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Reliability benefit of smart grid technologies: A case for South Africa

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Abstract
The South African power industry faces many challenges, from poor performing networks, a shortage of generation capacity to significant infrastructure backlog and an ageing work force. According to the Development Bank of South Africa (DBSA), the key challenge facing the industry is ageing infrastructure. Smart grid technologies are a class of technologies that are being developed and used by utilities to deliver electrical systems into the 21st century using computer-based remote control and automation. The main motive towards smart grid technologies is to improve reliability, flexibility, accessibility and profitability; as well as to support trends towards a more sustainable energy supply. This study identifies a number of smart grid technologies and examines the impact they may have on the distribution reliability of a test system. The components on the selected test system are the same as those found on a South African feeder. The bulk of the load in test system was modelled using load data collected in South Africa. This study will consider a number of different cases, with the base case incorporating the impact of aged infrastructure on the reliability of the system. The smart grid technologies were then introduced into the system and their impact on distribution reliability was determined. These different cases were also compared to the alternative of replacing the aged and worn out infrastructure with new infrastructure. The findings of this study indicate that the identified smart grid technologies improve the reliability of the system, mainly by decreasing the outage duration experienced by customers on the network. An even better performance was achieved when the ageing infrastructure was replaced with new infrastructure.

Keywords: distribution reliability, smart grid, feeder automation

1. Introduction

The distribution sub-system in South Africa, much like many other countries in the world, is still based on 20th century technology (DBSA, 2012). According to NELT (2007) and SANEDI (2012a), 20th century technology cannot efficiently sustain a 21st century economy, and power networks need to be 'modernized'. A report released in 2007 by the National Energy Regulator of South Africa (NERSA) on the state of the Electricity Distribution Industry (EDI) infrastructure, indicated that although there were pockets of good performance, assets needed urgent rehabilitation and investment (NERSA, 2007). A study conducted in 2008 by EDI Holdings on the state of the distribution grid of the country, revealed that the distribution grid infrastructure was ageing and poorly maintained, and that its state was steadily deteriorating. The study estimated that the maintenance, refurbishment and strengthening backlog in the distribution grid amounted to about 27.4 billion 2008 South African Rand (2008 ZAR). This backlog was growing at an alarming rate of 2.5 billion ZAR per annum (EDI Holdings, 2008). The same study pointed out that the current practices in the EDI do not promote business sustainability and economic growth. It also highlighted the fact that the increased use of an under-maintained distribution grid could be a potential risk to the industry.

A more recent report released in 2012 by the Development Bank of South Africa (DBSA) on the State of South Africa's Economic Infrastructure, identified ageing infrastructure as the key challenge for the electricity generation, transmission and distribution sectors. The other challenges faced in the South African power industry include: poor performance networks, shortage of generation capacity, significant infrastructure backlog, ageing work force, inability to effectively introduce renewable energy options into the grid, and the inability to effectively introduce demand response strategies (SANEDI, 2012b).

The term 'smart grid' refers to a class of technologies that are being developed and used by utilities to deliver electrical systems into the 21st century using computer-based remote control and automation (NELT, 2007). Smart grid technologies have been proposed as one of the possible means of implementing new technologies and techniques into the grids of different countries (SANEDI, 2012a). The main motive towards smart grid technologies is to improve reliability, flexibility, accessibility and profitability; as well as to support trends towards a more sustainable energy supply (Slootweg, 2009).

This paper will focus on the improvement smart grid technologies could have towards improving distribution reliability.

2. Distribution reliability

Reliability may be defined as the probability of a system performing its required tasks, adequately for a period of time and under set operating conditions (Billinton & Allan, 1992). This definition in itself highlights the uncertainty surrounding the ability of the power system to perform as desired, and therefore, the purpose of power system reliability evaluation and assessment, is to try and quantify the reliability of a system for planning and decision making.

Reliability indices are used extensively in the power system industry as a means to quantify and assess reliability. Reliability indices measure the frequency, duration and severity of disturbances on the network and give insight into the performance of the system. These indices can be regarded as being predictive indices or past performance indices. The indices considered in this study are System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Momentary Average Interruption Frequency Index (MAIFI) and Expected Energy Not Supplied (EENS). These indices are calculated as follows (Billinton & Allan, 1994; Brown, 2006):

$$\text{SAIDI} = \frac{\text{sum of customer interruption duration}}{\text{total number of customers}} \quad (1)$$

$$\text{MAIFI} = \frac{\text{total no customer momentary interruptions}}{\text{total number of customers served}} \quad (2)$$

$$\text{SAIFI} = \frac{\text{total no customer sustained interruptions}}{\text{total number of customers served}} \quad (3)$$

$$\text{EENS} = \Sigma\, L_i\, r_{i,j} \lambda_{i,j} \quad (4)$$

where: L_i is the average load at load point i
$r_{i,j}$ is the outage duration of load point i due to the failure of load point j
$\lambda_{i,j}$ is the failure rate of load point i due to the failure of load point j

In this study, a momentary interruption is defined as an interruption with duration greater than 3 seconds but not longer than 5 minutes, as defined by the NRS 048-6:2006 specification for the Electricity Supply Industry for medium voltage (MV) and low voltage (LV) systems (Chatterton *et al.,* 2006).

3. Smart grid technologies

Smart grid technologies refer to a group of improved technologies and concepts, that use digital and other advanced technologies, to monitor and manage the transmission of electricity from all generation sources, to meet the varying electricity demands of end users (IEA, 2011). In a broad sense, a "smart grid" refers to a conventional electric power system equipped with these technologies for the purpose of reliability improvement, ease of control and management, integrating of distributed energy resources and electricity market operations.

One of the most appealing advantages of smart grid technologies is the reduced reaction and restoration time. This is most apparent when a fault has occurred. Ordinarily when a disturbance causes a fault on the network, grid operators are unable to identify the exact location of the faulted section of the feeder. The repair crew are dispatched, and have to perform trial and error switching actions on circuit breakers and isolators, in an effort to find the exact location of the fault. This can take a considerable amount of time during the day and more especially at night or during unfavourable weather conditions, resulting in an increased outage duration (Kazemi, 2011). There are a number of smart grid technologies which have been developed in order to reduce the fault location time. These are discussed below:

i) Distance to fault estimator

Fault locators reduce the impact of faults as they speed up the restoration process, by allowing isolating and switching operations to be performed much faster (Morales-España et al., 2009). Distance to fault estimators, are an optional module of modern distribution protection equipment which can be used for estimating the fault location. When a fault occurs, this module calculates the fault location as a distance from the substation to the fault. It can also notify the control centre or utility repair crew of this information crew using a suitable communication medium. By using distance to fault estimators, a much smaller zone of the distribution network is inspected for faults. However, when a feeder has multiple taps, there might be several probable fault locations for the fault distance indicated by this module. In order to overcome this problem, distance to fault estimators should be used in conjunction with fault passage indicators (Kazemi, 2011).

ii) Fault passage indicators

Fault passage indictors are devices which are located at strategic points along the feeder, and are designed to indicate whether fault current has passed that particular point. They are usually installed at points where switching decisions can be made. Fault passage indicators are able to distinguish between fault current and load current. Several fault passage indicators installed along a feeder will enable quick identification of the passage of fault current. The status of these devices can be recognized remotely or by visiting its physical location. In the past, fault passage indicators could only be used in radial distribution networks, but there are new generation fault passage indicators which can be used in other electricity distribution networks (Newman, 1990; Kazemi, 2011; Nortech, 2013).

iii) Feeder automation

Feeder automation is an automatic control scheme that is used for automatic fault location, isolation, and service restoration (FLISR) in an electricity distribution network. Utilizing modern computer technology, micro-electronics and communication technology, modern feeder automation technologies conduct operations and risk assessments, in order to make decisions regarding the operation of the distribution feeders and the distribution grid as a whole (Huang *et al.*, 2012).

An automated grid is self-healing and recovers quickly from faults. When a permanent fault occurs, the customers affected by the fault may be categorized into two groups. The first group of customers are those who will have to wait until the faulted feeder section has been repaired. The second group includes those customers whose power supply has been interrupted, but can be restored through the main or alternate supplies by means of switching and isolating healthy and faulted feeder sections (Kazemi, 2011). In most cases, the second group is larger than the first group (Uluski, 2010; Kazemi, 2011).

In the case of manually operated distribution systems and feeders, the fault isolation and service restoration activities can only be done after the fault has been located. However, feeder automation can reduce the outage duration and restore supply to as many customers as possible by performing FLISR automatically. Automatic FLISR can restore service to customers in one minute or less, resulting in significant reliability improvement compared to traditional manual switching (Uluski, 2010; Kazemi, 2011).

4. Experiment design

4.1 Reliability model

The reliability model is required to evaluate the system indices, which give an indication on the reliability of a network.

i) Test system

A suitable test was needed and the RBTS (Roy Billinton Test System) was selected. Although it is not a South African test system, its system components are similar to those of the South African power system. It contains all the major elements of a distribution system and its simplicity allows for analysis using simulation techniques. Other advantages of the RBTS include the fact that is best suited for educational purposes; it is used extensively in research and it is well defined. Feeder 1 (F1) of bus 6 of the RBTS was selected. It is shown in Figure 1 (Billinton & Jonnavithula, 1996). The feeder components include overhead lines (O1 to O12), MV/LV transformers (T1 to T6), disconnector switches (S1 to S5) and load points (LP1 to LP6).

ii) Simulation technique

The time sequential Monte Carlo Simulation (MCS) technique selected for the evaluation of reliability. The availability of high speed computing facilities make it a more viable option because MCS yields more information on load point and system indices. Time sequential MCS is flexible and has a high reality potential. MATLAB, a high level technical computing language was used to execute the MCS. The

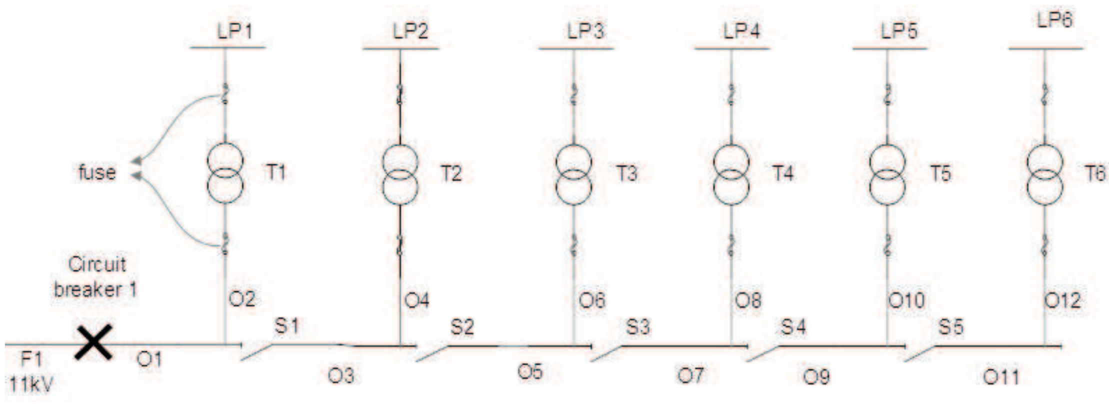

Figure 1: Diagram of selected test system – (Feeder 1 of Bus 6)
(Billinton & Jonnavithula, 1996)

simulation algorithm adopted, was based on the technique developed by Billinton & Wang (1999).

The failure rates for the different system components in the MCS are given in Table 1. The input parameters for the reliability study are given in Table 2.

Table 1: Component failure rates
(Allan et al., 1991)

System component	*Failure rate*
Circuit breaker 1	0.006 (failures/yr)
O1-O12	0.065(failures/yr.km)
T1-T6	0.259 (failures/yr)

Table 2: Input parameters

Input parameter	*Average (hours)*
Time To Locate Fault (TTLF)	1.5
Repair time (RT)	
overhead lines	5
breaker	4
transformer	200
Switching time	1
Reclosing time	1minute

4.2 Load model

The incorporation of a load model, allowed for the determination of how much energy was not supplied to customers as a result of the interruptions.

The customer load model was developed using data from the RBTS data sheet and NRS data collected in South Africa. This study only considered residential and commercial customers. The customers at each load point were defined as shown below.

Table 3: Customer distribution of test system

Load point	Number and type of customers
1	138 Residential
2	126 Residential
3	138 Residential
4	126 Residential
5	118 Residential+2 Commercial
6	118 Residential+3 Commercial
Total	**764 Residential+5 Commercial**

i) Residential load profile

NRS Load Research data was used in the development of a realistic residential load model, which could represent the load consumption of a South African household. NRS Load Research data comprises of the load consumption data collected in 5 minute intervals for different residential households in different locations in South Africa. This data was collected between 1994 and 2003.This data was used to develop a profile of the load consumption in amperes (A) of a residential customer residing in Claremont, Johannesburg, South Africa.

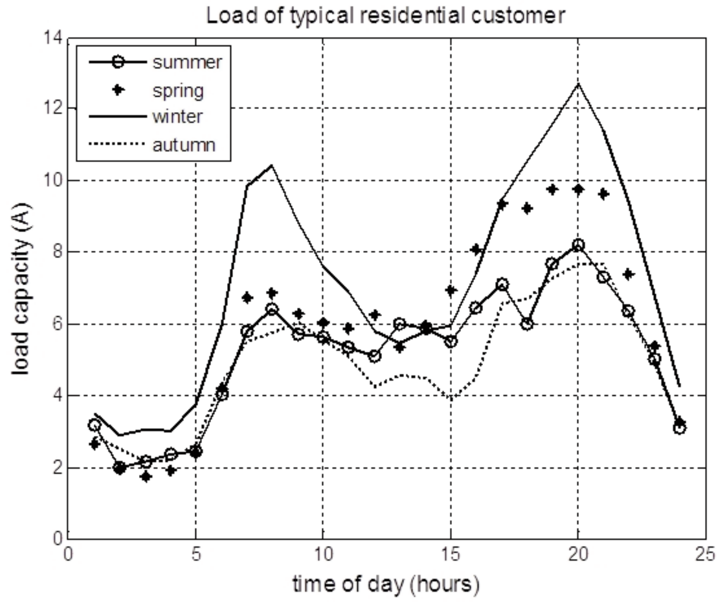

Figure 2: Residential 2oad profile
(NRS Load Research Group, 1994-2003)

ii) Commercial load profile

There are 5 identical commercial customers on the feeder. There are 3 commercial customers on LP5 and the remaining 2 on LP6. All 5 were assumed to be in the retail business. The loads of the commercial customers were time dependent and remained the same regardless of the season of year. The load of these customers was based on data given with the RBTS and this is indicated in Table 4.

Table 4: Commercial customer load profile
(Billinton & Jonnavithula, 1996)

Time of day	*Load per commercial customer (MW)*
00:00 -07:59	0.0497
08:00-17:00	0.085
17:00-23:59	0.0497

4.3 Cases

Six different cases were considered in this study. The abbreviated names of the different cases are given in parenthesis. In each case, an input value(s) from Table 1 and/or Table 2 was changed. All the six cases and the change(s) in input parameters for each case are discussed below:

i) Case 1: aged transformers (aged tr)

This is the base case to which all other cases will be compared.

The effect of aged equipment was incorporated into the system. The reason is that ageing infrastructure was outlined by the DBSA as the leading challenge facing the electricity industry. The effect of ageing was incorporated in the form of aged transformers. Transformers represent a significant cost to the electric utilities, both as a capital investment and as an ongoing operating expense. They can account for up to 20% of the total distribution capital spending per annum (Van Zandt & Walling, 2004). As transformers age, their internal condition deteriorates, increasing the risk of failure (Wang *et al.*, 2002; Bartley, 2011). According to Bartley (2011), ageing transformers are a huge risk to the electric power supply and could cause major losses.

All the transformers in this case were assumed to be aged and worn out. The average failure rate of transformers in this case was 0.259 failures/year based on data collected by Jagers & Tenbohlen (2009) on distribution transformers in South Africa.

ii) Case 2: Fault passage indicators and distance to fault estimators (FPI & DFE)

This case investigated the effect of fault passage indicators and distance to fault estimators on the system performance of the base case. These smart grid technologies assist in the location of faults after an interruption has occurred. Therefore, for this case the input parameter, TTFL, was reduced to an average of 0.5 hours (Kazemi, 2011).

iii) Case 3: Feeder automation (feeder auto)

The impact of feeder automation was investigated in this case. Feeder automation implemented automatic FLISR. This procedure results in a decrease in both the fault location time and switching time. In this case TTLF and switching time both had an average duration of 30 seconds (Uluski, 2010).

iv) Case 4: new transformers (new tr)

Case 4 investigated the performance of the system if all the transformers in the system were to be replaced with new transformers. Hence, a decreased average transformer failure rate of 0.035 failures/year (Jagers & Tenbohlen, 2009) was used in this case.

v) Case 5: new transformers, fault passage indicators, distance to fault estimators (new tr & FPI and FDE)

This case considered the inclusion of new transformers, fault passage indicators and distance to fault estimators. The purpose of this case is to determine the impact of fault passage indicators and distance to fault estimators on a network with non-aged transformers.

vi) Case 6: new transformers and feeder automation (new tr & feeder auto)

This case considered the inclusion of both new transformers and feeder automation.

5. Results and analysis

5.1 SAIDI

The results of SAIDI for the different cases described above are given in Table 5. SAIDI gives an indication of the average number of hours each customer on the feeder experiences with no electricity supply in a calendar year due to a component in the network failing.

Table 5: SAIDI results

SAIDI (hours/customer year)		
Case	*Magnitude*	*Percentage difference*
1. aged tr (base case)	9.10	-
2. FPI & DFE	8.83	-2.9%
3. feeder auto	8.19	-10.0%
4. new tr	0.27	-97.0%
5. new tr & FPI & DFE	0.24	-97.3%
6. new tr & feeder auto	0.20	-97.8%

From Table 5, it is evident that the base case has the highest magnitude of SAIDI. A decrease in SAIDI is experienced when fault passage indicators and distance to fault estimators are introduced into the system. These smart grid technologies assist in decreasing the time it takes the repair crew to locate a fault. The impact of this is reflected in the decrease in SAIDI.

An even greater decrease is realised when feeder automation is implemented. Feeder automation detects and isolates faults within 1 minute, allowing customers whose energy supply can be immediately restored via switching, to be reconnected in a shorter period of time. It also facilitates in the quick identification of faults to be attended to by the repair crew. These operations are responsible for the decrease in SAIDI. For example, previously in the base case, the failure of component O7 from Figure 1, would result in customers of LP1 incurring an outage of about 2.5 hours but with the implementation of automatic FLISR, this duration is reduced to 1 minute.

Case 4 explored replacing the aged transformers with new transformers, which have a much lower failure rate. From Table 5, it is observable that a large decline in SAIDI is experienced from the base case to case 4. The main reason is the failure rate of the transformers. The transformers in the base case are assumed to be worn out and aged, and therefore they are more prone to failure. Transformers also have the longest repair time of about 200 hours, followed by overhead lines, with a repair time of about 5 hours. Therefore, a decreased transformer failure rate, as experienced in the case 4, results in a tremendous decrease in the outage duration experienced by customers. This drastic decrease in outage duration is reflected in SAIDI.

The incorporation of the selected smart grid technologies and new transformers was explored in cases 5 and 6. A further decrease in SAIDI from case 4 was experienced, but the bulk of the decrease is attributed to the implementation of the new transformers.

5.2 SAIFI & MAIFI

The results of SAIFI for the different cases are given in Table 6. SAIFI is the average number of sustained interruptions each customer on the feeder experiences in a calendar year due to a component in the network failing. The magnitude of the frequency of momentary interruptions, MAIFI, is depicted in Table 7.

Table 6: SAIFI results

SAIFI (interruptions/customer year)		
Case	*Magnitude*	*Percentage difference*
1. aged tr (base case)	0.73	-
2. FPI & DFE	0.73	0%
3. feeder auto	0.49	-32.8%
4. new tr	0.56	-23.3%
5. new tr & FPI & DFE	0.56	-23.3%
6. new tr & feeder auto	0.34	-53.4%

Table 7: MAIFI results

Case	*Magnitude*
1. aged tr (base case)	0.00
2. FPI & DFE	0.00
3. feeder auto	0.23
4. new tr	0.00
5. new tr & FPI & DFE	0.00
6. new tr & feeder auto	0.22

The highest magnitude of SAIFI is experienced in the base case. The magnitude of MAIFI in the base case is 0, meaning all interruptions experienced in this case were sustained. The implementation of passage indicators and distance to fault estimators had no impact on SAIFI and MAIFI. These two technologies do not affect the state or condition of the main system components, but instead assist in the location of faults, after an interruption has occurred. They do not help to prevent the occurrence of faults. Therefore, no impact on both SAIFI and MAIFI is observed in case 2. On the other hand, the implementation of feeder automation resulted in a decrease in SAIFI and an increase in MAIFI. Feeder automation implements fault detection, location and isolation. It then restores electrical energy supply to customers who need not be disconnected from the main supply. This group of customers instead experience a momentary interruption, where they previously would have experienced a sustained interruption. Therefore, the implementation of feeder automation sees a decrease in SAIFI and an increase in MAIFI.

The magnitude of SAIFI in the case 4, where new transformers were introduced into the system, is much lower than that of the base case. This is attributed to avoided interruptions due to the decreased transformer failure rate of the new transformers. No momentary interruptions were experienced in case 4. The magnitude of both SAIFI and MAIFI in case 5 is the same as that of cases 2 and 4. As already mentioned, fault passage indicators and distance to fault estimators, have no impact on the frequency of interruptions, therefore, the addition of these technologies to case 4, would result in no impact to both SAIFI and MAIFI as observed in case 5.

SAIFI in case 6 dropped to less than half its magnitude in the base case. The implementation of new transformers resulted in avoided interruptions, whereas feeder automation increased momentary interruptions and decreased sustained interruptions by carrying out FLISR.

5.3 EENS

Table 8 compares the average amount of energy not supplied to the customers on the feeder in one calendar year.

Table 8 EENS results

EENS (kWh/ year)		
Case	*Magnitude*	*Percentage difference*
aged tr (base case)	58 848.92	-
FPI & DFE	54 555.47	-7.30%
Feeder auto	53 656.91	-8.80%
new tr	11 392.73	-80.6%
new tr & FPI & DFE	10 923.03	-81.4%
new tr & Feeder auto	9 434.54	-83.9%

The base case has the highest EENS because the EENS is directly related to the outage duration as given in equation 4. Therefore, the greater the decrease in outage duration and failure frequency, the greater the decrease in EENS. Once the aged transformers in the system were replaced with new transformers, a decrease of about 80% was realized in the unsupplied energy. The further integration of smart grid technologies into the system with new transformers, results in an additional but smaller decrease in the EENS magnitude.

The EENS represents the amount of energy that the customer could have consumed, but could not because they were disconnected from supply. This could translate to different things for different sectors. For example in the commercial sector it could mean a loss of sales and for the industrial sector, it could translate to the loss of production.

6. Conclusions

In this study, the reliability benefit of a number of smart grid technologies was examined. A feeder containing all the fundamental components of a distribution grid i.e. fuses, transformers, overhead lines, circuit breaker and disconnector switches, was selected from the RBTS and used as a test system. The load of the system consisted of mainly residential customers and a few commercial customers. The loads of the residential customers were defined using load data collected in South Africa. A number of cases were considered where the identified smart grid technologies were implemented. These were compared to the base case which contained aged transformers, since ageing was identified as the key challenge the South Africa power industry is facing.

The key findings of this study point to following:

i) The high failure rate of the transformers in the base case contributed significantly to the failure frequency. This is clearly indicated by the decline in SAIFI when these aged transformers are replaced with new transformers. The aged transformers also significantly increased the outage duration because the average repair time of the transformers is very large (about 200 hours) compared to that of the other components in the system. This observation was apparent in the comparison of SAIDI for the base case and case 3. Each time a transformer failed, an outage duration equivalent to the repair time of 200 hours was incurred. This drastically increased SAIDI.

ii) Distance to fault estimators and passage fault indicators do not have an impact on SAIFI. This is because these technologies do not contribute towards the prevention of faults. On the other hand, feeder automation has a positive impact on SAIFI and MAIFI. Feeder automation resulted in a significant decrease in SAIFI and an increase in MAIFI. The main reason for this would be the speed at which feeder automation locates and isolates faults and then restores customers not directly impacted by a fault. This group of customers, not directly impacted by a fault, would experience a momentary interruption instead of a sustained interruption.

iii) The identified smart grid technologies had an impact on the reduction of TTLF. This impact was carried through to SAIDI. Feeder automation had a more of an impact on SAIDI than the distance to fault estimators and fault passage indicators. Feeder automation prevents customers not directly impacted by the failure of a component from experiencing a sustained interruption. Therefore, a potential outage duration of about 2.5 hours for a customer was reduced to 1 minute.

iv) The decrease in feeder outage duration, as a result of the implementation of the identified smart grid technologies, is carried through to the EENS of the feeder. The cases with higher outage duration also experienced a higher EENS, because it is dependent on outage duration.

v) The findings have highlighted that the identified smart grid technologies have no impact on the frequency and rate of interruptions, but decrease the total outage duration of the feeder. They also pinpointed that a network with aged infrastructure has a much higher failure rate, and that this increase is carried through to the increased outage duration of the system. When the aged transformers were replaced with new transformers, the SAIDI, SAIFI and EENS decreased drastically and with some of these indices, it more than halved. None of the selected smart grid technologies had as much of a positive impact on the system reliability as the new transformers. This therefore stresses the importance of first identifying and correcting the root causes of the underlying problems in the system before investing in further technologies, which may not address these fundamental problems adequately.

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