This article has been accepted for publication in a future issue of this journal, but has not been fully edited. Content may change prior to final publication. Citation information: DOI 10.1109/TPWRD.2014.2366436, IEEE Transactions on Power Delivery

Prioritizing the Restoration of Network Transformers using Distribution System Loading and Reliability Indices

Roupchan Hardowar, *Member, IEEE,* Sergio Rodriguez, *Member, IEEE,* Resk Ebrahem Uosef, *Member, IEEE,* Francisco de León, *Senior Member, IEEE,* and Dariusz Czarkowski, *Member, IEEE*

***Abstract* – A method is proposed to prioritize the repair or replacement of out-of-service transformers that feed a heavily meshed secondary grid. Priority assigned to restoration of a specific transformer is based on the risk reduction that results from this replacement. Risk is defined as the reduction in the probable number of customers out of service should the transformer return to service. This measure of risk addresses both the possibility of network collapse following feeder failures (occasioned by load induced failure of transformers or feeders) and local customer impact on the secondary network. The prediction of risk makes extensive use of load predictions for feeder sections, network transformers, and secondary mains. A software tool has been developed implementing the equations proposed in this paper. This software gives system planners and operators the ability to quickly and economically select the next transformer to be repaired or replaced.**

***Index Terms*—Distribution system contingency analysis, line out distribution factor, network reliability, risk assessment.**

I. Nomenclature

$RiskIndex$	Sum of impacted customers created by having a transformer remaining out of service.
T_i	Transformer index; represents the difference between transformers taken out of service and when they are back in service.
α	Equipment loading divided by equipment rating.
δ_1	Probable number of customers interrupted as a result of transformer overloads.
δ_2	Probable number of customers interrupted as a result of primary feeder overloads.
δ_3	Probable number of customers interrupted as a result of secondary mains overloads.
NC	Number of customers served.
NT	Numbers of transformers that pick up new additional when a transformer is out of service.
NF	Numbers of feeders that pick up new load when a transformer is out of service.
SM	Number of secondary mains that are overloaded as a result of a transformer being out.

R. Hardowar, S. Rodriguez, and R. Uosef are with Consolidated Edison Company, New York, NY 10003 USA (e-mail: hardowarr@coned.com rodriguezse@coned.com, uosefr@coned.com).

F. de León, D. Czarkowski are with the Department of Electrical and Computer Engineering of New York University, Six Metrotech Center, Brooklyn, NY, 11201 USA (e-mail: fdeleon@nyu.edu , dc1677@nyu.edu).

II. Introduction

CONSOLIDATED Edison Company of New York, Inc. operates the world's largest underground electric system [1]. In New York City alone, Con Edison supplies electric service to 7,700,000 people through a complex electric distribution system comprising 64 second contingency networks, nearly 29,000 network transformers, and over 85,000 miles of underground cables, including primary feeders, secondary mains, and customer service cables. Individual customers are served by a low voltage secondary grid which in turn is supplied by feeders through network transformers; see Fig. 1. In such a large and complex system, some 300 to 600 transformers are typically out of service at any given time awaiting upgrade, maintenance, or repair. Although this is less than 2% of the network transformer population, significant financial, planning and operational resources are required to restore a transformer. In order to manage the economical restoration of network transformers effectively, an optimization algorithm is required to standardize transformer impact and execute a "system need" restoration philosophy. This paper presents such a method.

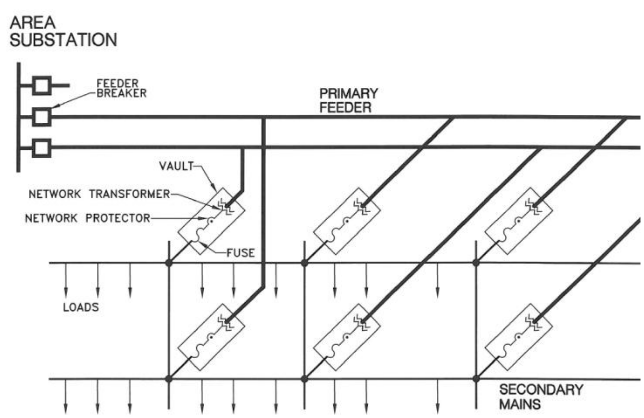

Fig. 1. Overview of network distribution system.

Distribution system planning relies on contingency analysis to identify weak links. First and second contingency (*N*-1 and *N*-2) design criteria are intended to ensure that the electric distribution system can sustain the loss of one or two feeders at peak system load without effecting electric service and keeping equipment operating within design limits.

Emergency Management Systems (EMS) makes use of real-time analysis of data obtained from the network to assist distribution system operators in making better decisions. The application of power flow [2], line outage distribution factors [3], and the bounding method [4] provides the tools necessary

This article has been accepted for publication in a future issue of this journal, but has not been fully edited. Content may change prior to final publication. Citation information: DOI 10.1109/TPWRD.2014.2366436, IEEE Transactions on Power Delivery

to efficiently identify where equipment overloads may occur because of out-of-service feeders and transformers. Network reliability software is used to predict the vulnerability of networks from cascading failures of primary feeders and widespread damage to the secondary grid.

The most important computation tools used by the EMS utilize contingency analysis and security risk analysis algorithms [5]. While numerous power flow methods for contingency analysis have been proposed for system planning [6], [7], it was found that for a large heavily-meshed underground network, the Z-bus matrix method is preferred [2]. In response to feeder failures, EMS evaluates current and anticipated conditions to identify situations that might result in violations of equipment loading criteria. With this capability, system operators are able to develop plans and operating strategies to mitigate such a potential emergency. In particular, constructing the system Z-bus matrix [2], [8] and running the power flow identifies loading on nearby network transformers.

A. Related Work

The Line Outage Distribution Factor (LODF) method is used primarily in power systems to approximate the change in the flow on one line caused by the outage of another line [3], [9], [10]. While this method is employed mostly in transmission systems [11],[12], nothing precludes its use to model distribution systems. In this method, a change in flow, ΔI_{jk}, in a branch connected between nodes j and k is caused by a change in flow of injected current, ΔI_{mn}, at bus m (see Fig. 2) and then the modified branch flows or LODF are calculated accounting for the known contingencies as:

$$LODF_{jk,mn} = \frac{\Delta I_{jk}}{\Delta I_{mn}} \tag{1}$$

The calculated line outage distribution factors and the bounding method allow for the identification of transformers subjected to significant load stress as a result of nearby out of service network transformers. The bounding method states that neighboring components pick up load in amounts that diminish with distance [12], [13], and [14]. This approach has been employed for evaluating branch outages, generating unit outages, and load outages [13] on the power transmission and distribution system, but to our knowledge has not been employed to rank distribution system restoration efforts. It does evaluate transformers loading, but ignores the impact of secondary mains and primary feeders.

Network transformers are monitored in real-time using the Remote Monitoring System (RMS) that employs Power Line Carrier (PLC) technology to collect the following real-time data: status of the transformers and associated network protectors, the load they carry, voltages and temperatures, a sample is shown in Table I. Network transformers can be out of service for a number of reasons: tank leaks, damaged network protector fuse, blocked open, upgrades, maintenance, and testing.

During a heat-wave, when temperature is up and equipment loading goes up, it is desirable that all transformers be in service to prevent overloads and maximize voltage quality. The current ad-hoc method employed for transformer restoration can be improved and streamlined to optimize cost and reduce dependence on the legacy resource intensive manual approach. The approach also requires running numerous power-flow studies to help identify heavily loaded areas. Forecasted increase in loading and temperature, moves network transformer ranking up or down in areas where demand changes significantly.

Although contingency analysis tools and real-time system conditions have provided ample data on transformer loading, no rigorous tool is available as yet to prioritize the return of transformers to service.

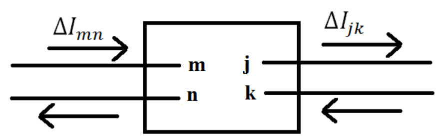

Fig. 2. Line flow as a result of injected current at bus *m*.

TABLE I
SAMPLE RMS DATA COLLECTED FROM NETWORK TRANSFORMERS

Transformers	nby	fdr	m&s	status	Loads(%)			Voltages			Temperature	
					A	B	C	A	B	C	T/Oil	H/Spot
VS00224	6	RM01	7G	closed	44	47	44	123	124	124	27	1.7
VS00823	6	RM02	3H	closed	18	18	18	124	124	124	17	2.6
V 01554	6	RM03	7G	closed	20	36	36	124	124	124	22	1.4
VS01797	6	RM04	3G	closed	36	39	39	124	123	124	0	3
V 01836	3	RM05	6G	closed	23	23	23	124	274	124	17	2.5
VS01928	6	RM06	3H	closed	26	28	26	123	124	124	24	2.5
VS02439	6	RM07	3H	bankOff	0	0	0	0	0	0	0	0
VS02922	6	RM08	3H	closed	18	20	18	124	122	124	17	0.2
VS03911	6	RM09	3H	closed	24	24	22	124	124	124	19	1.4
V 04417	6	RM10	7G	closed	34	36	36	124	124	124	19	2.5
VS04644	6	RM11	3H	closed	23	23	23	124	124	124	14	1.9

B. Contributions of the Paper

The contributions of this paper are: (1) propose a rigorous and robust algorithm to rank the replacement of network transformers; and (2) validate and use the proposed algorithm to rank 300-600 network transformers replacement on a large meshed distribution network.

The developed computer program runs an iterative process of power flow and network reliability evaluation, replacing one out of service network transformer at-a-time, which computes loading and reliability indices, then computes the load contribution while having individual transformers out of service. This computed load contributions is normalized by the number of customers per network to prioritize the return to service of network transformers. The algorithms analyze and quantify the contribution to risk of each out-of-service network transformer and rank the benefit that will ensue should a transformer be restored.

III. FORMULATION OF RISK INDEX USING THREE TYPES OF DISTRIBUTION SYSTEM EQUIPMENT

The proposed approach to prioritizing the restoration of out-of-service transformers relies on experience, data and tools

This article has been accepted for publication in a future issue of this journal, but has not been fully edited. Content may change prior to final publication. Citation information: DOI 10.1109/TPWRD.2014.2366436, IEEE Transactions on Power Delivery

developed in recent years to predict loads in networks, and network reliability performance.

The contribution to risk associated with an out-of-service transformer is defined in terms of the reduction in the anticipated number of network customers who will lose service in a specified time period (e.g., the duration of a heat wave) should the transformer not be returned to service, all other out-of-service transformers remaining out of service. Risk, of course, can also be expressed in terms of a contribution to the likelihood customers would be exposed to low voltage; voltage reduction is a measure that is used to lower the risk of collapse on a highly stressed network. Risk might also be expressed in terms of the financial risk to customers and the utility that results from the loss of power or voltage reduction. An attractive feature of the proposed measures of risk is that it can be applied system-wide rather than be limited to providing guidance for transformer restoration within a single network.

By examining all out of service transformers, the transformer that contributes most to risk is identified and its return to service is given priority. This process is then repeated to prioritize the subsequent return to service of other transformers.

Both planning and emergency response functions within the utility benefit from this approach. Prioritizing the restoration of out-of-service transformers helps to prevent operational problems during the high-load summer months. This is particularly important to prevent failures caused by overloading during system peak-time when resources are in higher demand. This method avoids the costly and ineffective dispatch of field crews to return low priority transformers to service. The risk index proposal allows resources to be reallocated to where they are needed the most.

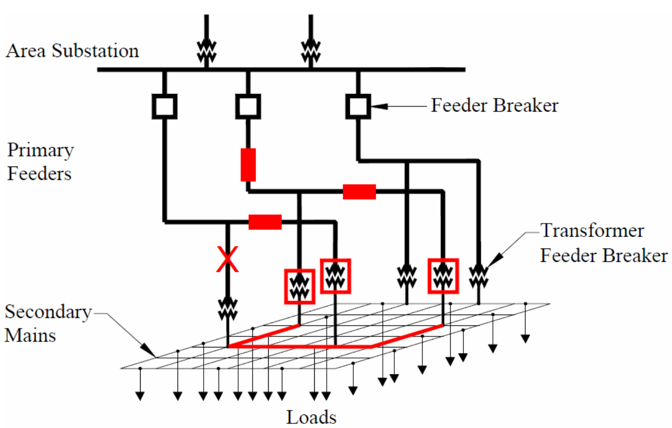

Fig. 3. Other sections pick up load with a transformer out.

A. Goal

To identify the out-of-service transformers that contribute most to the risk of customer impact resulting from load shift on transformers, feeder sections, secondary mains, and other out-of-service transformers and feeders.

B. Operations

Risk can be accessed in response to the evolving network status in response to multiple feeder and transformer feeder during a heat wave. The restoration of a transformer to service results in lower loads on other transformers and therefore decreases the likelihood of their failure. Fig. 3 illustrates how a transformer out of service affects other transformers, feeders and secondary mains.

The reduced risk a transformer out of service and the benefits obtained by returning it into service are characterized by the following equation:

$$T_i = (RiskIndex)_{i\ out\ of\ service} - RiskIndex_{\ i\ in\ service} \tag{2}$$

The risk index itself is expressed as a sum of the likely number of customer impact that will result from the failure, out of service, of overloaded transformers, feeders, and secondary mains as:

$$RiskIndex = \delta_1 + \delta_2 + \delta_3 \tag{3}$$

where: δ_1 is the probable number of customers interrupted as a result of transformer overloads, δ_2 is the probable number of customers interrupted as a result of primary feeder overloads, and δ_3 is the probable number of customers interrupted as a result of secondary mains overloads. A factor α measures the relative load of every equipment and is computed as:

$$\propto = \frac{equipment\ loading}{equipment\ rating} \tag{4}$$

The number of customers impacted as a result of other transformers that have increase loads is computed as:

$$\delta_1 = NC \sum_{j=1}^{NT} f(\propto_j) \tag{5}$$

where:

NC is the number of customers served by the network.

NT is the number of transformers that pick up additional load when a transformer is out of service.

$f(\propto_j)$ is the probability of a load induced failure of an in-service transformer participating in network collapse.

Function $f_1(\propto_j)$ is a monotonically increasing function of transformer load developed from the analysis of historical transformer failure given by:

$$f(\propto_j) = f_1(\propto_j)(c_j) \tag{6}$$

where:

$f_1(\propto_j)$ is the probability of transformer failure given its relative load α_j.

c_j is the conditional probability of network collapse after the failure of transformer j and the feeder that serves it.

The probable number of customers interrupted as a result of other feeders picking up the load for a given set of transformers and feeders that are out of service is:

$$\delta_2 = NC \sum_{k=1}^{NF} g(\propto_k) \tag{7}$$

where:

NF is the number of feeders that are overload

$g(\propto_k)$ is the probability of a load-induced failure of feeders participating network collapse. This term is defined as:

$$g \propto_k \ = g_1(\propto_k)(d_k) \tag{8}$$

where:

$g_1(\propto_k)$ is the probability of feeder k failing given its load α_k.

d_k is the conditional probability of network collapse after the failure of feeder k.

Function $g_1(\propto_k)$ is a monotonically increasing function of feeder load developed from the analysis of historical feeder failure data as a function of load, ambient temperature, and feeder composition.

Finally, the predicted number of customer impact that will result from overloaded secondary mains is calculated as follows:

$$\delta_3 = \frac{Increment\ in\ Load}{Average\ Load\ per\ Customer} \tag{9}$$

This calculation addresses the restoration of customers who are already without power as a result of the transformer restoration. It does not, however, address the avoidance of load induced failure of secondary mains and additional customer impact that might otherwise be avoided were the transformer restored.

The equation of δ_3 is determined from overloaded secondary mains that are then assumed to be burned out. It is assumed that the unrelieved overload of secondary mains will result in their failure, thereby affect customers. After their failure, loads are dropped, and this is then converted to number of customers that are dropped as a result of the burned out secondary mains.

C. Planning

The application of the approach described above in planning the non-emergency restoration of out-of-service transformers can be made by either evaluating the risk associated with a number of diverse heat wave scenarios or by simulating the reliability performance of the network and secondary grid and then ascertaining the contribution to customer impact made by each out-of-service transformer.

D. Network Reliability functions and Conditional Probabilities

When the software developed is executed, variables c_j and d_k are calculated in real-time, using current network condition with possible primary feeders out, using the network reliability simulation module. The Network Reliability Evaluator (NRE) is an operating tool that predicts the likelihood of cascading network failures and possible network collapse in a heat wave, given existing feeder contingencies, predicted network loads, and ambient temperatures. In this tool a what-if scenario computes the conditional probability of cascading failures should another feeder fail. For feeder k, the network collapse after its failure is d_k. Similarly, for transformer j fed by feeder k, the conditional probability of network collapse after the failure of the transformer j is c_j.

E. Implementation

Once the reductions in risk have been calculated for the restoration of out-of-service transformers, one at a time, transformers are assigned a rank. The control center can use the resulting list to restore transformers in order of priority.

If there are nine transformers on the banks-off list, all are taken out of the network model and power flow is run. All overloads (transformer, primary feeder sections, and secondary mains) are identified. With one of the banks replaced and all other eight banks out. This process is repeated for each out-of-service bank and results in a total of ten power flow simulations.

IV. Failure Rates of Equipment

The failure rates used for feeder sections, joints, transformers, and other equipment are those used in network reliability models. They reflect temperature, load, the age and type of equipment presence of multiple feeders within a manhole, and other factors found to impact reliability.

As illustrated in Table II, eight transformers are out of service simultaneously and cause eight other transformers to pick up the load. These are the loading conditions that are used in (5). The overloads refer to transformer operating above their normal ratings. When all out of service, in this case we have 8 transformers, they are all taken out simultaneously from the power flow model, and they caused an additional 8 transformers to be overloaded.

TABLE II
OVERLOADS WITH ALL BANKS OFF SIMULTANEOUSLY

Transformers Out	Transformers overload	% Overloads
V1	V25	152
V2	V21	145
V3	V20	140
V4	V26	135
V5	V24	120
V6	V23	110
V7	V22	103
V8	V27	103

V. Impact Of Temperature and Load

A. Temperature Impact on Transformer Reliability

Transformer ratings reflect a number of factors: tank design, mass of oil and metal, design criteria such as top-oil and hot-spot temperature, vault conditions, daily load factors, and operating ambient temperature. Fig. 4 depicts the loading of a typical distribution network where the network peak load is at 7 pm, which is typical of a residential neighborhood. This loading indicates that the network transformers are heavily loaded two times per day 11 am and 7 pm.

The maximum allowable load on a transformer is defined as the maximum peak load that can be safely applied to a given transformer such that neither the calculated hot spot nor the top oil temperatures exceed their respective maximum allowable temperatures limits. In the IEEE algorithm [15], equations consider these factors which are implemented in a computer program, thereby giving each transformer on the network a calculated rating based on its individual characteristics.

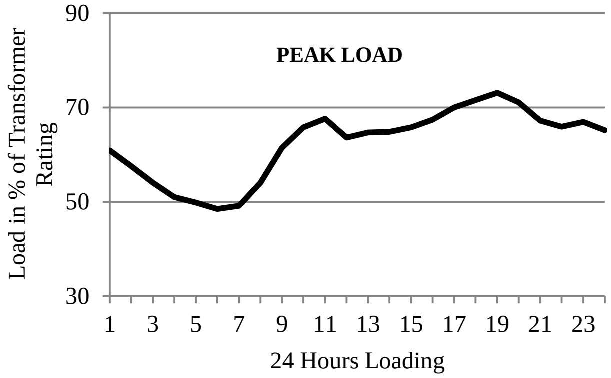

Fig. 4. Typical residential load cycle with a double peak.

Should transformers be allowed to operate at loads in excess of this rating, their failure rates will increased rapidly; see Fig. 5. As the percent loading goes up on the transformer, its failure rate goes up. This was computed using historical data of loading and temperatures collected from transformers over the past 10 years.

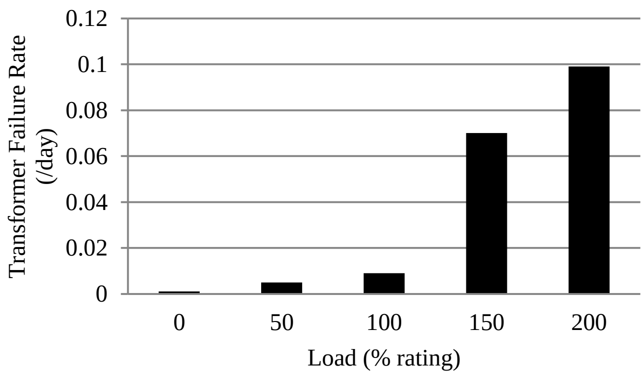

Fig. 5. Failure rate as a function of the prevailing load [16].

B. *Temperature and Load Impact on Primary and Secondary Cables*

The continued exposure of secondary cable to loads in excess of their normal ratings will result in cable failure. A secondary network served by network transformers is depicted in Fig. 6. Transformer V1234 is one of the transformers out of service, its loading at bus compartment BC1234 will have no interruption since there is a street tie to manhole, M55555. However, the secondary mains from M55555 to SB999 will carry the new load and therefore become overloaded. We also see that there are three primary cables RM01, RM02, and RM03 feeding this network area.

The effect of temperature on primary underground cable has been well characterized. As the loading shift to other cable sections on the secondary grid, the temperatures in the ducts also rise. Joints and cable sections of specific types and age exhibit widely different failure rates; see Fig. 7. These variations can be distinguished from the effect of loads.

VI. Risk Index Algorithm

The customers' impact calculation is performed as shown in Fig. 8. The equations proposed in this paper were implemented in a computer program: PlanRealStat. The program is executed each day with the known banks-off and the resulting ranking data are published to the local intranet. System planners use the recommendations to implement improvements to the grid for the next summer peak.

The program is also used under real-time system conditions. System known conditions with all banks-off (transformers that are out of service), feeder(s) out, and open-mains (secondary cables that are burned out) data are input into the program. Operations use the program to make last minute decisions on system hardening before the next-day heat wave. The following operations are performed:

1) **Power Flow**: compute α of feeder, transformers, and secondary mains before and after the restoration of an out-of-service transformert
2) Identify failure rates of individual components.
3) **Network Reliability**: compute probability of contingencies needed for individual transformers and feeder calculation (c_j, d_k).

where:

α Equipment loading divided by equipment rating

c_j, d_k Conditional probability of equipment failure

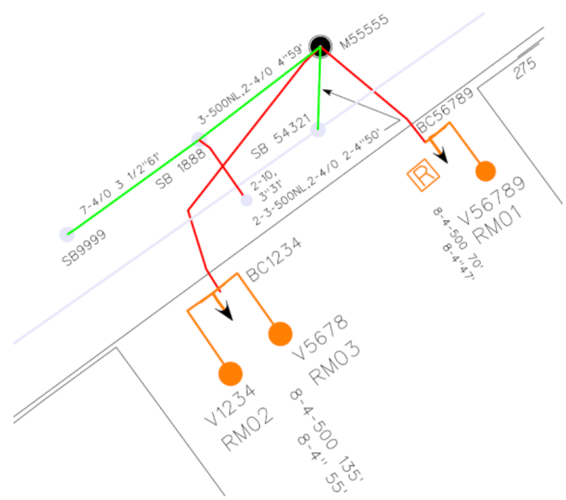

Fig. 6. Secondary mains where overloads occur.

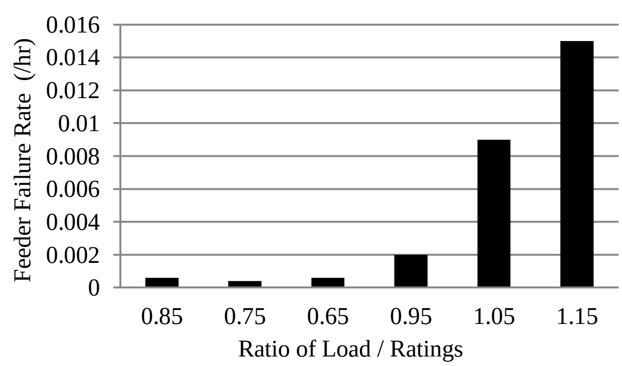

Fig. 7. Feeder failure rate as a function of load at 85 °F [16].

This article has been accepted for publication in a future issue of this journal, but has not been fully edited. Content may change prior to final publication. Citation information: DOI 10.1109/TPWRD.2014.2366436, IEEE Transactions on Power Delivery

TABLE III
TRANSFORMER(S) OVERLOADS IMPACT AS A RESULT OF TRANSFORMER V7769 REPLACED

Network Impacted Transformer when V7769 Replaced	Network Feeders	Loading with Transformers Out	Loading with "a" Transformer Replaced	Reduction in Feeder Failure Rate ($x10^{-3}$)	10M04	10M05	10M06	Measure of Impact
					Total Contribution to Feeder failure and Network Collapse ($x10^{-3}$)			
TM1879	10M05	165	154	11	0	11	0	
V1878	10M04	111	103	8	8	0	0	
V399	10M04	157	155	2	2	0	0	
V4534	10M02	122	117	5	0	0	0	
V8773	10M04	166	160	6	6	0	0	
VS459	10M06	148	142	6	0	0	6	
VS8725	10M05	110	106	4	0	4	0	
					20	20	10	
					63.08	36.17	26.87	**126**

TABLE IV
PRIMARY FEEDER OVERLOADS IMPACT AS A RESULT OF TRANSFORMER V7769 REPLACED

	Feeders	10M01	10M02	10M04	10M05	10M06	10M12
All Measures Considered	Rating	757	830	723	455	450	450
Feeder Loading when all Transformers are Out and when VS7769 is Replaced	VAll	1003.60	1117.80	1044.10	723.50	586.50	536.70
	VS7769	1009.30	1118.80	1083.00	710.60	577.50	533.50
Feeder Load / Feeder Normal Rating	VAll	1.33	1.35	1.44	1.59	1.30	1.19
	VS7769	1.33	1.35	1.50	1.56	1.28	1.19
Failure rate multiplier (allowing for load effects)	VAll	6.21	6.55	8.11	10.44	5.85	4.08
	VS7769	6.33	6.57	8.97	9.99	5.53	3.97
Ratio of failure rates	VS7769	1.02	1.00	1.11	0.96	0.95	0.97
Considering likelihood of network collapse given failure ($x 10^{-3}$)	VS7769	0.11	0.02	0.51	-0.13	-0.07	-0.01
Measure of Customers Impact							**16.23**

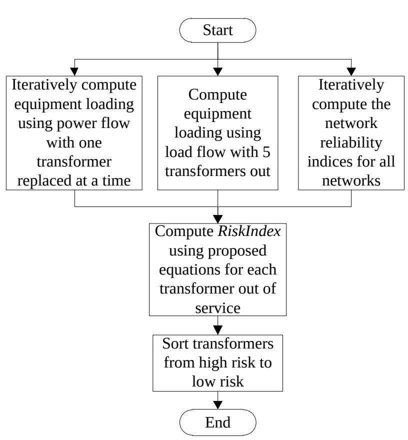

Fig. 8. Implementation of the proposed method.

VII. NUMERICAL EXAMPLE

A numerical example is presented in this section to illustrate the process of using the proposed risk index equations. All calculations are performed for a network with 16 primary network feeders and 347 network transformers serving 38,275 customers. Network performance during a heat wave is considered with two primary feeders, 15 transformers, and 121 secondary mains out of service.

A transformer that is taken out of service poses risk to other transformers by having them pick-up its load and therefore become overloaded. As a result of the overload, the secondary mains and primary feeders in the vicinity of the overloaded transformer become overloaded in turn. These changes in feeder load also result in an increased probability of failure.

These effects are described in (3) with an example given in Table III. The customers' impact is calculated where there are five out of service transformers and they are replaced one at a time. We can see that by replacing V7769, 126 customers are relived from potential low voltage, or being dropped from the grid. Calculating the risk index shows the impact on the likelihood of network collapse of having a transformer out of service (5). A ratio is calculated using the transformer loading and the transformer rating.

A transformer that is taken out of service results in the redistribution of load and thus possibly load-induced feeder failures and a greater likelihood of network collapse. A relative load is calculated using the feeder loading and the feeder rating. This ratio is then summed as shown in Table IV and is computed in (7). As a result of replacing V7769, we can see that there are 16 customers relieved from potential network problems.

Finally, secondary network mains are also impacted by having a transformer taken out of service and therefore, secondary mains sections overload contributes to the risk index. If there are 35 secondary mains that get overloaded, we assume that they get burned out and therefore remove all 35 from the model and then identify the total load that gets drop. Table V shows that when transformer VS7769 is out of service, 1.33 potential customers get dropped.

The reduction in risk resulting from the restoration of a single transformer to service is calculated for each out-of-service transformer. Table VI presents the results from ranking one distribution network with five transformers out of service. There are five network transformers that are out of service in the example. The wide variation in risk reduction makes prioritization easy in this case. If one would replace one transformer on this network, it should be transformer VS7769. A second transformer to be replaced is V508. The two transformers that have zero impact will be considered the next day when the software analyzes the new system conditions. The network condition changes daily as a result of work being done, failure of equipment, or newly added customers.

TABLE V
SECONDARY FEEDER SECTIONS OVERLOADS

	kVA Dropped	Customer Impacted
VAll	20	2.21
VS426	0	0.00
V2544	8	0.88
V1278	0	0.00
V508	0	0.00
VS7769	12	1.33

TABLE VI
RISK RANKING OF HAVING TRANSFORMERS OUT OF SERVICE

Transformer Replaced	Transformer Impact	PrimaryFeeder Impact	Secondary Mains Impact	Total Impact
VS426	0.00	0.00	0.00	0
V2544	3.94	0.07	0.88	5
V1278	0.00	0.00	0.00	0
V508	7.88	0.00	0.00	8
VS7769	126.12	16.23	1.33	144

Table VII shows a subset with the rank for a large meshed distribution networks where some transformers from a particular network will have less impact compared to others from other networks. From this table, system operators can quickly identify networks where crews must immediately be dispatched for transformer replacement. From an economic perspective, funding can be sent to regions that have networks with highest impact. The network numbering is not in numerical order since a transformer on one network may have a higher impact than a transformer from a different network.

It was determined that 44% of network transformers that were out of service have no system impact on network loading under contingency N-2. These transformers will be reconsidered on a daily bases when the software is run. With a change in customer demand and new customers added to the neighborhood, these transformers may deem needed again; else they can become candidates for relocation.

TABLE VII
RISK RANKING FOR ALL NETWORKS IN A LARGE DISTRIBUTION AREA

Networks	Transformers	Probable Customer Impact
Network (1)	V1	202
	V2	190
Network (2)	V18	186
Network (3)	V21	104
Network (2)	V4	101
Network (1)	V22	98
Network (2)	V18	55
…	…	…

VIII. CONCLUSIONS

A method to prioritize the repair or replacement of network transformers has been proposed. The method has been implemented in software that is used to rank all existing networks on a large distribution system with 300-600 transformers out of service at a given time. Because of the large number of transformers to be replaced, manual efforts needed to run numerous power flow studies and visual identification of maps have proven to be costly and error prone.

The method proposed in this paper intends to target spending and concurrently maximize system reliability. Transformers with high impact on the networks will have high prioritization for replacement and are replaced immediately. Transformers with no impact at all will be left unchanged for the next year and then be considered again (because of load growth in the area).

The method developed in this paper is of general applicability. It has been used for the prioritization of transformer replacement. However, it can also be applied for the prioritization of secondary mains replacement.

ACKNOWLEDGMENT

The authors would like to thank the following people for their time and support: David Allen, Peter Van Olinda, and Mohamed Kamaludeen.

This article has been accepted for publication in a future issue of this journal, but has not been fully edited. Content may change prior to final publication. Citation information: DOI 10.1109/TPWRD.2014.2366436, IEEE Transactions on Power Delivery

REFERENCES

[1] U.S. DOE. (2103), "Bright Lights, Big City: A Smarger Grid in New York," https://www.smartgrid.gov/.

[2] L. Powell, *Power system load flow analysis*. New York: McGraw-Hill, 2005.

[3] Y.-C. Chang, W.-T. Yang, and C.-C. Liu, "Improvements on the line outage distribution factor for power system security analysis," *Electric Power Systems Research*, vol. 26, pp. 231-236, 1993.

[4] V. Brandwajn, "Efficient bounding method for linear contingency analysis," *IEEE Trans. Power Del.*, vol. 3, pp. 38-43, 1988.

[5] V. Glamocanin, D. Andonov, M. Kacarska, and B. Stojkovska, "Efficient screening method for branch contingency selection of overloads," in *Electrotechnical Conference, 1998. MELECON 98., 9th Mediterranean*, 1998, pp. 901-905 vol.2.

[6] J. Kang, W. Ma, L. Fu, and F. Ma, "A load flow method using line-to-line voltages for ungrounded distribution power systems," in *Electric Utility Deregulation and Restructuring and Power Technologies, 2008. DRPT 2008. Third International Conference on*, 2008, pp. 1205-1210.

[7] M. Ramamoorty and B. J. Seshaprasad, "An improved method for load flow studies of large power systems," *India, IEE-IERE Proceedings -*, vol. 9, p. 93, 1971.

[8] T. H. Chen, C. Mo-Shing, K. J. Hwang, P. Kotas, and E. A. Chebli, "Distribution system power flow analysis-a rigid approach," *IEEE Trans. Power Del.*, vol. 6, pp. 1146-1152, 1991.

[9] Gu X. T. ler, G. Gross, and L. Minghai, "Generalized Line Outage Distribution Factors," *IEEE Trans. Power Del.*, vol. 22, pp. 879-881, 2007.

[10] G. Jiachun, F. Yong, L. Zuyi, and M. Shahidehpour, "Direct Calculation of Line Outage Distribution Factors," *IEEE Trans. Power Del.*, vol. 24, pp. 1633-1634, 2009.

[11] G. C. Ejebe and B. F. Wollenberg, "Automatic Contingency Selection," *IEEE Trans. Power App. Syst.*, vol. PAS-98, pp. 97-109, 1979.

[12] F. D. Galiana, "Bound Estimates of the Severity of Line Outages in Power System Contingency Analysis and Ranking," *IEEE Trans. Power App. Syst.*, vol. PAS-103, pp. 2612-2624, 1984.

[13] J. L. Carpentier, P. J. Di Bono, and P. J. Tournebise, "Improved efficient bounding method for DC contingency analysis using reciprocity properties," *IEEE Trans. Power Del.*, vol. 9, pp. 76-84, 1994.

[14] L. Wehenkel, M. Glavic, and D. Ernst, "Multi-Area Security Assessment: Resuits using Efficient Bounding Method," in *Power Symposium, 2006. NAPS 2006. 38th North American*, 2006, pp. 511-515.

[15] "IEEE Guide for Loading Mineral-Oil-Immersed Transformers," *IEEE Std C57.91-1995*, pp. 1-112, 2012.

[16] D. Allen, "Distribution Reliabiltiy Course Con Edison," 2012.

Roupchan Hardowar (S'98–M'08) received his B.Sc. and M.Sc. degree in electrical engineering from the Polytechnic School of Engineering of New York University (NYU-Poly), Brooklyn, New York, in 2004 and 2009 respectively and is currently pursuing his Ph.D. degree in electrical engineering at the same institution.

His work experience at Consolidated Edison includes: network distribution primary cable ratings, smart meters data quality, and mesh network/non-mesh network systems reliability.

Sergio Rodriguez (M'14) received his B.Sc. degree in electrical engineering from the State University of New York (SUNYIT - SUNYISET), Utica, New York 2005 and in 2009 received M.Sc. also in electrical engineering from Manhattan College, Riverdale, NY.

His work experience at Consolidated Edison includes: Design, construction, operations, and maintenance of electric power distribution networks for Con Edison of New York.

Resk Ebrahem Uosef (M'01) received the B.Sc. and M. Sc. degrees in electrical engineering from Alexandria University Faculty of Engineering, Alexandria, Egypt, in 1979 and 1981, respectively. He received a second M.Sc. degree and the Ph.D. degree in electrical engineering from Polytechnic University, Brooklyn, NY, in 2007 and 2011, respectively.

He was an engineer in a hydropower generating station in Egypt, and then he was the owner of a consulting firm for an electric construction company in Egypt. He joined Distribution Engineering Department, Consolidated Edison, New York, in 2003, and is currently responsible for Con Edison's distribution system design and analysis.

Dr. Uosef is a Registered Professional Engineer in the State of New York.

Francisco de León (S'86–M'92–SM'02) received the B.Sc. and the M.Sc. (Hons.) degrees in electrical engineering from the National Polytechnic Institute, Mexico City, Mexico, in 1983 and 1986, respectively, and the Ph.D. degree also in electrical engineering from the University of Toronto, Toronto, ON, Canada, in 1992.

He has held several academic positions in Mexico and has worked for the Canadian electric industry. Currently, he is an Associate Professor in the Department of Electrical Engineering at New York University, Brooklyn, NY. His research interests include the analysis of power phenomena under nonsinusoidal conditions, the transient and steady-state analyses of power systems, the thermal rating of cables and transformers, and the calculation of electromagnetic fields applied to machine design and modeling.

Dr. de León is an Editor of the IEEE Transactions on Power Delivery and the IEEE Power Engineering Letters.

Dariusz Czarkowski (M'97) received the M.Sc. degree in electronics from the University of mining and Metallurgy, Cracow, Poland, in 1989, the M. Sc. degree in electrical engineering from Wright State university, Dayton, OH, in 1993, and the Ph.D. degree in electrical engineering from the University of Florida, Gainesville, in 1996.

In 1996, he joined the Polytechnic Institute of New York University, Brooklyn, NY, where he is currently an Associate Professor of electrical and computer engineering. He is a coauthor of Resonant Power Converters (Wiley Interscience, 1995). His research interests are in the areas of power electronics, electric drives, and power quality.

Dr. Czarkowski has served as an Associate Editor for the “IEEE Transactions on Circuit and Systems”.