A Stochastic Framework for Short-Term Operation of a Distribution Company

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***Abstract*—This paper presents a stochastic framework for short-term operation of a distribution company (disco). The proposed framework optimizes disco's operational decisions in two hierarchical stages. The first stage, called day-ahead operation stage (DAOS), deals with the operational decisions on purchases from the day-ahead market and commitment of distributed generation (DG) units. The objective of this stage is to minimize the expected operating cost while the financial risk exposed by uncertain real-time prices and loads is restricted to a given level. The model associated with this stage is based on the mixed-integer programming (MIP) format. The second stage, named real-time operation stage (RTOS), deals with disco's activities in real-time. In RTOS, decisions are made on real-time market transactions, dispatch of online DGs, and invocation of load curtailments (LCs) such that the expected operating cost is minimized. This stage is formulated as a nonlinear programming (NLP) problem. To investigate the effectiveness of the developed framework, it is applied to a typical Finnish 20-kV urban distribution network.**

***Index Terms*—Autoregressive moving average, conditional value at risk, distributed generation, distribution company.**

Nomenclature

Indices and Sets

f, F	Index and set of distribution feeders.
g, G	Index and set of DG units.
G_i	Set of DG units connected to bus i.
i, j, B	Indices and set of buses.
t, t', T	Indices and set of time periods, e.g., hours.
ω, Ω	Index and set of possible scenarios for the future.

Parameters and Constants

a, b, c	Cost function coefficients of DG units.
MSC	Main substation capacity.
P^D, Q^D	Active and reactive power loads.
$R^{\mathrm{UP}}, R^{\mathrm{DN}}$	Ramp-up/down limits of DG units.
SU, SD	Start-up and shut-down costs of DG units.
$T^{\mathrm{UP}}, T^{\mathrm{DN}}$	Minimum up/down times of DG units.
x	Reactance of distribution feeders.
Y, θ	Magnitude and phase angle of admittance of distribution feeders.
ρ^{DA}	Day-ahead market price.
ρ^{RT}	Real-time market price.
ρ^{Q}	Reactive power price.
ρ^{LC}	Price of power decreased by LC.
$p(\cdot)$	Occurrence probability of $(\cdot)$.
α, β	Confidence level and risk parameter.

Functions and Variables

I	Commitment state of DG units.
P, Q	Active and reactive powers of distribution feeders.
P^{DA}	Power purchased from day-ahead market.
P^{RT}	Power purchased from real-time market.
$P^{\mathrm{LC}}, Q^{\mathrm{LC}}$	Active and reactive powers decreased by LC.
$P^{\mathrm{DG}}, Q^{\mathrm{DG}}$	Active and reactive powers of DG units.
Q^{imp}	Reactive power imported from the external grid.
Q^{sh}	Reactive power of shunt compensators.
V, δ	Voltage magnitude and phase angle.
$X^{\mathrm{on}}, X^{\mathrm{off}}$	On and off times of DG units.
η, ζ	Auxiliary variables used in CVaR calculation.

Symbols

$(\cdot^{*})$	Optimal value of $(\cdot)$.
$(\bar{\cdot}), (\underline{\cdot})$	Upper and lower limits of $(\cdot)$.

Acronyms

ARMA	Autoregressive moving-average.
CVaR	Conditional value at risk.
DAOS	Day-ahead operation stage.
DG	Distributed generation.
LC	Load curtailment.
MIP	Mixed-integer programming.
NLP	Nonlinear programming.
RTOS	Real-time operation stage.
disco	Distribution company.

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I. INTRODUCTION

A. Aim

DELIVERING electricity to the customers in their territory is the main responsibility of the distribution companies (discos) [1]. A disco, as a private company, seeks to supply electricity to the customers with the lowest possible operating cost. In order to attain this goal, a disco has to make appropriate decisions on participating in day-ahead and real-time electricity markets, load curtailment (LC) invocation, and commitment of distributed generation (DG) units. In this way, a disco is exposed to volatile real-time prices and uncertain loads.

This paper aims to develop a stochastic framework for optimizing the decisions made by discos in a daily time horizon. The objective of the proposed framework is to minimize the expected operating cost while the risk imposed by uncertainties is restricted to a predetermined level.

B. Literature Review and Contributions

A brief review of the literature on the optimal decision framework of a disco who seeks lower operating costs is discussed here. A nodal pricing scheme for DG units reflecting their share in network loss reduction was proposed in [2]. Accordingly, this new pricing scheme would reward DGs based on their contribution in the reduced feeder losses. Moreover, this paper has shown that there would be a significant price discrepancy between nodes due to high marginal losses. Impacts of demand response realized by different time-varying electricity rating strategies on the optimal forward market purchases of a disco were studied in [3]. An energy acquisition model for a disco was developed in [4] wherein the disco has multiple options to acquire electric energy including grid purchases, investor-owned DGs, disco-owned DGs, and LC options. The model developed in [4] has been extended in [5] to include the dynamic behavior of other discos. The proposed model is a bi-level optimization problem wherein the revenues earned by individual discos are maximized in the upper sub-problems, while the total generation costs and compensation costs for LCs are minimized in the lower sub-problem. In [6], the model developed by [4] and extended by [5] has been further developed to incorporate the ac power flow constraints. The incremental contribution of DG units in network losses was integrated into the short-term operation of a distribution network [7].

A two-stage hierarchical model for a disco to determine his optimum operational decisions has been developed in [8]. The developed model is a general framework that can be a basis for many related works. In the first stage of the model, the power purchased from day-ahead market and commitment of DG units are determined; whereas, dispatch of online DG units, participating in real-time market, and LC invocation are the decisions made in the second stage. Reference [8] assumed that the next day predicted demand is purchased from the day-ahead market and then, any deviation from the forecasted values is procured from the real-time market. This assumption may result in higher operation costs since the shares of day-ahead and real-time markets are not optimized. Also, the developed model is in the mixed-integer nonlinear format that may face convergence problems.

Besides the reviewed papers, there are a few other works focused on the distribution network operation such as network reconfiguration for loss reduction [9], charging coordination of electric vehicles for loss reduction and voltage profile improvement [10], and control of energy storage systems for voltage regulation [11].

This paper extends the model developed in [8]. In this paper, unlike [8], the level of involvement in day-ahead and real-time markets is optimized. In the developed model, the uncertainties associated with real-time prices and loads are taken into account. These uncertainties were ignored in the existing articles. In addition, in this paper, dissimilar to [8], the disco risk imposed by the uncertainties is restricted to a predefined level. Finally, the optimization problems developed here are of MIP and NLP types that can be solved via available solvers.

C. Approach

The new approach is based on a scenario-based stochastic programming [12]. The uncertainties on real-time prices and loads are taken into account using time-series approaches [13] which enable constructing a set of scenarios. The initial set of scenarios is trimmed using a well-accepted scenario reduction technique to make computational burden tractable.

The developed framework consists of two hierarchical stages namely day-ahead operation stage (DAOS) and real-time operation stage (RTOS). In DAOS, a decision is made on how to participate in the day-ahead market and when to start-up and shut-down DG units. The objective is to minimize the expected operating cost while maintaining a reasonable level of risk. The risk is modeled through the conditional value at risk (CVaR) approach [14]. In RTOS, a decision is made on how to involve in the real-time market, how to dispatch online DGs, and how to invoke LCs. The objective in this stage is to minimize the expected operating cost. The resultant problems are in MIP and NLP formats.

II. THEORETICAL BASIS

A. Uncertainty Characterization

A disco encounters two major sources of uncertainty namely future real-time prices and future loads. The scenario-based stochastic programming method is employed here to handle the uncertainties [12]. In this method, disco's decisions are made considering the value of the objective over a set of likely scenarios for the future. In this paper, a scenario is a sequence of hourly real-time prices and loads. The time series autoregressive moving-average (ARMA) model is used to generate likely scenarios [13]. The ARMA model expresses the future values of a parameter as a linear function of its past values and the past values of a noise. Although increasing the number of scenarios improves the accuracy of resultant solution, a large number of scenarios is usually cumbersome for real-world applications. Therefore, the initial set of scenarios generated by ARMA is reduced to a tractable set using a well-accepted scenario reduction method [15]. A scenario reduction technique, by eliminating least effective scenarios, provides an effective tool to compromise between accuracy and tractability. Among available algorithms, an iterative technique designated as *fast-forward* is used in this paper. Given a set of initial scenarios, the algorithm picks a scenario such that the probability distance between the reduced and original sets of scenarios is minimized.

B. Risk Measure

Several techniques can be found in the literature used for risk management such as minimum variance, value at risk, and CVaR methodologies to name just a few [14]. Among these approaches, CVaR has received more attention especially in portfolio optimization of energy service providers [16]. In general, CVaR denotes the expected loss of a predefined percent of the worst scenarios. In this paper, CVaR is used to model the risks faced by a disco for uncertain real-time prices and loads. Accordingly, CVaR is defined as the expected cost of a given percent of scenarios with higher costs. The risk measure is integrated into the developed model as a constraint which enforces the risk within a pre-specified level.

III. Developed Decision Framework

This paper considers a price-taker disco who can acquire electrical energy from multiple sources including day-ahead and real-time markets, DG units, and LC options. In order to minimize the operating costs, the disco has to determine the amounts of energy purchased from day-ahead market, exchanged with real-time market, produced by DG units, and curtailed by LCs. The two-stage decision framework is shown in Fig. 1. While the disco is fully aware of the day-ahead market prices for next 24 hours, both the hourly purchases from the day-ahead market and commitment of DG units are determined at the beginning of the day. These decisions are optimally made through the DAOS problem which is solved once a day. Throughout the day, keeping in mind his day-ahead decisions, the disco makes decisions on the amounts of power to be exchanged in real-time market, produced by online DG units, and the load to be curtailed by LCs. The RTOS problem is solved once an hour to optimize these decisions.

A. Day-Ahead Operation Stage (DAOS)

1) Objective Function: The objective function associated with day-ahead decision stage can be formulated as

$$\begin{aligned}\text{Minimize} &\sum_{t\in T}\rho_t^{\mathrm{DA}}P_t^{\mathrm{DA}}+\sum_{\omega\in\Omega}\sum_{t\in T}p(\omega)\rho_{t,\omega}^{\mathrm{RT}}P_{t,\omega}^{\mathrm{RT}}\\ &+\sum_{\omega\in\Omega}\sum_{t\in T}\sum_{i\in B}p(\omega)\rho_{i,t}^{\mathrm{LC}}P_{i,t,\omega}^{\mathrm{LC}}+\sum_{t\in T}\sum_{g\in G}X_{g,t}^{\mathrm{on}}\mathrm{SU}_g\\ &+\sum_{\omega\in\Omega}\sum_{t\in T}\sum_{g\in G}p(\omega)\left[a_gI_{g,t}+b_gP_{g,t,\omega}^{\mathrm{DG}}+c_gP_{g,t,\omega}^{\mathrm{DG}^2}\right]\\ &+\sum_{t\in T}\sum_{g\in G}X_{g,t}^{\mathrm{off}}\mathrm{SD}_g. \qquad (1)\end{aligned}$$

The first term is the total cost of power purchased from the day-ahead market. The second term represents the expected cost of the power procured from the real-time market. The third term denotes the expected cost of compensating LCs.

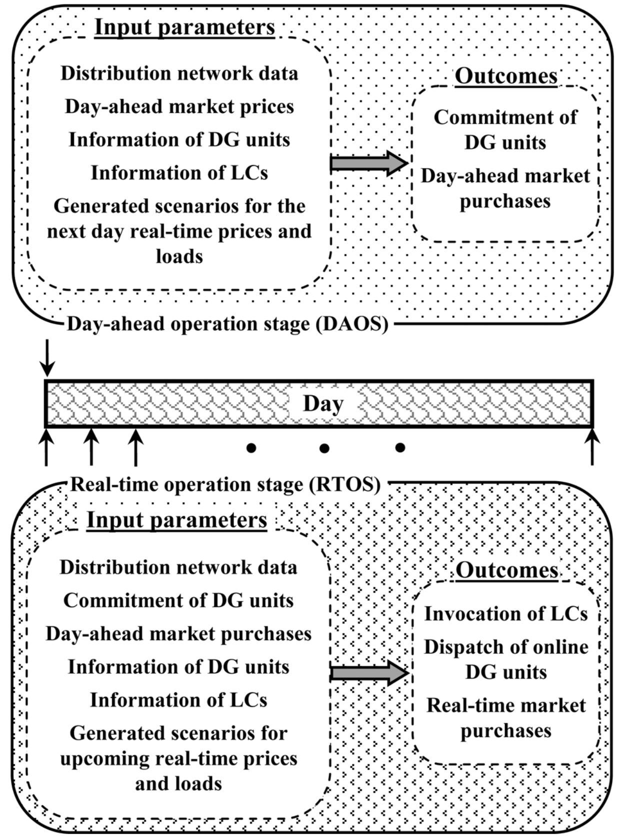

Fig. 1. Proposed two-stage decision framework for discos.

The fourth, fifth, and sixth terms of the objective function represent the start-up cost, the expected production cost, and the shut-down cost of DG units, respectively. The quadratic terms of DG units' production costs are approximated using piecewise linear method in order to make the model linear [17]. It is worthy to note that, in some deregulated systems, discos are forbidden from owning/operating DG units and thus, they would not pay the production cost of DG units. DG units and their operating costs, however, are considered here to keep the mathematical model general.

2) Constraints: Technical constraints considered in the day-ahead decision making of a disco are as follows.

Network Equations: These constraints guarantee that the operating point satisfies the power flow equations. The DC power flow model is adopted in the day-ahead operation model so that the DAOS problem statement is kept linear. It has to be noted that the inaccuracy induced by DC network model does not make a great concern since the solution of the DAOS problem is inherently exposed to various sources of error such as the uncertainty of predicted real-time market prices and loads. The active power flowing through the feeder connecting bus i to bus j at time t and scenario ω can be calculated from

$$P_{ij,t,\omega}^{f}=\frac{1}{x_{ij}^{f}}(\delta_{i,t,\omega}-\delta_{j,t,\omega});\quad \forall f\in F,\forall t\in T,\forall\omega\in\Omega. \qquad (2)$$

Feeder Flow Limits: These constraints ensure that flow of feeders are limited by their capacities

$$-\overline{P_{ij}^{f}} \leq P_{ij,t,\omega}^{f} \leq \overline{P_{ij}^{f}}; \quad \forall f \in F,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{3}$$

Active Power Balance Equations: These constraints ensure the balance of the active power at different nodes except the main substation

$$\sum_{g \in G_i} P_{g,t,\omega}^{\mathrm{DG}} + P_{i,t,\omega}^{\mathrm{LC}} - \sum_{f \in F \& j \in B} P_{ij,t,\omega}^{f} - P_{i,t,\omega}^{D} = 0; \quad \forall i \neq 1,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{4}$$

Main Substation Active Power Balance Equation: The main substation bus is the only connection point between a distribution network and the external grid. Thus, the power purchased from the wholesale market should be injected at this point. The power balance equation in the main substation is used to calculate the active power imported from the external grid

$$P_{t}^{\mathrm{DA}} + P_{t,\omega}^{\mathrm{RT}} + \sum_{g \in G_i} P_{g,t,\omega}^{\mathrm{DG}} + P_{i,t,\omega}^{\mathrm{LC}} - \sum_{f \in F \& j \in B} P_{ij,t,\omega}^{f} - P_{i,t,\omega}^{D} = 0 \quad i = 1,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{5}$$

Main Substation Capacity Limit: This constraint guarantees that the power imported to a distribution network is limited by the capacity of transformers located in the main substation

$$P_{t}^{\mathrm{DA}} + P_{t,\omega}^{\mathrm{RT}} \leq \mathrm{MSC}; \quad \forall t \in T,\ \forall \omega \in \Omega. \tag{6}$$

Distribution Transformer Capacity Limits: These equations ensure that the loading of distribution transformers are limited by their capacities

$$P_{i,t,\omega}^{D} - P_{i,t,\omega}^{\mathrm{LC}} \leq \overline{P_i}; \quad \forall i \in B,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{7}$$

DG Units Generation Limits: These constraints guarantee that the power generated by a DG unit is within the upper and lower generation limits of that unit

$$I_{g,t}\underline{P_{g}^{\mathrm{DG}}} \leq P_{g,t,\omega}^{\mathrm{DG}} \leq I_{g,t}\overline{P_{g}^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{8}$$

Available LC Limits: This constraint ensures that the amount of LC invoked by the disco at bus i, time t, and scenario ω is positive and also limited to the total demand at that bus

$$0 \leq P_{i,t,\omega}^{\mathrm{LC}} \leq P_{i,t,\omega}^{D}; \quad \forall i \in B,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{9}$$

Note that the amount of LC invoked is a continuous variable while the load interruption is usually adopted in a discrete manner in a real-world. This is a well-accepted assumption that is adopted here to simplify the problem statement.

DG Units Ramping Constraints: The power generated by DG units should adhere to the ramp rate constraints, i.e., ramp-up and ramp-down constraints, as

$$P_{g,t+1,\omega}^{\mathrm{DG}} - P_{g,t,\omega}^{\mathrm{DG}} \leq [1 - I_{g,t+1}(1 - I_{g,t})]R_{g}^{\mathrm{UP}} + I_{g,t+1}(1 - I_{g,t})\underline{P_{g}^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega \tag{10}$$

$$P_{g,t,\omega}^{\mathrm{DG}} - P_{g,t+1,\omega}^{\mathrm{DG}} \leq [1 - I_{g,t}(1 - I_{g,t+1})]R_{g}^{\mathrm{DN}} + I_{g,t}(1 - I_{g,t+1})\underline{P_{g}^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega. \tag{11}$$

The above constraints are not in a linear format since they contain the product of binary variables. However, this issue does not make any concern because they can be converted into linear expressions adopting the technique presented in [18].

DG Units Minimum Up/Down-Time Constraints: These equations ensure that the commitment of DG units respects the minimum up and minimum down time constraints

$$\sum_{t'=1}^{T_g^{\mathrm{UP}}} I_{g,t-t'} \geq T_{g}^{\mathrm{UP}} X_{g,t}^{\mathrm{off}}; \quad \forall g \in G,\ \forall t \in T \tag{12}$$

$$\sum_{t'=1}^{T_g^{\mathrm{DN}}} (1 - I_{g,t-t'}) \geq T_{g}^{\mathrm{DN}} X_{g,t}^{\mathrm{on}}; \quad \forall g \in G,\ \forall t \in T. \tag{13}$$

Again, the product of binary variables can be converted into linear expressions [18].

Coordination Constraints: These constraints guarantee that the relationships between binary variables denoting the status of a DG unit are logical and there is no conflicting situation

$$I_{g,t+1} - I_{g,t} \leq X_{g,t+1}^{\mathrm{on}}; \quad \forall g \in G,\ \forall t \in T \tag{14}$$

$$I_{g,t} - I_{g,t+1} \leq X_{g,t+1}^{\mathrm{off}}; \quad \forall g \in G,\ \forall t \in T \tag{15}$$

$$I_{g,t+1} - I_{g,t} = X_{g,t+1}^{\mathrm{on}} - X_{g,t+1}^{\mathrm{off}}; \quad \forall g \in G,\ \forall t \in T. \tag{16}$$

Risk Constraints: These constraints are incorporated into the optimization problem to manage the risk imposed by uncertain real-time prices and loads

$$\begin{aligned} &\frac{1}{1-\alpha} \sum_{\omega \in \Omega} p(\omega)\eta_{t,\omega} - \zeta_t \\ &\quad \leq \beta \Bigg\{ \rho_{t}^{\mathrm{DA}} P_{t}^{\mathrm{DA}} + \sum_{\omega \in \Omega} p(\omega)\rho_{t,\omega}^{\mathrm{RT}} P_{t,\omega}^{\mathrm{RT}} \\ &\qquad + \sum_{\omega \in \Omega}\sum_{i \in B} p(\omega)\rho_{i,t}^{\mathrm{LC}} P_{i,t,\omega}^{\mathrm{LC}} + \sum_{g \in G} X_{g,t}^{\mathrm{on}}\mathrm{SU}_g \\ &\qquad + \sum_{g \in G} X_{g,t}^{\mathrm{off}}\mathrm{SD}_g + \sum_{\omega \in \Omega}\sum_{g \in G} p(\omega) \\ &\qquad \times \left[a_g I_{g,t} + b_g P_{g,t,\omega}^{\mathrm{DG}} + c_g P_{g,t,\omega}^{\mathrm{DG}^2}\right] \Bigg\}; \quad \forall t \in T. \end{aligned} \tag{17}$$

The left side of (17) is CVaR, i.e., the expected operating cost in $(1-\alpha) \times 100$ percent of the worst scenarios. The right side is the expected operating cost at hour t multiplied by β. Here, β models the tradeoff between the expected cost and risk. The value of β depends on the disco preferences. A risk-averse disco selects a value close to one to hedge risk. The favorite value, however, would be large for a risk-taker disco that prefers to be exposed to a higher risk in the hope of achieving a lower cost. Here, the value of this parameter is assumed to be known.

CVaR Constraints: These constraints are required for calculating CVaR

$$\rho_t^{\mathrm{DA}} P_t^{\mathrm{DA}} + \rho_{t,\omega}^{\mathrm{RT}} P_{t,\omega}^{\mathrm{RT}} + \sum_{i\in B} \rho_{i,t}^{\mathrm{LC}} P_{i,t,\omega}^{\mathrm{LC}} + \sum_{g\in G} X_{g,t}^{\mathrm{on}} \mathrm{SU}_g + \sum_{g\in G} \left[a_g I_{g,t} + b_g P_{g,t,\omega}^{\mathrm{DG}} + c_g P_{g,t,\omega}^{\mathrm{DG}^2} \right] + \sum_{g\in G} X_{g,t}^{\mathrm{off}} \mathrm{SD}_g + \zeta_t - \eta_{t,\omega} \le 0; \quad \forall t\in T,\ \forall \omega \in \Omega \tag{18}$$

$$\eta_{t,\omega} \ge 0; \quad \forall t\in T,\ \forall \omega\in\Omega. \tag{19}$$

In the above expressions, ζ_t establishes a threshold to identify $(1-\alpha)\times 100$ percent of the worst scenarios at hour t. Also, $\eta_{t,\omega}$ is the difference between ζ_t and the network operating cost at hour t in $(1-\alpha)\times 100$ percent of the worst scenarios and zero otherwise. The above problem is based on the MIP format which can be solved via available solvers. The optimal decisions from this optimization problem include the commitment of DG units and day-ahead market purchases which are passed to the RTOS problem as an input parameter.

B. Real-Time Operation Stage (RTOS)

1) Objective Function: The objective function of the real-time decision making of a disco seeks to minimize the expected cost of providing customers' load as

$$\text{Minimize} \sum_{t\in T} \rho_t^{\mathrm{DA}} P_t^{\mathrm{DA}^*} + \sum_{\omega\in\Omega}\sum_{t\in T} p(\omega) \rho_{t,\omega}^{\mathrm{RT}} P_{t,\omega}^{\mathrm{RT}} + \sum_{\omega\in\Omega}\sum_{t\in T}\sum_{i\in B} p(\omega)\rho_{i,t}^{\mathrm{LC}} P_{i,t,\omega}^{\mathrm{LC}} + \sum_{t\in T}\sum_{g\in G} X_{g,t}^{\mathrm{on}*}\mathrm{SU}_g + \sum_{\omega\in\Omega}\sum_{t\in T}\sum_{g\in G} p(\omega)\left[a_g I_{g,t}^{*} + b_g P_{g,t,\omega}^{\mathrm{DG}} + c_g P_{g,t,\omega}^{\mathrm{DG}^2}\right] + \sum_{t\in T}\sum_{g\in G} X_{g,t}^{\mathrm{off}^*}\mathrm{SD}_g + \sum_{\omega\in\Omega}\sum_{t\in T} p(\omega)\rho_{t,\omega}^{Q} Q_{t,\omega}^{\mathrm{imp}}. \tag{20}$$

The first, second and third terms of (20) respectively represent the total payment for the power procured from the day-ahead market, the expected cost of the power purchased from the real-time market, and the expected compensation cost of LCs. The fourth, fifth and sixth terms of the objective function represent the start-up cost, the expected production cost, and the shut-down cost of DG units, respectively. The last term represents the cost of the reactive power imported from the main grid. In the above problem, the ramp rate limits are inter-temporal constraints since, because of them, the actions taken now affect future time periods. That is why the RTOS problem needs to be defined with multi-period look back and ahead.

2) Constraints: Technical constraints considered in the real-time decision making are described in the following.

Network Equations: Similar to the DAOS problem, these constraints ensure that the operating point satisfies the power flow equations. In contrast to the DAOS problem wherein the DC model of network is used, the AC power flow equations are taken into account in the real-time operation model. The active and reactive powers flowing through the feeder connecting bus i to bus j at time t and scenario ω are as

$$P_{ij,t,\omega}^{f} = -Y_{ij}^{f} V_{i,t,\omega} V_{j,t,\omega} \cos\left(\delta_{i,t,\omega} - \delta_{j,t,\omega} + \theta_{ij}^{f}\right) + Y_{ij}^{f} V_{i,t,\omega}^{2} \cos\left(\theta_{ij}^{f}\right); \quad \forall f\in F,\ \forall t\in T,\ \forall\omega\in\Omega \tag{21}$$

$$Q_{ij,t,\omega}^{f} = -Y_{ij}^{f} V_{i,t,\omega} V_{j,t,\omega} \sin\left(\delta_{i,t,\omega} - \delta_{j,t,\omega} + \theta_{ij}^{f}\right) + Y_{ij}^{f} V_{i,t,\omega}^{2} \sin\left(\theta_{ij}^{f}\right); \quad \forall f\in F,\ \forall t\in T,\ \forall\omega\in\Omega. \tag{22}$$

Active and Reactive Power Balance Equations: These equations guarantee the balance of the active and reactive powers at different nodes except the main substation

$$\sum_{g\in G_i} P_{g,t,\omega}^{\mathrm{DG}} + P_{i,t,\omega}^{\mathrm{LC}} - \sum_{f\in F \& j\in B} P_{ij,t,\omega}^{f} - P_{i,t,\omega}^{D} = 0; \quad i\ne 1,\ \forall t\in T,\ \forall\omega\in\Omega \tag{23}$$

$$\sum_{g\in G_i} Q_{g,t,\omega}^{\mathrm{DG}} + Q_{i,t,\omega}^{\mathrm{sh}} + Q_{i,t,\omega}^{\mathrm{LC}} - \sum_{f\in F \& j\in B} Q_{ij,t,\omega}^{f} - Q_{i,t,\omega}^{D} = 0; \quad i\ne 1,\ \forall t\in T,\ \forall\omega\in\Omega. \tag{24}$$

Main Substation Active and Reactive Power Balance Equations: These equations are used to calculate the active and reactive powers imported from the main grid

$$P_t^{\mathrm{DA}^*} + P_{t,\omega}^{\mathrm{RT}} + \sum_{g\in G_i} P_{g,t,\omega}^{\mathrm{DG}} + P_{i,t,\omega}^{\mathrm{LC}} - \sum_{f\in F \& j\in B} P_{ij,t,\omega}^{f} - P_{i,t,\omega}^{D} = 0; \quad i=1,\ \forall t\in T,\ \forall\omega\in\Omega \tag{25}$$

$$Q_{t,\omega}^{\mathrm{imp}} + \sum_{g\in G_i} Q_{g,t,\omega}^{\mathrm{DG}} + Q_{i,t,\omega}^{\mathrm{sh}} + Q_{i,t,\omega}^{\mathrm{LC}} - \sum_{f\in F \& j\in B} Q_{ij,t,\omega}^{f} - Q_{i,t,\omega}^{D} = 0; \quad i=1,\ \forall t\in T,\ \forall\omega\in\Omega. \tag{26}$$

Bus Voltage Limits: These limits guarantee an acceptable voltage level at all nodes. The main substation in a distribution network plays a similar role with the voltage controlled buses in transmission networks. Thus, the voltage magnitude at the main substation bus is held constant

$$\underline{V_i} \le V_{i,t,\omega} \le \overline{V_i}; \quad \forall i\in B,\ \forall t\in T,\ \forall\omega\in\Omega \tag{27}$$

$$V_{i,t,\omega} = \text{Constant}; \quad i=1,\ \forall t\in T,\ \forall\omega\in\Omega. \tag{28}$$

Main Substation Capacity Limit: This constraint is incorporated to avoid overloading the transformers located in the main substation

$$\left[\left(P_t^{\mathrm{DA}} + P_{t,\omega}^{\mathrm{RT}}\right)^2 + Q_{t,\omega}^{\mathrm{imp}^2}\right]^{0.5} \le \mathrm{MSC}; \quad \forall t\in T,\ \forall\omega\in\Omega. \tag{29}$$

Distribution Transformer Capacity Limits: These equations are incorporated to limit the loading of the transformers located in distribution substations

$$\left[\left(P_{i,t,\omega}^{D} - P_{i,t,\omega}^{\mathrm{LC}}\right)^2 + \left(Q_{i,t,\omega}^{D} - Q_{i,t,\omega}^{\mathrm{LC}}\right)^2\right]^{0.5} \le \overline{P_i}; \quad \forall i\in B,\ \forall t\in T,\ \forall\omega\in\Omega. \tag{30}$$

Feeder Flow Limits: These constraints cap the flow of feeders with their capacities

$$-\overline{P_{ij}^{f}} \leq \left(P_{ij,t,\omega}^{f^2} + Q_{ij,t,\omega}^{f^2}\right)^{0.5} \leq \overline{P_{ij}^{f}};$$
$$\forall f \in F,\ \forall t \in T,\ \forall \omega \in \Omega. \quad (31)$$

Shunt Compensator Capacity Limits: These constraints enforce the reactive power of compensators within their maximum and minimum limits

$$\underline{Q_i^{\mathrm{sh}}} \leq Q_{i,t,\omega}^{\mathrm{sh}} \leq \overline{Q_i^{\mathrm{sh}}}; \quad \forall i \in B,\ \forall t \in T,\ \forall \omega \in \Omega. \quad (32)$$

DG Units Generation Limits: These constraints guarantee that the active and reactive powers of DG units are bound within their corresponding maximum and minimum limits

$$I_{g,t}^{*}\underline{P_g^{\mathrm{DG}}} \leq P_{g,t,\omega}^{\mathrm{DG}} \leq I_{g,t}^{*}\overline{P_g^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega \quad (33)$$

$$I_{g,t}^{*}\underline{Q_g^{\mathrm{DG}}} \leq Q_{g,t,\omega}^{\mathrm{DG}} \leq I_{g,t}^{*}\overline{Q_g^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega. \quad (34)$$

DG Units Ramping Constraints: These constraints guarantee that the power generated by DG units satisfies the associated ramp rates

$$P_{g,t+1,\omega}^{\mathrm{DG}} - P_{g,t,\omega}^{\mathrm{DG}} \leq [1 - I_{g,t+1,\omega}^{*}(1 - I_{g,t,\omega}^{*})]R_g^{\mathrm{UP}}$$
$$+ I_{g,t+1,\omega}^{*}(1 - I_{g,t,\omega}^{*})\underline{P_g^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega \quad (35)$$

$$P_{g,t,\omega}^{\mathrm{DG}} - P_{g,t+1,\omega}^{\mathrm{DG}} \leq [1 - I_{g,t,\omega}^{*}(1 - I_{g,t+1,\omega}^{*})]R_g^{\mathrm{DN}}$$
$$+ I_{g,t,\omega}^{*}(1 - I_{g,t+1,\omega}^{*})\underline{P_g^{\mathrm{DG}}}; \quad \forall g \in G,\ \forall t \in T,\ \forall \omega \in \Omega. \quad (36)$$

Available LC Limits: Similar to the case of the day-ahead operation model, the amount of LC invoked by the disco is capped with the associated upper limit

$$0 \leq P_{i,t,\omega}^{\mathrm{LC}} \leq P_{i,t,\omega}^{D}; \quad \forall i \in B,\ \forall t \in T,\ \forall \omega \in \Omega. \quad (37)$$

Constant Power Factor Load Reduction: Since invoking LC lessens both the active and reactive powers of a given load point, this constraint is incorporated to keep the associated power factor constant

$$P_{i,t,\omega}^{\mathrm{LC}}Q_{i,t,\omega}^{D} - Q_{i,t,\omega}^{\mathrm{LC}}P_{i,t,\omega}^{D} = 0; \quad \forall i \in B,\ \forall t \in T,\ \forall \omega \in \Omega. \quad (38)$$

The RTOS problem, described by (20)–(38), is based on the NLP format. The optimal decisions from this optimization problem include the invocation of LCs, dispatch of online DG units, and real-time market purchases.

IV. Numerical Results

A. System Description

The proposed framework is applied to a typical Finnish 20-kV urban distribution network. The basic data of the system can be found in [19] and [20]. The single-line diagram of this distribution network is depicted in Fig. 2. The main substation as the only connection point between the distribution network and the external grid supplies 144 distribution substations (20/0.4 kV) through 6 underground cable feeders. In the following simulations, three 500-kW DG units are assumed to be connected to buses 2, 26, and 59.

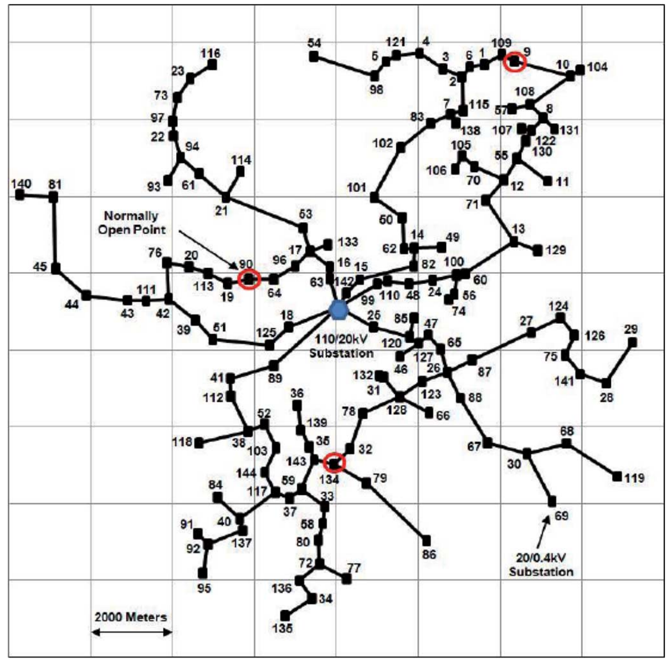

Fig. 2. Single-line diagram of the Finnish 20-kV distribution network [19].

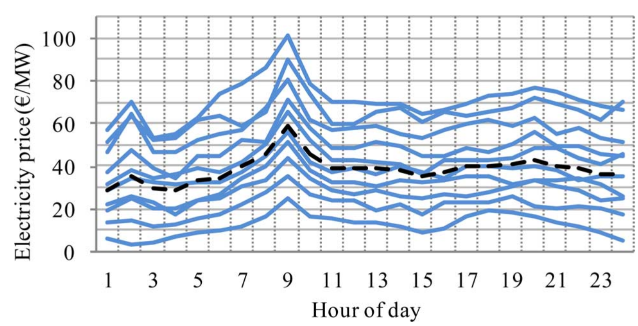

Fig. 3. Real-time price scenarios.

B. Data

The ARMA model corresponding to real-time prices is estimated through the Nordic electricity market data from January 2010 to December 2011. The historical data of the Nordic electricity market are available online at [21]. Thereafter, the uncertainty of next day prices is modeled via a set of 1000 scenarios which are reduced to 10 scenarios. The real-time price scenarios as well as the expected real-time prices are depicted in Fig. 3. In this figure, the dashed black line shows the expected real-time prices. The day-ahead, predicted real-time, and actual real-time prices are illustrated in Fig. 4.

An ARMA model is also determined for electricity load using the Nordic electricity market data from January 2010 to December 2011. Implementing the ARMA model, the next day

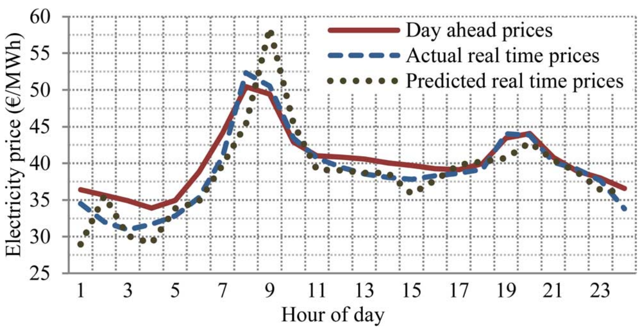

Fig. 4. Day-ahead, predicted real-time, and actual real-time market prices.

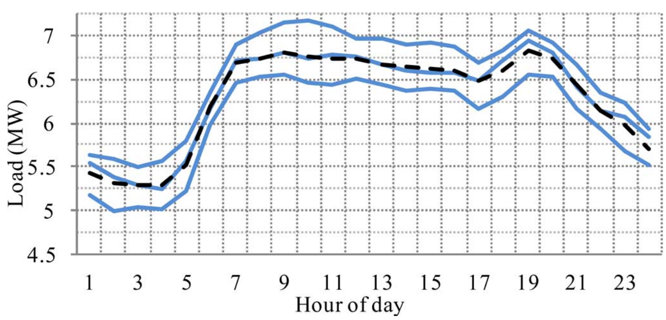

Fig. 5. Load scenarios.

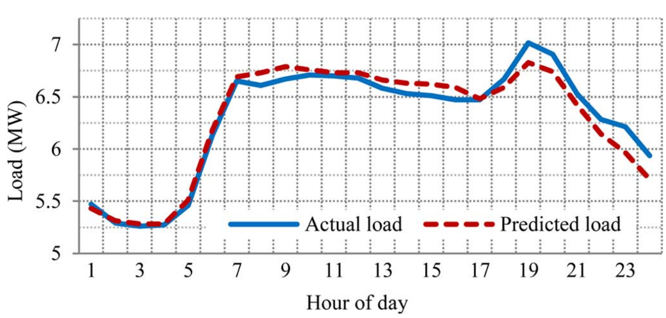

Fig. 6. Predicted and actual electricity loads.

load uncertainty is modeled via a 100-scenario set which is reduced to 3 scenarios. The load scenarios as well as the expected loads are shown in Fig. 5. In this figure, the dashed black line depicts the expected hourly loads. It should be noted that different load points in the network have the same profile.

The predicted and actual electricity loads are illustrated in Fig. 6. As anticipated, the prediction error in electricity load forecasting is much lower than that of electricity price forecasting. This is the main reason that fewer scenarios are used for modeling the load uncertainty compared to the numbers required for modeling the price uncertainty.

Combining 10 price scenarios and 3 load scenarios, a joint scenario set of 30 scenarios is achieved. Note that the probability of each resulting scenario is equal to the product of the occurrence probability of corresponding load and price scenarios. The scenarios are considered as input data for simulations. Finally, it should be noted that all of the data used in case studies are available online at [22].

Note that the number of scenarios is usually determined on the basis of a tradeoff between the accuracy of the results and

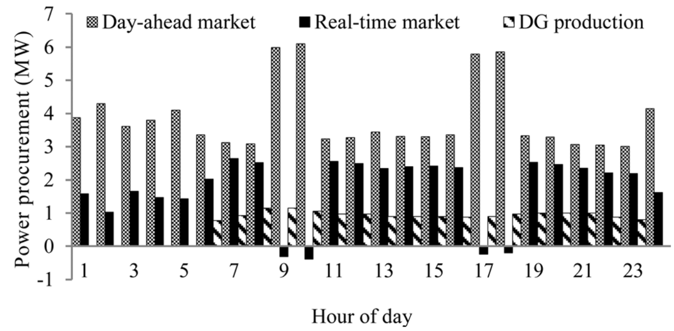

Fig. 7. Electricity procurement strategy of the disco.

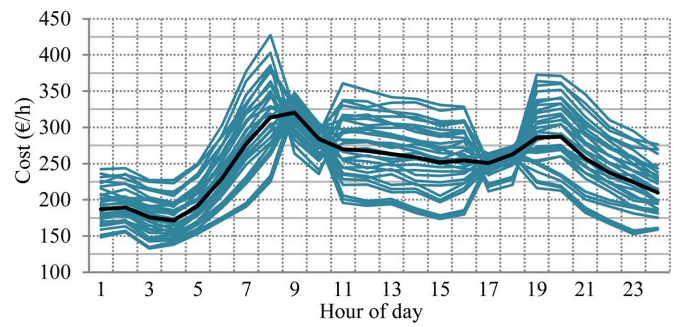

Fig. 8. Hourly procurement costs for different scenarios.

computational complexities. Too few scenarios might lead to inaccurate results, while too many scenarios may make the problem computationally difficult. In this paper, the number is determined through engineering judgments such that the accuracy of the results is guaranteed.

C. Results

The DAOS problem is solved for the risk parameter of $\beta = 1.2$ and the confidence level of $\alpha = 0.9$. Fig. 7 provides the information on procurement strategy of the disco. Since day-ahead prices are lower than the predicted real-time prices at hours 9, 10, 17, and 18, the disco, reasonably, prefers to involve in day-ahead market rather than uncertain more expensive real-time market at these hours. However, at the remaining hours, the disco compromises between the more expensive day-ahead market and risky real-time market. According to the results, the shares of day-head purchase, real-time purchase, and DG production from the disco energy procurement are 61%, 27%, and 11%, respectively. Hence, day-ahead market is the main source of electricity for the considered disco. Note that the share of LC is zero mainly due to high penalty costs, i.e., ρ^{LC}, and the great technical condition of the Finnish network. The considered network neither suffers from capacity shortages nor from under voltage problems.

The hourly procurement costs for different scenarios are depicted in Fig. 8 in which a black line shows the expected hourly costs. It can be observed that cost variance and hence risk are higher when the share of volatile real-time market is higher. In contrast, cost variance is less at hours 9, 10, 17, and 18 since, during these times, the disco relies on day-ahead market rather than volatile real-time market.

TABLE I
INFORMATION ON THE TOTAL PROCUREMENT COST [€]

Decision framework	Cost of the best scenario	Expected cost	Cost of the worst scenario
Reliance on real-time market	2018.12	5809.17	10495.6
Proposed stochastic optimization	4621.03	5919.44	7431.86
Reliance on day-ahead market	5377.52	6030.06	6336.43

TABLE II
INITIAL AND REVISED DISCO DECISIONS AND ASSOCIATED COSTS

Hour	DG [MWh]		Real time [MWh]		Cost [€/h]	
	Initial	Revised	Initial	Revised	Expected	Actual
1	0	0	1.585	1.630	186.77	197.03
2	0	0	1.024	1.027	189.37	185.76
3	0	0	1.656	1.681	175.85	177.94
4	0	0	1.465	1.501	171.35	176.24
5	0	0	1.429	1.393	191.52	188.82
6	0.773	0.682	2.024	2.123	229.62	235.02
7	0.917	1	2.644	2.562	277.37	283.88
8	1.149	1.433	2.520	2.127	313.86	326.63
9	1.149	1.5	-0.321	-0.786	320.31	319.24
10	1.056	1.467	-0.392	-0.825	283.89	287.34
11	0.965	1.097	2.561	2.404	269.66	275.91
12	0.965	0.957	2.498	2.487	267.59	271.64
13	0.891	0.992	2.342	2.187	263.28	264.93
14	0.891	0.946	2.399	2.307	258.87	260.02
15	0.891	0.741	2.415	2.508	251.38	257.55
16	0.873	0.908	2.369	2.244	254.02	255.49
17	0.891	1.069	-0.240	-0.355	250.67	257.18
18	0.965	1.083	-0.205	-0.233	262.51	269.65
19	0.992	1.152	2.534	2.574	285.57	305.57
20	0.992	1.271	2.465	2.385	287.11	302.13
21	0.992	1.109	2.350	2.391	257.41	266.88
22	0.873	0.990	2.215	2.278	237.32	249.18
23	0.798	0.810	2.190	2.429	224.15	239.98
24	0	0	1.622	1.829	210	213.28

Table I lists information on the total procurement cost over the considered horizon. It also provides a comparison between the proposed stochastic optimization framework and two extreme cases of reliance on day-ahead market and reliance on real-time market. Note that these extreme cases are deterministic since their procurement strategies are already fixed without considering the uncertainties. Owing to the results, reliance on day-ahead market yields a higher expected cost with lower risk. In contrast, reliance on real-time market leads to lower expected cost with much higher risk. In this case, the procurement cost may increase by more than 80% over the expected cost. The stochastic optimization framework, however, compromises between the expected cost and risk considering disco preferences. Here, the procurement cost increases by 26% in the worst scenario.

As discussed earlier, day-ahead decisions are based on the forecasted loads and real-time prices. Thus, the disco has to revise his decisions throughout the day according to the actual loads and prices. Here, disco decisions on the dispatch of online DGs and real-time purchases are revised via the RTOS problem. Initial and revised decisions as well as the resultant costs are illustrated in Table II. As shown in this table, the initial and revised values are somewhat different. The main reason for the difference comes from prediction error. The revisions observed in the results can be grouped into the following types:

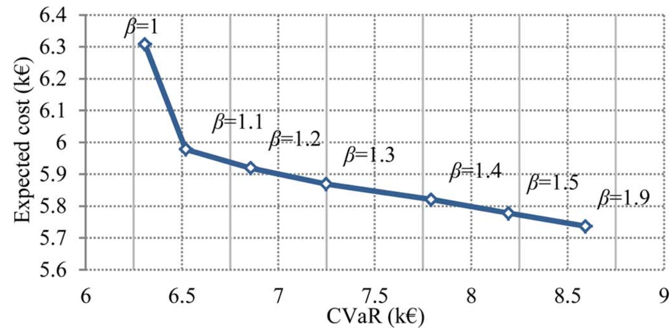

Fig. 9. Expected cost versus CVaR.

Type 1: in this type, DGs are not committed; hence, the difference between the predicted and actual loads is inevitably exchanged in real-time market. In such a situation, the difference between the initial and actual real-time exchanges and the difference between the predicted and actual load are the same. Evidently, procurement cost can be either decreased or increased according to the difference between the predicted and actual real-time prices. Hours 1 to 5 and 24 are samples for this type of revision.

Type 2: in this type, DGs output power and real-time purchase are increased. This occurs when a disco has underestimated load in DAOS. The changes in real-time purchase and DGs production depend on real-time price. The amount of the electricity produced by DGs is increased as the associated real-time price increases. Clearly, procurement cost increases since more electricity is procured. Hours 19 and 21 are samples for this type of revision.

Type 3: in this type, DGs output power is increased and real-time purchase is decreased. The reason for this is that higher real-time price occurred. Hours 7 and 20 are examples for this type of revision.

Type 4: in this type, DGs output power is decreased while real-time purchase is increased. This is due to overestimating real-time price in DAOS. Hours 6 and 15 are samples for this type of revision.

Type 5: in this type, DGs output power and real-time purchase are both decreased. This occurs when electricity demand is overestimated in DAOS. Hour 12 is a sample for this type.

It should be noted that the above revision types are observed in this case study; hence, the provided 5-type grouping is not general. For example, the underestimation of both real-time price and demand definitely decreases real-time purchase while it may either decrease or increase DGs output power.

D. Solution Sensitivity

Fig. 9 provides the evolution of the expected cost versus CVaR for different values of β. It can be seen that the expected cost is decreased and CVaR is increased as β increases. The expected cost is ranged between $\mathrm{k€}5.7$ and $\mathrm{k€}6.3$. Also, CVaR is ranged between $\mathrm{k€}6.3$ and $\mathrm{k€}8.6$. For a risk-averse disco ($\beta = 1$), both of the expected cost and CVaR are $\mathrm{k€}6.3$. On the other hand, the expected cost is $\mathrm{k€}5.7$ with the CVaR of $\mathrm{k€}8.6$ for a risk-taker disco ($\beta = 1.9$).

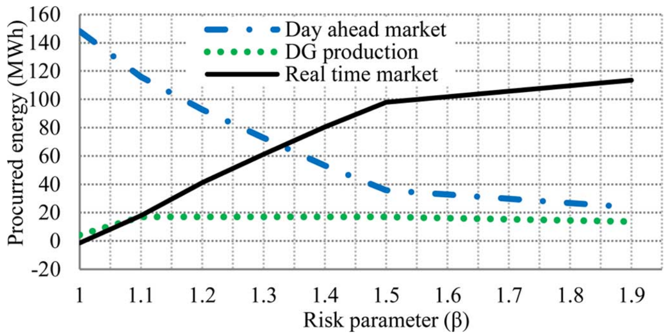

Fig. 10. Electricity procurement of the disco for different risk parameters.

TABLE III
TOTAL PROCUREMENT COST [€] FOR DIFFERENT DECISION FRAMEWORKS

Decision framework	Total procurement cost
Reliance on real-time market	5896.73
Proposed stochastic optimization	5873.71
Reliance on day-ahead market	6075.43

Fig. 10 provides the information on the energy procurement of the disco for different values of β. As expected, a risk-averse disco prefers day-ahead market to hedge against risk; while, a risk-taker disco selects real-time market in the hope of achieving lower cost. Owing to the results, the reliance on real-time market decreases as the concern on risk increases, resulting in a higher share of day-ahead purchase. The energy produced by DGs is lower when the risk weight is too small or too large. For $\beta = 1$, DGs are committed at peak hours when day-ahead prices are higher. However, they are committed even at off-peak hours to hedge against risk if β is between 1.1 and 1.8. Again, DGs are no longer required to be committed at off-peak hours for risk management purposes when $\beta = 1.9$.

The capability of the new framework (like any other decision making framework) strongly depends on forecasting accuracy. Evidently, the superiority of the developed framework increases as forecasting error decreases. Table III compares the total procurement cost for the proposed framework and two extreme cases when forecasting error is negligible. As shown in this table, the proposed framework results in the least procurement cost.

V. CONCLUSION

This paper presented a stochastic framework for a disco to optimize his short-term operational decisions so that the expected operating cost is minimized given a pre-defined risk level. The framework consists of two hierarchical stages. The first stage, named DAOS, determines day-ahead market purchases and up/down times of DG units for next day. The second stage, called RTOS, determines real-time market purchases, dispatch of online DGs, and invocation of LCs for next hour. The proposed framework was applied to a distribution network with actual data from Finland. Owing to the results, the framework effectively compromises between expected cost and risk. The results indicate that reliance on real-time market decreases as the concern on risk increases while the share of day-ahead purchases increases by restricting the disco's exposure risk. In addition, DGs' production increases when the disco concerns about risk since they are kept more online to hedge against the risk.

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