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ORIGINAL PAPER

Implementation of capital deferral algorithm in real distribution systems considering reliability by managing major faults

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Abstract

Distribution automation technology plays a key role on power system reliability by providing faster detection, isolating the faulted area and restoring the fault. In this paper, the impacts of distribution automation are considered on radial distribution system in the event of substation transformer bank malfunction at maximum load level with the aim of deferring the big capital investments. The aim of the proposed method is not only to increase physical impact such as the reliability but also to monetize physical measures into significant economic benefits by deferring the overall investment costs. The proposed algorithm is tested with the real distribution system data, and it is shown that it can obtain remarkable economic benefits by deferring the larger capital equipment investments by making smaller investments in distribution automation.

Keywords Capital deferral · Smart grid economy · Smart grid investments · System reconfiguration

1 Introduction

All over the world, power utilities have encountered problems due to the growing demand for electricity against the backdrop of an aging electric power infrastructure coupled with the lack of information needed for wise investment decisions. These problems affecting quality and reliability are driving up the cost of electric power and are resulting in increased customer interruptions. Most major contingencies worldwide are the result of storms, floods, hurricanes and other severe weather conditions. According to the report published by White House [1], it was disclosed that 679 widespread power interruptions happened due to severe weather conditions during 2003–2012. Moreover, the cost of weather-related power failures was estimated to be between $18 and $33 billion per year. Fifty million people and 61,800 MW of loads in the location of Midwest and Northeast of USA and Ontario, Canada, were impacted due to an electrical power blackout in 2003. This blackout gave rise to cost ranged $4–10 billion in the USA. [2].

In the electric power grid, it is so crucial to provide electricity services to the customers in reliable and economical manner due to high expenditure of customer interruptions. To deduce about system reliability, reliability indices are used to get information about the overall system performance, behavior and response by measuring the frequency, duration and severity of contingencies of the power system. Two groups of reliability indices which are named as customer-based and load-based reliability indices are used to evaluate the overall system reliability at the distribution level. The commonly used reliability indices based on customers are System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). SAIDI indicates the average interruption duration per customer and is computed as a ratio of "sum of all customer interruption duration" and "the total number of customers served." SAIFI, on the other hand, shows the average interruption time that a consumer would experience and is calculated as ratio of "total number of customer interruptions" and "the total number of customers served." Lastly, CAIDI gives information about average interruption restoration time [3]. Reliability of a distribution system can be improved in at least two ways. The first way is to decrease the frequency of power interruptions by

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performing regular maintenance and repairs for the power system components [4]. In the literature, researchers have connected energy storage units to improve transmission and distribution (T&D) system reliability and defer T&D system upgrade costs [5, 6]. The authors of [7] have studied the improvement of distribution system reliability without distribution automation and the deferral of distribution capital investment using an independent power producer, like distributed generation (DG) technologies. Ref. [8] presents a genetic algorithm (GA) optimization approach to optimally allocate the energy storage devices so that transmission and distribution upgrades are deferred by energy storage deployment. This works take into consideration the load growth and aging infrastructure during 20 years. In [9], the authors have focused on return on investment for grid scale storage and the effects of energy storage on transmission and distribution system investment deferral.

Another way of reducing the interruptions is to integrate automation technology to the distribution network. Automated reconfiguration of power systems can be enabled via smart grid distribution automation, which gives opportunities to isolate the faults, quickly divert the power flows and prevent overloading of system components [10]. The self-healing functionalities of the distribution systems, automated failure location detection, isolation and restoration, are carried out via utilization of smart grid automation technology like system monitoring systems and automatic switches. Smart grid automation is used to improve the efficiency, reliability and power quality, and to introduce cost–benefits by decreasing service restoration time.

Some papers in the literature have tackled the impacts of smart grid automation technologies on reliability issue. In [11–16], with this technology, it has been showed the improvements on reliability of aged infrastructure by declined the interruption duration. By using Monte Carlo method, the effects of automated switches have been investigated on distribution system reliability [17]. The distribution automation impacts on French distribution system have been studied in [18], and the improvements have been observed in terms of fault diagnosis, fault isolation and network restoration time. The proposed method in [19] have evaluated on various industrial substation in order to show how the automated substation can enhance the reliability of the system by providing fast automatic switching actions. To observe the effects of communication networks, it has been investigated for the performance of distribution automation [20, 21]. Moreover, a distributed multi-agent method was proposed in [21] to examine the performance of a fault location and isolation. The authors in [22] have studied the economic analysis of automated sectionalizing switches in the event of contingencies. The economic analysis considers an annual financial loss related to process trips. With an optimization approach based on a genetic algorithm, they determine the best allocation of automated sectionalizing switches to increase reliability indices and to reduce financial losses.

Considering the aforementioned literature, the enhancing system reliability or the reduction in the capital cost has been investigated with distribution automation, but in this work both objectives are merged together in the aim of enhancing reliability, while the aim of achieving maximum economic benefit by capital deferral with small investment in a real power distribution system has been taken into consideration. The proposed algorithm is tested on a network consisting of eight feeders supplied by two substation transformers that are failed at peak load considering the worst case scenario in these distribution systems. The investigated system model was formed in DEW software [23] to analyze system performance. The structure of the paper is organized as follows. Section 2 gives the information about system used in this study. Then, a reconfiguration algorithm for contingency restoration and deferral of capital investment are proposed in Sect. 3. Numerical results are presented to demonstrate the effectiveness of proposed algorithm in Sect. 4, and conclusions are summarized in Sect. 5.

2 System description

The geographical area of interest in central Rockland County, NY is shown Fig. 1, which consists of different kind, number and size of customers. The electrical power system covers a region of approximately ten square miles

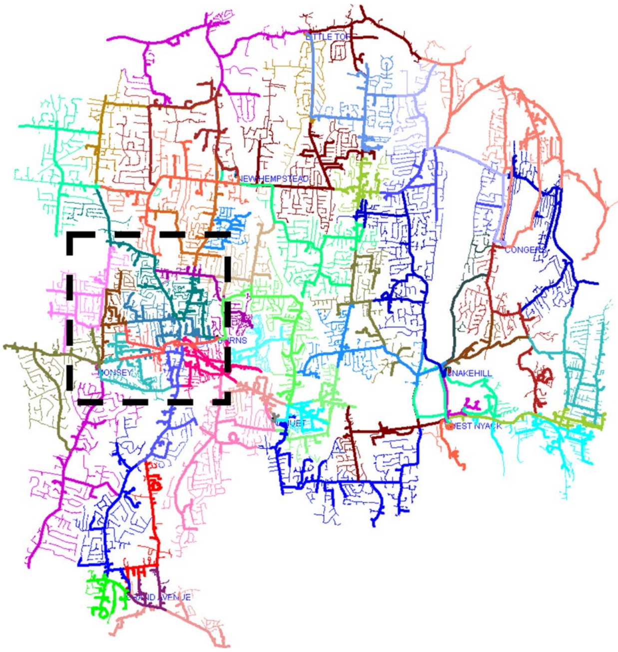

Fig. 1 System model

and performs electrical service to approximately 21,000 customers. This area is of interest due to the possibility of transformer bank 2 within the main substation exceeding planning criteria for backup during a substation transformer bank or bus failure. Based on load growth and backup requirements of other substations in this area, infrastructure development in the form of a new substation in Central Rockland would be necessary. The main substation contains 8 feeders, each of which is 13.2 kV, as given in Fig. 2. Within the existing substation, there are two 42 MVA transformers, Bank 1 and Bank 2. Each feeder has a midpoint recloser, tie reclosers and SCADA operable automated reclosers where they all can be used for distribution automation when they are installed. The midpoint recloser is placed at the midpoint of the feeder, and SCADA operable reclosers, or automated switches, are used to sectionalize the circuit for each 250 customers. Automated tie reclosers, which are normally open, are used to connect adjacent feeders.

When a bank or bus fault occurs in the substation, automated tie breakers, shown in Fig. 2, will automatically transfer load. As an example, Bank 1 failure, or the losing of 13.2 kV bus fed from Bank 1, Feeder 5 will be automatically transferred to Bank 2. And besides, each of the other feeders rendered services by Bank 1 will be transferred. This load transfer is implemented as long as the ampacity of the limiting circuit component is not exceeded.

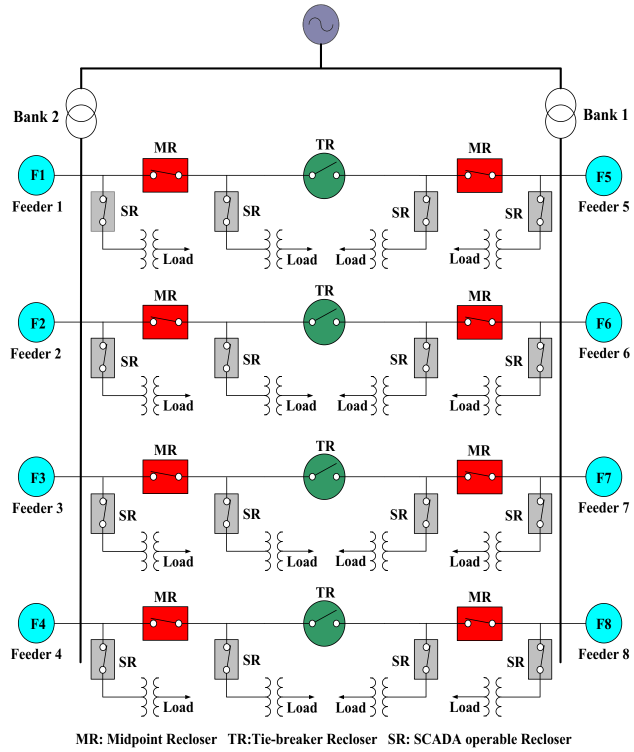

Fig. 2 Used pilot substation

During the 6 years study, which covers the period between 2012 and 2017, six various models, three of them for manual switching and the remaining three for automated switching, were used. The different models took into account the changes to feeder configurations and the constructions made over the aforementioned time period. Also, customer counts and loads were modified on an annual basis according to the load growth forecast. The feeders, which were equipped with smart grid automatic restoration devices, are listed by years of automation, as shown in Table 1.

3 Capital deferral algorithm

3.1 Reconfiguration algorithm for contingency restoration

The reconfiguration for restoration algorithm for the capital deferral study is shown in Fig. 3. This configuration was used in [24] to decrease the customer interruption in the event of storm-related outage and cost benefits of smart grid investment were examined. The objective of this algorithm is to manage sectionalized devices to restore power. When a major contingency occurs in the system, the reconfiguration algorithm starts to isolate the failure by opening switches in outage area. Then, the appropriate switches list to be closed is generated by the reconfiguration algorithm to restore the power at the boundary of the outage area. After the most appropriate switch closes, it is observed whether the closed switch gives rise to a violation of any constraint in the system. If there are violations like low voltage or over voltage, the algorithm re-opens the switch and replaces it from the appropriate switches list. Otherwise, power flow is provided to restore the outage area. Then, the algorithm updates the available switch list, and the reconfiguration chooses any additional switch to close for restoring power. This loop proceeds until the interrupt area is fully restored, or no further switching action is possible to restore power. Lastly, when this process is finalized, the reconfiguration algorithm recloses the switches which opened during the isolation in the outage area.

Table 1 List of automated circuits by years

Year	Automated circuits	Bank
2012	Feeder 7, Feeder 8	1
2013	Feeder 4, Feeder 1	2
2014	Feeder 3, Feeder 6, Feeder 5	1 and 2

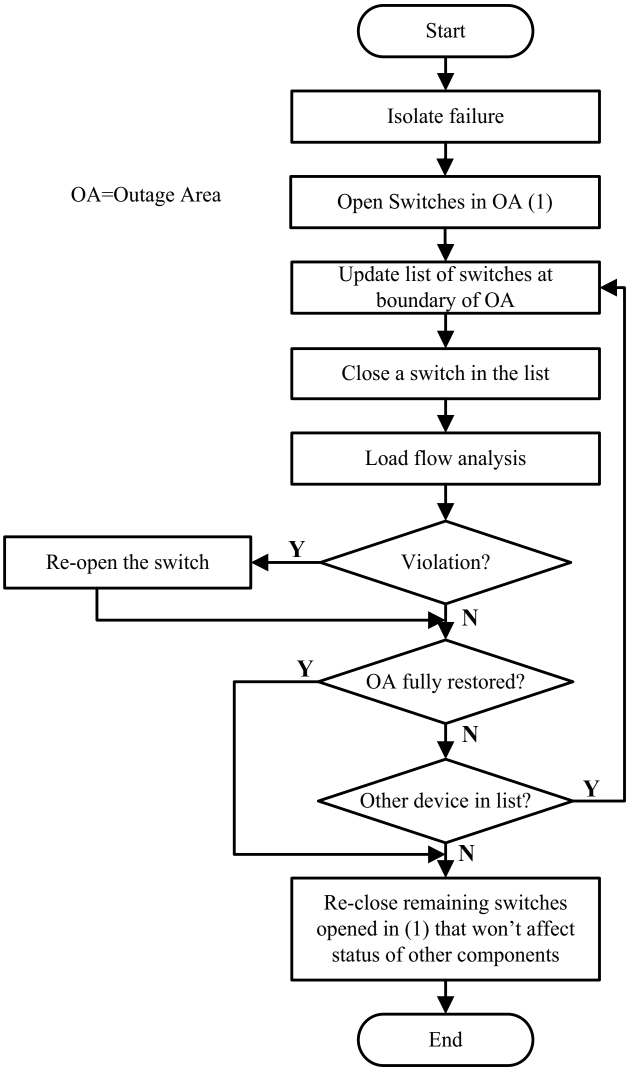

Fig. 3 Reconfiguration algorithm for capital deferral [24]

3.2 Capital deferral algorithm

The planning criteria for a substation transformer have two key requirements, one for normal operations and one for contingencies. First, the load connected to a substation must not exceed the normal rating of the bank. Second, the maximum customer interruption hours based on a transformer bank failure must be less than 60,000 customer hours. Since the substation considered here has two transformer banks, in the event of the failure of one bank, for the feeders considered here 62% of the load fed by the faulty transformer bank must be transferred to the other transformer bank. The remaining 38% of the load must be restored within 24 h, which may be satisfied by installing a portable substation.

The forecasted customer growth for this station shows that the station will exceed the planning criteria of 60,000 customer interruption hours [(number of customers out of service × hours out of service)] by 2018. One design solution to meeting this reliability problem is to install a new substation. However, this is a very expensive solution.

To help defer the construction of the new substation, capital projects have been designed to provide load relief to existing substation from the adjacent stations so the customer hours generated by loss of an existing substation bank can meet criteria. These capital projects were carried out in two stages. The first took place in 2013 and includes the reconfiguration of underground circuit exits out of neighboring substations, and added two more circuits to free up circuit capacity on the circuit ties with the existing substation. The next capital project occurred in 2014 and includes the construction of a new station north of neighboring substation. This station contains two 50 MVA 138/13.2 kV transformers with eight feeders. Also, in 2014, the two neighboring substation 35 MVA non-LTC 138/13.2 kV banks were replaced with two 50 MVA Load Tap Changing (LTC) banks.

The assumptions made in this study are as follows:

- When there is a failure, a team for switching each circuit.
- The aftermath of fault and fault isolation, one (1) hour and 15 min, is needed for the initial manual switching action and each additional action, respectively.
- During 4 h time period after the failure, ANSI/IEEE C84 B ratings are used, which allow voltage to drop to a minimum of 109 V. Furthermore, Long Time Emergency (LTE) which has 4 h, 51MVA ratings for transformer banks is used for the long-term switching contingency. For the bigger than 4 h fault period, it is subject to a minimum of 114 V and 42 MVA normal transformer bank ratings.
- A mobile substation for emergency backup will be installed to restore power within 24 h is the second bank in the station or the circuit ties cannot be restored customer.

The flowchart for the reconfiguration is shown in Fig. 4. A transformer bank failure at peak load is assumed to be the worst contingency to maximize the number of customers restored. The reconfiguration algorithm starts to operate using the emergency voltage levels and the LTE transformer ratings. The devices that the reconfiguration algorithm can operate are given in Table 2.

The same algorithm is performed four (4) hours after reaching the peak. In that case, the transformer loading definitely must not go beyond the normal ratings of transformer bank and the minimum voltage level of 114 V. Then, customer interruption hours are estimated for the manual switching scenarios thanks to results from the reconfiguration algorithm and are added to the estimated results for the first 4 h. While the first transformer in the substation is running, the same evaluation is carried out

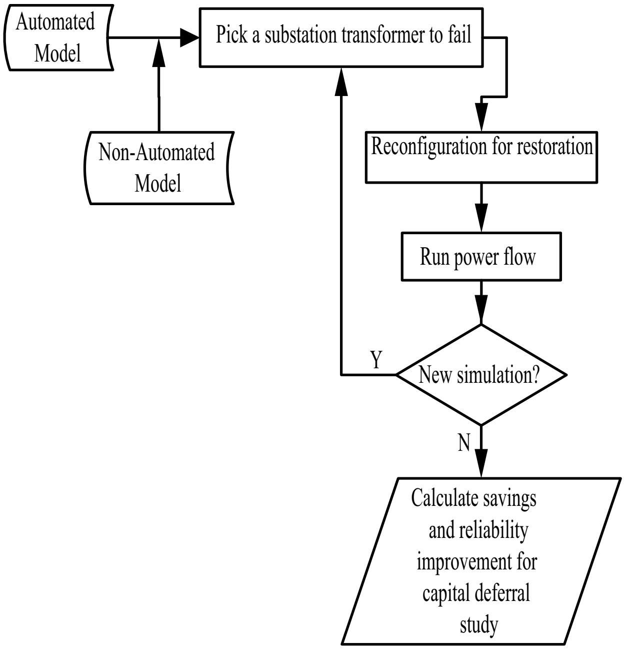

Fig. 4 Capital deferral algorithm

Table 2 The devices list used in algorithm

Used devices	Manual switching	Automatic switching
Substation feeder breakers		✓
Substation bus tie breakers		✓
Distribution disconnect switches	✓	
Distribution (GOAB) switches	✓	
Distribution electronic reclosers		✓
Distribution SCADA operable switches		✓

GOAB gang-operated air break

for the second transformer failure, and this process is iterated every year until 2017.

The same procedure is also realized for the switching model equipped with smart grid distribution automation to examine the savings of customer interruption hours. To further decrease the number of customer interruption, the manual switching can only be used together with smart grid automation devices. The automated devices and the used devices for manual switching list are as shown Table 2. While "distribution GOAB switches" and "distribution disconnect switches" are used for manual switching, "distribution electronic reclosers" and "distribution SCADA operable switches" are used in the automated model. Customer interruption hours are computed for the smart grid automation according to assumptions given above [25].

4 Results and discussion

4.1 Reliability results

Figure 5 shows customer interruption hour comparisons for manual cases and automated circuit cases as a function of year in case of an either transformer failure happening in Bank 1, or 13.2 kV bus served by Bank 1 failure. As manual switching steps increased due to load growth between 2012 and 2013, a small increment in the manual column occurred. However, this increment is not shown in the automated circuit column for feeders 7 and 8, requiring more manually switching steps, were automated in 2012. A decline was observed in both columns from 2013 to 2014 due to upgrading of a transformer capacity at the neighboring station in 2014 for backup of Feeder 5. Additionally, all manual switching steps were removed by the automatization of Feeder 5 and Feeder 6 in 2014, and so customer interruption hours by manually switching were canceled out by smart grid, and so customer interruption hours by manually switching were canceled out by smart grid automation and capacity increase in substation. So, customer interruption hour's number annihilated via smart grid automation is 8101 h for Bank 1.

The comparison of the customer interruption hours of manual cases and automated circuit cases as a function of year in the event of a transformer Bank 2 failure, or a 13.2 kV bus provided by Bank 2 failure is shown in Fig. 6. The customer interruption hours from 2012 to 2013 for both cases are lessened by increasing transformer capacity at adjacent station in 2013, which ensures tie backup support to Feeder 3. The difference between the manual and automated

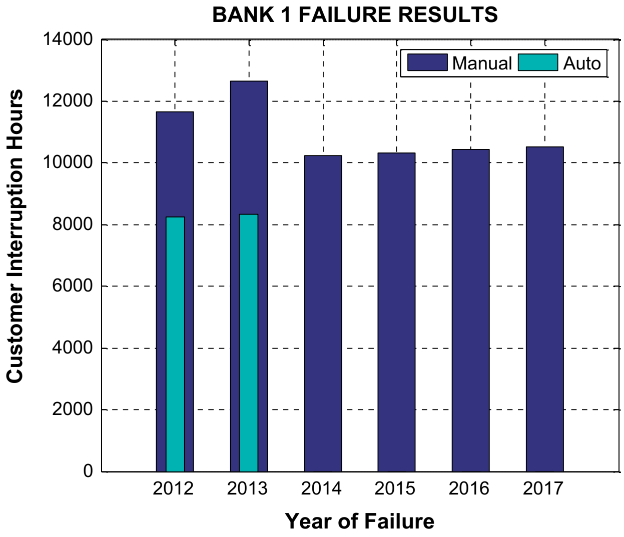

Fig. 5 Interruption hours results of Bank 1

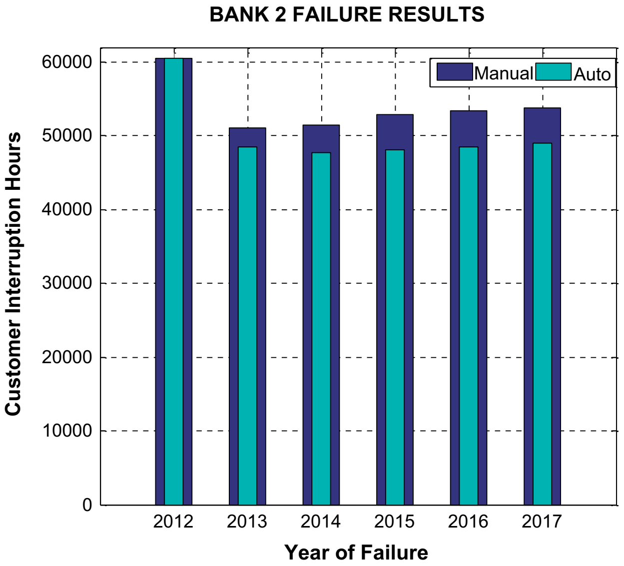

Fig. 6 Interruption hours results of Bank 2

columns in 2013 occurs because of the automation of Feeder 1 and Feeder 4, where many of savings are provided by eliminating the manual switching steps on Feeder 1. When compared, a lightly loaded Feeder 4 necessitates the reduction in manual switching steps due to the automated station bus transfer, and therefore it does not receive benefit from smart grid automation as much as Feeder 1. With automation of Feeder 3 in 2014, the additional savings in interruption hours are obtained because of ample backup from the neighboring station. Because the load increment requires more manual switching steps, an increase takes place in the manual column in 2015. The long-term outage (> 4 h) of Feeder 2 is responsible for most customer interruption hours that needs mobile substation installation for restoration. The net number in the customer interruption hours reduced by smart grid automation for Bank 2 is 4850 h.

Table 3 compares the reliability results both 2012 and 2017. The reliability indices SAIDI, SAIFI and CAIDI are calculated according to data obtained as a result of a transformer bank fault as shown in Table 3. According to results, a remarkable improvement is not observed in the manual switching case. In the automated case, while the all indices demonstrate a 100% improvement for Bank 1, up to 48% improvement is observed for Bank 2.

As a result of this study, it is clear that the customer interruption hours are declined by the smart grid automation of substation compared with the manual switching results. The cause of this reduction is the decrease in crew switching time for the automated case. By automatized circuits together with their respective neighbor ties, it is possible to get an elimination or a reduction in customer interruption hours arising from manual switching actions.

4.2 Cost benefit of results

Table 4 presents the cost of the smart grid implementation and capital work required to defer the construction of the new substation.

Table 5 shows that the smart grid automation is much less costly than the traditional approach (building a new substation) to solve the reliability problem. To demonstrate cost benefits of smart grid automation, present value (PV) indication is used in this paper, which calculates the present day value of an amount of money that is received in the future. Equation is given by:

$$\mathrm{PV} = \frac{\mathrm{FV}}{(1 + r)^n}$$

Table 4 Investment cost required for this study

Year	Capital work cost ($k)	Smart grid implementation cost ($k)	Total ($k)
2012	–	493	493
2013	4144.5	563	4707.5
2014	3693.5	897	4590.5

Table 3 The obtained reliability indices results

Metric	2012 (base line)				2017 (after project completion)			
	Manual		Auto		Manual		Auto	
	Bank 1	Bank 2	Bank 1	Bank 2	Bank 1	Bank 2	Bank 1	Bank 2
The number of customers interrupted	7037	7328	3192	7328	5825	7328	0.00	7328
Customers interruption duration (hours)	8.75	50.75	5.50	50.75	8.00	50.25	0.00	28.00
Total number of customers served	7037	8883	7037	8883	6098	9299	6098	9299
SAIDI	0.001243	0.005713	0.000782	0.005713	0.001312	0.005404	0.000000	0.003011
CAIDI	0.001243	0.006925	0.001723	0.006925	0.001373	0.006857	0.000000	0.003821
SAIFI	1.000000	0.824947	0.453602	0.824947	0.955243	0.788024	0.000000	0.788024

Table 5 A comparison between a conventional and smart grid plan regarding present value of capital cost to provide an upgrade deferral from 2021 to 2029

	2012 initial cost ($k)	Conventional plan			Smart grid plan					
		In-service year	Total ($k)	2021($k)	In-service year	Total ($k)	2012 ($k)	2013 ($k)	2014 ($k)	2029 ($k)
Smart grid	0	–	0	0	2013–2014	1953	493	563	897	0
OHead distribution	3500	2021	4037	4037	2029	4584	0	0	0	4584
Transmission UGnd	13,500	2021	15,573	15,573	2029	17,682	0	0	0	17,682
Distribution UG exits	3000	2021	3461	3461	2029	3929	0	0	0	3929
Station (GIS)	20,000	2021	23,071	23,071	2029	26,195	0	0	0	26,195
				Total ($k)					Present value (PV) ($k)	
Conventional plan				46,143					23,767	
Smart grid plan				54,344					16,753	
PV saving									**7014**	

where PV is present value, FC is future value, r is rate of return, and n is number of periods. The value of r in this study is 7.65%.

Thus, implementing smart grid automation on the seven substation circuits defers the need to construct a $46 million substation for 8 years, resulting in a present value savings of $7.014 million. The planning criteria are satisfied because the smart grid automation reduces the customer interruption hours below 60,000. In addition to deferring the cost of the new station, the smart grid automation benefits the service area in terms of reliability during storms and other contingencies. The smart grid automation, when coupled with the capital construction for 2013 and 2014, defers the need for the new substation until 2029.

5 Conclusions

Smart grid automation was considered to reduce the customer interruption hours in the event of a pilot substation transformer or bus failure at peak load. It was also aimed to further defer the construction of a new substation by reducing the number of customers affected by interruptions with auto-restoration.

The new algorithm proposed to provide faster restoration to able to keep reliability criteria and cost-effectiveness during major substation bank failure. The radial reconfiguration algorithm provides to considerably reduce the customer interruption hours by using automated switch. The case studies allow observing how distribution automation improves the reliability indices. When the project is completed in 2017, the enhancement of SAIDI, SAIFI and CAIDI indices are 100% for Bank 1. While SAIDI and CAIDI indices improve up to 44.27%, SAIFI indices remain unchanged.

Capital deferral study is used to determine whether adding smart grid automation to distribution circuits can defer significant capital investment. The planning has determined that by automating seven of the circuits fed by pilot substation to their respective ties and reducing customer counts between main line automation devices to 250 customers would permit the construction of the new substation to be deferred from 2021 to 2029. In conventional plan, the system reliability remains within the reliability criteria until 2021, and total investment in 2021 to satisfy 60,000 customer hours planning criteria is computed approximately $46 million. In contrast to conventional plan, the smart grid plan requires just under $2 million investment till 2014. Moreover, there is no need for extra cost to make upgrade with smart grid plan until 2029.

The results for each cases showed that proposed algorithm worked during the contingency by satisfying reliability criteria. Also results showed that proposed algorithm can defer building the capital investment 8 years by providing over 7 million dollar savings.

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