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Feasibility study of the implementation of A.I. automation techniques in modern power distribution networks

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ABSTRACT

Contemporary power distribution networks are no longer regarded as passive power system elements. On the contrary, novel control systems are being constantly developed over the last decade, aiming to achieve reliability improvement and operational optimization by means of power loss reduction, prompt fault detection and power restoration etc. A crucial aspect of the systems developed to achieve these goals will inevitably be their ability to integrate new functions without the need for further investment. In this paper, a multi agent system (MAS) initially developed for fault detection and power restoration is studied with respect to these issues. More specifically, a feasibility analysis is conducted regarding the implementation of the MAS on a segment of the underground 20 kV power distribution network of the city of Thessaloniki, Greece. The analysis focuses on the initial investment cost and the payback of the application, as well as on the additional benefits for the power distribution system operator due to the system reliability improvement. The ability of the MAS to incorporate loss reduction algorithms without further investment is also studied, and the respective benefits of the power distribution system operator are analyzed. Moreover, the feasibility analysis is generalized so as to be able to be applied to any power distribution automation implementation with similar attributes.

1. Introduction

One of the most critical issues concerning contemporary power distribution networks is their classic treatment by the power companies as passive elements within the power systems. This classic treatment can be clearly observed in the traditional configuration of these systems, as in most cases the power companies have no feedback concerning the real time status of their networks at medium voltage (MV) and low voltage (LV) level. More specifically, the power companies usually have at their disposal information concerning real time operation at the level of the high voltage (HV) to MV power substations separating the power transmission from the power distribution networks. Moreover, in many countries including Greece, most switching operations at these voltage levels (except of the ones at the aforementioned HV/MV power substations) are performed manually. Consequently, any power restoration procedure after a fault takes a considerable amount of time, as it basically consists of the dispatch of a technical crew, which conducts a series of manual operations at the MV/LV substations aiming to locate and isolate the fault.

For several decades, this traditional power distribution system configuration worked without presenting significant problems. Over the last decades however, the power consumption has increased dramatically, especially in urban areas. It is estimated that the largest proportion of losses in power networks corresponds to distribution networks; for a typical system in a developing country, distribution losses account for approximately 8% of the total electrical energy produced [1]. Moreover, an additional issue is imposed by the nature of urban power consumption, which is characterized by significant reactive power flow due to the massive deployment of residential air-conditioning units. These issues have demonstrated the importance of concepts such as power distribution automation and power loss reduction.

Automation has been applied to power distribution networks in order to achieve significant service reliability improvement for electricity customers [2–4]. Other approaches investigate reliability improvement and interruption cost minimization based on appropriate switch location or relocation across a distribution feeder [5,6]. Finally, significant research has been conducted on loss reduction in distribution systems via network reconfiguration. These applications are based on the development of algorithms for switching operations utilizing heuristic, fuzzy logic and other approaches [7–9].

An important aspect concerning any investment towards the aforementioned goals is the ability of the deployed system to be

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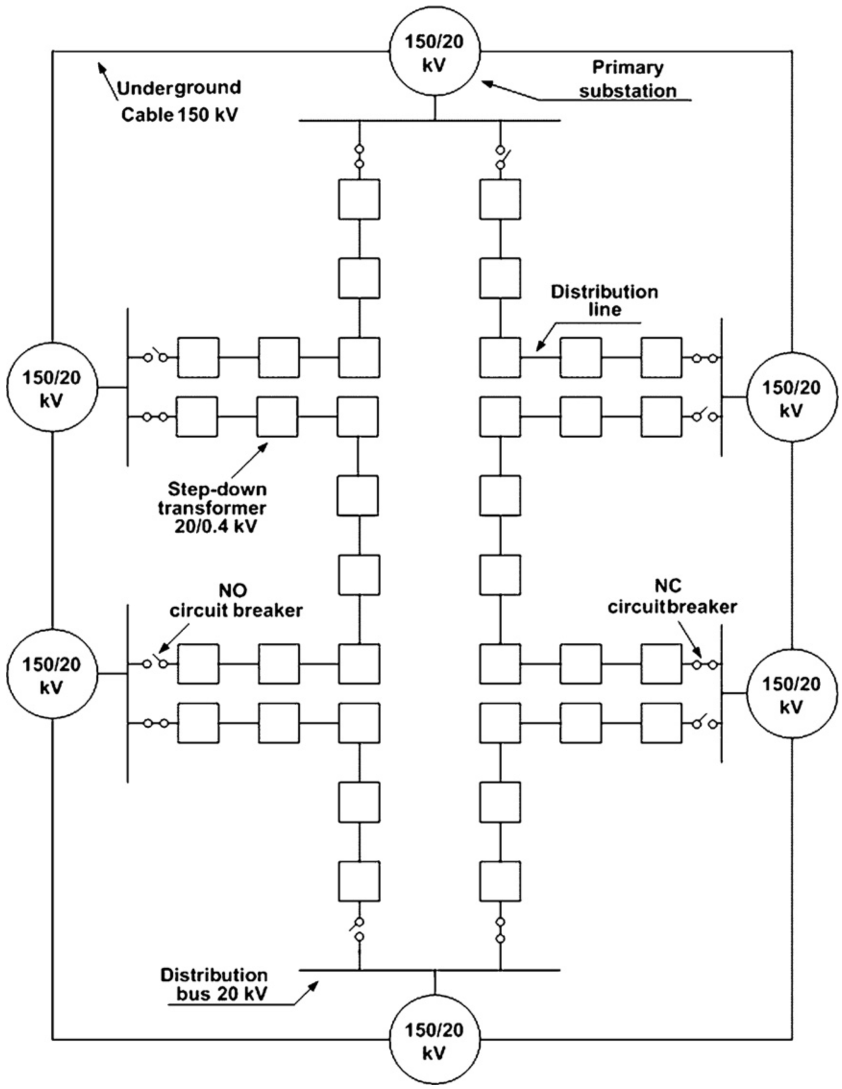

Fig. 1. Typical topology of distribution networks.

enhanced by incorporating additional functions. Moreover, the proposed systems found in the literature are usually based solely on theoretical assumptions, and are seldom tested with regard to data originating from real power distribution networks.

In this context, this paper investigates the economic viability concerning the deployment of a multi agent system (MAS) proposed in Refs. [10–12]. The MAS considered was originally designed for fault detection and power restoration. In this paper, the MAS is considered to be deployed on a real segment of the power distribution network of the city of Thessaloniki, Greece, and its performance is assessed by the use of information regarding the specific segment's actual loading profile. Moreover, the MAS ability to incorporate power loss reduction techniques by means of upgrading its software is studied.

In the second part of the paper, the necessity for the development of a power distribution automation system is analyzed. The operation of the MAS is explained, and techno–economical information regarding its implementation is offered. The techno–economical information is also linked to all power distribution automation systems with similar attributes. In the third part, essential operational aspects concerning power production, transmission and distribution in Greece are presented, and the cost and potential benefits concerning the implementation of automation techniques on power distribution networks are presented. Moreover, the segment of the power distribution network of the city of Thessaloniki used for the assessment of the MAS is presented. Details regarding its topology and the nominal characteristics of its transformers are provided along with the essential investment cost regarding the MAS implementation. In the fourth part of the paper, the payback of the investment concerning the MAS implementation on the specific network segment is specified. Furthermore, additional benefits from the system reliability improvement due to the implementation of the MAS at the specific network segment are presented. The analysis is based on real load curves concerning typical working days. Finally, in the fifth part of the paper the essential algorithms are presented, which will have to be incorporated to the MAS in order for it to provide power loss reduction functionality. In addition, the respective benefits for the power distribution system operator concerning the implementation of these algorithms are presented.

2. Power distribution automation systems

2.1. Necessity of development

Power distribution systems in Greece consist of groups of interconnected radial circuits, as shown in Fig. 1. The power lines

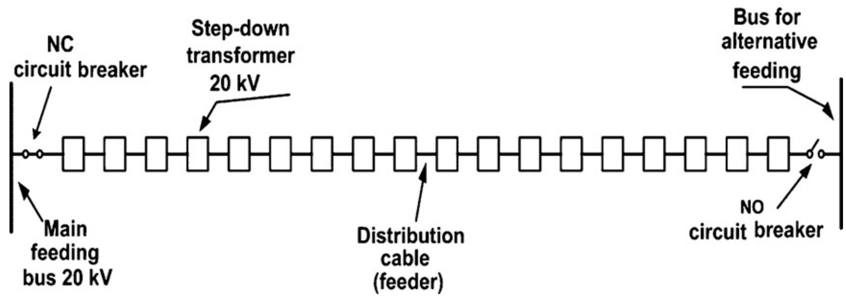

Fig. 2. Typical layout of urban distribution feeder.

interconnecting the step down transformers may be underground cables or overhead lines.

Considering a single feeder, as it can be observed in Fig. 2 it will consist of a series of step down transformers (20/0.4 kV), interconnected in most cases of urban power distribution networks by underground cables. The feeder is connected at both ends to a HV/MV power substation, so as to be able to be supplied with power from two alternative points. In both ends there is a MV circuit breaker, whereas the MV/LV transformers are equipped with load switches.

In the case of a fault occurring at any point of the power lines interconnecting the step down transformers of the feeder, the circuit breaker at the active feeding point will trip, and the whole line will undergo a power outage. At this point, a technical crew will be dispatched to locate and isolate the fault. The crew will initially travel to the middle step down transformer of the feeder, where it will manually operate its load switches, dividing the whole line into two autonomous segments. Consecutively, the control center of the operation will close the circuit breakers at both ends of the line, feeding thus both its segments with power. The circuit breaker at the segment with the fault will naturally trip again, limiting thus the search area for the crew.

This procedure will go on, with the technical crew dividing each time the search area into two segments, until the fault is located between two sequential step down transformers. At this point, the crew will isolate the fault by operating the load switches of these two transformers, and the circuit breakers at the ends of the feeder will close, providing thus all implicated customers with power. According to the power company currently in charge of the power distribution networks in Greece (Public Power Company, PPC), this procedure lasts an average of 2 h. This is therefore the average time, during which the customers implicated in an outage will have no power.

Evidently, the necessity rises for the development of an automated system, which will be able to manage faults in a power distribution system, locating and isolating them as swiftly as possible, improving thus the quality of service towards the customers.

2.2. Multi agent system

The MAS architecture proposed in Refs. [10–12] implements similar groups of collaborating software agents which are expected to join decisions and actions to achieve a common goal. The goal is to autonomously perform swift and effective fault management on MV power distribution lines. The system is capable of locating and isolating simultaneous or even cascading line faults. The basic feature of the proposed MAS is its ability to monitor and react to the real time network conditions. In this context, two characteristics are of utmost importance, namely the implementation of a heuristic algorithm, and the distributed nature of the system. Both of these characteristics ensure the swift response of the system to any disturbance.

Two basic states describe the system's operation; the steady-state and the fault isolating state. The MAS will not change to fault isolation state unless it realizes fault detection followed by total voltage and current loss across all phases (fault cleared).

As soon as the circuit breakers (CBs) have tripped to clear the fault, the MAS will change to fault isolation state [10]. The adjacent MAS installations, hosted in adjacent substations, exchange messages containing their corresponding fault detection status. The result is that the MAS installations of substations adjacent to the fault will realize that a fault occurred between them. Thereafter, these systems proceed to fault isolation by opening the load switches located at both sides of the fault. Finally power restoration is achieved by closing the circuit breakers at the terminals of the line. The duration between the tripping of the circuit breaker at the end of a feeder due to a line fault and the power restoration for all customers involved lies in the magnitude of 1 min. This characteristic comprises also the main advantage of the MAS in comparison to the traditional fault location techniques used in passive distribution systems.

2.3. MAS hardware requirements

As analyzed in Refs [10–12], a set of required apparatus must be installed on each transformer for the proposed MAS implementation. This set consists of the following devices:

- One embedded computer, powered by uninterruptible power supplies (UPS), for hosting and implementing the agent's ontology.
- Two motor driven MV (20 kV) load switches. The local agent (hosted in the embedded computer) is responsible for the operation of these switches. The open–close operations are executed via an appropriate signal between the computer and the motor of the switch.
- Inductive and/or capacitive couplers along with MV modems will enable power line communications (PLC). Couplers must be installed in such a way that the communication between the agents is ensured even if the load switches are opened.
- Current and voltage transformers for the measurement of the voltage and the current of every phase of the feeder.
- IEDs (intelligent electronic devices) for real time metering of the current, voltage, power factor, active and reactive power at the transformer. The IEDs' role should be restricted to recording the electrical parameters of the substation, and to indicating local fault detection.

In this study it is assumed that initially, i.e. before the MAS installation, the only available data for the feeder's condition are given by an existing SCADA system, and only the two circuit breakers at the terminals of the feeder are remotely controlled. The total installation cost of the above set of devices is estimated to be about 75,400 €.

The determination of the hardware requirements for the MAS implementation was based on retail prices for the above mentioned apparatus. These prices were provided by established companies in the area of Power Systems:

- 2650 € for 3 current transformers
- 3750 € for 3 voltage transformers
- 7000 € for 2 motor driven load switches (switchgear not included)
- 60,000 € for 6 couplers
- 500 € for UPS
- 1000 € for IED
- 500 € for one embedded computer

As it can clearly be observed, this cost is extremely high for any reasonable investment, considering the fact that it corresponds to only one transformer. However, it can be seen that the largest proportion of this cost corresponds to the couplers, which will be used for the powerline communication system. Given that the only purpose of the powerline communication system is the information exchange among the transformers, the total cost can be greatly reduced by the use of an alternative means for communication. For the purposes of this study, a GSM communication system will be used, which is already utilized by the PPC for the communication among the HV/MV power substations and certain MV/LV transformers. The retail price of this system is 1,800 € per transformer, and its use will reduce the total installation cost to 17,200 € per transformer.

It should be also noted at this point that the greatest proportion of the aforementioned cost corresponds to the essential equipment for the measurement of the three-phase voltages and currents at the MV level of the MV/LV step down transformers. The cost corresponding to the metering equipment, along with the respective cost of the motor driven load switches will be however common for the implementation of all power distribution network automation techniques. Therefore, the analysis presented in this paper can be easily adopted for the feasibility study of any other similar automation technique.

3. Implementation aspects

3.1. Power production, transmission and distribution in Greece

Until 1999, there was a single corporation responsible for power production, transmission and distribution in Greece. This corporation was the Public Power Corporation S.A. (PPC). Following the electricity market deregulation however, a new organization was established in order to take over the management of the power transmission system (Hellenic Transmission System Operator S.A., HTSO). PPC is today one of the power production corporations selling electrical energy to the HTSO, while it is also still responsible for the management of the power distribution systems in Greece. In the meantime, the establishment of an independent corporation which will take over the management of the power distribution networks is still pending.

Within this framework, the corporation solely responsible for the operation and development of the power distribution networks is and will be the one managing these networks, i.e. the power distribution system operator (PDSO). In the scenario presented in this paper, this corporation will have to undertake the investment cost of the MAS implementation. On the other hand, this corporation will also gain from the potential benefits of the MAS.

3.2. Potential benefits of the MAS implementation

At a basic conceptual level, the potential benefits of the MAS implementation will include a profit due to the acceleration of fault detection and power restoration resulting in the prevention of profit loss. In addition to that however, there will also be a social benefit corresponding to the reduction of the power not served to customers in the case of a power outage. This benefit should be also taken into account, as it concerns both the customers, as well as the improvement of the quality of service offered by the PDSO.

A number of indices can be found in the literature concerning the quantification of the concept of the quality of service. Two among the most common ones used will be used in this work, namely [13]:

- The system average interruption duration index (SAIDI), defined as: (sum of customer interruption durations)/(total number of customers served).
- The expected energy not supplied (EENS)

Both indices are further analyzed in the following paragraphs.

3.3. Power distribution network segment

A typical urban power distribution network segment was selected as a test case in the study. The selected segment lies in the eastern part of Thessaloniki, Greece. It consists of five MV power

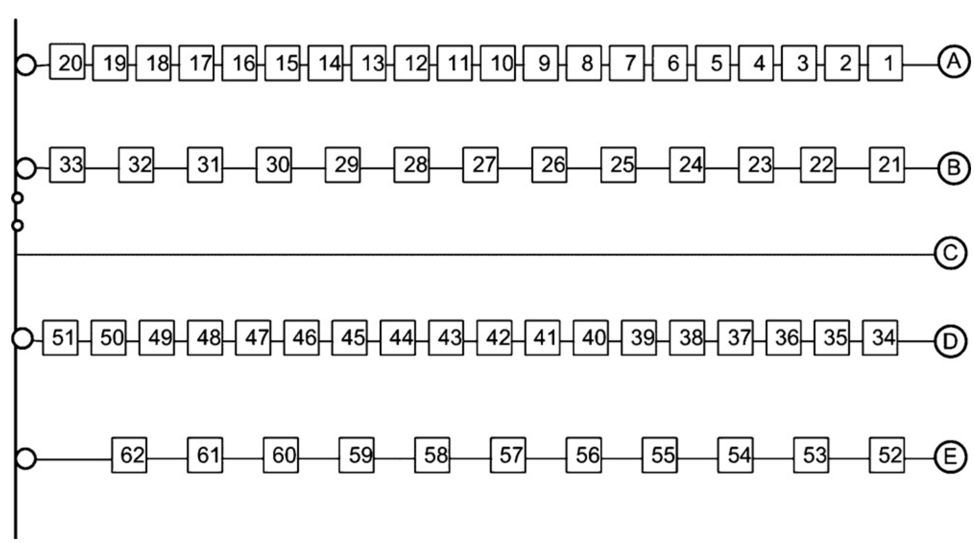

Fig. 3. Layout of selected power distribution network segment. (a) Typical working day in winter (b) Typical working day in summer.

Table 1
Transformer rated power for all feeders.

Feeder A		Feeder B		Feeder D		Feeder E	
Transformer no.	Rated power (kVA)	Transformer no.	Rated power (kVA)	Transformer no.	Rated power (kVA)	Transformer no.	Rated power (kVA)
1	630	21	630	34	1000	52	630
2	630	22	630	35	630	53	630
3	630	23	630	36	630	54	630
4	630	24	630	37	630	55	630
5	630	25	630	38	630	56	630
6	630	26	1630	39	630	57	630
7	1000	27	1000	40	630	58	630
8	630	28	630	41	1260	59	1400
9	630	29	630	42	630	60	630
10	630	30	630	43	630	61	630
11	630	31	630	44	630	62	630
12	630	32	630	45	630		
13	630	33	630	46	630		
14	630			47	1000		
15	250			48	630		
16	630			49	1000		
17	630			50	500		
18	500			51	400		
19	630						
20	630						

Table 2
Length and electrical parameters for all interconnecting lines (ties) of feeders A, B.

Feeder A				Feeder B			
Tie	R' (Ω/km)	X' (Ω/km)	L (km)	Tie	R' (Ω/km)	X' (Ω/km)	L (km)
A-1	0.15	0.108	1.4428	B-21	0.15	0.108	2.2463
1–2	0.15	0.108	0.1706	21–22	0.15	0.108	0.1241
2–3	0.15	0.108	0.3781	22–23	0.15	0.108	0.2688
3–4	0.15	0.108	0.1743	23–24	0.15	0.108	0.1729
4–5	0.15	0.108	0.1302	24–25	0.15	0.108	0.1155
5–6	0.15	0.108	0.3272	25–26	0.15	0.108	0.1589
6–7	0.153	0.110	0.1977	26–27	0.15	0.108	0.2373
7–8	0.156	0.111	0.1183	27–28	0.15	0.108	0.341
8–9	0.15	0.108	0.3632	28–29	0.15	0.108	0.3843
9–10	0.15	0.108	0.5386	29–30	0.1601	0.1139	0.1584
10–11	0.15	0.108	0.0868	30–31	0.049	0.0351	0.3167
11–12	0.15	0.108	0.1546	31–32	0.15	0.108	0.1047
12–13	0.15	0.108	0.1472	32–33	0.15	0.108	0.2834
13–14	0.15	0.108	0.241				
14–15	0.15	0.108	0.3134				
15–16	0.15	0.108	0.5561				
16–17	0.15	0.108	0.3054				
17–18	0.15	0.108	0.2282				
18–19	0.15	0.108	0.2545				
19–20	0.15	0.108	0.1024				

Table 3
Length and electrical parameters for all interconnecting lines (ties) of feeders D, E.

Feeder D				Feeder E			
Tie	R' (Ω/km)	X' (Ω/km)	L (km)	Tie	R' (Ω/km)	X' (Ω/km)	L (km)
D-34	0.15	0.108	0.7154	E-52	0.1536	0.1204	2.0738
34–35	0.15	0.108	0.8422	52–53	0.15	0.108	0.1809
35–36	0.15	0.108	0.1413	53–54	0.15	0.108	0.1917
36–37	0.15	0.108	0.2139	54–55	0.15	0.108	0.2287
37–38	0.15	0.108	0.0912	55–56	0.15	0.108	0.2821
38–39	0.15	0.108	0.1929	56–57	0.15	0.108	0.2408
39–40	0.15	0.108	0.4426	57–58	0.15	0.108	0.141
40–41	0.15	0.108	0.1546	58–59	0.15	0.108	0.2937
41–42	0.15	0.108	0.2565	59–60	0.15	0.108	0.1877
42–43	0.15	0.108	0.0833	60–61	0.15	0.108	0.1878
43–44	0.15	0.108	0.2420	61–62	0.15	0.108	0.2479
44–45	0.15	0.108	0.2783				
45–46	0.15	0.108	0.1652				
46–47	0.15	0.108	0.2343				
47–48	0.15	0.108	0.3211				
48–49	0.15	0.108	0.2472				
49–50	0.15	0.108	0.5335				
50–51	0.15	0.108	0.1885				

Table 4
Length and electrical parameters for feeder interconnections.

Tie	R' (Ω/km)	X' (Ω/km)	L (km)
A–B	0.15	0.108	1.2963
B–C	0.15	0.108	0.9969
C–D	0.15	0.108	0.6798
D–E	0.15	0.108	0.7238

Table 5
Number of expected faults for feeders under study in a 25 year period.

Feeder	Number of expected faults in a 25 year period
A	32
B	25
D	28
E	23

lines which start at the same HV/MV power substation, and run mostly underground, with only a small section consisting of overhead lines. These lines are used to feed a number of MV/LV power transformers as shown in Fig. 3.

The selected area is a representative urban district, and it includes mostly residential and commercial consumers. As can be observed in Fig. 3, the network segment includes a backup feeder (feeder C) intended to take on loads from adjacent buses if necessary. PPC provided all the essential information regarding the power distribution network segment under study. More specifically, PPC offered information about the rated power of all MV/LV step down transformers, length, type (overhead or underground) and electrical parameters of all line segments interconnecting the transformers, as well as load curves for all feeders.

For each feeder, it was considered that its load is divided among the step down transformers it feeds in proportion to their rated power (a policy followed by PPC itself due to the lack of measurements at the MV/LV transformers). The rated power of all transformers can be observed in Table 1, whereas the length and electrical parameters of all interconnecting lines (ties) are presented in Tables 2 and 3. Moreover, the corresponding information regarding the ties among the feeders is presented in Table 4.

In order to assess the feasibility of the investment concerning the automation of this network segment, the worst case scenario was selected, namely that none of the equipment required for the aforementioned MAS implementation is available prior to the investment. For the network segment under study, this assumption means that an investment of 17,200 € will be required for every step down transformer (a total of 1,066,400 € for the whole network segment). In the following paragraphs, this investment cost will be compared to the financial profit and the additional benefits due to the MAS implementation. Two distinct scenarios will be analyzed regarding fault detection and power restoration, as well as power loss reduction.

4. Fault detection and power restoration scenario

4.1. Test cases

The analysis for this scenario is based on the assumption that in the case of a fault occurring at the network segment under study, the MAS will locate the fault and restore power to all involved costumers in about 1 min. As aforementioned, the PPC reports an average of 2 h for the same procedure without the MAS. Therefore, for every fault occurring after the MAS implementation, the profit and potential benefits can be calculated for the 2 h that will be saved due to the MAS operation. Moreover, the PPC reports an annual fault frequency of 21 faults/100 km for the MV power distribution network, which translates to 0.21 faults/km. Taking into consideration a payback time of 25 years, the respective number of expected faults for feeders A, B, D, E of Fig. 3 during this time is shown in Table 5. Faults in feeder C do not affect customers (as it is a backup feeder), therefore they are not taken into account. Nevertheless, it should be mentioned that feeder C is only shown in this analysis because of its presence in the actual power distribution network segment under study. Its existence however does not affect the functionality and efficiency of the MAS.

Four different test cases are considered regarding the faults at the feeders. These include faults occurring during typical working days, whereas the respective aforementioned 2 h time frame for every fault is shown in Table 6. The four test cases correspond to faults occurring on the noon or evening of a typical working day in summer or winter.

These faults are considered to occur recurrently at every feeder under study for the payback time period, according to each feeder's fault frequency. This way, it is ensured that all feeders will have sustained all test case faults with the same probability over this time period.

The power demand during each fault is calculated based on the respective typical load curves for the feeders under study provided by the PPC, considering the selected time frames. These load curves are considered to correspond to the year of the MAS implementation, and they are presented in Fig. 4a and b for feeder A, in Fig. 5a and b for feeder B, in Fig. 6a and b for feeder D, and in Fig. 7a and b for feeder E.

For each case, the power demand is considered without loss of accuracy to be constant and equal to the load average as calculated for the respective 2 h period from the load curves. The respective average loads for each feeder and each case, which will be used in the following calculations, can be observed in Table 7.

According to the PPC, the annual load increase for the city of Thessaloniki is 2%. Moreover, when the loading of a feeder reaches 80% of its rated power, the PPC adds a new feeder to the network in order to take on half of the old feeder's loads. These two elements have been taken into account in combination with the load curves of Figs. 4–7 for the calculation of each feeder's loading conditions for every fault during the payback time of 25 years.

Table 6
Fault test cases.

Test cases	Time frame
Test case I	Winter noon (12:15–14:15)
Test case II	Winter evening (17:45–19:45)
Test case III	Summer noon (12:15–14:15)
Test case IV	Summer evening (19:15–21:15)

Table 7
Average loads for each feeder and each test case.

Feeder	Average load (kW), test case I	Average load (kW), test case II	Average load (kW), test case III	Average load (kW), test case IV
A	3475	4350	3910	4080
B	1500	2020	1585	1770
D	3375	4400	3850	4040
E	1540	1810	1835	1885

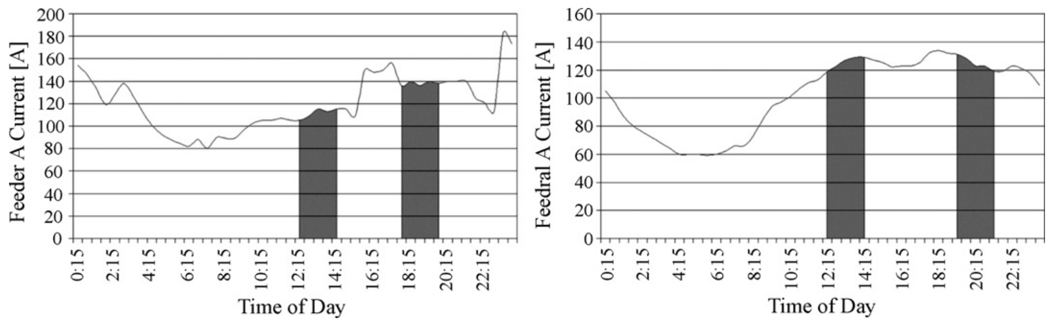

Fig. 4. Load curves for each test case regarding feeder A. (a) Typical working day in winter. (b) Typical working day in summer.

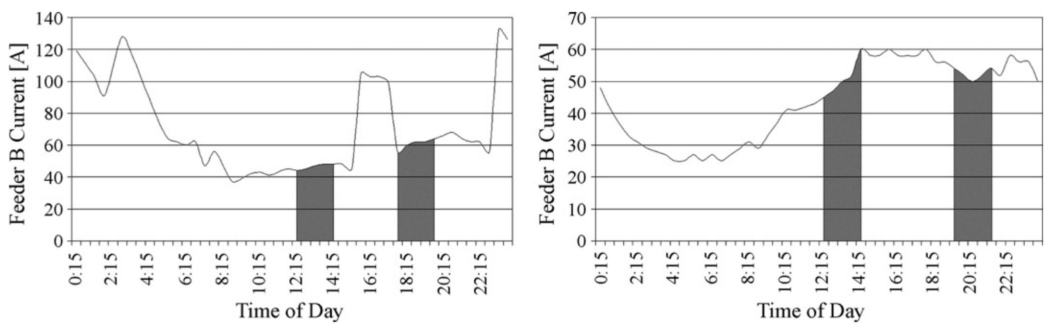

Fig. 5. Load curves for each test case regarding feeder B. (a) Typical working day in winter. (b) Typical working day in summer.

4.2. Investment payback

The MAS implementation requires an investment which will solely burden the DSO. Among the other benefits that this investment will bear, the DSO is bound to take into consideration its payback. This payback will basically accrue from the elimination of the EENS due to MV line faults, as these faults will be handled by the MAS. This will produce additional revenues for the DSO from the sale of this energy.

For every fault occurring at a feeder, the EENS can be calculated as:

$$\mathrm{EENS} = \sum_{j=1}^{n} TL_j \ t_j \tag{1}$$

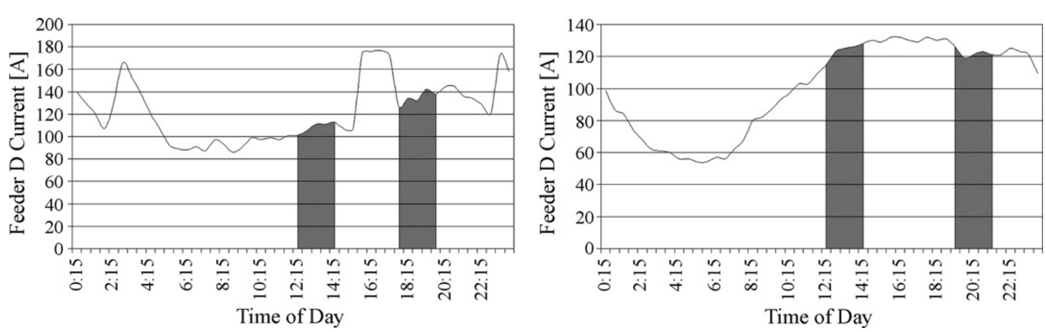

Fig. 6. Load curves for each test case regarding feeder D. (a) Typical working day in winter. (b) Typical working day in summer.

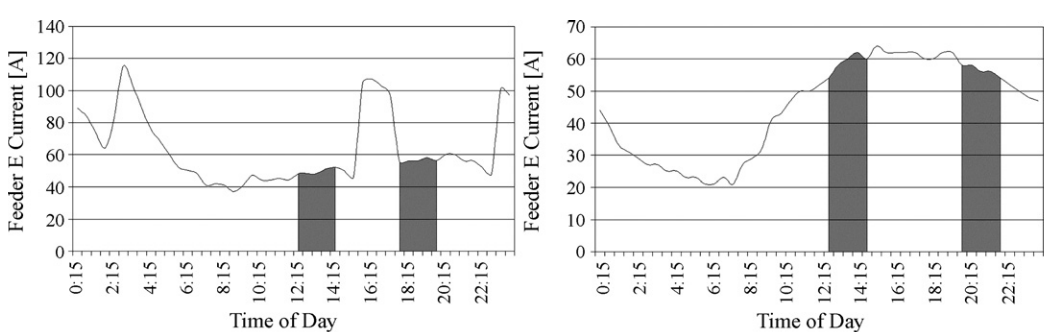

Fig. 7. Load curves for each test case regarding feeder E. (a) Typical working day in winter. (b) Typical working day in summer.

Table 8
ECOST and CNAPD values for electrical power customers in Greece (2001).

Customer type	ECOST ($)	CNAPD ($/kW)
Industrial	10,937	13.66
Commercial (business)	909	4.09
Commercial (organizations)	2000	11.09

where: n: number of step down transformers at the feeder with the fault, TL_j: loading of transformer j for the time period of the fault (kW), $j=1,\ldots,n$, and T_j: duration of the fault (considered here to be equal to 2 h).

Considering all faults at all the feeders of the power distribution network segment under study for the aforementioned payback time of 25 years, the total EENS that will be spared due to the MAS implementation will equal to 748,105 kWh. The sale of this amount of energy will produce the direct PDSO payback. More specifically, the cash flow that will be produced by every saved fault will be equal to the product of the respective EENS of the fault with the value of 1 kWh. Considering this latter value, the present value of 0.1 €/kWh was used as an initial estimation, whereas for every fault within the 25 year period this value was readjusted regarding the year of the fault occurrence and an annual inflation rate of 3.5%. Consequently, the calculated cash flow was reduced to present value by the use of a nominal discount rate of 8%.

The sum of all calculated cash flows reduced to present value produced a result of 44,476 € concerning the direct PDSO payback for the MAS implementation. As can be clearly observed, this direct payback is negligible as compared to the investment cost of 1,066,400 € that will be required for the MAS implementation.

4.3. Reliability improvement

The calculation of the payback that will accrue for the PDSO due to the MAS implementation may indicate that the investment is not feasible; however it is not sufficient in order to draw a general conclusion. More specifically, in any investment concerning the improvement of power distribution quality of service, a study should be conducted regarding the determination of customer costs associated with electric energy supply interruptions, as the investment may be regarded as feasible if the investment cost is less than the customer cost [14]. Considerable work has been done around the world on this subject. The CIGRE TF 38.06.01 report [15] illustrates this work and the methodologies developed to assess customer interruption costs and utilize these data in a wide range of applications.

A value for customer interruption cost assessment, in regard to customer types, is adopted by a complete and detailed interruption cost analysis based on a customer survey implemented in Greece in 2001 [16], concerning three types of customers:

- industrial
- commercial (business)
- commercial (organizations)

The survey provides two types of interruption cost indices, the average cost per interruption ($/int) and the Cost Normalized by Annual Peak Demand (CNAPD) ($/kW). These values are known as 'aggregated averages'. The CNAPD can be calculated as the ratio of the sum of interruption costs to the sum of the respective peak demand for all customers. The respondents were asked to calculate their costs for an interruption (Expected Customer Interruption Cost-ECOST). For a 2 h scenario the results obtained are shown in Table 8, whereas the results concerning the ECOST values have also been translated into the corresponding CNAPD values:

Table 9
CNAPD values for electrical power customers in Greece in present value.

Customer type	CNAPD (€/kW)
Industrial	15.5
Commercial (business)	4.63
Commercial (organizations)	12.6

Since in this study all costs and economic values are expressed in €, a conversion of the CNAPD from $/kW to €/kW is implemented based on the exchange rate between the two currencies in 2001 and the readjustment of the CNAPD to present values. In Table 9 values for CNAPD, expressed in €/kW for year 2008, are presented.

Moreover, the corresponding CNAPD for residential customers is considered to be 1.0 €/kW [17].

The benefit that will arise for the customers due to the prevention of power interruptions can be calculated by the estimation of the interruption costs that would burden them if the MAS had not been implemented. Apart from the customers, this benefit will also be of great importance for the DSO, as it will improve its reliability and thus its status in a deregulated energy market.

For the calculation of the customer interruption costs that will be spared due to the MAS implementation, the apportionment of the involved loads according to the aforementioned customer types is essential. For the power distribution network segment under study, this apportionment is as shown in Table 10:

The problem of determining the benefit that will arise for the customers due to the MAS implementation reduces thus to calculating for each customer type the unsupplied power in the case of each fault within the investment payback time of 25 years. Consecutively, the unsupplied power for every fault and every customer type will have to be translated into the corresponding interruption cost, and all the resulting interruption costs will have to be readjusted to present values. The sum of the readjusted interruption costs will offer the benefit of the customers due to the MAS implementation.

The unsupplied power for a customer type in the case of a fault can be calculated with:

$$\mathrm{UNP}_i = \sum_{j=1}^{n} TL_j \; p_i \tag{2}$$

where: UNP: unsupplied power (kW), i: customer types according to Table 10, $i=1, 2, 3$, n: number of step down transformers at the feeder with the fault, TL_j: load of transformer j for the time period of the fault (kW), $j=1,\ldots,n$, and p_i: percentage of feeders' load applied for customer type i, as shown in Table 10.

The benefit (in present value) for every fault can be calculated respectively as follows:

$$\mathrm{BM}_{(\mathrm{PV})} = \sum_{i=1}^{3} \frac{\mathrm{CNAPD}_{g,i}\ \mathrm{UNP}_i}{(1+\alpha)^{(g)}} \tag{3}$$

where: $\mathrm{BM}_{(\mathrm{PV})}$: monetary benefit (present value) (€), i: customer types according to Table 10, $i=1,\ldots,3$, g: year of fault occurrence, $g=1,\ldots,25$, CNAPD: cost normalized by annual peak demand according to the year of fault occurrence and customer type, and α: nominal discount rate 8%.

Table 10
Loading apportionment into different customer types for the power distribution network segment under study.

Customer type	Percentage of total feeder loading
Residential	55%
Commercial (business)	30%
Commercial (organizations)	15%

The consideration of all spared faults at all the feeders of the power distribution network segment under study for the time period of 25 years in combination with expressions (2) and (3) yield a total benefit of 1,037,574 € for the network segment customers due to the MAS implementation. As aforementioned, this benefit should also be taken into account along with the investment payback that will accrue for the DSO.

4.4. SAIDI index

The SAIDI index basically provides information about the average interruption duration that a customer will have to suffer in a specific location. This average interruption duration is affected of course by a number of parameters, such as cause of interruption (e.g. fault, scheduled maintenance etc.), fault severity in the case of an outage, location, accessibility etc. Considering the power distribution networks, the MV line faults comprise the largest proportion of possible faults that can lead to an outage, however there are also other causes of possible outages, such as faults at the 20/0.4 kV step down transformers or at the LV power lines. The scope of this work is not to assess all possible kinds of faults and calculate an exact value for the SAIDI index, but to assess the improvement to the SAIDI value due to the MAS implementation.

As aforementioned, the PPC reports an average interruption of 2 h (or 120 min) for all customers involved in a MV line fault. This is the part of the total SAIDI value that corresponds to these faults. The MAS implementation however reduces fault location and power restoration times in the case of such a fault to times around 1 min, eliminating thus the 120 min factor of the MV power line faults in the total value of the SAIDI. This introduces a significant improvement of the SAIDI factor, which will also improve the status of the DSO within a deregulated energy market.

5. Loss reduction

5.1. Generally

It can be observed up to this point that the investment concerning the power distribution network segment under study is only marginally justified. However, the study insofar regards only aspects concerning fault detection and power restoration, while the implemented equipment will be able to provide additional services, from which the DSO will also benefit. One of these services concerns power loss reduction. More specifically, the equipment that will be utilized for the investment under study will provide monitoring services concerning the MV/LV step down transformers of the power distribution network, as well as remote switching capabilities. These two aspects may be combined in order to provide load reallocation among the feeders through network reconfiguration, for the purpose of reducing power losses over the distribution lines. Given that the essential hardware to perform these operations will be provided by the system under study, it can be deduced that the implementation of power loss reduction reduces to the essential system software upgrade.

Various algorithms and techniques have been developed for the reconfiguration of power distribution networks through switching operations, so as to achieve loss reduction. The basic concept behind the power distribution network reconfiguration for power loss reduction purposes consists in reallocating loads among the available feeders by changing the operating status of the corresponding load switches (open/close). In a typical power distribution network, the number of the load switches is substantially large, presenting a corresponding significant number of possible switching operations (2^m for m load switches). Moreover, given that a number of constraints have to be taken into account during the power loss reduction procedure, the conclusion can be drawn that heuristic methods are simpler to be implemented and more adequate in order to address the problem. In this work, the implementation of a heuristic algorithm proposed in Ref. [18] is considered for the power loss reduction regarding the distribution network segment under study.

5.2. Methodology

Based on the work of Goswami and Basu concerning power distribution networks reconfiguration algorithms [19], Ghosh and Das developed an algorithm using two basic heuristic rules [18]. The result of their work was the minimization of the essential switching operations for the reconfiguration of a power distribution network, and thus the reduction of the necessary CPU time for the algorithm implementation. The two rules introduced by Ghosh and Das regard the decision making procedure concerning the open tie switches which will have to be closed in a power distribution network for optimum reconfiguration:

1. Among the open tie switches of a power distribution network, the one which will have to be closed for maximum loss reduction is the one with the highest potential difference across its poles.
2. If the potential difference across the poles of any open tie switch is negligible (less than a pre-specified value), the closing of this tie switch will not offer to the network loss reduction.

The algorithm resulting from these two basic rules was used in this work for the reasons explained in the previous paragraphs. This algorithm is essentially an iterative procedure determining each time the necessary switching operations. During each iteration, the algorithm determines which one among the open tie switches of the network segment under consideration has the highest potential difference across its poles. If this potential difference is smaller than a pre-specified value, the algorithm terminates, otherwise it reaches a decision to close the respective tie switch. Consequently, a loop will be formed in the network segment. The algorithm will proceed to examine all resulting branches, and open the one with the lowest current, restoring thus the radial network structure. This procedure will go on, until all open switches have a potential difference across their poles lower than the pre-specified value.

5.3. Test case

The implementation of the loss reduction algorithm concerning any given power distribution network segment requires the knowledge of currents and voltages at all MV/LV step down transformers. As aforementioned however, the power distribution network segment under study does not include the essential equipment for this purpose. The measurements presented here concerning the feeders' loading are provided by a SCADA system at the HV/MV power substation, at a rate of one measurement per 30 min. Moreover, it should be noted once again that the measurements regard the feeders' total currents. The method used to determine each MV/LV transformer's current is based on the respective policy followed by the PPC, which consists of dividing the feeder's total current among its transformers, according to each transformer's rated power. The steps of this method are the following:

1. At first, the installed power is calculated for every feeder, as the sum of the rated power of all the MV/LV transformers of the respective line. For the power distribution network segment under study, the loading capacity of all feeders according to the

Table 11
Loading capacity of each feeder according to number and rated power of corresponding transformers.

Feeder	Loading capacity (kVA)
A	$S_{tot} = 17 \times 630 + 1 \times 1000 + 17 \times 250 + 1 \times 500 = 12{,}460$
B	$S_{tot} = 12 \times 630 + 2 \times 1000 = 9560$
D	$S_{tot} = 12 \times 630 + 3 \times 1000 + 1 \times 400 + 1 \times 500 + 1 \times 1260 = 12{,}720$
E	$S_{tot} = 10 \times 630 + 1 \times 1400 = 7700$

rated power of the corresponding MV/LV step down transformers is shown in Table 11.

2. Subsequently, the ratio S_i/S_{tot} is calculated for every transformer, where S_i the rated power of transformer i, and S_{tot} the total loading capacity of the corresponding feeder, as shown in Table 11.
3. This ratio is used along with the total current value of the feeder, in order to calculate the current of transformer i as follows:

$$I_i = \frac{S_i}{S_{tot}} I_{tot} \tag{4}$$

4. Finally, the power served by transformer i is calculated by the current given by expression (4), considering the transformers' nominal voltage of 20 kV, as well as the PPC average power factor regarding urban power distribution networks, i.e. $\cos\phi = 0.93$.

Concerning the heuristic algorithm that will be used in this study, it is evident that it requires constant loading conditions to function. If the loading conditions of the network segment under study change, the algorithm must be used again in order to produce a new evaluation. In practice however, the loading of a power distribution feeder is constantly changing, introducing thus a problem which is inherent to all power loss reduction techniques. In order to address this problem, an investigation was conducted concerning the loading curves of all feeders under study, so as to determine specific time periods within a day, during which the corresponding feeder loads could be considered constant and equal with the feeder's average load. The criterion used to determine such time periods was the preservation of the feeder's minimum and maximum loads within ±15% of the average load for the period. The background for the determination of this criterion was the ascertainment that the algorithm would not produce two different results for load values within the same time period. This approach resulted in a number of time periods within a day, during which the algorithm can be used. It should be also noted that the selected time periods were common for all feeders under study, as their load allocation among different customer types is approximately equal. This means that their load profiles follow approximately the same patterns during common days.

The analysis of the load curves produced a conclusion regarding their similarities. More specifically, it was observed that the daily load curves for the duration of a year can be divided into four groups according to load level and profile. The resulting four groups essentially coincide with the four seasons of a year. Naturally there are small dissimilarities among the load curves considering the three months of each season; analysis however suggests that these dissimilarities do not significantly affect the loss reduction procedure for these months.

The most significant differences correspond to load levels during the transition months between the seasons, i.e. February, May, November and August. For these four months, the respective analysis was conducted separately; it was however again based on the suggestion that the load profiles within a month present a similar profile, as well as similar load levels.

The results of the analysis are presented in Table 12. It should be mentioned that the energy saved by loss reduction which is presented in Table 12 corresponds to a single time span for each day, in order to keep a minimum daily usage of the respective load switches. For that purpose, for every given day the respective time period is selected which will produce the maximum loss reduction. It is interesting to notice, that for the months between November and May, this time period is daily between 23:15 and 03:45 (due to the PPC's reduced night tariff), whereas for the months between June and October the daily needs for residential air-conditioning shift this time period between 11:30 and 21:00. It is evident, that the benefit from loss reduction will increase significantly if more time periods are used within a day.

Table 12
Energy saved due to loss reduction per month within a year.

Month	Saved energy due to loss reduction (kWh)	Time period
January	3189	23:15–03:45
February	1532	23:15–03:45
March	1154	23:15–03:45
April	1025	23:15–03:45
May	1100	23:15–03:45
June	4039	11:30–21:00
July	3315	11:30–21:00
August	3150	11:30–21:00
September	2750	11:30–21:00
October	2830	11:30–21:00
November	2925	23:15–03:45
December	3150	23:15–03:45
Annual total	30,160	

5.4. Loss reduction benefit

In a deregulated market, the DSO buys the energy inserted in its system from the transmission system operator (TSO) at the system marginal price (SMP). In Greece, SMP is currently set to 0.08 €/kWh. This price will be used in this work for the determination of the benefit that will be produced for the DSO due to the implementation of the aforementioned loss reduction technique for the power distribution network segment under study. More specifically, the energy spared from the loss reduction technique implementation is energy that the DSO will not need to buy; therefore it can be translated to an indirect profit for the DSO. In order to evaluate this benefit for the initially suggested payback time period of 25 years, a respective benefit will be calculated for every year within the payback period, assuming that electricity prices follow the general inflation rate of 3.5%. The total benefit from the loss reduction implementation on the regarded power distribution network segment in present value will be then:

$$PV = \sum_{z=1}^{25} \frac{SE\ c\,(1+b)^z}{(1+a)^z} \tag{5}$$

where: PV: present value (€), SE: saved energy per year (kWh), 30,160 kWh in this case as shown in Table 12, c: cost/kWh for the initial year (0.08 €/kWh), b: 3.5% annual value increase, almost equal to the inflation, a: nominal discount rate 8%, and z: year of analysis.

Expression (5) yields for the total benefit due to loss reduction implementation in the aforementioned payback time 36,350 €.

5.5. Overall benefit due to the implementation of automation techniques

Table 13 presents the investment cost concerning the MAS implementation on the regarded power distribution network segment, versus the overall profits and benefits, which stem from the MAS operation for a payback time period of 25 years. The MAS is considered to be an automation technique of typical requirements, and the regarded profits and benefits are considered for the two

Table 13
MAS implementation cost versus overall profits and benefits.

MAS implementation cost (€)	1,066,400
DSO profit from fault detection and power restoration (€)	44,476
Customer benefit from fault detection and power restoration (€)	1,037,574
DSO benefit from loss reduction (€)	36,350

basic MAS operations analyzed in this work, namely fault detection and power restoration, as well as loss reduction.

As shown in Table 13, the total profits and benefits due to the MAS implementation concern both the DSO, as well as its customers. Moreover, as it can clearly be observed, the combined profits and benefits for the DSO are not sufficient to justify the investment. However, as aforementioned, for the evaluation of the investment the customer benefit should also be taken into consideration [14]. In this case, it can be deduced that the MAS implementation is feasible.

6. Conclusions

In this work, the feasibility of a power distribution automation system of typical hardware requirements is investigated. More specifically, a Multi Agent System proposed in the literature is considered which initially offers fault detection and power restoration functions. The MAS is considered to be implemented on a real power distribution network segment located in Thessaloniki, Greece, for which all operational data is available over a time period of one year. A full analysis is conducted regarding the investment cost, as well as the profits and benefits that stem for both the DSO and its customers due to the MAS implementation. Moreover, it is explained that any power distribution automation system shall provide services additional to its initial purpose in order to maximize the benefits of its implementation. In this context, the regarded MAS is considered to incorporate via a software upgrade a simple heuristic algorithm concerning loss reduction. The additional benefits produced for the DSO due to the loss reduction technique implementation are also specified. Finally, the initial investment cost of the MAS implementation is compared with the combined profits and benefits that the system will produce for both the DSO and its customers. From this procedure it is deduced that taking into consideration the customer benefits, the MAS implementation is feasible.

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