Hierarchical Probabilistic Coordination and Optimization of DERs and Smart Appliances (5.3)

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Background and Motivation

Massive deployment of Distributed Energy Resources (DERs) (wind, solar, PHEVs, smart appliances, storage, etc.) with power electronic interfaces will change the characteristics of the distribution system:

• Bidirectional flow of power with ancillary services.
• Presence of non-dispatchable and variable generation.
• Non-conventional dynamics → inertial-less characteristics of inverters.

Market Approach: Incentive/price market and local controls

Our Approach: Create an active distribution system supervised with a distributed optimization tool. Specifically:

Develop an infrastructure for monitoring and control supervised by a hierarchical stochastic optimization tool that will enable:

• Maximize value of renewables.
• Improve economics by load levelization (peak load reduction) and loss minimization.
• Improve environmental impact by maximizing use of clean energy sources.
• Improve operational reliability by distributed ancillary services and controls.
Hierarchical Optimization Scheme

Three-level hierarchical optimization architecture:

- **Optimization Level 1**: feeder optimization (including aggregators, utility and customer owned resources, etc.)
- **Optimization Level 2**: substation optimization (optimize all feeders connected to a substation)
- **Optimization Level 3**: system optimization (optimize all substations)
Feeder Optimization Problem: Definition

Given:

A planning period (typically one day).
A feeder with a number of DERs and topology under direct control
Directives from the higher level optimization
  Total stored energy in all feeder resources during the planning period (plan).
  Minimum reserve and spinning reserve margin in all feeder resources within the planning period (plan).

Determine:

The optimal (minimum cost) operating conditions of DERs, appliances, etc. subject to meeting the directives from the higher optimization level over the planning period – with no inconvenience to customers.
Feeder Optimization Problem: Formulation

Reference Only

\[ \min = f(x, u) \quad \text{Operating cost of the feeder} \]

\text{s.t}

\[ E(t_h) = \sum_{s_i} E_{s_i}(t_h) \quad h = 0,\ldots, n \quad : \text{Total stored energy in all feeder resources during the planning period} \]

\[ SR(t_h) \leq \sum_{s_i} (S_{s_i,N} - P_{s_i}(t_h)) + \sum_{g_i} (S_{g_i,N} - P_{g_i}(t_h)) \quad h = 0,\ldots, n \quad : \text{Spinning Reserve Capacity} \]

\[ R(t_h) \leq \sum_{s_i} (S_{s_i,N} - P_{s_i}(t_h)) + \sum_{g_i} (S_{g_i,N} - P_{g_i}(t_h)) \quad h = 0,\ldots, n \quad : \text{Reserve Capacity} \]

\[ E_{s_i,0} \leq E_{s_i}(t_h) = E_{s_i}(t_{h-1}) - P_{s_i}(t_h) \cdot \Delta t \leq E_{s_i,N} \]

\[ 0 \leq \sqrt{P_{s_i}^2(t_h) + Q_{s_i}^2(t_h)} \leq S_{s_i,N} \quad h = 0,\ldots, n \quad : \text{Storage devices constraints} \]

\[ 0 \leq \sqrt{P_{g_i}^2(t_h) + Q_{g_i}^2(t_h)} \leq S_{g_i,N} \quad h = 0,\ldots, n \quad : \text{Generating units capacity constraints} \]

\[ 0 = g(x, u) \quad : \text{Power flow constraints} \]

\[ 0 \leq h(x, u) \quad : \text{Operational constraints of the feeder (e.g. bus voltage magnitude, distribution lines and transformers capacity constraints} \]
Feeder Optimization Problem: Object-Oriented Methodology

Each Device is modeled with a set of Quadratized Equations in terms of State and Control variables in a standard syntax (QSnC model).

- Device QSnC model (Quadratized State ‘n Control Form):

\[
\begin{bmatrix}
    I(t_k) \\
    0 \\
    I(t_{k,m}) \\
    0
\end{bmatrix} = Y_{eq_x} \cdot \begin{bmatrix}
    \tilde{X}_v(t_k) \\
    \tilde{X}_u(t_k) \\
    \tilde{X}_v(t_{k,m}) \\
    \tilde{X}_u(t_{k,m})
\end{bmatrix} + \begin{bmatrix}
    [\tilde{X}_v(t_k) \ X_v(t_k) \ X_u(t_{k,m}) \ X_v(t_{k,m})] \cdot F_{eq_x,x_{-1}}(t_k) \\
    [\tilde{X}_v(t_k) \ X_v(t_k) \ X_u(t_{k,m}) \ X_v(t_{k,m})] \cdot F_{eq_x,x_{-n}}(t_k) \\
    [\tilde{X}_v(t_k) \ X_v(t_k) \ X_u(t_{k,m}) \ X_v(t_{k,m})] \cdot F_{eq_x,u_{-1}}(t_k) \\
    [\tilde{X}_v(t_k) \ X_v(t_k) \ X_u(t_{k,m}) \ X_v(t_{k,m})] \cdot F_{eq_x,u_{-n}}(t_k)
\end{bmatrix} F_{eq_x,u_{-n}}(t_k) - B_{eq}(t_k)
\]

In Matrix notation:

\[
I(x, u) = Y_{eq_x} \cdot x + \left\{ x^T \cdot F_{eq_x,i} \cdot x \right\} + Y_{eq_u} \cdot u + \left\{ u^T \cdot F_{eq_u,i} \cdot u \right\} + \left\{ x^T \cdot F_{equ,i} \cdot u \right\} - B_{eq}
\]
Develop device models in QSnC object form

Define the optimization problem

Linearize the optimization problem

Solve the linearized optimization problem

Compute the new operating point

Check violation for the modeled constraints

Yes

Update optimization problem

Add new violated constraints to the model

No

Check violation for all constraints

Yes

Next Iteration

No

Zero mismatches?

Yes

End

No
Feeder Optimization Problem: Object Oriented Analytics

Example Computational Process: Linearization

• The linearization of the constraint is performed with the co-state method

\[
\frac{dJ(x^o, u^o)}{du} = \frac{\partial J(x^o, u^o)}{\partial u} - \hat{x}^T \frac{\partial g(x^o, u^o)}{\partial u} \\
\hat{x}^T = \frac{\partial J_k(x^o, u^o)\left(\frac{\partial g(x^o, u^o)}{\partial x}\right)^{-1}}{\partial x}
\]

• Device QSnC model in matrix notation (object oriented model):

\[
g(x, u) = Y_{eqx} \cdot x + \{x^T \cdot F_{eqx,i} \cdot x\} + Y_{equ} \cdot u + \{u^T \cdot F_{equ,i} \cdot u\} + \{x^T \cdot F_{eqxu,i} \cdot u\} - B_{eq}
\]

• Constraint model in matrix notation (object oriented model):

\[
J(x, u) = A_j \cdot x + x^T \cdot B_j \cdot x + D_j \cdot u + u^T \cdot E_j \cdot u + x^T \cdot F_j \cdot u + c
\]

• Computation of each component based on the object oriented model:

\[
\frac{\partial g(x^o, u^o)}{\partial u} = Y_{equ} + \{u^{o,T} F_{equ,i}\} + \{(F_{equ,i} u^o)^T\} + \{x^{o,T} F_{eqxu,i}\}
\]

\[
\frac{\partial g(x^o, u^o)}{\partial x} = Y_{eqx} + \{x^{o,T} F_{eqx,i}\} + \{(F_{eqx,i} x^o)^T\} + \{(F_{eqxu,i} u^o)^T\}
\]

\[
\frac{\partial J(x^o, u^o)}{\partial u} = D_j + u^{o,T} \cdot E_j + (E_j \cdot u^o)^T + x^{o,T \cdot F_j}
\]

\[
\frac{\partial J(x^o, u^o)}{\partial x} = A_j + x^{o,T \cdot B_j} + (B_j \cdot x^o)^T + (F_j \cdot u^o)^T
\]
Substation Level Optimization: Stochastic DP

**Given:** A substation with several distribution feeders, Peak storage, peak capacity, etc. for each of the feeders, Performance criteria (e.g. operation cost), and A planning horizon (e.g. day, week, etc.)

**Compute:** Directive values for each feeder at each stage k that result in minimum optimal substation operation cost over planning horizon.

**Solution method:** Stochastic Dynamic Programming

\[
R^*_{k+1}(E_{k+1}, R_{k+1}, SR_{k+1}) = \min_{E_k, R_k, SR_k} \left[ R^*_k(E_k, R_k, SR_k) + E\{C^*(E_{k+1}, R_{k+1}, SR_{k+1}, G_A, L)\} \right]
\]

**Subject to:**

- \(E_{\min} \leq E_k \leq E_{\max} \quad k = 0, 1, \ldots\)
- \(R_{\min} \leq R_k \leq R_{\max} \quad k = 0, 1, \ldots\)
- \(SR_{\min} \leq SR_k \leq SR_{\max} \quad k = 0, 1, \ldots\)
- \(Q_{\min} \leq Q_k \leq Q_{\max} \quad k = 0, 1, \ldots\)

**Transition cost:**

\[C(E_{j,k-1}, SR_{j,k-1}, R_{j,k-1}, E_{i,k}, SR_{i,k}, R_{i,k})\]

The transition costs are computed from the feeder optimization level.
Hierarchical Optimization: Example Test System

12.47 kV, 9 MVA substation, 3 distribution feeders

- The loading of the feeder is about 50% of its capacity, i.e. 4.5 MVA
- 3.3% penetration of DERs (total of 300kW).
- 60% of the houses are assumed to have storage devices that comprise an additional 3.3% of the feeder rating (300 kW total capacity) with a storage capability of 600 kWh.
Hierarchical Optimization Results (One Day)

Byproduct: Achieved 20% peak load reduction
**Business Case**

**Probabilistic Production Cost (PPC) Analysis**

**Comparison Methodology:**
(a) Probabilistic simulations to evaluate and compare operating costs, fuel utilization (pollution) and reliability with and without the proposed optimization.
(b) Quantify benefits resulting from the proposed optimization scheme

Given a probabilistic “composite load” model (composite load demand curves - forecast) for the time period under consideration and the available generating units of the system:

The expected generated energy for each unit taking into account the effects of scheduling functions (economic dispatch, pollution dispatch, etc.) within the time period considered, the random forced outages of the units and maintenance schedules.

The expected operating cost and fuel utilization.

Reliability indices such as LOL, EUE, etc.
A typical utility system was used as a test-bed with 22 GW capacity and 40 generator units (coal, nuclear, oil, natural gas).

Assumed 6.6% penetration of DERs and storage devices.

### PPC Analysis—Results

(Thermal Units: Economic Dispatch based on Fuel Cost)

<table>
<thead>
<tr>
<th></th>
<th>Non-Optimized Scenario</th>
<th>Optimized Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of load probability</td>
<td>0.04173</td>
<td>0.00227</td>
</tr>
<tr>
<td>Generated energy (MWh)</td>
<td>297,841.709</td>
<td>297,018.599</td>
</tr>
<tr>
<td>Unserved energy (MWh)</td>
<td>1,103.695</td>
<td>32.896</td>
</tr>
<tr>
<td>Total production cost (k$)</td>
<td>8,234.674</td>
<td>7,945.566</td>
</tr>
<tr>
<td>Average production cost (cents/KWH)</td>
<td>2.7648</td>
<td>2.6751</td>
</tr>
<tr>
<td>Total CO2 emissions (kg)</td>
<td>125,671,208.46</td>
<td>124,906,337.604</td>
</tr>
<tr>
<td>Total NOx emissions (kg)</td>
<td>381,722.746</td>
<td>379,289.922</td>
</tr>
</tbody>
</table>

### Annual Production Cost Savings:

(k$ 8234.67 - k$ 7945.57) × 365 days = $ 105.520 M
Cost / Benefit Analysis

Expected Investment Cost

<table>
<thead>
<tr>
<th>Investment</th>
<th>Cost ( Million $)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>DERs &amp; Storage</td>
<td>1,470</td>
<td>Investment Cost</td>
</tr>
<tr>
<td>AMI</td>
<td>200</td>
<td>Instrumentation Cost</td>
</tr>
<tr>
<td>DMS Software &amp; Hardware</td>
<td>5</td>
<td>Distribution Management System Cost</td>
</tr>
<tr>
<td>Total</td>
<td>1,675</td>
<td>Total Investment Cost</td>
</tr>
</tbody>
</table>

Annualized Equivalent Cost (AE) – Assume: Interest rate of 8%, 20 year Economic Lifetime, Zero Salvage Value at the End of Life

\[ 1,675 = \sum_{n=0}^{19} \frac{AE}{1.08^n} \quad \Rightarrow \quad AE = $157.96 \text{ Million} \]

The cost of the infrastructure is higher (by 33.2%) than the expected benefit. However if the benefits from improved reliability, and reduced pollutants is taken into account, the attractiveness of the proposed approach will increase.
SIDE BENEFIT 1: Generating Unit Cycling: Definition, Effects and Evaluation Indexes

**Definition of Cycling:** Operation of a generating unit at short duration varying output levels

**Effects of cycling:**
- Increased operation and maintenance costs
- Reduced unit and system reliability

**Cycling Evaluation Indexes:**
- **Number of Cycles:** the number of cycles which have a duration less than 1 hour, that a unit experiences within one day
- **Average MW variation per cycle:** The sum of the MW variation of all the cycles during a day over the number of the cycles within one day.

\[
\text{Average MW Variation} = \frac{\sum \text{MW Variation per cycle}}{\text{Number of cycles}}
\]
Coal Unit Cycling Example

Economic Dispatch result for a coal unit.
Non-optimized and optimized scenarios.

<table>
<thead>
<tr>
<th>Coal Unit</th>
<th>Number of Cycles</th>
<th>Average MW Variation per cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Optimized Scenario</td>
<td>22</td>
<td>56.23</td>
</tr>
<tr>
<td>Optimized Scenario</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Conventional generator cycling reduction as a byproduct of the hierarchical optimization scheme
SIDE BENEFIT 2: Capacity Credit of Non-Dispatchable Generation

**Wind Farm Capacity Credit** is the capacity of a dispatchable unit with a specific forced outage rate (FOR) that will provide exactly the same reliability improvement as the wind farm capacity.

The Reliability of System is Evaluated with:
- Loss of Load Probability (LOLP)
- Expected Amount of Un-serviced Energy (EAUE)

**Computational Approach:** The PPC tool is used to evaluate the capacity credit of wind farms using the LOLP and EAUE.

<table>
<thead>
<tr>
<th>FOR</th>
<th>Capacity Credit (MW) Wind Capacity 2000 MW (10%)</th>
<th>Capacity Credit (MW) Wind Capacity 4000 MW (20%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.19</td>
<td>500</td>
<td>915</td>
</tr>
<tr>
<td>0.15</td>
<td>435</td>
<td>830</td>
</tr>
<tr>
<td>0.12</td>
<td>411</td>
<td>796</td>
</tr>
<tr>
<td>0.08</td>
<td>397</td>
<td>767</td>
</tr>
<tr>
<td>0.06</td>
<td>385</td>
<td>752</td>
</tr>
</tbody>
</table>
Accomplishments and Potential Uses

Accomplishments

• Infrastructure for real time monitoring and extraction of the real time model of the system (utility and customer owned equipment).

• Object-oriented and autonomously executed hierarchical stochastic optimization algorithm that provides the control signals for the distributed resources (model based control).

• Business case analysis that quantifies implementation costs and benefits / comprehensive studies.

Potential Uses

• Load Levelization (peak load reduction) with no customer inconvenience (coordinated approach to demand response).

• Loss minimization by balancing the feeder (coordinated scheduling of non-essential customer loads and resources).

• Increased Operational Reliability by utilizing (a) the ability of inverters to provide ancillary services, (b) the ability of distributed resources (smart appliances, thermal loads, EVs, etc.) to provide reserve capacity, and (c) the ability of the proposed system to provide coordinated demand response.

• Reduction of conventional generating unit cycling
Project Publications to Date


