ALTERNATIVE SOLUTIONS FOR ADVANCED SECURITY OF SUPPLY

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ABSTRACT

The restrictions regarding the maximal length of outages especially under major storms has resulted in massive underground cabling (UGC) projects in the network companies in Finland and Sweden. Due to these expensive investments the network fees of many network companies have increased to the extent that the customers have reacted. In both countries, the authorities have announced restrictions to the rate of increase of the network fees. Thus, the network companies are now searching for alternative solutions to underground cabling. This task is here addressed by performing case studies on the network of a rural primary distribution substation area of the Vaasan Sähköverkko distribution company. The case studies include technical, reliability, economic and regulatory aspects and evaluations of possible implementations of different alternative network technologies.

INTRODUCTION

Alternative solutions to improve the security of supply in future distribution systems are needed for two reasons. The repair time of medium voltage (MV) underground cables is long, especially in harsh winter conditions. Underground cabling is not economically justified in sparsely populated regions. However, the current Finnish legislation sets strict limits to the length of outages. In building plan areas, the length of outages must not exceed 6 hours and in other areas 36 hours. There is room for alternative solutions to meet this challenge [1].

The Unified Modelling Language (UML) research method is implemented. Instead of simulation analytic calculation is used to show discovered impacts [2]. Benefit functions are reliability, normal conditions and major storm outage costs as well as different regulatory incentives. The physical operational environment is one of the most important factors that differ among the network companies. The impact of this is demonstrated by varying the fault frequency and frequency of major storms. The impact of the local physical environment is shown by the selection of the case study networks, an isolated island area network and a typical low power rural area network.

Technologies surveyed include low voltage (LV) connected battery energy storage (BES), implementation of the 1000 V distribution system in low-power feeder laterals, feeder automation (FA) and both mobile and fixed backup power generation. The impact of implementing these technologies is then compared to increasing the underground cabling level of the case study network (Table 1).

Table 1. Investigated alternative technologies.

Technology	ID	Description
Present network	RC	5-7 remote control sections
Battery energy storage	BES	4 BES: 25 kWh, one 2x50 kWh
1000 V distribution	1 kV	5-9 light-loaded laterals
Line reclosers	R	Trunk line and main lateral
Mobile reserve power	RP	Connected to LV
Fixed reserve power	FRP	500 kVA on Bergö island
Underground cabling	UGC_	UGC of feeder trunk line surrounded by forest in protection zone _

The results are typical investment costs, distribution system reliability indices, annual total outage costs, annual regulatory incentives and payback times of the alternative technologies as well as recommendable implementations of different technologies.

IMPLENTATION OF THE ALTERNATIVE TECHNOLOGIES ON THE ACTUAL NETWORK

The primary distribution substation supplying the studied rural area network includes four outgoing feeders. Based on the total annual outage cost of the feeders two feeders were selected to be investigated.

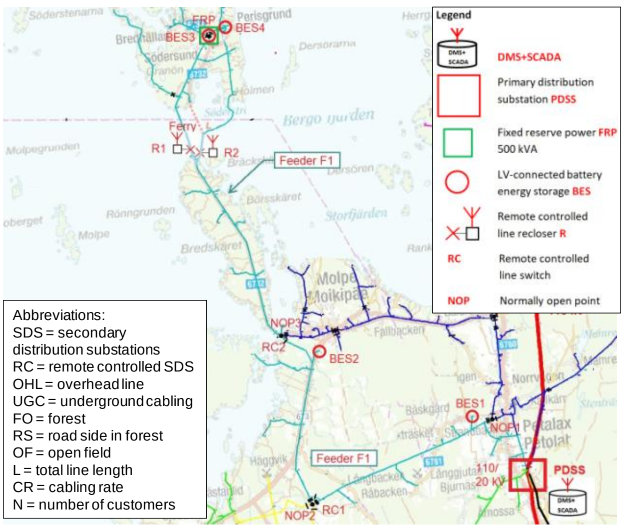

Figure 1. Implemented alternative technologies in the investigated feeder F1. ID:s, see Table 1.

Feeder F1 with a line length of 74 km consists of 7 remote controlled sections (Figure 1). The peak power is 2.4 MW and average customer density 14.3 customers/km (Table 2). Feeder F2 is a typical rural area feeder with a line length of 66 km and a cabling rate of only 5 % (Figure 2). This feeder, consisting of 5 remote controlled sections, has a peak power of 1.1 MW and a customer density of 6.5 customers/km (Table 2). There are no building plan areas in the investigated network.

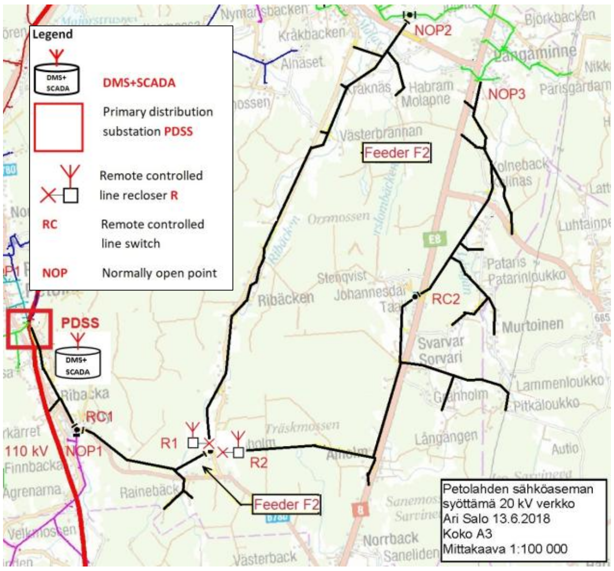

Figure 2. Implemented alternative technologies in feeder F2 are 1000 V distribution (1 kV), reclosers (R) and underground cabling (UGC).

Table 2. Network, power and customer data of the investigated network. Abbreviations, see Figure 1.

	SDS/ RC	UGC km	OHL, km			L km	CR %	P kW	N
			FO	RS	OF				
F1	64/9	12.8	16.4	31.2	13.6	74	17	1055	1055
F2	47/4	3.0	21.9	7.8	33.4	66	5	449	432

The effects and cost-effectiveness of the above described alternative technologies are compared to selective underground cabling of the feeders, where only the feeder trunk line surrounded by forest in different protection zones, is cabled.

RESULTS

Alternative technology investments

The costs of the different technology investments implemented into the two actual feeders are presented in Table 3 with bold numbers. To be comparable with the other investments, the costs of technologies which include cabling are subtracted with the cost of a new corresponding OHL network. Of the alternative technologies the most expensive investment is BES and the most inexpensive are line reclosers and mobile reserve power because it can be used in the whole distribution area.

Table 3. Investment costs [3].

Technology	Component groups	Feeder	
		F1/ k€	F2/ k€
BES [4]	3x25 kWh 2x50 kWh Investment cost (2000 €/kWh)	150 200 **350**	
1 kV [5]	Investment cost Corresponding OHL network Comparison cost	1077 -929 **148**	390 -304 **86**
R	Remote controlled line reclosers Investment cost	**53.4**	**53.4**
RP	Mobile reserve power 410 kVA Investment cost	**68.1**	**68.1**
FRP	Fixed reserve power 500 kVA Investment cost	**100**	
UGC1	Investment cost Corresponding OHL network Comparison cost	390 -278 **112**	144 -102 **42**
UGC2	Investment cost Corresponding OHL network Comparison cost	175 -134 **41**	170 -118 **52**
UGC3	Investment cost Corresponding OHL network Comparison cost		558 -402 **156**

Reliability indices

To compare the technologies regarding their impact on electricity distribution reliability, feeder average *SAIFI*, *SAIDI* and *MAIFI* are calculated. In the developed adaptive calculation model the reliability indices are expressed by the number and features of the components of the distribution system, the network configuration and automation (protection, remote control). This enables the reliability indices to be calculated for the different alternative technologies [6]. The results are presented in Figure 2. The technology which improves *SAIFI* most is line reclosers in both the feeders as the customers upstream of the reclosers are protected from the influence of faults downstream of the reclosers. In feeder F1 fixed reserve power is the technology which has the largest impact on *SAIDI* because except for the first part of the feeder there are no alternate pathways available. In feeder F2 underground cabling of feeder trunk pathways in forest in protection zone 3 reduces *SAIDI* most due to the line route forestry and the high power in the protection zone and lack of remote control in the normal open point.

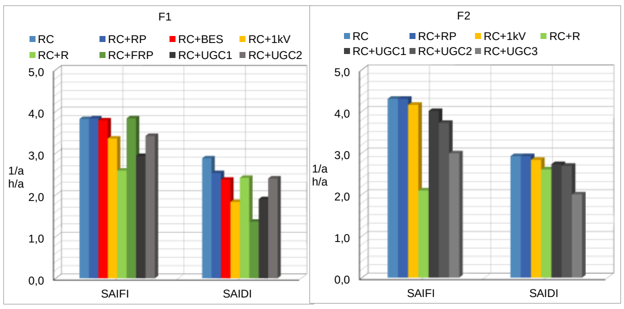

Figure 2. SAIFI and SAIDI of the alternative technologies implemented in the studied feeders.

Short interruptions and voltage dips

The calculation of the number of short interruptions ($MAIFI$) of the different technologies is based on the local frequency of high speed auto-reclosing (HSAR) and delayed auto-reclosing (DAR) in the actual network and the length of OHL in forest and roadside installation of OHL in forest in the different protection zones of the feeders.

The annual number of voltage dips (Dips) is calculated from the outage statistics of the actual network. Short-circuits in any of the primary distribution substation feeders causes Dips also in all the other feeders connected to the substation. Thus the number of annual Dips for the actual feeders is known. The annual average number of Dips for the alternative technologies is then calculated according to the influence of the applied technology on Dips (Figure 3). Because the operating time of the present over-current relays is over 100 ms, over-current protection does not reduce the number of Dips. Cabling reduces the number of Dips due to reducing the number of short-circuits. Series connected BES cancels the Dips in its distribution area. In present BES technology parallel connection is used, which requires supply interruption to connect the BES. To be able to calculate the monetary value of the benefit of the Fault-Ride-Through (FRT) function the calculation has been performed assuming that BES is series connected.

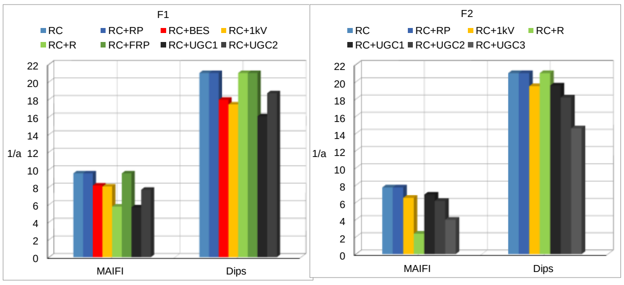

Figure 3. MAIFI and annual number of Dips of the alternative technologies implemented in the studied feeders.

Outage costs under normal conditions

The power and energy not supplied $PENS1$ is calculated for the different protection zones by means of the per unit cost for demand and energy not supplied [7]. The outage costs of HSAR and DAR are calculated using the local network auto-reclosing (AR) frequencies and the corresponding per unit cost for demand. Only OHL surrounded by forest (100 %) and OHL with roadside installation in forest (50 %) are considered to cause AR.

The annual outage cost under normal conditions $OC1$ is then:

$OC1 = PENS1 + HSAR + DAR$, where
$PENS1$ = annual cost of power and energy not supplied
$HSAR$ = annual outage cost due to HSAR
DAR = annual outage cost due to DAR

Major event outage costs

To be able to calculate the outage costs of major events (ME) a class I definition major event is modelled [8]. According to the results of a 10000 Monte Carlo-simulation of a similar rural area network the expected maximum fault repair time of the network area is 42 h [9]. For the network studied in this paper a fault repair capacity per feeder of 0.35 faults/h was defined. The fault repair process is assumed to start after two hour duration of the storm.

Major event outage cost ME:

$ME = PENS2 + SC12 + SC24 + 36h$, where
$PENS2$ = power and energy not supplied in major event
$SC12$ = standard compensation for outage duration longer than 12 h
$SC24$ = standard compensation for outage duration longer than 24 h
$36h$ = Penalty for outage duration longer than 36 h in areas outside building plan areas

The major event outage cost is converted to annual outage costs for the next twenty years using the annuity method. The annual total outage costs of the different technologies applied to the two investigated feeders are presented in Figure 4. According to [10] the network companies have to establish and update every second year a development plan on how to fulfil the maximum outage duration times in their distribution areas. By the end of year 2028 long outages are no longer permitted (red colours in Figure 4). As the underground cabling of the networks in building plan areas is completed all the network company major event repair resources can be used in areas outside the building plan areas. The study shows that doubling the major event fault repair resources (REP), long outages are avoided with all technologies.

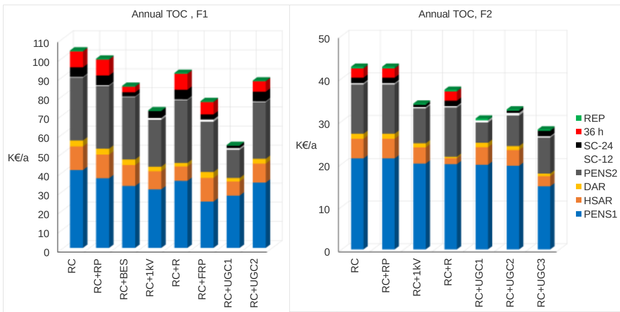

Figure 4. Normal condition and major event annual total outage cost of the alternative technologies implemented in the studied feeders.

Regulatory incentives

To encourage the network companies to make electricity distribution quality improving investments the Finnish Energy Authority (FEI) has introduced regulatory incentives [11]. The monetary value of these incentives of the different technologies is here used to calculate the payback times of the implementation of the different technologies.

The quality incentive QI:

$QI = \Delta OC1 + \Delta PENS2$, where

$\Delta OC1$ = savings in normal conditions annual outage cost of the applied technology compared to the actual network

$\Delta PENS2$ = cost savings of power and energy not supplied in major event of the applied technology compared to the actual network

The investment incentive II:

$II = DASLD_{i,k} = \frac{RV_i}{LT_i} \times \left(\frac{CPI_k}{CPI_{2016}}\right)$, where

$DASLD_{i,k}$= duly adjusted straight-line depreciation of network component *i* in year *k*

RV_i= duly adjusted replacement value of network component *i*

LT_i= techno-economic life time of network component *i*

CPI_k = consumer price index in year *k*

CPI_{2016} = consumer price index in year 2016

The efficiency incentive EI:

$EI = (100\% - CREI) \times \Delta KOPEX$, where

$\Delta KOPEX$ = savings in fault repair and maintenance costs of the applied technology compared to the actual network

$CREI$ = company related efficiency improvement target

The regulatory incentive RI is then:

$$RI = QI + II + EI$$

The regulatory incentives of the different alternative technologies are presented in Figure 5. Because BES has the highest investment cost and shortest life time it has the highest investment incentive, while the quality incentive is dominant for the other technologies.

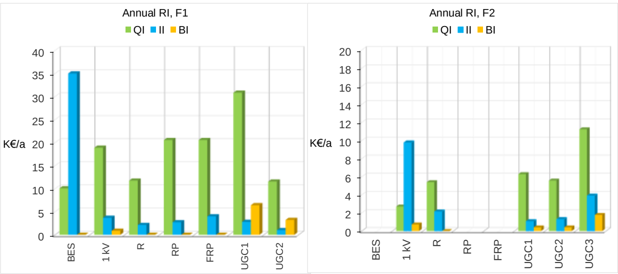

Figure 5. The annual regulatory incentives of the alternative technologies implemented in the studied feeders.

SUMMARY

Now the payback times of the different implemented technologies can be calculated.

The payback time PBT is then:

$PBT = \frac{INV}{RI}$, where

INV = applied technology investment costs when the corresponding OHL distribution line investments replacement costs are subtracted from the cabling investment costs

RI = Regulatory incentive

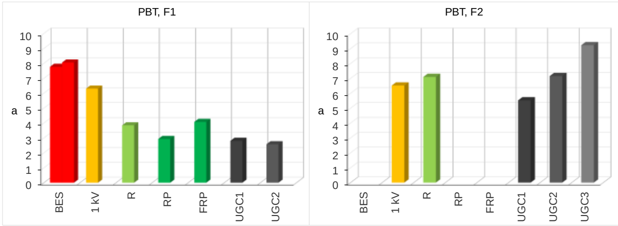

Figure 6. Payback times of the different technologies applied to the actual feeders. For BES the shorter payback time stands for BES equipped with the FRT function.

The calculated payback times of the different alternative technologies are presented in Figure 6. Remote controlled line switches are the basic technology of the Finnish distribution network operation and fault handling process, while remote controlled line reclosers are cost-effective to improve customer reliability indices and reduce normal conditions outage costs. Small-sized LV-connected BES reduce/avoid also major event long interruptions in their distribution area. In isolated areas with no alternate pathways use of mobile reserve power provided by an independent power producer could be cost-effective also in unplanned outages although with increasing outage savings fixed reserve power also becomes cost-effective.

Tripling normal conditions fault frequency and major event frequency halves the payback time of underground cabling, the 1000 V distribution system and reserve power while the effect on the payback time of BES and line reclosers is much less (10-20 %). By attending the electricity market the cost-efficiency of BES is further improved.

Minimising the effect of major disturbances is an optimisation task between the network maintenance and cabling rate as well as available major event outage repair resources. The network companies are preparing for fulfilling the demands of the Finnish Electricity Market Act by 2028. This study has shown, that the incentives included into the Finnish regulation model, broadens the available cost-effective technologies to avoid long interruptions in major events.

Table 4 lists shown impacts on the given benefit functions. Included are also some impacts that are known from other research [12]. BES and technologies relying on cabling (UGC, 1 kV) all reduce outage costs and improve electricity distribution quality. BES is, however, the only technology that has an impact on almost all benefit functions. The current widest potential refers to reducing the impact of major storms. In the future TSO is becoming more and more dependent of DSO regarding electricity market services. Network company owned BES can contribute to these services. When integrating renewable energy sources (RES) into the grid, FRT equipped BES meets the demands of the digital society by avoiding/shortening outages and cancelling Dips.

*Table 4. Benefit functions of the investigated alternative technologies where + indicates here shown impact and * is known to have an impact [12].*

Benefit functions		Technology	RC	BES	1 kV	R	RP	FRP	UGC
Invest- ment		Size Deferral	+	 *		+	+	 *	
Outage costs	Normal condi- tions	PENS1 HSAR DAR	+	+ + +	+ + +	+ + +	+	+	+ + +
	Major storms	PENS2 SC12 SC24 36 h		+ + + +	+ + + +			+ + + +	+ + + +
Quality	Relia- bility indices	SAIFI SAIDI MAIFI Dips	 +	+ + + +	+ + + +	+ + +	 +	 +	+ + + +
		U control Regulation incentives	 +	* +	 +	 +		 +	 +
Electricity market		Reserve Market Reactive power		* *				* *	
Operation		Power balancing Inertia		* *				* *	
RES integration		Energy storage		*					

CONCLUSIONS

The differentiation of the allowed maximum outage duration in planned and non-planned areas in 2013 has for most network companies led to investments in electricity distribution reliability improvements which have decreased the available monetary resources to renew the ageing infrastructure. In sub-urban and rural areas the investments have been dedicated to increasing the cabling rate of planned areas (Figure 7). This may, however, be a too expensive solution for non-planned areas. As energy efficiency improvement, distributed generation and especially small-sized RES are increasing the average power in MV networks is decreasing while the maximum power is increasing. Because the network outage status at present comprises only the MV level an upgrade of the automatic meter reading (AMR2) meters is needed to establish the status on customer level. With small-sized LV-connected BES the electricity distribution availability improvement measures can be focused to certain locations with severe physical environments. BES can thereby be an alternative or complement to increasing the cabling rate of the network to fulfil the demands on the maximum outage time in harsh weather conditions. This is possible by utilising the already high cabling rate of LV-networks.

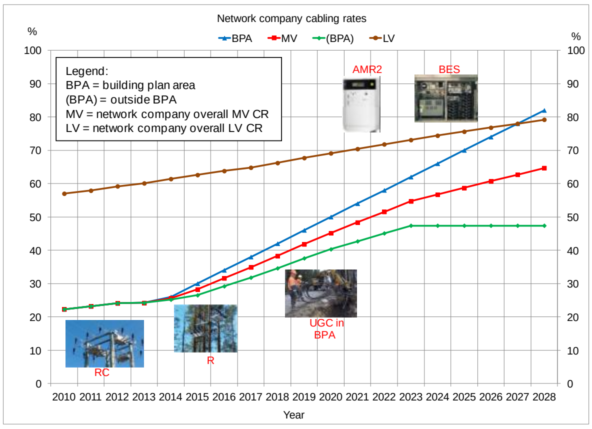

Figure 7. Strategy to fulfil legal and regulatory demands on electricity distribution availability in sub-urban and rural areas.

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