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Electricity Supply to Africa and Developing Economies – Challenges and Opportunities

Topic 3: Planning for the future in uncertain times

Methodology for Assessing the Impact of Intermittent Generation on Utilities

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Abstract **- Renewable, non-synchronous, intermittent generation is becoming more widespread. The penetration of such generation on utility networks presents challenges in terms of system operation and therefore security. Acknowledging that the integration of such generation is continuing and becoming increasingly a reality every year, it has become necessary to evaluate and consider potential solutions to allow for this while at the same time maintaining system integrity. In an environment where system development is expensive; has significant time horizons; and access to electricity is low (but is actively sought to be remedied), this is particularly relevant. In this paper, we present a first step in this process. We approach the issue, not with a view to determine how the system should develop over time, but rather with a view to determine the current constraints to the integration of intermittent generation and mitigations for same. In this way, it may be possible to allow greater access, if albeit intermittently, over the short to medium term in anticipation of future network developments. Our purpose here is to present a methodology by which it is possible to determine, on a case by case basis, the extent to which renewable intermittent generation can be integrated onto a utility network. Our methodology has been developed through institutional experience gained through the execution of similar studies in various utilities in Africa.**

Keywords – renewable energy, high penetration, intermittency, inertia, capacity factor, optimisation.

Overview

The methodology presented in this paper highlights the challenges associated with high penetrations of non-synchronous, intermittent, renewable sources. While individual plants are required to achieve grid code compliance, it is the responsibility of the utility (as the supplier of last resort) to ensure that the power system operates reliably without interruption and in the most economical way possible. This paper focuses on the system-wide impacts of renewable penetration, which can be used as a planning tool to identify technical and financial limitations. Firstly the magnitude of intermittency will be established, followed by the technical impacts associated with high penetration scenarios. Following this the financial impacts are highlighted and a typical optimisation process is presented.

Intermittency

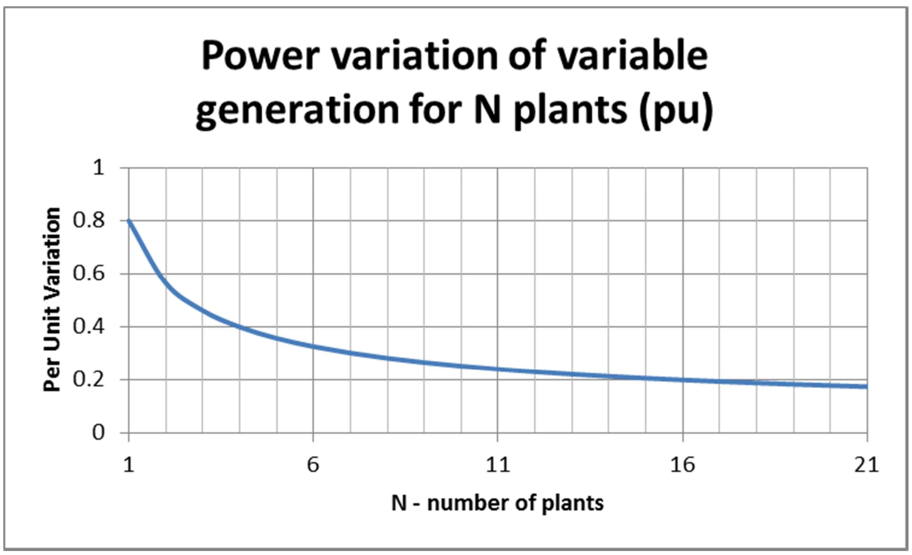
There are many studies that have been carried out on the smoothing effect of geographical distribution on the power output of variable generation [1] [2] [3] [4] [5].

For example, Mills and Wiser [1] indicate that a single plant can have an 80% unavailability (or variation) over one (1) minute intervals. Five (5) PV plants in close proximity have only a 40% variation and twenty-three (23) PV plants distributed over a 400 square kilometre area can have only a 20% variation of available power. Based on these values, we use their method of calculating the maximum expected variation for a number of uncorrelated plants (which they showed is a reasonable assumption if plants are more than 20 km apart [1]), and given in the equation below.

$$r \propto \frac{1}{\sqrt{N}}$$

Where *r* is the deviation from the maximum available power in per unit and *N* is the number of uncorrelated plants. Figure 1 presents the above formula graphically for up to 21 plants.

Figure 1: Per unit power variation on 1 min intervals for N number of plants



It follows that it is beneficial to have a higher number of small plants than fewer large plants to obtain a certain capacity goal. The above analysis assumes that all plants are equal in size, and have the same statistical variation. The above provides a good first approximation where no output data is available.

If the plant sizes are known and output data exists, an approach which considers this information can be used. The equation below provides a solution when considering the plant size as well as the correlation between any two plants.

$$\sigma_{\Delta P}^{t} = \sqrt{Var(\Delta P^{t})} = \sqrt{\sum_{i=1}^{n} \sum_{j=1}^{n} Cov(\Delta P_i^t, \Delta P_j^t)}$$

The covariance between two plants can be calculated by multiplying their maximum individual variation (ΔP^t) (where *t* is the timescale under consideration) with one another and then multiplying by the correlation between the two plants in question. The square root of the summated covariance provides the maximum variation for the time period under investigation.

The correlation between plants can be used to assess different time periods while the maximum individual variation can be varied using statistical probabilities. 1-minute interval data was used for operational PV plants and Table 1 and Table 2 show the results of a statistical analysis which was run on the data. The plants are almost completely uncorrelated over short time periods with significant values only appearing at the 30-minute time period. To a large extent, this can be attributed to movement of the sun which is inherently predictable in its movement. The maximum short-term variation decreases rapidly as more risk of occurrence is taken on. The amount of risk the utility is willing to take on directly influences the spinning reserve requirements of their power system as can be seen in Table 3. For islanded systems, the risk represents load shedding and unserved load whilst for large interconnected systems it may represent emergency rate penalties for offending utilities.

Table 1: Plant correlation

Period	**Correlation**
1-minute	0.0055
5-minute	0.0225
10-minute	0.0449
30-minute	0.2140
60-minute	0.4370

Table 2: Individual plant short-term variation

Percentile	**Variation (%)**
99.99	76
97	23.4
95	15.3

Table 3: 1-minute spinning reserve requirement

Percentile	**Required Spinning reserve (MW)**
99.99th percentile	56.71
97th percentile	17.01
95th percentile	11.34

Technical Impact

The technical impact on power systems can be assessed from two points of view, steady-state and dynamic. A steady-state assessment looks at longer-term planning whilst dynamic assessments address short-term dispatch and operational requirements.

Steady-state assessment

The steady state assessment is concerned with the distributed nature of intermittent renewables and the effect it has on conventional power system operation.

System loading

Individual plant sizes are limited by their positioning and surrounding electrical infrastructure. Renewables tend to have a positive effect on system loading due to their decentralised positioning. However, care needs to be taken when generation exceeds load. The rating of step-up transformers and transmission lines can be exceeded, especially under contingency conditions which will result in curtailment of the plants.

A further factor to consider is transmission losses. Initially, lines become less loaded as the effective local load is reduced, reducing transmission losses. As distributed generation continues to increase, power flow along the transmission system will reverse and increase once more, increasing system losses.

System voltage

The natural voltage required for generation in combination with the de-loading of transmission lines due to distributed generation can result in high voltages on both the transmission and distribution systems. This can cause complications if sufficient reactive power control is not available and in particular, where solar photo-voltaic plants are concerned, the transition from afternoon to evening can complicate operation since the rapid loss of generation along with the rapid increase of load can result in low voltages.

Fault Levels

Intermittent renewables technologies are generally asynchronous in nature in that they are connected to the power system through inverters which decouple the generation from the grid. The fault contribution of these technologies (1-1.5 times rated current) are reduced when compared to their conventional synchronous generation counterparts.

It follows that if conventional generation is displaced by asynchronous technologies, the system fault levels will also be reduced. This has an effect on existing protection settings especially where fault currents start to approach the load current in extreme cases.

Dynamic assessment

Whilst there are many technical factors which will limit the amount of intermittent renewables which can be integrated onto any power system, by far the most important is the amount of spinning reserve required to maintain frequency stability on the system.

As more intermittent power is introduced into the system, the operators may be tempted to turn-off some of the conventional generation which is at a sub-optimal dispatch. By doing this they run the risk of reducing the power system's capability of dealing with both the natural intermittency as well as a N-1 generation contingency.

The worst-case scenarios occur at the moment of highest penetration. These are generally identified as follows:

1. Midday minimum load with maximum PV and wind output.
2. Global minimum load (generally in the early hours of the morning) with maximum wind output.

If the system can be operated in such a way so that is can survive both the intermittency and a loss of the biggest generator without inducing under-frequency load shedding (UFLS), an adequate operational philosophy can be developed for all other load conditions. However, if the conditions cannot be survived and UFLS is invoked, the maximum technical capability of the system has been exceeded.

In general, conventional generation governors can respond to intermittency as long as the required capacity is immediately available. That is, provided the spinning reserve is available in the system, the system will in principle recover. This said, during this recover process, the system frequency may drop below particular limits which may lead to load shedding and other protective measures. The rate at, and extent to, which the frequency drops is a function of both the online system inertia and the governing ability (in MW/s) of online generation. This implies that intermittency itself is not the cause of large frequency deviations but rather the reduced system inertia which occurs as a consequence of asynchronous generation displacing conventional synchronous generation.

Figure 2 below provides a visual indicator of the role inertia plays in power system frequency response. Its direct influence is on the initial rate of change of frequency (ROCOF) which is used as an early indicator for the severity of a frequency deviation. By carrying out dynamic frequency simulations, a minimum inertia constant can then be determined for any operating scenario. This value can be used as a hard limit along with the requirement of adequate spinning reserve capacity when conducting techno-financial optimisations which are discussed further in a subsequent section.

Once this hard limit has been found, and paying due regard to minimum dispatch levels of synchronous generation, it is possible to determine the maximum penetration levels of renewable energy subject to the need to maintain at least as much spinning reserve as the expected potential intermittency. Again, this level of intermittency may be chosen as a function of the operator’s appetite for risk. Additionally, it is possible that the level of intermittency will be within the required spinning reserve for other credible network contingencies.

In determining the system inertia constant, it is not sufficient to just sum the *H-values* of each of the generators on the network since each *H* is in per unit rated against the individual generator’s MW or MVA rating. Only actual inertia (as opposed to inertia constant) can be arithmetically summed. It is important to note that any particular value of *H* is only relevant insofar as the base against which it is calculated is known. The inertia *J* of a single machine can be calculated as follows:

$$J_i = H_i . S_{nom_i}$$

With the total system inertia, for *n* online generators, being:

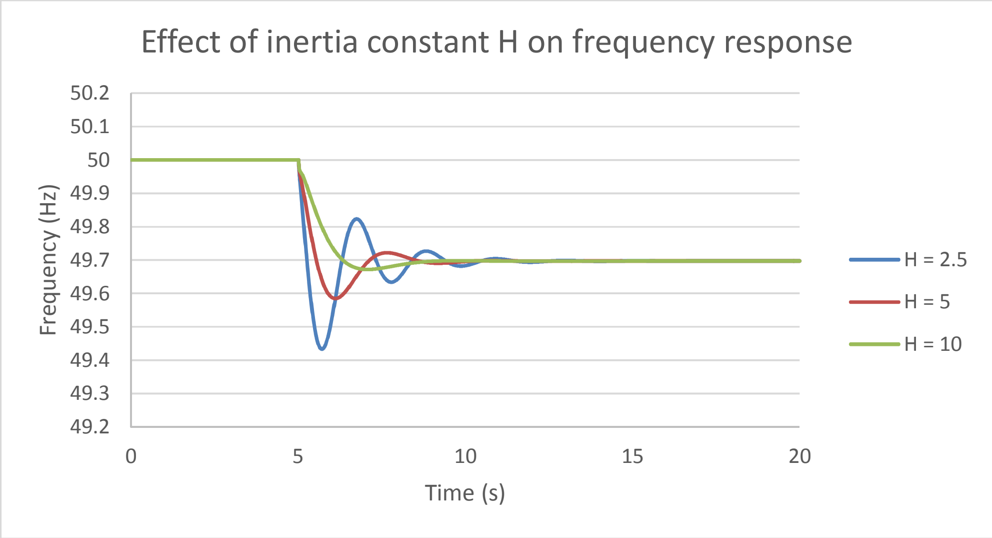
$$J_{sys} = \sum_{i}^{n} H_i . S_{nom_i}$$

The system inertia constant is then:

$$H_{sys} = \frac{J_{sys}}{S_{nom_{sys}}}$$

Where $S_{nom_{sys}}$ is largely arbitrary. Normally, one would choose $S_{nom_{sys}}$ to be the sum of the nominal apparent power of online generators, however, the need to provide a direct comparison between various system dispatches across scenarios, $S_{nom_{sys}}$ should be held the same.

Figure 2: Frequency response with varying levels of inertia



Financial Impact

The financial impact on utilities can be split into embedded and utility scale generation which are discussed further below.

Embedded Generation

Embedded generation is considered a disruptive technology as it alters the way a power system is operated both technically and financially. Any distributed generation within municipalities reduces their net load and therefore the energy supplied by the utility. From a utility's perspective, this could result in an under-recovery on their supply tariffs.

The concept can be demonstrated as follows:

Contracts with external power supplier like other utilities and IPPs typically consist of a fixed charge (depending on the type of IPP) and an energy charge (which is often a pass-through cost). Tariffs are normally set one time every year and if they predict that more energy will be sold than reality, the tariff will be set too low resulting in an under-recovery. A simple example is presented below. The values utilised are for illustrative purposes only.

Table 4: Effect of miscalculating required energy supply

Fixed Charge (c)	Energy Charge (c/kWh)	Total Energy (kWh)	Average Cost of Energy (c/kWh)
4000	100	60	166
4000	100	30	233

The risk for a utility is that it is difficult to plan for the amount of energy which will be provided from embedded generation due to many smaller projects (rooftop solar) not being recorded and communicated accurately as well as intermittency.

The impact due to a reduction in energy requirements is not the only effect on a utility. Further utility scale issues related to its own plant costs and capacity factors are explored in the next section.

Utility Scale Generation

Unlike embedded generation, utility scale projects do not reduce sales (they do not reduce the demand of customers such as municipalities), however, they do effect the cost of supplying a country. The change in cost is due to intermittency and sub-optimal dispatch of existing or new generation as well as offsetting a possible cheaper source of power.

The abovementioned effects need to be looked at simultaneously to carry out a meaningful analysis. One method is through developing load duration curves and using them in conjunction with screening curves (which considers plant capacity factor) to determine the likely cost of generation at a specific time of year.

As an example, if PV generation is netted off against demand, the resulting profile is the demand which needs to be serviced by existing, new or imported power sources. Figure 3 nets off 50% midday PV and 100% midday PV with the demand for an existing utility. The resulting load duration curves are plotted in Figure 4.

Figure 3: Net Demand after PV Integration

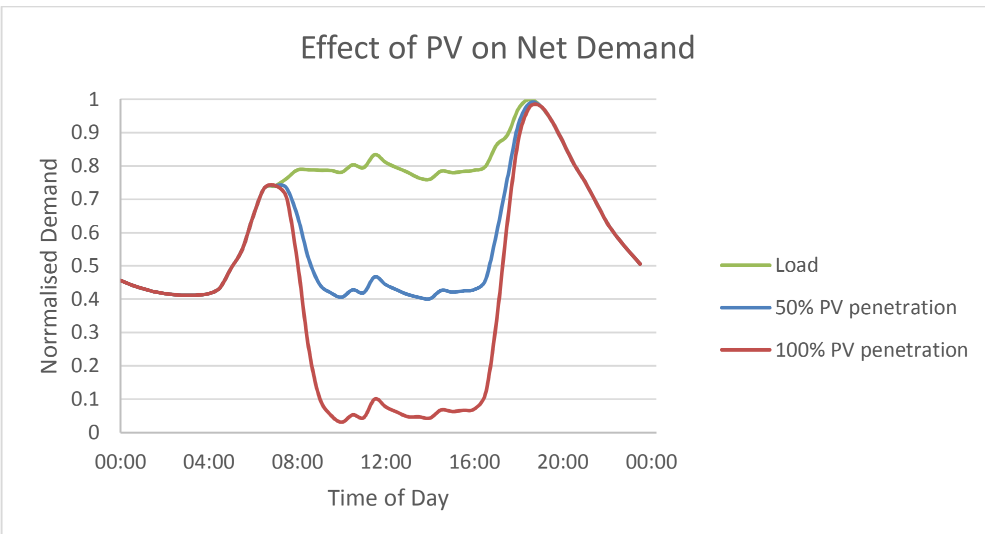
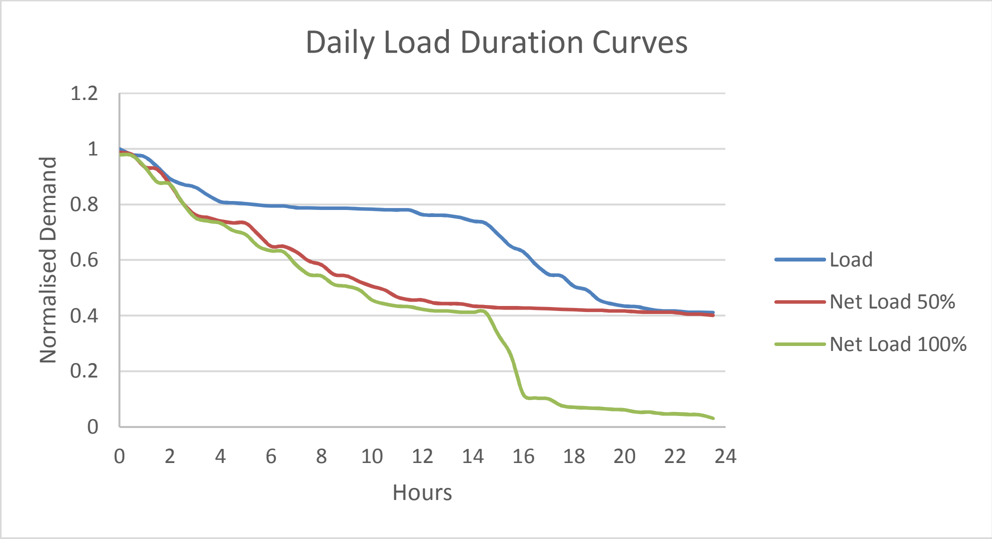


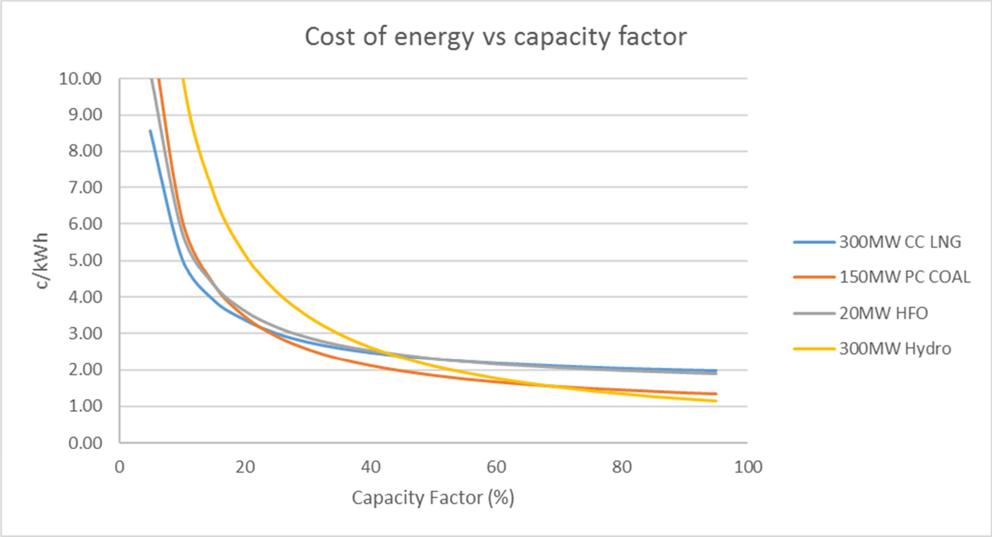
Figure 4: Effect of PV on Load Duration Curve



In the example above (for this particular utility), it can be seen that the base load generation requirements remain unchanged for renewable penetration of up to 50%. For penetration levels beyond this, for a country where generation to meet the existing demand is already in place prior to the installation of intermittent renewables, this represents a reduction in the effective capacity factor of their existing base load plants. In many cases the existing plants provide cheaper energy to that of intermittent renewable sources which results in an immediate increase in the overall cost of energy even before capacity factors are taken into consideration. Where renewable intermittent energy is cheaper than existing base load plants, this may not necessarily be the case.

Figure 5 is a graphical representation of typical base load power plant capacity factors. For all technologies, the cost of energy decreases as the capacity factor increases as the capital costs are recovered over a larger base. Peaking technologies will generally have a much lower cost at lower capacity factors compared to base load plants due to their lower capex. It is clear that plants operating at lower capacity factors will provide energy at a higher cost so it is important to keep (base load) capacity factors as high as possible.

Figure 5: Effect of capacity factor on cost of energy



A further issue which reduces existing plant capacity factor, is intermittency. A power system should have enough spinning reserve to cater for loss of its largest unit as well as any natural variations in power introduced by intermittent sources. This implies that existing generation will potentially have to be kept online at sub-optimal capacity factors to deal with these variations.

To summarise, when considering intermittent renewables in the energy mix which may even have a cheaper c/kWh cost than existing generation, a wholistic approach needs to be taken which considers the effect of reducing the capacity factors of existing plants as well as the cost of dealing with intermittency.

Techno-financial optimisation

The previous sections described the technical impacts and resulting limitations placed on the power system as well as the possible financial impacts on meeting the energy demand. Once the required penetration level is proven to be technically possible, the dispatch needs to be optimised to achieve the most economical solution.

The optimisations are best carried out using specialist software such as PLEXOS. It has the capability to optimise the unit commitment of capacity to the level that both capacity availability and reserve availability are optimal. The software balances out the opportunity cost to the generator from forgoing capacity (and the associated loss of efficiency) to provide reserve availability

Another key feature is that the above optimisation is undertaken so as to produce the optimal schedule for planning maintenance outages of all the units, so that capacity availability is optimised for the whole period, in the most economically and technically efficient way.

For each time period modelled and solved, the full commitment of units for both production and reserve, along with the planned outage schedule for all units can be reported on. It is also important to other key system characteristics like those provided in Table 5.

Table 5: Capacity Adequacy System Report

Parameter	**Unit**
Min Inertia Constant	
Min Reserve	MW
Reserve Trigger Level	MW
Reserve	MW
Reserve Margin	%
Capacity Required	(where applicable) MW

Conclusions

The paper has highlighted the most common components which should be considered when integrating large amounts of non-synchronous, intermittent, renewables onto a power system. These components may not apply to every situation but provide a starting point in determining what is technically possible and the financial effect of achieving the proposed penetration level. There are however further factors which are not covered in this paper which could become a limiting factor such small signal stability or government policy. These other factors, in the same way as those presented in this paper, need to be identified and considered on a case by case basis.

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