RTO Scale Unit Commitment Test Cases

Test case data set status and preliminary results

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Overview

Origin:
- June 2010 FERC conference, discussion of large scale test problem creation

Purpose:
- Create a data set that can be used to model RTO-scale unit commitment and economic dispatch. Intended to be used to produce representative unit commitment models.
  - Not intended to simulate the exact operation of an actual RTO.
- To enable benchmarking of methods among researchers and engineers to test improvements optimization methods and demonstrate formulations
- Similar to IEEE test sets (14 bus, 73 bus, etc), but larger (> 10,000 bus) and contains more day ahead market characteristics (e.g. demand bidding, virtual bidding).
The Data Set

- Contains information to construct an approximation of an RTO day ahead unit commitment.
  - To test scheduling, dispatch and pricing optimization algorithms. Not to replicate reliability functions, mitigation functions, or other analysis.

- RTO scale system
  - Network – over 10,000 buses, over 15,000 transmission elements
  - Generators - over 1,000 generating units, including wind following a profile
  - Loads – including fixed demand, price sensitive demand, demand response
  - Inc and dec bids
Data Set

- Generator data – from EIA 411, EIA 860, EPA, NREL, RTO website
- Generators offer curves estimated, created using data from publicly available sources
- Demand data – RTO website
- Network data – Obtained from an RTO
- Generator and Demand data was assembled from public information, CEII restrictions on the network model
Ramp Rates

- Ramp rate inputs were developed from statistical analysis of EPA data on units in the RTO. Ramp rates predicted as a function of the unit nameplate capacity.

- Similar analysis undertaken to predict min run level as a function of max capacity.
Day Ahead Unit Commitment

- This talk discusses a model that was created to verify that the data set produces reasonable solutions.

- Scenarios in the data set:
  - The data set contains information for two days: Summer (Day A), Winter (Day B) both were solved.
  - Each day has different demand information; variation in network and generator information.

- Day ahead unit commitment (UC) - Mixed Integer Programming problem. Modeled in GAMS and solved using a leading solver.

- Model is a “first order approximation” of an RTO Day Ahead UC:
  - Includes: Commitment and dispatch constraints, transmission constraints, flowgates, reserves, inc/dec bids, price responsive demand, DR, wind.
  - Does not include: AC feasibility iteration, contingencies, self-schedules, losses.
Day Ahead Unit Commitment – Sets and Indices

Sets and Indices

- $t \in T$: Time periods (hours)
- $g \in G$: Generators
- $dr \in DR$: Demand Response Resources
- $pd \in PD$: Price Responsive Demand Bids
- $inc \in INC$: Inc Bids
- $dec \in DEC$: Dec Bids
- $r \in R$: Market Entities/Resources
  - $R = G \cup DR \cup PD \cup INC \cup DEC$
- $n \in N$: Network Buses
- $n^b_r$: Market Entity to Bus Mapping
- $k \in K$: Transmission Elements (XFMRs, Branches)
- $int \in INT$: Interfaces
- $k^{int}$: Subset of branches belonging to interface $int$
- $n^f_k$: Transmission Element From Bus
- $n^t_k$: Transmission Element To Bus
- $s \in S$: Bid/Offer curve Steps
Day Ahead Unit Commitment – Variables

Variables

- $Q_{rst}$: MW cleared for market entity $r$, step $s$, hour $t$
- $Q_{rt}^{\text{tot}}$: Total cleared MW for market entity $r$, hour $t$
- $\text{NetInj}_{nt}$: Net Injection (if positive) Withdrawal (if negative) at bus $n$ in hour $t$
- $Q_{r+}^{g_t}$: Ramp up variable
- $Q_{r-}^{g_t}$: Ramp down variable
- $\text{Res}_{gt}$: Reserves provided by generator $g$, hour $t$
- $\text{V}_{gt}$: Startup variable for generator $g$, hour $t$
- $\text{W}_{gt}$: Shutdown variable for generator $g$, hour $t$
- $\text{U}_{gt}$: Commitment variable for generator $g$, hour $t$, $\text{U}_{gt} \in \{0,1\}$
- $f_{kt}$: Transmission element $k$ flow in hour $t$
- $f_{kt}^{+//-}$: Monitored transmission element limit relaxation
- $F_{kt}^{+//-}$: Flowgate limit relaxation
- $s_{kt}^{+//-}$: Global power balance violation
Parameters

- $F_k^{\text{Max}}$: Transmission Element Long Term Thermal Rating
- $\text{LIM}_{t}^{\text{int}}$: Interface Limit in period $t$
- $P_r^{\text{Max}}$: Resource Maximum Cleared Quantity
- $P_r^{\text{Min}}$: Resource Minimum Cleared Quantity
- $N_{Lg}$: No-Load Cost for generators
- $U_{Tg}$: Min Run Time for generators
- $D_{Tg}$: Min Down Time for generators
- $R_{g}^{\text{Max,up}}$: Max ramp-up rate for generators
- $R_{g}^{\text{Max,dn}}$: Max ramp-down rate for generators
- $MW_{rs}$: MW quantity Bid/Offer for resource $r$ step $s$
- $C_{rs}$: Cost Bid/Offer for resource $r$ step $s$
Day Ahead Unit Commitment – Model Parameters

INJ^{\text{Loop}}_{nt} \quad \text{Uncompensated Loop flow injections at bus } n \text{ (negative if withdrawal), hour } t

INJ^{\text{Tie}}_{nt} \quad \text{Tie Schedule Injections at bus } n \text{ (negative if withdrawal), hour } t

INJ^{\text{Wind}}_{nt} \quad \text{Wind power day ahead forecast at bus } n \text{, hour } t

DEM^{\text{Fix}}_{nt} \quad \text{Day ahead fixed demand at bus } n \text{, hour } t

DEM^{\text{Forecast}}_{nt} \quad \text{Day ahead forecast demand at bus } n \text{, hour } t

SF_{nk} \quad \text{Shift factor for injection at bus } n \text{ on element } k \text{ relative to a withdrawal at the slack bus}

d_r \quad \text{Indicates whether a market entity cleared MW is an injection or withdrawal: } 1 \text{ for injection, -1 for withdrawal}

Pen^{\text{branch}} \quad \text{Limit relaxation penalty for transmission elements}

Pen^{\text{flowgate}} \quad \text{Limit relaxation penalty for interface}

Pen^{\text{balance}} \quad \text{Constraint violation penalty for system power balance}
Day Ahead Unit Commitment - Formulation

- The Objective Function

Minimize:
(Start Up Costs) + (No Load Costs) + (Generator Energy Dispatch Costs) +
(Demand Response Costs) + (Virtual Supply Costs) + (Constraint
Violation Penalty Costs) -(Price Sensitive Demand Value) - (Virtual
Demand Value)

**Minimize**

\[ z = \sum_{rs} \sum_{s} \sum_{t} C_{rs} Q_{rst} d_{r} + \sum_{g} \sum_{t} (V_{gt} S_{Ug} + U_{gt} N_{Lg}) \]

\[ + \sum_{k} \sum_{t} \text{Pen}_{branch} \left( f_{kt}^+ + f_{kt}^- \right) + \sum_{i} \sum_{t} \text{Pen}_{flowgate} \left( F_{kt}^+ + F_{kt}^- \right) \]

\[ + \sum_{t} \text{Pen}_{balance} \left( S_{t}^+ + S_{t}^- \right) \]
Day Ahead Unit Commitment - Formulation

- Power Balance and Network Constraints

\[ \sum_r Q_{rt}^{\text{tot}} d_r = \sum_n \text{DEM}_{nt}^{\text{fix}} - \sum_n (\text{INJ}_{nt}^{\text{Tie}} + \text{INJ}_{nt}^{\text{Loop}}) + (s_t^+ + s_t^-) \quad \forall t \quad \lambda_t \]

Dual variable

**(system power balance)**

**(net injection/withdrawal at bus)**

\[ \sum_{\{r|n^b_r=n\}} Q_{rt}^{\text{tot}} d_r - \text{NetInj}_{nt} = \text{DEM}_{nt}^{\text{fix}} - (\text{INJ}_{nt}^{\text{Tie}} + \text{INJ}_{nt}^{\text{Loop}}) \quad \forall n, t \]

**(thermal transmission constraints)**

\[ f_{kt} - \sum_n \text{NetInj}_{nt} S F_{nk} = 0 \]

\[- F_k^{\text{max}} \leq f_{kt} - f_{kt}^+ - f_{kt}^- \leq F_k^{\text{max}} \quad \forall k, t \quad \mu_{-kt}, \mu_{+kt} \]

Note that this formulation is *lossless*
Commitment Constraints

(startup and shutdown constraints)
\[ V_{gt} - W_{gt} - U_{gt} + U_{g,t-1} = 0 \quad \forall g,t \]

(minimum run time for generators)
\[ - \sum_{t' = t}^{t + UT_g - 1} \frac{U_{gt'}}{UT_g} + V_{gt} \leq 0 \quad \forall t \]

(minimum down time for generators)
\[ - \sum_{t' = t}^{t + DT_g - 1} \frac{U_{gt'}}{DT_g} + W_{gt} \leq 0 \quad \forall t \]
Day Ahead Unit Commitment - Formulation

(offer curve constraints)
\[ Q_{\text{rt}}^{\text{tot}} - \sum_s Q_{\text{rst}} = 0 \quad \forall \ r,t \]
\[ Q_{\text{rst}} \leq MW_{rs} \quad \forall \ r,s,t \]

(generator max capability and minimum run level)
\[ Q_{\text{rt}}^{\text{tot}} + Res_{gt} - P_g^{\text{max}} \cdot U_{gt} \leq 0 \quad \forall \ g,t \]
\[ Q_{\text{rt}}^{\text{tot}} - P_g^{\text{min}} \cdot U_{gt} \geq 0 \quad \forall \ g,t \]

(ramp rate constraints)
\[ Q_{\text{gt}}^{\text{tot}} - Q_{\text{gt-1}}^{\text{tot}} - Q_{\text{r+}}^{\text{gt}} \leq 0 \quad \forall \ g,t \]
\[ Q_{\text{r+}}^{\text{gt}} - 60 \cdot U_{\text{gt-1}} \cdot P_{\text{max,up}}^{\text{g}} - P_g^{\text{max}} V_{gt} \leq 0 \quad \forall \ g,t \]
\[ Q_{\text{gt-1}}^{\text{tot}} - Q_{\text{gt}}^{\text{tot}} - Q_{\text{r-}}^{\text{gt}} \leq 0 \quad \forall \ g,t \]
\[ Q_{\text{r-}}^{\text{gt}} - 60 \cdot U_{\text{gt-1}} \cdot P_{\text{max,dn}}^{\text{g}} - P_g^{\text{max}} W_{gt} \leq 0 \quad \forall \ g,t \]
Day Ahead Unit Commitment - Formulation

(reserve constraints)

\[ \sum_g \text{Res}_{gt} + \sum_{g \in \text{OfflineSupp}} P_g^{\max} (1 - U_{gt}) \geq \text{SysRes}_t \quad \forall \ t \]

\[ \sum_g \text{Res}_{gt} \geq 0.5 \times \text{SysRes}_t \quad \forall \ t \]

(non-negativity, binary constraints)

\[ Q_{gt}^{\text{tot}}, Q_{rst}, Q_{r^{-}}_{gt}, Q_{r^{+}}_{gt}, \text{Res}_{gt} \geq 0 \]

\[ U_{gt}, V_{gt}, W_{gt} \in \{0,1\} \]
<table>
<thead>
<tr>
<th>Solution Time Summary (minutes)</th>
<th>Summer</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Presolve</td>
<td>13.3</td>
<td>11.4</td>
</tr>
<tr>
<td>Root Node Linear Program</td>
<td>11.4</td>
<td>11.4</td>
</tr>
<tr>
<td>Branch and Bound</td>
<td>13.4</td>
<td>7.6</td>
</tr>
<tr>
<td>Nodes Explored</td>
<td>0 (root)</td>
<td>0 (root)</td>
</tr>
<tr>
<td>Final Solve (presolve + LP)</td>
<td>20.3</td>
<td>20.8</td>
</tr>
</tbody>
</table>

Things that could speed this up?
- Better formulation of the problem; experiment with solvers and settings
- Starting point

Machine: Virtual machine with 4x 2.40 GHz CPUs and 64 GB RAM
MIP - After the root node LP is solved, the branch and bound search for an integer solution

- Previously slide shows time to solution within 5% of best possible
- Allowing the algorithm to continue, charts show solution improvement with time (for Day A)
- After about 20 minutes, a solution with around 1% optimality gap was found, not proven optimal after 100 minutes (1% ~$150,000 gap)
Day Ahead LMPs

- Max, Min and Average Day Ahead LMP across all buses by Hour
  - Day A:
    - Max LMP $804.20 at Bus 1648
    - Min LMP $(171.40) at Bus 1506
  - Day B:
    - Max LMP $301.82 at Bus 1021
    - Min LMP $(64.59) at Bus 1051
Day Ahead LMPs by Zone

Demand Weighted LMP by Zone Day A

Demand Weighted LMP by Zone Day B
### Day Ahead LMPs By Zone

<table>
<thead>
<tr>
<th>Zone</th>
<th>LMPs (Day A)</th>
<th>LMPs (Day B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZONE4</td>
<td>$-5.00</td>
<td>$-5.00</td>
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<tr>
<td>ZONE5</td>
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<td>ZONE23</td>
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<tr>
<td>ZONE19</td>
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<td>$6.00</td>
</tr>
</tbody>
</table>

**Note:** Demand Weighted LMPs for both Days.

### Demand Weighted LMP Both Days

![Graph showing LMPs by Zone for both days.](chart.png)
Congestion in the Day Ahead solution

- The data set contains 5 flowgates (interfaces). In the model, these were monitored in addition to over 4,000 individual transmission elements, for congestion.
- Day A: Day ahead congestion on flowgate 3.
- No flowgates were congested in Day B, at day ahead demand levels.
In each scenario, significantly high congestion on multiple transmission elements
Congestion in the Day Ahead solution

Branch and Transformer Congestion - Day B

$\$/MWh

Hr

$-$ 100 200 300 400 500 600 700 800

Branch906 Branch1394 Branch3135 Branch3136 Branch6513 Branch2805 Branch2808 XFM R371 XFM R691 Branch1311 Branch2424 Branch2458 Branch2965 XFM R1295
Day Ahead Generation – by Fuel Type

Generation by Fuel Type and Hour - Day A

Generation by Fuel Type and Hour - Day B

Generation Quantities clearing in the representative day ahead market scenarios
Other formulations of the problem

- “B-Theta” linear approximation of power flow

Whereas the previous formulation in this presentation used shift factors to compute flow on monitored transmission constraints, the B-theta formulation treats voltage angle at each end of the line as decision variables:

\[ f_{kt} = -B_k (\theta_{nt} - \theta_{mt}) \]

Nodal power balance constraints

\[
\sum Q_{rt}^{tot} d_r - DEM_{nt}^{fix} + (INJ_{nt}^{loop} + INJ_{nt}^{tie}) - f_{k(n,.)t} + f_{k(.,n)t} = 0
\]

With this formulation, the single period (hour) formulation of the model solves in less than two minutes.

Multiple period optimizations with this formulation can grow rapidly in solution time.
Next Steps

- Determine limits on access to the data set
- Evaluating possibility of additional data sets
- Evaluate the need to add additional detail to the data set and model (or a follow on data set)
  - Self Schedules
  - AC parameters
- Acknowledgements
  - Michael Higgins (FERC)
  - Joann Staron (P3 Consulting)
- Questions?