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# Generator Contract and Transmission Investment Options in Nigeria: Cost and Security Implications

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***Abstract*—Contractual arrangements with generating plants in Nigeria have lead to improved power generation facilities, but also new constraints. It is important to select operational stances and future investments that provide flow pattern flexibility that continues to widen options for generating parties in the bulk electricity trading pool, and accommodate different unit commitment patterns. This paper confirms and quantifies that there are mild negative consequences for hourly cost and security due to take-or-pay contracts, using a security constrained optimal power flow. It then applies an optimal transmission expansion methodology to determine transmission asset investments may improve power system security in Nigeria, rather than reducing the total level of power delivered. Several candidate lines are proposed based on the intersection of optimal line choices for separate contingencies.**

***Index Terms*—contracts, take-or-pay**

## I. Introduction

The history of power sector reform in Nigeria started with a restructuring of the generation business, which led to independent power producers. Decades of low investment and over-extension had created dysfunction regarding asset maintenance and management, and degraded customer-utility relationships, as well as significant uncertainty [1]. The need to encourage investment in further generation led to the consideration of take-or-pay contracts, to ensure viable project economics. Serving as much as power to the public as possible has been supported by independent power plants: but geographical placement of units has not necessarily been optimal from a security perspective. It is a possibility that increasing flows and power wheeling have lowered security level even though more energy may have been served over time.

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This paper attempts to quantify the likely cost of security, in terms of both operating expenditure and reduced load served, and also evaluate the consequences of take or pay contracts with a view to optimal generation costs. The question of what tradeoffs may exist between hourly costs and reliability is a crucial one that requires not only detailed simulations with an AC power flow model, but also more forward looking considerations. It is first of interest to know what tradeoffs may exist between hourly costs and reliability, and then consider where investments might go to reduce risk.

## II. Paper Structure and Contributions

The model and input data of the study are briefly introduced in Section III. The particular limitations and constraints of the Nigerian high voltage grid are then outlined in Section IV through a process of of security constrained optimal power flow computations. Having established the nature of preventative and corrective options with regard to credible contingencies, Section V continues to present the changes to operational costs and load shedding actions for the two forms of applied constraint: 1) the present *take-or-pay* agreements for specific generators 2) the prospect of constraining load allocation proportions to reflect distribution company performance as reflected in the Multi-Year Tariff Order (MYTO). A simplified grid model is then employed along with at DC power flow transmission expansion problem formulation (TNEP) to evaluate transmission reinforcement options needed in the immediate future.

### A. Take or Pay Contracts

A take-or-pay contract is an agreement between a purchaser and a seller that requires the purchaser to either

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pay for and take delivery of a pre-specified quantity of a commodity or service at a set price at specific time intervals ("take") or pay for the same quantity without taking delivery ("pay"). Take-or-pay contracts are common in the electricity industry industry where gas producers require that a gas generation power plant pay for a certain percentage of a well's (or field's) deliverable gas regardless of whether the power generation company actually accepts the gas. [2]

## III. Security Constrained Optimal Power Flow

The output of an optimal power flow provides the operating condition of the system that minimizes total system cost and meets all technical and network constraints. Typically, the solution is economically optimal, however it is not necessarily secure. If we consider that a transmission line can become unavailable due to a contingency, the currents and voltages associated with the OPF recommended dispatch of generations may violate limits, or a solution may no longer exist. The security constrained optimal power flow (SCOPF) is an extention of the OPF problem which takes into account constraints arising from the operations of the system under a predefined set of contingencies. Typically, the concept of SCOPF is to augment the initial OPF with additional constraints that relates to contingency states or to the effect an outage of an element would have on the system.

The SCOPF problem is formulated for buses $i$ in the overall set of buses $\Omega$, which can have sets $G_i$ of generators, sets $\Delta_i$ of loads, and sets $\Lambda_i$ of outgoing branches. The primal variables are $\{V_i, \delta_i, P_g, Q_g, P_{ik}, Q_{ik}, S_{ik}\}$ and for each contingency $\omega$, $\{V_i^\omega, \delta_i^\omega, P_g^\omega, Q_g^\omega, P_{ik}^\omega, Q_{ik}^\omega, S_{ik}^\omega\}$. The objective function includes the total generation cost. Conventional quality constraints for active and reactive power balance, and additional OPF constraints per contingency $\omega$h are included to ensure that if the contingency $\omega$ occurs, then there is a feasible operating condition.

There are two approaches that leads to different formulations of the SCOPF. The SCOPF can be formulated in the preventive or corrective mode, and lead to preventatively and correctively secure systems, respectively [3]. In a preventatively secure system, without any remedial action, none of the probable contingencies causes constraint violation. On the other hand, in a correctively secure system, any post contingency constraint violation can be removed by suitable available remedial actions. In this paper, we consider preventatively a secure system, as the contingencies considered are not easily dealt with by existing under frequency or over voltage automatic systems, and because operation is otherwise manual. A number of issues make the SCOPF much more challenging than the OPF problem: the significantly larger problem size, the need to handle more discrete variables describing control actions (e.g. the start up of generating units and network switching) and the variety of corrective control strategies in the post-contingency states [4].

## IV. Modeling and Assumptions

A generation fleet, grid topology, and line/transformer ratings current as of 2018 have been configured in the software PowerWorld for study. The unit commitment and loading selected are from a peak-load case reported on in 2017 [5] that reflect the highest delivery of power in Nigeria observed to date. This case, named the *full model* in this paper, has representation of lines down to 132kV and loads attached at 33kV. The cost function optimized is based on realistic generator costs estimated through discussions with the Nigerian Bulk Electricity Trader.

A system secured against credible contingencies is not always maintained in Nigeria, due to constraints of available units and confounded functioning of remedial action schemes such as UFLS [6]. To evaluate a target prospective operation, however, the high delivery case has been compared against a preventative dispatch determined using the security constrained optimal power flow (SCOPF) routine of PowerWorld.

In order to consider the transmission expansion problem, the *full model* has been reduced to represent the essential behaviour of the high voltage network in Nigeria, with loads and generation connected at the highest voltage level of 330kV, and some aggregation of the generation performed. The case is named the *reduced model* in this paper, and its DC load flow has been modeled for the purposes of understanding transmission reinforcement and expansion options.

## V. Results

The true operational cost of a robust bulk electricity system should be estimated based on realistically secure load flow. The first sub-section of results thus reports on preventative stances identified as feasible for the *full model* Nigerian grid based on a full AC model and an SCOPF analysis.

The likely improvements of the network should draw on the same credible contingencies, but can be based on a DC analysis of the *reduced model* that retains essential high voltage topology.

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### *A. Secure Operational Costs in Base and Take or Pay Cases*

The SCOPF routine of PowerWorld has been scripted to examine ten particular line contingencies reported as credible by operators at National Control Centre (NCC), as listed in Table I. In addition to respecting active and reactive power limits, voltage limits reflecting Nigerian grid code have been imposed at all buses. Since the solving algorithm of Powerworld supports the inclusion of operational decisions, the following degrees of freedom were granted to the optimization, in order of priority: generator active and reactive power dispatch, reactor switching and tap-changing, and load shedding. When applied for the case of individual contingencies, the load shedding and change in costs reported in Table I result. The deviations in cost are computed from the base case peak load conditions reported in [5].

TABLE I: SCOPF, Individual Contingencies

| Label | Contingency Name | Load Shed (MW) | Hourly $\Delta C$ (k USD) |
|---|---|---|---|
| B | Ikeja West-Egbin | 650 | -115 |
| C | Aja-Egbin | 650 | -115 |
| G | Kaduna-Kano | 199 | -4.2 |
| H | Makurdi-Jos | 199 | -4.2 |
| I | Ugwuaji-Makurdi | 194 | -4.2 |
| A | Akangba-Ikeja West | | |
| D | Omotosho-Ikeja West | | |
| E | Omotosho-Benin | 196 | -22 |
| F | Alaoji-Onitsha | | |
| J | Odukpani-Ikot Ekpene | | |

The outcomes have been grouped to reflect that two contingencies of southern lines (B and C) constitute drastic reductions in load served, due to their occurrence in the highest load density region of Nigeria. The consequence of conservative dispatch to prevent against these contingencies was judged to be excessive, and not preferable to running the risk of their occurrence.

Contingencies G, H, and I require approximately 200MW of load shed to prevent, and yet do not reduce system costs. The remaining contingencies can be protected against with a similar level of load shedding and a higher reduction in operating costs.

The consideration of single contingencies indicates that most of the credible contingencies with the exception of B and C can be combined in a *N-1* list, for coverage by a single SCOPF calculation that yields a dispatch at new cost and level of reduced load allocation (or load shed) sufficient to prevent against any member of the *N-1* list.

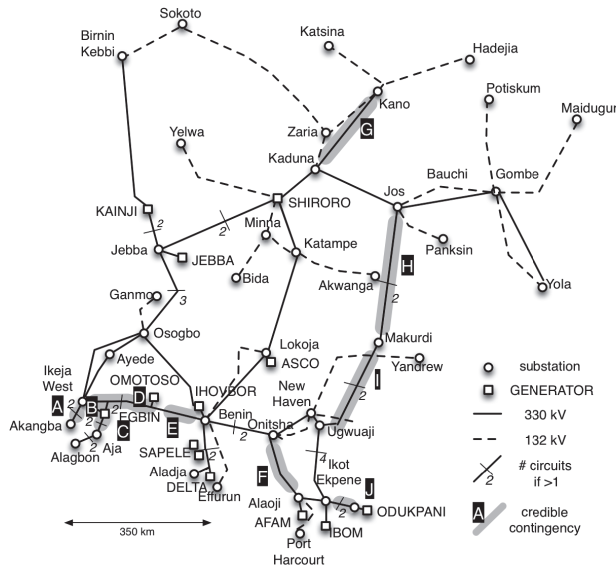


Fig. 1: Credible contingencies in the Nigerian High Voltage Grid, labelled West to East.

### *B. Effects of Take or Pay*

The take-or-pay contracts enjoyed by a subset of generators, namely Olorunsogo, Omotoso, Okpai, Afam VI, Odukpani, and Azura, were represented as an optional additional constraint that could be used to study the difference made by such contracts on operations.

The pragmatic subset of credible contingencies was taken as a requirement for preventative dispatch to achieve *N-1* security. The base case of no preventative measures has been used as the key comparison basis in Table II.

The results for *N-1* indicate a slight reduction in operating costs, but most significantly a load reduction of almost 194 MW, demonstrating that the high-delivery dispatch not only had an unrealistically low cost, but also was not secure.

The additional constraint of allowing specified generation levels by "take or pay" generating stations, results in a deviation in operating costs, as well a larger amount of load shedding needed to maintain security. In particular, operating costs increase by approximately 10%, and the load shed increases by 24MW, or approximately 12%. In reality, preventative load allocation would occur in multiples of feeders, so the increase in operating cost may be the more significant result.

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TABLE II: System Performance of Base Case (shaded) and Deviations

| Dispatch Case | N-0 (M NGN) | N-0 (MW) | N-1 (M NGN) | N-1 (MW) |
|---|---|---|---|---|
| Base Case | 5885 | 5369 | -34.7 | -194 |
| Take Or Pay | +502 | 0 | +492 | -218 |

### *C. Optimal Capital Expenditures on Transmission Reinforcement*

The insecurity identified in the previous sections can be addressed by considering transmission reinforcement and expansion options. The literature on transmission expansion planning (TEP) considering security constraints is well known. Some contributions can be found in [7], [8]. The multi objective TEP equation in (3a) is to minimize the total investment cost $F_1$

$$\min \mathbf{F_1} \quad = \quad C_k \cdot x_k \tag{1}$$

for selected candidate paths indicated by a binary variable $x_k$ (which indicates whether a prospective line is built $(x = 1)$ or not $(x = 0)$), and corresponding cost $C_k$, generation cost as in (**??**) (here now $\mathbf{F_2}$) and a total load shedding cost

$$\min \mathbf{F_3} \quad = \alpha \sum_{i \in \Omega} r_i \tag{2}$$

with punishment factor $\alpha$ for each shed load $r_i$.

For $\omega$, one of $N_c$ contingencies, the multi objective transmission expansion problem with original lines $\Lambda_{0i}$ and candidate lines $\Lambda_{+i}$ available at each bus $i$ in $\Omega$ as a set $\Lambda_i = \Lambda_{0i}\Lambda_{+i}$ is presented as follows

$$\min \mathbf{z} = \mathbf{F_1} + \mathbf{F_2} + \mathbf{F_3}, \text{s.t.,} \quad \forall i \in \Omega : \tag{3a}$$

$$\sum_{k \in \Lambda_i} P_{ik}^{\omega} = \sum_{g \in G_i} P_g + r_i - \sum_{d \in D_i} L_d \tag{3b}$$

$$0 = P_k^{\omega} - \mathbf{B}_k(\theta_i^{\omega} - \theta_j^{\omega}), \quad k \in \Lambda_{0i} \tag{3c}$$

$$-M_k(1 - x_k) \leq P_k^w - \mathbf{B}_k(\theta_i^w - \theta_j^w) \leq M_k(1 - x_k), \quad k \in \Lambda_{+i} \tag{3d}$$

$$-P_{ik}^{max} \leq P_{ik}^{\omega} \leq P_{ik}^{max}, \quad k \in \Lambda_{0i} \tag{3e}$$

$$-x_k P_{ik}^{max} \leq P_{ik}^{\omega} \leq x_k P_{ik}^{max}, \quad k \in \Lambda_{+i} \tag{3f}$$

$$P_g^{min} \leq P_g \leq P_g^{max}, g \in G_i \tag{3g}$$

$$x_k \in \{0, 1\}, k \in \Lambda_i \tag{3h}$$

$$-\pi \leq \theta_i^{\omega} \leq \pi \tag{3i}$$

$$\omega = 0, 1 \cdot \cdot N_C \tag{3j}$$

where line impedance is the susceptance $B_k$, angles are the linearized angle $\theta_i$, and flows are purely real due to the DC power flow assumptions. Objective Equation (3a) is constrained by equations (3b) - (3i). Constraint equation (3b) represents the conservation of power (Kirchhoff's 1st law) in each node of the system. Constraints (3c)-(3d) (Kirchhoff's 2nd law) for the equivalent DC circuit for existing and candidate transmission circuits respectively. The constraint on existing and candidate branch flows to be within upper and lower bounds is shown in constraint equation (3e)-(3f). The generation upper and lower bounds are included in equation (3g) the binary line existence variable in (3h), and the angle constraints in (3i).

Table III show the results of solving (3a) on the *reduced system* using CPLEX 24 under GAMS, on a SGI R12000, 400-MHz-based processor with 500 MB of RAM, with optimality gap 0.01. The base case was studied along with a number of contingencies. Some contingencies that appeared separate (A,B,C) in the full model are aggregated in the reduced model. All candidate lines selected in this study by any optimization run are shown in Fig. 2, labelled as lower case letters.

In the base case, 123k USD is required to develop a viable case that eliminates the overload effects of contingencies J, H, G, and F. The TNEP evaluation shows that these contingencies are related. Table III shows further investment costs as incremental for each contingency. Even further investment is required, if the formerly studied contingencies A/B/C, I, and D, as well as an additional contingency $\star$ related to losing the line connecting the generator Olorunsogo, are to be countered through investment. With the exception of the Lagos area reinforcements, the contingencies requiring further investment are closely tied to ensuring generators in the south-east are able to deliver their power to distant loads.

TABLE III: Expansion Decisions to Eliminate Load Shedding; Base (shaded) and Per Contingency

| Case Candidate Label | Inv Cost (k USD) | $d$ | $e$ | other |
|---|---|---|---|---|
| Base | 123 | 2 | 1 | - |
| G | - | 2 | 1 | - |
| H | - | 2 | 1 | - |
| F | - | 2 | 1 | - |
| J | - | 2 | 1 | - |
| A,B,C | +9 | 2 | 1 | $a$ |
| I | +13 | 2 | 1 | $f$ |
| $\star$ | +25 | 2 | 1 | $b$ |
| D | +78 | 2 | 1 | $c$ |

Base Case: Generation Cost 5444 M USD

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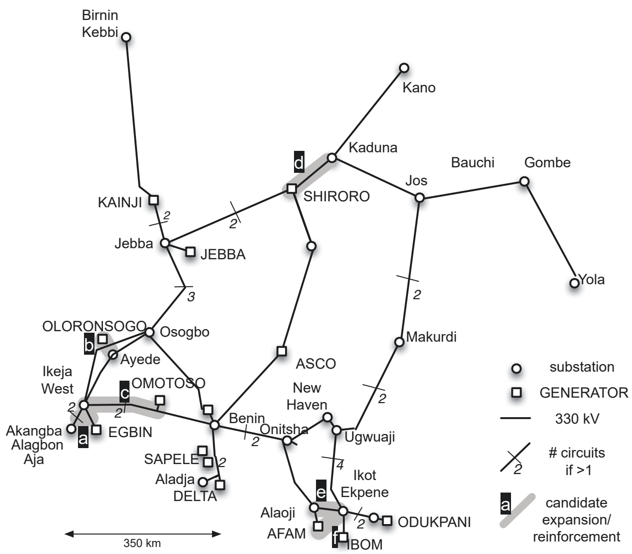


Fig. 2: Identified expansion/reinforcements in the Nigerian High Voltage Grid, labelled West to East.

## VI. Discussion

Taking the two studies (SCOPF and TNEP) of Section V together, a picture emerges of higher risk operation that requires investment to ensure security. Without a consideration of credible contingencies, the original high-load case originally reported in [5] may be an optimistic estimate of feasible power delivery by as much as 200MW; while this was achieved in practice, SCOPF analysis (Section V.A) and operational experience confirm this is likely an insecure dispatch. Table II indicates that whether operation is secure or not, the provision of take-or-pay contracts (Section V.B) results in approximately a 10% increase in system operational costs, and slightly more load shedding (equivalent to an additional 24 MW, or several feeders worth) to ensure security. The load shedding performed lowered operational costs, but is clearly undesirable. TNEP analysis (Section V.C) shows that a combination of shoring up of load area transmission (candidates $a, d$) and generation evacuation (candidates $b, c, e, f$) would restore the system to secure operation without load shedding relative to the base case.

## VII. Conclusion

This paper has examined realistic full and reduced models of the Nigerian high voltage transmission system, operating for a case of high power delivery of 5.5 GW. Mildly increased cost and reduced security resulting from enforcing take-or-pay contracts have been quantified. However, the required load shedding to remain secure in the face of credible contingencies even without take-or-pay contracts has likely not before been quantified or operationally deployed, and is of a similar size regardless of whether take-or-pay is implemented. Because of the obvious need to not load shed, and liberate value from existing generation, specific transmission investments that would reduce the impact of the credible contingencies studied have identified and are recommended for further study.

Although the peak-load case selected for evaluation is a challenging and also desirable configuration, throughout the year other unit commitment cases occur that may also have challenging security tradeoffs, delivering lower loads with greater fragility. A full evaluation of security and costs should include other likely unit commitment and load scenarios encountered throughout the year, and an assessment of reliability experienced at customer nodes should include outage rate information.

## Acknowledgment

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