LONG TERM TRANSMISSION EXPANSION PLANNING FOR NIGERIAN DEREGULATED POWER SYSTEM

A systems approach

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MASTER ON ECONOMICS AND MANAGEMENT OF NETWORK INDUSTRIES

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DEDICATION

To Claret and Bill:

It was a long time

To Daddy and Nonso:

It was a brief Moment

To all who have hope in the Nigerian power system:

There shall be no darkness there

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INTRODUCTION

The International Energy Agency universal access report of 2011 showed that Nigeria has 76 million people without electricity representing 49% of her population. This makes her a key entity in the global aggregate data of 2010 that was accounted for by UNEP, which indicated that approximately 27 per cent of the world's populations (i.e. 1.6 billion people) still do not have access to electricity; with more than 99 per cent of this statistics in developing countries; and 80% of the later in rural areas . Having concurred that restructuring and deregulation of the electric power sector is a major step to achieve universal access to electricity, Nigeria embarked on the restructuring and deregulation of her power sector. This translated to a total change of the power system modus operandi of which the power system planning is one.

In as much as there is a national energy policy that used an international accredited models to plan for the energy demand and supply forecast for up to 2030 In Nigeria, there has not been a translation of this energy demand and supply plan into generation expansion planning and consequently transmission expansion planning is lacking in old regulatory regime and not even present in the latest. Furthermore, while this planning could have been easier ab initio due to centralized system and mono actor approach, the deregulation of the sector complicates any planning approach in the current regulatory regime, of which the complexity is as a result of the conflicting interest of many stakeholders in the current decision making arena. Subsequently planning will be carried out along the value chain of the power system by different actors, mostly independent of each other of which the input of one plan might affect the other as observable in generation and transmission planning which are the most essential. Therefore, there is no doubt that transmission expansion planning is a complex multi-actor decision making process of a socio-economic challenge that is technically constrained.

The technical constrain of Transmission expansion planning is not only in lack of decision making tools but plagued locally by lack of data, which is a major challenge in a new deregulated system like Nigeria; and also globally by a consensus on an acceptable methodology that should be used for this planning. With the conflicting opinion of static approach which can be snowballed over the years by experts and dynamic approach that could take care of future defined planning horizon, challenges of universal acceptable algorithm and level of detail independently, a lot of work has been done on transmission expansion planning to lack of satisfaction of the decision makers. Nonetheless, one would not agree less that a transmission expansion plan that is long termed, indicative, furnishing the details of an optimal investment and operation requirements , minimizes total cost, maximizes welfare while not compromising on the system reliability and security is the choice of every policy maker in a deregulated power system. The Nigerian power system opinion is not different as buttressed by section 3 of the national grid code

With this background set, it becomes obvious that a Long term transmission expansion plan that is multi-actor based and multi-criteria evaluated is essential for the healthy and sustainable deregulated power sector of Nigeria; not only to meet their aim of less than 15% of Non served energy by 2030, follow a planned generation mix and experience a massive industrialization by 2020 but also to conform to the Roadmap of UNEP and IEA of universal electrification by year 2050.

This document is an effort to develop a relatively detailed Long term transmission expansion plan for the deregulated power sector using TEPES, a novel model developed by IIT of Universidad Pontificia Comillas. This plan is aimed at designing a long term transmission plan that is indicative from a systems approach, hence minimizing cost and optimizing welfare giving incentives to the multiple agents in the related value chain of the deregulated power system of Nigeria. An optimal Long term transmission expansion plan is developed over the horizon of year 2030 by a proper scrutiny of various most likely scenarios, hence justifying the policies of the existing generation mix, a extra High voltage overlay (765KV EHV) and suggestive generation location following expected demand growth and spatial evolution. Finally a brief regulatory suggestion were made to support the developed plan

CHAPTER 1

1 ELECTRICITY IN NIGERIA

Electricity is undoubtedly a key driver of the socio-economic and technological development of every nation. In the case of Nigeria the electricity demand is far above the supply and the available supply is very epileptic .The major cause has been attributed to the transportation of electricity that is poor due to lack of infrastructure and weakness of existing transmission infrastructures driving lack of investment in generation. The implication is with her population of almost 160 million people, the access to this epileptic source of electricity is barely half of her population translating to an energy poor society with 121 KWh per capita which is 50 times less than an average country in Europe that has 10% of her population (Worldbank 2003). As a result, the acute electricity problem of Nigeria, in the presence of her vast natural resources is a major element of her very low human development index as it is widely accepted that there is a strong correlation between the socio-economic development and the availability of electricity. This apparently lead to the urgent need for a sector reform and restructuring which mostly translates to a decentralized power system planning with the challenges associated with the new operational environment of which long term transmission planning is a major concern.

In the bid to follow up with this deregulation, an electric power policy plan exist which has mandated the Energy commission of Nigeria (ECN) to make the long term energy demand and supply plans that will guide the country towards industrialization. Following the vast amount of natural resources in Nigeria (as shown in table 1) , three demand and supply forecast was explored that could achieve the perfect electricity generation fuel mix that will ensures the efficient utilization of natural resources (see appendix 3). However, for these demand and supply scenarios, there has never been a long term transmission plan that will support the expected evolution in the power sector. This invariably, has led to the epileptic power supply in the country arising partly from existing radially designed transmission line and partly from generation concentration in one region, leading to an excess stranded generation even when the total current generation in the country is far below 40% of forecasted generation for 2012. Therefore, it becomes obvious that there is a need for a succinct road map in transmission system of Nigeria. This will not only support the strict adherence to the generation and demand plan together with the expected fuel mix, but also give incentive to the various investors in the power sector following the current restructuring process.

Consequently, this thesis takes a systems approach to tactfully identify, design and evaluate a long term transmission expansion plans for restructured Nigerian electric sector taking the forecasted generation capacity and energy policy decisions into consideration. This implies a multidimensional approach to transmission expansion planning in Nigeria, most likely for the first time.

1.1 Electric Transmission system in Nigeria prior to restructuring

By 2010, when the last major transmission project was completed in Nigerian , 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).The voltage control policy for transmission is 330 kV (+ 5% / - 15%), 132 kV (+ 10%/ - 15%) and the equivalent frequency control is 50 HZ (+/- 4%) (See appendix 2).

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 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 (see figure 1.2) .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 (see appendix1). 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.

Energy Resources in Nigeria	
Energy Type	**Reserve Estimates**
Crude Oil	36 billion barrels
Natural gas	185 trillion cubic feet
Coal	2.75 billion metric tons
Hydro	14.750MW
Solar Radiation	3.5-7.0 Kwh/m2-day
Wind Energy	2.0-4.0
Biomas	144 million tons/year
Wave and Tidal energy	150,000 TJ/(16.6x106 toe/yr

TABLE 0-1 ENERGY RESOURCES IN NIGERIA

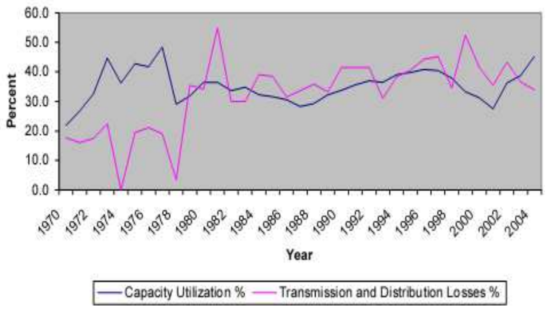

FIGURE 0-1 CAPACITY UTILIZATION AND LOSSES

With the recent deregulation, generation and transmission planning becomes very essential not only to foster the fast needed growth in the electric sector of Nigeria, hence other sectors that is highly dependent on energy; but also to give various appropriate long and short term incentives to the foreign investors coming into Nigeria to invest in power sector. Moreover, this should place Nigeria in the right position for the good interconnection that is anticipated for the West African power pool project (Adegbulugbe, et al.).

The map shown in figure 1.2 is the transmission network of Nigeria with the expected lines as of 2011 which will serve as the starting point for this work.

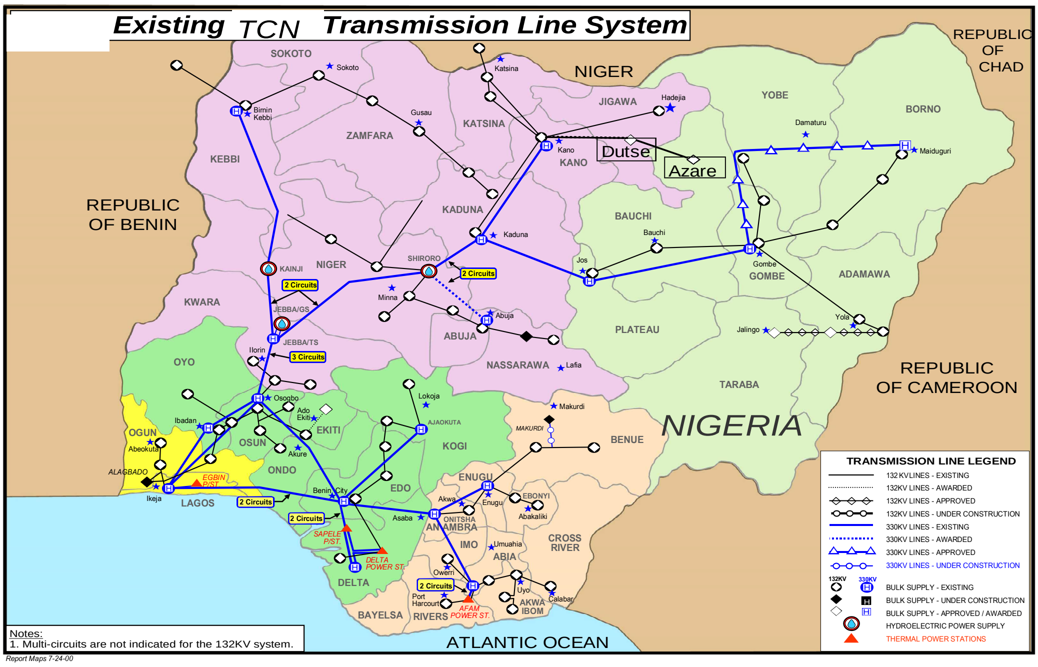

FIGURE 0-2 NIGERIA TRANSMISSION NETWORK

1.2 An insight into the current Nigerian Electric Transmission

The power system architecture could be represented in figure 1.3, in which power is generated at 11KV to 23KV and stepped up to be transmitted at 330KV as the highest voltage and then stepped down to 132KV . Distribution starts at 33KV being the stepped down Voltage from 132KV and then subsequently stepped down to 11KV where large factories can connect from. Supply to households is distributed at 400KV/230KV.

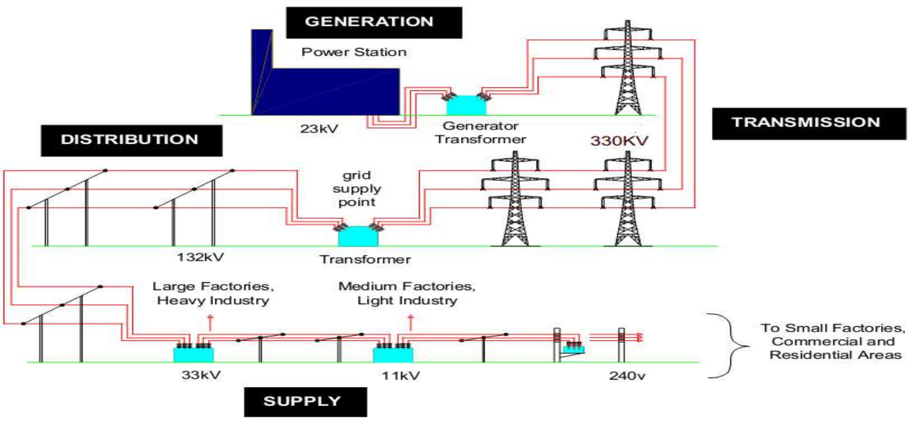

FIGURE 0-3 THE NIGERIAN ELECTRIC NETWORK STRUCTURE

In this current regulatory regime, a relative understanding of the weight of the electric infrastructure challenges led to different deregulation policy initiatives of which most of them emanated from World Bank standards and some were institutionally transplanted neglecting the adverse effects[1] (Martin, konstantinos and Mamodouh 2002). This, combined with the severity of the service failures, supported the public acceptability and political viability of electricity market liberalization in Nigeria. Nonetheless, this is a good general step to the specific problems.

As a result of the liberalization, a large number of power projects are currently under consideration across the value chain; regulators and other stakeholders will prefer and also be better off with an approach that will take the objectives of every actor into consideration- a systems approach. In this resultant value chain, transmission is of paramount importance not only because of the indicative nature of the wheeling capacity that is expected to be available, but also because of its supportive role in optimal generation locations breaking the chicken and egg problem loop.Consequently, many proposals suggest the reinforcement of existing lines (Ekwue 1984) or use of similar routes (Akin 1978), which if acceptable, makes the decision makers to face many challenges of the best use of limited transmission corridors and optimum invested capital. However, a closer looks shows that the challenges are not short of

- *What should be the long term pattern of the transmission system in the face of evolving power system sector?*
- *What is the expected timing of capacity additions and in what percentage of increment?*
- *How can all the projects across the value chain be integrated optimally and which section shall invest first (generation or transmission)?*
- *Will incremental expansion lead to a coherent overall design?*
- *Should higher capacity lines be built as part of a plan for an extra-high voltage overlay that could avoid unnecessary proliferation of lines and better use of the gas reserve in the south and east in the long-run?*

[1] Martin et-al argued that the effectiveness of economic policy that arise institutional transplantation is hardly a solution to socio-technical problems especially when the country transplanting is not alike in legal and cultural framework hence their advice against 'xeroxing' and their advice for a multiple model approach that goes from the general to the specific.

The attempt to solve the aforementioned issues shall entail a more consolidated approach to Transmission expansion planning (TEP) , which is also driven by section 3 of the Nigerian national grid code[2] that supports a systems approach that is holistic and non-discriminatory that may require a *pari-passu* development of the electricity and gas transport.

This systems approach that gives a relatively non-exclusive answer to the above questions will invariably imply a long-term plan for transmission expansion. The efficacy and efficiency of such a plan will depend on the proper selection of scenario analysis, which will produces alternate futures based on the expected growth and variation of major demographic parameters like the population growth, preferred technology fuel mix, regulatory policy etc., Further application of this perspective to the transmission planning entails dynamism which will imply that each of such scenario produce a possible demand and resource trajectory (timing of events and their geographical locations) for which a transmission plan must be developed following the forecasted demographic factors evolution . Afterwards, the probability of each of the scenario and the resultant approximations through the measures of central tendencies of the generated plans should be an important technical and policy decision making tool for an informed recommendation by the transmission planners.

The aim of transmission planning should not be mistaken as the prediction of the future grid configuration; rather it should be seen as a systematic approach to make the best possible recommendation about what to do today to meet future expectations. Hence, by considering the future options, their costs and likelihood in a systematic approach, good choices shall emerge that will tend to minimize future regret about past decisions.

Armed with this goal and the subsequent approach, the next challenge is the choice of the proper analytical and decision-making tool. This choice was made through an issue paper explained in appendix 2.

1.3 Approaching Transmission Challenges of the Nigerian restructured electric sector

In an effort to achieve a reasonable electricity supply targets and milestones and to subsequently design a good transmission network that is proactive, it is essential to have

[2] The national Grid code is one of the three network codes (the grid code, the distribution code and the metering code)that came into force in august 1,2007 that contains the day-to-day operating procedures and principles governing the development, maintenance and operation of effective, well coordinated and economic transmission system following the IEC 61000-3-7

energy demand and supply projections for Nigeria using internationally accepted energy modeling techniques. In view of that, the Energy Commission of Nigeria (ECN) has been collaborating with the International Atomic Energy Agency (IAEA) under an IAEA regional project titled ―Sustainable Energy Development for Sub-Saharan Africa (RAF/0/016) where they used the various tools for demand and supply projections.[3] However there has not been a clear plan in transmission and this is a major issue in the electricity sector of Nigeria and cannot be left to sleep.

Even so, the challenges of ensuring adequate, reliable and widely accessible electricity service involves more than summing up numbers (the mega-watts and the size of investment) and getting other technical things seemingly right. The fundamental policy issue is to ascertain what should be done, given the resource endowment, the political, economic, technological, environmental constraints in Nigeria.

Therefore the transmission investment challenge must be appropriately positioned in this context of a constrained multi-objective, incentive compatible optimization problem. They have several dimensions, namely, size, security of investment and input supply, human resource requirements, investor/ producer incentives (e.g., electricity tariff level and structure, regulatory framework and macroeconomic environment). Relative to this context, the procedure will most probably be preferred to be based on the constrained optimization of the most likely investment (selected candidate lines) in the transmission and systems operations of electricity in Nigeria.

From the demand side which is an essential input to transmission investment planning, the current level of electricity demand underestimates the true level of demand in Nigeria given the high level of *suppressed*[4] demand. The estimation of potential level and growth in demand must incorporate these factors for greater forecasting accuracy. Moreover, power exportation to the neighbouring Niger Republic and other plans to connect Nigeria with other countries in ECOWAS through the West African Power Pool Project by 2014 should be essential in the TEP. A relative accurate estimate has been done with the MEAD and MESSAGE software of IAEA.[5]

[3] The Energy Commission of Nigeria (ECN) was established by Act No. 62 of 1979, as amended by Act No. 32 of 1988 and Act No. 19 of 1989, with the statutory mandate for the strategic planning and co ordination of national policies in the field of energy in all its ramifications.

[4] This comes from huge industries and households that use the private generators

[5] MEAD,MESSAGE see appendix 3

Based on the suggested planning factors to be adopted, an assumption is made using the recent projection in a generating capacity that should increase from 6000 MW in 2007 to 35 GWh in 2015, a six-fold increase (Ibitoye and Adenikinju 2007). This is expected to further triple to 105 GWh in 2025 before slowing down to reach 164 GWh in 2030. This system expansion is expected to eliminate current electricity poverty and raise electricity per capita from the current extremely low level of 140KWh to 1,110KWh in 2015 and to 5,000KWh in 2030.

1.4 Problem statement

According to Rittel and Webber, a transmission expansion problem can be considered as a "wicked problem" where technology issues intertwine with policy issues laden with uncertainty, making the recent problem itself a problem[6] (Rittel and Webber 1973). Hence transmission expansion which involves a pluricentric decision making requires an initial structured problem analysis that will indicate the need for a model and moreover, the appropriate modeling approach. This is also essential to avoid direct policy transplantation and mirroring of transmission network designs from other countries which can be catastrophic partly because Nigeria is a country with its peculiar cosmopolitan challenges that can only be addressed in her context and partly because, in transmission planning as a policy issue, there is no "one size fits all" (Martin, konstantinos and Mamodouh 2002). In order to get the right problem, a multi-actor problem approach was used to delineate this engineering and policy challenge and subsequently this thesis will *design the long term transmission expansion plan for Nigeria* (15 -30 years), *that will determine the technical characteristics and installation time of the new network facilities so that the total expected investment and systems operation cost (including the consumer outage cost) will be minimized while not compromising on the optimal acceptability of technical reliability and environmental challenges* .

The detail of this multi-actor, multi-criteria problem stems from the essence of liberalization of the Nigerian power sectors and the need to provide a proactive, reliable and stable transmission network *ab initio* that will ride on the accurate forecasted energy demand and supply by ECN to provide incentives to investors to help Nigeria bridge her massive energy divide. This policy approach was also done through the *issue paper* attached in appendix 2.

[6] Rittle and Webber listed 10 characteristic of wicked problems of which one of them is that "Wicked problems are problems"

The expected policy approach will be; to have and use the right decision support model that will enable Nigeria muddle through this challenge while understanding that the TEP in Nigeria is in a network based decision making arena (Bueren, Klijn and Koppenjan 2003) (Lindblom and Woodhouse 1993).

1.5 Importance of transmission expansion planning in Nigeria

As stated earlier, the circumstances for transmission expansion planning in Nigeria have changed owing to deregulation of the electricity markets leading to the separation of generation and transmission expansion .The generation expansion will be driven by market based initiatives of which adequacy can be traded, whereas the network expansion is aimed at guaranteeing the security of supply which can be seen as a public good[7] (De Vries 2004). This may imply various risks due to diversified interest of stakeholders, exercise of market power and lack of transparency especially for market that is still in its cradle. Hence there is a need for a decision making tool that will take these issues into consideration to design an optimal situation that will not only maximize welfare but minimize cost while making sure that investment is optimal.

Furthermore, the investments in transmission and generation in deregulated market depend on market signals that might be erroneous by neglecting many externalities[8]. Therefore, deceptive price signals may force developments towards suboptimal system expansion in favour of some generators over others (Joe October, 2006). This is succinct in Nigeria as the gas reserve is dominant in the southeast and most commercial centres (Portharcout, Lagos) are located there. However, the new transmission expansion planning in Nigeria should not only be based on healing and strengthening the weak existing network (which was most likely the former approach)[9], neither only on network congestion alleviation, nor on minimization of consumer costs only. Rather, a market based approach with the drive to improve competition and maximize market efficiency is a basic requirement. This is in line with the fact that abiding by the classical centralized planning methodology in a deregulated system may yield suboptimal decisions that could hinder expected competition (Cagigas and Madrigal 2003).

[7] System adequacy as a public good arise due to indifference of the customers to adequacy and risk averse nature of the investors

[8] , e.g. production external costs and loop flows of transmitted power

[9] See the new plan of reinforcement in appendix 3

Additionally, even though Nigeria is not in Annex I countries of the Kyoto protocol, the imminent call for environmental concern in energy usage processes cannot be neglected. Hence the complexity and uncertainty emanating from these concerns might mandate a planning methodology to incorporate the planned generation fuel mix development and power transmission network considering also emissions reduction targets and market structures in order to create sustainable future interconnected electricity networks that is relatively optimal (see figure 4)

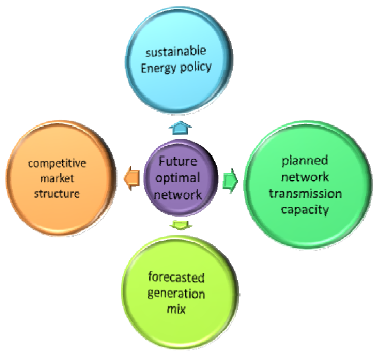

FIGURE 0-4 OPTIMAL FUTURE TRANSMISSIONNETWORK COMPONENT

1.5.1 Motivation

The main motivation of this work is the need for the use of a relatively accurate decision support model to design the long term (tactical) transmission expansions plan for Nigeria deregulated power sector, that will determine the reliable investment plans of new facilities for supplying the forecasted demand at minimum investment and system operation cost while taking the energy policies and expected generation fuel mix into consideration. The results of this work are expected to be relatively accurate although it takes inputs from the forecast of other models that could be subject to systematic error but this is considered to be minimal. This work was further motivated by the operating history of Nigerian electricity sector that just started undergoing restructuring and unbundling. ECN followed suit by having an elaborate plan for demand and supply that was carried out using the MEAD and MESSAGE model of the IAEA, which generated some detailed scenarios that can be considered as an essential input to TEPES model. In the face of these expected demand and supply scenarios, there is also a need for an elaborate transmissions network plan that will evacuate these expected generation to the various demand centers and these needs are to be developed *together*, if not the later before the former. An additional motivation is the investor’s needs for a detailed transmission plan to incentivize them to invest at the right time and place. Not only that, the dynamism of the transmission plan will provide a locational signal for the investors especially when the locational signal is essential in achieving the right proposed energy fuel mix and proper generator location distribution. This is aimed towards the minimization of investment cost relative to the demographics factors especially population and commercial activity distribution and expected growth.

The resultant decisions support system for defining this TEP (and others at large) is at the tactical level, of which the major result will be defined in terms of set of network investment decisions for the coming years.

The aim of this work is to use TEPES[10] , a dynamic transmission expansion planning model to automatically determine the optimal transmission expansion plan for Nigeria electric system that will simultaneously satisfy the three main challenging and conflicting issues in transmission planning which are the dynamism, the stochasticity of parameters and the multi-criteria operational concerns.

1.5.2 Objectives

The main objective of this work is to use an optimization decision support model to develop a tactical transmission plan for the liberalized electric sector of Nigeria leveraging on the forecasted demand and supply scenarios that were already in place. Hence this plan will use TEPES[11], a decision support model that was developed in IIT of Universidad Pontificia Comillas, that is based on DC load flow to make a binary investment decisions while considering the existing network topology as the starting point which is always preferred (J. I. Perrez-Arriaga 2009). With the candidate lines predefined including the latest tenders by TCN and other criteria such as the likely lines that can come up in the nearest future based on a priori analysis of the expansion methodology, expected historical demographics evolution and corresponding anticipated load flow analysis encompassing projected regional population growth and concentration, TEPES will automatically determine the optimal expansion plan .The expansion plan will be dynamic in the sense that the scope of the model evaluation will be several years in a

[10] TEPES Model (Long-Term Transmission Expansion Planning Model for an Electric System)
[11] http://www.iit.upcomillas.es/aramos/TEPES.htm

long term. It will also take care of the stochastic parameters that influence the optimal transmissions plan while not neglecting the stochasticity in the scenarios that are associated with the expected renewable energy sources; in the energy sources fuel mix, electricity demand, hydro inflows and fuel costs. Furthermore, the expansion plan will be multi-criteria based; implying that it will incorporate into the objective functions and other quantifiable objectives. Precisely, TEPES model will consider the transmission investment and the variable operation cost including emissions (if necessary in the case of Nigeria). Also the reliability cost that is associated with the generation and transmission contingencies will be considered in the model.

Secondary objectives includes

- Evaluation of transmission plans scenarios based on different points of view (operations cost for different operating conditions and associated scenarios, the reliability assessment of N-1 generation and transmission criteria).
- Design of a proactive plan that will be meshed in topology at minimum cost by analyzing the efficacy of the new super-grid[12] proposal and proposing a better approach if need be.
- Policy choice of the scenarios and this will be used for further strategic recommendation in the Nigeria electric sector.
- The analysis of the current legislations and regulation by NERC and recommendation in terms of access and remuneration of the proposed investments

[12] See appendix 3; the Nigerian government is proposing a super-grid network that will be at an EHV of 765KV , riding side by side of the 330KV but meshing the total network

CHAPTER 2

2 THE TRANSMISSION EXPANSION PLANNING PROCESS

The objective of most long-term transmission expansion planning (TEP) is to establish when and where to build the new transmission facilities required to economically and reliably supplying the forecasted load at minimum cost. The implied cost is in two parts- the investment and system operation cost. However, this is not best determined in a non-probabilistic approach as there are uncertainties introduced by the input parameters (e.g forecasted load and forced outage rate of lines and generators) and hence the probabilistic measure of uncertainty becomes essential.

In the deregulated electrical sector, the transmission system operators are responsible for the burden of transmission planning which in most cases is preferred to be proactive than reactive. Subsequently in Nigeria, this responsibility is for the Transmission Company of Nigeria (TCN). In this work, transmission planning will incorporate the data that was already gotten from the long term demand forecast and aforementioned supply forecast from the ECN varied out using the different scenarios. This is in line with the suggestion of Ignacio Perez- Arriaga , that in order to carry out a transmission plan, there is a need for a forecast of the demand and generation expansion / retirement plan. This, with the set criteria which can be reliability, cost minimization or welfare maximization, can be used to get the best candidate plan from different adopted scenarios (J. I. Perrez-Arriaga 2009). This is shown schematically in figure 2.1.

Because of the fact that Nigerian electricity sector just started her deregulation and restructuring, it is strongly suggested that efforts should be made to integrate this transmission planning into an indicative planning. This should be more than a scenario analysis by allowing the degree of freedom that is healthy for the Nigerian electricity market while complementing the market in many situations (Ignacio and Pedro 2008). Thus there is a need to have a plan whose aim should be to enshrine what should happen in the future into a holistic approach considering all the stakeholders, clarifying the necessary requirements to achieve the energy target in the Nigeria in time frames of maybe 10, 15 and 30 years. Modifying J Black definition, “indicative planning should attempt to promote a more stable, rapid and efficient growth in the electricity market via the exchange of forecast leading to generally held set of consistent expectations especially with the Nigerian energy market and expectation target" (Black 1968)

Transmission as a whole in electric power industry can be broken down into three segments- investments, pricing and access with each a complement to the other. In as much as all of them are important, investment is the major challenge in terms of uncertainty and technical challenges as the other two are more of a regulatory challenge than a technical constrained issue. This is the driver for the myriads of decision support tool evolving using various methodologies.

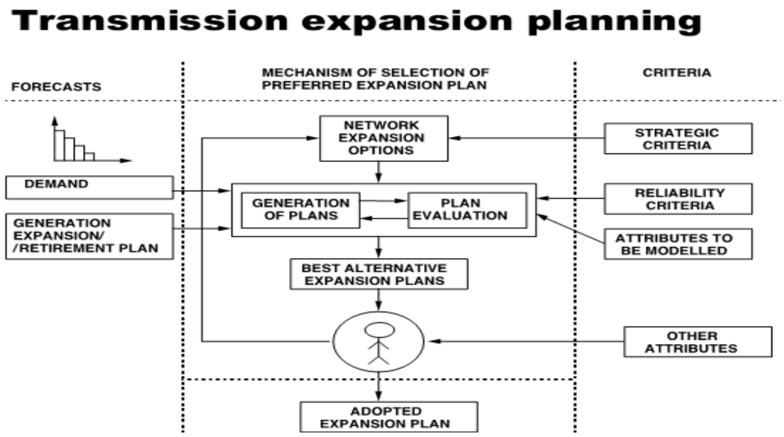

FIGURE 0-1 TRANSMISSION EXPANSIONS PLANNING IN PICTURES (SOURCE MIT OCW13)

The classic tools that are well developed and broadly applied in transmission system planning were power flow and dynamic stability analysis. These tools are more of analytical than synthesis tools and were used to evaluate the performance of proposed additions to the transmission system against reliability criteria for system performance. They led to transmission system ratings that allow transmission system operators to preserve system reliability while efficiently allocating the energy needs of the system users. In recent years, to the inability of the aforementioned approach to address operational costs associated with a given load forecast or existing profile, resource portfolio and transmission network, production cost simulation analysis has been added to the group of tools available for transmission planning. This is because production cost simulations were also used to identify transmission system congestion, and invariably these areas of the system may be candidates for economically justified expansion of

[13] MIT OCW:

system capacity. These seemingly powerful tools still have the limitation of assumption of a given network design with the implications of the specification of the networks made by the planner to the whims and caprices of his experience and engineering judgements. Thus the application of these tools in a long term scenario screening exercise will require an extensive investment of engineering and time of human resource to test a network plan for each scenario extension.

In response to this enormous amount of labour and complexity, a transportation model[14] has often been substituted for a true transmission model. This is because optimization techniques for transportation problems are developed and well understood, allowing the screening study to use lowest overall delivered cost of energy as an objective function. Nonetheless, the approximation by transportation model is poor in addressing system physics; producing transmission plans with lots of uncertainties. This is particularly true if the challenge is to compare varying cases and approaches to construction of a transmission system overlay, especially when the comparative loading between the overlay and the existing system mostly depend upon the relative impedance of the network. The neglect of these impedances implies a trade-offs between accuracy and precision in the transmission planning. In the pursuit of methods to get closer to an acceptable level of accuracy and precision simultaneously in transmission planning, an evolution of methodologies has been experienced, albeit each is not devoid of tradeoffs that others considered being relatively important.

2.1 Challenges in transmission expansion planning and modeling

The ideal transmission expansion planning model is expected to overcome a lot of challenges. These include the consideration of ohmic losses; the algorithm should consider the operation, the security and the quality cost. These cost are expected to be calculated a priori instead of a posteriori , considering a set of scenarios that were selected while minimizing the investment and load curtailment cost. Also the demand in each year in the planning horizon should be taken care of; multiple contingencies in network usually called common cause failure (failure of more than one component) should also be included. Hydrological scenarios are another issue that should be considered together with the highest uncertainty that could arise from the various limitation of the sector deregulation especially in generation expansion. It will also be preferred if model

[14] Transportation model that is basically based on Kirchhoff's first law

could establish when circuits should be installed (i.e. set out the optimal addition for each year which is called static planning). The model algorithm is also expected to be robust to redesigning, rearranging, and upgrading and respond to load curtailment cost according to its magnitude.

After liberalization of Nigerian power sector, new objectives based on market performance and market operation are meant to emerge. Then the necessity for having a proper transmission plan becomes succinct of which the concern will include the models and the algorithms that can also take care of emerging problems that was unforeseen as a result of competitive activities. This also points to an indicative planning like the one that is practiced in Peru or Colombia which will help in having a harmonic plan that will stimulate efficient investment and minimize the cost transmission service.

Another set of challenges in the design of this proper transmission planning as a subset of indicative planning, is a need for a consensus on the criteria for this planning model and its algorithm that will be optimal for all stakeholders and maximize welfare. These criteria include

- The definition of the objective function (the attribute to measure the goodness of the solution for each of the considered scenario). This can be minimum operation cost, maximum benefit/cost which might not be the maximum global welfare all the time.
- Then the definition of the decision criterion that is used to choose the transmission plan is also important. There is also dilemma in choosing between the realist view of Expected Value, the optimistic view of Maximax conditions, the pessimistic view of Maximin conditions and the opportunistic view of Minimax condition.
- The balancing between the adaptations of the transmission plan to any contingencies that was unforeseen at the time of planning at optimal cost (flexibility) and the dynamism of the plan.
- The proper correlation between the transmission planning and the generation expansion which provides the greatest uncertainty level due to the risk profile of the investors' that is sometimes affected by socio-political climate and the temporal order of investment[15].
- Also the difficulties in cost of expansion assessment, and the proper correlation between the transmission planning and pricing especially when the system is in transition stage.
- The dilemma of optimization of existing network or total planning afresh and the issue of

[15] The chicken and egg problem of who starts investments first- the TSO or the GENCO's

likelihood of flexible technologies like FACTS taking a dominant role in the future.

Even though, all these cannot be simultaneously satisfied , however most can be included in a robust planning tool knowing that the consensus on the decision making conditions might be more of a policy challenge than a technological concern and this was addressed in the issue paper using multi-actor approach in the appendix 2.

2.2 State-of-the-Art of transmission expansion planning

Network design problems is a central infrastructural problem of which the aim is to establish links (electric lines) that allows the flow of commodities (electricity) to satisfy some demand expectation which is mostly complex. An aspect of network design problems that explains long term transmission planning in deregulated environment is called Fixed-Charge Network design (FCND)problems which is built on the theory that the use of the transmission lines requires the payment of a fixed cost (e.g the cost of investment in the line construction) and then system use cost. This design approach then focuses on the selection of arcs in a graph that will satisfy at the minimum cost, the flow requirement. These arcs (transmission lines) have an associated fixed cost if they are to be a part of the solution. Transmission planning has a limited capacity hence falls in the sub part of FCND called capacitated fixed charge network design. The aim becomes to have a proper design that can yield better operation levels and investment reduction implying that this problem poses both technical and socio-economic challenges.

For a long period of time, the only tools for long term expansion planning were analysis tools such as power flow. However, because of this multi-faceted challenges, transmission expansion planning should be more of synthesis than analysis as acknowledged by Latorre et al in their detailed work for state- of- the art literature review. They defined a synthesis transmission planning model as “any calculation tool, that taking some input information as a starting point, combines different predefined transmission expansion options by itself in order to provide one or more quasi-optimal transmission plans” (Latorre, Rubén Darío, et al. 2003). This state of the art analysis is carried out from historical development perspective that shows major milestones mathematical algorithms applications and from the *problem solution* perspective that shows the major milestones in complexity of TEP tools. The reason is that most development in transmission planning still conflicts in approach and there have always been some major detours in mathematical algorithm applications.

2.2.1 Historical development of TEP

The first approach to solve this synthesis problem was in 1970, in which Garver formulated it as a power flow problem , applying linear programming algorithm to find the most direct routes from generation to loads. New linear flows were computed on the assumption that capacity in all rights of way and circuit additions were made on the largest overload (Garver 1970.). A step further in the same year was by Kaltenbatch et al with a combination of linear and dynamic programming where the linear programming was used for find the minimum cost capacity requirement for generation and demand changes while a continuous sequence of investment was deciphered using the dynamic programming (Kaltenbatch, Peshon and Gehrig 1970). An effort to apply only dynamic programming by Dusonchet and El-Abiad was very restricted due to computational and application intensity available then (Dusonchet y El-Abiad 1973).

In 1972 Fischl and Puntel proposed the concept of an “adjoin network” in combination with DC power flow model which further shaped the necessary susceptances (continuous) change to minimize the cost of the transmission reinforcements. In an effort to find the closest discrete value of these susceptances, a heuristic procedure, called “nearest neighbor method” was adopted (Fischl & Puntel, 1972). In 1979 there was an advent of sensitivity analysis approach by De Champs et al in which they used the susceptances sensitivity analysis within a linear programming formulation constrained by the DC power flow generations bounds . The objective function was formulated as a load reduction minimization problem to reduce all network operation violations (DeChamps & Vankelecom, 1979). Monticello et al further proposed its use in interactive tools for transmission planning where a sensitivity analysis with respect to circuit’s susceptances of what was referred to as a “least effort” index was used to rank the possible line additions with a resultant optimal solution that emulated DC power flow solution (Monticello, Santos, Pereira, Cunha, Praga, & Park, 1982).

Two years later, Villasana proposed two approaches .The first formulation is a combination of DC power flow model with a transportation model in which the DC model evaluated the power flow for the existing transmission facilities while the transportation model was used to compute the flow overload leveraging on Graver’s approach .The second method applied linear mixed integer formulation(LMIP) (Villasana, 1984).

Pereira et al. first applied mathematical decomposition schemes in transmission planning using Benders decomposition to break the global problem into two subproblems: the Master investment subproblems, which chooses the trial expansion plan, and the operation sub problem that analyzes the trial investment decisions and expresses operational violated constraints in terms of investment variables through Benders cuts (Pereira, et al. 1985.) .This was plagued by huge computational requirement.

Aware of these computational issues, in 1990, Pinto and Nunes used an implicit enumeration algorithm to Benders decomposition approach to reduce computational efforts in two techniques: electrical unfeasibility reduction and cost reduction. Nonetheless, the global problem formulation remained nonlinear and non-convex (Pinto and Nunes 1990).

Another decomposition method by Levi and Calovic in 1991 approached the transmission planning problem into two problems, one dealing with investments specified as a minimum cost network program decomposed into two subproblems, the first one dealt with initial load flow, which was solved by minimum load curtailment model, and; the second one used the marginal network model to obtain the superimposed load flows and other with operating decisions. (Levi and Calovic 1991)

In 1994, Latorre-Bayona and Peréz-Arriaga proposed a heuristic method that took advantage of natural problem decomposition in operation and investment subproblems. The investment subproblems is solved using a heuristic procedure in which the search was organized in a tree format and started from an initial solution provided by other models. A truncation criteria was adopted by this approach to classify the investment variables (branches of the tree representing the candidate lines), in three ways: lines included on the initial plan by the user which belong to the optimal solution called the questioned, the lines that was introduced by the user which belong to the optimal solution called the attractive and the frozen variables. There was flexibility in the width and depth limit of the search tree and limit on the number of evaluations of the operation subproblems (Latorre-Bayona and Pérez-Arriaga 1994). Prior to that, IIT has also worked on a benders decomposition approach for long term planning in 1991 of which the model PERLA, was perfect except for its constraint in dynamism (Andres, et al. 1991)

The challenge of linearity is that Benders cuts which may cutoff the feasible region , thus excluding the optimal solution was approached in 1994 by Romero and Monticelli in which they proposed the use of a three phases hierarchical decomposition approach as a solution to this challenge .The first hierarchy solved the transmission planning by Benders decomposition considering only the transportation model for the operation subproblems and relaxed the integrality constrains of investment variables. Then the network model was switched to a hybrid model (DC model for existing branches and transportation model for new branches) in the second phase. Finally, the last phase considered the DC model for all branches of operation subproblems and solved the investment subproblems by a modified implicit enumeration algorithm (Romero and Monticelli, 1994). The number of stages was still a problem.

A year later, Oliveira et al. reduced the stages of the hierarchical decomposition to two phases with slight differences. The first one considered only the transportation model but did not relax the integrality of investment variables and the second phase was equal to the last phase used in (Romero and Monticelli, 1994).The difference between these two approaches was the way of solving the master investment subproblems. While the previous approach achieved optimality in the solution using a customized implicit enumeration algorithm, the later applied a heuristic algorithm aimed at reaching only for a feasible solution in order to reduce the computational burden of solving a succession of hard combinatorial investment subproblems (Oliveira, Costa and Binato 1995).

2.2.2 Historical Approach of TEP

In a holistic approach, (Perez-Arriaga, Gomez and Andres 1987) in summary explained the general problem with a skilful candour. Another early attempt to approach it qualitatively in a comprehensive manner using optimization and sensitivity analysis was also done by Latorre (Latorre 1993) . One thing that is common in these approaches is that transmission expansion planning which is usually long time implies a horizon of more than 10 years. It is also important to realize that most practical cases of expansion of the transmission network is not just a question of reinforcing an already existing network, but may entail significant changes in network topology of which the Nigerian network requires. Furthermore, the expansion planning (especially the Nigerian case) may have to deal with disconnected networks at the early point of the planning process because of addition of new generating/load nodes to the system, or when the interconnection of previously isolated systems has to be studied. Hence the dogma of regular power flow analysis methods are not directly applicable at the early stages of the planning process and may require a more comprehensive and sophisticated approach. Hence, it becomes necessary to apply a methodology that can be basically used for screening a diverse set of expansion alternatives from which one or more attractive options are selected for more detailed consideration.

Consequently, transmission planning problem (selection of these expansion alternatives) has been arguably approached as a static problem and also as a dynamic problem and is an interesting problem as many literatures have shown (Latorre, Rubén Darío, et al. 2003) (El-Abiad and Dusonchet, 2003) (Andres, et al. 1991). It has also been seen to be deterministic or stochastic (Buygi, et al. June 2006).The static approach which is simpler and faster to implement because of less details, implies the study of the steady state system in one snapshot, in which the worst case scenario is usually analysed while the dynamic approach looks at the problem in a specific period of time taking the topology changes, demand evolution and generation evolutions into consideration. Recently a hybrid approach has been in the use which is a combination of the static and dynamic approach claimed to be a very powerful tool for large scale system because of its simplification and relatively reduced computational time (Romero, et al. Fevereiro e Março 2007). However, it has not been used mostly due to the increased complexity that has been seen in the recent times in the models and with its analysis.

Handling the planning horizon has also been approached with different methodologies. Nevertheless, indifferent as the timeframe might seem for instance one snapshot, a multi-period or many snapshots in different periods, the solution method can either be a mathematical optimization approach, a heuristic approach or a mixture of both that is referred to as Meta – heuristic. Heuristic which entails a step by step approach in generating, evaluating and selection of expansion options with or without the users help (interactive or non- interactive) makes extensive use of sensitivity analysis which is multi-objective or multi-criteria based (Perez-Arriaga and Latorre-Bayonna November, 1994) (P. Maghouli, S. H. Hosseini, et al. May 2009.), (Alseddiqui and Thomas 2006). This leaves a challenge of whether an optimal decision making in a multi-objective and multi-criteria environment can avoid optimization in place of heuristics.

This challenge has led to an optimization dominated solution, in which the transmission planning scenarios are formulated as an optimization problem with the objective function (OF) set as the criterion to measure on the same ground, the goodness of each expansion scenario. The associated limitations are formulated as the constraints which can be from environmental, technical, economic and reliability. In a case of multi –criteria system, a multi-objective optimization function may result. This optimization can be solved by different approach depending on the level of complexity as suggested by (Cohon 2004) , where it was considered that a multi- objective optimization problem with *n* decision variables, *m* constraints and *p* objectives could be formulated as in eq 2.1, with $Z_1, \ldots Z_p$ as the p objective functions

$$Max\,\{Z(x_1, x_2, \ldots, x_n,)\} = Z(x_1, x_2, \ldots, x_n,)$$

$$\{Z_2(x_1, x_2, \ldots, x_n,)\} = Z_n(x_1, x_2, \ldots, x_n,) \qquad 2.1$$

s.t:

$$\{\, g_i(x_1, x_2, \ldots, x_n,)\} \leq 0, i = 1, 2, \ldots, m \qquad 2.2$$

$$x_j \geq 0, j = 1,2, \ldots, m \qquad 2.3$$

Unlike a single optimization problem with a single identifiable optimal solution, a multi-objective optimization problem result is a set of optimal solutions usually referred to as a 'pareto optimal' which means that there is no other feasible solution that can favour one objective without affecting another. This appears in various optimizations problem formulations.

A transmission expansion problem most times is a non-convex optimization problem, where the objective or any of the constraints are non-convex[16]. This has commanded a lot of literatures that covered the genetic algorithm which has been on the high list of applications (Escobar, Gallego and Romero May 2004). The resultant measures applied are referred to as automated procedures that are appropriate for non-convex problems or for problems that poses difficulty in locating the global optimum (Chebbo and Irving 1997).

Considering the linearity and non- linearity that can be ascribed to the objective function or the applied constraints, the resultant mathematical models that uses these approach can be solved by linear programming (LP) if the equations are linear (Villasana, Garver and Salon 1985), (Alguacil, Motto and Conejo August 2003), non-linear programming (NLP) if there is non-linear element in OF or constraints (Padiyar and Shanbhag January 1988), also by dynamic programming (DP) (Newman April 2008). A large portion of differences that can be observed in the applied methods in most literatures are in the objective of the optimization. In the case of transmission expansion where there is a need to simultaneously minimize the investment cost, the operational costs and /or reliability criteria, this problem could be solved using decomposition technique like Dantzig-Wolfe, Benders, Lagrangian relaxation and Augmented

[16] A convex optimization problem is a problem where all of the constraints are convex functions, and the objective is a convex function if minimizing, or a concave function if maximizing. Linear functions are convex, so linear programming problems are convex problems. With a convex objective and a convex feasible region, there can be only one optimal solution, which is globally optimal.

Lagrangian decomposition, (Conejo, Castillo and Minquez 2006). In the case of issues like lump sum investment characteristics represented as a discrete variable, then a mixed integer approach might be appropriate. Treating integer variables is much more complicated than treating continuous variables, and this is why problems including a mixture of such variables are denominated as problems with complicating variables. .

Categorizing in terms of complicating variables and complicating constraints, complicating variable finds its solution only with Benders' decomposition[17]. A typical example is the issues of hydrothermal coordination with multiple stages that presents themselves in staircase structures can only be solved when decomposed, breaking up the hydro reserve balance equations that connect stages. A problem of the following problem structure is a major issue in deregulated power systems according to (Cerisola and Ramos 2002) and can be written as eq. 2.4

$$\text{Min z} = c^1(\mathrm{x}) + \mathrm{c}^2(\mathrm{y})$$

Subject to

$$A^{11}(\mathrm{x}) = \mathrm{b}^1$$
$$A^{21}(\mathrm{x}) + A^{22}(\mathrm{y}) = \mathrm{b}^1$$
$$x \geq 0, \mathrm{y} \geq 0; \mathrm{x}, \mathrm{y} \in \mathbb{R}^{\mathrm{n}} \qquad 2.4$$

Applying Benders decomposition, means that this central problem can be divided into the master problem regarding the investment decisions in eq 2.5

$$\text{Min z} = c^1(\mathrm{x}) + \mathrm{d}(\mathrm{x})$$

Subject to

$$A^{11}(\mathrm{x}) = \mathrm{b}^1$$
$$x \geq 0, \mathrm{x} \in \mathrm{V} \qquad 2.5$$

And the sub problem that refers to the operational conditions for the proposed investment of the master variable (x), (Sozer, Park and Valenzuela October 2008), (Orfanos, et al. June, 2010)

$$\mathrm{d}(\mathrm{x}) = \{ \min \mathrm{c}^2\mathrm{y}/\mathrm{A}^{22}\mathrm{y} = \mathrm{b}^2 - \mathrm{A}^{21}\mathrm{x}/\mathrm{y} \geq 0\} \qquad (2.6)$$

V represents the set that guarantees the stage feasibility for the first stage solutions.

Recently a semi-dynamic heuristic approach, essential for a deregulated environment where a central decision maker is responsible was proposed by (Papaemmanouil 2011) . The approach could solve the social welfare maximization problem for several discrete steps considering different preferences for environmental policy implementation or transmission network changes.

[17] The first sub-problem, called the master problem usually solves the relaxed version of the original problem and obtains a value for a subset of variables. The second sub-problem called the auxiliary problem then obtains the values of the remaining variables while fixing the first ones and these are used to generate the cuts for the sub-problem. The auxiliary problem is the original problem with the variables obtained in the master problem fixed.

Its semi-dynamism implies that although the problem could be solved for a certain time period of several years, the discrete steps (which correspond to years as only one snapshot of year is considered in each step) refer to a static representation of the system. The heuristic component refers to topology or transmission capacity changes for many marginal production costs cases in a methodology that consists of two parts, one part includes the multi-criteria analysis for providing short term information to the decision maker and the other consists of a cost benefit analysis that accommodates the decision maker with long term information of economic profitability. The combination of both parts, the so called integrated multi-criteria cost-benefit analysis, is expected to lead to an optimal additional transmission capacity in case that marginal production costs are provided. However, proper definition of social welfare is still very elusive to be precisely represented mathematically.

In summary, the state-of – the art of transmission planning evolution remains towards modeling (optimization) of which decomposition is the most attractive form of representation, although its dynamism is not very common (Ramos, Languages for model development (in spanish) 2000). The tools for developing this planning models could be a general purpose language where C language and Fortran is still the most preferred and yet to be obsolete. In the languages or environments for Numerical and symbolic calculations, spreadsheets like excel, MATLAB, MAPLE and Mathematica has proven to be very useful. However, most planning tools have preferred to use the modeling systems since it provides a good approach to analyse the optimization formulation and results. Most popular systems are GAMS, AMPL, LINGO, XPRESS and AIMMS and they support a variety of algorithmic optimization codes called solvers of which CPLEX, OSL and LAMPS are some examples.

2.3 Mathematical Decomposition in Transmission expansion problem

Knowing that Long term transmission expansion planning (LTEP) can be broken into two parts namely *determination of the optimal investments in new system capacity and the determination of the associated system operating cost and-supply reliability* naturally indicates the need and use of mathematical decomposition technique to achieve a global optimization of the investment and associated operation cost by using separate mathematical algorithm if need be. An iterative approach of a separate investment and operation sub-problems guarantees granularity, modularity, flexibility and consistency implying that modular and separate standalone models can be aggregated and used to approach this complex problem.

The TEP problem of eq2.4 can be reformulated as a minimum cost capacity expansion optimization problem shown as

$$\mathrm{Min}\ z = c(x) + d(y)$$

Subject to

$$A(x) > b$$
$$E(x) + F(y) > h \qquad 2.7$$

The decision variable x represents the transmission investment decisions with the first constraints associated to it. The variable y represents the operation decisions with the second constraint associated to it. E(x) shows that the capacity decision affects the operational decisions, making the above equation to be best approached as a two staged decomposition process.

Firstly an installed capacity decision that is feasible is made (investment capacity) x'defined as

$$A(x') \geq b \qquad 2.8$$

Leveraging on this capacity decision x', the efficient operation decision is made to minimized the operation cost d(y)

$$\mathrm{Min}\ d(y)$$
$$\mathrm{ST;}\ F(y) > h - E(x') \qquad 2.9$$

If the optimal solution to the operation problem is d(y′), then it can be expressed as a function of the capacity decision $\alpha(x)$

$$\alpha(x) = \mathrm{Min}\ d(y),$$
$$\mathrm{st{:}}\ F(y) > h - E(x) \qquad 2.10$$

This reduces the capacity problem to

$$\mathrm{Min}\ z = c(x) + \alpha(x)$$
$$A(x) > b \qquad 2.11$$

Implying that $\alpha(x)$ is the solution to the operational sub-problem for any given x provided it can be gotten. While other decomposition methods can solve complicating constraints, benders decomposition can solve complicating variable (Conejo, Castillo and Minquez 2006)

2.3.1 Benders decomposition

In benders decomposition, the value of $\alpha(x)$ can be gotten with a defined level of accuracy at the expense of the number of iteration solution of the operational problem.

The approach involves starting with an approximation of $\alpha(x)$ as its lower bound called $\widehat{\alpha}(x)$, then the capacity problem is solved for the approximation (based on the algorithm that suites the problem) as

$$\text{Min } z = c(x) + \hat{\alpha}(x)$$

$$A(x) > b \qquad 2.12$$

With its solution $\underline{z} = c(x') + \hat{\alpha}(x')$, invariably as the lower bound of the problem the original problem

The value of x' is used to solve the operational problem and the solution pair of (x', y') gives the upper boundary problem. The difference between the upper boundary and lower boundary is compared with a tolerance value to check the optimality or otherwise generate a new $\hat{\alpha}(x)$ and the iteration goes on until convergence is reached. This is achieved through benders cut which is a linear constraint formed from the associated Lagrange multipliers of the operational sub-problem that measures the change in the operational cost by the marginal changes in candidate lines.

The ability to solve the investment and operational problem differently with an upper and lower tolerance boundary most times guarantees convergence.

2.3.2 Benders Decomposition applied to Transmission expansion problem

Considering transmission expansion problem as a fixed charge network design problem, the master deals with the integer variables (line investment) while the sub-problem deals with the actual flow of electricity which is a continuous problem.

During the solution process these two sub-problems trade information by which the master informs the auxiliary about investment decisions (transmission capacity additions) and the auxiliary informs the master about transmission needs (cuts). Hence the investment sub-problem principally models the economics of the planning process while the operation sub-problem represents the power flow equations, with various degrees of detail according to the current level in the hierarchy. The auxiliary problem takes an investment plan generated by the master problem and minimizes the use of candidate generations to supply the load without violations in the set operational constraints. If at a given step of the solution process, the investment decisions are such that a feasible operating point can be easily obtained with zero generation from the candidate generators, then a partial solution has been obtained for the expansion problem and the process proceeds to the next level. Conversely, when a feasible operating point cannot be obtained without recurring to the candidate generators, important information about operation requirement is sent back to the investment sub-problem through the benders cuts which can be added to the investment sub-problems as extra constraints. Technically this can be considered very important as they inform the investment sub-problem of additional transmission capability.

The investment sub-problem deals with basically two major constraints categories which include: the number of investment variables (which might imply the maximum number of circuit acceptable in a given branch of the network for example) and an corresponding representation of the operation constraints (like the reliability indices which consists of the set Benders cuts that becomes available at any stage of the process. Hence the more the investment sub-problem knows about network operation, the better the investment decisions will be, and the faster the convergence to the optimal solution. This is due to the fact that the investment sub-problem keeps the existing cuts when it moves to next levels of network representation and subsequently learns about system operational needs as the expansion process evolves.

(Romero and Monticelli 1994) emphasized that a major obstacle to the practical application of the Benders approach is the convexity issues since the network expansion planning problem is non-convex . This issue can be more obvious in the expansion planning problem when the addition of new circuits is allowed in branches which initially do not have any circuits and he suggested a hierarchical approach to eliminate this issue. However in “generalized benders decomposition” (Geoffrion 1972) suggested the use of non-linear duality theory that allows benders decomposition to be applied to non –convex problem, making them convex by fixing set of variables.

Applying this to the transmission expansion planning implies the use of a step increasing cost capacitated network design of node arc approach that involves that the cost of purchasing a capacity for a link is given by a step increasing cost capacity function (Costa 2005).

Formulated in node arc method as

$$Minimize \sum_{(i,j)\in A} \left(\sum_{k\in K} c_{ij}^{k}\, x_{ij}^{k} + \sum_{t=1}^{T} f_{ijt}\, y_{ijt} \right) \qquad 2.13$$

Subject to

$$\sum_{j/(i,j)\in A} x_{ij}^{k} - \sum_{j/(i,j)\in A} x_{ji}^{k} = \begin{cases} d_k \quad i = O(k), & \forall k \in K \\ 0, \quad i \notin \{O(k), D(k)\}, & \forall k \in K \\ -d_{k,} \quad i = D(k), & \forall k \in K. \end{cases} \qquad 2.14$$

$$\sum_{k\in K} x_{ij}^{k} \le \sum_{t} C_t\, y_{ijt}, \qquad \forall (i,j) \in A. \qquad 2.15$$

$$\sum_{t=1}^{T} y_{ijt} \leq 1 \ , \forall (i,j) \in A. \qquad 2.16$$

$$x_{ij}^{k} \geq 0, \qquad \forall (i,j) \in A, \forall k \in K \qquad 2.17$$

$$y_{ijt} \in \{0,1)\}, \forall (i,j) \in A, t = 1 \dots T. \qquad 2.18$$

Knowing that the objective function is to minimize the sum of the variable and fixed cost as shown in equation 2.13, the variable x_{ij}^{k} represents the power flow on the line (formulated as an arc problem). Equation 2.15 is the constraint that guarantees the demand satisfaction while 2.14 ensures that the flow in the capacity is constrained to the available capacity. Various formulations of this in benders decomposition application are available (Gabrel, Knippel and Minoux 1999). The formulation that is applied in TEPES can be seen in appendix 5.

CHAPTER 3

3 METHODOLOGY

Transmission planning can be broken into three according to the temporal scope of the planning and consequently, the associated level of uncertainty: Strategic planning (15-30 yrs), tactical planning (10-15 yrs) and operational planning (up to 10 years). In this work, a tactical approach was adopted to plan the Nigerian network using TEPES (long term Transmission Expansion Planning Model for an Electric System) that was developed in the IIT[18] .

TEPES transmission expansion planning model automatically determined the expansion plan that simultaneously satisfied many attributes that includes some of the above named criteria. In dynamism, the model has a scope of 18 years in the long term horizon, representing the decisions to be taken yearly, with periods of 4 monthly (tertile), a sub-period of weekdays and week end and various load level (Ramos 2001).

The issue of stochasticity is grouped into operations scenarios (hydroelectricity etc) and reliability scenarios (generation and transmission contingencies). Also, the model is multi-criteria based, considering the transmission investment and variable operation cost (including generation emission cost), reliability cost associated with generation and contingencies arising from transmissions. For the later, the optimization method uses a functional decomposition based on Benders decomposition between an automatic plan generator (master problem) and the evaluator of different characteristics like operation costs for diverse operating conditions, reliability assessment of N-1 criterion in generation (sub-problem) etc.

The evaluator (Operation model) is based on DC power flow considering that transmission investment decision is lump-sum and thus binary. (Roman and Grzegorz Oct,2005) showed that DC power flow emulates (AC) optimal power flow (OPF) and despite all of the progress that have been made, the full AC OPF has not been widely adopted in real-time operations. Instead, system operators often use simplified OPF tools that are based on linear programming (LP) and decoupled DC system models. Historically, this was mainly due to the lack of powerful computer hardware and efficient nonlinear AC OPF algorithms. However, with the advent of low-cost parallel computers and the continued progress of silicon integrations, the speed has now become a secondary concern, after the algorithm robustness. The remaining prevalent argument for picking LP-based DCLF over NLP-based AC OPF is that LP algorithms are deterministic and

[18] http://www.iit.upcomillas.es/aramos/TEPES.htm

always yield solutions albeit not necessarily the desired ones, while the NLP algorithms are less robust and experience slow convergence or even divergence in worst-case scenarios.

TEPES was created using GAMS 23.7 under Microsoft window 7 and uses CIPLEX 12.3 as MIP solver. Figure 3.1 will be used as the basic framework that is adopted for the network planning tailored to be in line with the planning objectives of Nigeria.

3.1 Transmission Planning Objectives for Nigeria

In general, the main objective of transmission expansion planning in the restructured electric power sector of Nigerian is to provide a non-discriminatory competitive environment for all stakeholders while not compromising on the level power system reliability. Hence, the expectation of this TEP is to provide for the requirements of stakeholders that are indicative which should drive investment in generation and other aspects of the power sector that will help achieve the energy policy goal of Nigeria. This is in line with the Nigerian grid code section 3.15 which stipulates that the objectives should include but not limited to

- Encouragement and facilitation of entrance and competition among electric market participants;
- Provision of non-discriminatory access to cheap generation for all consumers especially in the southern part of the country with abundance of gas
- Alleviation of transmission congestion and hence rational reduction of stranded generation which will reduce the network charges
- minimizing the risk of investments through minimizing the costs of investment and operation;
- increasing the reliability of the network while not compromising on the flexibility of system operation;
- Minimizing the environmental impacts.

Hence, to address these issues, the methodological approach of this transmission planning first considered the influence of uncertainty especially from the inputs.

3.2 Uncertainties and Lack of precision in data

The uncertainties that are associated with TEP can be classified in two categories: *random* and *non-random* uncertainties. Random uncertainties are variations of those parameters, which are repeatable with a known probability distribution. Hence, their statistics can be derived from the historical values. Example is uncertainty in load. Non-random uncertainties are from evolution of parameters that are not repeatable, and hence, their statistics cannot be derived from the past observations. Its example is the uncertainty in generation. Within these two broad categories of uncertainty, there are data that cannot be *precisely* expressed and they are referred to as fuzzy or vague data and the challenge in modeling them is different from the approach of the of the data that are clear.

Since the implications and methods of modeling random and non-random uncertainties differ from the approach due to the degree of vagueness of data in power systems, it is essential to identify their sources *ab initio* through separate methodologies and classify them as input to the TEP model. For the current status of Nigerian powers system, the most likely sources of random uncertainties are

- load sizing ;
- Cost of generation and consequently likely bid of expected generators;
- power production and bid of independent power producers (IPPs);
- wheeling transactions;
- Availability of generators, lines, and other system facilities (EFOR).

While the sources of non-random uncertainties are from:

- generation expansion/retirement;
- load growth rate;
- Transmission facility expansion and retirement time , cost and rate;
- Evolution of market rules

The likely source of lack of precision and ambiguity in criteria arises from the subjective decisions concerning the various uncertainties ascribed to the

- importance degrees and hierarchy of stakeholders in decision making;
- importance weights(degrees) of planning criteria from the viewpoint of different stakeholders;
- Occurrence degrees of possible future scenarios.

Probabilistic methods running inside the TEPES Model was used to take care of random uncertainties. Scenario analysis that is also in TEPES incorporated the non-random uncertainties while the ambiguity or vagueness was analysed in the issue paper using the policy analysis of multi-actor systems.

3.3 Model overview and use

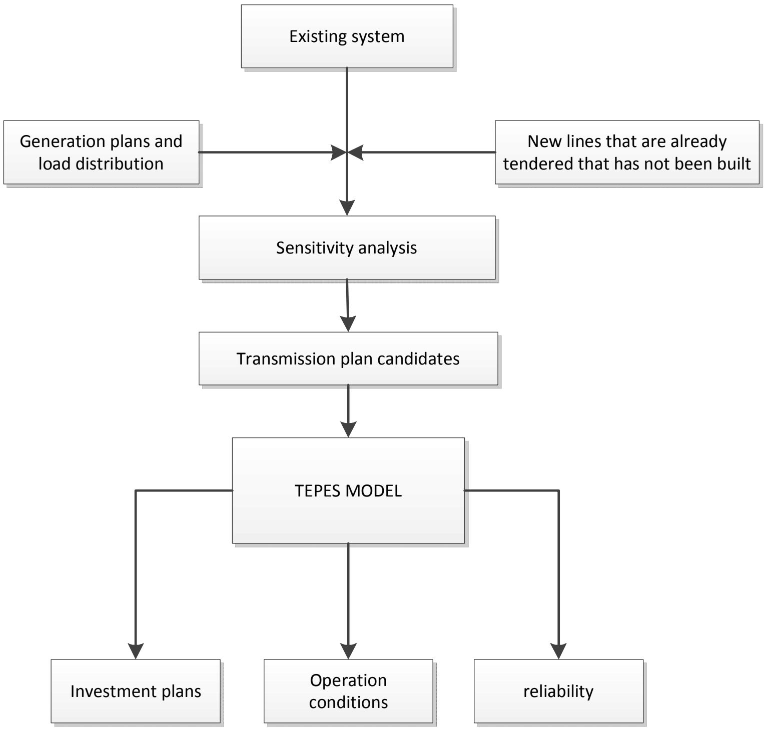

FIGURE 0-1 METHODOLOGY FRAMEWORKS FOR TRANSMISSION EXPANSION PLANNING

In model formulation for electricity market, there are usually three aspects based on the level of focus- Physical, commercial and economic. The physical aspects of the model that depicts the physical characteristics of the context, the commercial aspect of the model that shows the market influence and the economic aspect of the model that shows that equilibrium formulation (Baldick 2010) . TEPES, even though can be seen to be more physical[19] and economic oriented[20], did justice to the commercial[21] aspects.

Using TEPES for 18 years transmission expansion planning (up to year 2030) in Nigeria is partly because a transmission expansion is tactical and TEPES is tactical (15-30 yrs) oriented and partly because the available data for demand and supply model is for 2030. The TEPES model output is the optimal transmission which is defined here as the decisions that minimizes the total annual investment , production and reliability cost in one year horizon across the multiple years that was

[19] Representation of the transportation and DCLF , thermal, voltage and stability constraints etc
[20] Takes of transmission constraints and congestion
[21] Shown in the LMP and the power flow rates.

considered. These decisions are formulated as linear objective function and linear constraints that results from the Benders decomposition process. The decisions variables include the lines that will be installed, the associated output of the generation units (unit commitment), and the power flows that corresponds to the investments. The short range marginal costs and the water values can also be observed. In Nigerian context, the use of TEPES is not only useful for the proposal of new TEP but also to check the newly proposed lines in the face of the generators that are coming up, to confirm that they are optimal[22].

Representation of the demand in the first year was done using load blocks and various load situations were considered in the cases that followed. This is partly to check various uncertainties that can arise from these loads and to make up for the loss of chronology that will arise due to the use of load blocks. Taking care of the stochasticity in hydrothermal coordination in the plan is also in TEPES and was done using scenario analysis in which different scenarios were considered for the various seasonal variations.

In representing the electric power flow system, there is choice to use the transportation model or the linearized DC flow model. This is essential as it can be used to test for the models adequacy in terms of lump sum investment. The nodes are linked in the network considering the number of circuit that can be available both for the existing lines and the candidate lines. The hydro generations is aggregated to a single unit recognizing that they can face two contingencies of energy limitation (not turbining below the minimum reservoir level due to water limitation) and the power limited (loss of turbine and turn around maintenance). The thermal plants are characterised by their availability (EFOR), rated maximum and minimum output, and the heat characteristics. The flexibility in this approach is that the variable production cost can be modified to include extra economic important that is essential in decision making.

In the output of investment modelling, TEPES decides the new transmission lines to be installed and the old corridors that need reinforcement. The investment cost which comprises of the expansion and installation cost can be derived too. The cost of the substations and the bay extensions can be gotten also[23]. In the operation sub model, TEPES uses the production cost

[22] The 765KV supergrid proposals and the HVDC on 132KV level for connections of hinterlands
[23] Included in the cost of lines

model which looks at the system normal operation to check the optimal units dispatch across the period while reliability aspect is used for checking the contingency.

The overview of the TEPES model as applied specifically to Nigerian case is as follows:

3.3.1 Indices

This is a description of the data that was included in the worksheet.

- Years: (*year 1: year18*) shows the length of the years that the LTEP will be planned on.
- Periods: (p01:p03); corresponds to the three major seasons (harmattan, rainy and dry) was used as the main periods for the plan. The harmattan season is usually dry and windy and occurs mostly from November to March, the wet season sets in from April to august and the remaining moths are characterised with high temperature which leads to very high power consumption due to air-conditioning requirements evident in the demand profile.
- Sub-periods and load levels: was divided into the weekdays that ranges from Monday to Friday and the remaining days of the week was categorised in a sub-period of weekends. The load levels was analysed from the load curve that was adapted to load duration curve which clearly showed three distinct load levels for each sub-periods. These were called peak, shoulder and off-peak.
- Scenarios: the scenarios were used to reflect the stochasticity in the primary source of energy and this is line with the seasonal changes too. They are labeled sc01, sc02 and sc03 with probability of 0.45, 0.35 and 0.2 respectively using historical annual average hours of occurrence.
- For the Transmission lines, the maximum number of circuits in a multi-circuit corridor was considered to be 4 both for the existing lines and the candidate lines.
- Generation technologies that were considered include the Renewable energy sources (RES), nuclear, coal, CCGT, OCGT, Hydro and oil. The thermal plants were tied to the bulk transfer stations from where they inject their power and there is provision for the relationship between hydro and corresponding reservoirs.

3.3.2 Nodes

For understanding the networks, Nigeria categorize according to 6 *areas* which corresponded to the six geo-political zones viz **North-Central, North-East, North-West, South-East, South-South and South-Wes**t. This was done using the consumption pattern, the load centers distribution and the former network configuration approach. Then the easiest way to derive the zones from these areas was to use the states of the federation, as Nigeria has almost a "one city state system" where the state capital is apparently the major load centre in the state (more than 75% of power consumption) except for few commercial cities like Kano, Lagos , Abuja and Rivers. This yielded 36 zones. The major substations in the zones (states) were gotten from the TCN of Nigeria were 136 number (see appendix 4).Nodes for the contracted lines to be built by the end of 2012 were also added as the existing nodes. *Katampe* (FCT_1) was used as the reference node which is consistent with the load flow analysis that has been carried out by the TCN.

3.3.3 Energy Demand and Supply Projections

In as much as it is laid down in the grid code of Transmission in Nigeria, that Demand Forecasts and associated factors are essential in transmission planning and the System Operator (TCN) should take a lot factors into consideration when conducting this long term Demand Forecasting, it is also a crucial part of the TEPES model. The factors that were taken into consideration in calculating the *demand data* for TEPES include the historical demand data, current and anticipated future land use, population and demographic forecasts, economic growth rates; and other information supplied by users as recommended[24].

In compliance to this, an already existing data of the demand forecast with clear and international acknowledged methodology was adopted in this work to produce relatively unbiased demand forecasts for TEPES use. The Transmission Network Demand into the future is from the System Operator Energy Demand and supply Projections (2000 –2030) using MAED and MESSAGE models respectively. Furthermore, a sensitivity analysis to determine the effect of an optimistic, realistic or pessimistic long term Demand Forecast on the transmission expansion planning will be carried out to depict the implications of uncertainty for each of the scenario and forms the basis for the alternatives of the case study. Consequently, in the course of this thesis, the following assumption stands for the scenarios that will be adopted:

[24] The Nigerian grid Code section 2.1.1 – 2.2.3, 3.2.1-3.2.3

- For demography, population was considered the major driver of energy demand and the median projection of population growth by the Nigerian National Population Commission, over the study period 2000-2030, was used. By this projection, the population is expected to grow from 115.22 million in 2000 to 268.81 million by 2030, with period growth rates that decrease from 2.98% p.a. over 2000-2005, to 2.64% p.a. over 2025-2030, or an average of 2.86% p.a. over 2000-2030.
- It is expected that the new nodes will not spring up at voltage greater than 132KV, rather the growth will be seen in the capacity growth of the existing cities and hence existing nodes and even if they spring up, they will be close to the existing cities so that their effect will be negligible[25].
- Applying this to the economy, the most important determinant of energy demand is the level of economic activity and its structure, measured by the total Gross Domestic Product (GDP) and the scenarios were developed as shown in the table 3.1 below and the electricity demand is shown in the figure 3.1 below

	Electricty Demand Projections per Scenario, (MW)						
	Scenario	Year 2005	Year 2010	Year 2015	Year 2020	Year 2025	Year 2030
SC01	Reference (7%)	5746	15730	28360	50820	77450	119200
SC02	High Growth (10%)	5746	15920	30210	58180	107220	192000
SC03	Optmistic I(11.5%)	5746	16000	31240	70760	137370	250000

TABLE 0-1 ELECTRICITY DEMAND PROJECTION SCENARIOS

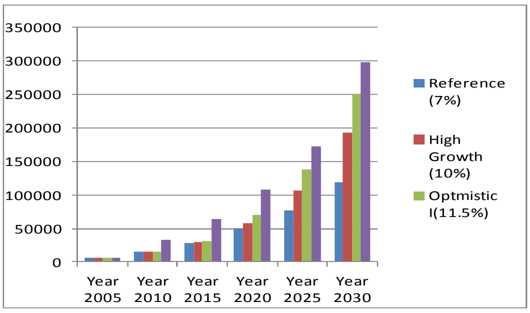

FIGURE 0-2 PROJECTED ELECTRICITY DEMAND SCENARIOS

The result of these scenarios was from the IAEA Model for Analysis of Energy Demand (MAED) was used to forecast the electricity demand spread over to 2030 in 5 years interval.

The electricity supply was also done by the IAEA model called Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) and the result of this planning is summarized in the table 3.2 and graph 3.3 below.

[25] Historical demography have followed this pattern except when new states were created

	Electricty Supply Projections per Scenario, (MW)						
	Scenario	Year 2005	Year 2010	Year 2015	Year 2020	Year 2025	Year 2030
SC01	Reference (7%)	6440	15668	28356	50817	77450	136879
SC02	High Growth (10%)	6440	15861	30531	54275	107217	192079
SC03	Optmistic I(11.5%)	6440	15998	31235	71964	177371	276229

TABLE 0-2 ELECTRICITY SUPPLY PROJECTION SCENARIOS

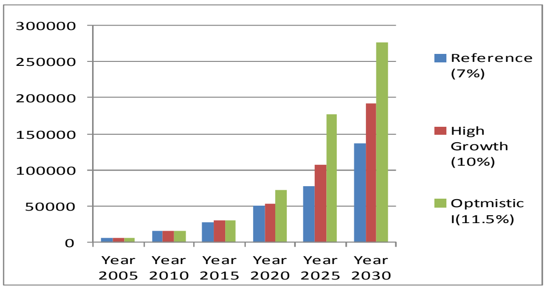

FIGURE 0-3 PROJECTED ELECTRICITY SUPPLY SCENARIOS

A detailed result of this forecast and the data that is of importance to be used in TEPES model is attached in appendix 4.

3.3.4 Load blocks from load duration curve

From the load duration curve, a set an approximate load blocks for the three periods of the year shows that for each week day, there are three distinctive load levels labeled *peak*, *shoulder* and *off-peak* and this is different from the peak , off-peak and shoulder for the weekends also.

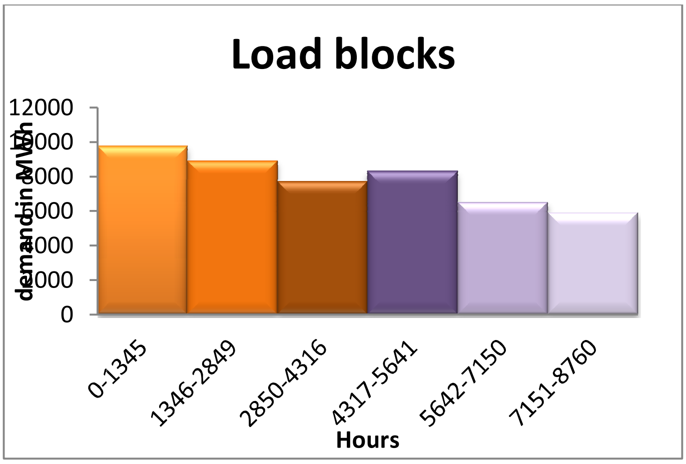

FIGURE 0-4 LOAD BLOCKS

3.3.5 Calculation of demand for TEPES model

Because of clarity for demand data for each of the node, for each of the scenarios and for each of the load level, a simple linear approximation and extrapolation method was used.

The population of each of the *nodes* and that of the *areas* over the past 25 years was gotten from the national population commission[26] and a linear regression model of nodal population growth

[26] Nigerian population commission

and the percentage contribution to the area was formulated using the historical data. Then the expected energy demand from the MEAD-el Model was shared according to percentage of contribution to the total demand (average participation). Subsequently, to generate this for all the scenarios and for all the load levels, a percentage contribution method was used from the load duration curve to distribute the resultant contribution of the node to its corresponding scenarios and the associated load levels.

3.3.6 Operating reserve

Operating reserve is another essential input to the model and this was calculated for every load level in each period and this was done for every scenario (sc01- sc03). Because of lack of general consensus on the formula for the calculation of the operating reserve, a method was adopted to include the largest unit, the percentage of hydro, percentage of thermal and percentage of intermittent renewable sources.

Operating reserve = Max (largest unit, (0.03*ThermCap + 0.07*HydroCap+0.5* InterCap))

Where *ThermCap* is the total thermal capacity, *HydroCap* is the total hydro capacity and *InterCap* is the total intermittent sources capacity. This was carried out for every scenario.

3.3.7 Generation

The generators were 82.3 percent thermal (existing and candidate), 0.0003 of wind and the rest of the capacity is accounted for by hydro plants of which newest Mambilla hydro – station will contribute to about 40% of the hydro capacity for the base case. The candidate plants accounted for the 23% of the thermal generation which are the plants that were certain to come online by the end of 2012 except for the nuclear that could be online by the end of 2015. The stranded generation due to transportation problem (evacuation and gas transport) accounted for the 55% of the remaining thermal generation. The reason of adding these generators was that the earlier estimated demand profile took them into consideration. However, this does not represent the expected energy fuel mix that was in the energy policy of Nigeria although there is a room for the accomplishment of this without a dramatic effect on the transmission plan.

For the hydro generation, the reservoir maximum and minimum capacities were considered and the inflow was also taken care of. The inflow is the aggregated inflow of the main river of the reservoirs and the other tributaries that enters into the reservoir. However, because of the multi-use implication of the reservoir, the natural inflows used in the scenarios were the inflows during the seasons (scenarios) compensated for the losses for other purposes[27]. Furthermore, the implication of reservoir and hydro plant above a reservoir was taken care of in Kainji which is located above the Jebba hydro plant.

For the thermal plants, the technologies that are involved were dominated by OCGT plants, then CCGT, hard coal, oil and Nuclear. The fuel cost for each of the scenarios for the thermal plants was gotten from the fuel cost projected by the MESSAGE model of IAEA. The carbon cost used for now is the carbon cost of Australia (25€/ton) which is relatively high but was used in order to stimulate the ingress of RES in the Nigerian power system, hence preparing them for the future (towards indicative planning).

	sc01	sc02	sc03
Nuclear	0.58	0.58	0.58
Hard_Coal	0.07	0.07	0.07
Imported_Coal	0.10	0.10	0.10
Oil	5.80	5.80	5.80
CCGT	0.20	0.20	0.20
OCGT	0.20	0.20	0.20

TABLE 0-3 FUEL COST FOR EACH OF THE FUELS

3.3.8 Generation growth

The generation growth is incorporated in TEPES in form of the year that they are going to come online. To take care of this two approached were used. In the first case, the generation fuel mix evolution in Nigeria was used to design fictitious generators that are placed arbitrarily on the network especially concentrating in the south and east where there is abundance of gas. Then the second case were placing the generators looking at the load concentration of the nodes and the natural resource endowment while respecting the expected generation fuel mix in appendix 3.

However this can be formulated as a generator placement optimization MIP problem that is cost minimizing where at each node *n*, the sum of the demand q_{nt} and the total generation g_{nst} of all plant *s* have to be equal to the net injection i_{nt}. Power plants *s* that is running, has upper and lower limit g^{max} and g^{min}. Moreover, the power flow on the lines *l* remains below the max power p^{max}. The power flow is a DC flow but TEPES already have generation and network contingency included. If the demand is fixed for a yearly period *t*, then the model can be adjusted to fit new generation placement which will be considered an endogenous parameter instead of exogenous.

[27] Agro use, drinking, evaporation etc

On assumption of a benevolent planner that seeks welfare maximization (maximization of total cost), the new generators for plant extensions g^{new} will be located in a node *n* by building a new plant *e* through a locational choice variable b_{ne}.

$$\min_{g_{nst}, i_{nt}, uc_{nst} p_{lt}, b_{ne}, g_{net}^{new}} \left\{ TC = \sum_{n,s,t} c_{ns} g_{nst} + \sum_{c,e,t} c_{ne}^{new} g_{net}^{new} \right\} \quad OF \qquad 19$$

$$|P_{lt}| \leq P_l^{max} \qquad \forall l, t \quad \textit{line flow constraint} \qquad 20$$

$$\sum_s g_{nst} + \sum_e g_{net}^{new} - q_{nt} - i_{nt} = 0 \; \forall n, t \quad \textit{energy balance eqaution} \qquad 21$$

$$uc_{nst} g_s^{min} \leq g_{nst} \leq uc_{nst} g_s^{max} \forall n, s, t \qquad \textit{generation constraint} \qquad 22$$

$$b_{ne} g_e^{min} \leq g_{net} \leq b_{ne} g_e^{max} \; \forall \; n, e \quad \textit{extension generation constraint} \qquad 23$$

The total numbers of new plants are restricted to the maximum number of new plants P_T

$$\sum_{n,e} b_{ne} \leq P_T \qquad \textit{extenion limit} \qquad 22$$

Thus considering a specific node *n* the required additional generator to satisfy the demand (equation 21) capacity has to be built up at the node by setting b_{ne} to 1 (equation 23) which in turn reduces the number of available generation units that is approved to be built (equation 24).

One thing is very essential for this to be valid. First, there shall be availability of the fuel type for the generators in all nodes, implying that gas pipeline networks needs to be available in Nigeria and rail networks also. However restricting some type of generators as a subset to specific sets of nodes could solve this bottleneck.

3.3.9 Networks

In as much as TEPES chooses the optimal solution when given the candidate lines, it still uses the existing condition of the network as the starting point. Hence the network section is divided into the existing network condition and the candidate lines.

For the existing lines, the longitude and latitude of the connecting points is used to define the lines (e.g. line FCT_1 – FCT_2), then the voltage level of the line and the distance in Kilometer. For Nigeria, there are two existing transmission voltage levels at 132KV and 330KV. The line parameters were gotten from the load flow analysis where the capacities were earlier defined.

The resistance and capacitance of the lines were also gotten in per unit. Then the most important parameter is the capacity of the line since the rating does not correspond to the amount of power that it can wheel at every particular time. The Net transfer capacity (NTC) is defined in TEPES as the product of the total transfer capacity (TTC) and the security coefficient (in p.u). However the TTC of the line depends on mostly three factors namely the thermal limit, the voltage limit and the stability limit of which the value varies and the worst case overrides the others. Hence the TTC of the lines were determined as

TTC = Max (thermal, voltage, stability limit)

This was done for the candidate line but with a little variation as explained below.

3.4 Candidate lines identification process and framework

Before using TEPES, it is expected that the candidate lines be identified and this concurs with the benders decomposition that runs in the algorithm. In transmission planning, the set of possible expansion plans is very large since between each two buses a new transmission line can be constructed. Therefore there are $n\ (n\text{-}1)$ possible candidates for expansion of an n bus network[28]. Most of these candidates do not satisfy the constraints of planning and must be eliminated and this was systematically approached using some index calculated and also with a static load flow analysis of the load in 2030 (using powerworld™) which helped in the extraction of the power transfer distribution factors (PTDF).

3.4.1 Criteria affecting selection of candidate lines

Firstly, there was an inclusion of the already contracted line of which their auction and tenders has been completed (see appendix 3), combined to the existing network to identify the critical paths in the networks. The criteria for critical path were based on many factors which include lines that connect major cities and generating stations (both existing and candidate) that transmit large amount of power. Also big nodes (load centres) connection to large stations was considered for power evacuation. Then a load flow analysis was used to identify critical lines and nodes from the critical paths, for the selected scenarios of different generation fuel mix and demand levels from the already developed scenarios. Existing lines with probability of overloading was considered to be either reinforced, build an adjacent lines by them or promoting the use of new technology like HVDC. Also the location of candidate generators influenced the decisions

[28] This gives 128*127 candidate lines in Nigeria

especially when this is going to drive the need for greener technologies adoption and proper utilization of primary energy source.

With regard to the transmission voltage requirements for each candidate lines , for meeting the system load and generation projections to year 2030, two alternative patterns of transmission development were most apparent: The continued expansion at 330 kV, or an introduction of a higher voltage class, such as 765kV, as an overlay on the existing 330-kV network. A heuristic approach based on transmission distances and capacity was used as explained in the following sections.

In the choice of strengthening the congested and most likely to be congested transmission corridors, the first approach was to mesh the network that was already radial using the highest existing voltage of 330 kV AC. This provided the first set of 29 candidate lines. Then the next approach was to solve the problem of power evacuation at minimized cost[29]. There is a lot of gas and coal in the southern part of Nigeria and the deregulation has attracted up 15000MW of generation to be installed before 2015 and this needs to be evacuated to the North and other load centers. Knowing that line reinforcement can relocate problems[30] (Stan Mark 2009), there were two approaches.

- For bulk power transfer (generation at above 1500MW) a higher voltage level was considered (765KV) for candidate lines
- For hauling of power from generation centres that are remote to close load centre or from major load centres to relatively smaller load centres without the need to stop in the middle, a HVDC candidate lines were suggested.

3.4.2 The 765 KV Supergrid -justification

The introduction of 765-kV voltage class as an overlay on both the 330KV and 132 KV network is essential for the continuation of the basic philosophy that a strong transmission network, adequate at all times to meet the most severe outage conditions, is indispensable to the successful operation of a fully integrated Nigerian power system especially after deregulation[31].

29 Heuristics was used since TEPEs will choose the optimal plan

30 Strengthening lines does not always solve congestion problem as it might relocate congestion problems

31 Presidential policy on power

In concordance, the earlier suggested 765KV super grid by the TCN was supported in this expansion planning not only because of the political affiliation but for other reasons like the basic economic soundness of transferring the primary burden of bulk power transmission of the relatively Nigerian weak network system from 330 to 765 kV. It was also based on a broad appraisal of the transmission capability characteristics of 765 relative to 330 kV, the comparison of cost per kilowatt of power transmitted at 765 versus 330KV for a range of distances applicable to the Nigerian system; and the consideration of the cost per kilovolt-ampere of capability of a 765- versus 330-kV network, taking into account the cost contribution of each major category of equipment (AEP 2010). Furthermore, from the perspective of resource conservation, a single-circuit 765-kV line can carry as much power as three single-circuit 500-kV lines, three double-circuit 330-kV lines, or six single-circuit 330-kV lines, implying a massive reduction on the overall number of lines and rights of way required to deliver expected equivalent capacity. Moreover the high capacity of 765-kV can easily facilitate the efficient and economical integration of large-scale renewable generation projects into the nation's transmission grid as projected in the expected generation fuel mix with the least required right of way (Gutman and Pugh 2007).

In terms of performance and design efficiency, power losses in a transmission line decrease as voltage increases. The implication is that the 765-kV lines that uses a higher voltage experiences the least amount of line losses. Higher transmission efficiency of 765-kV can be attributed mainly to its higher operating voltage (and thus lower current flow) and larger thermal capacity/low resistance compared to lower voltage lines. This also allows 765-kV lines to carry power over significantly longer distances than lower voltages. With up to six conductors per phase, 765-kV lines are virtually free of thermal overload risk, even under severe operating conditions (Dunlop, Gutman and Marchenko 1979). This implies that by shifting bulk power transfers from the under lying lower-voltage transmission system to the higher-capacity 765-kV system, overall system losses are reduced significantly. New 765-kV designs have line losses of less than one percent, compared to losses as high as 23 percent on some existing new lines. The overlay of a 765-kV system allows for both scheduled and unscheduled outages of parallel lower voltage lines without risk of thermal overloads or increased congestion.

Looking at costs minimization shows that the use of 765-kV technology takes advantage of economies of scale as a typical 765-kV line costs approximately €3.04 million/Km. For equivalent capacity, three 500-kV lines at a cost of €7.9 million/Km or six 330-kV lines at a cost of €11.06 million/Km would be required. In other words, 765-kV construction is only 29% of the cost of 330-kV and 39% of the cost of 500-kV for a comparable system. Furthermore, utilizing 765-kV will result in a substantial reduction in system losses. For example, a loss reduction of 250 megawatts, equates to saving as much as 200,000 tons of coal, and 500,000 tons of CO2 emissions per annum. Not only that, the addition of 765-kV systems relieves the stress on underlying, lower voltage transmission systems, postponing the potential need for upgrades of these networks. This results in additional savings for end-use customers over time.

3.4.3 Reducing the candidate lines to a sizeable number

As stated in section 3.3.1, the number of transmission candidate lines can be enormous and this affects the number of iterations of the benders decomposition and computation power. Hence the most important lines have to be added and this demands a methodological approach.

The first step in this approach was to select All Possible Candidates (APC) in order to form a mesh network with voltage profiles based on the afromentioned criteria. This was then reduced to All Feasible Lines (AFC) by removing the likely excess lines due to environmental or technical violations. The AFC was reduced to All Good Candidate (AGC) by retaining only the lines that achieves the following ranked by attractiveness of choice

- Connect one or more buses to avoid islanding
- Reduces overload using the static load flow
- Improves power transfer profile (considering higher voltage profile)

Then from the AGC, all the lines were singly removed to check the one that causes islanding and about 21 lines were selected called $\boldsymbol{La}$. With La, the remaining candidate lines from AGC were used to calculate the first index called candidate Evaluation function 1

$$\text{Candidate Evaluation Function 1 (CEF1)} = \sum_{i \in L} OC_i$$

Where L is the set of candidate lines, OC_i is the Overload capacity which represents the difference between the limit during normal loading conditions (LNC) and the available capacity limit (ACL). The most attractive candidates with lowest CEF1 that will reduce overloading were selected and called $\boldsymbol{L_b}$ taking the computing power of available computers into consideration.

Then with L_a and L_b combined, each of the remaining candidates of AGC was added and another index for Free Capacity (FC) was calculated as

$$\text{Candidate Evaluation Function 2 (CEF2)} = \sum_{i \in L} FC_i$$

FC is the free capacity defined as the difference between available capacity limit and loading at normal conditions. The candidates with the highest CEF2 were selected and called ***Lc***. Then the final candidates lines are the sum of La, L_b and Lc.

3.5 Transmission planning process framework

Transmission planning in a restructured process differs from the centralized environment and can be divided into transmission investment and transmission planning (Wu, Zheng and Wen 2006). The relationship between the external data sources and the TEPES model is shown in Figure 3.5 modified from (Wu, Zheng and Wen 2006)

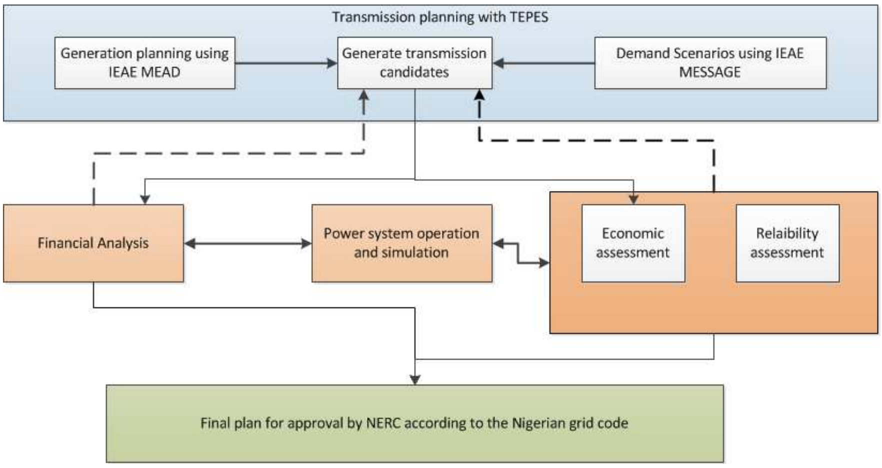

FIGURE 0-5 THE TRANSMISSION PLANNING PROCESS

Thus the approach will be to input the demand forecast and the generation plans that have been developed for the different scenarios to enable TEPES determine the optimal decisions from the specified candidate lines while recognizing the uncertainties concerning the generation expansions and forecasted load growth. In the deregulated regime, the future revenue from the transmission investments depends on the operation method of the system and the financial analysis requires a simulation of the future power system operation. The main issue behind this plan also depends on a fixed business model which is a result of the issue paper[32].

3.6 Alternative scenarios for transmission expansion

The case studies for the Nigerian TEP followed the case studies of demand and supply forecast by the ECN (hereafter referred to as A, Band C that conforms to the three scenarios of energy demand and supply growth). Based on the existing demand and supply scenario, the cases were designed in two major scenarios

1. The generation was left to follow the current trend[33] of using the abundance of gas that is in the country hence concentrating generation in the south and eastern part of Nigeria (case A1, B1 and C1)

2. The generations were distributed to the closest nodes with the types of generation ensuing from the sources of fuels that is closely available to the node. This was achieved while adhering to the future generation fuel mix that was expected by 2030 (case A, B, and C) making sure generation and demand is balanced[34].

For each of the cases (A, B and C), The energy supply evolution (see appendix 3) for 2030 less the amount of energy that is supposed to be available by 2012 was divided across 18 years adding the buffer required for the operating reserve. Then, it was ensured in the model input, that at least generators of the resultant capacity come online every year until 2030. The value of lost load (VOLL) was pegged at 3000 €/MWh.

Then each of the models was run for different consideration in the scenarios by varying some model parameters that represents uncertainties in the real world. First transportation model was used, and then DCLF was considered to valid its adequacy. The contingency in network was carried out, as well as contingency in generation while testing the CO2 price influence in a varying approach as explained in the later sections. Finally, a combination of chosen model parameters and CO2 choice was used as the final candidate alternatives. After

[32] See appendix 2

[33] The current trend stems from the need to use CCGT as a double tool – Power generation and to stop gas flaring thus encouraging gas plant locations in the south where the gas abound

[34] Including the reserve percentages

a multi-criteria analysis, decision criteria were applied to make recommendation for each likely scenario.

In the above two umbrella scenarios, the following assumption holds.

- No more nodes were created as it was assumed that the growth of the cities will be from the inside out, meaning that the existing nodes will remain the major nodes from now till 2030 and might only need expansion as the cities grows. This could change but the changes is not expected to overwhelm 132KV and sub-transmission plans which can ride on this plan
- For the generation fuel mix, the generator types found at each of the nodes were the according to the fuel type that is closest to it, reducing fuel transportation cost. This may invariably affect the unit commitment and may create disparity in cost of electricity in the country at the long run. The generation capacities are expected to grow as forecasted.
- The relative Energy non served (ENS) was considered to be in the acceptable level of 15% since almost 40% of the land mass might be very expensive to reach (like in the case of Colombia[35]) and the demand has been calculated assuming everyone in the country is involved, which is not very possible.
- No hydro reservoir was constructed after Lokoja[36] although it has a relatively very large amount of water and better flow compared to upstream. This is because of the dredging of the river and the policy[37] needs to use it for inland waterways.
- Transmission line candidates at 132KV was relatively small since it will increase the number of candidate lines at the detriment to the number of iteration and partly because it will complement the 330KV for short distances. Most candidate lines of 132KV are the HVDC that were recently considered in Nigerian transmission tender[38].

Case A (Reference case scenario)

This is the reference growth scenario with an expected GDP growth of 7% per annum which considered manufacturing to be the major driver of the growth by 2030 accounting for the

[35] Colombia reference

[36] Is the meeting point of river Niger and river Benue and has a higher volume of water and better flow.

[37] http://www.njtr.org/njtrshighlight_files/Adejare%20et%20al.%20Vol%202%281%29.pdf

[38] http://tenders.nigeriang.com/federal-government-tenders-in-nigeria/pre-qualification-of-contractors-for-year-2011-hv-transmission-lines-and-associated-transmission-substations-at-transmission-company-of-nigeria-tcn/3110/

overall 15% GDP compared to the 6% of the base year. Its implication is an expected per capita electricity consumption rise to 4000kWh/annum from 200kWh/ annum. This also means that the average electricity demand growth is about 10.6% from the base year to hit the ultimate forecasted 119200MW. The Case A is with the forecasted fuel mix while Case A1 considered the current evolution of generation installation in the south where there is abundance of gas. The results of each compared.

Case B (High growth Scenario)

This case is in the expectation of a GDP growth of 10% per annum of which the manufacturing sector will contribute to 22% of its total by 2030. This will drive the per capita electricity consumption to about 5000kWh per annum implying a demand an average electricity demand growth of about 13.25 % per annum relative to the base year to reach a total of 192GW by 2030.

Case C (optimistic Growth Scenario)

The expected GDP growth was escalated to 11.5% per annum with the expectation that the manufacturing sector could contribute to about 25% of this growth. Its implication is the increase in per capita electricity consumption to 6000kWh/ per annum by 2030 through a relative average demand growth of 14.73 % per annum that will cumulate to 250GW in 2030.

3.7 Results

The results of the model for each of the cases and in each scenario were analysed using various approaches which directly or indirectly applied the output of the model. They include the evolution of the power non served (PNS) , the short range marginal cost (SRMC) ,the amount of the lines that were added, the number of circuits for each voltage level, etc. This will be done over the planned horizon of 18 years. This is shown in table 3.4

The first approach was to conduct rough run of the model with only 330KV as the highest voltage level and with the proposed line layout of 765KV connecting major bulk generation and proposed bulk generation point. The result coincided with the theoretical analysis from section 3.4.1. Also it was observed that it was cheaper to use some 765KV, had better reliability and less candidate lines were used, thus reducing computing power. Table 3.4 the cases and scenarios using the proposed 765KV as the highest voltage level.

Cases					Installed capacity: # Circuits	Installed capacity: Length (KM)	Cost (million euros): Investment	Cost (million euros): systems operation	Cost (million euros): Reliability: Generation reliability	Cost (million euros): Reliability: Network reliability
without expected generation mix				Case A1	97	12156	28456	169254	NA	NA
without expected generation mix				CaseB1	103	12765	29212	178112	NA	NA
without expected generation mix				Case C1	114	12996	29919	181113	NA	NA
with expected generation mix	Without adeqaucy		continous investment decisions + Transport Model	Case A	79	10228	27154	91056	NA	NA
with expected generation mix	Without adeqaucy		continous investment decisions + Transport Model	CaseB	82	11079	28974	107112	NA	NA
with expected generation mix	Without adeqaucy		continous investment decisions + Transport Model	Case C	82	11079	28974	107112	NA	NA
with expected generation mix	With adeqaucy	Investment decisons	Binary investment decisions	Case A	80	10423	28006	109864	NA	NA
with expected generation mix	With adeqaucy	Investment decisons	Binary investment decisions	CaseB	84	11257	28987	116987	NA	NA
with expected generation mix	With adeqaucy	Investment decisons	Binary investment decisions	Case C	84	11329	29796	116987	NA	NA
with expected generation mix	With adeqaucy	(+) Power flow	DCLF	Case A	69	9762	14901	97322	NA	NA
with expected generation mix	With adeqaucy	(+) Power flow	DCLF	CaseB	71	10748	16083	152147	NA	NA
with expected generation mix	With adeqaucy	(+) Power flow	DCLF	Case C	78	10061	15741	143634	NA	NA
with expected generation mix	With adeqaucy	(+) Reliability	Network Contingency	Case A	63	9755	12024	161090	NA	2672
with expected generation mix	With adeqaucy	(+) Reliability	Network Contingency	CaseB	70	9835	13761	144356	NA	2206
with expected generation mix	With adeqaucy	(+) Reliability	Network Contingency	Case C	71	100632	17473	153112	NA	2712
with expected generation mix	With adeqaucy	(+) Reliability	Generation Contingency	Case A	67	9339	16010	112446	238	NA
with expected generation mix	With adeqaucy	(+) Reliability	Generation Contingency	CaseB	76	10737	13391	124698	8282	NA
with expected generation mix	With adeqaucy	(+) Reliability	Generation Contingency	Case C	74	10848	16095	115176	7904	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2Base (4€/ton)	Case A	75	9528	15845	109238	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2Base (4€/ton)	CaseB	76	10158	15845	109238	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2Base (4€/ton)	Case C	76	10158	15845	109238	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2 evolve (4€/ton + 1 € annual increment)	Case A	70	9508	18696	112013	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2 evolve (4€/ton + 1 € annual increment)	CaseB	74	9459	14935	95200	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2 evolve (4€/ton + 1 € annual increment)	Case C	81	11253	23170	100553	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2 extreme (25€/ton)	Case A	73	10375	22513	145304	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2 extreme (25€/ton)	CaseB	81	11253	23170	100553	NA	NA
with expected generation mix	*With CO2 price* +DCLF+ Binary Investment decision		CO2 extreme (25€/ton)	Case C	81	11253	23170	100553	NA	NA
combination	With CO2 price + Adequacy	Gen Reliability	CO2Base	Case A1	91	12341	17382	102765	6841	NA
combination	With CO2 price + Adequacy	Gen Reliability	CO2Base	CaseB1	89	11715	18941	88657	7085	NA
combination	With CO2 price + Adequacy	Gen Reliability	CO2Base	Case C1	85	10759	19098	104930	7888	NA

TABLE 0-4 RESULTS OF THE CASES FOR EACH SCENARIO

The analysis of the output will start with comparison across the scenarios (case A against CaseA1), across the cases (Case A across case B) and finish with economic analysis across the cases for a chosen scenario

3.7.1 Comparison across Scenarios

The assumption that was tested across each of the scenarios is the variation of the government policy on expected generation fuel mix percentages, then variation of the modeling parameters to emulate real life situations (adequacy), reliability of the network in terms of generation and network failure and the likely influence of CO2 price. Most graphs used in this analysis shall follow the peak period of the weekday since it is a good representation of the installed capacity unless indicated otherwise.

3.7.1.1 Impact of government policy – TEP with and without Fuel mix

Analysis of Case A

The fuel mix was observed, but all adequacy parameters were neglected

A total length of 10228 km of transmission lines were planned to be added in 18 years which comprises of 3750km of 765KV of 12 circuits, 5222 km of 330KV in 35 circuits and 1256 km of 132 KV in 22 circuits (of which 831 km is for HVDC in 13 circuits). The evolution of expected line installation showed a need for massive investment in the first year for a forklift upgrade of a total length of 9673 km. Subsequently a circuit is added in 2nd year, 3 circuits in the 3rd and the final circuit in 4th year and there was no other investment until year 18. However, the usage of the line (line flow) became higher with a total average capacity usage varying from 40% to 85% in the first and final year of the planning horizon. This showed the need for a fast response to meet system security requirements and then a gradual system optimization follow-up procedure over the longer term.

		LENGTH	CCT
765KV		3750	12
330KV		5222	35
132KV	AC	425	9
	HVDC	831	13
Total number of circuit			69
Total lenghth of circuit		10228	

TABLE 0-5 THE CAPACITY INVESTMENT OF CASE A IN THE FUEL MIX SCENARIO

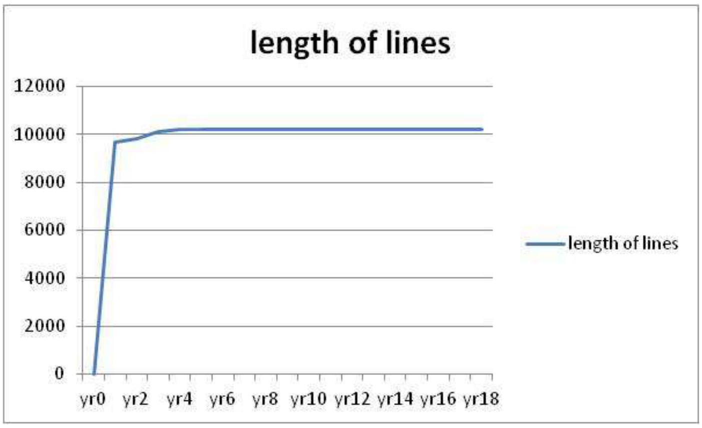

FIGURE 0-6 EXPECTED EVOLUTION OF LINE INSTALLATION FOR CASE A WITH THE FUEL MIX SCENARIO

Inspection of the evolution of the expected short range marginal cost (SRMC) revealed that it was relatively on a perpetual decline. In the first year, greater number of nodes had a very high SRMC (of 1363€) which dropped to 14€ in year 18 (see appendix 6 for samples). However, one obvious observation is the cost of electricity around the nodes that was close to the Kainji Dam and Shiroro dam experienced 0 SRMC and this has three reasons. First, this is expected because of the large capacity of the dams and smaller units that were installed leading to the spilling of water. Secondly, it has to be remembered that Dams in Nigeria contribute more than 55% of their flow for water for irrigation and drinking implying that the water spillage can be neglected and the value of water may not be very important here. Finally, because of the West African interconnection that could possibly come before 2020, Nigeria is expected to be a net exporter of electricity to Benin, Niger and even Cameroun. This is strategic to the location of the dams and even the 765 KV overlay for bulk transfer (at Kebbi, Kano and Mambilla). This implies that additional units can be added to the dams to meet up these demands[39] hence reduction of the flow to precisely what is used now could be misleading.

On an examination of the evolution of power non-served (PNS), one could observe a stable and total reduction in load shedding[40] as the years extend with the convergence of the range of PNS in each period and sub-period and each load level from 1000 MW to less than 100 MW. Even though the hinterlands could have less connection and could be better done using microgrid, this planning shows a good expectation. It is also to be observed that the percentage of PNS to the demand decreased from more than 40% of what it is currently now to about less than 3%.

The unit commitment output showed two things- First , that relatively not more generators were committed as the years goes by which is expected because of the demand increment, however, the generators showed more spatial dispersions (scattered all over the country) that early implying the contribution of local generation[41]. Even though in some the scenarios, periods, sub periods and load levels, there were more generators committed in year 1 than year 18, there was less unserved energy in year 18.

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[39] Effort to reduce the water spillage by reducing the inflows to the amount that corresponds to the value required for the generator might be erroneous due to lack of actual data and this could be speculation.

[40] Load shedding measured as a percentage of population that has to be curtailed due to generation inadequacy and this was less than 13% by the end of the eighteen years

[41] Confirmed by looking at the locations of the generators

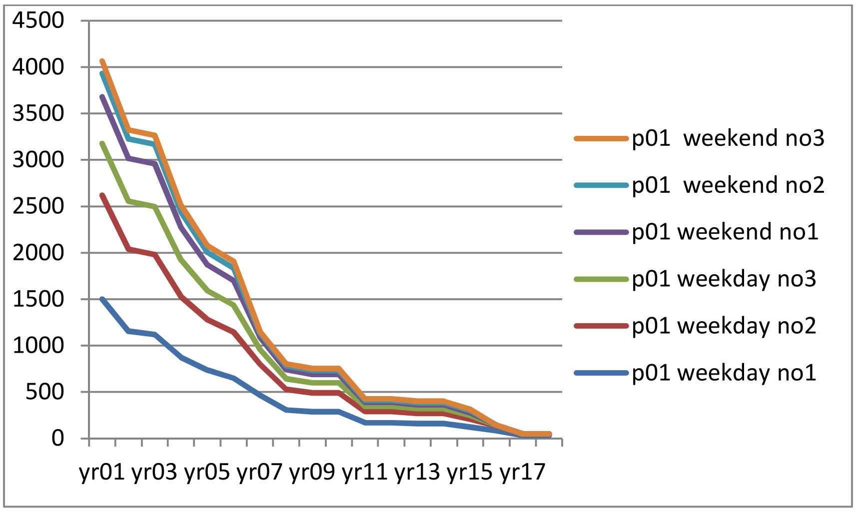


FIGURE 0-7 GRAPH OF THE EVOLUTION PF POWER NON SERVED FOR PEAK PERIOD FOR ALL LOAD LEVELS FOR CASE B

The deduction consequently is that spatial location of the generation means less network loss and thus more electric power available relative to when the generators are concentrated to one place. This also implies that less generation can be used to meet more demand and more fuel mix is represented. This can also be observed in the capacity production of each generator.

			p01	p01	p02	p02	p03	p03
yr01	sc01	SAP	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc01	IJR	1.0	0.1	0.8	0.6	1.0	0.6
yr01	sc01	DLT	0.1	0.0	0.1	0.1	0.1	0.1
yr01	sc01	OJI	1.0	1.0	1.0	1.0	1.0	1.0
yr01	sc01	GRG	1.0	1.0	1.0	1.0	1.0	1.0
yr01	sc01	OMT	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc01	PPL	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc01	ALJ	1.0	0.9	1.0	0.9	1.0	0.9
yr01	sc01	GRU	0.1	0.0	0.0	0.0	0.1	0.0
yr01	sc01	EGB	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc01	AES	0.5	0.4	0.4	0.4	0.7	0.4
yr01	sc01	AGP	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc01	OBJ	0.3	0.3	0.3	0.3	0.3	0.3
yr01	sc01	SUP	0.1	0.0	0.0	0.0	0.1	0.0
yr01	sc01	GEO	1.0	1.0	1.0	1.0	1.0	1.0
yr01	sc01	GTP1	1.0	1.0	1.0	1.0	1.0	1.0

			p01	p01	p02	p02	p03	p03
yr18	sc01	PPL	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	OBJ	0.2	0.1	0.2	0.1	0.2	0.1
yr18	sc01	CGT1	0.3	0.1	0.3	0.2	0.3	0.3
yr18	sc01	SNG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	FBC1	1.0	1.0	1.0	1.0	1.0	1.0
yr18	sc01	CoalKG	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	CoalAB	0.1	0.0	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG3	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG4	0.1	0.1	0.1	0.1	0.2	0.1
yr18	sc01	GasLAG7	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc01	BRNcoal3	0.2	0.0	0.0	0.0	0.2	0.0
yr18	sc01	YBcoal1	0.1	0.0	0.1	0.0	0.1	0.0
yr18	sc01	ZMFcoal2	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	SKTcoal3	0.4	0.2	0.3	0.3	0.4	0.3
yr18	sc01	KNcoal4	0.5	0.4	0.4	0.4	0.5	0.4

TABLE 0-6 UNIT COMMITMENT OF CASE C IN YEAR 1

TABLE 0-7 UNIT COMMITMENT OF CASE C IN YEAR 18

Analysis of Case A1

The fuel mix was not observed, but all adequacy parameters were neglected

The result was that 12156 Km total length of line was installed with a dominance of 6004 km of 765 KV, 5498 Km of 330KV lines and the rest are in the 132 KV voltage level. It was also observed that the SRMC was declining but relatively higher than the values of case A at more than 45%. Nonetheless, the power non served was decreasing at a minimum rate relative to case

A and also the power non served at the end of year 18 is 6 times more. Pockets of high cost in short term marginal cost was observed in the North-East region sequel to congestions of transmission lines and inadequate power served. The percentage of installed line usage showed wide disparity of heavy flows for lines in the South and very little flow for lines in the North relative to Case A where the flow was almost evenly distributed. The reason can be attributed to the excess generators that are located in the south and east because of the abundance of gas and the ensuing power haulage bottleneck.

Furthermore almost all the candidate circuit from south to north were added making the total number of lines to be higher than observed in the case observing the expected fuel mix, even though most transmission corridors at the from South to North were congested (100 % flow) . Moreover, even with the higher length and capacity usage of installed 765KV, it is quite difficult to evacuate the power in the south. This can be seen from the unit commitment of the generators which showed that while there was un-served energy, some generators never came online implying a disincentive to invest more. The meshing of the circuit was less than the observed in the fuel mix case (case A). There were more generators in yr 18 than yr1 on the contrary to what was observed in case A and also more capacity of the generators being used in yr 18 than yr1. There is more flow in the line in year 18 than year 1 showing that the existing lines that were in use were overloaded due to generation concentration in one area and also , in adequate transmission lines.

Another scenario that would have been added was the extension of gas pipelines to the North to provide level playing field to the agents especially for gas thermal plant infrastructure. This was neglected because, despite the lack of information in analyzing the incorporation of the cost of the gas pipeline, there are other disadvantages. This includes the single point of failure especially when one loses the major gas pump stations and the implied cost of having multiple stations. Furthermore, it could give access to political turmoil making one geopolitical zone to be the hub of power generation which could also provide and heighten terrorism appetite. Moreover, it could not be easily disproved that it limits competition for the greener technologies whose abundance is in the North, hence jeopardizing the future generation mix policy.

With these reasons, it becomes apparent to analyse across the scenario that respects the forecasted generation fuel mix Not only because of the disparity that can be seen in the amount of lines that evacuated less power, but also in the investment and system operation cost that was 2.6% and 5.3% more when the fuel mix was not respected. The above observed trend also applies to case B against B1 and C against C1 in similar evolution.

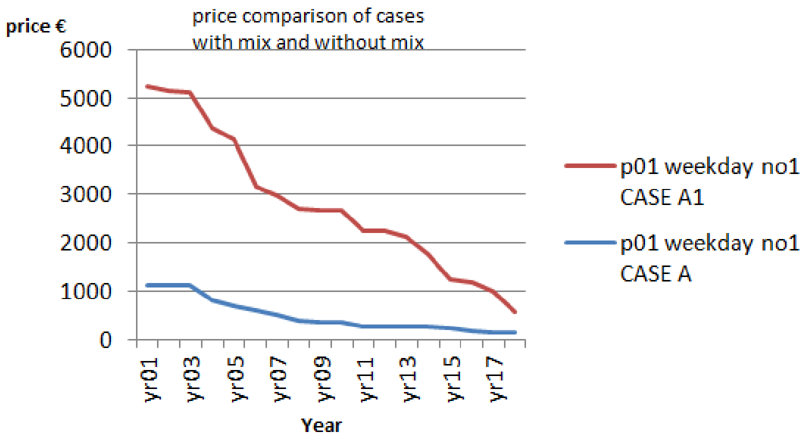


FIGURE 0-8 PRICE EVOLUTION COMPARISON OF CASES WITH FUEL MIX AND WITHOUT (CASE A *VS* A1)

3.7.1.2 *With the fuel mix and checking the adequacy of model parameters in steps*

The case of respecting the fuel mix but ignoring the adequacy of model settings (the parameters settings that compares the discrete versus continuous investment decisions and transportation versus the DC load flow (DCLF) models of the line flows)

It was observed that for all cases, there was an underinvestment's when the model ran on transportation flow model and continuous investment settings compared to when only the binary investments and transportation settings was observed. The reason can be attributed to the fact that binary investments takes care of the lumpiness of transmission investment and hence more lines were installed and consequently more investment and systems operation cost.

However when DCLF[42] was used in addition to the binary investment decisions, it was observed that the flow pattern changed in the output. Lines were more used than when transportation model (Kirchhoff's first law) was used. The implication is that fewer lines were installed in all cases and the investment and system operation cost was drastically reduced. Nevertheless, the

[42] Was only used in parallel candidate lines

tradeoff between transmission CAPEX and system operation OPEX can be a conflicting policy issue.

On the addition of generation contingency, less number of circuits was marginally observed; albeit, this was at a cost. The investment cost was higher but the system operation cost was lower for all cases also. The reasons were that higher number of 765KV and 330KV were installed and the pattern of circuit connection was different. This translated to a slightly higher investment cost on less number of circuits but lower system operation cost.

The deduction was the need to respect the fuel mix policy in order to avoid overinvestment, include the binary settings to take care of lumpiness of investments, include DCLF to emulate the natural flows of electricity and avoid overinvestment's and finally , check the contingencies to avoid lower operation cost assumptions. Moreover, the evolution of electricity prices for all the scenarios in the chosen cases (eg case A and A1) shows that electricity prices are better in all scenarios when the fuel mix is taken into consideration than when the fuel mix is not given that there is no plan to have a gas pipeline in the country. This is evident in figure 3.8 below that shows that wide range in the price for the first period in the first scenario for the peak period in the week day.

3.7.1.3 Carbon prices, with fuel mix, binary investment decision and DCLF in the model

The influence of carbon price was added in the plan following the influence rising awareness of climate change and the need to include it in planning even though it might not be observed in the new Nigerian electricity market and this was done in the model in three steps: the first was to use a very low carbon price of 4€/ton called *CO2 Base*, then a base of 4€/tom with a 1€/ton increment per year called *CO2 Evolve* and extreme case of 25€/ton called *CO2 extreme*.

Generally, it was observed that the lower the CO2 value, the lower number of circuit installed and this is also averagely lower than when CO2 price was not taken into consideration. The reason is that more generators were committed over the years in the south because of the gas that has lower CO2 compared to the coal that is found in the North. This translates to more lines that were needed to evacuate power generated in the gas abundant south.

Incorporating a value for the *carbon emission* (Ranging from 4 €/ton to 25[43] €/ton) even though it favored the production with CCGT that are likely to be located in the south (showed by more unit commitment of CCGT), the observed variation was not far from the model output without CO2 price. The reason is that the commitment of the CCGT was limited by the amount of transmission corridors that could be installed[44]. Nonetheless, there was a variation in the number of lines that came up (longer in kilometers by approximately 2000 Km at the end of year 18 years horizon) when avoiding the fuel mix and installing most of the generators in the south and when adhering to the fuel mix and incorporating CO2 prices. Thus, the deduction was that the prices of electricity could most likely be better when the expected generation fuel mix is adhered to even when C02 price is added. It was also observed that the system operation cost was much lower which can be likened to the fuel price and CO2 price.

3.7.1.4 The implications of transmission planning respecting the expected Generation Mix

Using a transmission planning that respected the forecasted generation mix has a lot of implications in the power system. Despite the reduction in the line capacity, reduction in transmission bottleneck between the North and the South, reduction in the stranded generation that has been plaguing the country, some trend in generation fuel use percentage could be observed.

The first observation is that there is while OCGT will dominate the generation from the first to the 4th year of the planning horizon, it is expected that almost all fuel mix will be approximately proportionally used between the 4th and the 6th year by which hard coal will dominate up to the 9th year and the generation will be proportionally used again with CCGT slightly dominating (see figure 3.9). The implications of this trend can be indicative in the fuel stock that can be encouraged by the government to avoid strategic behaviour in fuel sales for the agents. It could also be observed that even though the nuclear power plant could be commissioned, its use might not be very necessary sequel to the location and power demand demographics seconding the discouragement of its installation despite the lack of expertise in Nigeria (see table 3.8).

[43] Highest carbon price as obtainable in Australia

[44] This is also because there could be limited right of way for transmission lines

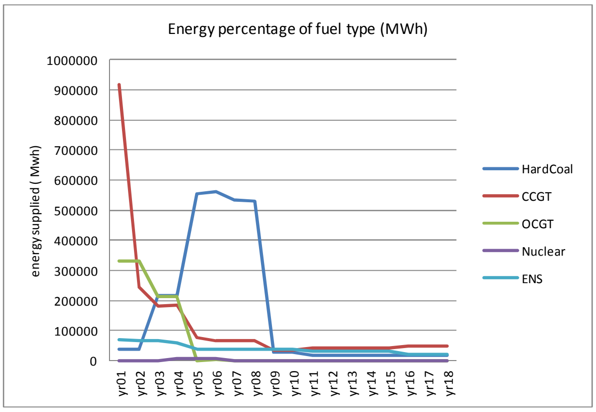


FIGURE 0-9 FUEL USE OVER THE PLANNING HORIZON

	HardCoal	CCGT	OCGT	Nuclear	ENS
yr01	36720	918570	330236	0	70804
yr02	36720	243729	330236	0	65644
yr03	216240	182991	211454	0	65644
yr04	216240	184386	211454	6324	57925
yr05	553981	77993	0	6324	38032
yr06	560134	67452	4388	6324	38032
yr07	532389	67452	1741	0	38032
yr08	531714	67452	0	0	38032
yr09	26474	34457	0	0	38032
yr10	26474	34457	0	0	38032
yr11	15765	40823	0	0	31666
yr12	15765	40823	0	0	31666
yr13	16421	40823	0	0	31009
yr14	16421	40823	0	0	31009
yr15	16421	40823	0	0	31009
yr16	16421	50520	0	0	21312
yr17	16421	50520	0	0	21312
yr18	16421	50520	0	0	21312

TABLE 0-8 THE ENERGY CONTRIBUTION OF EACH FUEL (YR1-YR18)

3.7.2 Comparing across the cases

Comparing across the cases is important in order to understand the influence of the demographic factors like electricity demand growth that indirectly shows population growth and the associated electricity supply growth has on the transmission planning.

It was observed that in all cases, as the demand grows, the capacity of transmission grows whether the fuel mix was respected or not (comparing across case A, B and C). However, in the case of certain changes like generation contingencies, it was observed that at a certain rate of growth, a diminishing return is experienced as it becomes cheaper to meet demand with local generators that are more expensive than to haul power over a longer distance and this is evident in the lower investment in the case of C (75 lines) than in the case of B (76 lines) found in generator contingency model run.

Specific analysis of the results of the model which indicated the tendency of more lines being installed as the demand increases (i.e. for higher demand scenarios) could be observed to reveal that in case A the number of circuits in yr1 was 66 and ended in yr18 with 69 while in Case C, it was higher; starting from 76 and ending with 78 for DCLF scenario. This implies a longer transmission corridors in the cases with higher demands (11253 Km against 9508km from case C and A respectively in the CO2 extreme). Nonetheless, the installation of circuits does not totally reflect the massive change in demand. In addition to more circuit installation, more line flows were experienced. The lines of Case B, even though it was a marginal shift in number of circuits and kilometers from Case A (76 ccts against 75) showed a heavy flow on the lines more than case A in CO2 base run. Furthermore, it is worth nothing that for all the cases, the configuration of the circuits that was considered optimal was not the same[45]. The implication of this is that the unit commitments of the generators are not similar and thus not equally not using the same generators.

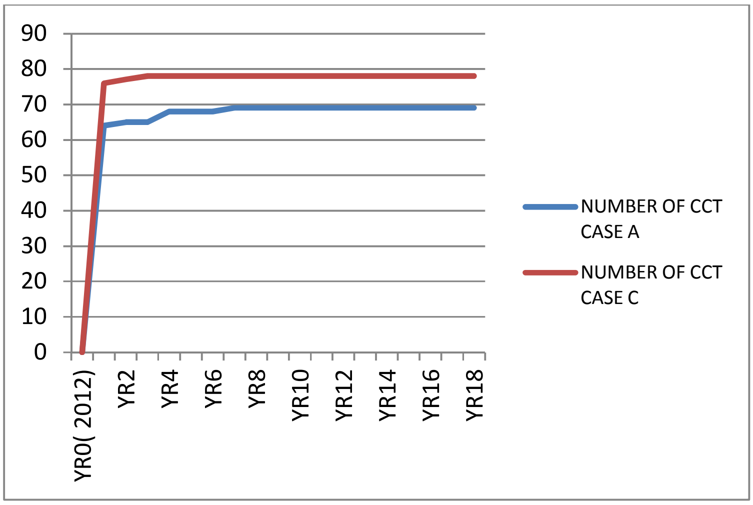


FIGURE 0-10 INSTALLED CAPACITY EVEOLUTION OF CASE A AGAINST C

The gross implication of the unit commitment that varies means that an outright comparison of the SRMC can be a little bit misleading in terms of cost but not utterly useless. The PNS in the case of CO2 was much lower. But this cannot be analysed without looking at the network configuration. In as much as less polluting technology were expected to be more expensive, their low cost in the case of Nigerian case study is significant only if the analysis is done together with installed capacity and unit commitment. The reason for lower cost was understood to be the higher utilization of Hydro generators and less polluting generators that are indicated by more line reinforcement around the hydro and the gas plants.

[45] Circuits are not additional.

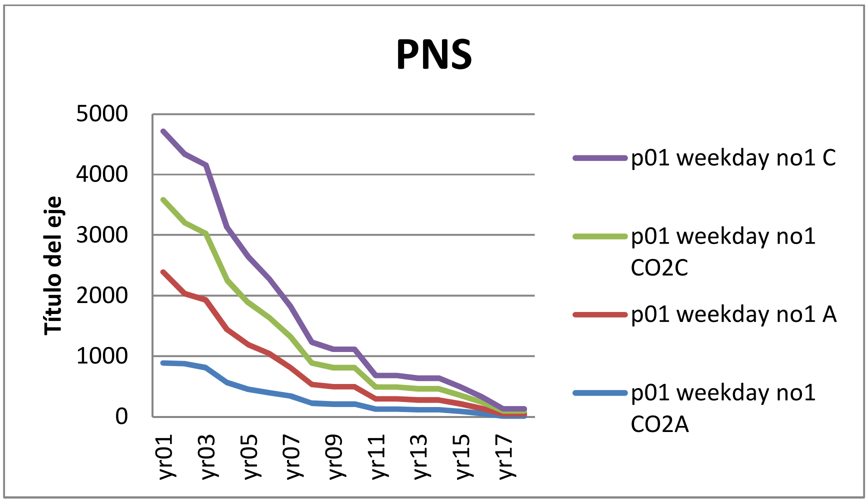


FIGURE 0-11 PNC OF CASE C AGAINST CASES A

With the introduction of CO2, more generators were committed favouring the generation market agents while minimizing the cost of electricity although the generators were not in full utilization. Thus on addition of CO2 , there is higher generator commitment and as the demand increases, the unit commitment increases too as observed across the cases.

One important deduction here is that at very low CO2 price, the variation of SRMC across the cases was minimal; implying that uncertainty in price effect of CO2 on the power market can be reduced by using a low CO2 price[46] which still provides a price signal to investment in high emission generation technologies.

Unit commitment of case C with CO2

			p01	p01	p02	p02	p03	p03
yr18	sc01	SAP	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	OMT	0.1	0.0	0.0	0.0	0.0	0.0
yr18	sc01	OBJ	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CGT1	0.5	0.5	0.5	0.5	0.5	0.5
yr18	sc01	SNG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	NUP2	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	CoalIM	0.1	0.1	0.1	0.1	0.2	0.1
yr18	sc01	CoalKG	0.2	0.0	0.1	0.1	0.2	0.1
yr18	sc01	CoalDLT	0.3	0.2	0.3	0.3	0.4	0.3
yr18	sc01	CoalPLT	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CoalANB	0.5	0.2	0.4	0.4	0.5	0.4
yr18	sc01	CoalAB	0.2	0.3	0.2	0.2	0.3	0.2
yr18	sc01	GasLAG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG3	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	GasLAG4	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	BRNcoal3	0.2	0.1	0.1	0.1	0.1	0.1
yr18	sc01	YBcoal2	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc01	JGWCoal2	0.5	0.3	0.5	0.4	0.5	0.4
yr18	sc01	ZMFcoal3	0.1	0.0	0.1	0.0	0.1	0.0
yr18	sc01	SKTcoal3	0.2	0.1	0.2	0.1	0.2	0.1

Unit commitmment of Case C

			p01	p01	p02	p02	p03	p03
yr18	sc01	PPL	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	OBJ	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CGT1	0.1	0.0	0.0	0.0	0.2	0.0
yr18	sc01	FBC1	1.0	1.0	1.0	1.0	1.0	1.0
yr18	sc01	CoalAB	0.1	0.0	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG3	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG4	0.1	0.1	0.1	0.1	0.2	0.1
yr18	sc01	GasLAG7	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc01	BRNcoal3	0.1	0.0	0.1	0.1	0.1	0.1
yr18	sc01	SKTcoal3	0.3	0.1	0.2	0.2	0.4	0.2

[46] Which is not really lower than what is obtainable in the EU now

unit commitment of Case B with CO2								
yr18	sc01	SAP	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	OMT	0.1	0.0	0.0	0.0	0.0	0.0
yr18	sc01	OBJ	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CGT1	0.5	0.5	0.5	0.5	0.5	0.5
yr18	sc01	SNG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	NUP2	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	CoalIM	0.1	0.1	0.1	0.1	0.2	0.1
yr18	sc01	CoalKG	0.2	0.0	0.1	0.1	0.2	0.1
yr18	sc01	CoalDLT	0.3	0.2	0.3	0.3	0.4	0.3
yr18	sc01	CoalPLT	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CoalANB	0.5	0.2	0.4	0.4	0.5	0.4
yr18	sc01	CoalAB	0.2	0.3	0.2	0.2	0.3	0.2
yr18	sc01	GasLAG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG3	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	GasLAG4	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	BRNcoal3	0.2	0.1	0.1	0.1	0.1	0.1
yr18	sc01	YBcoal2	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc01	JGWCoal2	0.5	0.3	0.5	0.4	0.5	0.4
yr18	sc01	ZMFcoal3	0.1	0.0	0.1	0.0	0.1	0.0
yr18	sc01	SKTcoal3	0.2	0.1	0.2	0.1	0.2	0.1

TABLE 0-9 UNIT COMMITMENT TABLES SHOWING VARIATION WITHIN AND ACROSS THE CASES FOR CO2

3.8 Adequacy of the solution

With the fuel mix respected, the adequacy of the solution was tested in stages. First was the comparison of *the investment decisions* in which the decisions were left as continuous variables and then set as discrete variables and the results was compared in terms of investment outputs, operation influence and the economic factors. In the investment factors, there were less transmission corridors when the investment decisions are continuous and this was expected as you can have 1.5 lines which are not possible in real life). Consequently, numbers of circuits were generally lower across the three cases. In terms of time of installation, the time was more spread in the continuous decision than investment decisions making the need for quick forklift line installations to appear less succinct. Looking at the economic indicators, the total investment cost in all cases for discrete investment decision was more than the total investment cost for continuous investment decisions. The variation was not more than 12% (as experienced in case C). The operation cost followed suit. Despite the computer resources required to run the model, it is obvious that this deviation is not large enough to ignore the use of discrete investment decisions that represents the real life situation.

The next approach was to analyse the modeling of the *network flow* in which the transportation model was used on the candidate lines and then a DC load flow (DCLF) was then used to check its adequacy. Also in terms of investment decisions it was also observed that the transportation model has some circuit deviations from the DCLF options across the cases (underinvestment). This grossly reflected on the economic factor (investment cost and operation costs) and the reliability factors (generation reliability cost) and the values were lower. The direct deduction is the need to respect the real life emulation of the network flow which favours DCLF.

Further, adequacy in the *reliability of the expansion plan* of the approach was checked in generation and network contingency and the results can be seen in table 3.4.

3.9 Final TEP alternative solution

From the analysis of the various options that were considered in the model and the likely uncertainty factors that could be varied across the cases, with changes in the scenarios; *the final scenario for the alternatives cases chosen was to compare case A, B and C respecting the fuel mix, with binary investment solution, using DCLF and generation or network contingency and all these applied with a CO2 decision of at least a 4€/ton* (showed in leaf green colour in the table 3.4). The reasons are as follows

- respecting the expected generation mix policy offered cheaper investment and system operation cost which is due to less installed capacity. Congestion cost is equally reduced and network reliability stands a better chance of having less cost.

- The choice of DCLF was as a result of sizeable marginal deviation from the transportation model counterpart and on the other hand better representation of the system as a whole (especially to avoid then overinvestment that was observed).

- The network and generation contingency serves as a sensitivity test to the TEP fragility exposure and to check how robust the model was.

- Then the CO2 price showed no deviation in system and investment operation cost for all the cases in CO2BASE with little deviation in CO2 extreme and high deviations in CO2evolve in terms of investment and systems operation cost. With almost the same number of lines installed, it became apparent that adding a CO2 price of 4€/ton will not add so much variation in the planning but sensitive enough to make the plan aware of the CO2 price especially for a non Annex A country in the Kyoto protocol of which Nigeria is.

Given these final cases based on the stated reason, chapter 4 assess the alternative (hereafter referred to as caseA^1, B^1 and C^1) using developed metrics from literatures to check the variability in the cases and if there is, choose one as a roadmap.

CHAPTER 4

4 EVALUATING TRANSMISSION PLANNING ALTERNATIVES

The expectations of transmission expansion planning of Nigeria are not far from what is generically obtainable-reliable network, efficient and cost effective connection of new generators. The grid code of Nigeria laid down the basic rudiments of the transmission planning in Nigeria of which the transmission expansion planning is a major part in section 3 of the code. (NERC 2010). The requirements are explained in the Planning code whose aim is to provide the guidelines and address the requirements for the System Operator to perform long-term expansion planning of the Nigerian Transmission System for 15 years and reviewed at least once every 3 years. The reasons for TEP shall involve the reinforcement or extension of the network, which should include but not limited to the consideration of candidate generation expansions, the introduction of a new substation or the modification of an existing substation and the changing requirements for electricity transmission facilities due to changes in factors such as Demand, Generation, technology Reliability requirements, and/or environmental requirements[47].

Even though this work may not address all these issues, it should be close to most of these challenges that is posed by the grid code. Additionally, knowing that in deregulated electric power sector, that investment and operation decisions in generation are market driven, the consideration of economic criteria is very essential.

4.1 Assessment of transmission expansion alternatives

In the former vertically integrated Nigerian power systems, the reliability of the lines at minimum investment cost would have been the major factor for the assessment of the expansion planning alternatives (Miao, ZhaoYang and Tapan Kuma 2005). However, with the advent of restructuring that is followed by deregulation, the context is changed as variety of actors get involved (P. Maghouli, S. H. Hosseini, et al. 2009). The new market objectives of the transmission expansion planning has now been tailored towards maintenance of system reliability and security standards, sticking to the environmental impact assessment and the improvement of economic performance or electricity market competition. (Hesamzadeh,

[47] Also the grid code expected that The long term expansion plan shall use at least the long term Demand Forecast (10 years) for the Transmission taking the refurbishment plan to replace ageing and the report is also expected to include sections that will address long-term demand forecast, long-term generation adequacy forecast, long-term transmission network adequacy forecast, long-term zonal supply and demand margin, long-term statutory outage plan for transmission infrastructure long-term refurbishment plan, alternatives (Identification and Analysis); capital program; and financial motivation. (Nigerian grid code section 3.15). this was taken care of in model input

Hosseinzadeh and Wolfs 2008). Most times it is recommended and ideal that a cost benefit analysis (CBA) be carried out on each transmission expansion because the importance of identification and quantification of the positive and negative economic impacts on the short and long run. (TEAM 2004). One major benefit of the CBA in TEP as a requirement is its efficacy in addressing the impact of transmission expansion planning on increasing user's access of generation and demand, creating incentives for new generation investment and on market competition.

Assessment of impacts can also be based on economic indices and reliability indices. These are incorporated into TEPES as a part of the output which uses the N-1 criteria as afro mentioned. Also there are generation contingency indices. However the economic assessment cannot rely on investment and operation cost alone especially in a multi-actor environment with conflicting actor choices. Other important indices categorized as competitiveness, customer choice and efficiency indices below, could be very essential and complementary (Hesamzadeh, Hosseinzadeh and Wolfs 2008). Consequently, a proper assessment of the expansion could be best done following figure 4.1 and is applied for final chosen cases.

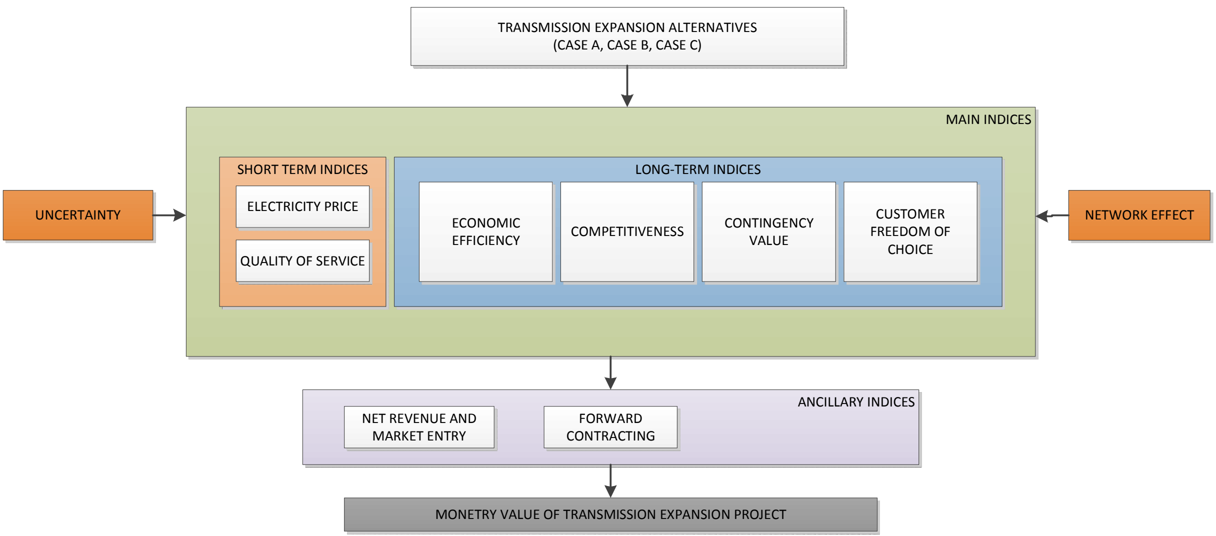


FIGURE 0-1 ASSESSMENT OF TRANSMISSION EXPANSION PROJECT

This reason of the framework in figure 4.1 is that the candidate TEP projects have to be justified, not only on the long term but also on its short term implications. This justification can be seen in form of main indices and the ancillary indices .In terms of long term, the main indices include the economic efficiency, the competitiveness indicators, the indicators for contingency values and the customer freedom of choice indicators. On the short term, the cost of electricity and the quality of service are the major indicators. These main indicators are affected by the uncertainties in the factors that are used for modeling *a priori* and by network effect *a posteriori*. This analysis will be focused on the main indices and the ancillary indices will be applied in the policy recommendation. Also having in mind that decision making in the power system is affected by network of actors which could invariably affect the results, this analysis could be understood to be contextually bounded.

4.1.1 Main indices

This includes the short term indices and the long term indices.

4.1.1.1 The short term indices

The short term indices will be focused on the electricity prices evolution and the quality of services.

The electricity price evolution

Comparing across the alternatives in terms of short term marginal prices showed that they border across the same range with different price pockets[48] (case A^1, B^1 and C^1). Analysis of the mean electric price[49] for case C1 (for all scenarios, for peak weekday) showed a decrease from a mean of 3568 to 50 Euros. While comparing across the cases for year 18 showed that case C has a higher mean electricity price for all scenarios, for peak weekday.

	N	Range	Minimum	Maximum	Mean	Std. Deviation	Variance
CYR1price	408	17483.00	.00	17483.00	3568.5613	5073.72159	2.574E7
CYR18price	408	13636.00	.00	13636.00	50.9534	674.27332	454644.516
Valid N (listwise)	408						

TABLE 0-1 VARIATION OF MEAN ELECTRICITY PRICE FOR CASE C^1

[48] Prices pockets occurs in clusters of 0 to 39 Euros with an outlier of 13636 Euros for all the cases

[49] Using SPSS

	N	Minimum	Maximum	Mean	Std. Deviation
CYR1price	408	.00	17483.00	3568.5613	5073.72159
CYR18price	408	.00	13636.00	508.2819	2424.52493
BYR1price	408	.00	13636.00	2808.2941	4608.90225
BYR18price	408	.00	13636.00	51.4289	674.25249
AYR1price	408	.00	13636.00	322.6005	1790.48117
AYR18price	408	.00	41.00	.9191	5.45032
Valid N (listwise)	408				

TABLE 0-2 VARIATION OF MEAN ELECTRICITY PRICES ACROSS THE 18 YEARS FOR ALL CASES

Quality of service

The quality of service in transmission network can be seen from different perspectives of which they could be broadly classified into regulatory and technical. In technical perspective, the distribution takes the largest chunk of the issue of quality of service[50]. However, some portion can be attributed to the transmission network. In the output of TEPES, this can be checked by two means which are- the energy non-served (ENS) and the congestion rate (number of lines with above to 90 % usage).

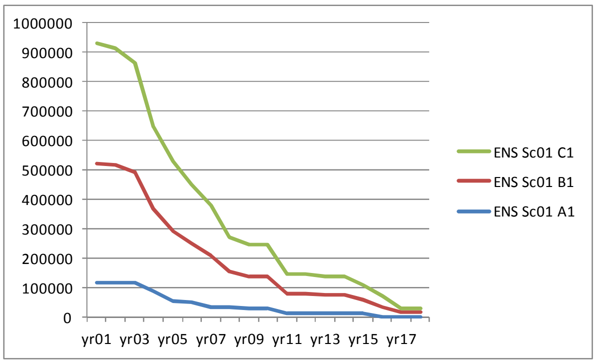


FIGURE 0-2 VARIATION OF ENERGY NON SERVED FOR ALL THE CASES

This was carried out for both contingency conditions and non-contingency conditions. In the non contingency conditions, for the three scenarios, it was observed that ENS was lower in the case A with lower demand but they all converged to the same point by the end of 18 years. In checking the contingency conditions, two approaches were used in TEPES. One was the use of generator contingency conditions (which considers the EFOR of the generators) and the other was the consideration of the network contingency conditions (N-1 criteria) and a few observations were made. Nonetheless the case of A^1 was better even though the rate of decline in C^1 was higher.

[50] 90 % Losses and failures in electric system is attributed to distribution network

The first observation was that in generator contingency, the reservoir storage reduced implying the need for the hydro generators and the rate of reduction corresponded to the demand rate thus lower in A[1]. This also can be attributed to the higher usage of the 765 KV transmission corridors as it was observed that they experienced heavier flows as the demand increases observed in case C[1]. More generators were also committed justifying the need to have more generation capacity as the demand increases. The pattern of unit commitment of the generators was also different from the cases as the network configuration differs.

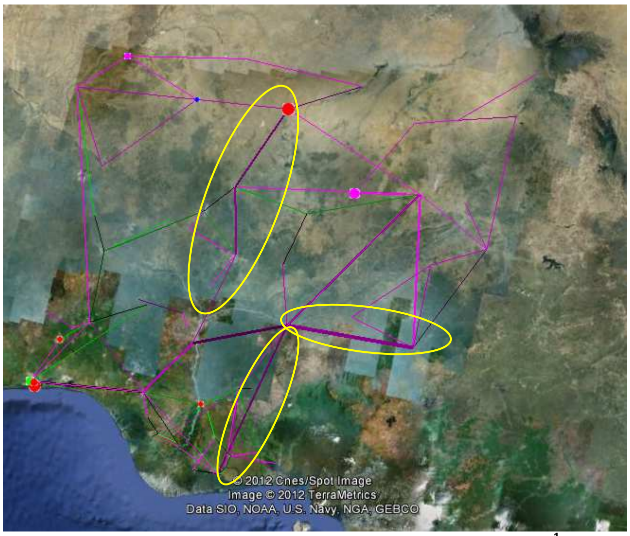


FIGURE 0-3 CONGESTION ON THE 765KV CORRIDORS OF CASE C[1]

4.1.1.2 Long term indices

The long term indices that will be used to compare the alternative plans include the economic efficiency, the competitiveness, the contingency values and customer freedom of choice. The first three can be directly or indirectly measured from the model while the last one is highly qualitative and subjective.

Economic efficiency

The economic efficiency can be analysed through the investment cost and the system operation cost of the alternative plans. This is shown in table 4.3 that the investment cost increased as the demand increases but the system operation cost did not due to transmission network configuration that is not identical hence, a unit commitment that is not the same.

	Economic efficiency (million €)	
	investment cost	systems operation cost
CASE A1	17382	102765
CASEB1	18941	88657
CASEC1	19098	104930

TABLE 0-3 ECONOMIC EFFICIENCY OF THE TRANSMISSION EXPANSION ALTERNATIVES

Contingency values

This can be analysed from the perspective of generation and network contingency. Looking at the generation contingency of the cases, it can be observed in table 4.4 that the contingency value does not depend on the demand growth but can be influenced by the generators unit commitment which is indirectly determined by the fuel mix and CO2 price that was added. This is evident case B1 that is higher than case C1 in terms of all parameters but was less in all other scenarios

	contingency value (million €)	
	Generation reliability cost	network reliability cost
CASE A'	238	2672
CASEB'	8282	2206
CASEC'	7904	2712

TABLE 0-4 CONTINGENCY COST OF EACH CASE

Competitiveness

This can be measured from many factors or their combination. First, the distribution of the electricity prices within the country at the end of the 18 yrs (number of different SRMC), the evolution of the mean electricity prices over the years[51] (mean variance between the average price from yr1 and yr 18), the level of congestion that is experienced in the lines (percentage of lines with more than 80%[52] usage at the end of the yr18).

The mean reduction in electric prices of the across the cases showed that it was progressive which is a good development with the plans as shown in figure 4.4

[51] This is on assumption that regulated tariff will apply prior to stability in the market when nodal price shall be used

[52] Nigerian Grid code stipulated that a transmission corridor is congested if the corridor is experiencing 80% usage

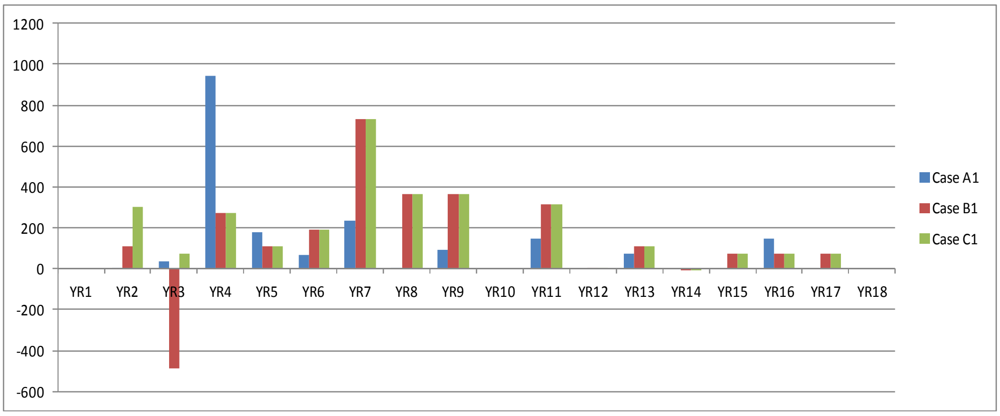


FIGURE 0-4 MEAN REDUCTION OF ELECTRICTY PRICE ACROSS THE YEAR.

The mean variance of electricity over the years showed an expected progressive reduction in electric prices due to the forklift transmission line upgrade and progressive optimization of the lines through this plan. This was calculated as

$$\frac{\overline{SRMC}_{YR_{n-1}} - \overline{SRMC}_{YR_n}}{n_{total}}$$

Where $\overline{SRMC}_{YR_{n-1}}$ is the average SRMC for all the nodes and all scenarios for year n,

Analysis of competition for the transmission alternatives can be seen as a snapshot in table 4.5

	competition			
	Number of different SRMC	*Mean variance of the average electricity prices*	*percentage of lines with congestion more than 80%*	*no of lines*
CASE A1	25	106.9	74%	67
CASEB1	26	135.3	54%	48
CASEC1	32	180	56%	48

TABLE 0-5 COMPETITION MEASURES FOR THE CANDIDATE TRANSMISSION LINES

4.1.2 Decision making for transmission expansion planning alternatives

The issue of choosing an alternative Long term transmission planning is a decision making process under uncertainty due to lack of knowledge of the probability of the states (demographic factors and drivers of TEP). Hence the choice of alternatives between these three scenarios can be largely based on the decisions' makers' attitude towards life. In order to aid this decision making process, two conservative approaches will be evaluated- the pessimistic approach (maximin) and the opportunistic approach (minimax). The aggressive approach of maximax is neglected due to the fact that it was mostly factored into the demand forecast and mostly because a pessimistic and conservative approach is used in this evaluation. The payoff table that was used was from the transmission assessment factors of section 4.1.

4.1.2.1 Maximin criterion

This decision approach fits the conservative and the pessimistic decision maker guaranteeing the minimum payoff for the conservative where a pessimist expects the worst possible result to occur.

Payoff table									
	Investement cost	System operation Cost	Gen Reliability Cost	Network reliability Cost	# of different SRMC	Mean variance of Average Electricty price	percentage of lines with congestion		Minimum
Case A	17382	102765	238	2672	25	106.9	74		25
CaseB	18941	88657	8282	2206	26	135.3	54		26
Case C	19098	104930	7904	2712	32	180	56		32
Maximum Payoff	32								
Maximin decision	**Case C**								

This decision criterion showed that it is most conservative to expand the Nigerian transmission network considering the optimistic generation plan of the ECN, hence case C.

4.1.2.2 Minimax Criterion

This criterion is an opportunistic approach in which the "lost opportunity or regret" incurred by failing to carry out the best alternative transmission plan is used as the evaluation factor. The regret table was built from the payoff table in which the regret for each decision alternative is the difference between the payoff value and the corresponding best pay off value. Then the maximum regret was calculated and the best decision corresponds to the alternative that has the minimum of these maximum regrets and this is also Case C

Regret Table									
	Investement cost	System operation Cost	Gen Reliability Cost	Network reliability Cost	# of different SRMC	Mean variance of Average Electricty price	percentage of lines with congestion		Maximum
Case A	1716	2165	8044	40	7	73.1	0		8044
Case B	157	16273	0	506	6	44.7	20		16273
Case C	0	0	378	0	0	0	18		378
MiniMax regret payoff	378								
MiniMax regret	**Case C**								

Thus it can be concluded that a conservative opportunistic and conservative pessimistic approach both favours the final case of C. Consequently the transmission expansion of Nigeria should take care of the optimistic generation and supply forecast and includes a CO2 policy while obliging itself to the policy layout of the expected generation mix. This has been carried out in this work.

4.2 Policy issues of transmission expansion in Nigeria

Even though the transmission expansion serves socio-economic and technical challenges, it policy implication is mostly socio-economic that is technically constrained. The transmission expansion is normally expected to be social welfare[53] maximizing however in deregulated power system, its underlying assumption that side payments and charges may efficiently distribute the social gains among the market agents might not hold because welfare transfer will be unfeasible or mostly subject to imperfection meaning that the welfare maximization objective might not be Pareto optimal. This counterintuitive results can better be explained by the economic theory of "second best" that suggest that when more than one market imperfection[54] occurs, correction of the one imperfection might not be pareto optimal.

Furthermore, the alternative objectives and scenarios of the transmission expansion can produce conflicting results between maximization of social welfare, maximization of producer surplus, maximization of consumer surplus and minimization of local power. Comparing across the cases, this can be seen in table 4.4 in which the case B^1 has a higher reliability cost compared to case C^1 but lower values in competition values of table 4.5. Also this effect can be seen when compared across the scenarios.

The conflict within these results can become clearer by the differentiation of the two economic effects of transmission expansion- the competition effect and the substitution effect. While the competition effect encourages the competition among the generators which is welfare maximizing, it can cause substitution effect for existing generator by its introduction of newer cheaper generation posing threat to older generators investment, which is undoubtfully welfare minimizing (Leautier 2001). Thus it is possible that the transmission plan that minimizes the local market power of generation firms (lower numbers of different SRMC) may differ from the

[53] Social welfare is very difficult to define but for simplicity is considered to the net of consumer and producers surplus.
[54] The market imperfection in transmission expansion includes the monopoly, the connectivity problem, few agents in the market etc.

expansion plan that maximizes welfare (lower investment and system operation cost) and vice versa (Sauma and Oren 2007). Therefore, the policy implications will be better seen in terms of investment, access and pricing although sometimes system modernization and reliability can be added which will generally explain the ancillary indices of figure 4.1.

4.2.1 Regulation and Policy Challenges in transmission expansion planning

It is obvious that the optimal transmission expansion plan is dependent on the objective that was applied, which in most deregulated electricity market like the current Nigeria electricity market, the multi-actor environment will imply conflicting objectives that is dynamic. Hence a TEP that totally eliminates network congestion might not be the best decision even when the investment cost is not a constraint.

It can also be observed that the optimal TEP is highly sensitive to the demand and supply parameters. The repercussion is that the cost structure of generators which is an assumption[55] can greatly alter market expectation. The consequence is that a proper generation expansion plan of Nigeria that assumes a uniform stochasticity to the TEP is essential for the total acceptance of this work.

Furthermore, the distributional effect of TEP suggests that a Pareto optimal decision may not be welfare maximizing, hence the design effect of transmission investment on the access and pricing regulation should be perfectly adapted to fit the long term and short term expectation of NERC while not distorting the market policy.

4.2.2 Regulatory recommendations for transmission planning

The socio- economic aspects transmission is a policy issues that is mostly regulatory and this greatly affect the net revenue of the electricity market, the rate of market entry and other issues like forward contracting and auctions in the market. To ensure that this transmission plan can hold, the following policy suggestions are recommendation

[55] Determined mostly by fuel cost and is static in this model while in real life is very volatile

4.2.2.1 - investment

Transmission planning Objectives

The objective of the planning should be re-focused mostly on have a healthy generation mix of which renewable will play a major role to ensure sustainability and technology trajectory follow-up on the long term. This has been adopted in this plan. The advantages is not only that a lower cost can be experienced as observed from the analysis, but given the cosmopolitan nature of Nigeria, a healthy fuel mix will favour the regional power development knowing that primary energy sources is scattered all over the country. Then on the short term, the plan should focus on congestion relief and the midterm focused on reliability enhancement.

Scope of the Authority of the planning processes

The transmission planning would be better if done from the federal to the state levels (top-down approach) by the TCN due to its natural monopoly nature. .However a hybrid can be allowed to interconnect regions that are not in the budget of the state due to some limitations that the regions can afford to cover especially for social purposes like connecting local villages that are in the hinterlands. A competition agency should be instituted to help foster competition between the generation expansion energy market and the TCN

Scope of planning process

The scope of the planning process should not necessarily extend beyond transmission planning but should be harmonized in time and space with the demand response plans, distributed power generation plans of other sections of the ministry and other regulatory development.

Preferential treatment

Preferential treatments that could distort the transmission planning like the federal permit option should be avoided to ensure that the planning process can have a realistic scheme for its management justified by performance except in dire cases where time of consideration may be an issue.

Authority

The transmission planning should be viewed from the national perspective with the sole power given to the TCN as an independent system operator. This is essential to avoid separation of the reliability of the transmission system from the transmission construction. However, the transmission system construction time and permit should be accelerated by federal jurisdiction to avoid delays that can fault transmission plans.

4.2.2.2 Transmission line Funding and cost allocation

Building the developed transmissions lines can cost 17 to 19 billion Euros depending on the case that was adopted and this raises a contentious issues of line funding and cost allocations.

Funding and cost allocations

The transmission line should be funded by the TCN who should be independent. However, prior to this, a healthy regulation on cost recovery should be in place to ensure fast and reliable cost recovery. The current multi-year tariff order (MYTO) that is in place is an RPI-X that is reviewed every two years[56]. The procedure could be better if the time frame is reviewed especially borrowing a leaf from the OFGEM of UK's RIIO model[57].

In terms of cost allocation, this should be on causality of which average participation is currently the best approach. Deep connection cost should be applied to the generators that locate to places more than the prescribed capacity and shallow connection charge shall be applied otherwise. Even though this could sound discriminatory, it can be counterbalanced by land permit that is limited by time to avoid seizure of good generators locations sites and associated market power.

[56] NERC MYTO- put reference

[57] OFGEM has developed a new model-RIIO that allows for innovation in the RPI-X regulation of natural monopoly

CHAPTER 5

5 CONCLUSION

Nigeria has restructured her power sector and massively started deregulating it. This implies a change in the method of planning from centralized to decentralize planning. It is obvious that planning is very essential and helpful in almost the entire value chain of the power sector and this was vividly shown in the generation and demand forecast that was earlier carried out by ECN of Nigeria which was an essential input to this work.

Even though there has been a plan has laid out an projected generation fuel mix up till year 2030 that is expected to satisfy this forecasted demand in three scenarios due to the abundance of the natural resources, however there has not been a vivid long term plan on transmission of this energy from generation centers to demand points even though transmission has been a major factor contributing to the current load shedding that is experienced in Nigeria.

The need to make a long term plan that will transport this power to the demand points while respecting the forecasted the generation fuel mix is the major aim of this project. A systems approach was used since it is obvious that in a decentralized power sector, it is necessary to adopt a network decision making approach to satisfy a multi-actor issue of which transmission planning was one .This plan is expected to serve as indicative, mitigating the risk of investors in locating generators while serving the main purpose of dynamically determining the investment and operation cost over the years while taking care of reliability both in networks and in generation.

Given the challenge for a transmission expansion planning that could follow the identified generation and demand growth trend, it was obvious that a long term dynamic approach is the most appropriate, although it is not common for reasons enumerated. In line with that, this work used TEPES, a novel dynamic optimization transmission model developed in IIT which did not only gave the yearly optimal investment plan and the implied cost but the associated operational procedures based on operational and reliability conditions that were specified. It is not expected that this will be a prediction rather indicate the rough estimated expected investment and operation cost for the government and private sectors. Having reckoned that the reliability of this TEP output depends on the reliability of the input (i.e. the demand and expected generation evolution), keen efforts were made to reduce the errors to the least achievable minimum.

Afterwards, it was observed that the planned 765KV overlay supergrid is a very welcome approach to bulk power transfer which is apparent due to the nature of the abundance and distribution of primary energy sources and the expected demographic factors evolution especially population and industrial growth. However, in some scenarios, the adopted network configuration might not be optimal. It was also pragmatic that continued transmission at 330 KV will not be economical and environmental friendly and that transmission at HVDC was also needed for likely direct connection to areas in which flows might need to be easily controlled for the stated reasons. The number of required transmission lines in Kilometers was decreasing as the year's increase, the interconnection increased also while none served energy sharply declined lower than the targeted value.

Having justified the transmission expansion planning to be technical, economic and regulatory issues that are intertwined; the economic bottleneck was approached using a suggestive regulatory design to support this transmission expansion planning in other to boost the confidence of all stakeholders.

A detailed analysis and continuous forward review that is inclusive is necessary to assure the stakeholders of security of investment.

5.1 Contributions of this project

This project developed a tactical transmission plan that leveraged on the forecasted demand and supply scenarios that were already in place to design a relatively detailed dynamic long term transmission plan for deregulated electric sector of Nigeria up to year 2030.

The plan was also analysed under network and generation contingency using the available load and generation scenarios. Fictitious generators were used corresponding to the generation fuel mix that was forecasted yielding an indicative planning of the likely location of generators in the near future to fulfill the expected fuel mix.

This plan also confirmed the need to respect the expected generation fuel mix showing that it will be better off not only in terms of natural resource utilization but also in terms of reducing the generation/ transmission bottleneck, foster competition in generation and reduce electricity price. It will also be beneficial in reducing the total cost of investment in transmission.

Regulatory suggestions on transmission issues were formulated both from the perspective of indicative planning and the perspective of sustainable electric power system.

5.2 Suggestions for further work

There is a need to carry out a good Reactive power expansion planning in order to support this TEP especially to control the flows.

Also environmental studies are essential to make sure those accurate kilometres of the line were used and that the line does not cross conservative areas and validate the cost that was suggested.

There is a need for indebt study on the incentives that will promote renewable generation so that the Northern part of the country can have electricity at almost the same price as the south and reduce the cost of transmission lines. This will also reinforce the plan that has been carried out.

There is also a need to study the implication of having a gas transmission network not only for the generation industry but also for the economy. The implications could be that this could relocate some of the gas generators to the North while still maintaining the fuel mix hence reducing the cost of electricity.

APPENDICES

A1. APPENDIX 1

Nigerian Electric Power Transmission Data

The following data has been taken into consideration in the long term expansion planning that was carried out using the TEPES Model. Most of them were gotten form the TCN of Nigeria and this data is valid as at December 2011.

A1.1 Transmission system Capacity

MAXIMUM VOLTAGE	330KV
STATUTORY LIMITS	313.5KV – 346.5KV
NOMINAL FREQUENCY	50HZ
STATUTORY LIMITS	49.75HZ – 50.25HZ

Table A1.1 Statutory Limits

PEAK DEMAND FORECAST	8,080MW
GENERATION CAPABILITY	5,317MW
PEAK GENERATION	4,162MW
MAXIMUM INSTALLED CAPACITY	5,482MW
MAXIMUM ENERGY GENERATED	93,224MWH

Table A1.2 Expected Capacity

#	Parameters	Qty
1	Capacity 330/132kV (MVA)	7,044
2	Capacity 132/33kV (MVA)	9,852
3	Number of 330kV Substations	28
4	Number of 132kV Substations	119
5	Total Number of 330kV circuits	60
6	Total Number of 132kV circuits	153
7	Length of 330kV lines (kM)	5,650
8	Length of 132kV lines (kM)	6,687
9	National Control Centre	1
10	Supplementary National Control Centre	1
11	Regional Control Centres	2

Table A1.3 Transmission system statistics

Presently the Grid consists of 5,650km of 330 kV transmission lines and 6,687km of 132kV transmission lines, all in AC without any HVDC. Also there are 28 numbers of 330/132kV Substations with total capacity at 7044 MVA and 119 numbers of 132/33/11kV substations with total capacity at 9852 MVA. This is expected to guarantee evacuation capability of above 5,000MW on 330kV and 8,000MW on 132kV network. Meanwhile the peak generation stands at 4,162.2 as at end of January 2012.

A.1.2 Major current challenges and associated Policy

The major challenges that the Nigeria transmission network has been experiencing is ***the radial grid structure, mostly single 330KV Circuits*** and *no EHV networks, concentrated generation due to availability of gas in the south and eastern part of the country that led to stranded generation capacity on the eastern network*. Hence evacuation of power is the most imminent in the power planning agenda and in the effort to solve this bottleneck of power evacuation, the table below shows the next planned effort and these will be taken into consideration in the candidate lines selection.

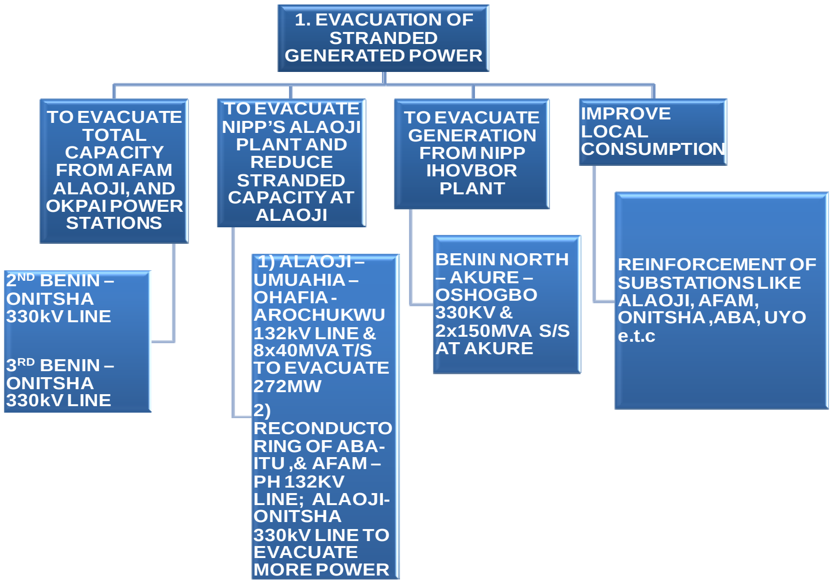


Figure A1.1 Current Stranded Power evacuation policy

Expanding this issue, the picture below shows the eastern zone and the necessary candidate line that will be coming up for the sole purpose of power evacuation.

Figure A1.2 Stranded part of Eastern network

The existing 330KV with the number of circuits is shown below

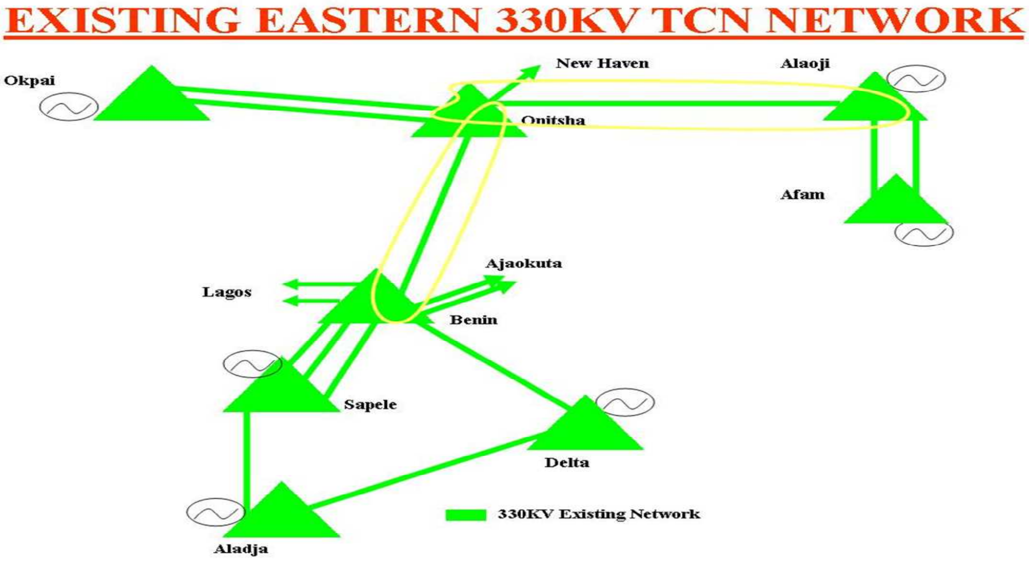


Figure A1.3 Congested eastern Transmission corridors

The highlighted areas showed the corridors that are congested and *may* need reinforcement. Also noting the line reinforcement may not be the solution to the problem, but may relocate the bottlenecks, the process of strengthening is accompanied by expansion that will span from now till 2014 and is depicted in the following diagram.

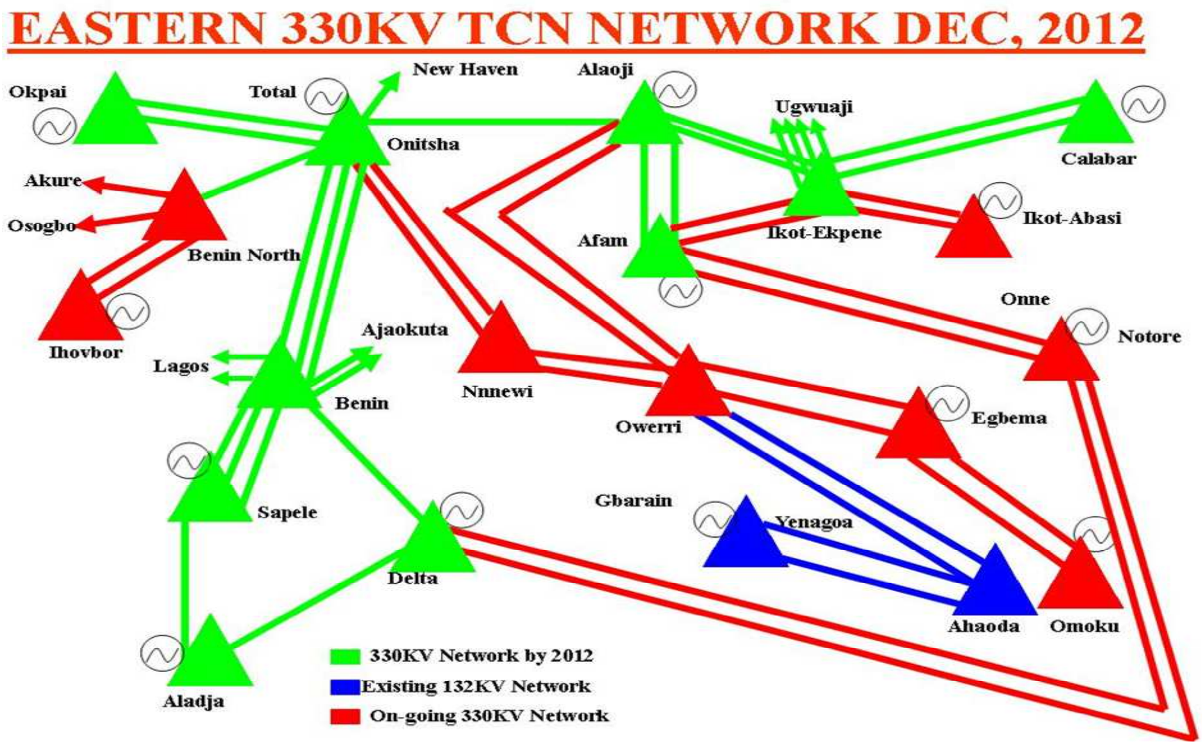
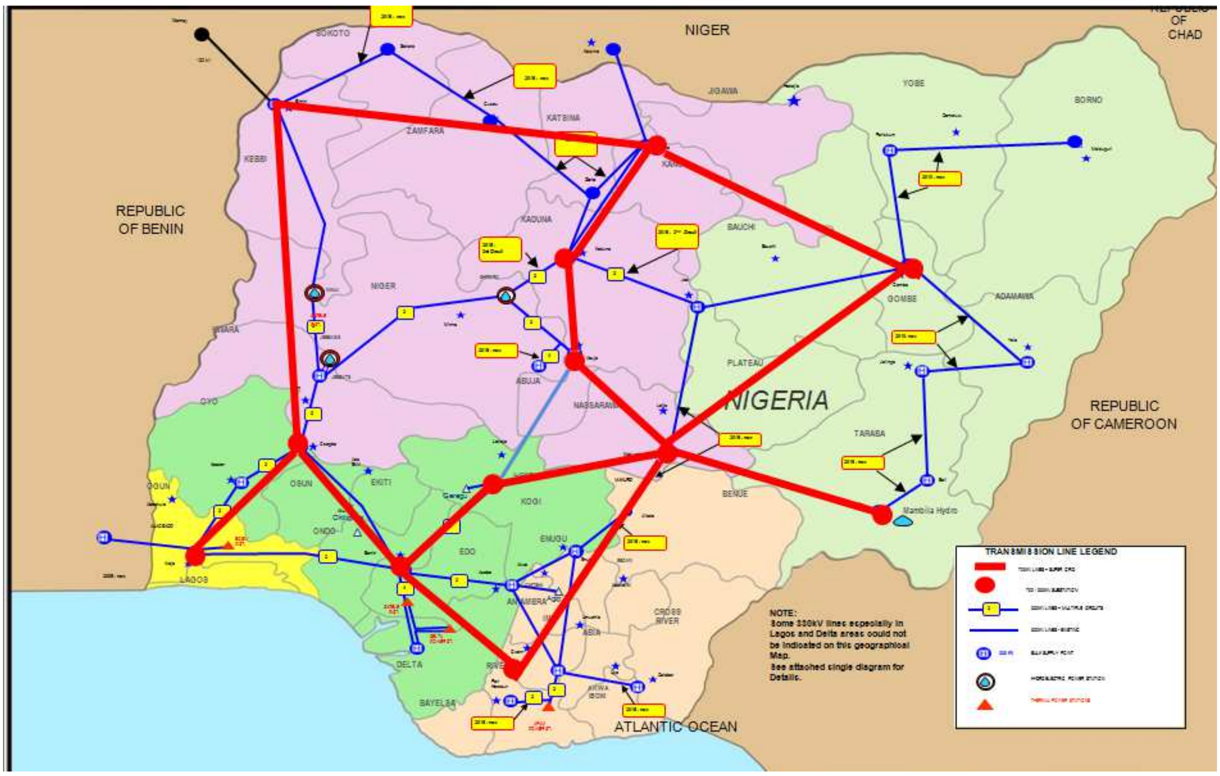


Figure A1.4 Expected expansion and reinforcement by 2014

A1.1.3 Transmission development

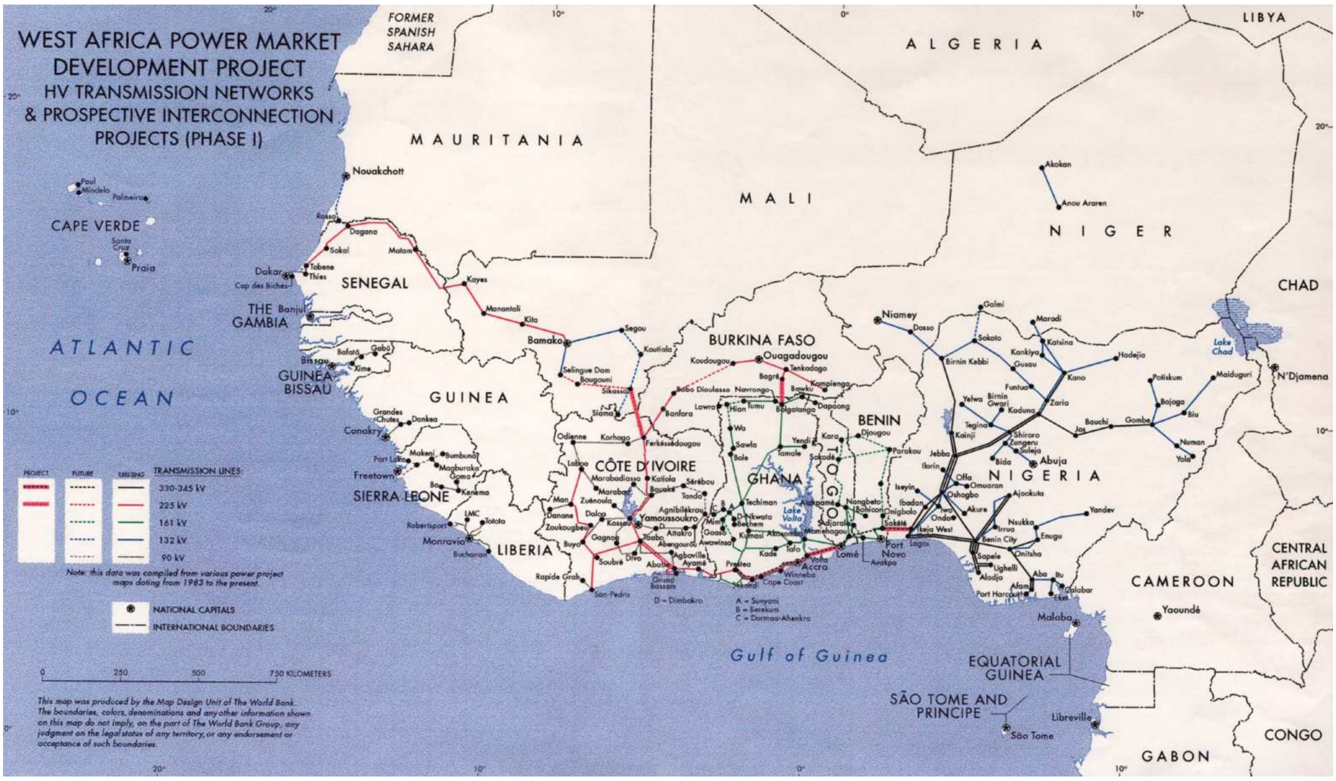
There is no detailed long term plan that spans over 15 years, rather work has commenced on statutory “TCN’s Transmission Development Plan” that is assumed to guide future development of the Transmission infrastructure. The development plan is expected to be implemented in phases of 10,000MW evacuation plan, followed by a 15,000MW evacuation plan and 20,000MW evacuation plan. It is more inclined to heuristics than optimization approach.

The 10,000MW Plan has been finalized for implementation. The next evacuation plan is the 15,000MW of which the introduction of the super grid (765 KV) is envisaged in the evacuation plan. Super grid is considered due to concentration of NIPP power stations in the south and the need for evacuation of power to the northern part of the country will be beneficial with the introduction of the super grid. Another importance of super grid is the meshing of the network and thus enhanced system wide voltage, especially in the northern parts of the network.



A1.1.4 West African Power pool

The West African power pool is an essential component in the power planning even though the issue of coupling will also be considered. However, Nigeria being the largest country in west Africa in terms of population and economy will be connected to other countries that will make Nigeria a net importer. The magnitude of power export and the point of connection shall be considered in the design of the interconnection.


WEST AFRICA POWER MARKET DEVELOPMENT PROJECT
HV TRANSMISSION NETWORKS & PROSPECTIVE INTERCONNECTION PROJECTS (PHASE I)
FORMER SPANISH SAHARA
ALGERIA
LIBYA
MAURITANIA
MALI
NIGER
CHAD
CAPE VERDE
SENEGAL
THE GAMBIA
GUINEA-BISSAU
GUINEA
ATLANTIC
OCEAN
SIERRA LEONE
LIBERIA
CÔTE D'IVOIRE
BURKINA FASO
GHANA
TOGO
BENIN
NIGERIA
CAMEROON
CENTRAL AFRICAN REPUBLIC
EQUATORIAL GUINEA
SÃO TOME AND PRINCIPE
GABON
CONGO
Gulf of Guinea
Lake Chad
Lake Volta
Nouakchott
Dakar
Banjul
Bissau
Conakry
Freetown
Monrovia
Bamako
Ouagadougou
Yamoussoukro
Accra
Lomé
Porto Novo
Niamey
Abuja
N'Djamena
Malabo
Yaoundé
Libreville
São Tome
Praia
TRANSMISSION LINES:
PROJECT
FUTURE
EXISTING
330-345 kV
225 kV
161 kV
132 kV
90 kV
Note: this data was compiled from various power project maps dating from 1983 to the present.
NATIONAL CAPITALS
INTERNATIONAL BOUNDARIES
0 250 500 750 KILOMETERS
A = Sunyani
B = Berekum
C = Dormaa-Ahenkro
D = Dimbokro
This map was produced by the Map Design Unit of The World Bank. The boundaries, colors, denominations and any other information shown on this map do not imply, on the part of The World Bank Group, any judgment on the legal status of any territory, or any endorsement or acceptance of such boundaries.

A2. APPENDIX 2

Issue paper for Nigeria transmission plan

A2.1 summary

The issue paper contains a proposal for conducting a study on the transmission network of Nigeria after liberalization. The focus is on the capacity of the network, its inability to wheel as much power as produced now and the main issue that borders the Nigerian transmission network after deregulation. Hence the objective is to study what is needed to have a sustainable and scalable transmission grid in Nigeria that will not only have enough capacity to transfer produced power but provide incentives for proper electric sector growth.

In order to delineate this problem to a specific problem statement, so that a proper research methodology can be applied, there is a need for a multi-actor approach.

System delineation

Using the *system diagram*, the various criteria were developed that was from the perspective of a problem owner who is the TCN of Nigeria. Then because of the socio-economic factors that affect this technological problem, there was a need to find out how they interrelate with each other.

In the bid to achieve that, the system was divided into its component viz the environmental, technological, political and economic subsystems .The various external factors that affect the current boundary context were connected to the various subsystems and the relationship between the subsystems were also connected together through the various causal diagrams.

Then the next approach was to find out how to extract the criteria and the various means which was formulated at the subsystem levels. The subsystem *means* were aggregated to the system level within the defined boundaries. The means included line reinforcement, locating generators close to demand source, locating generation close to primary fuel, having a higher voltage transmission as an overlay to reduce the issue of right of way etc.

However, this problem cannot be solved in isolation or only from the perspective of the TCN. Other actors (agents) are involved in the Nigerian electricity sector. They were identified and their degree of importance were analysed and they were categorised. The most important with blocking power included the market operator called the Nigerian bulk trader, the generating companies, the regulator (NERC), the Bureau of public procurement and the citizens. Through an integrated actor analysis that involved identifying the actors and mapping them in a network, their interest and objectives were harmonized with that of the TCN and the main challenge is to find a common problem formulation that can fairly meet the interest and objective of all the major actors. Obviously it was observed that this is a multi-actor – multi-issue agenda

Problem reformulation

Having carried out an uncertainty analysis to reduce the knowledge gap that abound this problem to a minimum, and subsequently conjoining the actors issues together, the problem was reformulated. The problem statement is

How can one design the long term transmission expansion plan for Nigeria (15 -30 years), that determines the technical characteristics and installation time of the new network facilities so that the total expected cost of supply (including the consumer outage cost) will be minimized while not compromising on the optimal acceptability of technical reliability, financial and environmental multi-criteria constraints .

This was broken down to different research questions that should apply different methodologies.

Research methodology

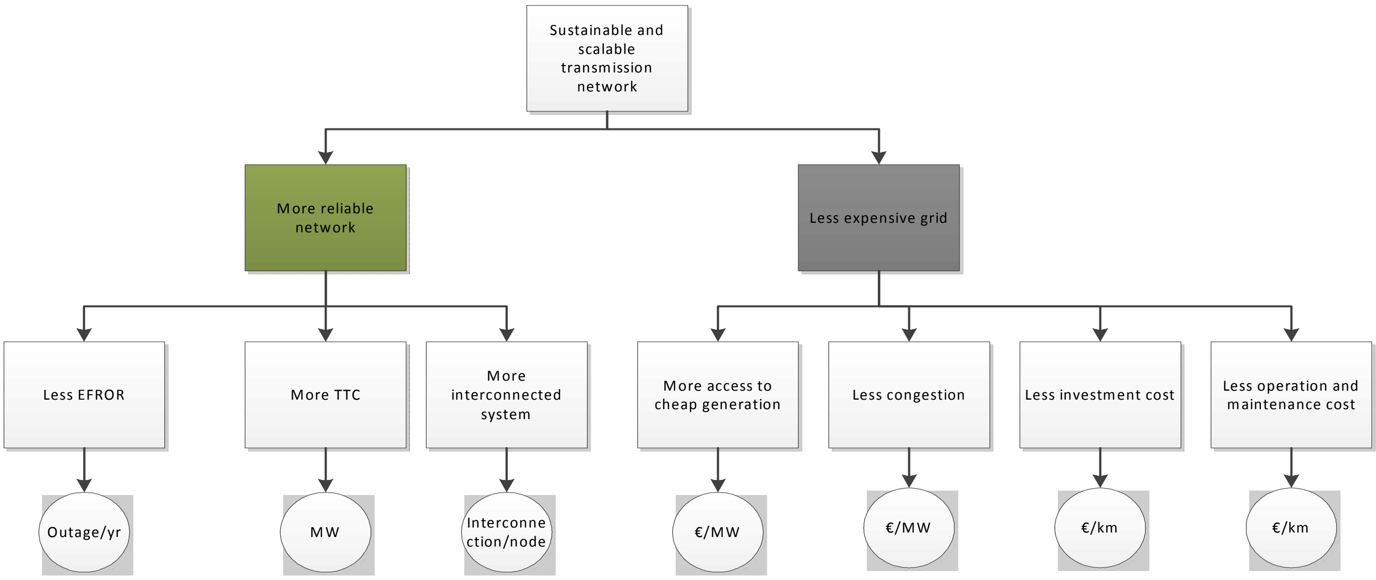
Research problem1: Design of tactical transmission plan for Nigeria
Type of Model: Optimization model
Time: Dynamic, discrete and continuous, stochastic with long term horizon

Aggregation: High because of demand and supply models that generate results used as input
Knowledge: Benders decomposition, mixed integer programming, optimization methods, GAMS.

Research problem2: Implication of plan to energy policy program
Type of Model: Multivariate -Regression analysis
Time: Dynamic: Static, continuous,
Aggregation: low because of the aim is oriented to implementation
Knowledge: Multivariate analysis, multi-criteria analysis

A2.2 Approach

Based on the boundary instituted by the assumption, a system is defined. The system which is a demarcated part of reality is a scalable and sustainable transmission network in a deregulated Nigerian electric sector. In this system (conceptual model), the objective is broken down to measurable quantities called *criteria*. This is through the objective tree method. From the objective tree below, the criteria for this problem were developed showing what the actor wants to achieve. They include the EFOR, the TTC, the interconnection rate, and access to cheap generation, rate of congestion, investment, operation and maintenance cost. The objective tree answers the question of "why".



The

These criteria were used in the system diagram. However in the system, there are exogenous factors that are contextual to the transmission problem of Nigeria. These factors are termed external because they influence the causal relationship of the Nigeria transmission problem but cannot be influenced. Then the next factor is the steering instrument that is called the means. They are the instruments that can be used to control the criteria from the objectives through various causal relationships.

The causal relationships are broken down into 4 subsystems namely economics, political, technical and environmental

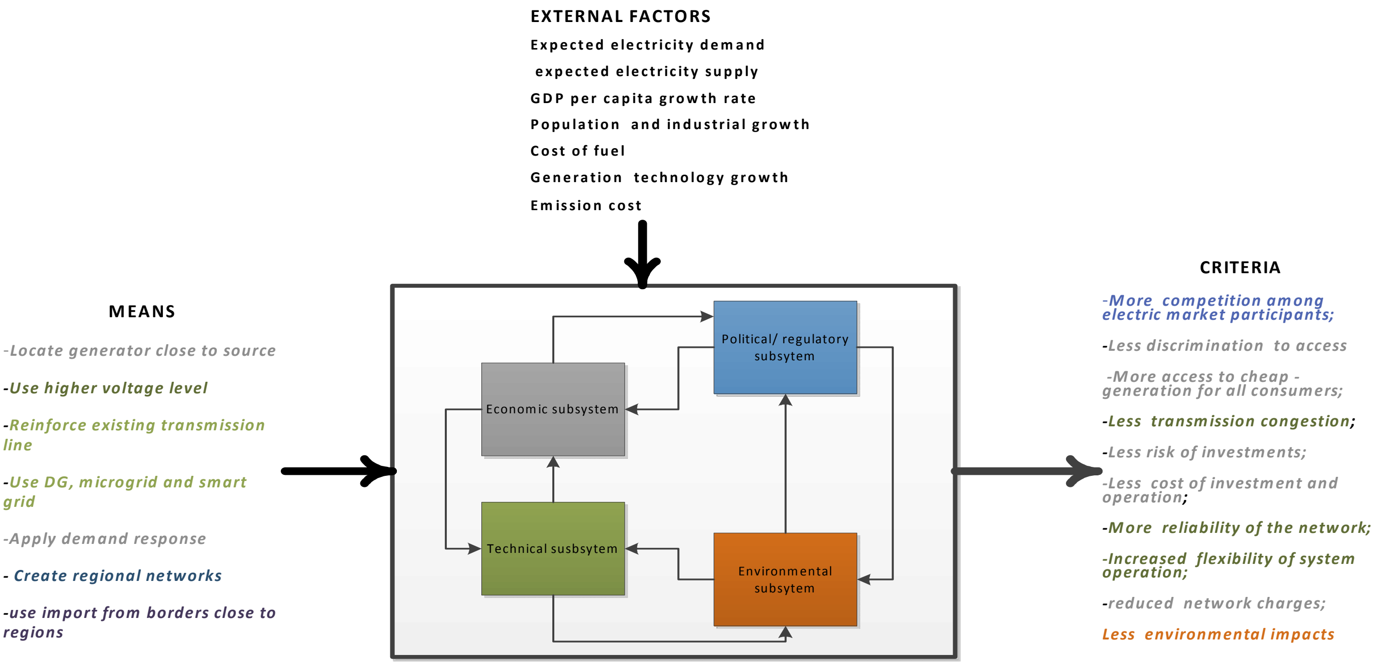


Figure A2.1 The System Diagram

The causal relationship of each of the subsystem with each other, the contextual factors and the means that can influence them to yield the expected criteria is shown. The colours shows the interfaces with other subsystem while the dashed line boxes showed the contextual factors.

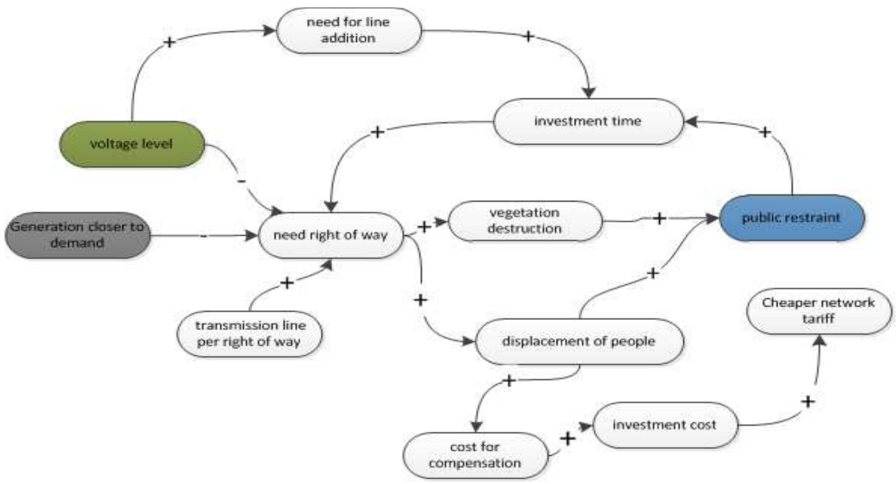


Figure A2.2 Causal relationship of environmental subsystem

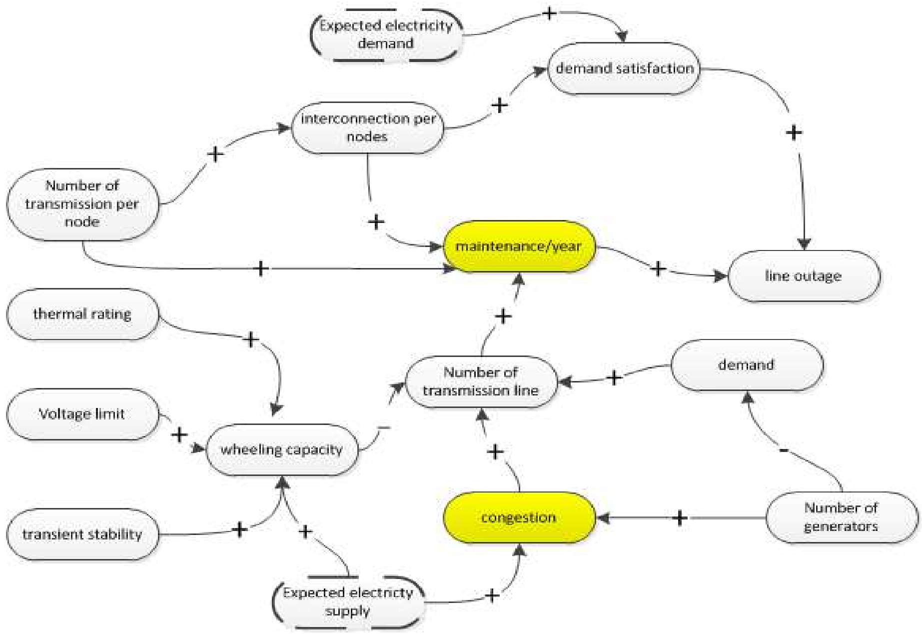


Figure A2.3 causal relationship of technical subsystem

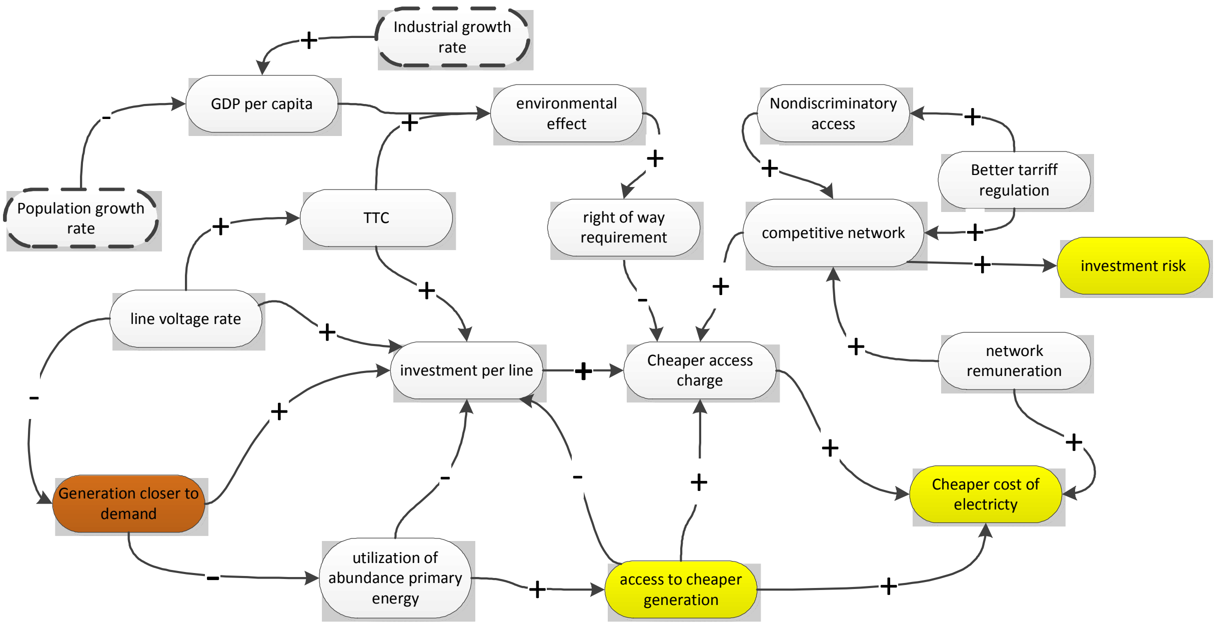


Figure A2.4 Causal relationship of economic subsystem

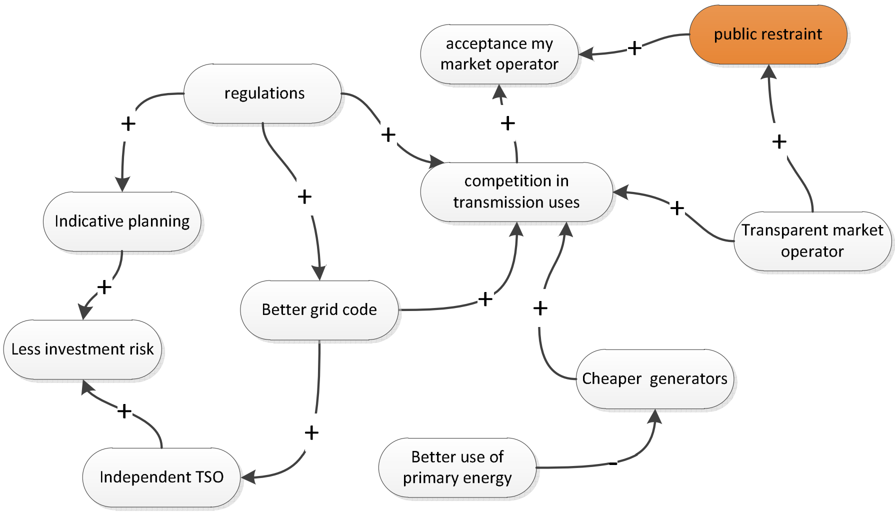
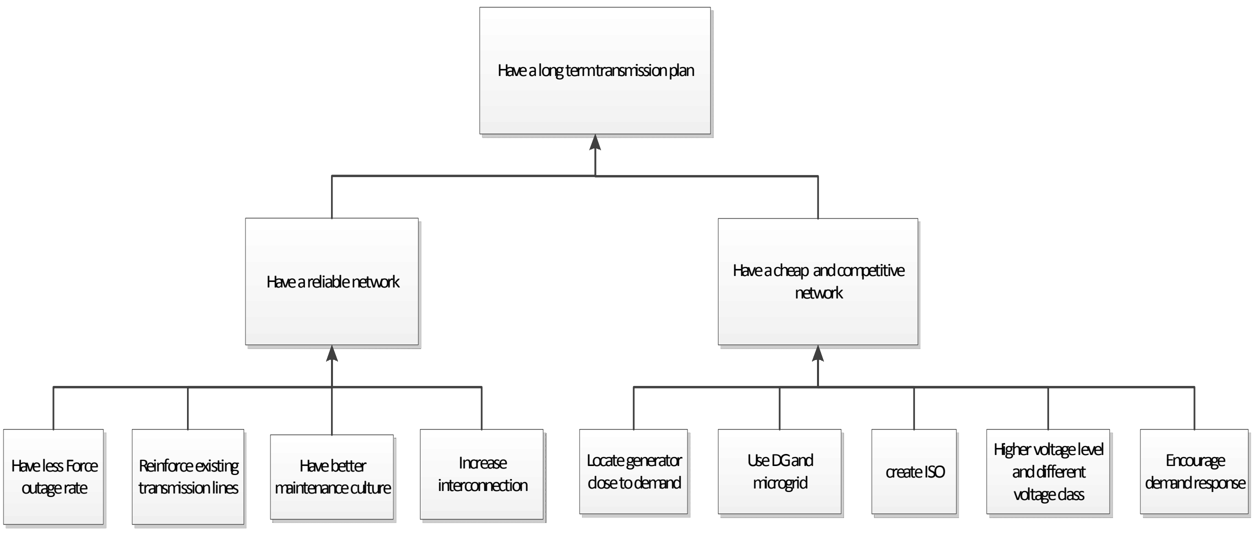


Figure A2.5 Causal relationship of political subsystem

The next step is to answer the question of 'how" to achieve the objective that has been laid down. This is achieved by using the *means-end diagram*. In the means-end diagram, arrows points upwards showing that it is a bottom up approach to build the proper problem solutions formulation. From the various means, the problem is formulated through the means-end diagram shown below.



Actor analysis

Sequel to its multi-actor context, there is a need to involve all the essential stakeholders so that their objectives can be harmonized with the objective of the problem owner, who is TCN of Nigeria.

This is summarized in the table below.

Actors	***desired objectives***	***Interest***	***possible solution***
National independent power project	proper utilization of natural resources (primary source of fuel)	IPPs should have access to cheap transmission	location of generations technology close to source of primary energy
	cheap and timely IPP projects	all generated power should be evacuated	having a robust and reliable transmission to evacuate the power and a plan that is indicative to ensure that
Generation companies	to have a viable generation business	To sell all the power generated at profitable prices	To have access to uncongested transmission grid,
TCN	To have a reliable and robust electricity grid	To have a sustainable transmission expansion plan that is scalable, that will ensure adequacy and security of the system.	To have a good transmission network road map rooted a an indicative planning that is holistic.
National electricity regulatory commission	To protect the consumers and the producers	To ensure nondiscriminatory access to electric grid to all stakeholders at the most sustainable price	To have a perfect transmission regulation that borders access, investment and pricing
Bureau of public procurement	To ensure that the procurement process by TCN followed the due process that is transparent and fair	To ensure that the transmission grid is the most competitive that is built through the best tender process with the best technology	to ensure that the tender process is transparent enough to promote good transmission investment in terms of size, technology and timing
Ministry of Power	To ensure that the citizens have access to power at all times and non of the stakeholders is cheated	To have a sustainable level of electricity that will drive the economic policies	To ensure the Nigerian deregulated electricity road map is achieved through proper monitoring and enactment so laws
Nigerian bulk trading company	To trade power in transparently and in real time	To have a viable trading platform that is competitive and hedges risk	to have powers to control all the power traded in the country to proper laws
The citizens	To have reliable source of power at affordable rate	to have sustainable access to electricity	to have an opinion in the approach to be used for electricity planning in the country.

A3. APPENDIX 3

Exogenous Data for TEPES Model from Energy commission of Nigeria (ECN)

A3.1 Country profile

Location: latitudes between 4° 1' and 13° 9' North of the equator and longitudes 2° 2' and 14° 30' east.

Land area of: 923. 768 sq km.

Solar Radiation: Annual average of 3.5 KWh/m^2-day in the south and 7.0 KWh/m^2-day in the North with 4-9 hour sunshine a day.

Demographics

Item	unit	2000	2005	2010	2015	2020	2025	2030
Population	[mill]	115.22	132.48	150.55	167.03	183.42	200.54	219.25
Population growth rate	[%p.a.]		2.83	2.59	2.10	1.80	1.80	1.80
capita/hh	[cap]		5.8	5.77	5.52	5.06	4.5	4
households	[mill]		22.85	26.10	30.27	36.11	44.38	54.60
rural pop	[%]		57.90	55.10	52.00	46.80	40.90	34.00

Table A3.1

A3.2 *IAEA Models and the results*

MAED (model for analysis of energy demand) was used for energy demand analysis and this was done in 2 steps where the results from energy demand MAED ***–e*** was used to calculate electricity demand using ***MEAD-el***. Then the results were used by the WASP model (Wien Automatic system planning package for electricity generation expansion planning) to plan for electricity generation expansion. The supply strategies were designed using the MESSAGE model (Model for energy supply strategy alternatives and their general environmental impacts) for the supply scenarios.

The GDP and population against the years for the different scenarios showed a high optimism in the high growth scenario as shown in Figure A3.1. The GDP forecast was used to get the final energy demand over the years for different scenarios as shown in figure A3.2

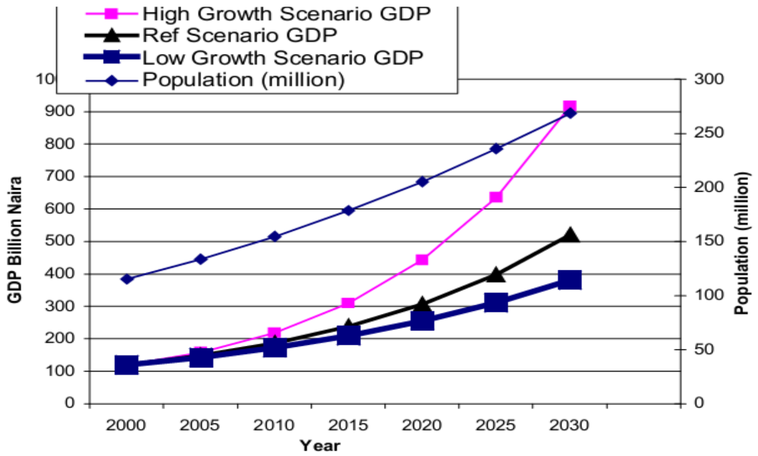


Figure A3.1 The expected GDP and population versus the scenarios

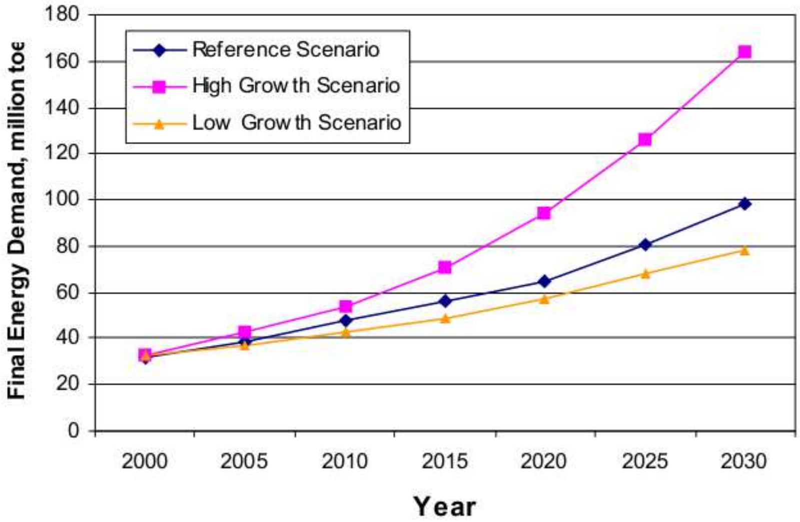


Figure A3.2 The expected total energy consumption against the year

Technical and economic data for the Power plants

The technical and economic data of the power plants are presented in the Tables below. Table A3.2 shows the existing thermal plants while the table A3.3 shows the candidate thermal plants that has been commissioned to be built in the near future (before 2015). Also the table A3.4 shows the existing hydro together with the major three candidate hydro. Note that the Hydro is only single basin and there is no pumped hydro for now.

TECHNICAL AND ECONOMIC DATA FOR EXISTING POWER PLANT														
		Minimum	Maximum	Heat rates (Kcal/KWh)		Fuel cost (Cent/10^6					Scheduled		Fixed	Variable
		operation Level	capacity		*Average*				Spinning		maintenan	Maintena	O&M(	O&M
Name	No of Units	(MW)	(MW)	*Minimum*	*Increment*	*Domestic*	*Foreign*	Fuel type	reserve	EFOR	ce (days	nce class	$/KW-	($/MWh)
AA1	0	10	26	3246	2898	47.4	0	Gas	10	10	12	50	0.47	1.02
EB1	6	55	220	3068	2790	47.4	0	Gas	10	10	12	200	0.42	1.02
SP1	2	60	120	3651	2482	47.4	0	Gas	10	10	12	150	0.27	1.02
DL1	0	5	44	3228	2868	47.4	0	Gas	10	10	12	50	0.08	2
SP2	0	20	75	3200	2871	47.4	0	Gas	10	10	12	100	0.47	2
AA2	1	25	27	3902	2649	47.4	0	Gas	10	10	12	50	0.84	2
AA3	1	25	75	3200	2871	47.4	0	Gas	20	10	12	100	0.42	2
AA4	0	40	138	3651	2482	47.4	0	Gas	10	10	12	150	0.43	2
DL2	2	5	25	3970	2610	47.4	0	Gas	10	10	12	50	0.62	2
DL3	2	5	20	3970	2406	47.4	0	Gas	10	10	12	50	0.62	2
DL4	6	5	100	3177	2810	47.4	0	Gas	10	10	12	100	0.62	2
IJR	1	5	20	3200	2871	57.4	0	Diesel	10	10	12	50	1.3	2
AS1	9	5	30	3970	2610	69.5	0	Gas	10	10	12	150	0.59	2
PA1	0	10	41	3270	2810	47.4	0	Gas	10	10	12	50	0.44	2
GER	0	40	138	3651	2482	47.4	0	Gas	10	10	12	150	0.43	2
OMT	0	10	41	3270	2810	47.4	0	Gas	10	10	12	50	0.43	2
ALJ	0	10	44	3200	2871	47.4	0	Gas	10	10	12	50	0.43	2
AGP	3	25	100	3177	2810	47.4	0	Gas	10	10	12	100	0.43	2
IBM	0	37	147	3132	2832	47.4	0	Gas	10	10	12	150	0.59	2.2
NIG	21	5	115	3177	2810	47.4	0	Gas	10	10	12	150	0.62	2

Table A3.2 Existing Thermal plants

TECHNICAL AND ECONOMIC DATA FOR CANDIDATE THERMAL POWER PLANTS													
Name	Minimum operation Level (	Maximum capacity (MW)	Heat rates *Minimum*	Heat rates *Average Increment*	Fuel cost (Cent/10^6 *Domestic*	Fuel cost *Foreign*	Fuel type	Spinning reserve	EFOR	Scheduled maintenance (	Maintenance class	Fixed O&M($/KW-Month	Variable O&M ($/MWh)
GTP1	20	50	4619	3299	47.4	0	Gas	10	12	15	50	2.5	2
GTP2	50	100	4541	3243	22.9	0	Gas	10	25	15	100	1.07	1.8
GTP3	25	150	4307	3077	47.4	0	Gas	10	12	30	150	1.08	2
CGT1	25	200	2176	1530	47.4	0	Gas	10	12	30	200	1.08	2
CGT2	25	400	2530	2430	47.4	0	Gas	10	12	30	400	1.08	2
SNG1	20	100	2980	2900	47.4	0	Gas	10	12	30	100	0.8	2
SNG2	20	200	2390	2130	47.4	0	Gas	20	12	30	200	0.68	2
FBC1	100	200	2490	2120	22.9	0	Coal	10	12	30	200	1.33	2
FBC2	200	400	2530	2490	22.9	0	Coal	10	12	30	400	1.33	2
OST1	100	200	2900	2840	49.1	0	FO	10	12	30	200	1.12	2
NUP1	150	300	2720	2440	0	697.8	Nuclear	10	15	61	200	3.33	2
NUP2	300	600	2720	2440	0	697.8	Nuclear	10	15	61	200	3.33	2

Table A3.3 Licensed Thermal plants

Existing , committed and candidate Hydro plants				
Hydroplants	Capacity	Average flow before 1980	Average flow after 1980	Difference in %
Existing and committed Hydro plants				
Kainji	550	173.8	139	-20
Shiroro	600	61.4	43.3	
Jebba	540	40.7	24.3	-40
Candidate Plants				
Mamb	2000	108	7607	-29
Zung	950	94	74.9	16.5
Dadi	39	16.5	14.8	-10

Table A3.4 Existing and Candidate Hydro capacity

Electricity Demand projection

The electricity demand projection for the scenarios is shown in figure A3.3 and shows the variations for the different scenarios.

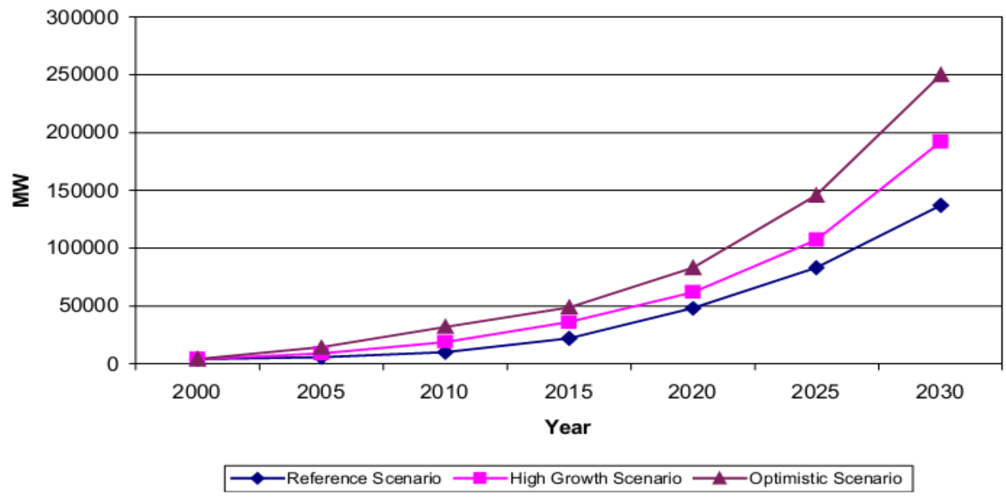


Figure A3.3 Output of the MAED-el model

The load curve for Nigeria can be seen in the figure A3.4 and Figure A3.5 shows the extracted load curve for Residents

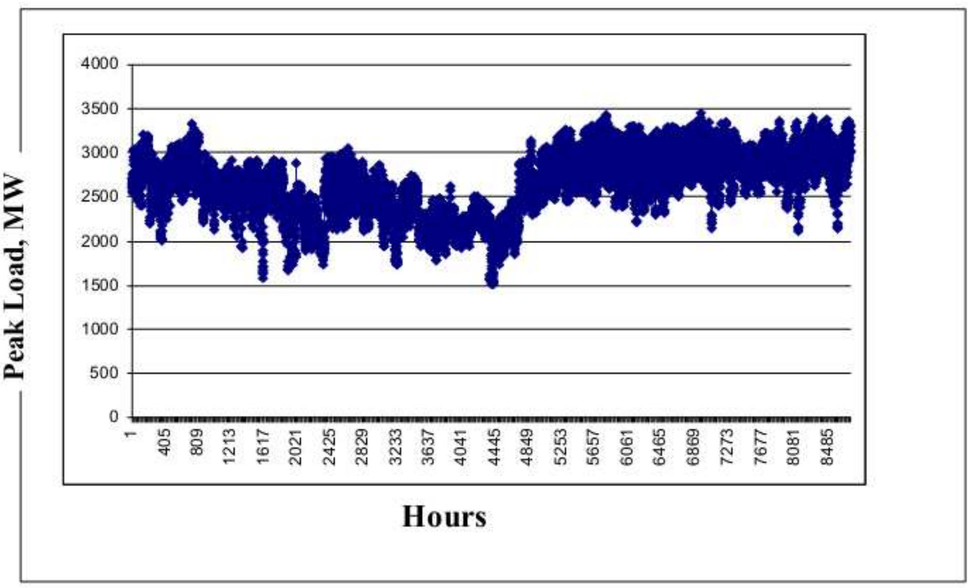


Figure A3.4 Load curve for Nigeria (as of 2010)

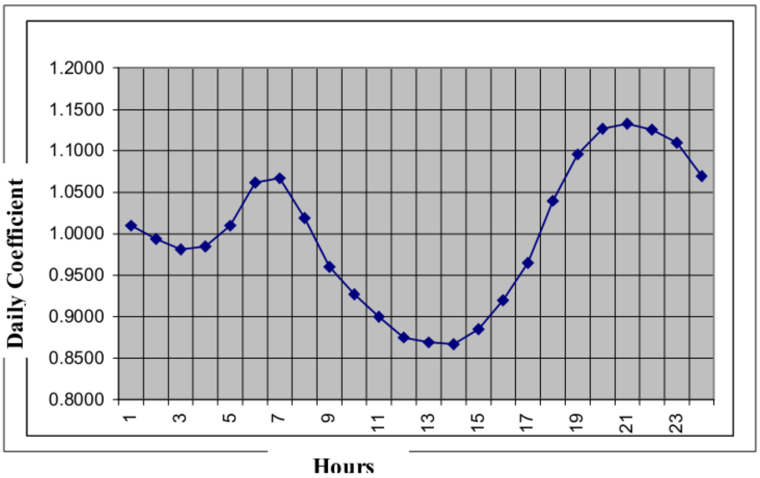


Figure A3.5 Residential load curve of Nigeria as of 2010

Electricity Generation System Expansion

The output of WASP model for the various optimal expansion plans for the electricity expansion plans from the electricity demand plans that was carried out using the MAED model output. With the goal of energy fuel mix, and supply sources diversification, the supply projections are shown below for different scenarios.

Supply projection by fuel Mix for the reference Scenario, MW								
Year	*Total Hydro*	*Coal*	*Gas*	*Oil*	*AGO*	*Nuclear*	*Renewable*	*Total*
2005	1730	0	4680	0	0	0	30	6440
2010	1769	0	13169	400	60	0	330	15728
2015	8219	600	17831	600	60	300	746	28356
2020	8219	2000	35958	1600	60	1500	1480	50817
2025	8219	7400	51626	2400	60	4800	2945	77450
2030	8219	10000	101500	3600	60	9900	3600	136879

Supply projection by fuel Mix for the High growth Scenario, MW								
Year	*Total Hydro*	*Coal*	*Gas*	*Oil*	*AGO*	*Nuclear*	*Renewable*	*Total*
2005	1730	0	4680	0	0	0	30	6440
2010	1769	0	13562	200	60	0	330	15921
2015	8219	1200	19188	800	60	300	746	30513
2020	8219	3000	38616	2000	60	3600	1480	56975
2025	8219	9000	77293	4000	60	5700	2945	107217
2030	8219	30800	128400	7800	60	13200	3600	192079

Supply projection by fuel Mix for the optimistic Scenario, MW								
Year	*Coal*	*Gas*	*Oil*	*AGO*	*Nuclear*	*Hydro*	*Renewable*	*Total*
2005	0	4680	0	0	0	1730	30	6440
2010	0	13639	200	60	0	1769	330	15998
2015	1200	20110	600	60	300	8219	746	31235
2020	4400	51405	1600	60	4800	8219	1480	71964
2025	11400	104347	3200	60	7200	8219	2945	137371
2030	27700	180150	10800	60	19500	8219	3600	250029

Table A3.5

A4. APPENDIX 4

TEPES input Data

A4.1The Defined Nodes

	Voltage	Latitude	Longitude	
	[kV]	[º]	[º]	
FCT_1	132	9.116	7.476	Katampe
FCT_2	132	9.151	7.332	Kubwa
FCT_3	132	8.474	6.946	Abuja City
FCT_4	132	9.013	7.473	Abuja Tow
NIGR_1	132	9.615	6.552	Minna
NIGR_2	132	9.114	7.220	Suleja
NIGR_3	330	9.813	6.156	Zungeru
NIGR_4	330	9.168	4.821	Jebba
NIGR_5	330	9.861	4.614	Kainji
NIGR_6	132	10.081	6.179	Tegina
NIGR_7	132	10.406	5.473	Kontangor
NIGR_8	330	9.973	6.830	Shiroro
NIGR_9	132	9.075	5.998	Bida
BEN_1	132	7.364	9.044	Yandev
BEN_2	132	7.725	8.498	Markurdi
BEN_3	132	7.601	8.481	Alade
KG_1	132	7.563	6.239	Okene
KG_2	132	7.684	6.479	Itakpe
KG_3	132	7.558	6.606	Ajaokuta T
KG_4	330	7.362	6.612	Ajaokuta
KG_5	132	7.132	7.661	Otukpa
KG_6	132	7.952	6.430	Obajana
KG_7	132	8.220	5.508	Egbe
KW_1	132	8.492	4.543	Ilorin
KW_2	132	8.139	5.092	Omu-aran
KW_3	132	8.140	4.726	Offa
NSRW_1	132	8.838	7.882	Keffi
NSRW_2	132	8.912	8.408	Akwanga
PLT_1	132	9.323	9.431	Pankshin
PLT_2	132	10.183	7.383	Maikeri
PLT_3	330	9.920	8.892	Jos_Town
TRB_1	132	8.899	11.368	Jalingo
TRB_2	330	7.269	11.006	Mambilla
TRB_3	132	7.881	9.778	Wukari
GMB_1	132	10.471	11.551	Ashaka ce
GMB_2	330	10.294	11.168	Gombe
GMB_3	132	9.817	11.316	Savannah
BRN_1	132	11.833	13.153	Maiduguri
BRN_2	132	11.164	12.761	Damboa
BRN_3	132	10.614	12.196	Biu
BRN_4	132	10.134	12.065	Dadinkow
BRN_5	132	12.382	13.841	New Marte
BRN_6	132	12.683	13.609	Monguno
BUC_1	132	10.316	9.846	Bauchi
ADM_1	132	9.200	12.504	Yola
ADM_2	132	9.458	12.029	Numann
ADM_3	132	10.270	13.251	Mubi
ADM_4	132	10.805	13.455	Gulak
ADM_5	132	9.824	12.625	Song
ADM_6	132	10.161	12.738	Gombi
YBE_1	132	11.703	11.072	Potiskum
YBE_2	132	11.763	11.960	Damaturu
SKT_1	132	13.059	5.226	Sokoto
ZMF_1	132	12.566	6.059	Talata_Ma
ZMF_2	132	12.182	6.670	Gusua
KBI_1	132	10.853	4.751	Yelwa
KBI_2	132	12.437	4.197	Birnin Keb
KTN_1	132	12.996	7.661	Kastina
KTN_2	132	12.544	7.827	Kankiya

	Voltage	Latitude	Longitude	
	[kV]	[º]	[º]	
KTN_2	132	12.544	7.827	Kankiya
KTN_3	132	11.515	7.330	Funtua
KN_1	132	12.700	4.950	Gagawa
KN_2	330	11.991	8.521	Kano
KD_1	132	10.564	7.430	Kaduna_to
KD_2	132	11.079	7.707	Zaria
KD_3	330	10.451	7.459	Kaduna
KD_4	132	9.443	8.004	Kwoi
KD_5	132	9.869	7.952	kachia
JGW_1	132	11.789	9.342	Dutse
JGW_2	132	12.441	10.022	Hadeija
IM_1	132	5.820	7.336	Okigwe
IM_2	132	5.475	7.056	owerri
ENG_1	132	6.263	7.273	Orji
ENG_2	330	6.459	7.526	New have
EBY_1	132	6.328	8.097	Abakiliki
EBY_2	132	6.474	7.780	Nkalagu
EBY_3	132	5.990	7.647	Mpu
ANB_1	132	6.022	6.906	Nnewi
ANB_2	330	6.151	6.773	Onitsha
ANB_3	132	6.209	7.068	Awka
AB_1	132	5.204	7.969	Itu
AB_2	132	6.406	7.549	Ugwuaji
AB_3	132	5.536	7.486	Umuahia
AB_4	330	5.106	7.369	Alaoji
AB_5	132	5.943	7.386	Ngodo
AB_6	132	5.617	7.833	Ohafia
RV_1	132	4.747	7.111	PH Main
RV_2	132	4.728	7.152	Onne
RV_3	132	5.332	6.651	Omoku
RV_4	132	5.083	6.648	Ahoada
RV_5	132	4.783	7.002	PH Town
RV_6	330	4.852	7.251	Afam
RV_7	132	4.801	6.843	Oporoma
RV_8	330	4.816	6.598	Egbema
ED_1	132	6.741	6.214	Irua
ED_2	330	6.379	5.612	Benin City
ED_3	132	7.126	6.207	Ukpilla
ED_4	330	6.406	5.683	Ihovbor
DLT_1	132	5.875	5.699	Sapele
DLT_2	132	5.708	6.574	Okpai
DLT_3	132	5.520	5.754	Effurun
DLT_4	132	5.356	6.307	Ugheli
DLT_5	330	5.717	6.437	Kwali
DLT_6	132	5.477	5.774	Aladja
DLT_7	330	5.541	5.915	Delta
CRV_1	132	4.818	8.236	Oron
CRV_2	330	4.956	8.350	Calabar
BYS_1	132	5.016	6.299	Gbarain
BYS_2	132	4.932	6.279	Yenogoa
BYS_3	132	4.547	6.019	igbomaturu
AKB_1	132	5.022	7.906	Uyo
AKB_2	132	5.192	7.938	Ikot_Ekpe
AKB_3	132	4.551	8.006	Eket
EKT_1	132	7.625	5.213	Ado
LAG_1	132	6.467	3.183	Ojo
LAG_2	132	6.508	3.094	Agbara
LAG_3	132	6.610	3.341	Ogba,Alau
LAG_4	132	6.520	3.381	Akangbe

Candidate line results

A5. APPENDIX 5

Equations of the Model

A6. APPENDIX 6

Results

Case A

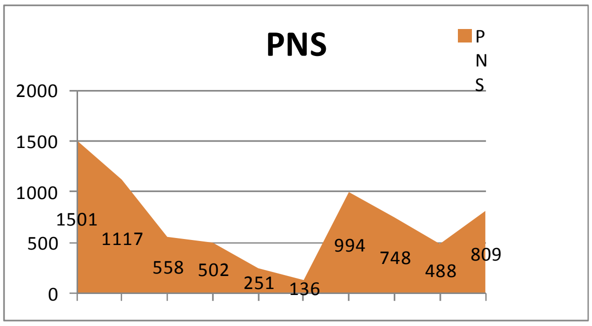
	PNS (power non served)																
	p01 weekday no1	p01 weekday no2	p01 weekday no3	p01 weekend no1	p01 weekend no2	p01 weekend no3	p02 weekday no1	p02 weekday no2	p02 weekday no3	p02 weekend no1	p02 weekend no2	p02 weekend no3	p03 weekday no1	p03 weekday no2	p03 weekday no3	p03 weekend no1	p03 weekend no2
yr01	1501	1117	558	502	251	136	994	748	488	809	180	488	1823	1372	1244	871	638
yr02	1155	884	516	462	210	96	809	658	448	695	139	448	1422	1059	966	733	584
yr03	1118	862	516	462	210	96	791	651	448	686	139	448	1374	1027	939	721	583
yr04	874	654	393	354	165	74	596	491	344	517	107	344	1100	795	718	543	442
yr05	736	544	312	277	135	74	491	398	269	421	98	269	911	669	604	444	355
yr06	648	497	292	262	135	74	450	368	255	388	98	255	786	595	545	409	330
yr07	465	334	158	132	42	22	298	226	125	244	29	125	591	418	373	262	192
yr08	308	220	114	98	42	22	198	153	94	165	29	94	398	275	244	176	134
yr09	287	205	107	92	42	22	184	143	88	153	29	88	371	256	227	164	125
yr10	287	205	107	92	42	22	184	143	88	153	29	88	371	256	227	164	125
yr11	169	120	55	46	21	15	106	78	44	85	17	44	223	151	134	92	67
yr12	169	120	55	46	21	15	106	78	44	85	17	44	223	151	134	92	67
yr13	159	112	51	42	20	15	99	72	40	79	17	40	211	141	125	86	62
yr14	159	112	51	42	20	15	99	72	40	79	17	40	211	141	125	86	62
yr15	123	85	39	32	20	15	75	54	31	59	17	31	167	108	95	64	46
yr16	84	49	7	3	0	0	39	21	2	26	0	2	125	70	58	30	14
yr17	34	15	0	0	0	0	11	3	0	5	0	0	62	25	19	7	2
yr18	34	15	0	0	0	0	11	3	0	5	0	0	62	25	19	7	2

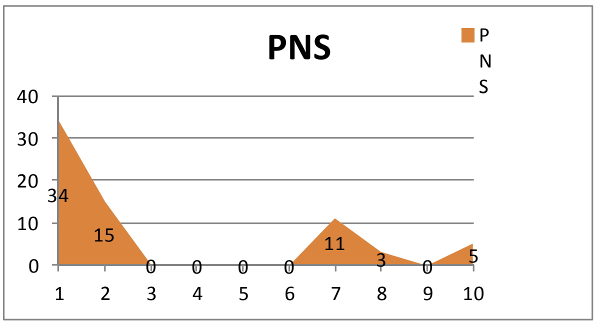
The power Non served for the Case A shown perpertual decline over the years for all load level, for Scenario 1

	LENGTH	Added Circuit
YR0(2012)	0	
YR1	8673	KN2-JGW2
YR2	8844	BUCI-YBE1 X 3
YR3	8844	
YR4	9492	KTN1-SKT1
YR5	9492	
YR6	9492	
YR7	9762	
YR8	9762	
YR9	9762	
YR10	9762	
YR11	9762	
YR12	9762	
YR13	9762	
YR14	9762	
YR15	9762	
YR16	9762	
YR17	9762	
YR18	9762	

		LENGHTH	CCT
765KV		3284	12
330KV		5222	35
132KV	AC	425	9
	HVDC	831	13
Total number of circuit			69
Total length		9762	

The installed circuit for Case A showing the different Voltage levels, the number of circuits and the length of lines with the additional lines that was installed at the particular year.





The PNS for case B in year 1 and yr 18 showing a lot of reduction in PNS due to capacity installation.

SRMC yr18														
0	**13**	**14**			**15**	**16**	**20**	**22**	**23**	**24**	**26**	**27**	**50**	**13636**
NIGR_1	KN_1	FCT_1	DLT_3	TRB_3	AB_2	NIGR_7	ED_4	OGN_2	RV_4	OGN_3	KG_2	BYS_1	OY_3	FCT_4
NIGR_2	KN_2	FCT_2	DLT_4	GMB_1	ED_3	KG_3		OGN_5	OND_1	OGN_4	KG_6	BYS_2		KG_7
NIGR_3	JGW_1	FCT_3	DLT_5	GMB_2	CRV_1	ZMF_1		OGN_6	OSN_2		RV_7			KW_1
NIGR_4		BEN_1	DLT_6	GMB_3	CRV_2	ZMF_2					BYS_3			KW_2
NIGR_5		BEN_2	DLT_7	BRN_1	AKB_1	KBI_1					LAG_1			KW_3
NIGR_6		BEN_3	OSN_1	BRN_2	AKB_2	KTN_3					LAG_2			NSRW_1
NIGR_8		KG_4	OSN_3	BRN_3	AKB_3						LAG_3			NSRW_2
NIGR_9		KG_5	OSN_4	BRN_4							LAG_4			KD_4
TRB_2		PLT_1	OY_1	BRN_5							LAG_5			KD_5
KBI_2		PLT_2	OY_2	BRN_6							LAG_6			EKT_1
KD_1		PLT_3	AB_5	BUC_1							LAG_7			
		TRB_1	AB_6	ADM_1							OGN_1			
		ENG_1	RV_1	ADM_2							OND_2			
		ENG_2	RV_2	YBE_1							OND_3			
		EBY_1	RV_3	YBE_2										
		EBY_2	RV_5	SKT_1										
		EBY_3	RV_6	KD_2										
		ANB_1	RV_8	KD_3										
		ANB_2	ED_1	IM_1										
		ANB_3	ED_2	IM_2										
		AB_1	DLT_1											
		AB_3	DLT_2											
		AB_4												

Short Range marginal cost of Case C in year 18 showing different price pockets and the number of nodes connected to it. Comparing it with the same layout in Yr1 below showed that while in yr 13636€ dominated the nodal price in the market, in year 18, it was dominated by 14€ which is very good.

SRMC yr1																
0	**22**	**23**	**24**	**25**	**26**	**27**	**31**	**1954**	**4563**	**4565**	**4891**	**5101**	**13636**			**14102**
NIGR_1	IM_1	RV_1	OGN_3	CRV_1	KG_2	IM_2	OGN_5	DLT_3	ED_2	ANB_2	EBY_3	OGN_2	KW_3	LAG_3	FCT_1	ENG_1
NIGR_2	AB_1	RV_2	OGN_4		KG_6	RV_4	OGN_6	DLT_4			ANB_1		NSRW_1	LAG_4	FCT_2	
NIGR_3	AB_2	RV_3			ED_4	BYS_1					AB_5		NSRW_2	LAG_5	FCT_3	
NIGR_4	AB_3	RV_5			DLT_2	BYS_2							PLT_1	LAG_7	FCT_4	
NIGR_5	AB_4	RV_6			DLT_6								PLT_2	OND_2	NIGR_7	
NIGR_6	AB_6	RV_8			DLT_7								PLT_3	OSN_1	BEN_1	
NIGR_8	CRV_2	DLT_1			LAG_6								TRB_1	OSN_2	BEN_2	
NIGR_9	AKB_1	OND_1			OGN_1								TRB_2	OSN_3	BEN_3	
	AKB_2				OND_3								TRB_3	OSN_4	KG_1	
	AKB_3												GMB_1	OY_1	KG_3	
													GMB_2	OY_2	KG_4	
													GMB_3	OY_3	KG_5	
													BRN_1	KD_2	KG_7	
													BRN_2	KD_3	KW_1	
													BRN_3	KD_4	KW_2	
													BRN_4	KD_5	YBE_1	
													BRN_5	JGW_1	YBE_2	
													BRN_6	JGW_2	SKT_1	
													BUC_1	ENG_2	ZMF_1	
													ADM_1	EBY_1	ZMF_2	
													ADM_2	EBY_2	KBI_1	
													ADM_3	ANB_3	KBI_2	
													ADM_4	RV_7	KTN_1	
													ADM_5	ED_1	KTN_2	
													ADM_6	ED_3	KTN_3	
															KN_1	
															KN_2	
															KD_1	

C1

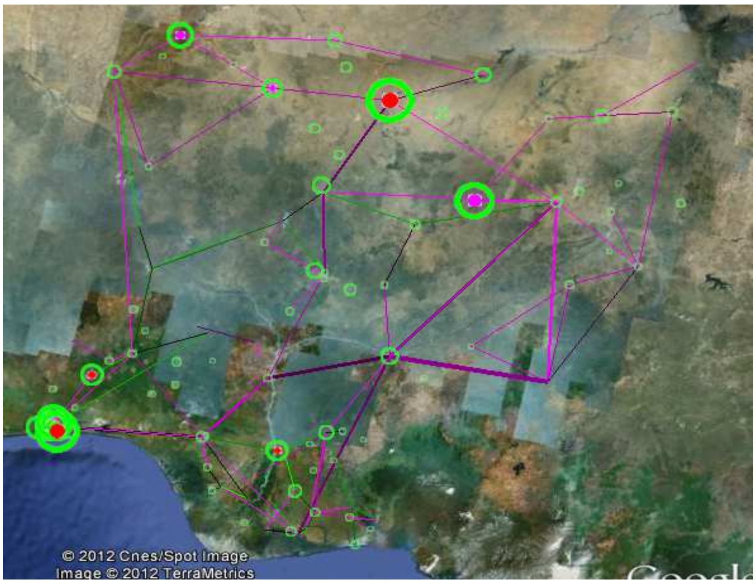
			yr01	yr02	yr03	yr04	yr05	yr06	yr07	yr08	yr09	yr10	yr11	yr12	yr13
FCT_1	FCT_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
FCT_1	FCT_2	n2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
FCT_1	FCT_2	n3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
FCT_1	KG_4	n1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
NIGR_1	FCT_2	n1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
NIGR_1	NIGR_8	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NIGR_1	NIGR_8	n2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
BEN_2	NSRW_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
BEN_3	BEN_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KG_4	BEN_2	n1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
KG_6	KG_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KG_6	KG_7	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KG_6	OND_3	n1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
KW_2	KG_7	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KW_2	KG_7	n2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NSRW_1	NSRW_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NSRW_2	PLT_3	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
TRB_2	BEN_2	n1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TRB_2	TRB_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
TRB_2	TRB_3	n1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
TRB_2	GMB_2	n1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
GMB_2	ADM_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
BRN_1	BRN_5	n1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4
BRN_1	YBE_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
BRN_5	BRN_6	n1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
BRN_6	YBE_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
BUC_1	GMB_2	n2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
BUC_1	YBE_1	n2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
ADM_1	TRB_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_1	TRB_1	n2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_1	BRN_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_1	BRN_4	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_1	ADM_5	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_3	ADM_4	n1	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_5	ADM_6	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ADM_6	ADM_3	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
YBE_2	YBE_1	n1	0.8	0.8	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SKT_1	KBI_2	n1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
SKT_1	KBI_2	n2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
KBI_1	ZMF_2	n1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
KBI_2	KBI_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KBI_2	KN_2	n1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
KTN_1	SKT_1	n1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
KTN_3	KD_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KN_2	GMB_2	n2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
KN_2	KD_3	n2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
KN_2	JGW_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KN_2	JGW_2	n2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
KD_3	FCT_1	n1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
KD_4	KD_5	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
KD_5	NSRW_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
JGW_2	KTN_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ENG_2	BEN_2	n1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
ENG_2	DLT_5	n1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
EBY_1	EBY_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
ANB_1	EBY_3	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
AB_3	IM_1	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
AB_3	AB_6	n1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
AB_4	AB_3	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
AB_5	EBY_3	n1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.7
RV_7	RV_8	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
RV_7	BYS_3	n1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
ED_2	KG_4	n3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0
DLT_1	ED_2	n1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
BYS_3	BYS_2	n1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
AKB_1	CRV_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
AKB_1	CRV_2	n2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
LAG_1	LAG_2	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
LAG_2	LAG_6	n1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
LAG_6	ED_2	n1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
OND_2	EKT_1	n1	1.0	1	1	1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Typical TEPES output for installed capacity

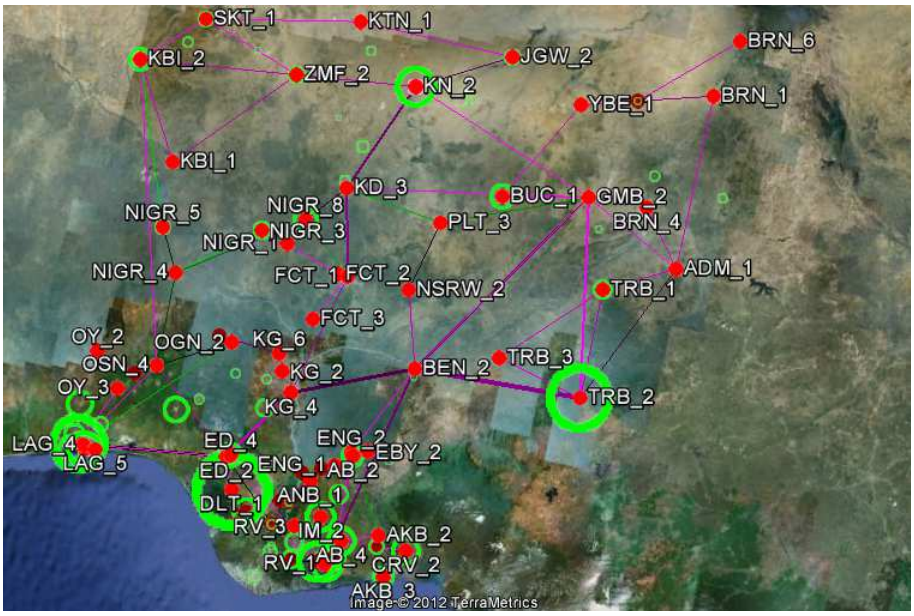
			p01	p01	p02	p02	p03	p03
yr18	sc01	SAP	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	OMT	0.1	0.0	0.0	0.0	0.0	0.0
yr18	sc01	OBJ	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CGT1	0.5	0.5	0.5	0.5	0.5	0.5
yr18	sc01	SNG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	NUP2	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	CoalIM	0.1	0.1	0.1	0.1	0.2	0.1
yr18	sc01	CoalKG	0.2	0.0	0.1	0.1	0.2	0.1
yr18	sc01	CoalDLT	0.3	0.2	0.3	0.3	0.4	0.3
yr18	sc01	CoalPLT	0.2	0.1	0.2	0.2	0.2	0.2
yr18	sc01	CoalANB	0.5	0.2	0.4	0.4	0.5	0.4
yr18	sc01	CoalAB	0.2	0.3	0.2	0.2	0.3	0.2
yr18	sc01	GasLAG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc01	GasLAG3	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	GasLAG4	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc01	BRNcoal3	0.2	0.1	0.1	0.1	0.1	0.1
yr18	sc01	YBcoal2	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc01	JGWCoal2	0.5	0.3	0.5	0.4	0.5	0.4
yr18	sc01	ZMFcoal3	0.1	0.0	0.1	0.0	0.1	0.0
yr18	sc01	SKTcoal3	0.2	0.1	0.2	0.1	0.2	0.1
yr18	sc02	OMT	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc02	OBJ	0.2	0.1	0.1	0.1	0.2	0.1
yr18	sc02	CGT1	0.5	0.5	0.5	0.5	0.5	0.5
yr18	sc02	SNG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc02	CoalIM	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc02	CoalKG	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc02	CoalDLT	0.3	0.1	0.2	0.2	0.3	0.2
yr18	sc02	CoalPLT	0.2	0.1	0.2	0.1	0.2	0.1
yr18	sc02	CoalANB	0.4	0.1	0.3	0.2	0.4	0.2
yr18	sc02	CoalAB	0.2	0.3	0.3	0.3	0.2	0.3
yr18	sc02	GasLAG2	0.1	0.0	0.1	0.1	0.1	0.1
yr18	sc02	BRNcoal3	0.1	0.0	0.1	0.1	0.2	0.1
yr18	sc02	YBcoal2	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc02	JGWCoal2	0.5	0.2	0.4	0.3	0.5	0.3
yr18	sc02	ZMFcoal3	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc02	SKTcoal3	0.2	0.0	0.1	0.1	0.2	0.1
yr18	sc03	OMT	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc03	OBJ	0.2	0.1	0.1	0.1	0.2	0.1
yr18	sc03	CGT1	0.5	0.5	0.5	0.5	0.5	0.5
yr18	sc03	SNG2	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc03	CoalIM	0.1	0.1	0.1	0.1	0.1	0.1
yr18	sc03	CoalKG	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc03	CoalDLT	0.3	0.1	0.2	0.2	0.3	0.2
yr18	sc03	CoalPLT	0.2	0.1	0.2	0.1	0.2	0.1
yr18	sc03	CoalANB	0.4	0.1	0.3	0.2	0.4	0.3
yr18	sc03	CoalAB	0.2	0.3	0.3	0.3	0.2	0.3
yr18	sc03	GasLAG2	0.1	0.0	0.1	0.1	0.1	0.1
yr18	sc03	BRNcoal3	0.1	0.0	0.1	0.1	0.2	0.1
yr18	sc03	YBcoal2	0.2	0.2	0.2	0.2	0.2	0.2
yr18	sc03	JGWCoal2	0.5	0.2	0.4	0.3	0.5	0.3
yr18	sc03	ZMFcoal3	0.1	0.0	0.0	0.0	0.1	0.0
yr18	sc03	SKTcoal3	0.2	0.0	0.1	0.1	0.2	0.1

			p01	p01	p02	p02	p03	p03
yr01	sc01	EGN	0.1	0.0	0.0	0.0	0.1	0.0
yr01	sc01	SAP	0.3	0.3	0.3	0.3	0.3	0.3
yr01	sc01	OMT	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc01	PPL	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc01	ALJ	0.3	0.3	0.3	0.3	0.3	0.3
yr01	sc01	OMK	0.1	0.2	0.1	0.2	0.1	0.2
yr01	sc01	GRU	0.1	0.0	0.0	0.0	0.1	0.0
yr01	sc01	EGB	0.3	0.1	0.3	0.2	0.3	0.2
yr01	sc01	AGP	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc01	OBJ	0.4	0.3	0.4	0.4	0.4	0.4
yr01	sc01	SUP	0.2	0.2	0.2	0.2	0.3	0.2
yr01	sc02	SAP	0.3	0.3	0.3	0.3	0.3	0.3
yr01	sc02	OMT	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc02	PPL	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc02	ALJ	0.3	0.2	0.3	0.3	0.3	0.3
yr01	sc02	OMK	0.1	0.2	0.2	0.2	0.1	0.2
yr01	sc02	EGB	0.3	0.1	0.2	0.1	0.3	0.1
yr01	sc02	AGP	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc02	OBJ	0.4	0.3	0.4	0.3	0.4	0.3
yr01	sc02	SUP	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc03	SAP	0.3	0.3	0.3	0.3	0.3	0.3
yr01	sc03	OMT	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc03	PPL	0.1	0.1	0.1	0.1	0.1	0.1
yr01	sc03	ALJ	0.3	0.2	0.3	0.3	0.3	0.3
yr01	sc03	OMK	0.1	0.2	0.2	0.2	0.1	0.2
yr01	sc03	EGB	0.3	0.1	0.2	0.1	0.3	0.1
yr01	sc03	AGP	0.2	0.2	0.2	0.2	0.2	0.2
yr01	sc03	OBJ	0.4	0.3	0.4	0.3	0.4	0.3
yr01	sc03	SUP	0.2	0.2	0.2	0.2	0.2	0.2

Typical TEPES output for Unit commitment of year 18 and yr1 at peak period of weekday



Typical TEPES output of installed line showing case C superimposed on the demand nodes.



The same output of Case C with the Nodal points earmarked

A

Descriptive Statistics

	N	Minimum	Maximum	Mean	Std. Deviation

SRMCA1	408	-10.00	13636.00	1930.3554	4058.96488
SRMCA 2	408	-10.00	13636.00	1928.9779	4059.44805
SRMCA 3	408	-10.00	13636.00	1894.8480	4018.98521
SRMCA 4	408	-10.00	13636.00	948.3775	3152.59945
SRMCA 5	408	-7.00	13636.00	768.2647	2911.12022
SRMCA 6	408	-7.00	13636.00	701.6544	2767.50291
SRMCA 7	408	-7.00	13636.00	468.1201	2178.33887
SRMCA 8	408	.00	13636.00	466.3775	2178.65761
SRMCA 9	408	-1.00	13636.00	377.1422	1998.57034
SRMCA 10	408	-1.00	13636.00	377.1422	1998.57034
SRMCA 11	408	-1.00	13636.00	229.0809	1558.71331
SRMCA 12	408	-1.00	13636.00	229.0809	1558.71331
VAR00013	408	-1.00	13636.00	154.8382	1277.03419
SRMCA 14	408	-1.00	13636.00	154.8382	1277.03419
SRMCA 15	408	-1.00	13636.00	154.8382	1277.03419
SRMCA 16	408	-1.00	40.00	6.4657	11.22580
SRMCA 17	408	-1.00	40.00	6.4657	11.22580
SRMCA 18	408	-1.00	40.00	6.4657	11.22580
Valid N (listwise)	408				

SPSS ouput of Case A[1] showing the mean and variation in SRMC for 18 years.

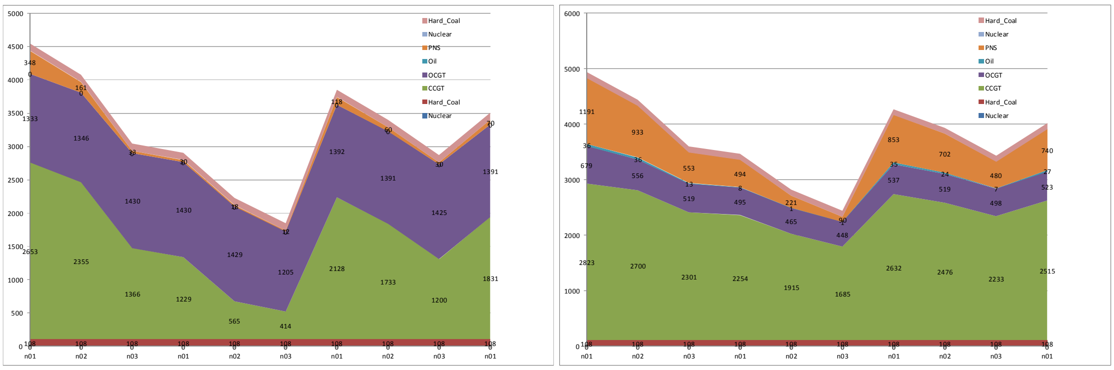
Descriptive Statistics

	N	Minimum	Maximum	Mean	Std. Deviation
SRMCB 1	408	.00	13636.00	2808.2941	4608.90225
SRMCB 2	408	.00	13636.00	2699.0588	4572.02044
SRMCB 3	408	.00	13636.00	3188.1422	4975.41391
SRMCB 4	408	.00	13636.00	2913.6495	4964.42244
SRMCB 5	408	.00	13636.00	2805.9044	4886.26912
SRMCB 6	408	.00	13636.00	2615.4926	4794.65002
SRMCB 7	408	.00	13636.00	1884.1201	4327.83660
SRMCB 8	408	.00	13636.00	1519.2647	3968.85510
VAR00009	408	.00	13636.00	1154.0980	3536.56286
SRMCB 10	408	.00	13636.00	1154.0980	3536.56286
SRMCB 11	408	.00	13636.00	839.0466	3032.79075
SRMCB 12	408	.00	13636.00	838.8799	3032.83579
SRMCB 13	408	.00	13636.00	731.2917	2843.10433
SRMCB 14	408	.00	13636.00	731.2941	2843.10372
SRMCB 15	408	.00	13636.00	656.7279	2712.86573

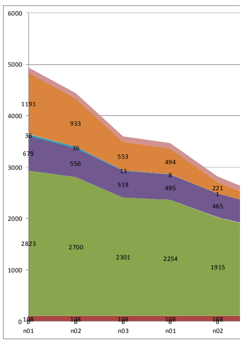
SRMCB 16	408	.00	13636.00	582.5368	2573.80408
SRMCB 17	408	.00	13636.00	508.2819	2424.52493
SRMCB 18	408	.00	13636.00	508.2819	2424.52493
Valid N (listwise)	408				

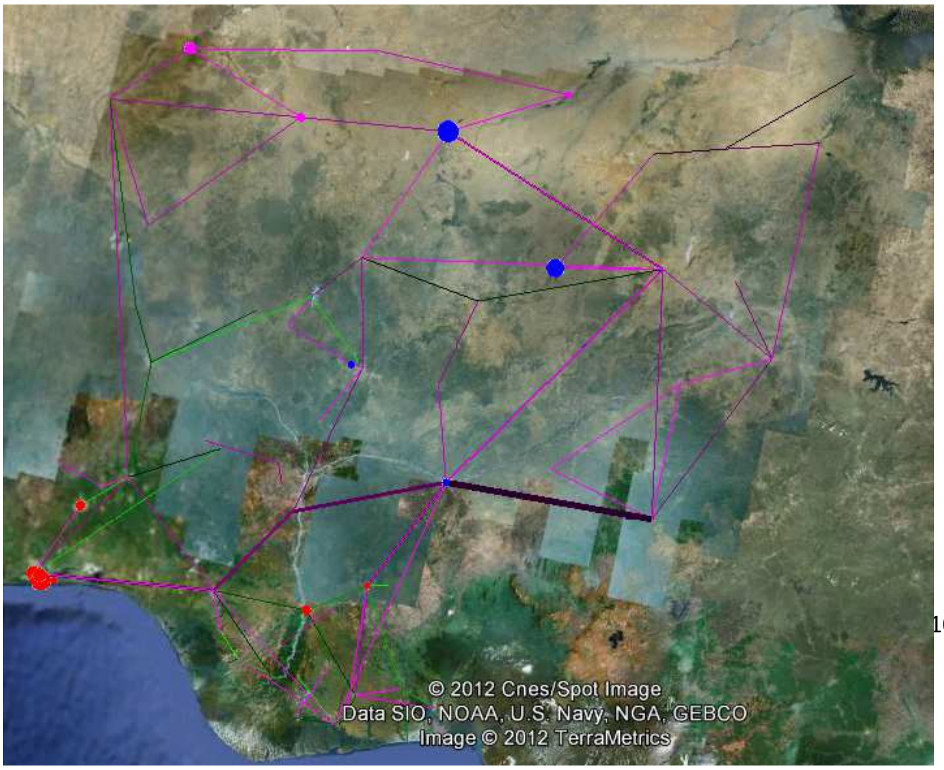
SPSS ouput of Case C[1] showing the mean and variation in SRMC for 18 years.

A1



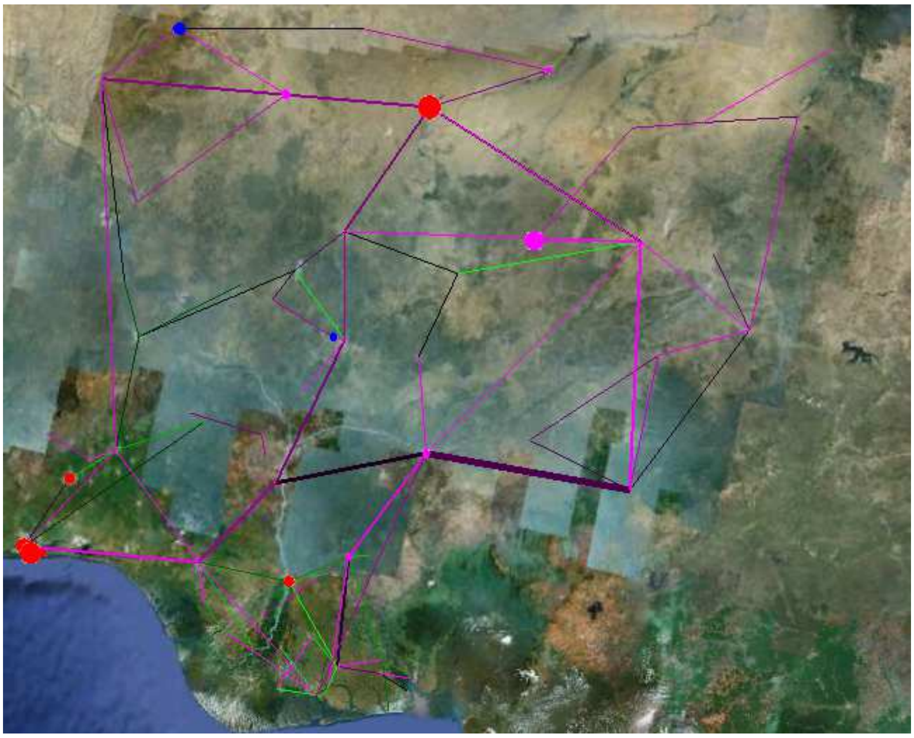
C1



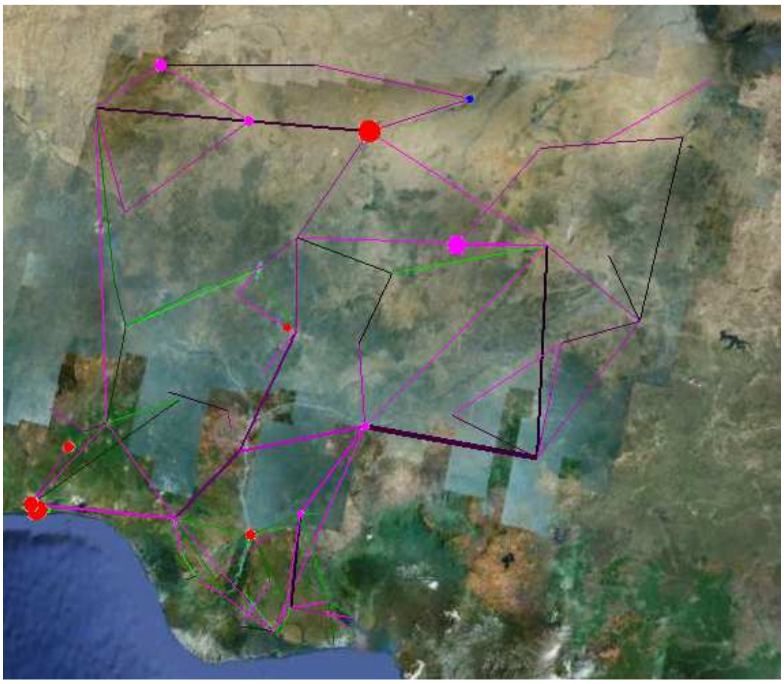


Typical TEPES output of power output of each fuel in generation with the PNS shown for generation reliability Case A, B and C

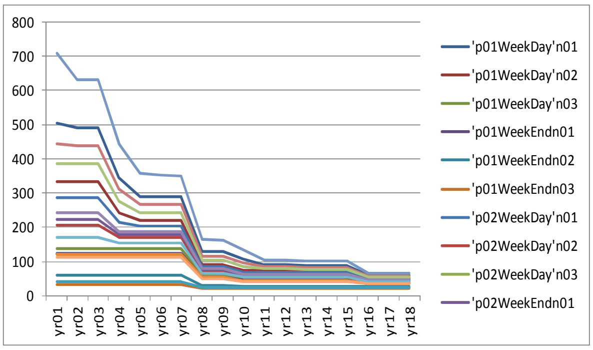
Line map of Case A[1]



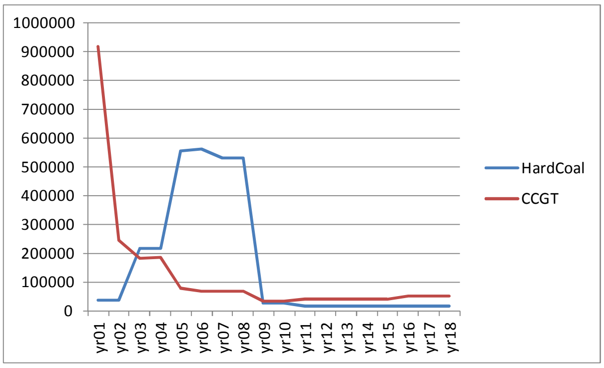
Line Maps of Case B[1]



Line maps of Case C[1]



Typivcal PNS eveolution over the years showing convergence of range from 700MW to less than 100MW



Fuel use evolution pattern showing change of dominace from gas to coal and back to equal contribution after the 9th year.

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