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Risk Averse Generation Maintenance Scheduling with Microgrid Aggregators

Saeed D. Manshadi, *Student Member, IEEE,* Mohammad E. Khodayar, *Member, IEEE,*

***Abstract*—This paper presents risk-averse long-term generation maintenance scheduling in the power systems with considerable installed capacity of microgrids. Microgrid aggregators facilitate the participation of microgrids in the wholesale market. In this paper, the effect of microgrids as controllable demand entities on the generation maintenance scheduling practices in the power system is investigated. The uncertainties in the marginal cost of generation in microgrids, the generation capacity installed within the microgrids, and the system electricity demand are captured using respective nominal values and uncertainty intervals. Moreover, the contingencies in transmission network are addressed by introducing additional variables. A two-stage robust optimization problem is formulated to determine a trade-off among the performance and conservativeness of the procured solution in the long-term operation horizon. The problem is formulated as a mixed integer linear programming problem and column-and-constraint generation procedure is used to solve the problem. The master problem minimizes the maintenance cost of the generation units subjected to generation units' constraints in the long-term operation horizon and the sub-problems determine the worst realization of the uncertainties and generate additional constraints in the master problem. The proposed methodology is applied to two case studies for a 6-bus and IEEE 118-bus power systems.**

***Index Terms*— Maintenance Scheduling, Outage Scheduling, Microgrids, column-and-constraint generation, uncertainty, two-stage robust optimization**

NOMENCLATURE

Indices:

i	Index of generation unit
l	Index for transmission line
m	Index for segment of the aggregated microgrid cost curve
s	Index of segment of the cost curve
t	Index of period

Variables:

$C_{b,t}^{g,m}$	Uncertain variable of marginal cost of segment m of aggregated microgrid on bus b at time t
$F_{i,t}$	Operation cost of unit i at period t
$f_{l,t}$	Power flow of the transmission line l at time t
$HF_{i,t}$	The number of periods in which the unit i was on maintenance at the beginning of period t
$HO_{i,t}$	The number of periods in which the unit i was available at the beginning of period t
$I_{i,t}$	Binary variable representing the status of unit i at period t, 0 for on outage, 1 for available
$P_{b,t}$	Injected power to bus b at period t
$P_{b,t}^{g,m}$	Generation of segment m of aggregated microgrid connected to bus b at period t
$P_{i,t}$	Generation dispatch of unit i at period t
$P_{i,t}^{s}$	Dispatch for segment s of unit i cost curve at period t
$P_{b,t}^{d}$	Demand on bus b at time t
$u_{b,t}^{d}, v_{b,t}^{d}$	Binary variables representing the uncertainties in demand
$u_{b,t}', v_{b,t}'$	Binary variables representing the uncertainties in generation capacity of microgrid
$u_{b,t}'''^{g}, v_{b,t}'''^{g}$	Binary variables representing the uncertainties in marginal cost of microgrid
$u_{l,t}''$	Binary variable representing the uncertainties in availability of components
$X_{i,t}$	Binary variable representing the transition to outage stage for maintenance of unit i at period t
$Y_{i,t}$	Binary variable representing the transition from outage to available mode for unit i at period t
$\alpha_{b,t}$	Uncertain variable for generation capacity of microgrid on bus b at time t
$\lambda_{(.)}^{(.)}, \mu_{(.)}^{(.)}$	Lagrangian Multipliers
$\theta_{b,t}$	Voltage angle at bus b at period t

Parameters:

$A_{i,b}$	Element of generation unit-bus incidence matrix
$C_{b,t}^{g,0}$	Marginal cost of the microgrid on bus b at time t
C_{i}^{s}	Marginal cost for segment s of the cost curve for unit i
E	Budget of uncertainty
$f_{l}^{\max}$	Maximum power flow of the transmission line l

The authors are with the Department of Electrical Engineering, Southern Methodist University, Dallas, TX. (e-mail: manshadi@smu.edu, mkhodayar@smu.edu).

k The number of contingencies in each period
L Total number of considered contingencies in the operation horizon
MC_i Maintenance cost of unit i
MHO_i Maximum number of periods in which unit i is available
NHO_i Minimum number of periods in which unit i is available
NB Total number of buses
NG Total number of generation units
NL Total number of transmission lines
NS Total number of segments in the generation unit cost curve
NT Total number of periods in the operation horizon
NW Total number of hours in period t
$P_{b,t}^{d,0}$ Demand on bus b at time t
$P_i^{\max}$ Maximum capacity of unit i
$P_i^{s,\max}$ Maximum capacity of segment s of unit i
RHF_i Required number of periods for maintenance of unit i
$S_{l,b}$ Element of transmission line-bus incidence matrix
X_l Inductive reactance of the transmission line l
$\alpha_{b,t}^0$ Generation capacity of microgrid on bus b at time t
ε Convergence tolerance
$\Delta C_{b,t}^g$ Deviation in marginal cost of the microgrid on bus b at time t
$\Delta P_{b,t}^d$ Deviation of demand on bus b at time t
$\Delta \alpha_{b,t}$ Deviation of generation capacity of microgrid on bus b at time t

I. Introduction

Generation maintenance scheduling determines the most effective periods for planned generation outages in order to maintain the reserve capacity margin and avoid costly demand curtailments in the power systems. Such practices could be coordinated with transmission maintenance scheduling [1]. The long-term generation and transmission maintenance scheduling is coordinated with short-term generation scheduling in [2] to improve the security of the power system. The coordinated generation and transmission maintenance scheduling that captures the degradation of generation and transmission assets and equipment malfunction because of loading or ambient temperature and weather condition is addressed in [3]. The uncertainties in the long-term and short-term operation including the random outages of the generation and transmission units, load forecast errors and fuel price fluctuations are captured by the proposed stochastic model for the coordinated generation and transmission maintenance scheduling in power systems in [4]. In [5] a risk-averse approach for generation maintenance scheduling in power systems with high penetration of renewable energy resources is proposed. In [6] the generation maintenance scheduling is coordinated with transmission maintenance practices considering the *N-1* contingencies in the generation and transmission components. Other factors including renewable resources and demand response practices were addressed in the generation maintenance scheduling in [7] and [8] respectively. While earlier publications were focused on procuring the outage schedule of the generation and transmission components, the impact of demand-side management and load control on the generation maintenance scheduling were not addressed. The demand realized by bulk power systems could be regulated using the controllable generation assets in the distribution networks to provide improved solutions for maintenance scheduling while maintaining the security and reliability of the bulk power system. In this context, microgrids are among the most viable solutions to regulate the demand in the power systems. Microgrids are considered as autonomous electric power systems with defined boundaries, local demand, generation, and/or storage facilities that can operate in grid-connected or island mode [9]. Regulating the demand by leveraging local generation assets in microgrids improves the economics and security measures of the generation maintenance scheduling practices. However, the uncertainty inherently exists in the available generation capacity in the microgrids, the marginal price of generating electricity and the demand that should be partly or completely served by bulk power system. Furthermore, the possible contingencies in transmission network will affect the power flow and the maintenance scheduling of generation units. Such uncertainties should be captured in the generation maintenance scheduling problem as they may result in economic inefficiencies and further jeopardize the long-term security of the power system. The uncertainties in power systems are captured using stochastic programming approach that leverages the probability distribution of the uncertain variables such as demand, renewable generation, and availability of the system components [10]-[15]. Such approach provides improved performance over the deterministic solutions, however, its computation burden will increase with the increase in the number of incorporated scenarios. Furthermore, the probability distribution functions for the uncertain variables may not be readily available. In order to address these challenges, robust optimization (RO) is introduced and applied to several engineering problems [16],[17]. The solution to RO problems provides risk-averse strategies by capturing the uncertainty boundaries without requiring the probability distribution function of the uncertain variables. Such solutions are favorable for long-term operation planning of power systems including maintenance scheduling as the security of the power system is maintained considering the worst realization of the uncertain variables. Furthermore, earlier publications [1], [3], [18], [19] addressed maintenance as a one-time practice in the operation horizon, while the minimum and maximum periods among sequential maintenance practices were ignored. Improving the mathematical model for the maintenance scheduling by addressing such limitations enables multiple maintenance practices for the generation units in the longer operation horizon.

This paper presents a risk-averse formulation for generation maintenance scheduling using microgrid aggregators in the bulk power system. Microgrid aggregators capture the characteristics of aggregated distributed generation units and demand served by a large number of microgrids. The system operators leverage the proposed framework in order to determine the most effective long-term generation maintenance schedule while ensuring the secure and economic operation of power systems through balancing the demand and supply. The system operator incorporates the characteristics of the generation units for maintenance practices including the minimum and maximum periods in which the unit should be on scheduled outage, the duration of the maintenance, and respective maintenance costs. Moreover, the system operator determines the marginal cost of the generation units and local generation assets for microgrid aggregators based on the submitted marginal costs (bids) for the short-term operation practices. The individual characteristic of the local generation in the microgrids is inherently captured by the aggregated generation bid, generation capacity, and respective uncertainties in such values. The presented formulation is a two-stage model in which the first stage captures multiple maintenance practices in long-term operation horizon by introducing the minimum and maximum time for the maintenance practices, and in the second stage, the worst realization of uncertainties in the long-term maintenance scheduling is revealed. The uncertainty in available generation resources of microgrids, the demand of the power system, the marginal cost of the microgrids as well as contingencies in the transmission network are addressed and further limited by the budget of uncertainty. The contributions of this paper are as follows:

- The long-term generation maintenance scheduling of power system is formulated as a two-stage robust optimization problem in which the first stage addresses the maintenance scheduling of the generation units, while the second stage captures the operation decisions once the worst realization of the uncertainties is revealed.
- A new formulation for long-term maintenance scheduling is presented that addresses multiple maintenance practices for generation units considering the minimum and maximum periods for the availability of the units prior to maintenance, as well as the required number of periods for the maintenance practices.
- The presented formulation determines the worst realization of uncertainties in the marginal cost of the microgrid generation, the capacity of the local generation assets in microgrids, electricity demand, and the availability of the transmission network components considering a certain budget for the uncertainties in the power system. Furthermore, the impact of the budget of uncertainty on the operation and maintenance costs is evaluated.
- The effect of the aggregated microgrids on the long-term generation maintenance scheduling is addressed by performing sensitivity analysis on the capacity of local generation and the marginal cost of electricity in microgrids.

The rest of the paper is organized as follows, the problem formulation and solution methodology are described in Sections II and III respectively. A case study to show the effectiveness of the problem is shown in Section IV. The conclusion is presented in Section V.

II. Problem Formulation

The mathematical formulation for the generation maintenance scheduling is presented in (1)-(24). The objective is to minimize the maintenance and the operation cost of the power system as shown in (1). The first term in (1) represents the maintenance cost for all generation units in the power system and the second term represents the operation cost of the system. The operation cost of the system is affected by several uncertain variables in the operation horizon. These uncertain variables are the demand in power system, the available local generation assets in microgrids that reduces the net demand realized by the power system, the marginal cost of the generation units in microgrids, and the contingencies in the transmission networks that changes the power flow pattern in the system and affects the operation cost. The second term in (1) represents the operation cost minimization that is further maximized over the variables in the uncertainty set. The operation cost of each generation unit is a quadratic cost function of the generation dispatch, which is further linearized using a piece-wise linearization technique as shown in (2)-(4) [20]. The dispatch of the generation unit is limited by the maximum capacity of the unit as shown in (5). The relationship between the binary variables representing the transition of the unit to outage state for maintenance, the binary variables representing the transition from outage to available state, and the state of the unit at each period is shown in (6). As shown in this constraint, once the unit goes on maintenance from the available state, $X_{i,t}$ will be 1 and the unit will change its state from available to unavailable. Similarly, once the unit becomes available from an outage state in the maintenance period, $Y_{i,t}$ will be 1 and the state of the unit ($I_{i,t}$) will change from 0 to 1. The number of periods in which the generation unit was available at the beginning of each period is determined by (7) and (8). Here, if the state of the generation unit is not transitioning from outage to available mode, the number of periods that a generation unit was available at the beginning of each period is increased by one. The number of periods the generation unit should be available is less than a maximum limit as shown in (9) and more than a minimum limit as enforced by (10). Therefore, the period in which the unit should go on maintenance is defined by constraints (9) and (10). Once the unit is recovered from the scheduled maintenance, the unit will be available for the minimum number of periods and can go on maintenance for the second time between the minimum and maximum periods assigned for the maintenance practices. The transition states are mutually exclusive as shown in (11). The number of periods in which the unit is on maintenance is determined by (12) and (13). The number of periods the unit should be on maintenance is enforced by (14)-(15). Here, once the unit is recovered from the outage state to the available state, $X_{i,t}$ is 0, and $Y_{i,t}$ is 1. Therefore, the number of periods the unit is on maintenance is enforced to be equal to RHF_i. The generated power at each bus is determined by (16) and the nodal power balance in the power system is determined by (17). The power transmitted through the transmission line is dependent on the difference between the voltage angles of the interconnected buses as shown in (18)-(19) if the transmission line is available. Here, once the transmission line is disconnected because of contingency, the voltage angles of the buses connected by the transmission line are relaxed. The power transmitted through the transmission line is limited by the capacity of the transmission line as shown in (20). The capacity of the local generation asset in microgrids connected to each node of the power system, is limited to a certain portion of the demand at the corresponding node as shown in (21). The uncertainty in the marginal cost of the generation units in microgrids, the uncertainty in the capacity of local generation assets in microgrids, and the uncertainty in the demand of the power system are limited by (22), (23), and (24) respectively. As shown in (22)-(24), the uncertain variables are identified by the nominal values and the uncertainty interval. The available generation capacity of microgrid aggregators is dependent on the available energy resources (e.g. renewable resources and fuel). Furthermore, the marginal cost of generation within microgrids is dependent on several factors including the generation technology, the fuel cost, and the inflation and interest rates. In order to capture the operation and maintenance costs, the investment costs, the inflation and interest rates, and the labor cost associated with the electricity generation within the microgrids, the Levelized Cost of Energy (LCOE) for the generated electricity within microgrids can replace the marginal cost. As the number of microgrids is large and the generation technology utilized in each microgrid could be different, capturing the marginal cost and generation capacity with respective uncertainties for each microgrid is challenging and practically infeasible in this problem. Therefore, the marginal cost and capacity of the local generation resources in microgrids with respective uncertainties are aggregated and associated with the microgrid aggregators.

$$\min \sum_{t=1}^{NT}\sum_{i=1}^{NG} MC_i \cdot X_{i,t} + \max_{u''_{l,t},C^{g}_{b,t},P^{g}_{b,t},P^{d}_{b,t}} \min_{P_{i,t}} \sum_{t=1}^{NT}\left[\sum_{i=1}^{NG} F_{i,t} + \sum_{b=1}^{NB}\sum_{m}^{NM} C^{g,m}_{b,t}\cdot NW\cdot P^{g,m}_{b,t}\right] \tag{1}$$

$$F_{i,t} = \sum_{s=1}^{NS} NW\cdot C_i^s \cdot P_{i,t}^s \qquad : \lambda_{i,t}^1 \tag{2}$$

$$\sum_{s=1}^{NS} P_{i,t}^s = P_{i,t} \qquad : \lambda_{i,t}^2 \tag{3}$$

$$P_{i,t}^s \le P_i^{s,\max} \qquad : \mu_{i,t,s}^1 \tag{4}$$

$$P_{i,t} \le P_i^{\max}\cdot I_{i,t} \qquad : \mu_{i,t}^2 \tag{5}$$

$$Y_{i,t} - X_{i,t} = I_{i,t} - I_{i,t-1} \tag{6}$$

$$HO_{i,t} \ge HO_{i,t-1} + I_{i,t-1} - MHO_i \cdot Y_{i,t} \tag{7}$$

$$HO_{i,t} \le HO_{i,t-1} + I_{i,t-1} + MHO_i \cdot Y_{i,t} \tag{8}$$

$$HO_{i,t} \le MHO_i \cdot (1 - Y_{i,t}) \tag{9}$$

$$HO_{i,t} \ge NHO_i \cdot X_{i,t} \tag{10}$$

$$X_{i,t} + Y_{i,t} \le 1 \tag{11}$$

$$HF_{i,t} \ge HF_{i,t-1} + (1 - I_{i,t-1}) - RHF_i \cdot X_{i,t} \tag{12}$$

$$HF_{i,t} \le HF_{i,t-1} + (1 - I_{i,t-1}) + RHF_i \cdot X_{i,t} \tag{13}$$

$$HF_{i,t} \le RHF_i \cdot (1 - X_{i,t}) \tag{14}$$

$$HF_{i,t} \ge RHF_i \cdot Y_{i,t} \tag{15}$$

$$\sum_{i=1}^{NG} A_{i,b}\cdot P_{i,t} = P_{b,t} \qquad : \lambda_{b,t}^3 \tag{16}$$

$$P_{b,t}^d - P_{b,t} - \sum_m P_{b,t}^{g,m} = \sum_{l}^{NL} S_{b,l}\cdot f_{l,t} \qquad : \lambda_{b,t}^4 \tag{17}$$

$$f_{l,t} + M(1 - u''_{l,t}) \ge \sum_{b}^{NB} S_{b,l}\cdot \theta_b^t \big/ X_l \qquad : \mu_{l,t}^6 \tag{18}$$

$$f_{l,t} - M(1 - u''_{l,t}) \le \sum_{b}^{NB} S_{b,l}\cdot \theta_b^t \big/ X_l \qquad : \mu_{l,t}^7 \tag{19}$$

$$\left|f_{l,t}\right| \le f_l^{\max}\cdot u''_{l,t} \qquad : \mu_{l,t}^3, \mu_{l,t}^4 \tag{20}$$

$$\sum_m P_{b,t}^{g,m} \le \alpha_{b,t}\cdot P_{b,t}^d \qquad : \mu_{b,t}^5 \tag{21}$$

$$C_{b,t}^{g,m} \in \left[C_{b,t}^{g,m,0} - \Delta C_{b,t}^{g,m}, C_{b,t}^{g,m,0} + \Delta C_{b,t}^{g,m}\right] \tag{22}$$

$$\alpha_{b,t} \in \left[\alpha_{b,t}^0 - \Delta\alpha_{b,t}, \alpha_{b,t}^0 + \Delta\alpha_{b,t}\right] \tag{23}$$

$$P_{b,t}^d \in \left[P_{b,t}^{d,0} - \Delta P_{b,t}^d, P_{b,t}^{d,0} + \Delta P_{b,t}^d\right] \tag{24}$$

The presented problem is formulated as a two-stage robust optimization problem [21] in which, the first stage problem determines the first stage i.e. “here-and-now” variables including the scheduled maintenance of the generation units in the power system, and the second stage problem will determine the second stage i.e. “wait-and-see” variables once the uncertainties are revealed. These variables include the generation dispatch of the available units, the flow of the transmission lines, the dispatch of local generation assets, as well as the realization of the uncertainties including the marginal cost and capacity of the microgrids’ generation, availability of the transmission lines, and the power system demand. The uncertain variables determined at this stage belong to a polyhedral uncertainty set and the objective is to minimize the sum of first-stage and second-stage costs

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considering a budget for the uncertainty that represents the conservativeness of the decision maker and the size of uncertainty interval.

III. Solution Methodology

The column-and-constraint generation approach as a cutting plane procedure is proposed to solve the presented two-stage robust optimization problem [22]. This approach has superior computation efficiency compared to the Benders decomposition [5]. The problem presented in (1)-(24) is presented in general form as (25)-(28) in which $\mathbf{x}$ is the first stage decision variable while $\mathbf{y}$ and $\mathbf{u}$ are the second stage (i.e. recourse) decision variables. The objective function (1) is represented as (25) and the set of constraints (26) represents all constraints with binary decision variables including the states and the transition states of the units that were formulated in (5)-(15). The set of constraints shown by (27) captures the second stage decision variables $\mathbf{y}$ such as the dispatch of generation units as well as the realization of the uncertain variables $\mathbf{u}$ such as the demand of power system and the capacity of local generation assets in microgrids. The feasibility set for first stage and second stage decision variables are shown in (28). As enumerating all scenarios with different realization of $\mathbf{u}$ is practically challenging, the solution approach leverages partial enumeration over a subset $\mathbf{u}$ considering the budget of uncertainty to determine a valid relaxation to the original problem. The presented column-and-constraint generation procedure further determines significant scenarios that contribute to the worst realization of the system operation cost.

$$\min_{\mathbf{x}} \mathbf{c}^T\mathbf{x} + \max_{\mathbf{u}} \min_{\mathbf{y}} \mathbf{b}^T\mathbf{y} \tag{25}$$

s.t.

$$\mathbf{Ax} \geq \mathbf{d} \tag{26}$$

$$\mathbf{Fx} + \mathbf{Gy} \geq \mathbf{h} - \mathbf{Hu} \tag{27}$$

$$\mathbf{x} \in \mathbf{\Omega_x}, \mathbf{y} \in \mathbf{\Omega_y} \tag{28}$$

The column-and-constraint generation procedure is implemented as a master problem and a sub-problem. The algorithm for this procedure is shown as below:

a) Set iteration $\psi = 0, LB = -\infty, UB = +\infty$ with the determined realization of uncertainty $\mathbf{u}^{*(0)}$,

b) Solve

$$\min_{\mathbf{x},\mathbf{y}} \mathbf{c}^T\mathbf{x} + e \tag{29}$$

s.t.

$$e \geq \mathbf{b}^T\mathbf{y}^{(\psi)} \tag{30}$$

$$\mathbf{Ax} \geq \mathbf{d} \tag{31}$$

$$\mathbf{Fx} + \mathbf{Gy}^{(\psi)} \geq \mathbf{h} - \mathbf{Hu}^{*(\psi)} \tag{32}$$

$$\mathbf{x} \in \mathbf{\Omega_x}, \mathbf{y} \in \mathbf{\Omega_y} \tag{33}$$

c) Set $LB = \mathbf{c}^T\mathbf{x}^* + e^*$ where $\mathbf{x}^*$ and e^* are the solution of (29)-(33); and go to (d),

d) Solve sub-problem (34)-(36) to determine the new realization of the uncertainties.

$$\max_{\mathbf{u}} \min_{\mathbf{y}} \mathbf{b}^T\mathbf{y} \tag{34}$$

s.t.

$$\mathbf{Fx}^* + \mathbf{Gy} \geq \mathbf{h} - \mathbf{Hu}^{(\psi+1)} \tag{35}$$

$$\mathbf{y} \in \mathbf{\Omega_y}, \mathbf{u}^{(\psi+1)} \in \mathbf{U} \tag{36}$$

e) Set $UB = \mathbf{c}^T\mathbf{x}^* + \mathbf{b}^T\mathbf{y}^*$ where $\mathbf{y}^*$ is the solution of (34)-(36); and check if $\frac{UB - LB}{UB} \leq \varepsilon$. If the condition is satisfied terminate the process, otherwise, add (37) and (38) to (29)-(33), then set $\psi = \psi + 1$ and go to (b).

$$\mathbf{Fx} + \mathbf{Gy}^{(\psi+1)} \geq \mathbf{h} - \mathbf{Hu}^{*(\psi+1)} \tag{37}$$

$$e \geq \mathbf{b}^T\mathbf{y}^{(\psi+1)} \tag{38}$$

Assuming that the worst realization of uncertainties occur at extreme points within the polyhedral uncertainty set, the sub-problem (34)-(36) is re-formulated as a mixed-integer programming problem shown in (39)-(52) by capturing the dual representation of inner minimization problem.

In order to determine the worst realization of the uncertain variables, binary variables $u_{b,t}^{d}$, $v_{b,t}^{d}$, $u'_{b,t}$, $v'_{b,t}$, $u''_{l,t}$, $u'''^{g}_{b,t}$ and $v'''^{g}_{b,t}$ are introduced. Each pair of variables is mutually exclusive as shown in (47)-(49). Moreover, an *N-k* contingency analysis is presented in (50), in which up to *k* components could be unavailable in each period. The budget of uncertainty limits the combination of the binary variables that yields the worst realization of the uncertain variables as shown in (51) and (52). Here, E and L are the budget of uncertainty chosen by the decision maker.

$$\max_{\substack{\mathbf{u},\mathbf{v},\mathbf{u}',\mathbf{v}'\\ \mathbf{u}'',\mathbf{u}''',\mathbf{v}'''}} \sum_{t=1}^{NT} \left[\begin{array}{l} \sum_{i=1}^{NG} \left\{ \sum_{s=1}^{NS} -P_{i,t}^{s,\max} \cdot \mu_{i,t,s}^{1} - P_i^{\max} \cdot \mu_{i,t}^{2} \cdot \hat{I}_{i,t} \right\} - \\ \sum_{b=1}^{NB} \left\{ \begin{array}{l} \lambda_{b,t}^{4} \cdot P_{b,t}^{d,0} + \lambda_{b,t}^{4} \cdot \left(u_{b,t}^{d} - v_{b,t}^{d} \right) \cdot \Delta P_{b,t}^{d} + \\ \mu_{b,t}^{5} \cdot \alpha_{b,t}^{0} \cdot P_{b,t}^{d,0} + \mu_{b,t}^{5} \cdot \left(u'_{b,t} - v'_{b,t} \right) \cdot \Delta\alpha_{b,t} \cdot P_{b,t}^{d,0} \end{array} \right\} \\ -\sum_{l=1}^{NL} f_l^{\max} \cdot \left(\mu_{l,t}^{3} + \mu_{l,t}^{4} \right) . u''_{l,t} + M \cdot \left(1 - u''_{l,t} \right) \cdot \left(\mu_{l,t}^{6} + \mu_{l,t}^{7} \right) \end{array} \right] \tag{39}$$

$$\lambda_{i,t}^{1} \leq 1 \qquad : F_{i,t} \tag{40}$$

$$-C_i^{s} \cdot NW \cdot \lambda_{i,t}^{1} - \mu_{i,t,s}^{1} - \lambda_{i,t}^{2} \leq 0 \qquad : P_{i,t}^{s} \tag{41}$$

$$\lambda_{i,t}^{2} - \mu_{i,t}^{2} - \sum_{i=1}^{NB} A_{i,b} \cdot \lambda_{b,t}^{3} \leq 0 \qquad : P_{i,t} \tag{42}$$

$$\lambda_{b,t}^{3} - \lambda_{b,t}^{4} \leq 0 \qquad : P_{b,t} \tag{43}$$

$$\lambda_{b,t}^{4} - \mu_{b,t}^{5} \leq NW \cdot \left[C_{b,t}^{g,m,0} + (u'''^{g,m}_{b,t} - v'''^{g,m}_{b,t}).\Delta C_{b,t}^{g,m} \right] \quad : P_{b,t}^{g,m} \tag{44}$$

$$\sum_{b=1}^{NB} \left[S_{l,b} . \lambda_{b,t}^{4} \right] + \mu_{l,t}^{6} - \mu_{l,t}^{7} - \mu_{l,t}^{3} + \mu_{l,t}^{4} = 0 \qquad : f_{l,t} \tag{45}$$

$$\sum_{l=1}^{NL} \left[-S_{l,b} \cdot \mu_{l,t}^{6} / X_l + S_{l,b} \cdot \mu_{l,t}^{7} / X_l \right] = 0 \qquad : \theta_b^{t} \tag{46}$$

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$$u_{b,t}^{d} + v_{b,t}^{d} \le 1 \tag{47}$$

$$u'_{b,t} + v'_{b,t} \le 1 \tag{48}$$

$$v_{b,t}^{\prime\prime\prime g} + u_{b,t}^{\prime\prime\prime g} \le 1 \tag{49}$$

$$\sum_{l=1}^{NL} u''_{l,t} \le k \tag{50}$$

$$\sum_{b=1}^{NB}\sum_{t=1}^{NT} u_{b,t}^{d} + v_{b,t}^{d} + u'_{b,t} + v'_{b,t} + v_{b,t}^{\prime\prime\prime g} + u_{b,t}^{\prime\prime\prime g} \le E \tag{51}$$

$$\sum_{l=1}^{NL}\sum_{t=1}^{NT} u''_{l,t} \le L \tag{52}$$

The binary-to-continuous variable multiplication in the objective function (39) requires further linearization as shown in (53)-(56) by introducing new auxiliary continuous variable ω. Here, φ is the continuous variable, u is the binary variable and M is a large number which is considered as the upper bound of the continuous variable φ.

$$\omega \le \varphi + M \cdot (1-u) \tag{53}$$

$$\omega \ge \varphi - M \cdot (1-u) \tag{54}$$

$$\omega \le M \cdot u \tag{55}$$

$$\omega \ge -M \cdot u \tag{56}$$

The solution to this problem is used to add more constraints (37), (38) to the master problem once the condition at step (e) is not satisfied. Utilizing the solution of (39)-(52) and (57)-(59), a new realization of uncertainties ($\mathbf{u}^*$) is captured by adding the constraints (37) and (38) to the master problem.

$$P_{b,t}^{d} = P_{b,t}^{d,0} + \Delta P_{b,t}^{d} \cdot \hat{u}_{b,t}^{d} - \Delta P_{b,t}^{d} \cdot \hat{v}_{b,t}^{d} \tag{57}$$

$$\alpha_{b,t} = \alpha_{b,t}^{0} + \Delta\alpha_{b,t} \cdot \hat{u}'_{b,t} - \Delta\alpha_{b,t} \cdot \hat{v}'_{b,t} \tag{58}$$

$$C_{b,t}^{g} = C_{b,t}^{g,0} + \Delta C_{b,t}^{g} \cdot \hat{u}_{b,t}^{\prime\prime\prime g} - \Delta C_{b,t}^{g} \cdot \hat{v}_{b,t}^{\prime\prime\prime g} \tag{59}$$

IV. Case Study

In this section, two case studies were presented to show the effectiveness of the presented approach as well as the impact of considerable penetration of microgrids on the maintenance scheduling practices in the power system. The first case study uses a sample 6-bus power system while the second case study utilize the modified IEEE-118 bus system.

A. 6-Bus Power System

In this section, a 6-bus power system, which is composed of 3 thermal generation units and 7 transmission lines is utilized. The characteristics of the transmission line and the thermal generation units are shown in Tables I and II, respectively. The generation cost curve for the generation units is piecewise linearized with four equal segments. The generation units G1, G2, and G3, are connected to buses 1, 2, and 5 respectively. The minimum and maximum available periods as well as the required maintenance periods for units G1-G3 were shown in Table II. The maintenance cost for G1, G2 and G3 are \$40,000, \$30,000 and \$10,000 respectively. The time step for this case study is one week and the operation horizon is one year (52 weeks). The weekly system demand profile is shown in Fig. 1.

In this case study, the contingency in transmission lines is ignored and the following cases are considered:

Case 1 – Maintenance scheduling without aggregated microgrids
Case 2 – Maintenance scheduling with aggregated microgrids
Case 3 – Maintenance scheduling without aggregated microgrids considering the uncertainties
Case 4 – Maintenance scheduling with aggregated microgrids considering the uncertainties
Case 5 – Maintenance scheduling with aggregated microgrids knowing the probability distribution of uncertainties

TABLE I
TRANSMISSION LINE CHARACTERISTICS

Line ID	From Bus	To Bus	Impedance (p.u.)	Maximum Power Flow (MW)
L1	1	2	0.170	100
L2	1	4	0.258	100
L3	2	4	0.197	70
L4	5	6	0.140	60
L5	3	6	0.018	120
L6	2	3	0.037	150
L7	4	5	0.037	70

TABLE II
THERMAL UNIT CHARACTERISTICS

Unit	C^1 (\$/MWh)	C^2 (\$/MWh)	C^3 (\$/MWh)	C^4 (\$/MWh)	P_{max} (MW)	*NHO* (Week)	*MHO* (Week)	RHF (Week)
G1	15	30	40	62.5	520	10	48	4
G2	20	32	46.25	73	360	10	48	5
G3	30	38	75	98	200	5	25	2

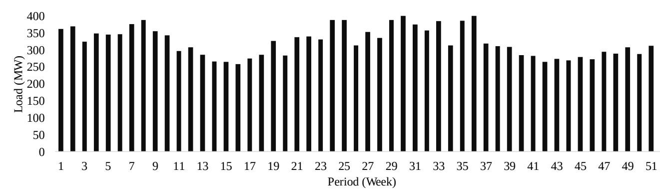

Fig. 1. Demand profile for one year

Case 1 – Maintenance scheduling without aggregated microgrids

In this case, no microgrid is considered in the power system and the maintenance schedules of the generation units are determined considering the nominal values for the demand in the power system. The total maintenance and operation cost is \$63.494M. In this case, unit G1 goes on maintenance in weeks 14-17 when the demand is low; unit G2 goes on maintenance in weeks 42-46, and unit G3 goes on maintenance in weeks 12-13 and 39-40. The total capacity on outage, in this case, is shown in Fig. 2.

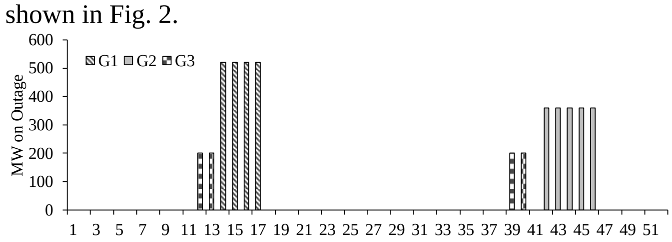

Fig. 2. Scheduled capacity on outage in Case 1

As shown in this figure, the minimum and maximum maintenance period for unit G3 are 5 and 25 weeks respectively. Therefore, once G3 goes on maintenance in weeks 12 and 13, it needs to go on maintenance in weeks 39 and 40.

In this case, the transmission lines L1, L2, L6 and L7 will be congested. By increasing the capacity of these lines to twice of the capacity shown in Table I, the maintenance scheduling pattern will change as shown in Fig. 3. In this case, the total maintenance and operation cost will decrease to $62.473M. As shown in this case, the congestion in the transmission line will impact the maintenance schedule of the generation units as well as the total maintenance and operation cost.

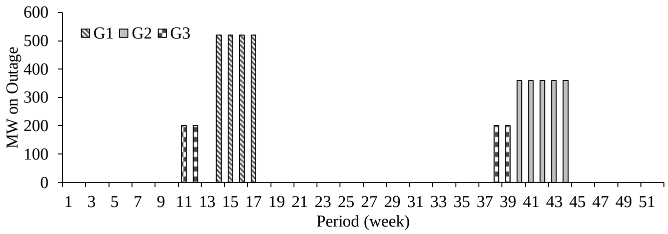

Fig. 3. Scheduled capacity on maintenance in Case 1 with the increase in the transmission line capacity

Case 2 – Maintenance scheduling with aggregated microgrids

Integrating microgrids in the power system provides higher flexibility at the demand side. Local generation assets in microgrids can serve the demand once the locational marginal price (LMP) of electricity falls beyond their marginal cost. In this case, the generation capacity of the microgrids is assumed as 30% of the demand on each bus. The marginal cost of the local generation assets in microgrids is 30 \$/MWh. Here, the total operation and maintenance cost is $62.217M and units G1 and G2 are scheduled for maintenance in weeks 14-17, and 40-44 respectively. Unit G3 goes on maintenance in weeks 9-10 and 34-35. The effect of microgrid on the net demand profile is shown in Fig. 4. The net demand is defined as the realized demand by the thermal generation units. In other words, the net demand is the demand of the power system which is not served by the generation assets within the microgrids. As shown in this figure, unit G1, which is the largest and cheapest available unit, will be on outage for maintenance in periods that the net demand is low. Similarly, unit G2 goes on maintenance in the periods that the net demand is reduced by utilizing the local generation of microgrids.

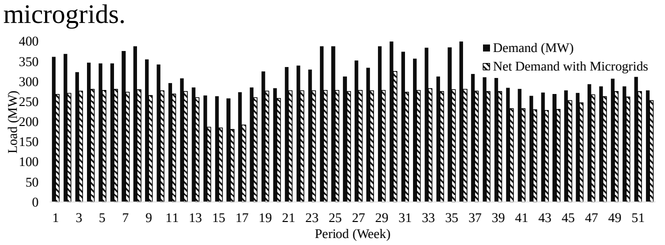

Fig. 4. Demand profile with and without microgrids

The microgrids will change the net demand profile and affect the scheduled maintenance for unit G3. As shown in this case, the scheduled maintenance is shifted from weeks 12-13 and 39-40 in Case 1, to week 9-10 and 34-35 in this Case. Moreover, as a result of deviation in the net demand the total maintenance and operation cost is decreased. As the generation capacity in the microgrids increases, the total maintenance and operation cost will further decreases. Once the microgrids are completely self-sufficient (i.e. the total demand can be served by local generation units in microgrids), the total maintenance and operation cost is decreased to $62.155M and units G1 and G2 will be on planned outage for maintenance in weeks 13-16 and 21-25 respectively. Moreover, unit G3 is maintained in weeks 23-24 and 48-49.

Case 3 – Maintenance scheduling without aggregated microgrids considering the uncertainties

In this Case, the uncertainty in demand is considered as ±10% of the nominal values that are shown in Fig. 1, and the budget of uncertainty is 100 uncertain variables in the operation horizon. The total maintenance and operation cost, in this case, is $72.08M. The generation units G1 and G2 will be on outage for maintenance in weeks 11-14, and 42-46 respectively. Unit G3 will be on outage for maintenance in weeks 15-16, and 40-41.

By comparing Case 3 to Case 1, it is shown that the total operation and maintenance cost is increased from $63.494M in Case 1 to $72.08M in Case 3 as a result of the introduced uncertainties in the long-term operation horizon. Introducing the uncertainties will also affect the pattern of the generation maintenance practices in the long-term operation horizon. As the budget of uncertainty decreases, the operation cost will decrease because the decrease in the flexibility to determine the worst realization of the uncertain variables. Once the budget of uncertainty is reduced to 30, the total maintenance and operation cost is reduced to $66.736M. Fig. 4 shows the total maintenance and operation cost with respect to the determined budget of uncertainty. As shown in Fig. 5, once the budget of uncertainty reached 240, the total maintenance and operation cost is not changed. Moreover, the increase in the uncertainty interval will lead to the increase in the total maintenance and operation cost. As shown in Fig. 5, once the uncertainty interval increases to ±15% of the nominal values, the total operation and maintenance cost will increase. Similarly, reducing the uncertainty intervals will reduce the total operation and maintenance cost.

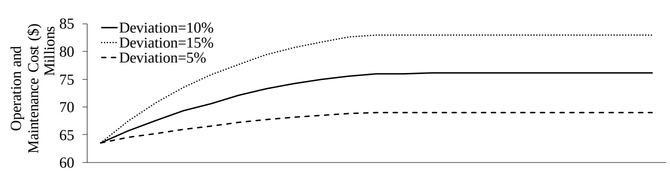

Fig. 5. Increase in the total operation and maintenance cost because of the increase in the budget of uncertainty

Case 4 – Maintenance scheduling with aggregated microgrids considering the uncertainties

In this Case, microgrids will serve the power system demand and the uncertainties associated with the marginal cost of the local generation assets in microgrids as well as the

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uncertainties in the generation capacity of microgrids are captured. The uncertainty bound for the marginal cost of generation assets in microgrids is ±20% of the nominal marginal cost. The uncertainty bound for the local generation capacity is ±10% of the nominal generation capacity within the microgrids. Once the budget of uncertainty is considered as 100 uncertain variables, the total maintenance and operation cost of the system is $67.886M, which is lower than that in Case 3. The scheduled outage for maintenance for units G1, G2 are in weeks 14-17, and 40-44 respectively. Unit G3 will be on outage for maintenance in weeks 26-27 and 51-52. Similar to Case 3, as the budget of uncertainty increases, the total maintenance and operation cost will increase. In this case, as the budget of uncertainty increases to 420, the total maintenance and operation cost increases to $72.183M. Moreover, the maintenance schedule pattern for G1 and G2 are shifted to weeks 44-47 and 48-52 and the maintenance of G3 is in weeks 15-16 and 42-43. By comparing Case 4 to Case 2, it is shown that the total maintenance and operation cost increased from $62.217M to $67.886M as a result of introducing the uncertainty sets in the risk-averse formulation. Furthermore, the generation maintenance pattern was changed.

Case 5 – Maintenance scheduling with aggregated microgrids knowing the probability distribution of uncertainties

In this case, the probability distribution functions of the uncertain variables are known and a risk-neutral solution using stochastic programming is proposed for the generation maintenance scheduling problem. The probability distribution function for electricity demand, the marginal cost of generation in the aggregated microgrids, and the generation capacity of the aggregated microgrids are considered as normal distribution functions with the mean values equal to the forecasted values and the standard deviation equal to 3.33%, 6.66% and 3.33% of the mean values. In the proposed probability distribution functions, the uncertain variables are between ±10%, ±20%, and ±10% of the mean values with 99.7% confidence interval. In this case, the uncertainties are captured by generating 3,000 scenarios using Monte-Carlo simulation and fast backward/forward method is used to reduce the number of effective scenarios to 12 by eliminating the low probability scenarios and bundle the comparable scenarios [23], [24].

The total maintenance and operation cost is $64.168M which is higher than that in Case 2 ($62.217M) and lower than that in Case 4 ($67.886M). Moreover, in this case, the generation units G1 and G2 were on maintenance in weeks 23-26, and 31-35 respectively. The generation unit G3 is on maintenance in weeks 15-16, and 42-43.

B. IEEE 118-bus system

The modified IEEE 118-bus system with the total demand profile shown in Fig. 6 is considered. The system is composed of 54 generation units and 186 transmission lines. Generation units G4, G10, G11, G27-G29, G36, G39, G40, G43-G45 with generation capacity over 300 MW are considered as candidates for the maintenance. The marginal cost of the aggregated microgrids is shown in Fig. 7. The capacity of the local generation in microgrids is 30% of the demand on the network bus. Unlike previous case study, the uncertainties in this case study include the contingencies in the transmission network. The candidate lines for N-1 outage are L1, L10, L15, L38, L51, L90, L94, L103, and L126. The deviation of demand, the marginal cost of the microgrid, and the local generation assets of the microgrids is ±10% of their respective nominal values. Cases 1-4 that were introduced for the previous case study are considered here.

In Case 1, where there is no microgrid in the system and there is no contingency considered, the total maintenance and operation cost is $649.422M and the planned outages for generation units were shown in Table III. Integrating microgrids in the power system in Case 2 decreases the total maintenance and operation cost to $529.38M, which is lower than that for Case 1.

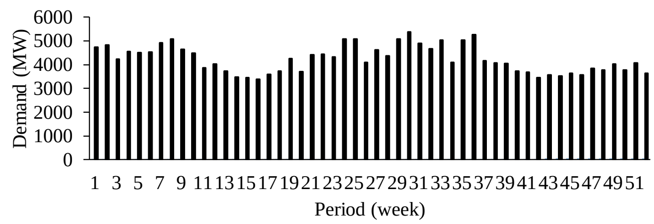

Fig. 6. Demand profile for IEEE 118-bus power system

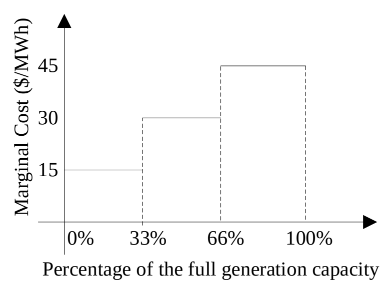

Fig. 7. Marginal cost of the local generation for the aggregated microgrids

The total maintenance and operation cost is further affected by the marginal cost (MC) of the generation units in microgrids as shown in Fig. 8. In this figure, the marginal cost of the microgrid aggregators is changed by applying marginal cost multiplier (MCM). Here, with the increase in the marginal cost of the local generation assets in microgrids, the generation units are used less frequent and the operation cost will increase. Moreover, increasing the capacity of the local generation assets in microgrids can further affect the net demand profile and reduces the total maintenance and operation cost of the power system. As shown in Fig. 8 with the increase in the capacity of the local generation assets with lower marginal costs, the total maintenance and operation cost decreases. As the marginal cost of the microgrids increases, the effect of microgrids on the total maintenance and operation cost of the power system decreases. Similarly, reduction in the installed capacity of low-cost local generation assets in microgrids will increase the total operation and maintenance cost.

In Cases 1 and 2, no contingency in transmission line was considered and the demand is set to the nominal values as shown in Fig. 6. In Cases 3 and 4, the demand and the marginal cost of the microgrids, as well as the capacity of the generation resources are considered as uncertain variables. Moreover, the worst realization of the *N-1* contingencies is also captured considering the budget of uncertainty for the contingencies in the transmission network. The budget of uncertainty for the contingency and other uncertainties in the operation horizon are 5 and 30 respectively.

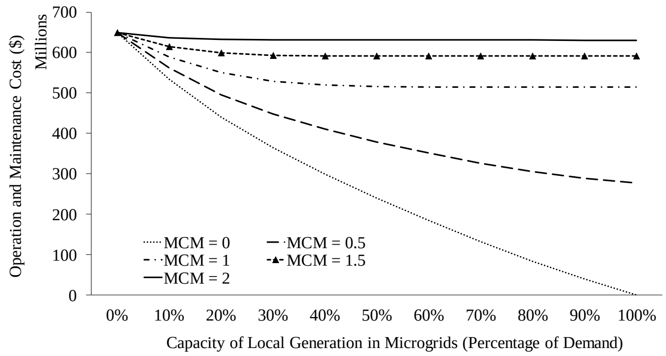

Fig. 8. Sensitivity of the total operation and maintenance cost to the installed generation capacity and marginal cost multiplier (MCM) of microgrids

TABLE III
SCHEDULED MAINTENANCE IN WEEKS FOR CASES 1-4

Component	Case 1	Case 2	Case 3	Case 4
G4	14-18	14-18	13-17	42-46
G10	40-42	40-42	14-16	12-14
G11	44-46	11-13	40-42	14-16
G27	14-16	50-52	16-18	49-51
G28	41-44	17-20	43-46	41-44
G29	48-50	14-16	41-43	18-20
G36	50-52	42-44	50-52	48-50
G39	43-45	14-16	41-43	34-36
G40	17-20	39-42	14-17	2-5
G43	40-42	42-44	46-48	40-42
G44	13-16	45-48	44-47	45-48
G45	46-48	45-47	18-20	15-17

TABLE IV
THE PERIODS OF TRANSMISSION NETWORK CONTINGENCIES FOR CASES 1-4

Component	Case 1	Case 2	Case 3	Case 4
L1	-	-	-	-
L10	-	-	-	-
L15	-	-	-	-
L38	-	-	2, 7, 8, 9, 10, 24, 25 29, 30, 31, 33	17
L51	-	-	14, 46	12,30,14,16
L90	-	-	5	21,22,26,12,2,9,10
L94	-	-	-	21, 19, 50, 43, 5, 14, 32, 48
L103	-	-	-	24,31
L126	-	-	-	29

Table III and IV show the determined outages for maintenance and the outages considered to yield the worst realization of the transmission network contingencies respectively. As shown in Table III, dispatching the local generation resources in microgrids will impact the maintenance schedule of the generation assets in the power system. Moreover, microgrids can reduce the total maintenance and operation cost of the power system by adjusting the net demand profile during the operation horizon. The total maintenance and operation cost in Case 3 is \$657.84M which is larger than that in Case 1 as a result of uncertainties captured. The total maintenance and operation cost in Case 4 is \$533.45M. Table IV shows the periods in which the contingencies in transmission network occurred for Cases 1-4. As shown in this Table, most contingencies applied to lines L38, and L94 in Cases 3 and 4 respectively.

V. CONCLUSION

This paper presents an approach for long-term maintenance scheduling in power systems considering with large penetration of microgrids and the uncertainties in the operation horizon. The uncertainty set captures the variation in the power system demand, the marginal cost of the microgrids, the installed generation capacity within the microgrids, as well as the contingencies in the transmission network. A two-stage robust optimization problem is formulated and column-and-constraint generation procedure is proposed to solve the presented problem. A budget for uncertainty is considered to address a trade-off between the conservativeness of the solution and the performance of the solution methodology. The presented approach is applied to two case studies. The sensitivity of the total maintenance and operation cost to the installed capacity of generation units in microgrids, the marginal cost of the microgrids, and the considered budget of uncertainty was shown in a case study. It is shown that if the marginal cost of the local generation in microgrids is small, leveraging the generation capacity of microgrids to regulate the demand will decrease the total operation and maintenance cost of the power system. Moreover, the total operation and maintenance cost is further decreased with the increase in the capacity of the low-cost local generation assets in microgrids. It is also shown that the risk-averse solution that captures the uncertainties in the long-term operation horizon will lead to higher maintenance and operation cost compared to the deterministic solution. The presented risk-averse solution further compared with risk-neutral solution knowing the probability distribution of the uncertain variables. It is shown that the risk-averse solution will lead to higher operation and maintenance cost as the worst realization of the uncertainties was captured.

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