Enhancing Dispatch Efficiency of the Nigerian Power System: Assessment of Benefits

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Abstract: Although developing countries typically deal with the challenge of mobilizing investments for adding new generation and transmission capacity to cope with high demand growth, there are often opportunities to enhance operation of existing generators and extract significant cost reduction as well as the ability to meet greater demand. This is particularly relevant for the Nigerian power system that has 13 GW of installed capacity but could meet only 5.2 GW of peak demand in 2018 at an average capacity utilization of 27% of its thermal (mostly gas) generation fleet. There are simple steps that can be adopted to restore merit-order based dispatch that can immediately yield an operational cost reduction. Increased plant availability, gas supply to power plants, and removal of uneconomic take-or-pay obligation are increasingly onerous tasks, but with commensurate significantly higher payoffs.

We have used a dispatch analysis model to show that merit-order based dispatch within the current constraints can yield an annual benefit of $29 million or 4% of variable costs. With the removal of physical availability constraints around plants and gas supply, benefits increase by an order of magnitude to $309 million, or 19% of total annual costs. If it is possible to get rid of the uneconomic take-or-pay obligations, benefits would further increase to $579 million or over 30% of total annual costs. These are major findings especially if we consider these in the context of tremendous financial stress in the power sector. Although we do not estimate the cost of implementing these measures, there are very little hard investments needed in some of these cases such as establishing a strict merit-order based dispatch or enhancing operational practices to improve plant and gas availability. There are indeed difficult commercial and institutional issues when it comes to renegotiating take-or-pay contracts, albeit the massive benefits in excess of half a billion dollar per year should make it a worthwhile undertaking.

Removal of operational and commercial constraints could also allow the Nigerian power system to meet increased demand to the benefit of unserved residents or businesses, and pave the way towards increased penetration of variable renewable energy (VRE) resources. We have shown that an addition of 500 MW solar capacity in the current system will earn reasonable return on investment between 4% and 9% and help to meet increased demand. However, an important precondition for adding large-scale solar is to raise the spinning reserve capability in the system through additional investments in flexible resources, namely, open cycle gas turbines (OCGT), pumped storage hydro or battery storage systems.

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1. Introduction

Least-cost operation of existing power sector assets calls for economic dispatch of generation resources subject to honoring technical constraints including system security. Efficiency of dispatch in power systems is an important health check of the existing system to ensure that the incumbent system is using resources efficiently up to its full potential and can improve to accommodate low carbon resources going forward. Inefficient dispatching may include unnecessary usage of expensive resources like diesel and/or leave part of the demand unserved that may translate into hundreds of millions of dollars. A dispatch efficiency study conducted for Bangladesh in 2014 [1] showed that even in a relatively small system of 11 GW (at the time of the study), well over a billion dollars could be saved by reducing unnecessary reliance on oil and use available domestic gas more efficiently. Absent a wholesale electricity market in 80% of the developing countries, it is critical that such a health check is performed on dispatch practices not only to reduce costs, but also to explore ways to introduce much-needed flexibility in these systems so that variable renewable energy (VRE) can ramp up rapidly without jeopardizing system reliability. These studies can also be extremely useful to examine any observed deviation in dispatch from a strict merit-order outcome and understand constraints that prevented the system from following a least-cost dispatch. The framework can also be used to perform a cost-benefit analysis of the "offending" constraint. For instance, availability of fuel, transmission constraints, system security requirements[1] are technical issues that may prevent dispatch from being optimal. However, it is worth asking the question what the reduction in system costs would be if these constraints are removed. A bigger barrier to least-cost dispatch are often the "commercial constraints" including expensive take-or-pay (ToP) generation contracts that may have been signed at certain point in time for various reasons (including severe power shortages that may have prevailed at the time). ToP obligations may mean that cheaper generation including solar and wind in the recent years cannot be fully dispatched because the sellers and buyers are locked into these contractual obligations. Again, it is worth asking the question what costs are being imposed on the system due to these obligations and seek ways to restore dispatch efficiency, e.g., contracts for differences (CfD) have been used to compensate the sellers for any losses they incur if they make room for cheaper generation. A comparison between the actual dispatch and the counterfactual economic dispatch through a dispatch efficiency study can therefore highlight important deficiencies, or constraints, in the power system and form the basis of a power sector reform or optimization program. Such exercise is especially warranted in developing countries where the dispatch process absent a market regime tends to be opaque, manual, and inefficient. The inefficiency of the dispatch process may have its genesis in the use of outdated dispatch process (e.g. manual merit-order dispatch absent a modern SCADA/EMS system), significant technical constraints (e.g. transmission limits or frequent transmission system outages, low power plant availability, restricted fuel supply, etc.), or significant commercial constraints (e.g. expensive power purchase agreements, high fuel prices, lack of available financing, etc.).

A dispatch efficiency study in generic terms answers the following research questions:

(a) How can we set an **efficient benchmark**, namely, an optimised generation dispatch?

(b) **Testing the sub-optimality of dispatch:** Are the existing generators used optimally to meet demand?

(c) **Dispatch diagnosis:** What explains the divergence from an efficient benchmark?

(d) **Renewable readiness:** Is the system ready to accommodate significant levels of renewable resources?

(e) **Remedial measures:** What needs to change to ensure improved utilization of existing generators? What additional measures need to be put in place to increase penetration of solar and wind?

[1] As an example, some generators may need to be on to provide voltage support, frequency control and inertia.

Previous dispatch efficiency studies have demonstrated that potential savings from implementing economic dispatch procedures can be significant with very little investment. Nikolakakis et al. demonstrated that massive savings in the range of 1.40 - 1.65 billion USD per year where possible in Bangladesh by comparing the actual and the optimal hourly dispatch [1]. The savings could be realized through simple technical measures (e.g. adoption of a proper dispatch optimization software) to enhance the dispatch optimization procedure and allocating 23% additional gas to the power sector. In India the implementation of a real-time economic dispatch engine for 52 thermal plants resulted in savings of more than 100 million USD per year [2] - [3]. At the same time, the economic dispatch resulted in a much smoother operation of coal plants. Efficient plants stay on all the time at their maximum available level and inefficient plants are shut down or remain stable at their minimum generation loading. A World Bank (WB) study for Uzbekistan highlighted potential annual savings of 34 million USD through a change in the dispatch of plants with an increased use of more efficient plants. Additional investments in the transmission network and higher availability of natural gas could further increase the benefits to about 100 million USD per year [4]. Chen et al. [5] report that economic dispatch of coal-fired generators in China could save 5.67% of the coal used for power generation per year (0.05 per cent of the Chinese GDP in 2014 or 9.1 billion USD). While multiple studies exist in the Asian context, to the best of our knowledge similar studies for African power systems at the country level have not been carried out previously. Our work focuses on the predominantly thermal system of Nigeria which suffers from different operational and commercial constraints.

1.1 Nigerian Context

Poor service delivery in Nigeria's unbundled power sector keeps hampering Nigeria's economy and its 202 million citizens. Even after privatization, power supply remains unreliable in the country. The low supply reliability results in low consumer willingness to pay, drives industry and businesses to pursue expensive off-grid alternatives (typically in the range of 0.20-0.30 USD/kWh compared to the grid based tariff of 0.16 USD/kWh) and causes economic losses of more than US$25 billion per year [6]. A 2018 World Bank Enterprise Survey shows that electricity supply is consistently the biggest constraint to doing business in Nigeria [6].

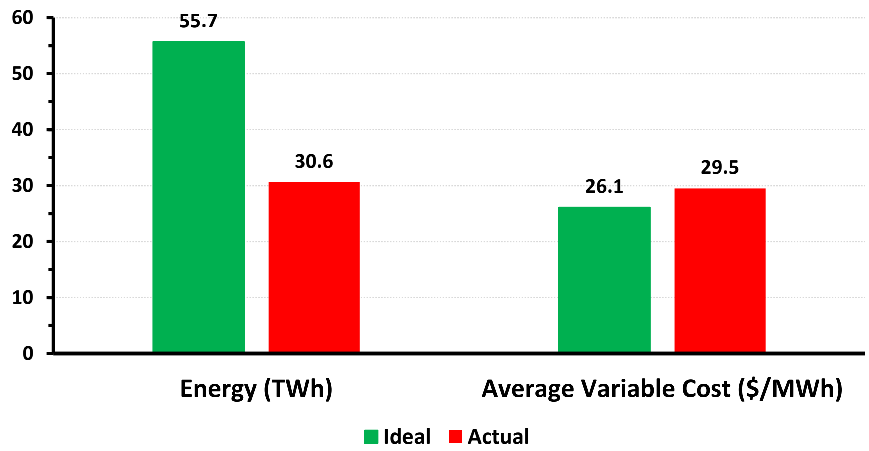
The poor service delivery results from a multitude of interlinked challenges: (i) low operational performance of generation and distribution companies (DISCOs); (ii) limited gas availability for generation plants; (iii) transmission network constraints; (iv) poor financial viability of power sector companies; (v) weak governance and inadequate enforcement of contracts; and (vi) lack of investment planning and procurement framework [6] [7] [8] [9] [10]. Poor financial viability of generation and distribution companies hampers their ability to maintain or upgrade their assets and carry out capital expenditure programs resulting in a decreasing supply reliability (e.g., low availability of power plants and frequent power outages for customers). Absence of cost-reflective tariffs and the low collection rate at 64% in 2019 [11] are two key sources of the poor financial viability of the DISCOs. These two problems manifest themselves through other constraints and there is a vicious circle that brings the performance of the sector down. For instance, low tariff and collection rates leads to a deteriorating supply reliability in the distribution networks, which in turn makes it difficult to raise tariffs and enforce collections. Poor financial viability of DISCOs and lack of enforcement of the contractual framework leads to low remittances from the DISCOs (27% of invoices in 2019 [11]) to the government-owned bulk trader (Nigerian Bulk Electricity Trading company or NBET). Lack of payments from DISCOs to NBET in turn affect NBETs ability to meet all its payment obligations towards generation companies (GENCOs) and the national transmission company (TCN). Poor financial performance of the sector leaves very little room to mobilize new investments and this leads to a reliance on Independent Power Producers (IPP) to bring in the investments, albeit often at a premium built into the Power Purchase Agreements (PPA). NBET's financial viability is further lowered due to expensive PPAs including the physical Take-or-Pay (ToP) provision with the IPPs. NBETs inability to pay the GENCO has either lowered the GENCOs financial standing or their willingness to sell power to NBET. Non-payments from NBET to GENCOs has reduced the operational efficiency including lower availability due to unwillingness to sell power and/or more outages due to delayed maintenance or unavailability of spare parts, and hence the GENCO's ability to honor fuel supply agreements with gas suppliers.

The absence of an investment planning framework and competitive procurement frameworks further exacerbates the sectoral issues leading to increased costs and contingent liabilities for the country. Finally, the transmission system is operating well below international reliability and security standards [7] resulting in total transmission and distribution losses of 12 percent in 2016. There were six major system collapses in 2016. Frequency and voltage recordings often exceed established norms. System collapses (when not caused by generation outages) are primarily the result of inadequate maintenance of outdated equipment and lack of a modern Supervisory Control and Data Acquisition (SCADA) system to manage real time operation and control.

As the discussion alludes to – there is a complex chain of constraints that throttle the sector and the upshot is a highly inefficient system operation. The installed power generation capacity is around 13 GW including 2 GW of hydro (three plants: Jebba, Kainji, and Shiroro) and 11 GW of gas-fired power plants. However, the available dispatchable capacity ranges between 3 to 5 GW and total energy generated in 2018 was only 33.7 TWh due to (a) low operational availability; (b) gas supply constraints resulting from non-payment for gas supply; (c) and gas pipeline vandalism.

Figure 1 shows at a high level the extent to which these constraints are affecting energy delivery and increasing generation cost. The "Ideal" scenario assumes increasing the gas fleet utilization from its current abysmally low level of 27% to a moderate average capacity factor of 50%. The "Actual" scenario shows actual Nigerian demand met in 2018 which is as much as 45% lower than this potential. Although Nigeria is endowed with domestic gas that is produced on average at low (variable) cost under $30/MWh, we infer from the system data that the average generation cost in 2018 in reality was at least 12% higher. Although the genesis of the low generation availability and high cost of generation is much deeper into the low tariff and collection rate, the process of addressing these issues and rebuilding the sector fundamentals can indeed start by fixing the relatively easier problem of dispatch. If more power can be generated at a lower cost, this can reduce the financial burden to some extent and improve power delivery. This in turn can make a tariff increase and collection rate improvement more likely than it would otherwise be, therein beginning to reverse the downward spiral we discussed above.

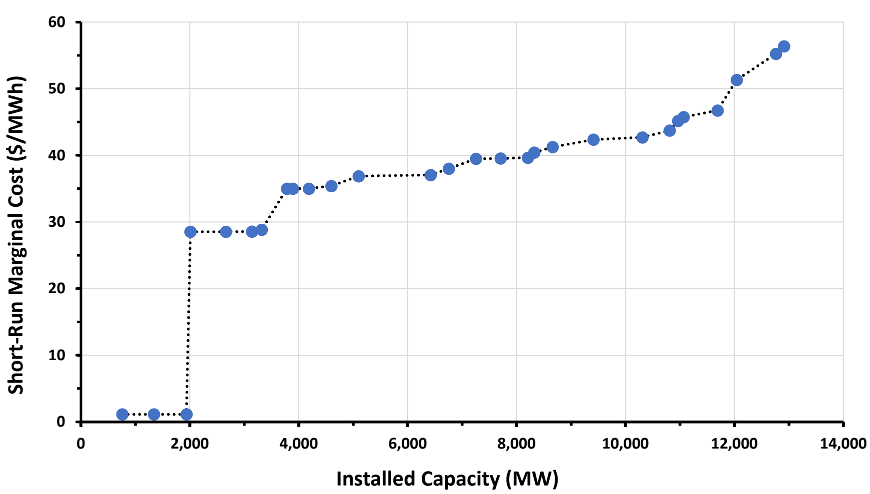
Figure 1. Energy and average variable generation cost: potential vs. reality



Notes: 'Ideal' is calculated assuming a 50% average capacity factor for the entire gas generation fleet at a generation efficiency of 45%. 'Actual': actual for 2018. Energy (TWh): Nigerian demand met through the grid. Average Variable Cost: Only fuel and variable O&M costs for generation using 2018 actual plant level costs.

A significant advantage for Nigeria is that the country has rich primary energy resources available at a low cost which may make the process easier. Figure 2 shows the merit-order curve. Nigeria has a relatively inexpensive generation fleet with 8 GW capacity under 4 USc/kWh and 12 GW under 5 USc/kWh. There are significant fixed costs attached to many of the plants – an issue that we will discuss in the context of the take-or-pay contracts. Nevertheless, operational enhancements can reduce unnecessary waste from running inefficient and expensive plants ahead of others.

Figure 2. Merit-order curve with short-run marginal cost of Nigerian generators.



This analysis investigates the potential benefits of improved performance in the generation subsector due to increased operational availability of power plants, increased availability of gas for power plants, and the optimization of PPA contracts coordinated with economic dispatch. Moreover, we analyze the benefits of integrating new variable renewable energy (VRE) resources in the Nigerian system and the impact of increased VRE penetration on spinning reserve requirements and prices.

1.2 Key Research Questions

The analysis covers a dispatch analysis for Nigeria. The specific research questions are:

1. Are the existing generating assets getting dispatched in the best possible way? Are there significant deviations between the observed actual and least-cost/optimal dispatch given constraints on technical availability of power plants or gas availability?
   We will base the analysis of this research question on energy costs only (short-run marginal costs). The bigger issue in Nigeria often relates to fixed charges and forced out-of-merit dispatch obligations built into PPAs which we consider as part of the research question 2.

2. What are the benefits of optimal dispatch under the existing PPA obligations (including energy, capacity charges and Take or Pay obligations)? What are the benefits of optimal dispatch under the existing PPA obligations (including energy and capacity charges) without the existing Take or Pay obligations in the absence of any plant availability or gas supply constraints?

3. What are the benefits for Nigeria if an additional 7.6 TWh per year (25% of the 2018 Nigerian demand met through the grid which stood at 30.6 TWh) could be generated in the absence of the existing plant availability and gas supply constraints?

4. What are the impacts of increased integration of VRE especially solar? What would the expected return on investment be for new solar capacity? What are the implications of imposing a spinning reserve constraint in a system characterized by a tight demand-supply balance like Nigeria?

1.3 Overview of Power System Modelling Literature

The basic dispatch optimization model with constraints on fuel availability and plant level availability to answer research questions 1, 2 and 3 is well established dating back to the eighties and described in detail in Wood et al. [12]. To analyze the impacts of increased VRE penetration we need to extend the dispatch optimization model to include co-optimization of spinning reserve. Co-optimization of spinning reserve and generation has extensively been studied since the late nineties. Initial work focused on the New Zealand and Australian market [13] [14]. The New Zealand and Singapore market implemented a DC approximation of the Optimal Power Flow (DC-OPF) [14] [15]. Ehsani at al. [16] discusses the concept of opportunity cost of spinning reserve and compensation mechanisms that the system operator can use. Introduction of variable/intermittent renewable energy tends to raise the requirement of spinning reserve [17]. The importance of this issue in capacity or energy constrained systems has been highlighted in the context of the Indian power system where variability of wind power caused market prices to go up dramatically in recent years [18].

There is a small but growing literature on the subject that combines the aspects of economic dispatch with ancillary services in power systems with potentially significant variable RE systems e.g., [19] [20] [21] [22] [23] [24] [25]. One of the significant highlights of the international literature covering primarily the geographies in North America and Europe is that these systems are primarily adjusting to the variability of renewables through an improvement in (a) accuracy of variable renewable energy supply forecasts, e.g., wind and solar forecasts in day-ahead and in real-time;

(b) flexibility of the non-renewable supply as well as demand response; and (c) pricing mechanism to pay for flexibility. These issues are important even in capacity surplus systems because flexibility cannot be assumed to be automatically available, and in fact may come at a significant opportunity cost [21] [24]. There are in fact significant challenges faced in systems where the VRE penetration increased rapidly as was the case in Germany [26], South Australia [27], Spain [28], Ireland [29], etc. However, these issues are *critically* important in systems where the demand-supply balance, even without variable renewables, has been tight as is the case in Nigeria. Any variability in renewable energy can have a profound impact on supply and hence prices as the case studies for India [18] and Bangladesh [1] amply demonstrate. Spinning reserve in such deficient systems can come at a significant premium.

2. Methodology

2.1 General

We use a robust methodology that can work with existing modelling tools and available data using the following steps:

1. **Establish an Efficient benchmark:** Develop a security constrained dispatch optimization model that dispatches all generating units in the power system on an hourly basis for one or more years. The model can reflect as many of the constraints that the system faced in reality. We use the Electricity Planning Model (EPM) developed by the World Bank Planning group (Chattopadhyay et al. [30]) to model the actual and optimal dispatch.
2. **Compare with actual dispatch:** Optimized dispatch can then be compared with the actual dispatch. If the actual system costs and underlying generation dispatch are significantly different from the efficient benchmark, one can pin-point the wasteful excess generation from expensive units as well as cheaper resources that were underutilized.
3. **Dispatch diagnosis:** This step follows steps 1-2 to set out the plausible reasons behind departure of the actual dispatch from the efficient benchmark that may fall into the following four broad categories:
    a. Poor dispatch practices including the fact that the system operator follows simple rules of thumb that do not adequately use the cheaper resources;
    b. Operational constraints such as low availability of power plants due to *inter alia* significant maintenance requirements/lack of spare parts/old equipment, limited fuel availability, limited water availability for hydropower plants;
    c. Commercial constraints imposed for example by take-or-pay (ToP) obligations of PPAs that force expensive generation to be dispatched ahead of their cheaper counterparts. These commercial constraints can often be a significant issue and if the PPA constraint parameters (e.g., take or pay volume and penalties associated with violating these) are known, it is possible to dig deeper into some of these issues and pinpoint the sub-optimal PPAs;
    d. Other constraints that are not captured in the modelling but had an impact on the actual dispatch (e.g., expensive generators that need certain minimum run hours in a year, available hydro that could not be utilized optimally due to environmental or agricultural restrictions, or there are other must-run conditions to maintain system voltage, etc.)
4. **Checking renewable readiness:** Steps 1-2 above can also be used to test the adequacy of spinning reserve for each hour. Availability of spinning reserve is critical to accommodate variability in solar and wind resources. The framework can be used, for instance, to check that, if x MW of wind/solar requires an additional 0.2x MW of spinning reserve to be carried[2], the spinning reserve can be elicited from the existing generators (and additional costs incurred to adjust the dispatch). We typically find that poor dispatch practices mean there is no allowance made for spinning reserve to cover for the largest source of generation

[2] The 0.2 multiplier relates to the uncertainty around solar forecasts for 1-2 day ahead dispatch. Although forecast accuracy has improved significantly especially for intraday dispatches, our experience working with operators in developing countries who do not have an integrated renewable desk in control centers in most cases including Nigeria suggest a maximum error band of 20% is still commonplace.

in the existing system, let alone cover for variability of solar/wind. If this is the case, there are additional measures needed to accommodate solar/wind even if these resources are cost-effective.

5. **Remedial measures**: Steps 1-4 can lead to a set of prioritized actions that may include:
    a. Enhancing dispatch practice by either upgrading the Supervisory Control and Data Acquisition (SCADA) system or adding an appropriate dispatch optimization tool in the Energy Management System (EMS).
    b. If the analysis identifies significant plant availability, fuel, reserve or transmission constraints, it is also important that remedial measures include investment in upgrading specific generation units or transmission lines, allocate wherever possible additional gas to the power sector, and consider flexible reserve investments including battery storage. The methodology presented in steps 1-4 is in fact a cost-benefit framework for each of these options.
    c. If the commercial constraints turn out to be a significant issue both for inefficient dispatch in the current system as well as detrimental to the entry of solar/wind in the system, they require special attention. There are several possibilities even within the realm of keeping the incumbent independent power producers financially whole. These may include offering the generators contracts for differences (CfD). Such contract would allow the system operator to dispatch the expensive plants at lower levels but compensating them nonetheless to the level that the PPA entails, so that the system does benefit from cheaper generation resources, including renewables, to be dispatched ahead of the more expensive plants. It may also allow for these generators to be paid a capacity charge and not be dispatched or waive the penalty associated with lower capacity factor. Other options may include introducing an ancillary service payment and get these expensive generators to offer spinning reserve and be paid for it.
    d. Renewable readiness needs to specifically address the issue of added flexibility. This may, first and foremost, include holding reserve on generators that are most flexible even if it means forgoing otherwise economic generation opportunity from these resources. For instance, hydro generators or flexible gas generators in the system may have to be operated quite differently. Hydro generators will need to hold water as “reserve” during hours of solar generation. In addition, large scale penetration of solar and wind may need more flexible capacity including battery or pumped storage, and possibly additional transmission capacity.

2.2 Model

We use the electricity planning model (EPM) implemented in the General Algebraic Modelling System (GAMS) to model dispatch optimization [30] [31]. We define optimal dispatch as the lowest cost dispatch that minimizes the system cost while accounting for system constraints discussed below. The objective function Z minimizes the sum of costs for all plants, revenue from power export with neighboring countries (Benin and Niger), and cost of unserved energy. The key variables are the power outputs for each generator (Gen_g):

$$Z = \sum_{g,f,m,d,t} Gen_{g,f,m,d,t} * Cost_g * Duration_t - \sum_{z_{ext,m,d,t}} Export_{Nigeria,z_{ext},t} * ExportPrice_{Nigeria,z_{ext}} * Duration_t + \sum_{m,d,t} U_t * VoLL * Duration_t$$

Where, g: set of generators (hydro or gas-based generators)
f: fuel type (hydro or gas)
m: set of 12 months in a year

d: set of days in a month
t: set of 24 timesteps (hours) in a day
Gen: power output of generator g with fuel f in timestep t (MW)
Cost: cost of generation (USD per MWh)
Duration: duration of a timestep t (1 hour)
Export: export of power from Nigeria to an external zone z_{ext} (Niger or Benin) in MW
U: Unmet demand (MW)
VoLL: value of lost load (USD per MWh)

The EPM dispatch model honors the following operating constraints:

1. Meeting local Nigerian demand for each time step;

$$\sum_{g} Gen_{g,f,m,d,t} - \sum_{z_{ext}} Export_{Nigeria,z_{ext},t} + U_t = LocalDemandMet_t$$

2. Maximum capacity limit (MW) and technical availability for each generating unit (%);

$$Gen_{g,f,m,d,t} \leq Cap_g$$

$$\sum_{d,t} Gen_{g,f,m,d,t} * Duration_t \leq Availability_{g,m} * \sum_{d,t} Cap_g * Duration_t$$

With Cap: Capacity of plant g (in MW)
Availability$_{g,m}$: monthly availability for plant g (%)

3. Monthly energy limit (MWh) for the hydro plants;

$$\sum_{d,t} Gen_{g,hydro,m,d,t} * Duration_t \leq HydroEnergyLimit_{g,m}$$

4. Monthly gas supply limits by thermal power plant (in billion cubic feet);

$$\sum_{d,t} Gen_{g,gas,m,d,t} * HeatRate_g \leq GasLimit_{g,m}$$

Where, HeatRate is the heat rate for a given gas plant (MMBTU per MWh)

The analysis of the renewable readiness involves adding one additional term to the objective function Z to penalize unmet spinning reserve and as such co-optimize dispatch and ancillary services:

$$Z = \sum_{g,f,m,d,t} Gen_{g,f,m,d,t} * Cost_g * Duration_t - \sum_{z_{ext,m,d,t}} Export_{Nigeria,z_{ext},t} * ExportPrice_{Nigeria,z_{ext}} * Duration_t$$
$$+ \sum_{m,d,t} U_t * VoLL * Duration_t + \sum_{m,d,t} UnmetSpinReserve_t * SpinResVoLL * Duration_t$$

Where, UnmetSpinReserve: unmet spinning reserve (MW), and
SpinResVoll: penalty for not meeting spinning reserve (USD per MWh)

Three additional constraints are also introduced to account for reserve requirements and the intermittency of VRE generation resources:

5. Solar power is limited by the hourly capacity factor (CF);

$$Gen_{g,solar,m,d,t} \leq CF_{solar,t} * Cap_g$$

6. Required spinning reserve must be met by existing generators;

$$\sum_g Reserve_{g,f,m,d,t} + UnmetSpinReserve_t = Required\ SpinningReserve_t$$

With $Reserve_{g,f,m,d,t}$: reserve provided by generator g (in MW)
Required Spinning Reserve: total amount of spinning reserve required (in MW).

7. Each generator can only assign a certain fraction of its capacity for reserve;

$$Cap_g * MaxReserveShare_g \leq Reserve_{g,f,m,d,t}$$

With $MaxReserveShare_g$: the maximum percentage of capacity that can provide reserve for a given generator.

2.3 Scenarios

Table 1 lists the different scenarios to answer the research questions together with the relevant costs and constraints.

Table 1. Overview of scenarios

Scenario	Description	Costs	Constraints
Actual	Actual dispatch to estimate current dispatch costs accounting for either variable charges only or all charges (energy, capacity, and ToP obligations)	Energy costs only or all charges	• Plant availability • Gas supply limits • ToP capacity (only when considering all charges)
50%AV	Availability of gas plants is increased to the maximum reported monthly availability allowing the system average gas plant capacity factor to increase from 27% to 50% while keeping reported gas supply limits.	Energy costs	• Gas supply limits
50%AV + 20%GAS	Gas plant availability is increased as for 50%AV scenario and the gas supply limit for each plant is increased with 20%.	Energy costs	• Gas supply limits +20%
50%AV + MAXGAS	Gas plant availability is increased as for the 50%AV scenario and gas supply constraints are lifted.	Energy costs	
Optimal-ToP	Optimal dispatch under the existing Take-or-Pay obligations	All charges (energy, capacity, and ToP obligations)	• ToP capacity obligations
Optimal-No-ToP	Optimal dispatch with no operational nor commercial constraints (no ToP obligations).	Energy and capacity charges	
High Demand	Demand is increased with 25% (7.6 TWh) in the absence of any constraints	Energy costs or the sum of energy and capacity charges	
RE-Solar	Assessing the benefits of new solar parks (500 MW or 1 GW) under different levels of demand.	Energy costs or the sum of energy and capacity charges	• Solar availability • Spinning reserve

The following comments provide clarification on the construct of these scenarios:

- Annual benefits are calculated as the difference in calculated annual system costs. The 50%AV, 50% + 20%GAS, and 50%AV + MAXGAS estimate the savings in energy (variable) costs versus the actual dispatch from either increased plant availability or a combination of increased plant availability and increased gas supply. These three scenarios will allow us to answer research question 1 and determine the relative contribution of lifting a) plant availability constraints and b) gas supply constraints, to the benefits under optimal dispatch.

- The Optimal-ToP and Optimal-No-ToP scenarios will help to answer research question 2 and give us an upper bound to the benefits relative to the actual dispatch since these two scenarios consider energy and capacity charges either in the presence of the existing ToP obligations (Optimal-ToP) or without the ToP obligations (Optimal-No-ToP).

- The High Demand scenario answers research question 3. Since only 35% of the forecast demand was met in 2018 [32], we calculate the potential benefits of meeting additional demand in the absence of plant availability and gas supply limits. We calculate a range of benefits where the lower end of the range refers to savings in energy costs only and the higher end includes savings in terms of both energy and capacity charges.

- The RE-Solar scenarios investigate the return on investment of adding either 500 MW or 1 GW of solar to the power system under increasing demand conditions (research question 4). The addition of 500 MW or 1 GW solar capacity is in line with the Master Plan 2019 [33] and the Renewable Energy Master Plan (REMP) which aims to install 500 MW solar PV by 2025 [34]. We choose to focus primarily on solar as VRE candidate given that wind energy potential in Nigeria is very modest [35]. Only few sites have wind speeds above 6 m/s at 30m height and the potential for wind power is definitely far lower than that for solar PV in the country [35].

- We consider the following demand conditions: current local demand met (in 2018: 30,589 GWh), demand met +25% (38,236 GWh), demand met +50% (45,883 GWh), and demand met + 75% (53,531 GWh).

2.4 Specific scenario inputs

Actual 2018 and 2019

The actual 2018 dispatch is taken from the 2018 TCN Technical Report [32]. Actual dispatch in 2019 is based on the average hourly power and associated total yearly energy output reported by the Presidential Power Sector Working Group [36].

Scenarios (50%AV, 50%AV + 20%GAS, 50%AV + MAXGAS)

Power plant costs only include the 2018 energy (variable) costs (fuel and variable operating cost) as extracted from the 2018 TCN Technical Report [32]. Inputs to model constraints (1-4) also come from the 2018 TCN Technical Report [32]: monthly demand met (GWh), maximum capacity by power plant (MW), monthly available capacity by plant (MW), and monthly energy limits for the three hydro plants (GWh). Total demand is based on the actual dispatch for all generators. As such, we keep the optimized and actual dispatch to produce identical total MW for each hour to keep them comparable. Observed values for monthly energy sent out in GWh are converted to generated power in each hourly timestep using the observed load profile for 2016. The load profile for Nigeria was obtained from the West African Power Pool Information and coordination center [37]. Exports are fixed at the observed monthly level

[32] and valued at 100 USD per MWh. Gas supply limits by power plant (in billion cubic feet) were obtained from the 2018 TCN Technical Report [32]. Unmet demand is set at 0 MWh as we only model the actual demand met and optimize dispatch to meet the same level of demand. However, unmet demand may be non-zero for scenarios that consider an increase in demand.

Scenarios (Optimal-ToP and Optimal-NoToP)

We use the 2019 PPA prices which include capacity, energy, and take-or pay (only for gas plants) capacity obligations and maximum 2019 capacity by power plant as obtained from the Presidential Power Sector Working Group [36]. Load profile, export levels, unmet demand (effectively fixed at 0 MWh) are the same as for the (50%AV, 50%AV + 20%GAS, 50%AV + MAXGAS) scenarios. Existing plant availability and gas supply constraints are omitted in both scenarios.

High Demand scenario

Unmet demand under the current conditions is valued at 500 USD per MWh (VoLL). VoLL estimates for private customers in the EU and USA span over a broad range from ~ 1000 USD per MWh to ~ 50,000 USD per MWh [38]. Estimates for the VoLL in Sub Saharan countries are scarce. Minnaar and Crafford [39] report a VoLL of 6.77 Rand (400 USD per MWh) for residential customers. Oseni and Pollit [40] give a range of VoLL from 480 USD per MWh to 4000 USD per MWh for Nigeria. We decided to use low end estimate of VoLL 500 USD per MWh to obtain a conservative estimate of dispatch efficiency benefits. Existing plant availability and gas supply constraints are omitted. Maximum plant capacity, load profile and export levels are the same as for the (Optimal-ToP and Optimal-NoToP) scenarios.

RE-Solar scenarios

The solar profile for the additional solar plants is assumed to be the same as for the future 70 MW Mangu plant in the Plateau state [41]. This is the largest candidate solar power plant with a signed PPA and a put and call options agreement. Solar irradiance data from the NASA MERRA-2 analysis and the EUMETSAT SARAH dataset were converted into power output using the Global Solar Energy Estimator model (GSEE) [42] [43]. The average solar capacity factor is 17.2%.

In the absence of any spinning reserve standard, we fixed the required spinning reserve at the maximum of (5% of hourly demand; size of the largest generation unit) plus 0.2 times the power output of the solar plants yielding a maximum spinning reserve requirement of 300 MW in the absence of any solar park. We assumed that the three relatively old hydro plants, solar parks, and older gas plants could not provide reserve. For the other gas plants the assumed maximum reserve share as a percentage of capacity is in the range of 5 to 10%.

We assume a typical spinning reserve cost of 10 USD per MWh to account for wear and tear of the generators that could provide reserve and also to some extent capital expenses that will need to be spent to render these plants to be able to provide frequency response. Unmet spinning reserve (SpinReserveVoLL) is penalized at 100 USD per MWh that largely reflect the risk of a system outage and matches the penalty used for any shortfall in spinning reserve in wholesale electricity markets where it is also kept well below the VoLL. Reserve prices are calculated as the marginal value of the reserve requirement constraint (constraint 6). Existing plant availability and gas supply constraints are omitted. Load profile and export levels are the same as for the (50%AV, 50%AV + 20%GAS, 50%AV + MAXGAS) scenarios.

Solar capacity is initially added at zero cost to obtain the annual **gross** benefits of adding solar. Gross benefits are calculated as the reduction in system costs for the *demand scenario with solar* versus the corresponding *demand scenario without solar*, less the total fixed operation and maintenance (FOM) for the solar plants. FOM per MW for solar plants is assumed to be 10,000 USD per MW. We derive the return on investment by calculating the internal rate of return for an initial capital outlay of 0.8 million USD per MW versus the accrued gross benefits over the economic lifetime of the solar park (25 years). We calculated the gross benefits and return on investment by accounting for a) only energy charges and b) energy and capacity charges for the existing generators. As such we obtain a range of gross benefits and return on investment values for solar parks with the low end of the range where we only consider savings in energy charges; and a high end wherein we account both for energy and capacity charges.

3. Results

3.1 Impact of increased plant availability and gas supply

Energy costs under actual dispatch amount to 994 Million USD for 2018 (Table 2) which is offset by 300 million USD of export revenue. Total variable costs including energy costs but excluding revenues from export (300 GWh) is 694 Million USD. The generation mix consists of 23% hydro and 77% gas. Average generation cost only accounting for variable costs stands at 29.5 USD per MWh (Figure 1). Increased plant level availability while maintaining gas supply limits in the 50%AV scenario leads to a 4% reduction in variable costs or 29 million USD per year (Table 2). The increase in average capacity factor for the Nigerian gas plants from 27% to 50% decreases the average generation cost by 3% down to 28.7 USD per MWh. With 20% more gas available, variable costs decrease further by 28 million USD per year giving a total benefit of 57 million USD per year in the 50%AV+20%GAS scenario. Average generation costs stand at 27.8 USD per MWh or a 6% reduction relative to the actual dispatch case. Lifting the gas constraints with an average gas plant capacity factor of 50% yields 115 million USD in benefits per year versus the actual case corresponding to a total 17% decrease in variable costs. Average generation costs of 26.1 USD per MWh for this 50%AV+MAXGAS scenario are 12% lower than that for the actual dispatch. The removal of gas supply limits has a larger impact on benefits than increased plant level availabilities. Improved plant availability leads to 29 million USD in benefits per year whereas unconstrained gas supply can lead to an additional 86 million in benefits (i.e., 115 Million USD minus 29 Million USD) or a three times larger benefit.

Table 2. Benefits for 50%AV, 50%AV+20%GAS, and 50%AV+MAXGAS scenarios vs. actual dispatch.*,**

Result	**Scenario**			
	Actual	**50%AV**	**50%AV+20%GAS**	**50%AV+MAXGAS**
Total Variable Costs (M USD)	694	665	637	579
Energy costs (M USD)	994	965	937	879
Hydro plants	9	9	9	9
Gas plants	985	956	928	870
Export revenues	300	300	300	300
Benefits vs. Actual (M USD and % reduction from Actual)	-	29 (4.2%)	57 (8.2%)	115 (16.5%)

*Total demand is 30,589 GWh for all scenarios.

**Total variable costs include energy costs less export revenues.

Figure 3. Total variable costs and average variable generation costs for actual dispatch, 50%AV, 50%AV+20%GAS, and 50%AV+MAXGAS scenarios.

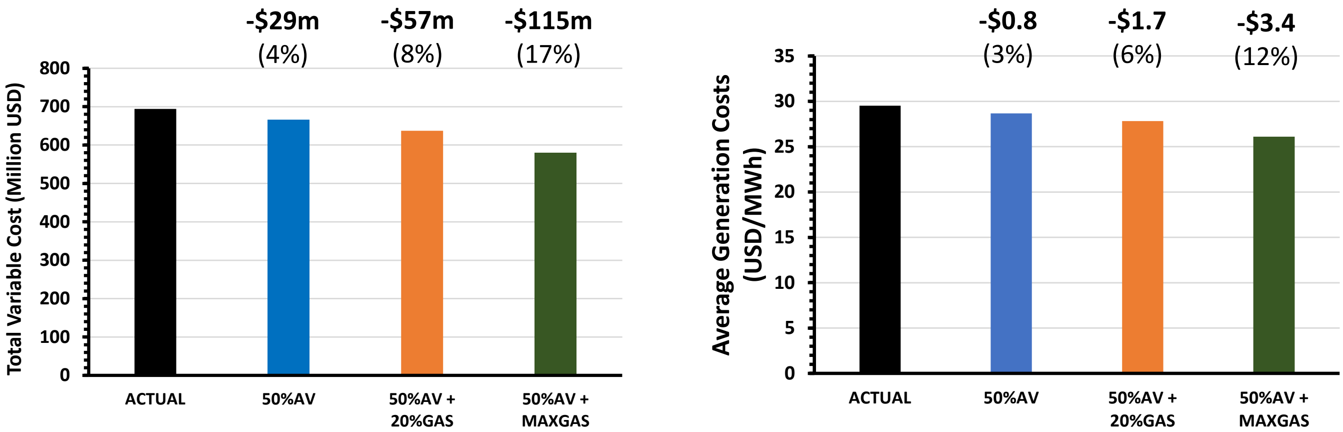


Figure 4 shows the cumulative generation across the actual dispatch, 50%AV, 50%AV+20%GAS, and 50%AV+MAXGAS scenarios. Removing availability constraints or gas supply constraints increases the output of mid-merit plants (with variable costs in the order of 25-35 USD per MWh), while reducing the output of the most expensive gas plants with variable costs above 35 USD per MWh. As expected from the benefit analysis (Table 2), the scenarios with increased gas availability (50%AV+20%GAS, 50%AV+MAXGAS) have a larger impact on the cumulative generation profile than the scenario with increased plant availability (50%AV). Figure 5 highlights the differences in costs (energy costs only as per [32]) by plant across the different scenarios. Costs increase for low and mid-merit gas plants on the right especially for the scenarios with increased gas supply and decrease for the most expensive gas plants on the left of the figure. Costs remain constant for the three hydropower plants (Kainji, Jebba, Shiroro) as shown in the middle of the figure because as zero short-run marginal cost limited energy plants, they are used fully in all scenarios.

Figure 4. Cumulative generation across different plant availability and gas supply scenarios.

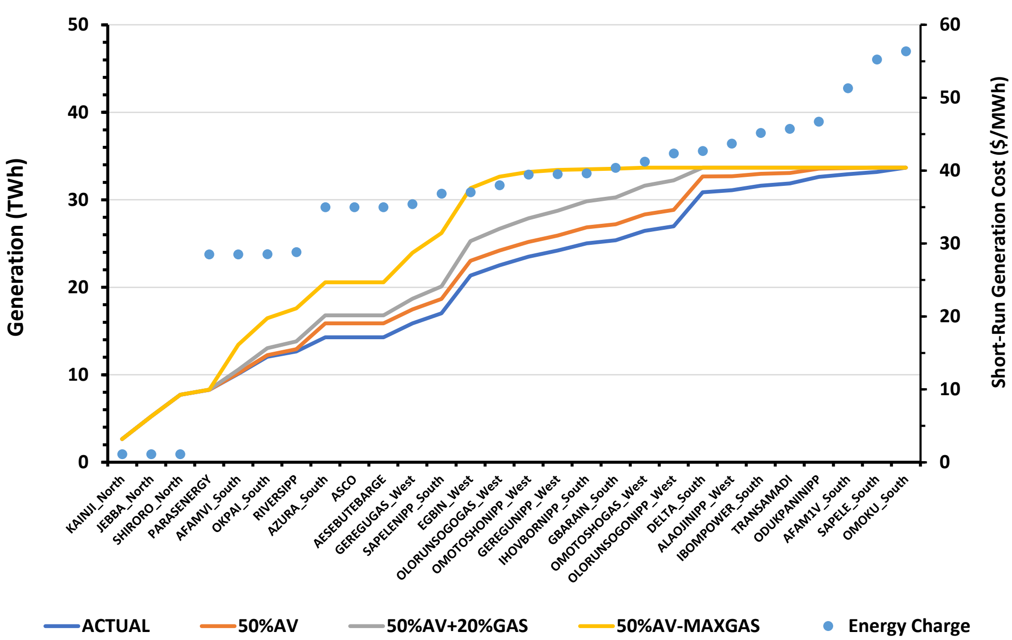
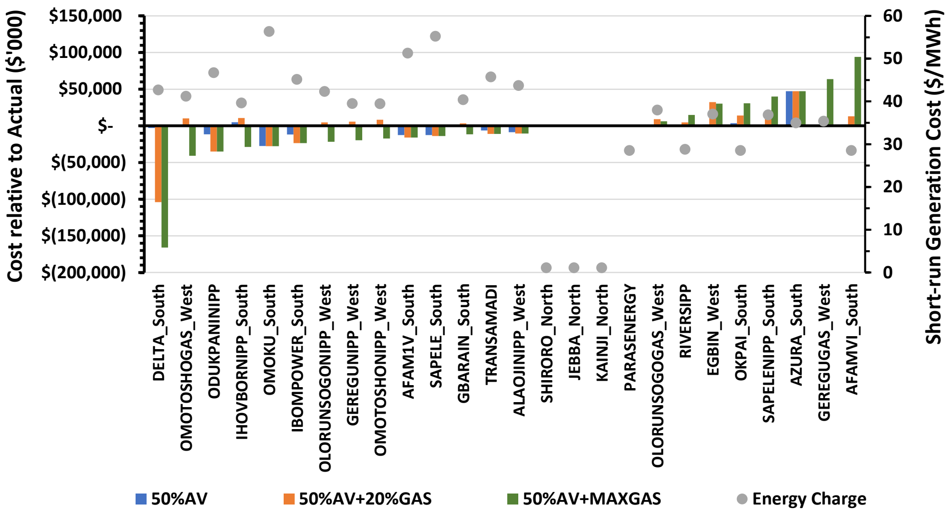


Figure 5. Cost differences by plant across different plant availability and gas supply scenarios.



3.2 Impact of ToP obligations

Inclusion of all charges (capacity, energy and take-or-pay obligations) as per [36] for the reported dispatch gives a total cost of about 1.7 billion USD comprising 501 million USD in capacity charges, 990 million USD in energy charges, 476 million USD in take-or-pay obligations less an estimated 300 million in export revenues. Optimizing the dispatch subject to honoring the existing ToP obligations, can yield substantially higher benefits of 309 million USD per year or a 18.5% reduction of total costs for the Optimal-ToP scenario. If the ToP obligations could be waived as we assume in the Optimal-NoToP scenario, annual benefits can rise further to 579 million USD or a massive 34.7% decrease in total costs relative to the actual dispatch.

Table 3. Benefits for Optimal-ToP and Optimal-NoToP scenarios vs. actual dispatch.*,**

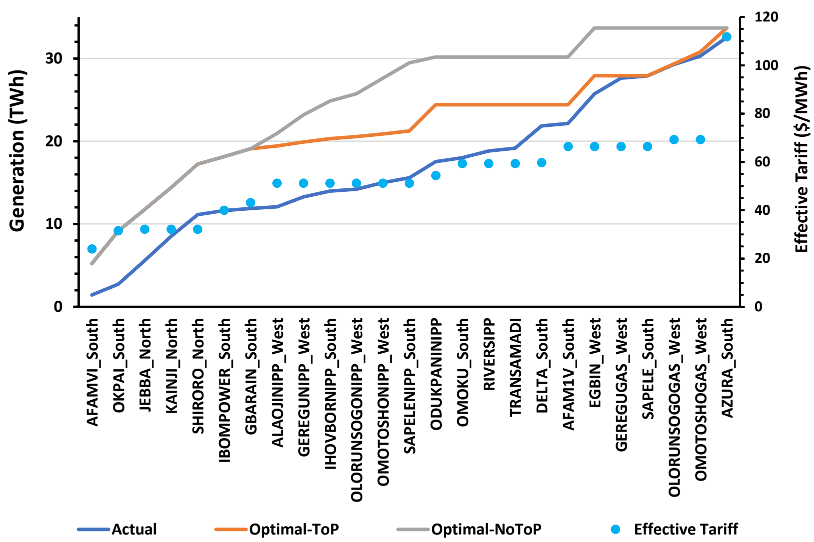
Result	**Scenarios**		
	Actual	**Optimal-ToP**	**Optimal-No ToP**
Total Costs (M USD)	**1,667**	**1358**	**1088**
Capacity charges (M USD)	**501**	**377**	**619**
Hydro plants	218	209	238
Gas plants	283	168	381
Energy charges (M USD)	**990**	**849**	**769**
Hydro plants	51	50	145
Gas plants	939	799	624
ToP charges (M USD)	**476**	**432**	**-**
Export revenues	**300**	**300**	**300**
Benefits vs. Actual (M USD and % reduction from Actual)	-	309 (18.5%)	579 (34.7%)

*Total demand is 29,534 GWh for all scenarios.

**Total costs include capacity charges, energy charges, take-or-pay obligations, and export revenues.

The benefits in the OptimalToP scenario stem from an increased use of low and mid-merit gas plants under the existing ToP obligations (Figure 6). The additional 270 million in annual benefits in the OptimalNoToP scenario relative to the OptimalToP are realized through an increased use of mid-merit gas plants displacing generation from the most expensive ToP gas plants such as Olorunsogo, Omotosho, and Azura (Figure 7). The cost changes by plant relative to the actual dispatch further highlight the increased use of mid-merit gas plants in the Optimal ToP scenario (Figure 8). In the theoretical case of no ToP obligations, cost reductions are the largest for the most expensive ToP plants Olorunsogo, Omotosho, and Azura.

Figure 6. Cumulative generation across different ToP scenarios.*



*Effective tariff based on assumption that ToP capacity is dispatched.

Figure 7. Dispatch of ToP plants across scenarios.

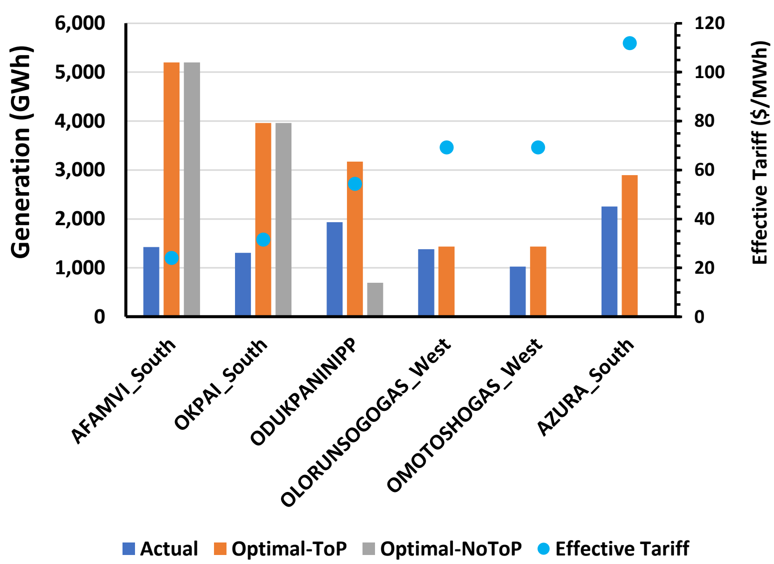
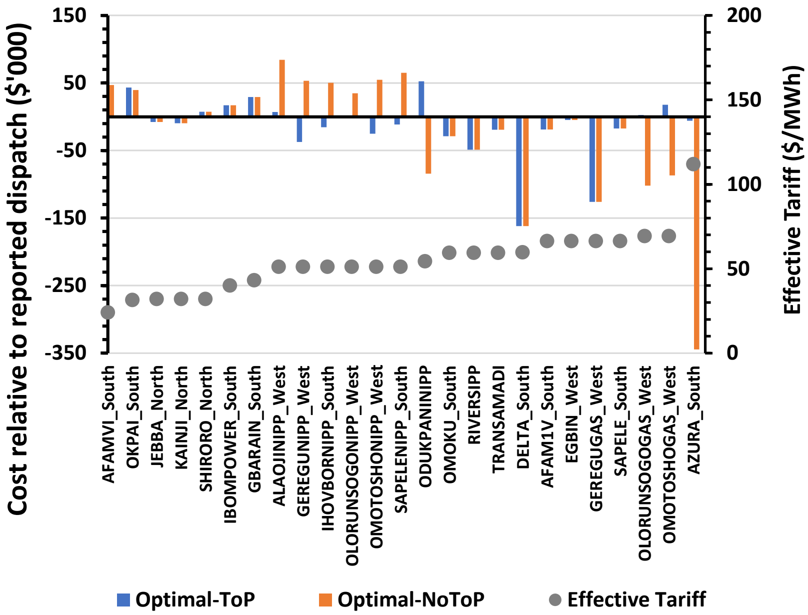


Figure 8. Cost differences by plant across different ToP scenarios.



The ToP scenarios have shown that a more substantial increase in annual benefits (309 Million USD) results from an optimal dispatch in which both plant level availability and gas supply limits are relaxed. Of these two constraints, we demonstrated that the gas supply limit is the most critical. Removal of ToP obligations can lead to an additional 270 million in annual benefits. In reality, renegotiating commercial contracts may be a protracted and litigious process that can be difficult to say the least, but a portion of these benefits can be targeted through renegotiation of the existing of PPAs wherever possible including the use of CfDs which will enable dispatch of cheaper plants. This is an important step towards setting up a wholesale electricity market and creating room for cheaper and cleaner energy in Nigeria. These steps are well worth considering not only because of the substantial monetary benefits that it can deliver but also as the start of streamlining the process for introducing a competitive spot market in due course.

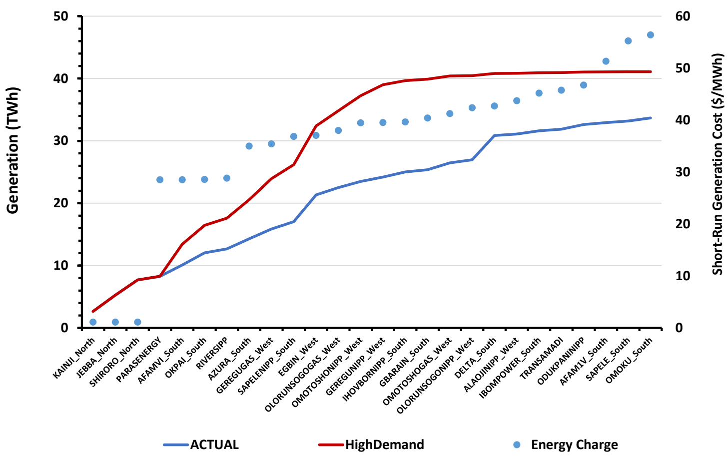
3.3 Increased Demand Scenarios

In the absence of plant availability and gas supply constraints the existing generation fleet can serve an additional 7.6 TWh per year through the grid (Table 4). The additional demand (~25% of 2018 generation) could be met at an additional 95 Million USD or a 10% increase in cost if we only consider energy charges (Table 4). Valuing the current unmet or underserved demand at 500 USD per MWh yields annual benefits of 3.7 billion USD. We find an upper value of 4.2 billion USD in benefits relative to the actual dispatch if we account for both energy and capacity charges. Increased gas supply and improved plant operation can thus not only significantly optimize the dispatch for the current generated amount (~30 TWh) but can also meet increased demand for the benefit of currently unserved customers. The additional demand can be met through increased generation of low and mid-merit gas plants (Figure 9).

Table 4. Benefits of meeting additional demand vs. actual dispatch.

Result	Scenario			
	Energy cost only [32]		**Energy and Capacity Charges** [36]	
	Actual Demand	**High Demand**	**Actual Demand**	**High Demand**
Total Costs excluding export revenues and unmet demand (M USD)	994	1,089	1,967	1,657
Export revenues (M USD)	300	300	300	300
Unmet demand costs (M USD)	3,824	-	3,824	-
Benefits vs. Actual (M USD)	-	**3,729**	-	**4,217**

Figure 9. Cumulative generation for actual dispatch and increased demand scenario



3.4 Assessing renewable economics and readiness Ren

The first issue of the economics of solar in the Nigerian system given its low-cost domestic gas resources needs some attention. If new solar needs to compete with the existing gas fleet for the same amount of energy that was delivered in 2018 based on energy charges only, it does not have a strong economic case. Solar in this case in essence competes with the cheaper end of the gas fleet. Addition of 500 MW solar capacity has relatively low annual benefits in this case. Gross annual benefits are in the range of 21.8 – 31.9 million USD with the lower end of the range only accounting for savings in energy charges and the higher end considering both savings in energy and capacity charges (Table 5). The Internal Rate of Return (IRR) on the investment is relatively low in the range of 3% to 6%. IRR would in fact reduce further as more solar is added to the system. The addition of 1 GW solar parks has, for instance, even lower returns in the range of 1% to 5% for the same level of demand. This is because the second block of 500 MW solar has lower incremental gross benefits in the range of 13.0 – 22.8 million USD pa than the first block of 500 MW which had gross benefits of 21.8 - 31.9 million USD pa. The first block of 500 MW solar capacity has higher gross benefits and returns since the first block of 500 MW solar will replace a larger amount of more expensive gas-based generation than the second block of 500 MW solar.

The economics of solar, however, looks more promising when we consider higher demand scenarios wherein new solar projects are used to meet additional demand and effectively compete with the more expensive end of the existing fleet of gas generators. Gross benefits and return on investment increase with increasing levels of demand met (or generation). For the first 500 MW of solar gross benefits increase from 21.8 - 31.9 million USD at the current level of generation to 25.7 - 47.8 million USD in case 75% more demand could be met. The corresponding return on investment increases from the 3% - 6% range to 4% - 11%. Returns are slightly lower for the second block of 500 MW with returns increasing from 1% - 5% under current generation conditions, to 3% - 10% at 75% higher generation levels. The associated incremental benefits for the second block of 500 MW solar increase from 13.0 - 22.8 million USD to 18.8 - 41.5 million USD.

Returns are attractive at increased levels of demand met (generation). The average expected return is only above 6% at 50% higher generation levels for the first 500 MW of solar. Therefore, solar PV capacity additions become more economically attractive once the current gas supply, take-or-pay, and plant level availability constraints are solved. Lifting these gas supply, take-or-pay, and plant level availability constraints will allow for increased generation and make a stronger business case for solar with increased returns. The addition of an initial 500 MW solar PV by 2025, in particular, is in line with the Renewable Energy Master Plan (REMP) and seems to be a plausible target.

Table 5. Gross Benefit and return on investment for 500 MW and 1 GW solar capacity addition for different demand scenarios.*

		Demand Scenario			
Solar Addition	**Result**	**Demand met (30,589 GWh)**	**Demand met +25%**	**Demand met +50%**	**Demand met +75%**
500 MW	Gross Benefit (M. USD)	21.8 - 31.9	22.7 - 35.7	24.4 - 39.6	25.7 - 47.8
	IRR (%)	3% - 6%	3% - 8%	4% - 9%	4% - 11%
1000 MW	Gross Benefit (M. USD)	34.8 - 54.7	36.7 -63.3	40.4 - 71.7	44.5 - 89.3
	IRR (%)	1% - 5%	1% - 6%	2% - 8%	3% - 10%

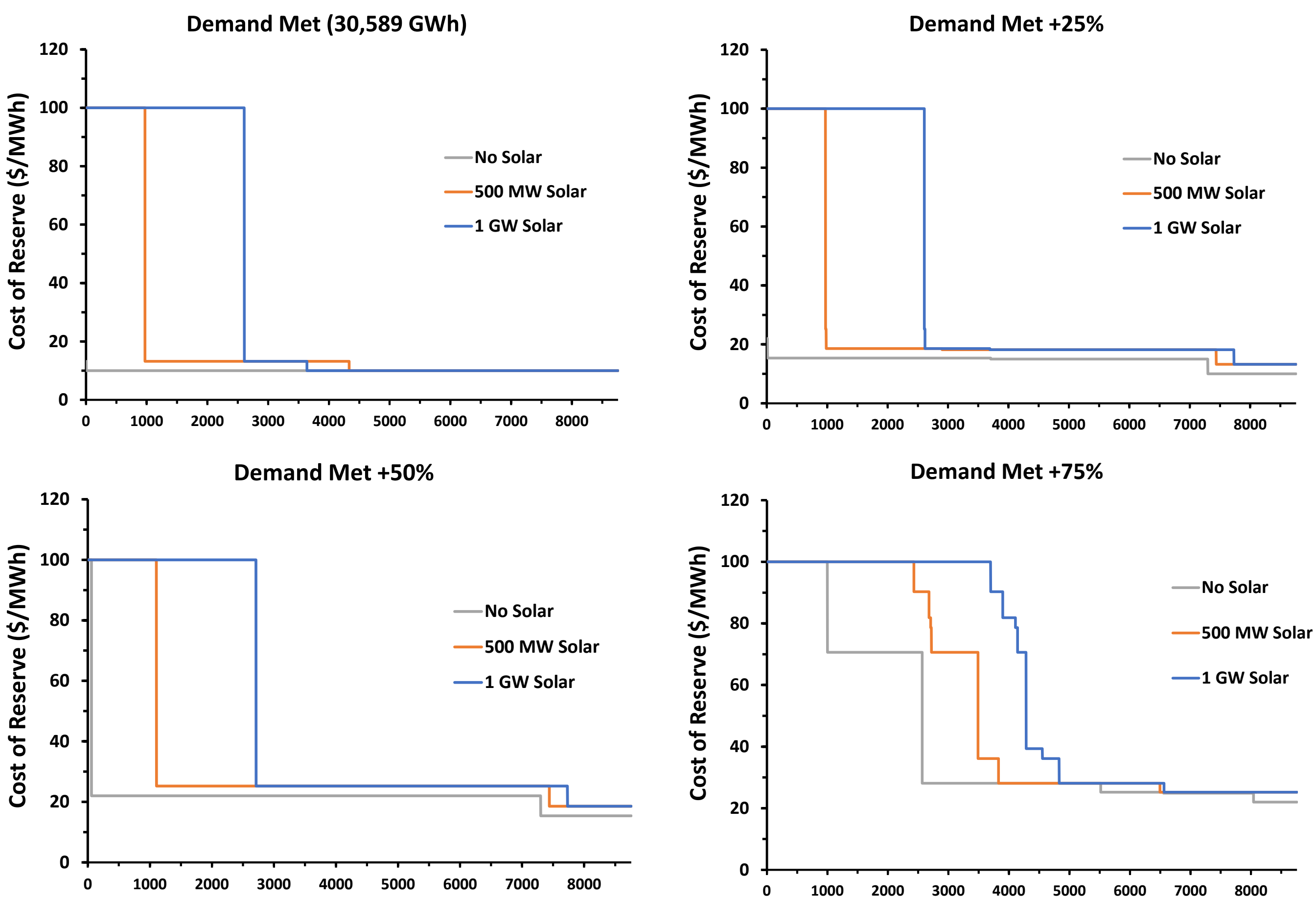
*Note: The lower end of the range for the gross benefits and IRR only accounts for savings in energy charges, the higher end of the range considers savings in both energy and capacity charges.

While solar economics look better at a higher level of demand, it also entails greater challenges to meet system security constraints, namely the spinning reserve requirements. Spinning reserve is likely to be provided only by a subset of relatively new generators and even that requires a level of sophistication to co-optimize allocation of spinning reserve and generation that does not exist at present. It also implicitly requires a spot price market for energy and ancillary services to compensate the generators for these services that do not exist. Nevertheless, it is useful to know what the best allocation of spinning reserve should look like, how these spinning reserves should be priced, and most importantly are there likely to be breaches of constraints for spinning reserve that should be addressed before large scale solar projects are connected to the system.

We have estimated the availability of spinning reserve based on typical % of capacity that is known to participate in spinning reserve services internationally for similar technology classes. It stands at 354 MW which if deployed to full amount is enough to meet the (n-1) security standard. Addition of solar would however add to this requirement as noted in the methodology discussion and would likely exceed the spinning reserve capability of the system. Once the spinning reserve capability is breached, it leads to two key outcomes: there is a spinning reserve MW shortfall for several hours if not a significant part of the year; and the spot price for spinning reserve reaches the penalty which we have set at 100 USD per MWh. Spinning reserve direct costs in our analysis are assumed to be 1 c/kWh (or 10 USD per MWh) for all generators, but prices will rise as (a) opportunity cost of spinning reserve is taken into consideration for hours when an economic generator has to hold back its generation to provide reserve; and (b) as eventually the system runs of all available reserve, prices will reach the penalty level of 100 USD per MWh.

Figure 10 shows the cumulative distribution of spinning reserve prices under the four demand conditions considering both energy and capacity charges. Average reserve prices increase with increasing deployment of solar capacity for each demand condition as the reserve deficiency as a percentage of time and associated unmet reserve increase with increasing solar capacity addition (Table 6). The duration of reserve deficiency increases with increasing solar capacity from 0% with no solar up to 30% with 1 GW solar addition resulting in a shift of the distribution of reserve prices to the right as the period in which prices are at the maximum level of 100 USD per MWh gets longer. Under current generation conditions average reserve prices could increase from 10 USD per MWh to 21.2 USD per MWh and 37.2 USD per MWh for solar additions of 500 MW and 1 GW, respectively. Absent solar capacity additions, the reserve requirement is always met resulting in low reserve prices of 10 USD per MWh throughout the year. With solar capacity additions at the current generation level (demand met) the distribution of reserve prices shows three parts: (a) an outer left part with reserve prices of 100 USD per MWh as the system is unable to meet reserve requirements, (b) an intermediate part with reserve prices around 13 USD per MWh and (c) an outer right part with minimal reserve prices of 10 USD per MWh. The intermediate part with reserve prices between the minimum level (10 USD per MWh) and the maximum level (100 USD per MWh) indicate that lower cost generators are backed down to provide spinning reserve and more expensive generators are dispatched to deliver power resulting in an opportunity cost of reserve around 3 USD per MWh (13 USD minus 10 USD per MWh).

Figure 10 Distribution of reserve prices for different demand scenarios and solar capacity additions.



For the case of no solar capacity additions average reserve prices increase by 11.4 USD per MWh when 50% more demand is met (21.4 USD per MWh versus 10.0 USD per MWh at the current generation level). At even larger levels of demand (demand met + 75%) reserve prices increase more sharply to 42.5 USD per MWh which is an increase of 21.1 USD per MWh versus the demand met +50% level. The increased reserve deficiency at the demand met +75% level (11% of the time) causes the largest increase in average reserve prices together with the increased opportunity costs of providing reserve. Scenarios with solar capacity additions show similar trends. Average reserve prices increase by about 10 USD per MWh for a 50% increase in demand from the current demand met level to the demand met +50% level: an increase of 12.4 USD per MWh for the 500 MW solar addition and 10.4 USD per MWh for the 1 GW addition. A further 25% increase in demand (from demand met +50% to demand met +75%) causes a larger rise in average reserve prices: an increase of 19.7 USD per MWh up to 53.3 USD per MWh for the 500 MW solar addition and a 14.3 USD higher price of 61.9 USD per MWh for the 1 GW solar addition, respectively. Again, average reserve prices increase with increasing generation levels due to increased reserve requirement and hence reserve shortfall, and increasing opportunity costs for providing reserve especially during times of high solar power production. Figure 12 shows an example of how the average hourly reserve requirement and reserve prices increase during the hours of the day with increased solar generation (10h – 16h) for the case of 500 MW solar addition and a 50% larger demand being met. Table 6 shows the reserve requirements going up from 300 MW at the lowest end (for demand met and 0 MW solar) to 542 MW at the other extreme (demand met + 75% and 1 GW solar). The former can be met comfortably using the existing gas fleet but as the spinning reserve capability limit is hit around the 354 MW mark, reserve shortfall reaches ~100 MW for 1 GW solar even for the demand met scenario and exceeds 200 MW for demand met + 75% with 1 GW solar.

As the different RE penetration scenarios show, the Nigerian system needs investments to provide fast reserve in order to allow for a) increasing levels of demand and b) increased penetration of variable renewable resources (solar PV). New investments could include open cycle gas turbines (OCGT), pumped storage hydro or battery storage systems. While added demand significantly enhances the economic case for solar, spinning reserve is an important prerequisite that will need to be met. This is certainly not an insurmountable problem as the technologies are well established. Adding 100 MW of additional spinning reserve capability, for instance, could be done by adding a peaking open cycle gas turbine that would cost $60 million or $4-5 million in annualized terms which can support up to 1 GW of solar for up to 50% additional demand.

Table 6 Reserve prices and requirements for different demand scenarios and solar additions.

		Demand Scenario			
Solar Addition	**Result**	**Demand met**	**Demand met +25%**	**Demand met +50%**	**Demand met +75%**
0 MW	Average reserve price ($/MWh)	10	14.3	21.4	42.5
	Reserve requirement (MW)	300	300 -324	300 - 390	300 - 422
	Reserve deficiency (% of time)	0	0	7	11
500 MW	Average reserve price ($/MWh)	21.2	26.6	33.6	53.3
	Reserve requirement (MW)	300 - 380	300 - 380	300 - 411	300 - 468
	Reserve deficiency (% of time)	11	11	12	27
1000 MW	Average reserve price ($/MWh)	37.2	42	47.6	61.9
	Reserve requirement (MW)	300 - 461	300 - 461	300 - 487	300 - 542
	Reserve deficiency (% of time)	30	30	31	42

Figure 11 Cumulative distribution of unmet reserve for different demand scenarios and solar capacity additions.

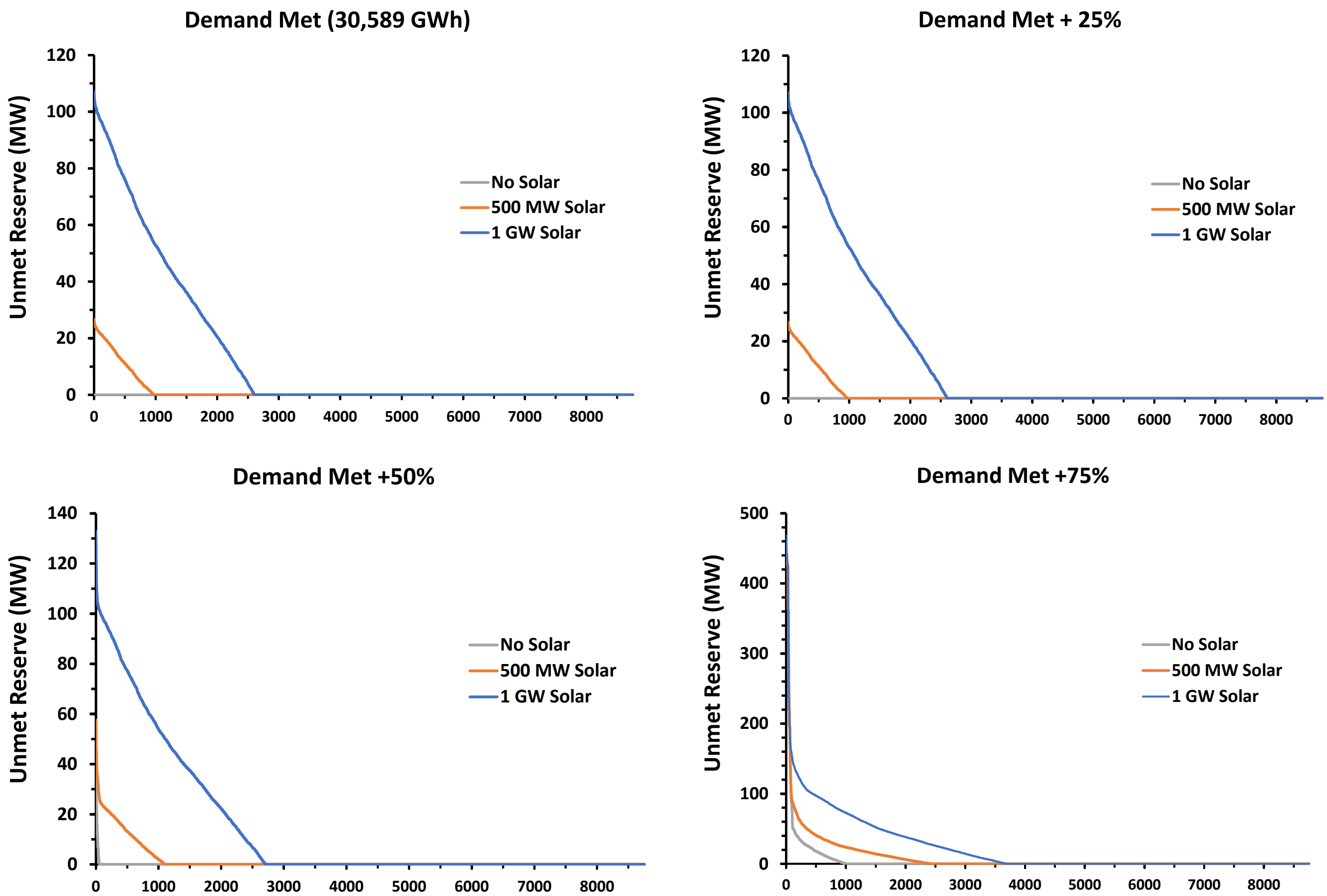
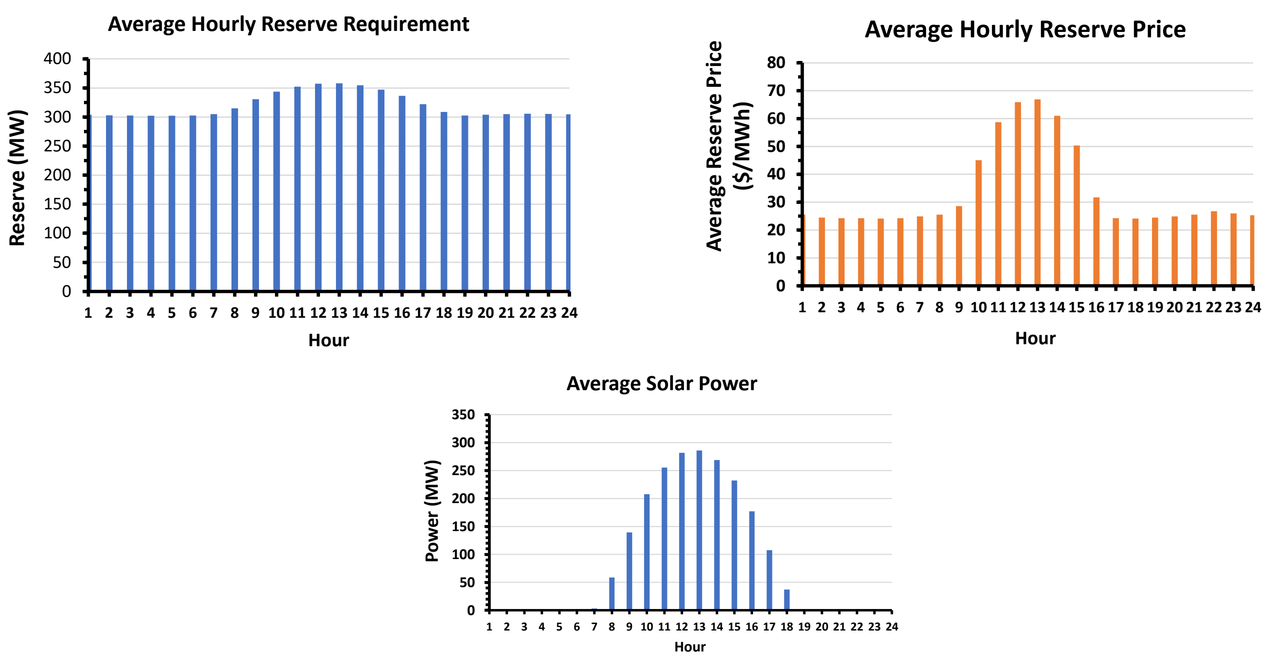


Figure 12 Average hourly reserve requirement, reserve price and solar power for 500 MW solar addition and 50% higher demand met.



4. Conclusions

Nigeria can significantly improve the utilization of the existing generation assets and reap significant benefits. The combined annual benefits from operational and commercial improvements such as increased plant availability, removal of gas supply constraints, and getting rid of uneconomic take-or-pay obligations could save 579 million USD in 2018 or a 29% reduction in total annual costs.

Short-term efforts to improve gas supply and infrastructure yield the largest benefits especially if they are combined with improved plant level availability. If the existing gas supply bottlenecks are moved and average plant availability can be improved from the current level of 27% to 50% - these measures alone can save 115 million USD.

There are even larger savings that can be achieved if the commercial contracts could be streamlined to reduce reliance on generators that have very large fixed charges and take or pay (ToP) obligations. Benefits could further increase to 579 million USD in case Nigeria can get rid of the uneconomic ToP obligations. There are alternative ways to achieve this end including contracts for differences (CfD) that leaves the generator financially whole but allows the system operator to optimize the dispatch and run cheaper generation resources first. Even if the existing physical ToP obligations are to be honored, there is significant room to optimize the dispatch based on total charges and rely less on plants that have high costs to save 309 million USD or a 19% reduction in total costs for a single year. This is a plausible interim measure that could be used and send the correct signals for renegotiating contracts.

There are significant positive spill overs from streamlining dispatch and rationalizing contractual arrangements. Implementation of operational and commercial measures in the medium term will be enable the system to meet higher demand from the existing capacity and also allow for increased penetration of variable renewable resources. In the absence of operational and commercial constraints the existing gas generation fleet could easily meet 25% more demand that would immensely benefit currently unserved customers.

Nigeria has good solar resources and aspirations to include it in the generation mix as reflected in its 2019 RE Master Plan. This would however require paying careful attention to two key issues, namely, demand and system security. The former matters because Nigeria has significant endowment of inexpensive gas and forcing solar at the current level of demand would mean new solar needs to compete with the low-cost end of the gas fleet that would render solar to be less competitive. We find that the business case for investments in new solar power capacity would also be more positive at increased levels of demand being met. At the current level of demand the solar return is in the range of 1% to 6%. For a 50% higher demand, solar PV projects can earn a better return on investment between 4% and 9% for a 500 MW solar capacity addition. Additional investments in flexible resources will be needed to meet increasing spinning reserve requirements at higher levels of demand with increased penetration of solar especially during periods of high solar power production. These investments could be in the form of open cycle gas turbines, pumped storage or storage hydro or battery storage systems.

The proposed operational and commercial improvements will bring significant benefits to the Nigerian power system. Nevertheless, parallel measures are needed to improve the financial position of the sector. A comprehensive reform program needs to include gradual implementation of cost-reflective tariffs together with improved collection efficiency and installation of (smart) meters to reduce non-technical losses. As the findings of the study shows, if the generation dispatch could be enhanced to save more than half a billion dollar per year and meet higher demand, it would help to break the cycle and pave the way to improve tariff and collection rate. Dispatch efficiency in many ways holds the key to arrest the deteriorating performance of the sector.

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