining the physical rights model or move to the financial rights model. Regardless of the answer to that question, Section 8 of the Grid Code must be significantly expanded.

Turning to pricing, according to the Rule 33 of the MRTS the market operator will be responsible for creating two prices: the Day-Ahead Price and the System Marginal Price (SMP). The System Marginal Price will be calculated as follows:

33. DETERMINATION OF DAY-AHEAD PRICE AND SYSTEM MARGINAL PRICE

33.1 Day-ahead Price

33.1.1 No later than 16:00 hours on the Pre-dispatch Day, the Market Operator shall publish the Day-ahead Price for each Dispatch Period of the Dispatch Day as a forecast of the Dispatch Price in a Dispatch Day.

33.1.2 For avoidance of doubt, the Day-ahead Price shall not form the basis of Settlement for Imbalance Energy traded during the relevant Dispatch Day.

33.2 System Marginal Price

33.2.1 Determination

After Metered Quantities have been determined in respect of each Dispatch Period of a Dispatch Day, the Market Operator shall determine the System Marginal Price no later than 16:00 hours on the Calculation Day.

33.2.2 Principles for determination of the System Marginal Price

(a) Subject to Rule 0, the Market Operator shall determine the System Marginal Price for each Dispatch Period of the Dispatch

Day by calculating an Ex-post Unconstrained Generation Schedule.

(b) *In calculating the Ex-post Unconstrained Generation Schedule, the Market Operator shall schedule Price Offers so as to minimise the offered cost of total Load, including losses, taking into account the following factors:*

(i) *the Price Offers and Quantity Nominations in respect of Generating Groups in the System Operator Control Area;*

(ii) *the actual maximum net availability of each Generating Group in the System Operator Control Area in the relevant Dispatch Period;*

(iii) *Operating Reserve requirement;*

(iv) *technical parameters of Generating Groups as contained in the relevant Registered Information;*

(v) *when applicable and approved by the Commission, a capacity support mechanism to create economic incentives for adequate availability and entry of new generation.*

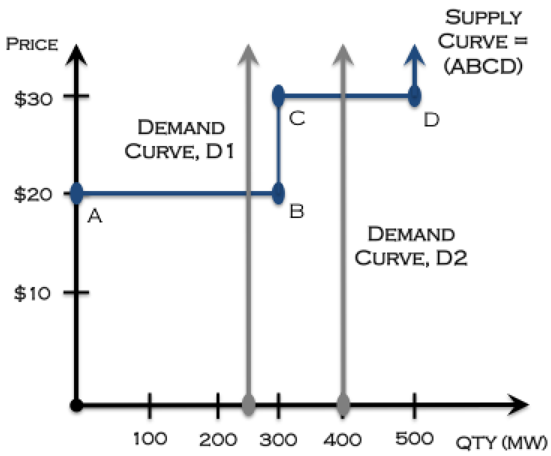
(c) *The Market Operator shall not take into account Transmission Constraints in the calculation of the System Marginal Price.*

33.2.3 System Marginal Price during Shortage of Generation

In the event load is shed by the Market Operator, otherwise than pursuant to an agreement with a Purchaser, the Market Operator shall take the VoLL as approved by the Commission from time to time and the Market Procedures for the calculation of Balancing Market prices in shortages conditions into consideration when fixing the System Marginal Price.

Given 33.1.2 it is curious why the rules require the publication of a Day Ahead Price, *i.e.,* since the price has no settlement implications and is only a forecast there does not appear to be any reason to calculate and the publish this price. Moreover, the Rules provide no guidance as to how this price will be determined.

To understand how the pricing mechanism described in Rule 33 will work we can use the 3-node model from Figure 15, *i.e.,* the unconstrained model. In Figure 23, we assume that G1 the generator at Node A has a capacity of 300 MW and a marginal cost of $20 per MW while G2, at Node B, has a generating capacity of 200 MW and a marginal cost of $30 per MW. We can create a "supply stack" or supply curve based on the price/quantity pairs for the two generators.



In order to determine the price, the market operator will overlay the actual metered quantities (Rule 33.2.1) on the actual supply curve for system. In the example in Figure 23, if the actual metered quantity is 250 MW then the system marginal price will be $20 per MW. If the actual load is 400 MW then the price will be $30.

Importantly there will be only one price for energy across all nodes on the system. Thus, in our three-node model the price at all three nodes will be $30 if actual load was 400 MW.

The efficiency of this pricing mechanism and therefore the efficiency of the market is directly related to whether the assumption of an unconstrained transmission grid is appropriate. To see why, we need to understand what happens when a constraint arises. A single supply curve is only relevant where there are no binding constraints. Once a constraint occurs there is no longer a single aggregate supply curve for the system. Moreover, the supply curve potentially changes for different levels of load.

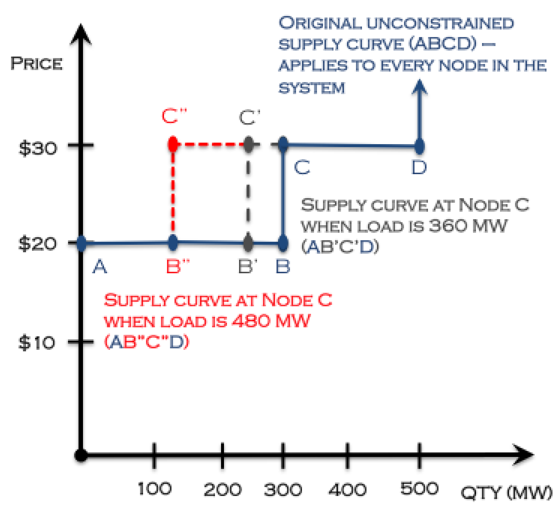


Figure 24: Examples of Actual Supply Curves in the Presence of a Transmission Constraint

For example, rather than using the unconstrained version of the three-node model from Figure 15, use instead the constrained version from Figure 16, *i.e.,* the transmission line AC has a 200 MW thermal line limit, and assume the load at Node C is 360. In this case the "supply curve" at Node C is given by AB'C'D in Figure 24, rather than ABCD (the unconstrained supply curve), because the maximum that G1 can produce at Node A is 240 MW. Similarly if the load at Node C is 480 MW then the supply curve at C is AB"C"D because the most that G1 will be able to produce at this load level is 120 MW (G2 will be able to produce 360 MW).

The existence of a binding transmission constraint necessarily means that the use of an unconstrained supply curve to set prices is going to abstract/deviate from the reality of actual grid operations. This is the reality of a constrained transmission system and there is no way for system operator to ignore this reality and be reliable. That is, if the operator were to dispatch the system as though it was unconstrained then the system will fail. Furthermore, binding constraints can change quickly and dynamically with the implication that the real time supply curve is potentially very volatile.

Fortunately, the MRTS and the Grid Code recognize that the system operator will be required to manage transmission constraints that arise in real time. Thus the management of the grid will be based on physical reality, whereas prices will not. The question then is what are the benefits and costs of disassociating prices from reality. More importantly, does this separation increase or reduce the likelihood of the market being able to achieve the goals set forth in Rules 2.1 and 2.2?

As we showed in Section 3.3, once the transmission constraint AC is binding, *i.e.,* once load at Node C exceeds 300 MW, then the underlying prices are different at each node. Figure 25 provides the correct prices as well as the prices that will result under the MRTS for each of the three nodes when load is 360 MW and there is a 200 MW thermal limit on line AC.

Node	Correct Price	Price Under MRTS Rules	Price Signal	Properties
A	$20	$30	Price is too high	Neither efficient not competitive
B	$30	$30	Correct Price	Efficient and competitive
C	$40	$30	Price is too low	Neither efficient nor competitive

Figure 25: Prices in the Three-Node Model when Load is 360 MW and there is a 200 MW Thermal Line Limit

Based on the discussion in Section 3.3 we know why the correct prices at Nodes A, B, and C are $20, $30 and $40 respectively. By ignoring the transmission constraint, the pricing mechanism in the MRTS effectively creates a mathematical average price and, as seen in the last column of the Table, these prices are neither efficient nor competitive at two of the three nodes. A market design that is predicated on average pricing cannot simultaneously produce market outcomes that are efficient and competitive. Thus the pricing methodology cannot, by definition, meet the objectives of Rules 2.1 and 2.2

Furthermore, by sending the wrong price signal, the mechanism potentially jeopardizes reliability. In this example, the load sees a price of $30 when it is actually costing $40 to serve the marginal MW of demand. Thus, by seeing an artificially low price, the load at Node C is incentivized to over consume relative to how much they would potentially take if the price were $40. In a similar manner G1, who has twice the effect on the constraint than does G2, is being incentivized to produce more than the system operator would like.

From the perspective of dynamic efficiency, *i.e.,* efficient investment, the prices encourage inappropriate investment. The information contained in the correct prices can be used to show the cost of the transmission constraint on AC;

- Cost of electricity to consumers at Node C: ($40/MW) * 360 MW = $14,400
- Payment to G1 at Node A: ($20/MW) * 240 MW = $4,800
- Payment to G2 at Node B: ($30/MW) * 120 MW = $3,600
- Payment to both generators = $4,800 + $3,600 = $8,400
- Cost of transmission constraint = $14,400 - $8,400 = $6,000

The excess of what consumers pay over the amount received by the generators is a measure of the value of the transmission constraint, which in this example is $6,000. This surplus should be returned to the load and there are a number of mechanisms that can be used.[53]

With regard to investment, the pricing mechanism in the MRTS:

- Does not adequately incentivize demand side management or distributed generation at Node C.
- Incentivizes expansion of G1, which will increase the effect of the transmission constraint.
- Does not allow for the valuation of the transmission constraint between Nodes A and C.

Finally the price averaging results in consumers having to pay higher net amounts for electricity.

- Cost of electricity to consumers at Node C under correct pricing: ($40/MW) * 360MW = $14,400 less return of surplus caused by transmission constraint = $14,400 - $6,000 = $8,400
- Cost of electricity to consumers at Node C under MRTS pricing mechanism: ($30/MW) * 360MW = $10,800

Thus consumers at Node C pay nearly 29% more for their electricity under the MRTS pricing scheme than they would under correct pricing.

The one supposed advantage of the pricing mechanism detailed in Section 33 is simplicity; there is a single price for everybody on the grid. However, this simplicity comes at a cost – higher prices for consumers, an inefficient market, inefficient investment, and a possible risk to reliable operations.

The operational effect of decoupling prices from reality is that the system operator lacks a market mechanism for balancing supply and demand in real time. The effect of this will be to increase the importance of command-and-control mechanisms that the rules allow. Thus we should expect to see, relative to other markets, heavy dependence by the system operator on reliability-must-run units and operating reserves including non-AGC secondary regulation, slow reserve and quick reserve, *i.e.,* these ancillary services will be used by the system operator to manage the transmission system. However, no ancillary services market is proposed in the MRTS rather the costs are administratively determined and then passed through to customers on a load ratio basis.

While the SMP is, by design, of no use to the system operator in managing the transmission system, it is likely to become relatively meaningless from a commercial perspective as well. The real "price" will be found in the uplift charges for the ancillary services markets because the transmission system is actually going to be managed through the use of ancillary services. Thus it would not be surprising to find that the SMP stays relatively constant despite fairly large changes in load and/or grid conditions because it is through the ancillary service "market" and not

[53] In a majority of markets, the surplus is returned through the financial transmission rights (FTR). But there are other possible mechanisms. For example, in markets where there are no FTRs the surplus has been returned via a reduction in the connection charges to the grid.

the "energy" market that the system operator is dispatching the system. This situation is neither efficient, nor competitive, nor transparent.

Recommendations

It is impossible to offer suggestions to improve the pricing philosophy contained in the MRTS while adhering to the requirement that there be a single System Marginal Price. The design philosophy of the MRTS hinges on the assumption that the transmission system is largely constraint-free. As was shown in this section, to the extent that this assumption is incorrect, then the design cannot achieve the objectives outlined in Rules 2.1 and 2.2.

Our preference is for the MRTS to be amended to incorporate nodal pricing. These prices can then be used as the basis for retail zones or hubs were prices could be averaged to reduce the complexity. This design philosophy links prices to reality and sends the right signals to the market.

We predict that the pricing system in the MRTS will result in substantial "side payments" to generators for the provision of ancillary services and, as a result the energy market will be far less relevant than the ancillary services "market."

Security and Settlement

Prudential requirements are necessary to insure the financial viability of the real time activities carried out by the dispatcher. As presented in Rule 15.3, the MRTS provides for three forms of security – cash, a letter of credit from a bank or financial institution, and a corporate guarantee of payment on demand. The success of every market depends on the robustness of the payment system

The explicit objective and resulting rules that serve to limit the amount of "imbalance energy" that is transacted serves to substantially reduce the required complexity of the prudential requirements.

15.3 Prudential Requirements

15.3.1 Notification by the Market Operator

The Market Operator shall notify each Applicant Participant of the amount of Security Cover that the Applicant Participant must provide pursuant to Rule 15.1. In accordance with Rule 15.3.2, the Market Operator shall estimate such amount within 3 Business Days of receipt of the Admission Application pursuant to Rule 15.1.3.

15.3.2 Form of Security Cover

Once approved as a Participant, each Applicant Participant shall provide and maintain the Security Cover in any of the following forms:

(a) Cash on deposit in an interest bearing escrow or trust account maintained at a bank or other financial institution acceptable to

the Market Operator, provided that the terms of deposit will include a conditions that the funds are payable to the Market Operator upon demand; or

(b) An irrevocable direct pay Letter of Credit, or other guarantee of payment that shall be executable on demand to the interest of the Market Operator, provided by a bank or financial institution acceptable to the Market Operator; or

(c) An unconditional and irrevocable guarantee of payment on demand to the Market Operator by an entity that has and maintains any of the following ratings:

(i) A short-term taxable commercial paper debt rating of not less than one of the following: (1) A1 by Standard and Poor's Corporation; (2) D1 by Duff & Phelps Credit Rating agency; (3) F1 by Fitch IBCA Incorporated; or (4) P1 by Moody's Investor Service; or

(ii) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (1) A1 by Standard and Poor's Corporation; (2) V1 by Fitch IBCA Incorporated; or (3) VMIG1 by Moody's Investors Service.

15.3.3 Amount of Security Cover

(a) During the Transitional Stage, the amount of the Security Cover to be provided by each Applicant Participant or, as the case may be, maintained by the Participant pursuant to these Rules shall be the estimated total amount due from such person for the next three (3) Billing Periods, for payment of the Transmission Usage Charge, the System Operator and Market Operator Administration Charge, and payment for any applicable Ancillary Services.

(b) During the Medium Term Market, the amount of the Security Cover to be provided by each Applicant Participant or, as the case may be, maintained by each Participant pursuant to these Rules shall be the estimated total amount due from such person for the next two (2) Billing Periods towards the purchase by such Participant, of Imbalance Energy, Ancillary Services and Reliability Must Run Services and payment towards the Transmission Usage Charge, the Cost of Imbalance Energy and the System Operator and Market Operator Administration Charge.

(c) *The initial amount of Security Cover to be provided by an Applicant Participant under paragraphs (a) and (b) above shall be estimated by the Market Operator on the basis of the information provided to the Market Operator by the Applicant Participant during the admission procedure undertaken in accordance with Rule 15.1 and the Market Operator's estimates of relevant charges and payments that are attributable to the Applicant Participant;*

(d) *Once the Applicant Participant is confirmed by the Market Operator as a Participant, the Participant shall maintain the amount of Security Cover identified under paragraph (c) above until such time that the Market Operator revises such amount under paragraphs (e) and (f) below;*

(e) *The Market Operator shall monitor, during each Billing Period, the estimated amounts payable to the Market by a Participant, based on the Preliminary Settlement for that Billing Period as compared to the amount of Security Cover supplied to the Market Operator by that Participant. If the total of the estimated amounts payable to the Market Operator at any time during the Billing Period is more than 80% of the amount of Security Cover provided by the Participant, the Market Operator shall notify the Participant of the same. Within 5 Business Days of receiving notification from the Market Operator, the Participant shall make a prepayment to the Market Operator in an amount sufficient to reduce the remaining estimated amount payable by the Participant to the Market to 50% of the Security Cover provided or, the Participant shall provide additional Security Cover to the Market Operator in an amount sufficient to reduce the estimated amount payable by the Participant to the Market to 50% of the increased Security Cover provided. The increased Security Cover shall thereafter be maintained by the Participant until the amount of such Security Cover is revised in accordance with this Rule 15.3*

(f) *The Market Operator shall monitor, on a rolling 2 month basis, the amounts payable to the Market Operator by the Participant on the basis of the Preliminary Settlement Statements and any Invoice that may be outstanding, as compared to the Participant's Security Cover supplied to the Market. If the amount payable to the Market for the any period of two months is more than 70% of the existing Security Cover, the Market Operator shall notify the Participant, in writing, informing the Participant to increase the Security Cover to the extent that the* *actual payments do not exceed 50% of the Security Cover, subject to paragraph (e) above. Within 5 Business Days after receipt of a notification to increase Security Cover, the Participant shall provide to the Market Operator evidence of such increased Security Cover as requested by the Market Operator in one of the forms specified in Rule 15.3.2. The Participant shall thereafter maintain the increased Security Cover until the amount of such Security Cover is revised in accordance with this Rule 15.3.*

(g) If a Participant fails to respond to any notifications received under paragraph (e) or paragraph (f) above within the time specified therein, the Market Operator may suspend all rights and privileges afforded to the Participant under these Rules in accordance with Rule 46.

15.4 Participant's On-going Reporting Obligations

15.4.1 Participant's Obligation to Report Changes in Filed Information

(a) Each Participant has an on-going obligation to inform the Market Operator of any material changes to:

(i) the assets or circumstances disclosed in its Admission Application made under Rule 15.1.3; or

(ii) or to any of the details appearing in Appendix 3; or

(iii) any modification to the technical and operational characteristics any of its equipment that is connected to the System Operator Controlled Grid.

(b) The Participant shall provide such information in the form specified in Appendix 3-B.

15.4.2 Failure to Report Changes

If a Participant fails to inform the Market Operator of any material change in the information provided with its Admission Application in compliance with Rule 15.4.1, which material change may affect the Reliability or safety of the System Operator Controlled Grid, or have a materially adverse effect on the trading obligations of other Participants, the Market Operator, may impose a penalty and/or suspend or terminate the Participant's rights in accordance with Rule 46.

Recommendations

The prudential requirements contained in the MRTS are fairly standard and are reflective of the fact the rules actively discriminate against transacting imbalance or spot energy.

We believe that guidelines regarding Letters of Credit from foreign banks should be explicit and comprehensive. The current wording states that a Letter of Credit can be "provided by a bank or financial institution acceptable to the Market Operator." It is doubtful the Market Operator will have the necessary skills and experience to evaluate the financial health of all possible banks let alone foreign banks. As such to avoid possible accusations of discrimination, while at the same time maintaining the integrity of the market payment system we advise that the rules contain a clear-cut set of transparent guidelines that can be applied to all market participants. We advise similar changes in the Rules with respect to the location of trust or escrow accounts, i.e., there should be explicit and comprehensive rules rather than simply "acceptable to the market operator."

Since the Transitional and Medium Term Markets are both physical markets, i.e., there is little or no opportunity for purely financial participation, the question of how to handle an exiting participant is less important. Nonetheless, we recommend making explicit that any amounts held as prudential requirements will not be released to a departing member until final settlement has occurred.[54]

Lastly we note, that subsequent to establishing the initial prudential requirements, the security cover is retrospective and not prospective. That is, the adequacy of the security cover does not reflect any seasonality. So for example, to the extent that a participant's exposure increases during a given month/season this will not be reflected in prudential requirements until after the exposure has increased. Given the current rules, this may cause the market operator to make additional security calls more frequently than needed.

Regarding settlement, without any desire to minimise the seriousness and importance of the topic, the essence of any market rules is simply to determine "price times quantity" for the relevant services. As a result the nuts and bolts of the settlement function are rarely incorporated in the rules, rather they are found in the companion business practice manuals. With that in mind, we note several issues pertaining to settlement that are relevant to a discussion of the rules and make the following recommendations:

1. *Settlement depends on information. Primarily information regarding production and usage. As such, robust metering is fundamental to transitioning from monopoly provision to competitive open access. In this regard, Rule 1.5.1 (iii) of the Grid Code, confers upon TCN the responsibility for ensuring proper metering at all Connection Points. It is critical*

[54] This wording could be added to Rule 15.7.4 - *Notwithstanding compliance with paragraph (b) of Rule 15.7.3, the Participant shall remain subject to and liable for all obligations and liabilities which it incurred as Participant or which accrued to it in that capacity prior to the Dispatch Day on which it ceases to be a Participant regardless of the date on which any claim relating to the respective obligations or liabilities may be made.*

that this responsibility extend to all points where power enters and exits the system, i.e., at every point where electrical power enters and exits the system there must be a revenue quality meter. To the extent that power is not metered then other some users will unwittingly be subsidizing other users. With respect to successful market implementation and operation there are three fundamental areas that must have robust solutions – reliable system dispatch and the related pricing, prudential requirements and metering. To this end, while the Grid Code confers the responsibility for ensuring proper metering, neither the Grid Code nor the Metering Code provides TCN with any ability to ensure the compliance of connecting entities with the metering standards.

2. *There will be errors, delays, and disputes related to settlement statements, invoices etc. and this necessitates the need for re-settlement. While the settlement rules contained in Rules 35 – 38 of the MRTS envision the need, and allow for, potential re-settlement to take place, there should be a defined process and timeline by when the process must be completed. For example, the Midwest ISO in North America has, encoded in the rules, four settlement periods – S7, S14, S55 and S105 – which take place 7, 14, 55, and 105 days after the specific operating day. After the complete settlement process takes place the bills are considered final unless the regulatory body mandates further re-settlement. This defined process provides market participants with surety regarding when they can "close the books."*

3. *The market operator should be required to define all potential charge types, i.e., credits and liabilities, as well as the determinants used to calculate the charge that could found on a settlement statement. Furthermore, each settlement statement should clearly and transparently list every charge type and the related value for each settlement period.*[55]

4. *In conjunction with the market participants and the Nigerian Electricity Regulatory Commission, the market operator should develop the appropriate protocols pertaining to ownership/proprietorship of data given to and used by the system and market operators both of who will have commercially sensitive information for their direct customers and, by inference, potentially for the customers of their customers.*[56]

<u>Governance and market surveillance</u>

With respect to governance, electricity markets are unique for several reasons. First, in nearly all cases electricity markets are the product of direct government intervention, *i.e.,* legislation and/or regulation. Second, the provision of electricity is fundamental to the health of the economy. Third, the market necessarily brings together physics, economics, and social policy. Fourth, electricity has very unique characteristics, *i.e.,* network production and lack of storage. As a result of these and other, reasons "good" governance of the market is critical.

[55] Presumably this will be included as Appendix 5 which is to be supplied by the market operator.
[56] It is entirely possible to discern the economic situation of grid connected entities by reviewing their electricity usage.

"Governance" consists of three separable branches that, in combination, serve to govern activity of the participants:

- Legislative,
- Judicial, and
- Administrative.

Theoretically, good governance requires the separation of each of these functions. However, for political reasons a clear delineation between the functions rarely occurs in electricity markets and the Nigerian market is no different than the rest in this regard.

Section 32 of the EPSR Act 2005 provides the Nigerian Electricity Regulatory Commission with the authority for the legislative function given the overall objectives of the Act. But this authority is not absolute because Section 33 (1) also provides that the Minister has some (undefined) authority with respect to certain aspects of the market.

32. *(1) Subject to this Act, the Commission shall have the following principal objects:*

(a) to create, promote, and preserve efficient industry and market structures, and to ensure the optimal utilisation of resources for the provision of electricity services.

(2) For the furtherance of the objects referred to in subsection (1) of this section, the Commission shall perform the following functions:

(a) promote competition and private sector participation when and where feasible;

(b) establish or, as the case may be, approve appropriate operating codes and safety, security, reliability, and quality standards;

(c) establish appropriate consumer rights and obligations regarding the provision and use of electricity services;

(d) license and regulate persons engaged in the generation, transmission, system operation, distribution, and trading of electricity;

(e) approve amendments to the market rules;

(f) monitor the operation of the electricity market; and

(g) undertake such other activities which are necessary or convenient for the better carrying out of or giving effect to the objects of the Commission.

(3) In the discharge of its functions, the Commission shall consult, from time to time, and to the extent the Commission considers appropriate, such

persons or groups of persons who may or are likely to be affected by the decisions or orders of the Commission including, but not limited to licensees, consumers, potential investors, and other interested parties.

33. *(1) The Minister may issue general policy directions to the commission on matters concerning electricity, including directions on overall system planning and co-ordination, which the commission shall take into consideration in discharging its functions under section 32 (2).*

To satisfy Section 32 (3) of the ESPR Act 2005, the Rule 42 of the MRTS provide for the establishment of a Stakeholder Advisory Panel. Despite the language contained in 42.2.1, *i.e.,* "and or approving amendments…", the Stakeholder Advisory Panel should be understood as a recommendatory and not a decision-making body. NERC has not delegated any policy-making authority to the market through either the MRTS or the Grid Code.

42.1 Constitution of Panels and Appointment of Counsellor

42.1.1 Stakeholder Advisory Panel

(a) The Commission shall constitute a Stakeholder Advisory Panel, which shall have the functions, powers and responsibilities specified in these Rules and the Grid Code.

(b) The members of the Stakeholder Advisory Panel shall be appointed in accordance with Rule 42.2

…

42.2 Stakeholder Advisory Panel

42.2.1 Functions relating to the Market Rules, Grid Code And the Market Operator Administered Market

(a) The duties of the Stakeholder Advisory Panel in respect of these Rules, the Grid Code and the Market Operator Administered Market shall include the following:

(i) reviewing these Rules and the Grid Code and proposing and or approving amendments thereto on an on-going basis; and

(ii) advising the Commission on such specific technical issues relating to the operation of the Market Operator Administered Market, as may be referred to the Stakeholder Advisory Panel by the Commission.

(b) *In exercising its powers and performance of its duties, the Stakeholder Advisory Panel shall comply with all applicable provisions of these Rules.*

The concern for any potential participant in this structure, is of course, that the policy-making body, *i.e.,* NERC, will become unduly political in their decision-making and the electricity market will become a vehicle through which the government may try use for political gain. This is especially relevant in the electricity sector given the immobility of the physical capital once the investment has been made. The Commission should be mindful of this as it performs the tasks assigned to it. While it is beyond the scope of this paper to address the process of how the Commissioners are appointed we do, however, recommend that the Commission adopt core principles that govern the process by which they reach decisions. In this regard transparency and consistency are particularly important. Private investors need to know that decision-making by the Commission will be based on sound operational, legal and economic principles.

While the MRTS does provide for the establishment of a Market Surveillance Panel (MSP) in Rule 42.4, the ultimate authority, per the ESPR Act 2005 rests with the Commission. In effect the MSP can be considered an "agent" of the Commission.

42.4 Market Surveillance Panel

42.4.1 Duties

(a) *The Market Surveillance Panel shall investigate any activity related to the Market Operator Administered Market or the conduct of a Participant and shall report thereon to the Commission in the manner specified in these Rules.*

(b) *Without limiting the generality of paragraph (a), the Market Surveillance Panel shall:*

(i) *monitor behaviour of Participants, and notify acts such as abuse of costs and abuse or possible abuse of market power;*

(ii) *monitor the efficiency of these Rules and market design, to identify and correct flaws as early as possible, and to propose mechanisms for solving or mitigating any problem in these Rules or its implementation;*

(iii) *assist the Commission in interpretation and implementation of these Rules;*

(iv) *review proposals on amendment of these Rules;*

(v) *monitor efficiency and impartiality of the System Operator and the Market Operator; and* *(vi) monitor development of competition and market efficiency.*

42.2.2 Reporting

(a) Upon completion of any investigation, the Market Surveillance Panel shall submit reports to the Commission and such other persons as are specified in Rule 44.

(b) Subject to paragraph (c), all reports of the Market Surveillance Panel prepared pursuant to paragraph (a) shall be made on a confidential basis to the Commission. A report of the Market Surveillance Panel made upon completion of an investigation respecting the conduct of a Participant shall also be provided to the Participant and the Market Operator in accordance with these Rules.

(c) The Commission shall make available for public inspection during its normal business hours at its offices, a copy of each report prepared by the Market Surveillance Panel pursuant to paragraph (a) above, subject to editing any portions thereof to remove any confidential or commercially sensitive information pertaining to any person or Participant.

Rule 44 describes the process of Market Monitoring that the MSP will follow:

44. MARKET SURVEILLANCE

44.1 Market Monitoring Functions

44.1.1 The Market Surveillance Panel shall monitor, evaluate and analyse the conduct of Participants and the structure and performance of, and activities in, the Market Operator Administered Markets including, but not limited t identifying:

(a) inappropriate or anomalous market conduct, including behaviour occasioning or likely to occasion abuse of market power, whether or not a person engages in such conduct unilaterally, or in conjunction with other persons ;

(b) inappropriate or anomalous market conduct in Dispatch Nomination;

(c) actual or potential design or other flaws and inefficiencies in these Rules and, the Grid Code and other rules and procedures of the System Operator and the Market Operator;

(d) actual or potential design or other flaws in the overall structure of the Market Operator Administered Market, including an assessment of whether any one or more specific aspects of the underlying structure of the Market Operator Administered Market is consistent with the efficient and fair operation of a competitive market; and

(e) such other matters as the Commission may direct in discharge of its functions under sections 80 and 81 of the Act.

44.1.2 To enable it effectively perform the monitoring function referred to in Rule 44.1.1 the Market Surveillance Panel shall develop, with the approval of the Commission, a system for the submission of market information, as well as a criteria for evaluating such information. To this end, the Market Surveillance Panel shall develop and Publish:

(a) a detailed catalogue of all of the data and/or categories of data required for the proper performance of its duties and the means of acquiring same directly from Participants; and

(b) a catalogue of the monitoring indices that will serve as a basis for its evaluation and analysis of the data so acquired.

44.1.3 The Market Surveillance Panel may request that a Participant provide it with information, other than that referred to in the catalogue developed under Rule 44.1.2(a), if the Market Surveillance Panels requires such information for the effective performance of its duties.

44.1.4 Market Surveillance Panel shall establish procedures for handling the data acquired by it in the exercise of its functions, including procedures for gathering and or acquiring such data, and for protecting any Confidential Information. Such procedures shall not conflict or be inconsistent with the provisions of Rule 47.4 and shall be included in the confidentiality catalogue referred to in Rule 44.1.2(a)

44.1.5 The Market Surveillance Panel shall not disclose Confidential Information pertaining to any Participant, which it acquires in the course of the performance of its functions under Rule 44.1.1, to any other Participant.

44.1.6 Each Participant shall provide the Market Surveillance Panel with any data referred to in the catalogue developed by the Market Surveillance Panel pursuant to Rule 44.1.2(a), as well as any other data requested by the Market Surveillance Panel pursuant to Rule 44.1.3.

44.1.7 The Market Surveillance Panel shall from time to time as it deems appropriate, and subject to approval of the Commission, re-evaluate and revise the catalogues referred to in Rule 44.1.2 and shall publish such revised catalogues in accordance with the said Rule 44.1.2.

44.1.8 Nothing in this Rule 44 shall preclude the Market Surveillance Panel from conducting such monitoring exercise, evaluation or analysis as it determines appropriate at any given time.

44.1.9 The Market Surveillance Panel shall, no less than once a year, and more frequently if so requested by the Commission, prepare routine reports on matters within the scope of its responsibilities pursuant to this Rule 44, including a summary of all complaints or referrals filed and all investigations conducted under Rule 44.2. Once annually, such reports shall contain the Market Surveillance Panel's general assessment of the state of competition within, and the efficiency of, the Market Operator Administered Market.

44.1.10 The Market Surveillance Panel may, from time to time, in its discretion, consult with Participants in relation to matters within Rule 44.1.1, provided that no Confidential Information shall be disclosed to any Participant without the prior concurrence of all other Participants to whom the Confidential Information relates.

44.1.11 Report of Improper Conduct

(a) If at any time, it comes to the attention of the Market Surveillance Panel that any Participant is engaged in any improper conduct, including failure to comply with any legal requirements falling within the jurisdiction of any person, board, agency or tribunal including, but not limited to, the Commission, or that that an Amendment to these Rules and or the Grid Code may be required, the Market Surveillance Panel shall prepare and submit to the Commission, a report detailing the improper activity and where applicable, recommending amendment of these Rules and or the Grid Code.

(b) If the report recommends an Amendment to the Market Rules and or the Grid Code, a copy of such report shall be sent to the Stakeholder Advisory Panel.

(c) If the report identifies a breach has or might have been committed by a Participant, a copy of such report shall be sent to the Market Operator and the concerned Participant.

44.2 Investigations

44.2.1 The Market Surveillance Panel shall have the power and the responsibility to conduct investigations into any of the matters specified in Rule 44.1.1.

44.2.2 Any person or authority, other than the Commission, wishing the Market Surveillance Panel to conduct an investigation into any matter referred to *in Rule 44.1.1, shall make a complaint or referral in writing to the Market Surveillance Panel, setting out:*

(a) the name and address of the complainant or person referring the matter;

(b) the particulars of the complaint or referral;

(c) any information or facts supporting the complaint or referral; and

(d) the signature of the person making the complaint or referral or, where that person is not an individual, the signature of a duly authorised officer or duly authorised representative of the person.

44.2.3 The Market Surveillance Panel may refuse to commence an investigation into any matter referred to it pursuant to Rule 0 if, in its sole discretion, it is of the view that an investigation is not warranted and shall, where an investigation has been initiated, have the right to discontinue the investigation, if it determines that the complaint or referral is:

(a) frivolous, vexatious, otherwise not material or was not or is no longer warranted;

(b) within the exclusive jurisdiction of another person, board, agency or tribunal; or

(c) the person making the complaint or referral fails to provide the information required pursuant to Rule 44.2.5 within the time specified by the Market Surveillance Panel.

44.2.4 In the event that the Market Surveillance Panel, pursuant to Rule 44.2.3 refuses to commence an investigation, or discontinues an investigation which it had commenced, it shall advise the person or authority that filed the complaint or made the referral, and shall also prepare and deliver a report to the Commission, detailing the matters specified in Rule 44.2.13.

44.2.5 The Market Surveillance Panel may, prior to making a decision pursuant to Rule 44.2.3, request that the person making the complaint or referral provide additional information relating thereto within such time as may be specified by the Market Surveillance Panel.

44.2.6 Upon determining that there is a prima facie case of improper conduct on the part of a Participant in respect of whom a complaint or referral has been made pursuant to Rule 44.2.2, the Market Surveillance Panel shall notify the Participant which is the subject of the complaint or referral that the Participant is the subject of an investigation and shall inform the Participant or cause the Participant to be advised of the outcome of the *investigation. Furthermore, upon written request in that regard, the Market Surveillance Panel shall notify the person or authority that made the referral of the outcome of the investigation.*

44.2.7 For the purposes of carrying out an investigation, the Market Surveillance Panel may request any Participant and the person who made the complaint or referral that resulted in the investigation to provide information in accordance with Rules 44.2.8 and 44.2.9.

44.2.8 A request for information pursuant to Rule 44.2.7 shall:

(a) be in writing;

(b) specify the information requested; and

(c) specify such time as, in the discretion of the Market Surveillance Panel, it is reasonable for the information to be provided.

44.2.9 Information provided to the Market Surveillance Panel pursuant to a request made under Rule 44.2.8 shall, if the Market Surveillance Panel so requires, be certified under oath or statutory declaration by the person to whom the request is directed or, in the case of a person who is not an individual, a duly authorised officer or duly authorised representative thereof, as being correct and complete to the best of that person's knowledge.

44.2.10 Upon a request for information by the Market Surveillance Panel pursuant to Rule 44.2.7, any Participant to whom such request is directed shall provide the information so requested, and shall cause any Affiliate that is in possession such information to provide the Market Surveillance Panel with the information.

44.2.11 Where a Participant or an Affiliate of a Participant fails to provide the information requested by the Market Surveillance Panel in accordance with Rule 44.2.10, the Market Surveillance Panel may apply to the Commission for an order to secure compliance with its request. The Participant and the Market Surveillance Panel shall comply with any decision made by the Commission in this regard.

44.2.12 Upon completion of an investigation, the Market Surveillance Panel shall prepare and submit to the Commission, a written report detailing, among other information:

(a) the subject matter of the investigation;

(b) whether the Market Surveillance Panel initiated the investigation on its own initiative or upon a referral or complaint pursuant to Rule 44.2.2;

(c) the findings of the investigation, including in appropriate cases, a statement that it was unable to reach a firm conclusion on the matter investigated and the reasons for such inability;

(d) any written response provided by a Participant pursuant to Rule 0 to a finding of improper conduct on its part by the Market Surveillance Panel; and

(e) the recommendations, if any, of the Market Surveillance Panel and the reasons for the recommendations.

44.2.13 Where the Market Surveillance Panel decides, pursuant to Rule 44.2.3 either not to initiate or to discontinuing an investigation, it shall prepare and submit to the Commission, a report detailing:

(a) the nature of the complaint or referral; and

(b) the reasons for the decision of the Market Surveillance Panel not to investigate the matter or to discontinue its investigations.

44.2.14 Upon review of the report submitted by the Market Surveillance Panel pursuant to Rule 44.2.13,, the Commission may approve, modify or reject in its entirety, the decision of the Market Surveillance Panel and may direct, where appropriate, the Market Surveillance Panel to undertake or continue such investigation in accordance with this Rule 44 and the provisions of paragraphs (a) and (b) of Rule 44.2.3 shall not apply in such cases

44.2.15 In the event that the Market Surveillance Panel decides, upon conclusion of an investigation, that a Participant has engaged in improper conduct, including but not limited to breach of these Rules and/or the Grid Code, and the Market Surveillance Panel intends to include such findings in its report to be issued in accordance with Rule 44.2.12 it shall discuss such findings with the and must give the Participant a reasonable opportunity to respond in writing to the findings before including same in the report. Where the Participant has not made any response within a reasonable time specified by the Market Surveillance Panel, the Participant shall be deemed to have elected to make no response.

44.2.16 Where the Market Surveillance Panel determines that action is urgently required in respect of the matters which are revealed during the course of an investigation, the Market Surveillance Panel may make an interim report to that effect to the Commission containing the applicable recommendations.

44.3 Dispute Resolution and Other Relief

44.3.1 The dispute resolution procedures provided by Rule 43 shall not apply to the activities of the Market Surveillance Panel.

44.3.2 Subject to Rule 44.3.1, nothing in this Rule 44 shall prevent any person from asserting any rights it may have under the Applicable Law, these Rules or the Grid Code.

44.4 Publication and Provision of Data

44.4.1 Participants may request that the Market Surveillance Panel provide data which is not Confidential Information collected or created in the course of the monitoring activities described in this Rule 4 and which is not otherwise required to be published by the Market Surveillance Panel or the System Operator and the Market Operator pursuant to these Rules or the Grid Code. Such data may be provided unless, in the opinion of the Market Surveillance Panel, such disclosure is reasonably likely to compromise the work of the Market Surveillance Panel. Where the provision of data imposes a significant burden or expense to the Market Surveillance Panel, the data may be provided on payment of a reasonable fee.

44.5 Audit

44.5.1 The activities of the Market Surveillance Panel shall be audited in accordance with procedures adopted from time to time by the Commission in consultation with the Market Surveillance Panel.

While we appreciate that interim nature of the market created by the MRTS as well as the infancy of competition and open access in the Nigerian electricity market, nevertheless we believe that Rule 44 does not provide adequate specificity for existing and prospective market participants regarding what behaviour constitutes an abuse of market power. At the very least, the MRTS should provide a definition of market power and a description of how abuse will be determined.

In the simplest possible terms, market power refers to the ability of a market seller to influence price. In the stylized world of perfect competition no individual seller has the "power" to raise or lower prices by their actions. Generically, anytime – for whatever reason – that a supplier has the ability to influence price through its production decisions, then it has, from an economic perspective, market power. In the textbook world of perfect competition, market power is limited because: (1) suppliers produce identical goods; (2) each supplier's individual output is insignificant relative to the market supply; (3) there are no barriers to entry or exit; and (4) buyers and sellers have perfect information. As a practical matter, however, these conditions do not hold in the real world for any commodity and, in particular, they do not exist for electricity.

In order to define market power it is first necessary to define the market itself – both geographically and by product.[57] Once the market has been defined, the next step is to evaluate the degree of concentration within the market, *i.e.,*, determine whether or not an individual supplier or subgroup of suppliers produces a significant portion of the market supply. The higher the degree of concentration the greater the potential market power held by those firms.

Unfortunately, the standard textbook economic approach to defining market power, while providing some insight into the problem, does not recognize several unique aspects of electricity as a commodity. These aspects include:

- For all but a limited number of end-use consumers, the demand for electricity is almost perfectly inelastic in real time. That is, the ability for a consumer, over a short period of time (*e.g.,* less than one hour), to see a price and take immediate actions in response is very limited. This means that a supplier with market power can reap tremendous financial gains by exercising that power over very short periods of time.
- When constraints in the transmission system arise, they have the economic effect of conferring market power on a subset of generators. These constraints are dynamic and can come and go very quickly. Depending on the market design, suppliers can often influence where, when and for how long constraints in the transmission system will arise.
- Generating units can and often do supply products into several integrated markets. For example, energy, capacity and ancillary services are all markets where a generator could sell their output. It is possible that a specific generator or subset of generators may have market power in one market (*e.g.,* reactive support, black start, ramp, *etc*.) but not in another market. Accordingly, they may take actions in one market to influence outcomes in related markets.
- Competitive electricity markets often experience substantial price volatility, particularly in gross-pool, energy-only markets.

Consequently, the situation in electricity, relative to more "normal" goods, is that the definition of market power requires a special methodology and a recognition that an instance of market power abuse can be very short lived, but with dramatic effects. At the same time, electricity markets are often volatile and this volatility may result in price spikes that are not necessarily a reflection of market power or its abuse. Any assessment of market power in volatile electricity markets needs to distinguish between its illegitimate use and legitimate pricing. This requires a cautious approach to market surveillance, recognizing that there are costs to both types of regulatory "errors," that is, not intervening when intervention may be necessary and intervening when it is not. While the costs of not intervening may be readily apparent in the short term (*e.g.,* rents for generators that take advantage of their market power), they need to be weighed against the less obvious, but often very significant, costs of inappropriate interventions (*e.g.,* dampened price signals and loss of investor confidence resulting in inadequate investment in new capacity and higher prices and less reliable supply in the medium to long term).

[57] Over time investment and technological progress may alter the definition of the geographic and product markets.

Economists have recognized that there are three basic empirical approaches to identifying market power in an electricity market, each having its own shortcomings and limitations.

The first approach is to focus on whether any firms have the ability to exercise market power. A number of measures assess each firm's share of the total supply (usually expressed as megawatts of generating capacity) in a given market or country. The idea behind these measures is straightforward: a market dominated by a few large firms will be more susceptible to market power than a market with numerous relatively small firms. To enable meaningful comparisons, the market shares can be aggregated into a Herfindahl-Hirschman Index ("HHI"), with higher values of this index indicating greater concentration and scope for market power.

An offshoot or hybrid of the concentration-ratio approach that has been adopted in other markets is the "pivotal supplier" test whereby measures are developed that generally indicate how often a given firm has to run at least some of its capacity, *i.e.,*, look at each firm's capacity relative to demand. While there are other more complex variations, the basic idea is the same: evaluate whether any firm is large enough relative to the market to allow it the ability to change its own output in a way that will affect the market price.

The principal shortcoming of this approach is that concentration measures can give an incomplete picture of the ability of firms to exercise market power. First, these measures generally do not reflect the effect of transmission constraints, which effectively change the size of the market by limiting the amount of competition at various locations on the network. Second, concentration measures do not consider the scope for entry by new firms. For a given level of concentration, a market where new investment is very slow (*e.g.,* due to heavy permitting procedures) will be more susceptible to market power compared to a market where entry is relatively easy.

The second approach focuses on whether any firms actually have exercised market power in a given period. To answer this question, regulators and economists look at detailed data on plant characteristics and input prices, and attempt to estimate a marginal cost curve for each generator. These estimates of marginal costs are compared to each generator's actual bid prices. Deviation of bid prices from estimated marginal cost indicate market power, provided that the estimate is correct. This approach requires significant amounts of data and is sometimes controversial because estimates of marginal costs will always carry a degree of imprecision.[58] A related method evaluates data on unplanned plant outages. If a given firm owns plants that are out of service more frequently than is statistically typical for the relevant plant age and type, then this may be considered evidence of market power (again, depending on the accuracy of the estimate).

The third approach focuses on whether the performance of the actual wholesale market matches the predictions of a simulation model with competitive characteristics. Some economists build complex simulation models that model the characteristics of a given wholesale market. They

58 For example, getting an accurate estimate of marginal cost can be particularly problematic in the case of hydro generation where the marginal cost of an extra unit of production includes complex considerations about future prices.

simulate market prices, bids and other output under the assumption that the market is highly competitive. These modeled outputs can then be compared to actual data from the real-world market. If it can be assumed that the market can be reliably modeled, this may be a useful approach, although it can be time consuming and the results can be difficult for a non-specialist to assess.

Different markets have relied on different approaches and the choice is depends on a many factors; history of the industry (*i.e.,* investor owned regulated monopolies or government ownership), legal structure, political structure and climate, etc. For example, energy regulators in the United States have often relied on the first two approaches by using various market concentration and pivotal supplier measures, as well as price/cost based benchmarks, to assess and, where necessary mitigate market power. In contrast, the Australian Energy Regulator ("AER") (and before it, the Australian National Electricity Code Administrator – NECA) has not established such market power criteria and price/cost-based benchmarks. Instead, the AER has focused on investigating whether the behavior has involved collusion or has had an anti-competitive intent.

Traditional economic analysis of market power originates from the "structure-conduct-performance" paradigm where structure refers to the degree of competitiveness (*i.e*., the lack of market power) in the industry. The conduct of firms in the industry is linked to the structure and performance is typically measured by the extent that market clearing prices exceed the marginal cost of production. The more competitive the industry is, the less ability firms have to influence price (*i.e*., conduct) and the closer the market price will be to marginal cost (*i.e*., performance).

The starting point for this methodology is to construct an *N-firm concentration ratio.* There are a number of different attributes of market outcomes that can be measured, *e.g*., revenues, profits, sales, capacity, etc. In an electricity market it might be useful to construct the 2 and 4-firm concentration ratios for output. The greater the concentration ratio the more economic power held by the *N-firms.*

The HHI is a more sophisticated and complex measure of concentration. The HHI equals the sum of the squared market share of all the firms in the market. That is, HHI = $\sum_i (S_i)^2$ where S_i represents the market share of firm *i.* For an industry where each of 5 firms has market share of 5%, 10%, 10%, 20%, and 55% respectively, the HHI would be 3650. In comparison, if all 5 firms had equal market share (i.e. 20%) the HHI would be 2000.[59]

Either of these measures is easy to calculate and provides an insight into the likely performance of industry. Given the construction of the HHI, it is more sensitive to the relative size of the largest firms and provides more information in industries that have high concentration ratios.

Unfortunately concentration ratios and the HHI, while of some use in electricity, are not granular enough to capture many of the unique aspects of electricity production. As a result, additional measures of market power have been developed specifically for the electricity industry.

[59] Industries with an HHI of 1800-2000 or less are typically defined as competitive. An HHI between 2000 and 6000 is indicative of a oligopolistic while an HHI above 6000 indicates a monopoly.

In contrast to structural measures of market power, behavioral measures rely on observable actions in the market. These measures focus primarily on withholding rather than size or concentration as indicators of market power. In particular, there are three types of withholding that are examined as part of a behavioral analysis. They are:

- Physical withholding, which occurs when a generator does not offer to sell their output even though price is above the marginal cost of production;
- economic withholding, which occurs when a generator submits bids that are unjustifiably high relative to its known operational characteristics or cost, so that the generator is not dispatched or the bids set the clearing prices; and
- uneconomic production, which occurs when a generator offers their output at a price below the marginal cost of production.

If a generator has market power and executes one or more of these offering strategies (*i.e.*, "conduct"), then it will be able to influence price (*i.e.*, "impact"). The basic methodology has been to implement various "screens" that are designed to identify instances where a supplier or set of suppliers is essential to meet the market demand. Should the supplier fail the screen, *i.e.*, their output is necessary, then a presumption of market power arises.[60] The fact that the supplier has failed the screen does not automatically mean, however, that it has to be mitigated or that sanctions need to be imposed

In the United States, the SMA screen was proposed by the U.S. Federal Energy Regulatory Commission ("FERC") in 2001 and was known as a pivotal supplier test. Passing the test was proposed to be a condition before an individual power supplier may be permitted to sell electric power at market-based rates. The basis for the test was to determine whether or not a given supplier's production was necessary or "pivotal" to meet the market demand. While this specific screen was not adopted by the FERC,[61] its basic premise – that of establishing the "necessity" of a given supplier or set of suppliers in meeting the electrical load – underlies most of the behavioral assessments that have been developed and implemented.

In response to the criticisms of the SMA screen, the FERC proposed and adopted two more refined screens. A generator failing either screen results in the presumption of market power on the part of the FERC. The first screen, the Uncommitted Pivotal Supplier Screen first measures the uncommitted capacity of a generator. This capacity is defined as the total generating capacity owned by the supplier plus any capacity under long-term contract. To arrive at the uncommitted capacity, obligations to "native" load, requirements for the provision of operating reserves and any long-term sales of energy are subtracted from the total available capacity. The resulting amount is termed the uncommitted capacity. A generator passes the screen if the uncommitted capacity of all other generators is sufficient to serve wholesale load. In other words, as long as the uncommitted capacity of a generator is not essential to meet load then that generator passes the

60 It is worth noting that to the extent demand for electricity is price sensitive, *i.e.*, the demand curve is elastic, then the problem of defining market power becomes more complicated.

61 The reason it was not adopted arose largely because of the difficulty in defining and accounting for obligations to serve "native" load.

screen. For this screen, the wholesale load is defined as the markets' annual peak load less all native load.[62]

In order to account for markets where there may be a high variation in load across seasons or where plant outages may temporarily confer market power, the FERC adopted a second screen, the uncommitted market share screen. Similar in concept to the previous screen, the uncommitted market share screen allows for two differences. First, rather than use the annual peak load as a proxy for wholesale load native load is allowed to vary seasonally. Thus the market is defined for each season. Second, planned outages are deducted from capacity. The rationale for allowing this is that generators on planned outages are unavailable to serve load and cannot be used to manipulate the market. A firm passes this screen if for all seasons it has less than 20% of all firms' uncommitted capacity.

These screens are not without some criticism. First, the market share screens fail to take into account actual supply and demand conditions in the market. Suppose that a supplier has a large market share but most of the capacity is "out of the money", *i.e.*, it is priced substantially over the market clearing price then in what sense does that generator have market power? Second, along a given supply curve a specific generator may have market power. For example, it is quite possible that a generator may have a small market share but could own a majority of peaking units or equivalently base load coal or nuclear units. Third, the choice of a 20% threshold is seen as arbitrary and either too high or too low.

As mentioned above, failure of either screen constitutes a presumption of market power on the part of the FERC. However, if a generator fails one of these screens they have the right to perform an additional test, known as the Delivered Price Test (DPT), to remove the presumption of market power.

There are three delivered price tests:

1. A pivotal "economic capacity" screen;
2. A concentration test for economic capacity (Delivered Price Test HHI); and
3. A concentration test for "available economic capacity" (HHI for available economic capacity).

For purposes of the DPT, "economic capacity" is capacity that has a marginal cost of no more than 105% of the "prevailing" market price. Moreover, "available economic capacity" is economic capacity less native load obligations. A generator will pass the first hurdle as long as the economic capacity of all the other generators in the market is sufficient to meet wholesale load requirements. Passing the second test requires a DPT HHI of less than 2500 *and* a market share of economic capacity of less than 20%. Similarly, the third test is passed if the HHI for available economic capacity is less than 2500 *and* the generator has a market share of less than 20% of such capacity.

62 Native load, is a term unique to the United States electricity industry and refers to the load within a utilities' franchise area that is not able to choose an alternative supplier.

While defining market power is a relatively academic exercise, determining when market power exists and whether there has been an abuse of the position can be difficult – particularly in electricity markets. As has been previously discussed, electricity is a unique commodity for a number of reasons and these must be taken account of in determining whether an abuse of market power has occurred. For example, acquiring gas on the spot market in a very short time frame may result in very high offer prices but in no way indicates an abuse of market power. Likewise, the physical characteristics of many base load generating units are such that it is efficient for them to continue running rather than shut down overnight or in periods of low demand but this resulting "excess" of generation will necessarily force the spot price to very low or even negative prices and the generators will need to recover revenues in times of higher demand. Again, this behavior is entirely rational, completely defensible and in no way represents an abuse of market power. These examples highlight the benefit, and even necessity, of having a market monitoring function that is fully versed in not only the law but the unique physical characteristics of electricity.

Recommendations

As currently written the MRTS provides little insight into how the market monitoring function will take place. This creates uncertainty for the market participants and impedes the transparency of the market.

Therefore, we recommend that the MRTS be amended to (1) provide a description of how market power will be defined, (2) explain how the exercise of market power will be determined and (3) describe what procedures will be used to mitigate the exercise of market power.

4.0 Section C: Conclusions and Recommendations

4.1. Conclusions and Recommendations

Over the past 10-15 years the Government of Nigeria has been moving towards establishing a competitive electricity sector. Having unbundled the industry from a vertically integrated monopoly into three separate sectors – generation, transmission and distribution/retailing – it is appropriate for the country to begin the next logical step in the evolution of the industry and initiate the process of allowing competition in the generation sector. The MRTS and the Grid Code represent a solid step in the right direction. We make the following recommendations in order to maximize the probability for the success of the process, the design, implementation and operation of the transitional and medium term market phases and the design, implementation and operation of the final market.

- As depicted in Figure 26, the current process for creating a competitive electricity market in Nigeria envisions a staged approach in which a Transitional Phase is followed by a Medium Term Stage and then a the Final Market. The MRTS are primarily focused on the Transitional and Medium Term Stages. In fact the MRTS provides no description or detail regarding the Final Market design. Moreover, there is little in the way of detail on the transition from one stage to the next.

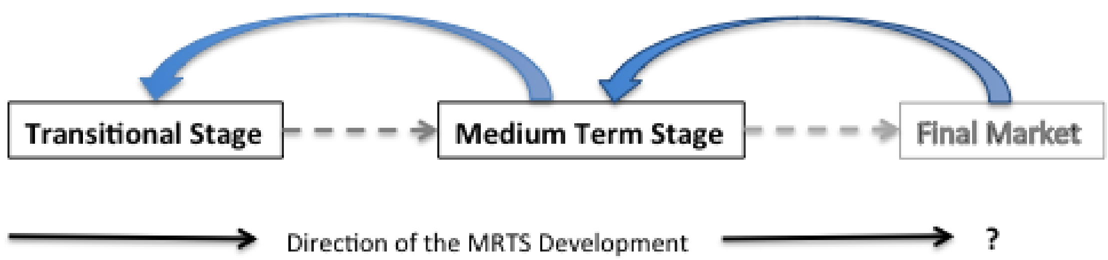


Figure 26: The Underlying Development Process of the MRTS and the Market

There is a fundamental problem with this approach in that there is no vision regarding the end state, *i.e.,* what will the Final Market look like, how will it work, what components will it have, will it be based on physical/financial transmission rights, how will prices be determined, etc.?

The need to understand the end state is not a luxury and its omission will have significant consequences. To the greatest extent possible the evolution of the market should be incremental. To the extent that bad market design forces structural changes then the evolution will be costly to implement and will cause dislocation in the industry/economy as well. For example, there is no doubt whatsoever the costly disaster that occurred in with the California electricity market was completely avoidable.[63] The effects of a poorly designed market are wide ranging. They include but are not limited to: high costs to end users, uncertain and inefficient contracting, inefficient infrastructure investment, costly and time consuming market re-design and implementation, etc. The crisis that occurred in the California electricity market was directly related to a poorly thought out final market design and was completely avoidable.

We therefore recommend that a White Paper describing the basic cornerstones of the Final Market be written, vetted through the industry and stakeholders and eventually adopted. The purpose of the White Paper is to connect or bridge the language and objectives of the EPSR Act 2005 to the market design process and then to the eventual market rules and finally to the operation of the market. The EPSR Act 2005 provides the government's objectives but it (correctly) does not provide the answer to "how" the objectives will be achieved nor does it address "why" a specific design is to be chosen. There are four discernible parts to the market design process and each has a deliverable:

(1) The underlying legislative or regulatory authority,

(2) The design process itself,

(3) The creation of the market rules, and

(4) The approval process.

The Final Market Design White Paper is, in essence, the deliverable for the second part.

Even though the MRTS, i.e. the market rules, have been created and approved does not change the need to address the second "part" of the process. The four components are integrated as well as integral for the design and operation of a successful market. Each step cannot be ignored or short-changed. The MRTS are by definition the interim and not the final rules and much debate, indeed most of the discussion on market design, implementation and operation within the Nigerian electricity sector still needs to take place. This is manifested in the MRTS through the lack of detail contained in the rules and the problematic rules provided for dispatch.

In Figure 26 we would have preferred that the basic elements - no substantial or specific detail is needed - regarding the final market had been worked out prior to the development of the medium term market rules. That is we would have preferred for the process to work backwards from the basic idea of what the final market will look like rather than incrementally towards an unknown target. The industry needs to fully understand and appreciate the importance of: the dispatch function, different mechanisms for allocating transmission capacity, the effect of unconstrained energy-only pricing, self-commitment of generation compared to centralized commitment, etc., in order to move to the final market design.

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[63] The aggregate cost has been estimated at US$40-$45 billion (see http://en.wikipedia.org/wiki/California_electricity_crisis)

It is crucially important for the White Paper to reflect the input and eventually the support of the stakeholders. As such, we recommend that a formal stakeholder process under the direction of the System and Market Operators be tasked with this project.

- Our second recommendation is that the consequences of the implicit assumption that the transmission grid is largely unconstrained should be verified. As discussed in the body of this report, the success of the market created by the MRTS is directly related to this assumption. The greater the significance - both financially and number of occurrences - of transmission constraints, the more likely the market will fail.
  Therefore, before any material work begins on implementing the Medium Term market, an analysis of the transmission grid should be conducted to validate the appropriateness of this assumption.

- Contingent on the findings with respect to the transmission constraints, our third recommendation is to evaluate the quantity, cost and availability of operating reserves that will be necessary to balance real time supply and demand.

- The MRTS dictates there will be a single unconstrained price for imbalance energy regardless of the location on the grid. To the extent there are transmission constraints this necessarily means the "energy" price will not be cost reflective. Specifically, some load will pay far less than their true marginal cost while others will pay far more. This pricing is neither fair nor non-discriminatory and will reduce or eliminate the transparency of the dispatch process. It may also risk the reliability of the system because the pricing signals are in direct opposition to the needs of dispatcher in ensuring system reliability, i.e. at locations where the dispatcher would like *greater* load, the price is artificially increased by the pricing rule, thereby *reducing* the quantity of electricity demanded, while at the same time, at locations where the dispatcher would like *less* load the pricing rule *encourages* consumption by artificially reducing the price. Therefore, our fourth recommendation is to eliminate the unconstrained price in favor of a price signal that is more reflective of cost causation.

- The fifth recommendation is to provide additional specificity to the Market Monitoring rules with respect to how market power will be defined, the methodology by which the potential abuse of market power will be determined by the Market Monitor and what procedures will be used to mitigate the use of market power.

- Related to the previous recommendation, regarding price offers made by generators, it is not clear whether the rules envision that the offer is supposed to be a single price offer (i.e., the offer includes the return to capital and the marginal cost of producing) or simply the marginal cost of producing the electricity.

- It is not clear whether transmission losses will be priced according to marginal or average losses. While either can be used, economic efficiency is obtained by using marginal losses, especially on a transmission system where line losses are significant.

- Both the MRTS and the Grid Code are silent with respect to how integration with the West Africa Power Pool and the adjacent electricity systems will take place. This becomes increasingly relevant as the ECOWAS Master Plan for WAPP is implemented. The rules should describe how the seams will be managed.

- We see no benefit and higher costs from separating the System and Market Operators.

Earlier in the report we discussed the fundamental problems that arise from basing a market on physical transmission rights. We have also identified the deleterious effects from using a simplistic pricing mechanism. In Figure 27 we provide a comparison of fourteen wholesale electricity markets in North America, Asia/Pacific and Europe as well as the proposed MRTS in Nigeria. In ten of the fourteen markets, the market design is predicated on multiple - either nodal or zonal - prices. The same ten markets are based on financial rather than physical transmission rights. There is a reason that over 70% of the established markets in this sample use multiple prices and financial transmission rights - experience has taught us that it is the preferred market design.

	Scheduling		Commitment		Dispatch						Ancillary Services		Market Monitoring
	Pre-Dispatch Schedule	Financially Binding Day-Ahead Market	Self-Commit	Centrally Administered SCUC[64]	Real-Time, Bid Based, SCED[65]	LMP	Settlement Prices: Generation	Settlement Prices: Load	Demand Participation	Financial Transmission Rights	Centrally coordinated	Co-optimized	Internal/ External Market Monitoring
North America:													
ISO-NE	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes		Internal & External
NYISO	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes	Yes	Internal & External
PJM	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes		External
MISO	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes	Yes	External
ERCOT	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes		External
CAISO	Yes	Yes	Yes	Yes	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes		Internal & External
Ontario	Yes	No	Yes	Yes	Yes[66]	No	Single *Ex Post* Unconstrained Price	Single *Ex Post* Unconstrained price	Yes	No	Yes	No	Internal & External
Alberta	Yes	No	Yes	No	Yes	No	Single *Ex Post* Unconstrained Price	Single *Ex Post* Unconstrained Price	Yes	No	Yes	No	External
Asia-Pacific:													
Philippines	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Nodal/Multi Zone LMP	Yes	Yes	Yes	Yes	Internal & External
Singapore	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Single Zone	Yes	Yes	Yes	Yes	External
Australia	Yes	No	Yes		Yes	Yes	Zonal LMP	Zonal LMP	Yes	Yes	Yes	No	External

[64] Security Constrained Unit Commitment
[65] Security Constrained Economic Dispatch
[66] Similar to the MRTS, Ontario actually runs the dispatch algorithm twice – constrained and unconstrained. The results from the constrained model are used to dispatch the system while the results from the unconstrained model are used to develop the uniform energy price.

New Zealand	Yes	No	Yes	No	Yes	Yes	Nodal LMP	Nodal LMP	Yes	Yes	Yes	Yes	External
Europe[67]:													
Ireland	Yes	No	Yes	Yes	Yes	No*[68]	Single *Ex Post* Unconstrained Price	Single *Ex Post* Unconstrained Price	Yes	No	Yes	No	External
UK	Yes	No[69]	Yes	Yes	Yes	No	Zonal Imbalance Price	Zonal Imbalance Price	Yes	No	Yes	No	External
Nigeria - MRTS	Yes	No	Yes	No	No	No	Single *Ex Post* Unconstrained Price	Single Zone	No	No	Yes	No	External

Figure 27: Comparison of Major Design and Operational Characteristics of Global Wholesale Electricity Market

[67] Nordpool relies on a separation of the financial and physical markets. The physical real time markets are run by the respective State-owned Transmission System Operators (TSOs) – in Norway that is Statnett SF., in Sweden it is Svnska Kraftnet, in Finland it is Fingrid and in Denmark it is Energinet.dk. This is a different structure than the proposed design in the MRTS. We would have to compare the real time dispatch procedures for each of the TSOs.
[68] "All generation units receive and supplier units pay the same SMP. There are however separate payments or charges for constraints and imbalances intended to compensate for dispatch which does not follow the merit order and to incentivise the following of dispatch instructions. Consequently all generator units are subject to central dispatch taking into account system constraints, reserve requirements and real time issues such as unplanned outages." Paul Conlon, ESBI, "The iINtegration of the Electricity Market in Ireland under the ISO Model." http://www.esbi.ie/news/pdf/White-Paper-Integration-Electricity-Markets.pdf
[69] The British Electricity Trading and Transmission Arrangements (BETTA) are based on balancing "imbalances" that occur around bilateral contracts. Although a spot market exists.