Title: Impact of partial unplanned outage modelling assumptions on long-term capacity planning validation

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Abstract:

Short-term power system models can be used to validate long-term expansion plans or to investigate the adequacy of possible future electrical power systems. When building these models, decisions need to be made about the level of detail that should be included. These decisions can be influenced by run time constraints as well as the availability of information. The ratio between partial and full unplanned outages of generators is unique to the specific system being modelled. Projections on these ratios are not always available and the impact of simplifying the representation of outages by, for example, omitting partial outages is not documented in the literature.

The 2030 power system planned for South Africa is used as a case study to investigate the impact that modelling the ratio of partial to full outages of various generation technologies has on system reliability metrics and electricity output. About 60% of all electricity generated in this weakly interconnected system is produced from coal fired power stations that experience partial outages, rendering this a useful case study. It is found that as the ratio of partial outages increases, the amount of electricity produced by coal fired power plants rather than other sources slightly increases, storage utilization significantly increases, and electricity production from gas and diesel plant significantly decreases. The amount of unserved energy and the loss of load probability decreases as the ratio of partial to full outages increases. Given the potential impacts of incorrect partial outage assumptions, the paper concludes that it is advisable to test the sensitivity of modelled results to the inclusion of partial outages in cases where information on their prevalence is not available. The impact of varying the relative size and duration of partial outages is found to have a much less significant impact on model outcomes. These aspects thus lend themselves to simplification.

The findings presented in this paper are relevant to those engaging in long-term capacity planning and research informing such planning, especially for weakly interconnected power systems that are currently heavily dependent on generating technologies that are prone to partial outages.

Keywords: Power system modelling, unplanned partial outages

1. Introduction

Throughout the last two decades the amount of variable renewable energy (VRE) being introduced into power systems worldwide has been increasing [1]. Large scale uptake in VRE introduces various complexities into the power system expansion planning process due to the variability and uncertainty they introduce on the electricity supply side of the balance between supply and demand. Various methodologies for increasing the accuracy with which the impact of VRE is accounted for in the planning process has been proposed [2].

To minimise model complexity and thus runtime, the long-term models used for power system capacity expansion planning tend to include as few details as possible. The ability to represent temporal details for both supply and demand, and granular detail on technical constraints and capabilities in the system, is subsequently severely limited. These temporal details, however, are required to at least some degree in order to assess the impact that the variability introduced by VRE has on system behaviour [3]. Methods for increasing the accuracy with which the impact of VRE is accounted for include increasing the accuracy of the representation of variability in the input data, including the representation of constraints such as ramping, and soft linking more detailed short-term models to the long-term models [4]. In the last case the short-term models can either be used to validate outputs or to feed information back into the long-term models. More detailed short-term models have also been used to study individual projected future years in order to investigate system adequacy, capacity factors for various technologies, and electricity cost in various scenarios [5].

Deane et al. [3] identify the inclusion, in short-term models, of parameters such as start costs, minimum stable generating levels and reserve margins as crucial for evaluating systems with VRE. In this study no mention is made of modelling the ratio between partial and full unplanned outages of generators. Gils *et al.*[5] does include data on partial outages in their analysis. They show that the inclusion of discrete outage events can have a significant impact when investigating system security. Their study uses detailed information on outage length and the size of the reduction in generating capacity to produce unitized unplanned unavailability curves that they combine to represent unplanned unavailability curves for lignite, hard coal and natural gas plant in the system under investigation. They run a Monte Carlo simulation where a set of these unplanned unavailability curves are created and then combined with historical data on planned outages. However, because they model the impact of generator unavailability on a level where unavailability is combined for each generating technology, the impact of distinguishing between partial and full unplanned outages is not shown.

Any generation plant in a power system may be shut down completely on a planned or unplanned basis when maintenance is required. Generating plants that include semi-redundant systems may also experience partial outages. In these cases, the plant will have its maximum output temporarily reduced to a value somewhere between its maximum load and minimum stable level of generation.

A report on current and projected unplanned outages on coal plants in the Australian energy market indicates roughly 40% of unplanned capacity loss coming from partial outages [7]. The latest four-year report on plants that report their results to the North American Electric Reliability Corporation (NERC) lists the contribution from partial outages at 25% of unplanned capacity losses on coal plant [8]. These two cases indicate both that partial losses make up a significant portion of unplanned capacity losses on coal plant and that this portion is variable from system to system.

In some jurisdictions the information required to characterise the outage events and behaviour might not be readily available. The South African system represents one such case. While the 2019 Integrated Resource Plan (IRP) [9] does contain projections on future energy availability factors (EAF) of existing plants, no indication is given in terms of the distribution between partial and complete outages in the projected data. A document released by the South African power utility, Eskom, does show that between April and September 2021 44% of unplanned capability loss was due to partial generation losses [10]. This however does not provide enough information to project future behaviour, as assessing and projecting power plant reliability requires the analysis of five to seven years of historical operational data [6]. Additionally, the values provided by the utility cover unplanned outages for all plants in the fleet, which while dominated by coal plant, also contains other technologies, some of which are not prone to partial outages. When modelling systems such as these, where little or no information is available on the share of unplanned outages that are partial, the temptation exists to simply model all unplanned outages as complete outages.

The question that arises from the above is whether such simplifications in the modelling process would significantly affect the results.

Outage behaviour cannot be assumed to be consistent in the long term as plants become more unreliable as they age [11,12] and the additional ramping caused by increased renewable penetration can cause additional deterioration [13]. Given the above, the question regarding the need for information on partial outages also needs to be answered to determine whether time and resources need to be spent, to not just project levels of plant availability for future systems, but also to project what patterns of availability might look like in terms of full and partial outages.

In order to investigate these questions, the planned 2030 South African power system, as detailed in the 2019 IRP is used as a case study.

The South African power system is currently heavily dependent on coal-fired power plants. The plan outlined in the 2019 IRP includes building significant VRE capacity over time while diminishing the contribution from coal, with wind expected to contribute 17.8% and PV 6.3% of total electricity production in 2030. However, it is still projected that 58.8% of South African electricity will be produced from coal at that point [9]. The South African system can thus be seen to be heavily reliant on large coal-fired power plants while being in the process of incorporating VRE. Additionally, the South African coal fleet is experiencing a high level of unreliability [21,22] and this high level of unreliability is expected to persist, at least in part, until 2030 and beyond [9]. South Africa is thus projected to have a power system in 2030 where a large portion of generating plant will experience partial unplanned outages while also experiencing a high overall level of unplanned outages in a system anticipating a significant share of renewable production. This, along with the fact that the system only has a few weak interconnections to neighbouring power systems, makes it an ideal test case for investigating the impact of distinguishing between full and partial outages when modelling an power system. If modelling partial outages were to have no particular impact on the outcomes for this system it would be safe to assume that they can be omitted from verification models for most other power systems.

In this study several scenarios are modelled to investigate the impacts that different percentage mixes of partial and full unplanned outages have on system reliability and the level of electricity production by each generating technology type. Additional scenarios are also considered to evaluate the impact of factors such as the average size of the reduction in generating capacity experienced during a partial outage, variations in outage duration and overall increases and decreases in the amount of capacity loss due to unplanned outages. These additional scenarios are considered both to evaluate the impact of these factors and to give context to the relative importance that including partial outages in the model has on outcomes.

Partial outages are only implemented on coal plant in this study. Partial outages are omitted on Pumped Hydro, Hydro and OCGT because they experience both a relatively low unplanned outage rate compared to coal plant and a very low ratio of partial outages [8]. This combination should result in the system impacts of omitting partial outages being minor when compared to the impact of partial outages on coal plant. This simplification additionally reduces model complexity and lowers run times.

In the case of nuclear plant, the overall unplanned outage rate is still very low [8,13], but the ratio of those outages that are partial is more comparable to coal. However, there are only two nuclear units in the South African system. Mitigating distortions caused by implementing partial outages as stochastic events to produce representative results would require an onerously high number of model runs. The results from studying the impact of partial outages on coal plant in a system dominated by coal plant should still produce insights that would apply to systems where nuclear plant dominates and the impact of nuclear outages are more significant.

This study contributes to the literature by:

- Demonstrating the scope of the impact that modelling various ratios of partial outages can have on modelled outcomes.
- Clearly showing that the sensitivity to a range of partial outage ratios should be tested if modelling is done on systems where such information is unavailable in cases where the generating plant in the system can experience partial outages.
- Identifying which characteristics of partial outage have a significant impact on model outcomes and which do not and thus lend themselves to simplification.

The study is structured to firstly provide a more in-depth overview of the causes and characteristics of full and partial outages on coal fired power plants in section 2. The methodology, inputs, models and scenarios used are then described in section 3, with results and conclusions presented and discussed in section 4 and 5.

2. Characteristics of Coal Plant Outages

Outages on coal-fired power plant can be divided between planned and unplanned outages. Planned outages generally occur on a scheduled basis and the schedule can be adapted to fit outages to predicted periods of either low demand or overall high plant availability. The duration of scheduled outages will vary depending on the work that needs to be done and not all plants will have outages scheduled in a given year.

Unplanned outages occur when the plant loses production capability due to an unplanned event. The rate at which unplanned outages occur depends on the reliability of the plant. As has been mentioned, unplanned outages may result in full or partial plant unavailability. In the event where a complete shutdown is required to repair a crucial piece of equipment or where failure has resulted in the unit tripping, a complete outage will result. Partial outages occur when only some production capability becomes unavailable. In some cases, this might happen due to plant unavailability on a system with partial redundancy. In addition to break downs on systems with some level of redundancy, partial outages may also occur due to reduced performance on critical systems without redundancy. One such case is a system where cooling system performance is impacted by high ambient temperatures.

Complete and partial outages are likely to impact on the rest of the power system in slightly different ways. Partial outages, by their very nature have a smaller impact on the system in terms of the amount of reserves that need to be deployed to mitigate them in the immediate aftermath of their occurrence. Given that the loss in production capacity is smaller, a partial outage would have to carry on for a longer period of time than a complete outage to have the same impact on a given plant's overall EAF. Figure 1 illustrates two scenarios where the same overall EAF is achieved by complete outages in the first case and partial outages in the second.

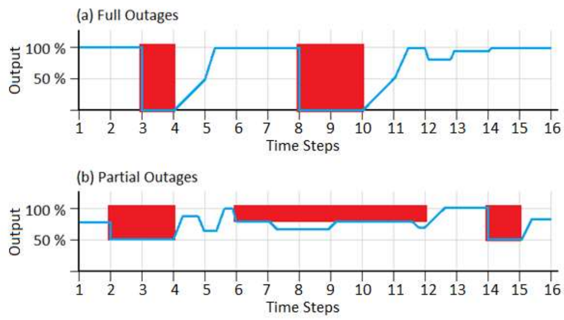

Figure 1: Demonstrating how full and partial outages can achieve the same EAF. Full outages are shown in (a) and partial outages in (b). Percentage unit output over time is plotted in blue and the red blocks indicate outage events.

It should be noted that EAF measures the availability of the plant to produce power, not the actual plant output. Thus, in both part (a) and part (b) of Figure 1 there are periods where the plant is available to produce 100% of output, but is not scheduled to do so. A distinction between the impact of full and partial outages can be observed in the plant behaviour shown in Figure 1 b) between periods 7 and 9. A plant experiencing a partial loss in production capability may still ramp down further and thus be able to contribute to overall system flexibility.

Additionally, once a partial outage has been cleared, the unit can ramp up and down according to system needs without the costs and delays that starting up a plant after a full outage entails. On the other hand, a coal plant operates at reduced thermal efficiency when running at part load. When comparing the thermal efficiency of two units with the same availability where one runs at part load for a given period and the other is off for part of the period and then started up and ramped up to run at full load for the rest of the period, the unit that experienced the partial outage may exhibit lower overall thermal efficiency for the period even when accounting for the starting costs of the other unit.

3. Modelling Methodology

Short term unit commitment models are used to verify that the power system designed during the long-term planning process are reliable and that the capacity factors and costs projected in the long-term models reasonably approximate the results found by the more detailed short-term models. This interaction can be seen in Figure 2. This study is primarily concerned with the impact that the approach taken to representing unplanned outages in these short-term models has on the projected overall electricity output by each generating technology type and the impact on system reliability.

A short-term unit commitment model based on the projected 2030 South African system, from the 2019 IRP [9], is used to investigate the possible distortions that can arise from unplanned outage simplifications. A main set of scenarios are modelled to investigate how system reliability, operational cost and the capacity factors of the generating plants in the projected system are affected when the split between partial and full unplanned outages are stepped from 0%/100% to 100%/0% in 25% increments. This serves to illustrate both the impact of excluding partial outages completely and the impact of over or underestimating their presence. To model this main set of scenarios, assumptions are made about the size and duration of the partial outages. The potential impact of these assumptions is investigated by modelling variations on two scenarios from the main set of scenarios.

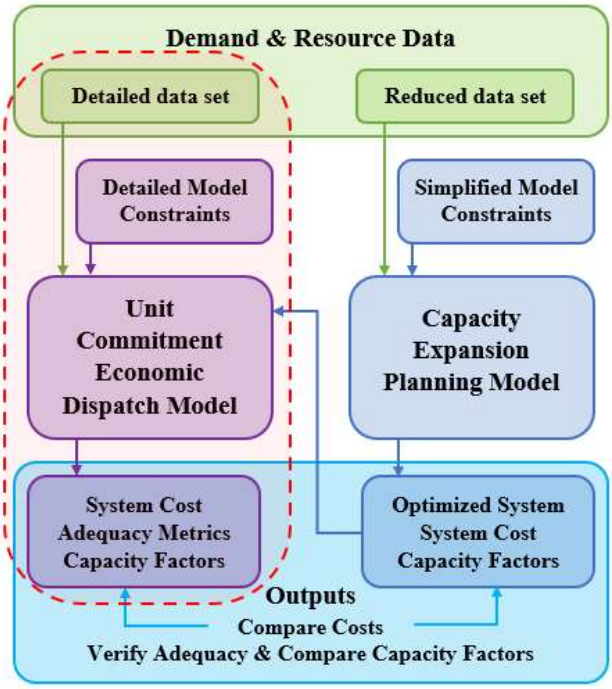

Figure 2: Process diagram for soft linking a unit commitment economic dispatch model to a capacity expansion planning model with the section pertaining to the unit commitment economic dispatch model outlined in red [4]

Details of the software used to build the unit commitment model and details of the projected system that is modelled is given in section 3a). The sources of the renewable data and plant characteristics used in the model is detailed in section 3b). All scenarios modelled during the study are described in section 3c) and validation of modelled results against the IRP results are discussed in section 3d)

a) Unit Commitment Model

Short term unit commitment economic dispatch models created using PLEXOS modelling software have been used in numerous studies [14,15] that investigate the workability of proposed energy systems. Models using the software has also been used by regulators during the planning process [16,17]. PLEXOS can be used to construct models with varying levels of technical and temporal detail. For this study an hourly copperplate model of the South African power system, as planned for 2030, is used. The focus is on obtaining realistic behaviour on an individual unit level to determine the impact of varying levels of representation for partial and full unplanned outages. Some of the characteristics that are included in the model are given in Table 1.

Table1: Main unit and system characteristics included in the model

Unit Characteristics
Max load
Min stable load
Ramp Rate
Heat Rate
Maintenance Rate
Forced Outage Rate

Start Costs
Fuel Cost
Variable O&M
Reservoir size (storage)
Cycle efficiency (storage)
System Characteristics
Reserve Margin
Demand

A breakdown of the modelled system composition by generation technology type is given in Table 2. The projected percentage contribution that each technology is expected to make towards meeting demand, as per the 2019 IRP, is also given.

The model is run without foresight of outage events. In order to prevent the impact of any particular outage event from skewing the outcomes a Monte Carlo simulation approach is followed with regard to unplanned outages, and 20 sets of outage patterns are used. The patterns are generated using assumed minimum, average and maximum outage durations in conjunction with the outage rate. Details on the assumed durations are provided in Addendum A.

Table 2: Planned percentage that each technology will make up of the total installed capacity by 2030 and the expected energy contribution by the technology to total annual generation [9]

Technology	***Nameplate Capacity***	***Expected Energy Contribution***
Coal	*43.00%*	*58.80%*
Nuclear	*2.36%*	*4.50%*
Hydro	*5.84%*	*8.40%*
Storage	*6.35%*	*1.20%*
PV	*10.52%*	*6.30%*
Wind	*22.53%*	*17.80%*
CSP	*0.76%*	*0.60%*
Gas & Diesel	*8.10%*	*1.30%*

b) Input Data

A single year's worth of hourly demand and renewable generation data is used in order to preserve the link between weather patterns and demand. The wind time series used in this study is generated using wind mast data collected during the South African Wind Atlas project [18]. The PV time series is generated using data captured by the SAURAN network of solar irradiance measuring stations [19]. The generated resource data for various sites is processed using NREL's System Advisor Model [20] to produce production profiles. In both cases hourly data from 2017 is used.

Economic data on fuel costs as well as thermal efficiency information by technology type is obtained from technical reports used in the studies that informed the IRP [23], along with information from the Eskom annual reports [21,22].

Information on individual plant capacity, ramping capabilities and projected outage rates for all plants as well as details on the storage capacity for various pumped storage facilities is drawn from the IRP addendums [9] and input studies [23], fact sheets supplied on the Eskom website [24-27], the South African grid code [28] and a publicly available Eskom procedure that includes details on the ramp rates that units must be able to achieve in order to contribute to different categories of reserve margin [29].

Startup cost for coal and gas plants are calculated using the fuel and financial costs supplied by Kumar *et al.* [30] and nuclear plant start costs are estimated using the values supplied by Van den Bergh & Delarue [31]. All values have been adjusted to account for inflation.

In the case of planned generating units that have not been constructed, design details of the most recently completed plant are assumed to apply. In the case where technology choice is unclear, such as with the planned additional storage, it is assumed that additional capacity would share characteristics with plant that is already in use.

More detailed model input values are supplied in Addendum A.

c) Scenarios

The main and variation sets of scenarios are depicted in figure 3. The main set of scenarios are set up to evaluate system outcomes in terms of system reliability, generating unit capacity factors and cost when the percentage of unplanned outages that are made up of partial outages is varied. Five ratios of full to partial outages are investigated at three levels of demand. Unplanned outages occurrences in the coal fleet are modelled as being 0%, 25% 50%, 75% and 100% full outages. The remainder of the capacity loss is made up of partial outages. For the main set of scenarios, partial outages are modelled as a 40% capacity loss. This value is used as it represents the smallest loss, rounded to the nearest 10%, that allows the expected loss on all coal units to be modelled as partial outages for the 0% full outage scenarios. The five allocations of full and partial outages are implemented for the low, medium and high levels of projected electricity demand considered in the IRP [9].

In addition to the main set of scenarios, there are a set of variation scenarios based mostly on the medium demand scenario with a 50-50 split between partial and full outages (50% FO Med) with one additional variation scenario based on the medium demand scenario with 100% full outages (100% FO Med). These variation scenarios are used to investigate the impact of other outage characteristics on model outputs. This is done both to evaluate the significance of these characteristics and to provide context for the relative importance of including partial outages when modelling planned power systems. Identifying which characteristics have the most impact on model outputs clarifies where resources should be deployed to gather information and make projections and where assumptions and simplifications can safely be used.

The impact of varying the average severity of partial outages is investigated by including scenarios where partial outages are modelled as 20% and 30% reductions in load. The coal plant is modelled to have minimum generation set at 40% thus making it possible for a unit to have a partial outage of up to 60% before reaching minimum generation. The 30% generation loss is selected to bisect this possible 60% loss and the 20% loss is selected as it is an equal but opposite offset from the midpoint compared to the 40% loss used in the 50% FO Med Scenario. The 20% and 30% reduction scenarios investigate the relative impact of more frequent, but less severe partial outages.

In all the above describe scenarios the simplification of using a single level of severity for all partial outages is used. The potential effect of this simplification is investigated using two scenarios with distributions of varying levels of partial outage severity. For both scenarios an average capacity loss of 40% is maintained. Partial outages are allocated as 20%, 40% or 60% generation losses. For one of these two scenarios the partial outages are distributed to have an equal duration across the different loss levels and in the other equal overall capacity loss is maintained. In order not to skew duration distributions only one level of capacity loss is assigned per generating unit.

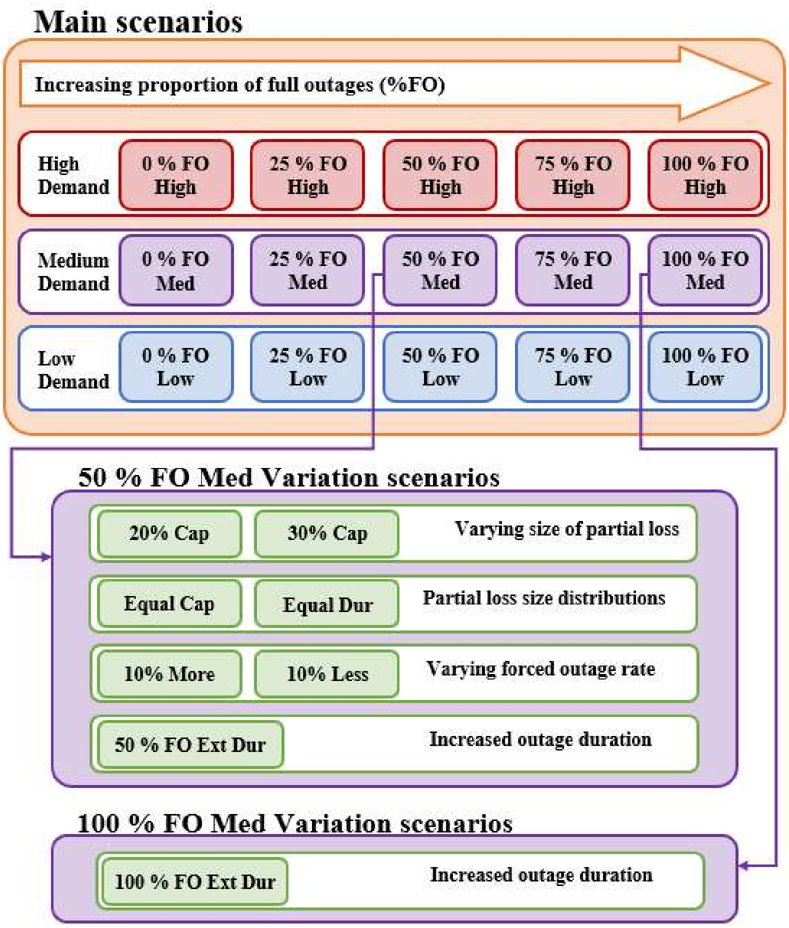

Figure 3: Scenarios modelled to investigate the impact of including or excluding partial unplanned outages when modelling the South African power system and to investigate the impact of varying partial outage characteristics.

Given that the overall projections of EAF made in the 2019 IRP for Eskom coal plants have so far proven to underestimate plant unavailability [22], the relative impact of under or overestimating EAF in projections should be understood in order to facilitate an understanding of the impact of including partial outages in a relevant context. To achieve this the 50% FO Med scenario is also modelled with the prevalence of all outages increased and decreased by 10%. It should be noted that the current performance of the Eskom coal fleet in terms of EAF is so far below the projected performance that the South African power system can be considered to be dysfunctional, with unserved energy fluctuating between 2 and 6 GWh [32] on an hourly basis. In order not to unduly distort the case study, it is assumed that the mitigations currently being put in place will be successful and that the coal fleet will return to the lower levels of unavailability projected in the IRP by 2030.

Finally, a set of scenarios where unplanned outage duration is doubled is included. This is done for both the 50% FO Med and for the 100% FO Med scenario.

d) Validation

Table 3 compares the expected contribution of each technology to total generation from the modelling used to inform the IRP [9] compared to this study's average modelled contribution for the 50% FO Low, Med and High scenarios. The 50% FO cases were used because they came closest to the known partial outage contribution for the current system as reported in [10]. The modelled results correspond well with the expected values. The largest discrepancy can be seen in the case of PV generation. The SAURAN measuring sites used to generate the PV production curve are spread out across the country. While measuring sites from areas with high PV production potential are included in the dataset, they do not dominate it. It is likely that using input data that was geographically dispersed without optimizing for best locations resulted in capacity factors that were lower than the ones used in the IRP. Using geographically dispersed PV generation reflects two current trends that were not as prevalent during the period when the 2019 IRP was being developed. New PV sites are being developed in areas with excess grid capacity and not in the areas with the best resources and there is a significant uptake in rooftop PV that also does not map to the best sites for PV production in the country.

The IRP includes the procurement of 2500 MW of capacity from the Grand Inga Hydropower Project [9]. In the absence of further technical information, it was assumed that the project would have a capacity factor similar to that of the Cahora Bassa Hydro Power Station in Mozambique (which contributes 1500 MW to the South African grid at peak capacity). This assumption appears to have resulted in the contribution from Hydro being overstated compared to the IRP modelling results.

Table 3: Expected contribution of each technology to total generation in the IRP [9] compared to the average modelled contribution for the 50% FO Low, Med and High scenarios.

Technology	***Expected Contribution (IRP)***	***Modelled Contribution (This Study)***
Coal	*58.80%*	*60.39%*
Nuclear	*4.50%*	*4.59%*
Hydro	*8.40%*	*9.39%*
Storage	*1.20%*	*1.27%*
PV	*6.30%*	*5.23%*
Wind	*17.80%*	*17.30%*
CSP	*0.60%*	*0.52%*
Gas & Diesel	*1.30%*	*1.31%*

4. Results

In this section the results from the main set of scenarios are discussed in section 4a), with the results from the variation scenarios discussed in section 4b).

a) Main Set of Scenarios

When analysing the main scenarios as shown in Figure 3, at all three demand levels a very clear impact can be observed in terms of the total electricity production by gas plant and storage plant. As the ratio of full unplanned outages increases the utilization of storage plants decreases and production by gas plants increases. The changes in output for both gas and storage is significant. For the medium demand forecast, electricity output from storage plant decreased by 25.7% from the 50% FO Med scenario to the 100% FO Med scenario, while production from gas and diesel plants increases by 20%. Coal plant production decreases as the ratio of unplanned outages due to full capacity losses increases. While the absolute size in the change in production from coal plant is in the same range as the change observed for gas and storage plants it forms a much smaller percentage of overall coal plant production. This interaction can be seen in Figure 4.

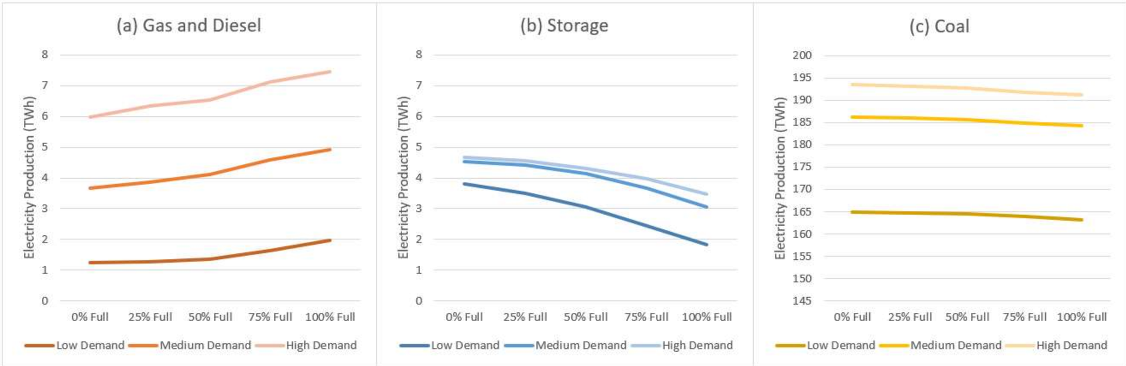

Figure 4: Impact of representing unplanned production capacity losses on coal plant as various percentage combinations of partial and full capacity losses on total annual electricity production in TWh by (a) gas and diesel peaking plant, (b) storage plant and (c) coal plant

As the ratio of partial outages decreases, less electricity generated by coal plant is used to charge storage plant during low demand periods. This leads to lower production from storage during high demand periods and this shortfall in production is then augmented by production from more expensive gas and diesel plant. This implies that if the South African electricity production system is modelled using only full unplanned outages, when sources like [10] suggests a reality of a closer to 50-50 split between full and partial unplanned outages, the utility of storage in the system may be severely underestimated. This would lead to the per unit cost of additional storage being overestimated and thus potentially to an underinvestment in storage.

For all scenarios the renewable energy that is produced is fully utilized without any curtailment. Figure 5 shows the maximum observed hourly LOLP and the unserved energy (USE) for the main set of scenarios. It is notable that for the low and medium demand forecast the maximum observed hourly loss of load probability (LOLP) increase by an order of magnitude when comparing a system with a 50-50 split between full and partial unplanned outages to one where only full unplanned outages are modelled. The increase is less severe for the scenarios using the high demand forecast, but LOLP still doubles. At the same time unserved energy increases with 140% with low demand, 67% with medium demand and 50% with high demand. These clear decreases in system reliability can be ascribed to the increased risk of large losses occurring at times when the system does not have the capacity to cope with them as the representation of unplanned outages moves, from smaller, more frequent, partial outages to larger, less frequent, but more severe, full outages. This impact is significant because increased uptake in renewable energy is expected to negatively impact on system reliability. If a system is transitioning from fossil fuels to higher shares of renewable generation and system reliability is underestimated due to the representation of unplanned outages, the capacity of the system to absorb renewable generation may be underestimated.

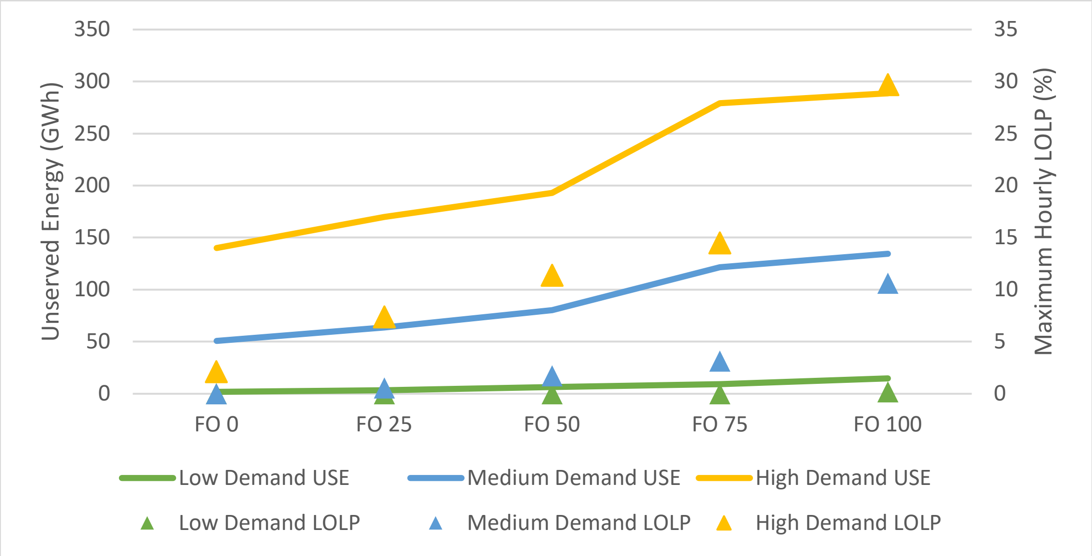

Figure 5: Reliability impact of modelling various ratios of partial unplanned outages, shown through unserved energy and maximum hourly LOLP

b) Variation Scenarios

The variation scenarios are included to investigate the impact that modelling various particular characteristics of partial unplanned outages may have on model results. The potential impact on results is investigated by adjusting the modelling of the following characteristics:

- **The average size of partial losses** – Investigated using the 20% Cap and 30% Cap scenarios. In the main scenarios partial losses are modelled as a 40% loss in generating capacity. This is changed to respectively 20% and 30% in these two scenarios.
- **Partial loss size distributions** - Investigated using the Equal Cap and Equal Dur scenarios. Both scenarios implement small, medium and large partial outages while maintaining and average partial capacity loss of 40%. In the Equal Cap scenario, the overall capacity loss is equally distributed between small, medium, and large partial outages and in the Equal Dur scenario the number of hours during which a unit experiences partial outages are equally divided between small, medium, and large partial outages.
- **Increased partial outage duration** – Investigated using the 50% FO Ext Dur and 100% FO Ext Dur scenarios. All outage patterns are created using distributions that are defined by setting minimum, maximum, and average outage durations. These two scenarios are based on the 50% FO Med and 100% FO Med scenarios from the main set of scenarios, but for both the length of the average outage

duration that is used to generate partial outage patterns is doubled. The distributions used for the main set scenarios can be seen in Addendum A.

- **Variation in forced outage rate** – Investigated using the 10% More and 10% Less scenarios. In these scenarios the overall capacity loss due to unplanned outages is increased and decreased by 10% relative to the capacity loss that is implemented in the 50% FO Med scenario.

The scenarios investigating the impact that the various approaches to modelling the size of the partial outage has on model outcomes is compared to the 50% FO Med scenario in terms of the generation from gas and storage in Figure 5. The variation between the 50% FO Med and 100% FO Med scenarios is included in the graph to provide perspective.

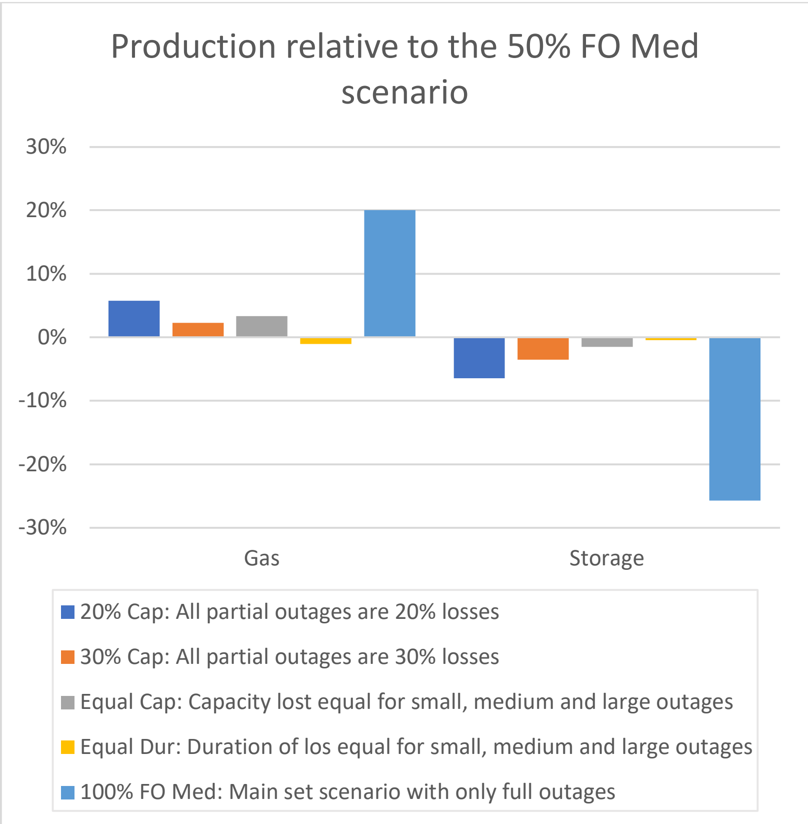

Figure 6: Change in electricity production by gas and storage plant when comparing various scenarios to a base case where partial outages make up 50% of forced outage capacity loss and all partial outages are modelled as 40% losses in production capacity.

Changing the average size of the partial outage in the system clearly has an impact on the balance between generating from gas and from storage. That impact is most severe when partial outages are modelled as smaller, more frequent losses in production capacity. The impact is, however, dwarfed by the impact of not including partial outages in the representation of unplanned outages.

As shown in Table 3, for the four variation scenarios shown in Figure 5 the largest impact on unserved energy occurs for the case where the average size of production loss stays at 40% capacity loss per outage incident, but equal amounts of capacity loss occur at individual loss levels of 20%, 40% and 60% (Equal Cap). Even in this case the

14.7 % rise in unserved energy, while not insignificant, is dwarfed by the 67% rise observed between the 50% FO Med scenario and the 100% FO Med scenario from the main set of scenarios.

Table 3: Impact various approaches to modelling the relative size of partial outages has on modelled unserved energy and how that compares with the unserved energy in the 50% FO Med scenario

	20% Cap	*30% Cap*	*Equal Cap*	*Equal Dur*	*100% FO Med*
Unserved Energy (GWh)	78.33	74.91	92.04	79.11	134.54
Variation from 50% FO Med	-2.36%	-6.62%	14.73%	-1.39%	67.71%

The impact that extending outage duration has on modelled electricity production from coal, gas, and storage and on unserved energy can be seen in Table 4. Production by technology type is most affected when comparing the two cases without partial outages.

Table 4: Impact of extending outage durations with all values shown in GWh

	50% FO Ext Dur	*50% FO Med*	*100% FO Ext Dur*	*100% FO Med*
Gas	4010	4108	4576	4931
Storage	4165	4132	3170	3068
Coal	185708	185622	184598	184200
Unserved Energy	*67*	*80*	88	135

For these cases extending outage duration results in a relatively small increase in coal production and a corresponding 10% drop in gas production. The impact on unserved energy is more pronounced. The relatively large decrease can be ascribed to the fact that extending outage durations results in a reduction in the number of individual outage incidents. This in turn reduces the chances for incidents of unserved energy to occur in the model immediately after an unplanned outage occurs.

Lastly, the impact of over or underestimating overall capability loss by 10% is examined, again using 50% FO Med as base case. A 10% increase in the amount of overall capacity loss experienced by all technology types results in a 0.8% reduction in coal plant production that is mostly compensated for by a 35% increase in electricity production by gas plants. This more constrained system also has a 58% increase in unserved energy. Decreasing unplanned outages results in a 0.4% increase in coal production that is balanced by a 30% reduction in gas plant output and a 6% reduction in storage output. A 54% decrease in unserved energy is also observed when unplanned outages are decreased.

The variation cases mostly show smaller changes to the amount of electricity produced by gas and diesel plant and from storage than is observed in the main scenarios. The notable exception to the is the case where the generating capacity loss due to unplanned outages is adjusted up and down by 10%. The same pattern plays out when considering levels of unserved energy. The correct overall estimation of generating plant availability and the ratio between full and partial thus emerge as the key variables to predict and incorporate in validation models.

5. Conclusions

This study set out to investigate the impact that including partial outage characteristics has on short term models that are used to validate long term capacity expansion models. Modelling the South African power system as projected for 2030 by the 2019 IRP was used as a case study. This system has a large fleet of plant that are prone to partial outages and the proportion of partial outages they experience is also on the high side of what is considered typical. Thus, the findings presented here are mostly relevant to validating long term plans in systems where a large portion of the generating plant can experience partial outages.

Key findings:

- Inclusion of partial outages significantly increases storage utilization, which could lead to the cost of including additional storage being overestimated and the benefits additional storage offers to the system being underestimated in cases where unplanned outages are only modelled as full outages.
- Inversely, inclusion of partial outages significantly decreases production by diesel and gas plant. In the South African system these plants are last on the merit order. The higher utilization of these plants when partial outages are not modelled may lead to the potential benefit of building additional plant that is cheap to build, but expensive to run being overestimated.
- Even though the proposed 2030 system is already designed to be reliable the improvements to reliability metrics when partial unplanned outages are included in the model are significant - reducing unserved energy by 67% and maximum observed hourly LOLP by an order of magnitude when moving form only representing full outages to having 50% of unplanned outages be partial in the medium demand case. Underestimating system reliability could lead to the amount of renewable energy that could safely be incorporated in the system being underestimated.
- When including partial outages, the impact of the percentage of capacity loss allocated to partial and full outages respectively has the largest impact on results while factors such as the average size of the individual capacity losses and changes to average outage duration are less significant.
- Diesel and gas consumption increased by 20% in the medium demand case when moving from a 50-50 split between full and partial unplanned outages to a scenario with only full unplanned outages. This is comparable to the increase in gas consumption that is observed when EAF drops by 10%.

The above shows that accurately representing partial unplanned outages when modelling the South African power system is crucial in order to avoid distorted outcomes. This also highlights the importance of creating projections, not only of the level of expected unavailability for each technology type, but also of the characteristics of that unavailability when planning and investigating potential future expansions to these systems.

Finally, this research shows that a cautious approach is required when deciding whether and how to include partial outages, or account for their lack when system specific information is unavailable. This caution is even more called for in cases where such a lack of information on partial outage characteristics coincides with systems with aging plant prone to partial outages that have high levels of unreliability. In these cases, it is advised that the sensitivity of the results to various levels of partial outages should be tested.

These findings are relevant to those engaging in long-term capacity planning and research informing such planning, especially for weakly interconnected power systems that are currently heavily dependent on generating technologies that are prone to partial outages.

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Addendum A

Table A1 gives general characteristics of the generating units modelled. Where no data is given the constraint was not included in the model. It should be noted that Run Up Rate refers to the rate at which a unit can ramp up from 0 MW to Min Gen and Max Ramp Up refers to the rate at which a unit can ramp up when operating between Min Gen and Max Gen. Max Ramp Down was also included in the model and the same values were used as listed for Max Ramp Up.

Table A.1: General Characteristics

Power Station	Units	Max Gen (MW)	Min Gen (MW)	Run Up Rate (MW/min)	Max Ramp Up (MW/min)
Coal					
Duvha	*4*	*575*	230	4	*10*
Lethabo	*6*	*593*	237	3.55	*10*
Tutuka	*6*	*585*	234	3.38	*10*
Matimba	*6*	*615*	246	3.167	*10*
Matla	*3*	*575*	230	2.5	*10*
Kendal	*6*	*640*	256	1.9	*11*
Majuba 1 to 3	*3*	*619*	248	1.85	*10*
Majuba 4 to 6	*3*	*666*	266	1.85	*11*
Medupi	*6*	*720*	288	6	*12*
Kusile	*6*	*720*	288	6	*12*
New Coal 2023	*1*	*750*	300	6	13
New Coal 2027	*1*	*750*	300	6	13
SasolInfrachem Coal	*1*	*125*	*50*	*2*	4
Sasol Synfuel Coal	*1*	*600*	*240*	*4*	10
Hydro					
Gariep	*4*	*90*			
Vanderkloof	*2*	*120*			
Cahora Bassa 1& 2	*2*	*750*			
New Hydro 1 to 4	*4*	*650*			
Storage					
Drakensberg 1 to 4	*4*	*250*			
Palmiet	*2*	*200*			
Steenbras 1	*1*	*180*			
Ingula	*4*	*333*			
New Storage A 1 to 3	*3*	*171*			
New Storage B 1 to 5	*5*	*315*			
Nuclear					
Koeberg	*2*	*930*	744	4	*4*
Gas					
Port Rex	*3*	*57*	17	15	15
Gourikwa	*5*	*147*	44	15	15
Acacia	*3*	*57*	17	15	15

Ankerlig	*9*	*147*	44	15	15
SasolInfrachem Gas	*1*	*175*	*53*	15	15
Sasol Synfuel Gas	*1*	*250*	*75*	15	15
DOEIPP	*6*	*167.5*	*50*	15	15
2024 gas	*6*	*166.67*	50	15	15
2027 gas	*12*	*166.67*	50	15	15
CSP					
CSP	*6*	*100*	40	2	2

Table A.2 gives the outage rates for all generating units in the simulation. The values in italics are taken directly from the 2019 IRP. Where information was not supplied, assumptions are based on values from the most similar unit where information is supplied.

Table A.2: Outage Rates

Power Station	Planned	Unplanned	Total EAF
Coal			
Duvha	7	32.79	*60.21*
Lethabo	7	19.61	*73.39*
Tutuka	7	34.92	*58.08*
Matimba	7	22.07	*70.93*
Matla	7	23.33	*69.67*
Kendal	7	20.06	*72.94*
Majuba 1 to 3	7	22.07	*70.93*
Majuba 4 to 6	7	22.07	*70.93*
Medupi	7	11.94	*81.06*
Kusile	7	13.58	*79.42*
New Coal 2023	7	13	80
New Coal 2027	7	13	80
SasolInfrachem Coal	*4.8*	*15*	80.2
Sasol Synfuel Coal	*4.8*	*15*	80.2
Hydro			
Gariep	2.925	2.925	*94.15*
Vanderkloof	2.455	2.455	*95.09*
Cahora Bassa 1& 2	*4*	*4*	92
New Hydro 1 to 4	4	4	92
Storage			
Drakensberg 1 to 4	6.815	6.815	*86.37*
Palmiet	3.05	3.05	*93.9*
Steenbras 1	*4*	*10*	86
Ingula	3.2	3.2	*93.6*
New Storage A 1 to 3	3.2	3.2	93.6
New Storage B 1 to 5	3.2	3.2	93.6
Nuclear			
Koeberg	10	5.46	*84.54*
Gas			
Port Rex	2.5	2.5	95

Gourikwa	2.26	2.26	*95.48*
Acacia	2.5	2.5	95
Ankerlig	2.25	2.25	*95.5*
SasolInfrachem Gas	*6.9*	*11*	82.1
Sasol Synfuel Gas	*6.9*	*11*	82.1
DOEIPP	*7*	*5*	88
2024 gas	2.5	2.5	95
2027 gas	2.5	2.5	95
CSP			
CSP	7	13	80

The values used to set up the distribution curves that were used when generating outage durations for the outage patterns used in the Monti Carlo simulation are given in table A.3 and A.4. Because the simulation was only run over a single year, the maximum outage durations were capped at the total allocation for the best performing unit in each grouping.

Table A.3: Planned Outage Durations in hours

	Max	Mean	Min
Coal (with 7% Planned Outages)	600	168	48
Coal (with 4.8% Planned Outages)	408	168	48
Hydro	192	168	48
Pumped	240	168	48
Nuclear	864	168	48
Gas	192	168	48
CSP	600	168	48

Table A4: Unplanned Outage Durations in hours

	Max	Mean	Min
Coal	336	72	2
Hydro	192	72	2
Pumped	240	72	2
Nuclear	336	72	2
Gas	192	72	2
CSP	336	72	2

The heat rates assumed for coal, gas and nuclear plants were taken from the technology data report generated by EPRI to be used as an input for the 2019 IRP [23]. Starting costs for coal and gas were calculated based on the cost descriptions given in Kumar et. al. [30] and made use of plant size and fuel cost assumptions that are consistent with those used in the rest of the model. The monetary values given in [30] were adjusted for inflation and fuel values were converted from MMBTU to GJ. These adjusted values are shown in Table A.5. Nuclear start costs were taken from Van Den Bergh & Delarue [31]

Table A.5: Start Cost

	Start	Coal Small Sub Critical	Large Sub Critical	Super Critical	Gas OCGT
Fuel Cost (GJ/MW Installed)	Hot	5.28	7.39	10.66	1.61
	Warm	7.04	10.55	18.04	1.61
	Cold	9.84	14.77	21.21	1.61
Other Cost (R/MW Installed)	Hot	77.81	95.21	98.57	32.32
	Warm	104.28	135.43	146.4	32.32
	Cold	134.99	172.28	196.56	32.32

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