Risk-based Maintenance Optimization for Transmission Equipment

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Abstract--**This paper describes a new maintenance selection and scheduling approach for bulk transmission equipment that is based on the cumulative long-term risk caused by failure of each piece of equipment. This approach not only accounts for equipment failure probability and equipment damage, as do most state of the art reliability centered maintenance (RCM) approaches, but it also accounts for the outage consequence in term of overload and voltage security in a rigorous and systematic way. The method is illustrated on a 600-bus model of a US utility system.**

Keywords--**Power system, transmission equipment, maintenance, reliability, risk, security and optimization.**

I. INTRODUCTION

The objective of the work reported in this paper is to develop a method of allocating economic resources and scheduling maintenance activities among bulk transmission system equipment so as to optimize the effect of maintenance with respect to the mitigation of component failure consequences. The central concept is that allocation of available economic resources for performing maintenance on a large number of facilities can be done strategically, as a function of cumulative-over-time system risk associated with network security problems such as overloads, low voltages, cascading overloads, and voltage instability, so as to minimize risk of wide-area bulk transmission system failures.

The work makes use of two previously developed technologies: risk-based security assessment and long-term sequential simulation. Risk-based security assessment [1,2] provide quantitative valuation of network security level, risk, using probabilistic modeling of uncertainties in loading conditions and contingency states. We developed a simulator [3,4,5] that performs sequential long-term simulation of a power system on an hour-by-hour basis. It creates an 8760-hour trajectory of operating conditions. The trajectory is formed by developing an hour by hour load forecast, together with a yearly unit commitment schedule and dispatch.

The long-term simulator, when integrated with hourly risk-based security assessment capability, provides year-long hourly risk variation for each contingency of interest. This information, when combined with a set of proposed maintenance activities and corresponding contingency probability reductions, yields cumulative (year-long) risk reduction (ΔCR) associated with each maintenance activity and associated possible start times. This overall process, (1) long term simulation with risk-based security assessment, (2) risk reduction calculation, and (3) optimal selection and scheduling, comprise what we call the integrated maintenance selection and scheduler (IMSS), illustrated in Fig 1. In this paper, we describe and illustrate the IMSS, including the long-term simulator (Section 2), risk reduction calculation, the selection of possible maintenance tasks and the effect that each maintenance task has on contingency probability (Section 3), the optimization problem associated with the maximization of risk reduction (Section 4), and illustration (Section 5). The significance of the work is that it uses operational requirements, in terms of system security, to influence decision-making about allocation of maintenance resources.

We note that this paper is similar to one previously published by the authors [6], but it has been extended to include a new optimization model and solution procedure, together with new results from application to a 600-bus model of a US utility system.

II. LONG-TERM SIMULATION WITH RISK ASSESSMENT

Cumulative risk assessment is useful in evaluating the system from an operation planner's perspective. It performs sequential, hourly simulation over a long term, e.g., 1 year, and it evaluates the security levels in terms of quantitative indices, reflecting risk of overload, cascading overload, low voltage, and voltage instability. The risk index R is an expectation of severity, computed as the product of contingency c probability $p(c)$ with contingency severity $sev(c|m,t)$, where m indicates the m^{th} contingency or corresponding maintenance activity, (and thus the network configuration in terms of network topology and unit commitment), and t indicates the hour (and thus the operating conditions in terms of loading and dispatch), given by $R(c,m,t)= p(c)sev(c|m,t))$. A reference "basecase" network configuration (with no maintenance activity) is denoted with $m=0$. The severity function captures the contingency severity in terms of overload, cascading overload, low voltage, and voltage instability.

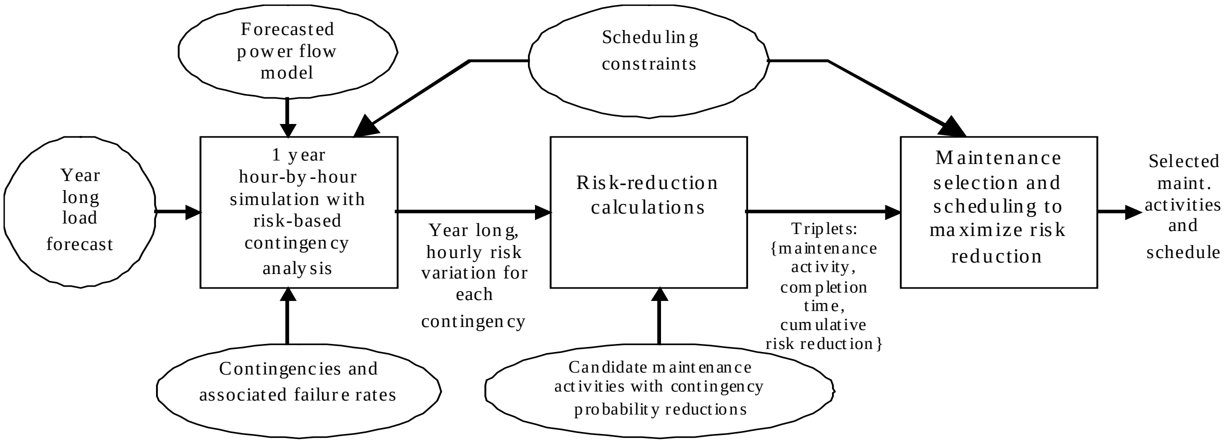

Fig.1: Integrated Maintenance Selector and Scheduler (IMSS)

The risk associated with any given network configuration and operating condition is computed by summing over the no-contingency condition (c=0) and all N contingencies:

$$R(m,t)=\sum_{c=0}^{N}p(c)sev(c\,|\,m,t) \qquad (1)$$

Even if there are no maintenance activities and contingency probabilities are constant, risk still varies with time because operating conditions, and therefore contingency severities, vary with time.

The long-term cumulative risk simulator performs a full power-flow based security assessment for each hour in the year, and associated risk indices are computed as described above. Therefore, given a contingency set, the simulator develops the power flow case and then, for each contingency, performs an assessment for overload, cascading overloads, low voltage, and voltage collapse. Overload and low voltage analysis are performed by simply modeling the contingency (e.g., removing one or more circuits and/or units) and re- solving the power flow. Cascading analysis is performed by successively outaging overloaded circuits. Voltage collapse analysis is performed using a continuation method [7]. Risk indices are computed using severity functions specific for each problem type. These functions, and other details, are provided in [1,2].

Three basic modules are required for use with the long-term cumulative risk assessment simulator, including load forecasting, unit commitment, and contingency set selection. The specific implementation used for each of these modules is interchangeable. The sequential approach used in our simulator evaluates a trajectory of operating conditions over time. The key features that drive the design are: (1) *Hourly assessment*: In making a one-year risk computation, some components may see their highest risk during off-peak or partial-peak conditions, when weak network topologies, weak unit commitment patterns, or unforeseen flow patterns are more likely to occur. (2) *Sequential simulation*: Load-cycles, weather conditions, unit shut-down and start-up time, or maintenance strategies are examples of chronologically dependent constraints that can affect reliabilities in ways that the snapshot models cannot capture. Thus, we require that the simulations be sequential in time.

We use several speed enhancements to offset the computational intensity of the simulator, as described in [2]. We mention here the two most effective of these. At each hour, the simulator first checks the conditions of that hour to those of all previously encountered (and assessed) hours. If the conditions (topology, loading, unit commitment, and dispatch) are similar, the risk indices computed for the previous hour are used for the current hour, thereby avoiding a repeated assessment. "Similarity" between conditions of different hours is quantified with a user-specified tolerance so that it is easy to control the run-time at the expense of less-refined results, while maintaining the two key features of the simulator design as described above. The second speed enhancement pertains to the voltage collapse assessment. This is done using the continuation power flow (CPF) [7], which is quite computational in its simplest form. Here, for each contingency, we take an initial "step" in the direction of loading increase that is long enough so that convergence can be interpreted as zero-risk for voltage collapse, and no further voltage collapse analysis need be done for that contingency.

III. RISK REDUCTION CALCULATIONS

The probability of failures decreases after a maintenance activity; otherwise the maintenance activity should not be performed. We know of no other way to identify failure modes affected by each maintenance activity except to review the literature and interact with industry engineers. With extensive literature review on this topic [8-25] together with some private resources obtained from industry contacts, we have developed a table where maintenance activities are matched to the failure modes that they affect. Appendix 1 provides a representative section of this table.

Given the hourly system risk variation over an extended period such as a year, we want to determine how different maintenance activities reduce the risk as a function of time when they are scheduled during the year. We assume that each maintenance activity decreases the probability of a particular contingency, and therefore probability reductions are in force from the maintenance activity completion time until the end of the year. Thus, each maintenance activity creates a risk reduction that is a function of its completion time. In addition, risk may increase during the maintenance activity due to the system weakening from possible maintenance outage. These ideas are captured analytically by defining m to denote a particular maintenance activity known to decrease the probability of contingency k by $\Delta p(m,k)$. Figure 2 illustrates a simple approach to obtaining $\Delta p(m,k)$. The bathtub curve in Fig 2 represents the hazard function $h(t)$ (which is proportional to the failure rate) of one component to be maintained. We assume that each maintenance renews the component so that its failure rate becomes $h(t_0)$. Thus, we have that $\Delta p=P(t_f)-P(t_0)$ is the maintenance induced contingency probability reduction. Reference [26] provides a more rigorous treatment of this problem.

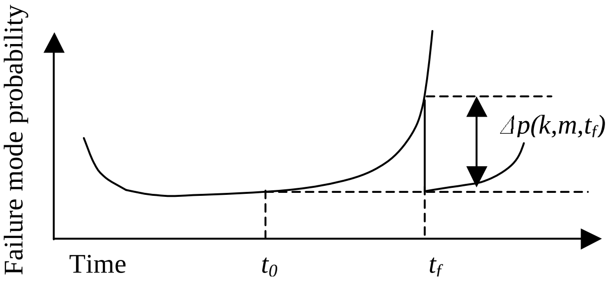

Fig 2. Maintenance induced contingency probability Δp

The cumulative-over-time risk reduction due to maintenance activity m is $\Delta CR(m,t_f)$, computed as a function of the completion time t_f according to:

$$\begin{aligned}\Delta CR(m,t_f) &= \Delta CR_{during}(m,t_f)+\Delta CR_{after}(m,t_f) \\ &= \int_{t_f-T_d}^{t_f}(R(0,t)-R_{during}(m,t))dt+\int_{t_f}^{8760}(R(0,t)-R_{after}(m,t))dt\end{aligned} \tag{2}$$

where T_d is the duration of the maintenance activity, $R(0,t)$ is the risk variation over time with no maintenance, and $R(m,t)$ is the risk variation over time with maintenance. The first integral in (2) is the risk reduction during the maintenance period, always non-positive indicating that risk may increase during the maintenance period. The second integral in (2) is the risk reduction after completion of the maintenance activity, always positive due to the decrease in failure probability. In each integral, $R(0,t)$ is obtained from the long-term simulator. If, during the maintenance period, no component is outaged, then $\Delta CR_{during}=0$. However, if the maintenance activity requires removal of component k (a generator, line, transformer, circuit breaker), then $\Delta CR_{during}<0$ because of changes in operating conditions, e.g., voltages, flows, etc., which change the severity of all contingencies except contingency k (contingency k cannot occur due to the fact that the corresponding component is on maintenance outage). Reference [6] shows that the total risk reduction associated with maintenance task m completed at time t_f is given by:

$$\begin{aligned}&\Delta CR(m,t_f) \\ &= \int_{t_f-T_d}^{t_f}[R(0,k,t)+\sum_{c=0,c\neq k}^{N}p(c)\big(sev(c\,|\,0,t)-sev(c\,|\,m,t)\big)]dt \\ &\quad+\frac{\Delta p(m,k)}{p(k)}\int_{t_f}^{8760}R(0,k,t)dt\end{aligned} \tag{3}$$

There are three main terms in the risk reduction expression of equation (3). The first term inside the first integral represents the reduction in risk, relative to the basecase, because of maintenance outage of component k means that contingency k can no longer occur. The second term inside the first integral, the summation, represents the change in risk (usually a risk *increase*) from all remaining contingencies due to the change in operating conditions caused by the maintenance outage of component k. The third term, the second integral, represents the risk reduction after the maintenance period from the maintenance-induced probability reduction of contingency k.

We see that in order to obtain the change in cumulative risk due to a maintenance activity, we need to evaluate the two integrals. The first integral requires $p(c)$ for all contingencies $c=0,N$ (which we assume to be available), the severity of all contingencies associated with the basecase configuration $(0,t)$, and the severity of all contingencies occurring under the weakened configuration (m,t). The contingency severities associated with the basecase configuration comes from one run of the simulator, but the contingency severities associated with configuration (m,t) would require rerunning the simulator for every weakened condition, i.e., for every maintenance activity m, and would be excessively computational. Thus we evaluate the first integral using approximate methods. For example, one might evaluate the severities associated with configuration (m,t) under the assumption that severity is linear, superposition holds, and the severity of removing two lines is the sum of the severity of removing each line alone. Alternatively, one might assume that maintenance activity m, which requires removal of component k, causes no change in severity so that $sev(c|0,t)=sev(c|m,t)$, and the summation in the first integral of (3) is 0. This might be true as a result of, for example, if we either require operator initiated system adjustments during the maintenance period or disallow any maintenance outage during a time period that results in significant risk. We accept this assumption for the remainder of the paper. Under this assumption, the total risk reduction associated with maintenance activity m completed at time t_f is:

$$\Delta CR(m,t_f) = \int_{t_f - T_d}^{t_f} R(0,k,t)dt + \frac{\Delta p(m,k)}{p(k)} \int_{t_f}^{8760} R(0,k,t)dt \qquad (4)$$

Thus, we need *R(0,k,t)*, the risk variation for each contingency under the basecase configuration, information obtained from a simulator run (these contingencies may be limited to only those contingencies having probability affected by a maintenance activity). In (4), the first term indicates the risk reduction accrued during the maintenance period because contingency *k* cannot occur and in general will be quite small. If one assumes, as we have above, that maintenance outages cause no severity increase, then it is reasonable to also neglect the first term in (4). This leaves us with only the second term in (4) and thus we have remaining only the important problem of how to obtain the contingency probability decrease *Δp(m,k)* due to the maintenance activity *m*. This problem is addressed in [26]. There may also be situations where it is desirable to schedule simultaneous maintenance activities. Reference [6] shows that, under the assumption that maintenance activities do not affect severity, severity function differences are zero, and neglecting risk reduction caused by the maintenance outage, the cumulative risk reduction is:

$$\Delta CR(m_1, m_2, t_{f1}, t_{f2}) = \int_{t_{f1}}^{t_{f2}} \frac{\Delta p(k_1, m_1)}{p(k_1)} R(m_2, k_1, t)dt \qquad (5)$$

$$+ \int_{t_{f2}}^{8760} \frac{\Delta p(k_1, m_1)}{p(k_1)} R(0, k_1, t) + \frac{\Delta p(k_2, m_2)}{p(k_2)} R(0, k_2, t)dt$$

IV. MAXIMIZING RISK REDUCTION

As indicated in Fig. 1, we first run the simulator to compute risk as a function of time for each hour over a long-term such as a year and then, for the example of this paper, use (4) to compute risk reduction associated with each proposed maintenance activity. This step results in triplets comprised of: {maintenance activity, completion time, risk reduction}. These triplets serve as the input to the optimizer, which we describe in what follows.

Let *N* be the total number of maintainable transmission components; *k=1,...,N* be the index over the set of transmission components; L_k be the number of maintenance tasks for component *k*; *m=1,…*L_k be the index over the set of maintenance activities for transmission component *k*; and *t=1,...T* be the index over the time periods.

For transmission maintenance, define *Iselect(k,m,t)*=1 if the m^{th} maintenance task for component *k* begins at time *t*, and 0 otherwise, *Iactive(k,m,t)*=1 if the m^{th} task for component *k* is ongoing at time *t*, and 0 otherwise. Define *d(k,m)* to be the duration of task *m* for component *k*, so that

$$Iactive(m,n,t) = \sum_{k=t-d(m,n)+1}^{t} Iselect(m,n,k), \forall (m,n,t) \qquad (6)$$

Also, *cost(k,m)* is the cost of the m^{th} task for component *k*, and *ΔCR(k,m,t)* is its cumulative risk reduction if it begins at time *t*. (In Section 3, we used notation *ΔCR(k,t)*; here, the additional argument is necessary because we have allowed various levels of each maintenance activity.) Let *Infeas(k,m)* be the set of time periods wherein task *m* for component *k* cannot be performed. Each {component, task} combination *(k,m)* is tagged with a budget category *B(k,m)=b∈1, 2, 3, 4,* where 1=transformer maintenance, 2=tree-trimming, 3=insulator cleaning, and 4=circuit breaker maintenance. *Crew(k,m)* is the required number of crews for the m^{th} maintenance for component *k*. *TotCrew(b,t)*is the total number of crews available for transmission maintenance category *b* at time *t*.

We have developed two forms for the resulting optimization problem. In problem 1, we are constrained by a cost budget; this problem conforms to the situation where the scheduler is also paying for the maintenance activities as in the traditional vertically integrated industry. In problem 2, we are constrained by only feasible schedules submitted by equipment owners. This problem conforms to the competitive industry where, for example, the ISO schedules for a large number of equipment owners who pay for their own maintenance. We present only problem 1 here as problem 2 can be solved as a special case of problem1.

$$Max\left(\sum_{k=1}^{N} \sum_{m=1}^{L_m} \sum_{t=1}^{T} \Delta CR(k,m,t) \times Iselect(k,m,t)\right) \qquad (7)$$

Subject to:

$$\sum_{n=1}^{L_m} \sum_{t=1}^{T} Iselect(k,m,t) \le 1,\ k = 1, \cdots, N \qquad (8)$$

$$Iactive(k,m,t) = 0, \forall t \in Infeas(k,m), \forall (k,m) \qquad (9)$$

$$\sum_{\substack{k=1 \\ (k,m):B(k,m)=b}}^{N} \sum_{m=1}^{L_m} Iactive\ (k,m,t) * Crew(k,m) < TotCrew\ (b,t), \forall t, b = 1,...4 \qquad (10)$$

$$\sum_{\substack{k=1 \\ (k,m):B(k,m)=b}}^{N} \sum_{m=1}^{L_m} \sum_{t=1}^{T} cost(k,m) * Iselect(k,m,t) < TotCost(b), b = 1,...,4 \qquad (11)$$

$$\sum_{k=1}^{N} \sum_{m=1}^{L_m} Iactive(k,m,t) * \Delta R(k,m,t) \le \Delta Rmax(t), \forall t \qquad (12)$$

$$Iselect(k,m,t) \in \{0,1\}, \forall (k,m,t) \qquad (13)$$

In this optimization problem, the objective (7) seeks to maximize the total cumulative risk reduction. The constraint (8) indicates that each component is maintained at most once during the time frame. Constraint (9) requires that each maintenance task be performed only within its feasible time period. Constraint (10) stipulates that the number of maintenance tasks ongoing during any period is limited by crew constraints. The constraint (11) represents the budget constraints. Constraint (12) ensures that maintenance task *(k,m)* resulting in a risk increase of *ΔR(k,m,t)* due to outage of component *k* at time *t* does not exceed the maximum allowable risk increase for time *t*, *ΔRmax(t)*. The maximum allowable risk increase for time *t* is set so that no maintenance outage may cause a violation of reliability criteria. To solve this optimization problem is to determine *Iselect(k,m,t),* which then determines *Iactive(k,m,t).* The problem is therefore an integer programming problem, a type known for its difficulty. We have tried three different solution methods: heuristic, branch and bound, and LP with combined DP/heuristic. The first two of these are described in [6]. We describe only the last of these here, since we believe it to be more promising in finding better solutions without significant increase in computation.

This approach first solves a relaxed linear program (LP) to obtain Lagrange multipliers on the budget constraint (11) and the risk constraint (12), and then develops a new objective function comprised of the original objective together with weighted cost and weighted risk, where the weights are Lagrange multipliers. It then solves knapsack problems over the labor constraints (10) one period at a time, where a period is taken to be one week. The procedure is as follows:

A. LP Relaxation to get dual variables: Solve a relaxed LP that includes all of the constraints (8)-(13) in order to get approximations on Lagrange multipliers μ_1-μ_4 on budget constraints 1-4 and λ_t, $t=1,\ldots T$ on the risk constraints. This LP is "relaxed" in that variables are allowed to be non-integer.

B. Solving knapsack problems: We move the risk and budget constraints to the objective function. The new objective function to be optimized is a weighted sum of cumulative risk reduction, cost, and period risk, with the various Lagrange multipliers quantifying the trade-offs between them. The problem of maximizing this objective subject to the labor constraints (10) is a classical knapsack problem, stated as follows:

$$\max F(Iselect(k,m,t)) = \sum_{k=1}^{N}\sum_{m=1}^{L_m} \Delta CR(k,m,t) \times Iselect(k,m,t)$$

$$-\sum_{b=1}^{4}\mu_b \left\{ \sum_{\substack{k=1 \\ (k,m):B(k,m)=b}}^{N} \sum_{m=1}^{L_m} \sum_{t=1}^{T} cost(k,m) * Iselect(k,m,t) - TotCost(b) \right\}$$

$$-\sum_{t}^{t+T_{max}} \lambda_t \left\{ \sum_{k=1}^{N}\sum_{m=1}^{L_m} \Delta R(k,m,t) * Iselect(k,m,t) - \Delta R\,max(t) \right\}$$

subject to

$$\sum_{\substack{m=1 \\ (m,n):B(m,n)=b}}^{M} \sum_{n=1}^{M_m} Iactive(m,n,t) * Crew(m,n) \le Crew(b,t), \forall t, b = 1,\ldots,4$$

There is a knapsack problem for each period, and they are solved in chronological sequence. Some qualifying remarks follow. (a) The risk reduction is only for the given period *t* and so the first term of the objective function does not sum over the time intervals. (b) The Lagrange multipliers on the budget constraints are found for the yearly budget, so the second term of the objective function does sum over the time intervals. (c) There is a Lagrange multiplier on maximum risk for each period, but in solving for a single period, if we can guarantee that no project has duration exceeding a single period, we need only include the constraint corresponding to period *t*. However, some projects may have durations exceeding one period (i.e., greater than 1 week). In this case, we must include the risk constraints for the current period *t* up to $t+T_{max}$, where T_{max} is the longest duration for any project. Therefore, the third term in the objective function must sum over period *t* to $t+T_{max}$. (d) Available hours for any period must be reduced by ongoing projects that began in earlier periods. (e) Constraint (8) is accounted for heuristically in the solution procedure, and the infeasible time periods from constraint (9) are enforced using negative objective function coefficients.

These knapsack problems may be solved to optimality using dynamic programming (DP), and this is reasonable for low-dimensionality problems. For high-dimensionality problems, DP is computationally expensive, so our solution algorithm allows for some percentage of the solution to be obtained heuristically using ratio scores (i.e. the ratio of each project's objective function to its required number of labor hours) to fill some percentage of the knapsack. The remaining space is then filled with dynamic programming. The solution procedure for this problem is as follows:

1. Choose a speed control percentage, SCP (0 is fast but suboptimal, 100 is slow but optimal). Set j=1.
2. For period j,
   a. Rank all unselected and feasible tasks in order of their ratio score. Identify the first N-ranked of these tasks, where N is chosen as a function of SCP (the larger is SCP, the larger is N).
   b. Identify the remaining (100-SCP)% of the tasks using dynamic programming.
   c. Flag all identified tasks as "selected."
   d. If j=8760, stop, else, j=j+1 and go to (a).

V. ILLUSTRATION

We have performed preliminary testing of the procedure, using the 600-bus model with hypothetical maintenance activities. The expected hour-by-hour 1-year loading trajectory used in the analysis is shown in Fig.2.

The top-ten contingencies with highest cumulative risk are listed in Table 1. We need to identify maintenance tasks to reduce the high risk caused by these contingencies. We have three categories of maintenance here: 1. Tree trimming; 2. Transformer major maintenance; 3. Transformer minor maintenance. Contingency 60 has the highest risk in the contingency list. The composite risk curve for contingency 60 is shown in Fig 3. We can see that the high cumulative risk for contingency 60 is due to some very high-risk hours. This is because the system is heavily stressed during these hours. The risk-reduction curve for maintenance (in this case, tree-trimming) to component 60 is shown in Fig 4. We observe a rapid drop of risk reduction during the peak-load period leading to the expected conclusion that if we apply the maintenance before the stress period, the cumulative risk reduction would be high. Due to the limitation of crews and feasible times, all maintenance activities might not be scheduled before the peak load period. So the optimization method will help to develop go good schedule.

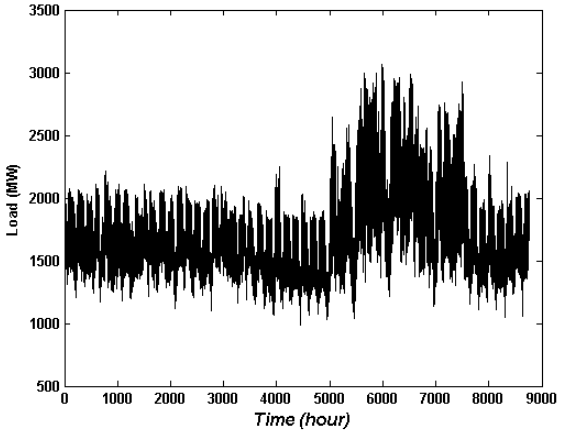

Fig 2: 1-year loading trajectory

TABLE1. TOP-TEN CONTINGENCIES WITH HIGHEST RISK

Contingency ID	Risk				
	LV	OL	VC	CC	Total
60	0.9421	0.4382	0.0171	0.0001	1.3975
59	0.2484	0.1516	0.0196	0.0002	0.4198
32	0.0654	0.0807	0.2450	0.0083	0.3995
38	0.0529	0.2159	0.0204	0.0251	0.3144
68	0.2450	0.0406	0.0246	0.0002	0.3105
18	0.2020	0.0089	0.0042	0.0000	0.2151
26	0.0679	0.1133	0.0211	0.0036	0.2059
27	0.1369	0.0458	0.0071	0.0108	0.2006
35	0.1186	0.0464	0.0266	0.0001	0.1916
66	0.0807	0.0553	0.0286	0.0001	0.1646

The optimization linear programming and combined DP/heuristic method has been applied on the maintenance scheduling of this system. To see the influence of constraint on the optimization, we developed three scenarios of constraints: 1. Crew strict constraint, in which we have enough budgets for all maintenance but very limited crew members; 2. Budget strict constraint, in which we have enough employees for all maintenance but very limited budget; 3. Both constraints, in which we do not have enough resources, either for man labor, or for budgets. The scheduling gives the results in Table 2.

We can see from the results that scenario III gets the largest risk reduction. For three scenarios, all of the maintenance activities are not scheduled because of constraints on crew members, budgets or both.

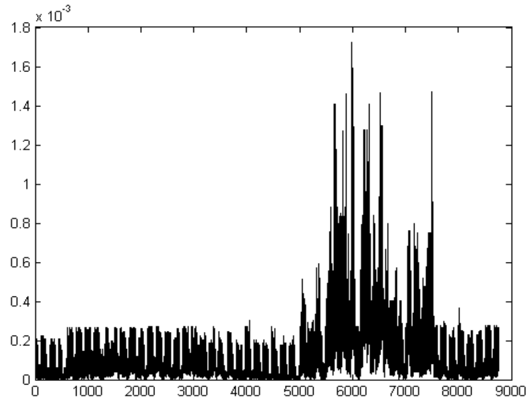

Fig 3: Composite risk of contingency 60 of one year

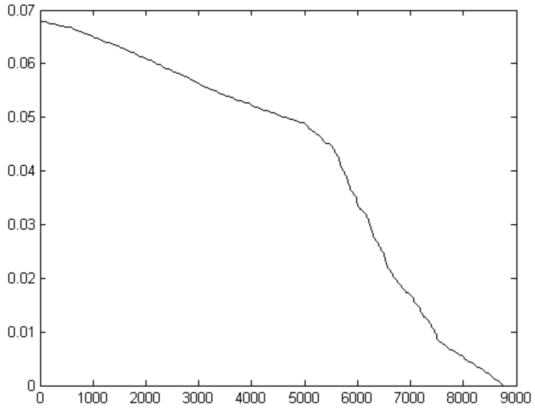

Fig 4:Risk reduction curve of maintenance 60

TABLE 2. SCENARIOS OF MAINTENANCE CONSTRAINTS

Scenario	Crew constraint for each type of maintenance			Budget constraint for each type of maintenance (k$)			*ΔCR*
	1	2	3	1	2	3	
I	3	5	4	130	180	90	22.773
II	30	50	40	13	20	24	34.806
III	10	16	13	63	147	12	46.692

In scenario I, very few maintenance activities are scheduled in each period because of the lack of employees, although we have enough funds. In scenario II, most of the maintenance tasks are scheduled during the beginning of the year, leaving the worker no work to do later in the year because of the limitation of budget. In scenario III, most of the maintenance will be scheduled because the crew and fund resources are allocated reasonably, while all constraints are satisfied. So it can also be helpful to check if the resource of maintenance is allocated economically, while optimizing the risk reduction. Table 3 gives representative part of the result of scenario III.

TABLE 3 MAINTENANCE SCHEDULE

Maint. Period	Type	Maint ID	Cost (USD)	Total labor hour	ΔCR
1	1	Trim2 Trim12 …	9600	364	12.913
	2	Xmrj3 Xmj7	24480	600	
	3		0	0	
2	1	Trim3 Trim5…	4400	362	6.935
	2	Xmrj3 Xmj7 (ongoing)	0	600	
	3	Xrmi17	749	40	
…	…	…	…	…	…
52	1		0	0	0
	2	Xmrj1 Xmrj4(on going)	0	600	
	3		0	0	
Total	1	48 tree trimming	63200	3792	46.692
	2	10 transformer major maintenance	96400	32700	
	3	17 transformer minor maintenance	12573	8160	

VI. CONCLUSIONS

We have made significant progress towards developing the Integrated Maintenance Selector and Scheduler so that it enables maintenance planners to account for the cumulative effect of risk associated with system security concerns such as overloads, low voltages, and voltage instabilities arising from component outages. Relationship between maintenance activities and failure modes are set up to facilitate the modeling of risk-based maintenance scheduling. Several optimization methods have been tried and new method is being developed and tested to get optimal solution for bulk transmission system component maintenance. We believe that this approach will provide the industry with a method of identifying the most effective way to expend maintenance resources.

VII. ACKNOWLEDGEMENTS

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APPENDIX 1: RELATIONSHIP BETWEEN MAINTENANCE ACTIVITIES AND FAILURE MODES FOR TRANSMISSION EQUIPMENT

Failure mode (criticality)	Components	Failure cause	Failure effect	Detection	Maintenance Activity	Frequency (typical data)
Insulation failure (high)	Insulation media (Transformer oil)	Oxidization of oil	Cause corrosion of the various metals within the transformer, particularly the iron	Oil screen test	Oil degasification; Oil filtering of non-pcb contaminated oil. Oil replacement	1 year
		Thermal decomposition of oil	Breakdown of the oil resulting in carbon formation, sludge and insulation deterioration. Possible catastrophic failure,			
		Contamination from moisture				
	Bushing	Solid insulation failure /moisture ingress /external contamination	Possible catastrophic failure/ personal safety	Power factor of bushing / visual inspection	Replacement, cleaning and greasing	6 year
Fail to transform voltage (high)	Insulation media	Turn to turn short	System instability. Loss of load and risk of cascading	DGA(Dissolved Gas Analysis)	Oil degasification; Oil filtering of non-pcb contaminated oil	1 year
	Winding	Open winding		Resistance test	Rewind of transformer	1 year for test
	Internal bolted/compression	Connection loose		Vibration analysis	Off line repair	1 year for analysis
	Core	Shifted core				
	External bushing connection	High resistance		Thermogragh inspection		
Loss of sealing (High)	Conservator	Moisture ingress, oxidization, corrosion	Possible catastrophic failure, low oil level alarm	Visual inspection / signals of leaks	External examination for oil leaks	1 month
	Insulation media (oil)	Gasket failure/weld fatigue			Sealing/ refilling	On demand
Pressure relief device block (high)	Pressure relief device	Corrosion, moisture ingress	Cannot release the pressure during internal fault	Visual inspection	Repair the blocked relief device	6 year
Winding overheat (Medium)	Winding	Excessive overloading, failure of cooling system or temperature devices	Winding resistance increase. Damage of winding	Thermograph inspection	Inspection of cooling system. Winding , test temperature device	6 year
Failure of cooling system (high)	Fans	Block, wrong direction, deterioration	Threat to useful lifetime of transformer. Can cause outage. Affects capacity	Thermograph alarm scan or cooling system operability test	Repair or replacement	6 years
	Pumps	Block, wrong direction, deterioration		Vibration test	Repair failed pumps	1 year for test
	External heat radiation	External heat radiation restriction		External visual inspection	Remove blocking items	1 year for inspection
	Temperature gauge and control circuit	Failure to operate		Function test	Calibration	6 years
Earthing malfunction (medium)	Neutral earthing	Earthing disconnected with the earth or resistance too large	Induced circulating currents	Grounding test	Repair, replace	
Looseness of fastenings (medium)	Connections and fastenings	Looseness of fastenings	Loss of sealing, mechanical strength, etc	Check the tightness of fastenings	Fastening	1-10 years
Surge arrester fail to operate (medium)	Surge protection facilities	Moisture ingress/ aging	Possible internal damage to the transformer and bushing	Power factor of surge arrester	Replacement	6 years
Sudden pressure relay trip fail to operate (high)	Sudden pressure relay trip	Subcomponent failure/ control circuit failure	Reenergize faulted transformer and destroy it/ personal safety	Functional test	Repair, replacement	6 years
Malfunction Breather system (medium)	Breather system	Block or cannot filtrate moisture or other contamination	Oil deterioration, overheat	Visual inspection	Remove the blocking items	6 months
Malfunction Buchholz (medium)	Buchholz	Wrong settings. Deterioration of age.	Damage of facilities	Commissioning test	Repair, replace	6 years