21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2021 Grid of the Future Symposium

Using Prescriptive Analytics to Optimize Electrical Distribution System Maintenance and Upgrades

D.A. TARVIN
Burns & McDonnell
USA

SUMMARY

Our aging electrical-distribution system is driving utilities toward strategic replacement of assets. When wires and poles were mostly new, a run-to-failure approach worked: failures were rare, and the resulting costs were low. Today, pre-emptively replacing the most-vulnerable and most-critical assets can reduce system-wide risks and add value for utilities and their customers. We formulate a utility client's distribution-system maintenance and upgrade problem as a mixed-integer program, which seeks to maximize total system-wide risk reduction while complying with budgetary and other constraints. We present computational results for a particular use case and describe further extensions.

KEYWORDS

Utility Analytics, Distribution Modernization, Capital Planning, Optimal Scheduling

datarvin@burnsmcd.com

INTRODUCTION

Before the outbreak of World War II, the United States set upon a path toward universal electrification. The Tennessee Valley Authority Act of 1933 (16 U.S.C. § 831K) authorized the Tennessee Valley Authority (TVA) to construct transmission lines that would enable the sale of TVA-generated power and provide transmission capacity for other generators. Soon after, the Rural Electrification Act of 1936 allowed for federal loans to support the development of electricity distribution systems in rural areas nationwide (7 U.S.C. § 904). In the years immediately following World War II, the nation's electricity network witnessed remarkable growth. The National Rural Electric Cooperative Association describes two-, three-, and five-fold increases in rural electricity systems, electricity consumers, and miles of energized lines, respectively [1]. This remarkable growth connected millions of previously unserved Americans to the power system and fostered economic expansion in previously underdeveloped regions. The rapid pace of development also provided an additional benefit to utilities; brand new transmission and distribution systems rarely experience failures and require little in the way of preventative maintenance. Utilities could trust in the reliability of their networks and make use of a "run-to-failure" approach to asset replacement.

Today, many utilities face a fast-approaching a wall of aging infrastructure. As far back as 2013, the American Society of Civil Engineers (ASCE) warned of increasing power disruptions and other reliability issues resulting from aging energy infrastructure equipment [2]. The all-new distribution systems of the 1950s have become today's largely antiquated ones. Yesterday's run-to-failure approach is no longer a viable strategy when a large share of a network's components teeter on the brink of failure. Ever-increasing system load compounds the challenges of an aging network. Growth in both the number of customers and in individual customers' demands further burden distribution systems, shortening component lifespans and weakening overall network reliability. The forthcoming growth in distributed generation via photovoltaic and wind resources will present other, previously unforeseen complications. The ASCE's most recent infrastructure assessment notes that utilities have recently increased investment and decreased outages. However, the Society cautions that additional infrastructure and improvements in reliability will be needed in the future [3].

Utilities must consider aging infrastructure in light of their obligations to customers, members, shareholders, and many others. Each utility continually balances efficiency, safety, reliability, and security. Like all businesses, utilities strive to be good stewards over resources of all types and over the environment more broadly. An entirely new, built from scratch distribution system might provide the greatest possible reliability. However, such a net-new system would be prohibitively expensive and wasteful.

Instead, utilities can develop affordable strategies that best minimize the risks associated with distribution-system failures. Such strategies help utilities meet their many, somewhat-conflicting obligations: (i) provide reliable power to customers, (ii) comply with budget limitations, and, increasingly, (iii) reduce the energy sector's environmental impacts.

A utility's approach to dealing with the wall of aging infrastructure must simultaneously address two individually challenging problems. First, the utility faces a capital-planning problem. Senior leaders commonly emphasize detailed preliminary project plans, portfolio-wide management and prioritization, and executive reviews to improve their utility's planning results [4]. This capital-planning problem requires the utility to appropriately distribute resources among the various elements of the distribution system over a multi-year planning horizon. While each utility has unique considerations, utilities often balance and prioritize elements such as overhead distribution, underground distribution, communication networks, and civil engineering projects, among others. Second, the utility faces a scheduling problem. A typical instance of this problem requires the utility to maximize overall system benefit by selecting which projects to execute in each year, all while satisfying cost, capacity, and precedence limitations.

The capital planning problem can take on a variety of forms depending upon, in part, whether the utility is investor-owned, municipal, or a cooperative. Therefore, we focus our effort on the scheduling element of the problem.

The remainder of this paper is organized as follows. Section 2 presents the utility scheduling problem and our solution method. Section 3 contains the computational results. Section 4 provides findings and recommendations for further opportunities.

METHOD

As discussed previously, addressing the wall of aging infrastructure requires the utility to solve a complex scheduling problem. Our solution approach employs a mixed-integer linear-program to select projects to execute during each year such that we maximize the net present value (NPV) of the overall reduction in system-wide risk. We do this while (i) satisfying separate, annual budget limits for underground and overhead projects and (ii) ensuring that all scheduled projects have a minimum ratio of benefit (i.e., risk reduced) to cost. We address several extensions to this present problem in the final section.

While we maximize the NPV of system-wide risk reduction, the method used to calculate risk reduction for individual projects is beyond the scope of this paper. We take the NPV of individual-project risk-reduction values as input parameters for our problem. We define our problem as follows.

$$\max_{x \in X} z^* = \sum_{p \in P, y \in Y} r_{p,y} x_{p,y} \tag{1}$$

$$s.t. \sum_{p \in \overline{P}, y \in Y} c_p x_{p,y} \leq \overline{b}_y \tag{2}$$

$$\sum_{p \in \underline{P}, y \in Y} c_p x_{p,y} \leq \underline{b}_y \tag{3}$$

$$\frac{r_{p,y}}{c_p} x_{p,y} \geq \underline{rcr} \tag{4}$$

$$\sum_{y \in Y} x_{p,y} \leq 1 \; \forall \, p \in P \tag{5}$$

where $x_{p,y} = 1$ if project $p \in P$ (the set of all projects) is scheduled during year $y \in Y$ (the set of all years in the planning horizon), and $x_{p,y} = 0$, otherwise; $\overline{P}$ and $\underline{P}$ are mutually exclusive sets of overhead and underground projects, respectively, which together span P; $r_{p,y}$ is the risk reduced by scheduling project p in year y; c_p is the cost of project p, which, unlike risk, is constant throughout the planning horizon; $\overline{b}_y$ and $\underline{b}_y$ are the overhead and underground budgets, respectively, in year y; and $\underline{rcr}$ is the minimum risk-reduction to cost ratio.

Our problem resembles many traditional scheduling problems, ranging from scheduling long-haul crew pairings [5], open-pit mine scheduling [6], and professional sports seasons [7].

These traditional scheduling problems (which we can formulate as optimization models with binary variables) can be difficult to solve, though many heuristic techniques provide sufficient solutions to certain scheduling problems [8]. As with many heuristic methods, these techniques do not guarantee an optimal solution, nor do they provide a bound on the optimal solution. However, what these methods can offer, in certain circumstances, is a high likelihood of obtaining a “good” solution in a “reasonable” time. Amidst (i) regulatory scrutiny, (ii) increasingly stringent environmental requirements, and (iii) a commitment to providing customer service, utilities may be unwilling to accept merely a high likelihood of a good solution, with no guarantees. Optimization may provide a more suitable method for solving the utility scheduling problem.

COMPUTATIONAL INSIGHTS

Our utility client's distribution network provided an excellent benchmark test for our optimization implementation. The utility, which serves several million customers across a multi-state service territory, required a ten-year, asset-replacement schedule that would provide maximum risk reduction under several budget scenarios.

The distribution system itself included both overhead and underground assets, with the utility considering nearly 85,000 infrastructure projects, with a ratio of two overhead projects for every underground project. In the baseline assessment, we considered a ten-year budget of $700 million, divided evenly across the planning horizon's ten years. Annual overhead and underground budgets were 85% and 15% of the total annual budget, respectively. In consultation with the utility, we established that the minimum risk-reduction to cost ratio (RCR) would equal zero for the baseline assessment. That is, the utility was willing to spend the entire budget even if some projects offered only negligible reduction in risk.

Along with the baseline assessment, we considered four additional ten-year budgets: $560, $630, $770, and $840 million. As with the baseline assessment, each of these budgets (i) had equal spending across the planning horizon's ten-years, (ii) allocated 85% of each annual budget to overhead assets and 15% to underground assets, and (iii) applied a minimum RCR of zero.

We instantiated the model using AMPL and solved it with the CPLEX solver on a computer with an Intel Core i7 processor and 64 GB of memory. Basic computational results in Table 1 provide the amount of risk reduced by our optimized schedule and also by an earlier schedule generated with a scheduling heuristic, the details of which are beyond the scope of this paper.

Table 1. Basic Computational Results

	Ten-Year Risk Reduction ($M)		
Ten-Year Budget ($M)	Optimized Schedule	Heuristically Determined Schedule	Optimization % Improvement
560	601.66	580.60	3.63%
630	657.91	634.87	3.63%
700	712.32	685.31	3.94%
770	765.08	737.89	3.68%
840	816.25	788.18	3.56%

We find that the optimization method increases the total risk reduction by more than 3.5% relative to the previous method. On average, that increase provides more than $2 million worth of additional annual benefit to the utility and its customers. We also observe diminishing returns as the ten-year budget increases. The overall risk-reduction to cost ratio for the optimized schedule is 1.07 for the $560 million budget, declining to just 0.97 for the $840 million budget.

We further considered the impact of minimum RCR on the amount of risk reduced, the number of projects completed, and the overall budget expenditure. For this sensitivity analysis, we considered the baseline, $700 million budget and varied the minimum RCR from 0 to 1 in increments of 0.1. With a minimum RCR of 1, the amount of risk reduced by the project must be equal to or greater than the project's cost. Table 2 provides results from this sensitivity analysis.

Table 2. Sensitivity Analysis Results

Minimum RCR	Ten-Year Risk Reduction ($M)	Ten-Year Spending ($M)	Projects Scheduled	Net Benefit ($M)
0.0	$ 712,345,317	$ 699,995,000	3084	$ 12,350,317
0.1	$ 712,349,185	$ 699,998,000	3091	$ 12,351,185

Minimum RCR	Ten-Year Risk Reduction ($M)	Ten-Year Spending ($M)	Projects Scheduled	Net Benefit ($M)
0.2	$ 712,331,219	$ 699,997,000	3123	$ 12,334,219
0.3	$ 712,325,196	$ 699,996,000	3099	$ 12,329,196
0.4	$ 712,313,255	$ 699,988,000	3121	$ 12,325,255
0.5	$ 710,701,773	$ 699,989,000	2999	$ 10,712,773
0.6	$ 698,191,816	$ 699,878,000	3047	$ -1,686,184
0.7	$ 660,064,082	$ 630,804,000	2825	$ 29,260,082
0.8	$ 619,886,442	$ 551,678,000	2553	$ 68,208,442
0.9	$ 580,216,230	$ 486,082,000	2337	$ 94,134,230
1.0	$ 541,771,613	$ 426,126,000	2043	$ 115,645,613

We find that as minimum RCR ranges from 0.0 to 0.6, there are enough viable projects to allow the utility to expend the entire budget. For each of these RCR values, the utility spends more than $699 million and schedules approximately 3000 projects. However, as RCR increases above 0.6, the number of projects that meet the minimum RCR threshold continues to decline; the utility schedules fewer projects and reduces less risk. Of interest, the net benefit (i.e., risk reduction less spending) increases with minimum RCR as the latter rises above 0.6. With minimum RCR of 1.0, the utility achieves a net benefit of more than $115 million dollars, while retaining more than $273 million of the ten-year budget.

NEXT STEPS

We continue to support utility clients by providing optimization insights that assist in capital planning and scheduling. Current and planned extensions to the scheduling model include (i) enforcing budget constraints for geographic regions within a utility's service territory, (ii) scheduling groups of related projects only within specified time windows, (iii) fixing individual projects in certain years, and (iv) scheduling multi-year projects.

ACKNOWLEDGEMENTS

This paper represents the work of an entire team of utility consultants and data scientists. Special thanks to Arlin Mire, Carol Bogacz, and Jason De Stigter.

BIBLIOGRAPHY

[1] National Rural Electric Cooperative Association. "History: The story behind America's electric cooperatives and NRECA." [Online]. Available: https://www.electric.coop/our-organization/history. [Accessed: 08-Aug-2021].

[2] R. Walton, 2015. "Why utilities are rushing to replace and modernize the aging grid." [Online]. Available: https://www.utilitydive.com/news/why-utilities-are-rushing-to-replace-and-modernize-the-aging-grid/361922/. [Accessed: 08-Aug-2021].

[3] American Society of Civil Engineers. "2021 Report Card for America's Infrastructure." [Online]. Available: https://infrastructurereportcard.org/cat-item/energy/. [Accessed: 08-Aug-2021].

[4] S.F. Gale, 2011. From Planning to Execution: How executives at top utilities contribute to the success of capital projects, technical report. [Online]. Economist Intelligence Unit. [Accessed: 08-Aug-2021].

[5] C. Barnhart, L. Hatay, E.L. Johnson, 1995. "Deadhead selection for the long-haul crew pairing problem," Operations Research 43 (3) 491-499.

[6] Rezakhah, M., E. Moreno, A. Newman, 2020. "Practical performance of an open pit mine scheduling model considering blending and stockpiling," Computers & Operations Research, 115:104638.

[7] M. Guzzo, 2004. "Striking it BIG: Local firm lands Major League Baseball scheduling contract." [Online]. Pittsburgh Business Times. [Accessed: 08-Aug-2021].

[8] A. Alonso-Ayuso, L.F. Escudero, M.T. Ortuno, C. Pizarro, 2007. "On a stochastic sequencing and scheduling problem," Computers & Operations Research 34 (9) 2604-2624.