STAFF REPORT

FEDERAL ENERGY REGULATORY COMMISSION

RTO Unit Commitment Test System

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STAFF REPORT PREPARED BY THE FEDERAL ENERGY AND REGULATORY COMMISSION

Acknowledgements

Joann Staron of P3 Consulting obtained and compiled information from PJM and other sources, and created the vast majority of the data set for this test system under contract pursuant to RFP 21777, June 18, 2010. Many of the descriptions of data sources and references in this document are directly derived from the work that she did in late 2010 and early 2011, including material that she prepared for the initial versions of the test system. FERC staff has closely worked with those initial versions of the test system, making formatting and other changes to ready the test system for a more general audience of users.

Federal Energy and Regulatory Commission staff from the Office of Energy Policy and Innovation performed the modeling and statistical analysis, and created the test model results described in this paper.

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July 2, 2012 revision – This version of the staff report is primarily to update the test problem results based upon July, 2012 updates to the generator characteristics and demand data files.

Table of Contents:

1. Introduction

This paper discusses a data set for industry use in examining potential improvements to certain software and models. The idea for this project arose out of the FY2009-FY2014 FERC Strategic Plan Initiative to examine potential improvements to day-ahead and real-time market efficiency through improved software and models. Through a June 2010 technical conference, FERC staff validated the idea and moved forward, with contractor assistance, to develop the test data set.

This paper describes the test system, along with a model that was built to verify the realistic nature of the data and the corresponding solution characteristics from that model. It provides users with detailed instructions on assembling the data in the test system into a working unit commitment optimization model (including the detailed mathematical formulation), and provides an overview of results from the base case model for two different days. With the eventual release of the data set to qualified sources, there exists the potential for the development of innovations that enhance the planning, operations, and dispatch of the wholesale energy markets.

2. Scope and Approach to the Project Test System

While several test systems have been developed and released for the purpose of performing comparative studies of reliability evaluation methodologies,[1] these test systems (while extremely useful for their intended purpose) do not contain all of the data and parameters that are needed to create large scale, day-ahead unit commitment optimization programs, such as those currently solved by most Regional Transmission Organizations (RTOs). The test system developed as part of this project helps to address this limitation by serving as a benchmark for industry evaluation of differing optimization problems. The data set utilizes, to the extent possible, data from publicly available sources.[2]

The current version of the test system includes the information to model a deterministic system, and to perform linearized power flow calculations (i.e., to perform unit

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[1] These include the IEEE RTS-79 and IEEE RTS-96 test systems.

[2] Examples: Energy Information Administration (EIA), http://www.eia.doe.gov/cneaf/electricity/page/data.html; Environmental Protection Agency (EPA), http://www.epa.gov/cleanenergy/energy-resources/egrid, and the PJM website data dictionary, historical energy market information, and publicly available parts of PJM FTR model information. PJM data dictionary: http://www.pjm.com/markets-and-operations/data-dictionary.aspx, PJM day-ahead market information: http://www.pjm.com/markets-and-operations/energy/day-ahead.aspx, PJM real-time market information: http://www.pjm.com/markets-and-operations/energy/real-time.aspx, PJM FTR model information: http://www.pjm.com/markets-and-operations/ftr/model-information.aspx#Slider2011. See the Appendices and the data set itself for more description of the data sources.

commitment and economic dispatch simulations with DC Optimal Power Flow (DCOPF) approximations, using mixed integer programming (MIP) and linear programming (LP) techniques). Elements not contained in the test system include a complete set of real-time data (in 5 minute intervals), load and resource forecast error distributions (for stochastic modeling) and sufficient information to perform full AC power flow calculations. The latter information would be necessary for AC Optimal Power flow (ACOPF) simulations and to enable benchmarking of additional algorithmic processes used in RTOs (for example, iterative AC feasibility checks on DCOPF linear solutions). The test system created is representative of, but not an exact replica of, the PJM RTO.[3] As many approximations and assumptions were made in order to build a feasible, working test system and model, it is very unlikely that the model could be used to replicate market operations on any given day. The test problem and then results contained in this paper are not intended to be used to perform benchmarking against actual system behaviors or characteristics. The data is not intended to be used for detailed market analysis or to analyze actual market outcomes, and in fact it is not likely to be useful for such analysis since only two days are represented and many simplifying approximations were made.

In mid 2011, staff used the test system to create day-ahead unit commitment and economic dispatch optimization models in the General Algebraic Modeling System (GAMS) programming language, and solved these models to create base case results.

3. Data Set Files

The data set primarily contains information that is intended for constructing day-ahead unit commitment optimization models, including day-ahead market unit commitment and residual unit commitment (RUC). This information includes detailed generator information, network topology, demand information (including demand bids and forecast demand), demand response, virtual bids and operating reserve information. The data set contains information that can be used to simulate real-time economic dispatch for selected hours in the operating day. The real-time data are primarily represented by load and wind output values which differ from the day-ahead forecast values. This allows for the creation of economic dispatch optimization models for a small number of periods corresponding to the commitment schedules modeled using the day-ahead data. The data set does not, however, contain detailed 5-minute data to simulate an entire day of real-time economic dispatch.

[3] Numerous approximations and estimations were necessary to ensure that a data set could be created without the use of confidential bid information. Approximations and estimations were used, for example, in mapping generators, loads and other resources to network locations, developing generator offer curves and determining operating characteristics such as ramp rates, minimum run levels and minimum run times. The FERC contractor signed the relevant Critical Energy Infrastructure Information agreement for access to RTO network models.

Files are contained in FERC eLibrary, under docket AD10-12-002. Files are organized such that Critical Energy Infrastructure Information (CEII) information and non-CEII information is separated.

Non CEII Summer and Winter files:

Generator_Data_Summer(Winter).xls
DA_Wind_Profile_Summer(Winter).xls
Interface Defs and Limits Summer(Winter).xls
Tie Schedules Summer(Winter).xls
Uncompensated_Parallel_Flow Summer(Winter).xls
Reserves_Summer(Winter).xls
Demand_ Summer(Winter).xls
RT Data_Summer(Winter).xls

CEII Summer and Winter files:
Generator to Bus Mapping_Summer(Winter).xls
ferc_test_model_data_set_Network_Summer(Winter).mdb – contains the network in Access .mdb format
PSSE files – contain network information. The .raw files are in Power System Simulator for Engineering (PSSE) (Siemens PTI PSS E™, .raw) format
PJM_Network_Model Summer(Winter).raw
PSS_PARS_Change_Case Summer(Winter).raw
par_data_summer(winter).xls

The PSSE and database files contain the PSSE bus names used by PJM. Other files use generic names (BUS1, BUS2, etc) and the *Generic Bus to PSS Bus Mapping Summer(Winter).xls* file maps between the generic bus names and the PSS bus names.

4. Data Description

Network Data

Description

- Network topology is contained in Siemens PTI PSSE raw data format (revision 28), and in Microsoft Access database format. This data set represents information of all network components including, buses, loads, generators, transmission lines, transformers, switched shunts, areas, zones and ownership.

Bus information used in creating the unit commitment model includes bus name, base kV, bus type and zone. Switched shunt information is included in the PSSE file, and in a separate table in the .mdb database. Any branch with a type equal to 4 was assumed to be disconnected and was not included in the network that was used to create the base case model.

Branch data includes from-bus, to-bus, circuit identifier, per-unit resistance, per-unit reactance, per-unit charging susceptance, normal and emergency thermal ratings and outage status. Any branch with outage status equal to zero was assumed to be out of the network and was not included in the network that was used to create the base case model.

In the base case model, transformers are treated as fixed and modeled as branches between buses. Similar to branches, transformers with an outage status equal to zero are not included in the network.

Interfaces are groups of branches for which a flow limit is monitored. Interface data are listed with their normal and contingency ratings for each hour of the day. In the base case unit commitment model, the normal ratings were used to model the interface limits.

Ties are modeled as injections for flows into the footprint and withdrawals for flows out of the footprint. In this data set, these can vary by hour. Loop flows are likewise modeled as fixed injections or withdrawals at certain buses. Without detailed models of the neighboring systems, it was not possible to model changes in loop flows due to different actions or events. As a result, the same loop flow injections and withdrawals that are modeled in the day-ahead data set (representing the anticipated loop flow incorporated into the day-ahead model) are used as loop flow values in the real-time intervals. This under-represents the uncertainty and redispatch that loop flow actually causes; users may wish to alter the assumptions using their own methodologies.

Source

Network files are from the PJM Financial Transmission Rights (FTR) model posting for the dates of August 1, 2009 (representing the summer case) and January 31, 2010 (representing the winter case). The network topology was taken from PJM FTR network files because they closely resemble the day-ahead market topology. Those who wish to access these files must submit a request to FERC for access to CEII approval, and must receive approval for access to this information. After a request for a CEII data set, FERC Administrative Law will look at the bona fides of the requestor(s). If FERC determines that disclosure to the requestor would not be problematic, FERC will notify PJM. PJM will notify its members and the members will have five days to object at FERC. If there are no objections, FERC will determine whether to release the data set to the requestor.[4]

Location of Data

Network topology information is found in the database and PSSE .raw files within the data set. Bus and branch information is included in both the PSSE and Microsoft Access database formats.

Transformer information is included in the PSSE file, and in tables in the .mdb database.

[4] PJM procedures are per verbal communication with PJM on August 30, 2011.

The *Interface Defs and Limits Summer(Winter).xls* spreadsheet contains the information needed to model the interfaces in the system.

The *Tie Schedules Summer(Winter).xls* files contain the generic name of the tie, generic bus name, and the injection or withdrawal associated with the tie at that bus for each of 24 hours. The *Uncompensated Parallel Flow Summer(Winter).xls* files contain the loop flow information which is incorporated into the model.

Generator Data

Description

This section describes the generator characteristics used to model the generator units in the unit commitment and economic dispatch, fixed wind injections, and generator bid data.

Generator names, characteristics (such as prime mover, fuel type) and operational parameters (such as megawatt (MW) capability, minimum run time, etc.) are provided along with offer curves (including startup and no-load costs) for each generator. Heat rate information is provided along with emissions information.

Hourly wind profiles are also included for wind generators in the data set. These are defined as both forecasts for the day-ahead model and output values for the real-time intervals. Wind generation is modeled as a fixed injection at the bus where the wind generator is located.

Source

Most of the data were collected from the Energy Information Administration (EIA) Reports 411, 860 and 923 and the Environmental Protection Agency (EPA) eGrid Datasets. Heat rate data were obtained from EIA Reports 1995 and 923. Nominal heat rate data were obtained from the EPA eGRID datasets. All EIA reports are available on the EIA website. The EIA 411 report is posted on the PJM Website at: http://www.pjm.com/documents/reports/eia-reports.aspx

Emissions data were taken from EPA eGrid. In addition to the parameters obtained from EIA and EPA, and those that were estimated, some default parameters were assumed, e.g., minimum run time and minimum down time. These defaults are taken from the parameter matrix found on p. 219 of the report at http://www.pjm.com/~/media/documents/reports/state-of-market/2009/2009-som-pjm-volume2.ashx.

Generator offer curves were derived for the generators in the data set, for the purpose of giving the data set enough information to run unit commitment and economic dispatch optimization algorithms. These curves are fictional, and should not be interpreted as actual cost curves associated with a particular generator. Generator offer curves were derived from historical PJM bid data as well as heat rate data obtained from EPA reports. The methodology to construct the price-quantity pairs on the offer curve consisted of several steps. First, historical generator bid data was downloaded from the PJM website. This information masks the name of individual generators and so there was not a mapping between this data and individual generating units. In the first pass, the historical data was divided into two categories based on $/MWh values. Higher cost curves were assumed to belong to generators in the eastern part of the RTO, and lower cost curves were assumed to be in the western part of the RTO. Then, curves were matched to generators by comparing the maximum bid quantity to the EIA 411 maximum output level for the generator. If the two values were within 10-15% of each other, the historical curve was considered a match for the generating unit.

For generators where no match was produced, heat rate information (from EPA data, as described on the next page) was used to create a curve for the generator. The heat rate was transformed into a price-quantity curve by multiplying the heat rate by fuel costs taken from monthly EIA reports for fuel types associated with that generator. Finally, the generator offer curves were adjusted so that they were monotonically increasing.

Generator ramp rates and minimum run levels (economic minimum, or eco-min) were not readily available in the sources used to develop the data sets. Additional analysis was conducted in order to develop these values.

The ramp rate analysis used the EPA's Continuous Emissions Monitoring System (CEMS) dataset for 2010 in the PJM states to estimate the ramp up and ramp down rates.5 EPA CEMS data is primarily a data set of emissions; however, it has two characteristics that make it useful for determining ramp rates: 1) it is unit level data, and 2) it has hourly generation output. The definition of a unit in the EPA CEMS data is not always identical to the definition of a unit in the EIA data, however, there is enough similarity to identify the prime mover for each unit and to identify or estimate the nameplate capacity of each unit.

The basic method of computing the ramp up and ramp down rates was to compute differences in generation output from one hour to the next hour. Data was filtered to eliminate outliers. The predicted percentage ramp curve was developed from a two-piece regression model where the bend in the curve is determined via maximum likelihood.

Figure 1 shows a scatter plot of steam turbine (ST) ramp up rates estimated from 2010 EPA data from units in the PJM region. The ramp rates are presented as a percentage of nameplate capacity, so a value of 0.5 percent means that a unit with a nameplate capacity of 1000 MW would ramp 5 MW per minute.

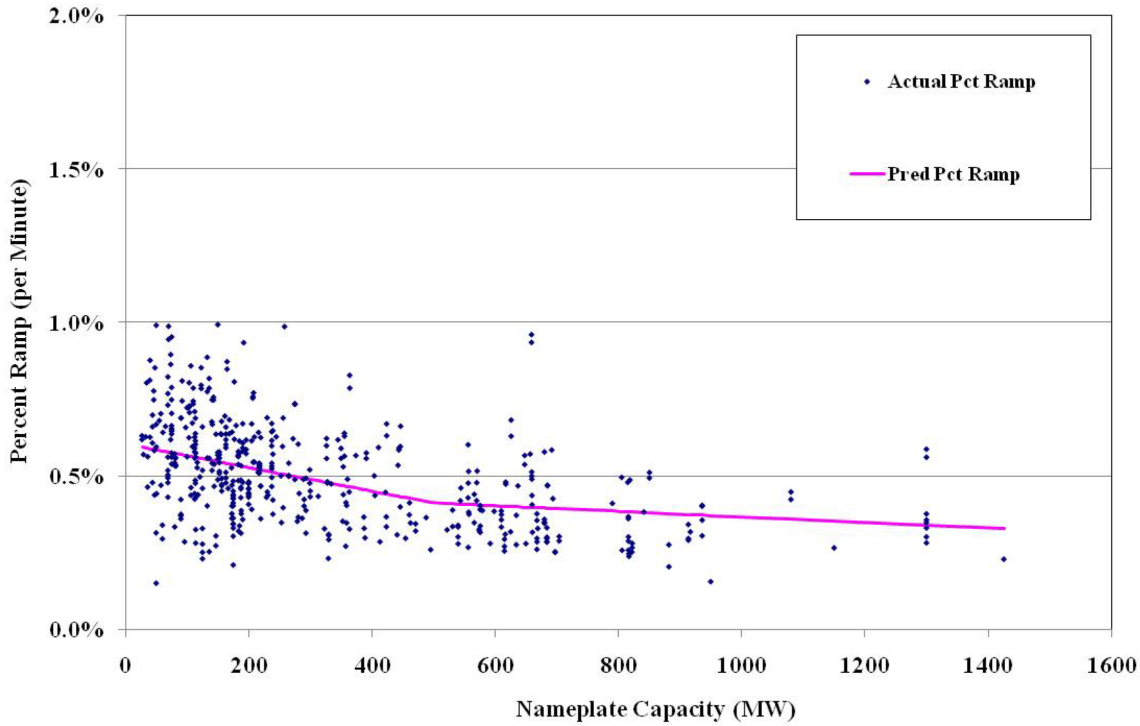

Figure 1: Percentage Up Ramp as a Function of Nameplate Capacity, Steam Units, PJM, 2010

Figure 2 displays the formulas for predicted percentage up ramp and predicted percentage down ramp for steam units. These formulas were used to estimate the up ramp and down ramp in the unit commitment and dispatch models because of the difficulty of directly matching EPA units to all of the units in the data set.

Figure 2: Formula for Predicted Percentage Up and Down Ramp, Steam Units, PJM, 2010

```
pred_pct_ramp=r_11+np*r_12 if np lt 500 MW;
pred_pct_ramp=r_21+np*r_22 if np ge 500 MW;
  r_11 = 0.006038;
  r_12 = -0.000003840;
  r_21 = 0.004573;
  r_22 = -0.0000009099;
np = nameplate capacity
```

```
abs(pred_pct_dramp)=dr_11+np*dr_12 if np lt 500 MW;
abs(pred_pct_dramp)=dr_21+np*dr_22 if np ge 500 MW;
  dr_11 = 0.006783;
  dr_12 = -0.000004314;
  dr_21 = 0.005138;
  dr_22 = -0.000001022;
```

Economic minimum (minimum run level) values were also estimated. A generator is much more likely to have a generator output at or just above eco-min than any positive level less than eco-min. The time that a generator would generate at levels more than zero and less than eco-min is when a generator is either ramping up or ramping down. As the data show, generators spend much less time in the ramp up and ramp down range than they do near their eco-min. This fact was used in estimating eco-min for each unit.

Figure 3 below shows the histogram average for steam turbines that have an estimated eco-min ratio (eco-min divided by nameplate capacity) from 0.5 to 0.6. This figure could also be interpreted as a typical histogram for a steam turbine. The threshold line determines which of the 10 bins correspond to ramp up and ramp down levels and which others correspond to normal operating levels. A threshold level was developed to determine which bins were likely to correspond to ramp up and ramp down levels and which were likely to correspond to normal operating levels. Of all the bins which surpass the threshold, the one with the smallest ratio of generation to nameplate capacity will define a range for the eco-min ratio. Rather than just choose the threshold by inspection we computed it using statistics on the average ramp up and ramp down output-to-nameplate capacity ratio. For example, for steam turbines the threshold was 3.6% of nameplate capacity, computed as the average plus 3.5 standard deviations of the ramp-up and ramp-down ratio for all steam turbine units.

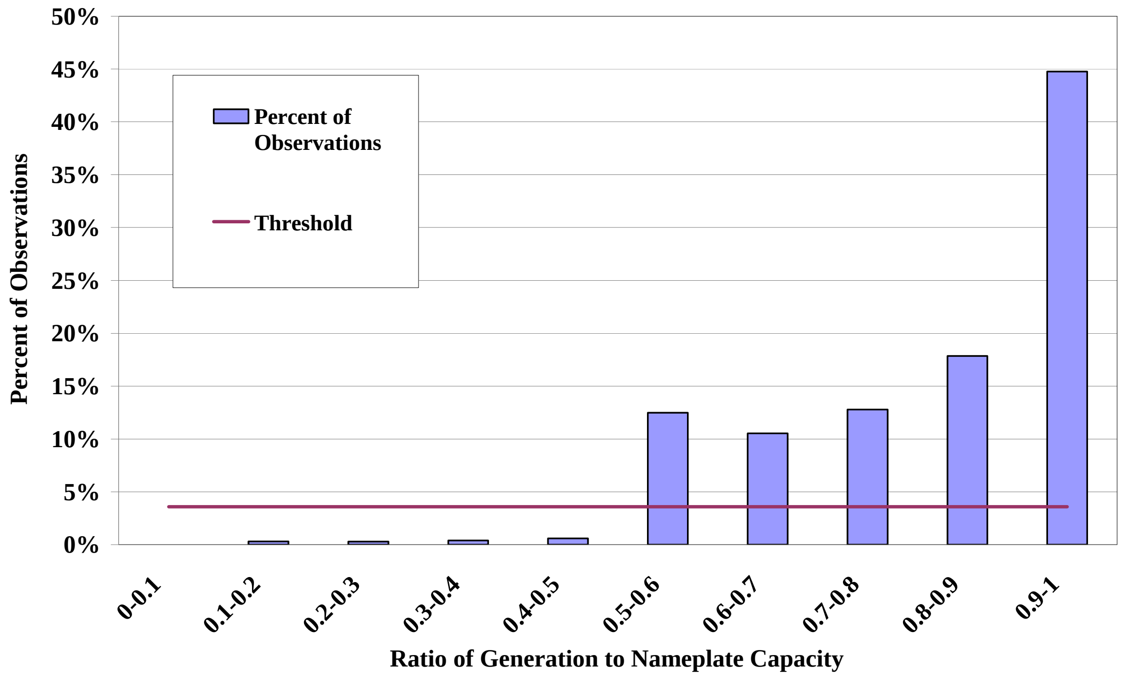

Figure 3: Histogram of Steam Turbines with an Estimated Eco-Min Ratio from 0.5 to 0.6

Figure 4 shows the thresholds for three different types of generators: steam turbines (ST), combined cycles (CC), and combustion turbines (CT).

	Average at EcoMin	Average Ramp Up/Down	Standard Deviation Up/Down	Threshold Rule	Threshold Value
Steam Turbine	0.21	0.007	0.01	mean + 3.5 s.d.	0.036
Combined Cycle	0.24	0.018	0.02	mean + 3.0 s.d.	0.076
Combustion Turbine	0.44	0.03	0.03	mean + 2.5 s.d.	0.100

Figure 4: Threshold Values for Different Types of Generators

The threshold method yields an eco-min ratio estimate that has a range of 10 percentage points. We refine this estimate by again applying the same 10-bin histogram methodology to all observations that occur in this eco-min bin to estimate eco-min to within 1 percentage point. The threshold for this second iteration is always 10 percent.

Figure 5 below shows the results of the eco-min estimation. We used these results to estimate the eco-min for each type of unit based on its prime mover and its heat rate. If the heat rate fell outside the range of estimates in Figure 6, the nearest estimate was used.

Heat Rate	Prime Mover		
(MMBTU/MWh)	CC	CT	ST
6000-7000	47%		
7000-8000	51%		
8000-9000	56%		63%
9000-10000	50%	81%	55%
10000-11000	42%	78%	38%
11000-12000		75%	26%
12000-13000		62%	22%
13000-25000		49%	29%

Figure 5: Estimated Eco-Min to Nameplate Capacity, by Prime Mover and Heat Rate, PJM, 2010

Location of Data
Generator information including operating characteristics and cost curve data are found in the *Generator_Data_Summer(Winter).xls* files.

The data needed to model generator operating characteristics is found in the Generator Characteristics tab of the *Generator_Data_Summer(Winter).xls* spreadsheets. The data needed to model generator offer curves are found in the Generator Offer Curve tab of the *Generator_Data_Summer(Winter).xls* spreadsheet. The Generator Heat Rates and Plant Emissions tabs contain information that can be used to incorporate heat rates directly into the model, or to model generating plant emissions. The Generator Status tab contains the assumptions about the initial commitment status for each generator. More detailed description of the information contained in these files is contained in Appendix A.

Hourly injection profiles for the buses where wind generators are located are contained in the *DA_Wind_Profile_Summer(Winter).xls* spreadsheets (day-ahead forecast values) and in the *RT_Wind_Profile_Summer(Winter).xls* spreadsheets (real-time interval persistence forecast values).

The data needed to map the generating units to the network is found in the *Generator to Bus Mapping.xls* files for each test system day.

Demand Data

Description

This section describes the demand data included in the data set, including demand bids, fixed demands and virtual bids used for modeling the day-ahead market unit commitment and forecast demand used for modeling the day-ahead RUC. Demand response resource information is described.

The day-ahead data sets contain fixed demand, demand bids and virtual (incremental and decremental, or inc and dec) bids which are modeled in the day-ahead market unit commitment. The day-ahead data sets also contain day-ahead forecast demand, which is used in the RUC. The real-time intervals contain real-time load information for the relevant interval. Demand response is present in both the day-ahead and real-time data sets. Demand information is mapped to the bus level.

Fixed demand is listed by generic bus name and hour of the day, likewise for day-ahead forecast demand. Demand bids are price-quantity pairs listed by generic bus name and hour of the day. Demand bids are modeled as willing to consume up to the price associated with their bids.

Information is included to represent demand response bids in the day-ahead and real-time data sets. The demand response resources are modeled as injections at load buses (mapped by generic bus name) that offer to respond at a single price (i.e., they have one step offer curves). Demand response resources are modeled as willing to respond by reducing demand at a price above the level associated with their bid.

Information needed to represent incremental (virtual supply) bids is included in the day-ahead data sets. There are two tables describing hourly quantity and price for each bid. Cleared inc bids are modeled as injections at the associated bus in the day-ahead model. Inc bids are mapped to the network using generic bus names. Dec bids are modeled as withdrawals at the associated bus, and are otherwise organized in the same way as inc bids in the data set.

Load for the real-time intervals is represented at the bus level, by generic bus name, for each interval (same format as the day-ahead forecast demand).

Source

Data for demand bids, virtual bids and demand response were obtained through the historical bids section of the PJM website, at http://www.pjm.com/markets-and-operations/energy/real-time/historical-bid-data.aspx.

The data used for demand bids was from the historical demand bids for the month of August 2009 (Summer) and January 2010 (Winter) as published by PJM. The dates of

8/1/2009 and 1/31/2010 were extracted from their respective files. Distribution factors were recalculated as necessary.

The data used was from the historical inc and dec bids for the month of August 2009 (Summer) and January 2010 (Winter) as published by PJM. The dates of 8/1/2009 and 1/31/2010 were extracted from their respective files. Distribution factors were recalculated as necessary.

The Demand Response Resource data was obtained from the PJM website under Historical Data.[5] The PJM data included bids broken down to Economic and Emergency and are aggregated to the zone level. Only economic bids were considered in this data set. The total zonal MWs were distributed to all buses within a zone based on their distribution factors.[6]

The forecast data was obtained from the PJM website for the dates used in creating the data set.[7] The forecast was then broken down by zone and distributed to all buses within that zone. The parameters used for disaggregation were defined in a file called *load_apportionment_hubs_and_zone.xls* file from the PJM website.[8]

The real-time load data was obtained from the PJM website.[9] (data from the day corresponding to each test set day were used). The demand was broken down by zone and distributed to all buses within that zone.

Location of Data

The *Summer(Winter)Demand.xls* files contain the information needed to represent demand bids, demand forecasts and demand resources in the day-ahead model. The *RT Data_Summer(Winter).xls* files contain the information needed to represent real-time loads in the real-time intervals.

5. Building the Base Case Model

In order to validate the data set, base case models were constructed using the input data previously described. Base case models were constructed for the day-ahead market unit commitment, day-ahead reliability unit commitment (RUC) and economic dispatch for

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[5] Found at the following link, demand response data is under "Demand Response Bids", http://www.pjm.com/markets-and-operations/energy/real-time/historical-bid-data.aspx

[6] Zonal MW-to-bus distribution factors were obtained from the file "Load_apportionment_Hubs_and_Zones.xls" which has its most recent version available at http://www.pjm.com/markets-and-operations/ftr/model-information.aspx#Slider2011.

[7] 2009 and 2010 Day-Ahead demand and Day-Ahead forecast information is available at: http://www.pjm.com/markets-and-operations/energy/day-ahead.aspx.

[8] Most recent version available at: http://www.pjm.com/markets-and-operations/ftr/model-information.aspx#Slider2011.

[9] Historical hourly load data is available at: http://www.pjm.com/markets-and-operations/energy/real-time/loadhryr.aspx.

real-time intervals. This section serves as a guide for constructing the base case models from the data set.

Building the Network Model

If you have PSS/E software, you can read in the .raw file to create the network. However, the PSS/E software is not necessary to create the network. The following steps can be followed to build the network model.

Buses

In the Microsoft Access .mdb database for each test system day, open the *PSS_BUS_DATA* table. This contains the bus data for the network. First, buses which are disconnected are removed from the network. These include all buses which have bus type (IDE) = 4.[10] The remaining buses are part of the network.

Branches

Next, in the same database, open the *PSS_BRANCH_DATA_28* table. This table contains the information that describes the branches in the network. All branches with ST=0 (out of service) should be removed from the network topology. The remaining branches are in the network. The column *PSS_BUS_NUM_I* represents the from-bus for the branch and *PSS_BUS_NUM_J* is the to-bus for the branch.   In the *PSS_BRANCH_DATA_28* table, the column *RATEA* represents the steady state thermal rating of the branch and the column *RATEB* represents the emergency thermal rating of the branch.

Transformers

Transformer data is contained in multiple tables in the database. The table *PSS_TRANSFORMER_DATA_28_RECORD1* contains the from-bus (*PSS_BUS_NUM_I*) and to-bus (*PSS_BUS_NUM_J*) for each transformer, as well as the outage status (transformers with the value of *STAT* = 0 are out of service and are removed from the network).

The table *PSS_TRANSFORMER_DATA_28_RECORD2* contains the per unit resistance and reactance values for each transformer. The table *PSS_TRANSFORMER_DATA_28_RECORD3* contains the thermal ratings for each transformer, the columns *RATA1* and *RATB1* hold the long term and emergency thermal rating information for transformers.

Shift Factors

Shift factors represent the sensitivity of flows on transmission elements to net injection at buses in the network. In other words, the shift factor from bus i to transmission element k represents the fraction of power injected by a generator at bus i that would flow over transmission element k. For shift factor computation, the reference bus is chosen as the

[10] IDE is the bus type, type 4 means the bus is disconnected.

bus in the *PSS_BUS_DATA* table with type (*IDE*) = 3.[11] Shift factor computation for the base case model used this single reference bus as the withdrawal point when calculating all shift factors. The base case model did not consider contingencies, so shift factors were only computed for the bus-branch model with no contingencies. Loss sensitivities were not computed for the base case model.

The calculation of shift factors for the base case model is discussed further in Appendix B.

In the base case model, a bus was considered to impact a transmission constraint if it had a shift factor with a magnitude of 0.05 or larger with respect to that transmission constraint. In other words, shift factors with an absolute value of less than 0.05 were omitted from the model in order to reduce solution time.

Monitored Elements

In the base case model, all branches and transformers with a rating *not* equal to 0, 9999, or 99999 are monitored in the optimization model. In other words, branches and transformers will have their thermal constraints enforced unless the rating in the data set is equal to one of the above values. In addition, branches and transformers with voltages below 115 kV were not monitored in the base case model (for transformers, this refers to the voltage at the low side of the transformer). In the winter base case problem, an additional modification is that the thermal limit on the branch from *BUS5344* to *BUS8453* is not monitored. In the summer base case problem, the branch from *BUS3246* to *BUS3247* and the transformer from *BUS1987* to *BUS1985* are dropped from the monitored list (a modification made to ensure feasibility of the base case models; alternatively these could be monitored but are overloaded at certain hours in the base case test model).

Interfaces

Interfaces are constraints that can consist of more than one branch, and are described in the *Interface Defs and Limits Summer(Winter).xls* spreadsheets. To compute shift factors for an interface consisting of more than one branch, superposition principles are applied and the shift factor calculation proceeds in the same way as for a single transmission element (i.e., the shift factors for the lines in the interface are additive).

Building the Generator Model

Generators are primarily modeled using the information contained in the *Generator_Data_Summer(Winter).xls* spreadsheets. This spreadsheet contains the information needed to model the operational characteristics of generators, and generator offer curves. Generators are modeled as being available to be committed by the day-

[11] Bus type 3 represents the reference bus.

ahead market, and fully dispatchable with the exception of wind generators which follow a profile. Combined cycle (CC) generators are assumed to operate on a single monotonically increasing offer curve (i.e., they do not have multiple configurations modeled). Hydro generators are assumed to be available for commitment and dispatch up to their full output.

Generators are mapped to the network using the information contained in the *Generator to Bus Mapping.xls* spreadsheet.

The detailed description of the generator model that was used in the base case model is contained within the mathematical model described later in this paper.

Building other Elements of the Model

In addition to generators and the network, other elements exist such as load forecasts, demand bids, virtual bids, demand response, reserves, etc. These model elements are discussed in this section.

Demand is modeled as a withdrawal at a node in the network (the location is determined by the mapping between demands and buses in the demand files). In the day-ahead market unit commitment, fixed demand, demand bids, virtual bids and demand response are modeled. In the RUC, fixed demand, demand bids and virtual bids are replaced with the day-ahead forecast demand. In the real-time model, the day-ahead forecast demand is replaced with the real-time load. Demand response resources are present in all three models.

The *Reserves.xls* spreadsheet contains hourly quantities of operating reserves which must be carried system wide. In the base case model, these are treated as contingency reserves, at least half of which must come from online generators that withhold their output below their maximum capacity (spinning reserves). Up to half of the requirement may come from offline non-spinning reserves, and the base case model assumption is that CTs and GTs can provide these off-line reserves.

There are two files which contain information on phase angle regulators (PARs): *par_data_summer.xls* and *PSS_PARS_Change_Case.raw*. These are contained in the PSSE folder in the *CEII\Network* folders for each day. PARs were not modeled in the base case model discussed in this paper (for simplicity), but are still included as part of the data set for those who wish to model them.

6. Mathematical Model for the Base Case Day-ahead Market Unit Commitment

Using the data in the above files, a day-ahead unit commitment problem can be formulated and solved using a variety of optimization software programs. The methodology of putting this data into an optimization problem is best conveyed by giving the mathematical formulation of the optimization problem. The 'base case' problem that was formulated and solved for this paper is described below.

Sets

$\mathcal{T}$	=	The set of time periods (24).
$\mathcal{S}$	=	The set of steps on the offer (bid) curve (10).
$\mathcal{N}$	=	The set of buses (nodes) in the network.
$\mathcal{K}$	=	The set of branches in the network.
$\mathcal{G}$	=	The set of dispatchable generating units.
$\mathcal{W}$	=	The set of wind generators.
$\mathcal{J}$	=	The set of generators that can provide offline reserves (assumed CTs and GTs).
$\mathcal{D}$	=	The set of price responsive demands.
$\mathcal{E}$	=	The set of demand response resources.
$\mathcal{Q}$	=	The set of fixed demands.
$\mathcal{A}$	=	The set of inc bids.
$\mathcal{B}$	=	The set of dec bids.
$\mathcal{C}$	=	The set of forecast unscheduled flows.
$\mathcal{H}$	=	The set of tie schedules.

c^{g}_{gs}	=	Energy offer for generator g on step s (\$/MWh).
c^{su}_{g}	=	Startup cost for generator g (\$).
c^{nl}_{g}	=	No load cost for generator g (\$).
c^{pd}_{td}	=	Energy bid for price responsive demand d in hour t (\$/MWh).
c^{dr}_{e}	=	Demand response offers for demand response e (\$/MWh).
c^{vs}_{ta}	=	Inc bid for virtual supply a in hour t (\$/MWh).
c^{vd}_{tb}	=	Dec bid for virtual demand b in hour t (\$/MWh).

p^{g}_{tgs}	=	Cleared offer qty from generator g on step s in hour t (MWh).
$\underline{p}^{g}_{tg}$	=	Total real power dispatch from generator g in hour t (MWh).
v_{tg}	=	Binary decision to startup generator g in hour t.
u_{tg}	=	Binary decision to commit generator g in hour t.
l_{tg}	=	Binary decision to shut down generator g in hour t.
p^{pd}_{td}	=	Cleared bid from price responsive demand d in hour t (MWh).
p^{dr}_{te}	=	Cleared offer from demand response e in hour t (MWh).
p^{vs}_{ta}	=	Cleared inc offer from virtual supply a in hour t (MWh).
p^{vd}_{tb}	=	Cleared dec bid from virtual demand b in hour t (MWh).
p^{fd}_{tq}	=	Fixed demand q in hour t (MWh).
p^{daf}_{tn}	=	Day-ahead forecast demand at node n in hour t (MWh).
p^{w}_{tw}	=	Forecast production from wind generator w in hour t (MWh).

p^{uf}_{tc} = Injection from unscheduled flow c in hour t (MWh).
p^{ts}_{th} = Injection from tie schedule h in hour t (MWh).

y^{bal} = Penalty cost on system power balance shortage or surplus (assumed 10000).
y^{flow} = Penalty cost on individual transmission thermal limits (assumed 5000).
$s^{bal,+}_{t}$ = System wide shortage variable.
$s^{bal,-}_{t}$ = System wide surplus variable.
$s^{flow,+}_{tk}$ = Transmission element thermal relaxation positive direction.
$s^{flow,-}_{tk}$ = Transmission element thermal relaxation negative direction.
f^{b}_{tk} = Flow on branch k in hour t (MWh).
δ_{nk} = Shift factor from bus n to branch k.
x_{tn} = Net injection at bus n in hour t (MWh).

z = Objective function market surplus variable ($).

$$Max \quad z = -\sum_t\{\sum_g [c^{su}_g v_{tg} + c^{nl}_g u_{tg} + \sum_s c^g_{gs} p^g_{tgs}] + \sum_a c^{vs}_{ta} p^{vs}_{ta} + \sum_e c^{dr}_e p^{dr}_{te} - \sum_d c^{pd}_{td} p^{pd}_{td} - \sum_b c^{vd}_{tb} p^{vd}_{tb} + y^{bal} [s^{bal,+}_t + s^{bal,-}_t] + y^{flow}[s^{flow,+}_{tk} + s^{flow,-}_{tk}]\}$$

Constraint Description (Dual Variable)

(1) System Power Balance (λ_t)

$$\sum_g \underline{p}^g_{tg} + \sum_e p^{dr}_{te} + \sum_a p^{vs}_{ta} - \sum_d p^{pd}_{td} - \sum_b p^{vd}_{tb} + s^{bal,+}_t - s^{bal,-}_t = \sum_q p^{fd}_{tq} - \sum_c p^{uf}_{tc} - \sum_w p^w_{tw} - \sum_h p^{ts}_{th} \quad \forall t$$

(2) Generator Dispatch in Hour (α_{tg})

$$\underline{p}^g_{tg} - \sum_s p^g_{tgs} = 0 \quad \forall t,g$$

(3) Generator Dispatch Step Limit (β_{tgs})

$$-p^g_{tgs} + P^{step}_{gs} u_{tg} \geq 0 \quad \forall t,g,s$$

(4) Generator Maximum Output (γ_{tg})

$$-\underline{p}^g_{tg} - p^{res}_{tg} + P^{max,g}_g u_{tg} \geq 0 \quad \forall t,g$$

(5) Generator Minimum Run Level (ε_{tg})

$$\underline{p}^g_{tg} - P^{min,g}_g u_{tg} \geq 0 \quad \forall t,g$$

(6) Demand Bid Max Quantity (ζ_{td})

$$-p^{pd}_{td} \geq -P^{max,d}_{td} \quad \forall t,d$$

(7) Virtual Supply Max Quantity (η_{ta})

$$-p^{vs}_{ta} \geq -P^{max,a}_{ta} \quad \forall t,a$$

(8) Virtual Demand Max Quantity (ι_{tb})

$$-p^{vd}_{tb} \geq -P^{max,b}_{tb} \quad \forall t,b$$

(9) Demand Response Max Quantity (κ_{te})

$$-p^{dr}_{te} \geq -P^{max,e}_{te} \quad \forall t,e$$

(10) Net Injection at Bus (μ_{tn})

$$x_{tn} - \sum_{g(n)} \underline{p}^g_{tg} - \sum_{a(n)} p^{vs}_{ta} - \sum_{e(n)} p^{dr}_{te} + \sum_{d(n)} p^{pd}_{td} + \sum_{b(n)} p^{vd}_{tb}$$

$= -\sum_{q(n)} p^{fd}_{tq} + \sum_{c(n)} p^{uf}_{tc} + \sum_{w(n)} p^{w}_{tw} + \sum_{h(n)} p^{ts}_{th}$ $\forall t,n$

(11) Flow on Transmission Element (ν_{tk})

$f^{b}_{tk} \quad -\sum_n x_{tn}\, \delta_{nk} \quad = \quad 0$ $\forall t,k$

(12) Maximum Flow on Transmission Element (ξ_{tk})

$-f^{b}_{tk} \quad + s^{flow,+}_{tk} \quad \geq \quad -F^{max,b}_{tk}$ $\forall t,k$

(13) Maximum Flow on Transmission Element, Reverse Direction (o_{tk})

$f^{b}_{tk} \quad + s^{flow,-}_{tk} \geq \quad -F^{max,b}_{tk}$ $\forall t,k$

(14) Startup-Shutdown-Commitment Relationship (π_{tg})

$v_{tg} - l_{tg} - u_{tg} + u_{t-1,g} \geq \quad 0$ $\forall t,g$

(15) Minimum Run Time (ς_{tg})

$$- \sum_{\underline{t} = t - r^{Run}_g + 1}^{t} v_{tg} + u_{tg} \quad \geq \quad 0 \qquad \forall t,g$$

(16) Minimum Down Time (σ_{tg})

$$- \sum_{\underline{t} = t - r^{Run}_g + 1}^{t} l_{tg} \quad - u_{tg} \quad \geq \quad -1 \qquad \forall t,g$$

(17) Maximum Ramp Rate Up (τ_{tg})

$-\underline{p}^{g}_{tg} + \underline{p}^{g}_{t-1,g} + P^{ramp}_{g}\, u_{tg} + P^{max,g}_{g}\, v_{tg}$

$\geq \quad 0$ $\forall t,g$

(18) Maximum Ramp Rate Down (υ_{tg})

$-\underline{p}^{g}_{t-1,g} + \underline{p}^{g}_{tg} + P^{ramp}_{g}\, u_{tg} + P^{max,g}_{g}\, l_{tg}$

$\geq \quad 0$ $\forall t,g$

(19) System Wide Spinnning and non Spinning Reserves (φ_t)

$\sum_g p^{res}_{tg} + \sum_{g \epsilon \mathcal{P}} P^{max,g}_{g}\, (1 - u_{tg})$ $\forall t$

$\geq \quad Res_t$

(20) Spinning Reserves (χ_t)

$\sum_g p^{res}_{tg} \geq \quad Res_t/2$ $\forall t$

$u_{tg}, v_{tg}, l_{tg}\ \epsilon\ \{0,1\}$

$\underline{p}^{g}_{tg}, p^{dr}_{te}, p^{vs}_{tu}, p^{pd}_{td}, s^{bal,+}_{t}, s^{bal,-}_{t}, s^{flow,+}_{tk}, s^{flow,-}_{tk}, s^{int}_{ti}, p^{g}_{tgs}, p^{res}_{tg} \geq 0$

In the above notation, *g(n)*, *d(n)*, etc. maps a resource, load, etc. to bus *n*.

Model for the RUC

In the base case RUC model, the formulation is similar to the one described previously. However, there are some important modifications. Fixed demand, price responsive demand and virtual bids are removed from the model (constraints (6)-(8) are dropped), and in constraints (1) and (10) the variables and parameters representing fixed demand, price responsive demand, and virtual bids are replaced with the withdrawals corresponding to the day-ahead demand forecast. Similarly, price responsive demand and virtual bid terms are dropped from the objective function.

Commitments that were made in the day-ahead market are assumed fixed in the RUC. In other words, for each generator g, if there was a commitment in any hour t, u_{tg} is fixed to 1 in the RUC. Additional commitments are allowed in the RUC, as long as the remaining constraints are satisfied. De-commitments from the day-ahead market schedule are not allowed in the RUC.

The objective function for the RUC does not minimize the energy component of production cost. It only minimizes commitment costs (startup and no-load costs). Generator and demand response variable cost terms are dropped (or set to zero). Penalty costs for constraint relaxations remain in the objective function.

Model for Real-time Dispatch

In the economic dispatch model for the selected real-time intervals, all commitments from the day-ahead market, plus additional commitments in the RUC, are assumed fixed. The single interval model can then be solved as a linear program because the startup and commitment decisions no longer have to be made (integer variables become fixed 0,1 parameters), and commitment related constraints (14)-(16) are redundant.

7. Results from the Base Case Model

Using the datasets and mathematical models described previously, FERC staff developed optimization models to validate that the test system could produce reasonable and realistic results. The models were written in the General Algebraic Modeling System (GAMS) language and solved with the Gurobi optimization solver on an application server with 8 Intel Xeon E7458 2.4GHz processors and 64 gigabytes (GB) memory (RAM). The model is formulated to maximize market surplus, and at the optimal solution the objective function values are actually negative. In the results discussion in this report, the objective function values are shown as positive numbers, which would be the result if the model were modified to minimize the negative of the objective function.

Day-ahead Unit Commitment

Solution Method

The problem formulated as described previously can be solved by a commercial solver if enough processing power and memory are available. With all constraints on branches and transformers above 115 kV included, the problem contains about 4,000 transmission constraints in every hour. With over 1,000 generating units each with binary startup and commitment decisions, and potentially over 1 million bus-branch shift factor values, the problem can be difficult to solve. The table below shows the amount of time that the summer problem takes to solve when 3,906 transmission constraints are included in each hour.

Table 1: Solution to the Summer Day-ahead problem with full constraints

Problem Summary	
Test Problem	Summer Day Ahead Unit Commitment
Formulation Type	DCOPF
Solver	Gurobi 4.0
CPU	8x Intel Xeon E7458 2.4GHz
Memory	64 GB RAM
Shift Factor Cutoff	0.05
Monitored Lines and Transformers kV Cutoff	all lines 115 kV and above
Algorithm	Mixed Integer Program
MIP Gap Tolerance	0.05
Solution	
Objective	$18,017,325
Best Bound	$17,276,545
Gap	4.11%
Time	
Presolve + Root Linear Program	2476
MIP Search	2777

The total solution time is over an hour. In addition, the memory requirements are very large (over 10 GB), and using this brute force approach to the solution may not be practical for some users of the test system.

Where the interest is only to produce results quickly, the solution time can be reduced by taking advantage of the fact that most transmission constraints are not likely to be persistently binding. We used the following method to reduce memory requirements and computation time.

In Step 1, the problem is solved without enforcing any transmission constraints except for interface constraints. Next, the flow on every single transmission line above 115 kV is calculated using the net injections and withdrawals at each bus, and the shift factors from each bus to each transmission line. Any line that has a flow within 20% of its thermal limit is flagged to be monitored. In Step B, the program is re-run including these constraints. If the same topology and generators are used repeatedly, Step 1 (10-15 minutes) can be solved once and the reduced list of monitored elements can be saved. The next two tables show the solution time for the Summer and Winter problem using this screening approach (times for Step 2).

Table 2: Solution to the Summer Day-ahead problem with reduced constraints

Problem Summary	
Test Problem	Summer Day Ahead Unit Commitment
Formulation Type	DCOPF
Solver	Gurobi 4.0
CPU	8x Intel Xeon E7458 2.4GHz
Memory	64 GB RAM
Shift Factor Cutoff	0.05
Monitored Lines and Transformers kV Cutoff	subset of lines above 115
Algorithm	Mixed Integer Program
MIP Gap Tolerance	0.05
Solution	
Objective	$17,977,310
Best Bound	$17,225,488
Gap	4.18%
Time	
Presolve + Root Linear Program	502
MIP Search	674

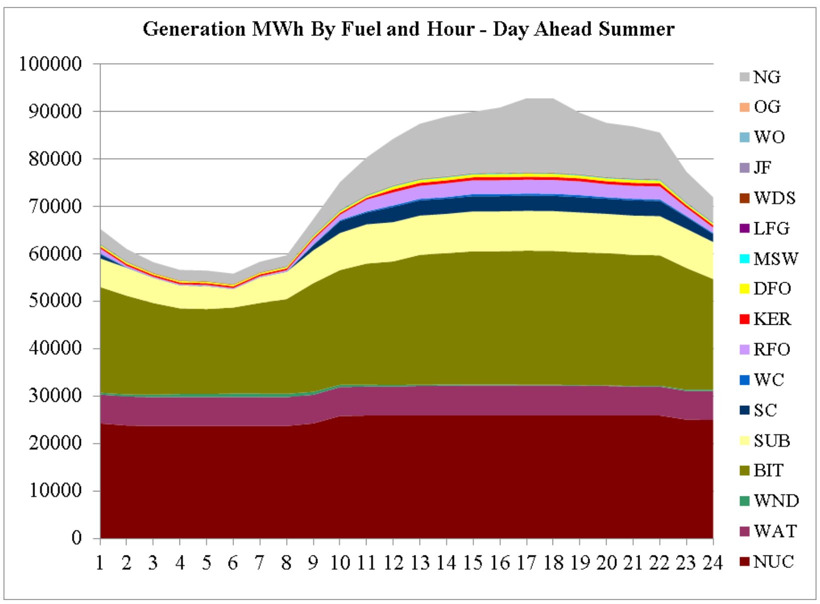
Table 3: Solution to the Winter Day-ahead problem with reduced constraints

Problem Summary	
Test Problem	Winter Day Ahead Unit Commitment
Formulation Type	DCOPF
Solver	Gurobi 4.0
CPU	8x Intel Xeon E7458 2.4GHz
Memory	64 GB RAM
Shift Factor Cutoff	0.05
Monitored Lines and Transformers kV Cutoff	subset of lines above 115
Algorithm	Mixed Integer Program
MIP Gap Tolerance	0.05
Solution	
Objective	$25,085,574
Best Bound	$24,666,532
Gap	1.73%
Time	
Presolve + Root Linear Program	530
MIP Search	123

Solving the RUC problem follows from the solution to the day-ahead unit commitment problem. After solving the day-ahead market unit commitment, substitute the day-ahead forecast demand for the demand parameters and variables in the day-ahead unit commitment (including virtual bids). Demand response is still present in the RUC. Fix the commitments which have already been made, and allow other commitment decisions to be made while minimizing only startup and no-load costs. The RUC can be an easier integer problem than the day-ahead unit commitment because so many commitment decisions are already fixed. The solution statistics for the RUC problems are contained in Appendix C.

Generation

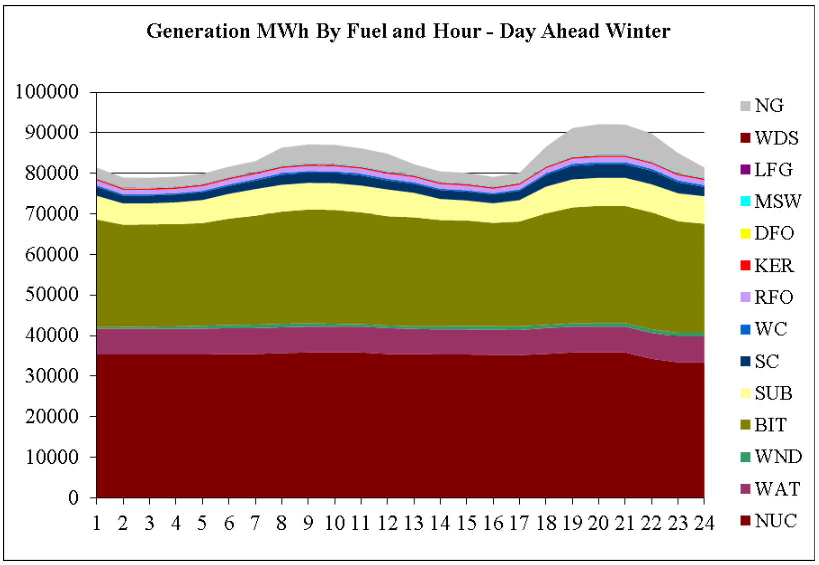
The following figures show the amount of generation, by type, that cleared in the day-ahead model for each of the days in the test system. The system has a large amount of coal and nuclear generation relative to other generation types.



Fuel Type	Percent of total energy produced over the day
Nuclear	35.4%
Bituminous Coal	33.3%
Subbituminous Coal	9.9%
Water	8.8%
Natural Gas	3.9%

Synthetic Coal	2.7%
Residual Fuel Oil	2.4%
Kerosene	2.4%
Distillate Fuel Oil	0.6%
Wind	0.5%

Figure 6: Cleared generation by hour in the Day-ahead Summer model and percent of energy by fuel type



Fuel Type	Percent of total energy produced over the day
Nuclear	42.1%
Bituminous Coal	32.1%
Water	7.4%
Subbituminous Coal	7.3%
Natural Gas	4.6%
Synthetic Coal	2.9%
Residual Fuel Oil	1.4%
Wind	0.9%
Waste/Other Coal	0.5%

Kerosene	0.4%
Municipal Solid Waste	0.2%
Landfill Gas	0.1%
Wood	0.1%
Distillate Fuel Oil	0.0%

Figure 7: Cleared generation by hour in the Day-ahead Winter model and percent of generation by fuel type

Demand Response

The system included demand response bidding into the day-ahead market. The following figures show the amount of demand response that cleared by hour in each model.

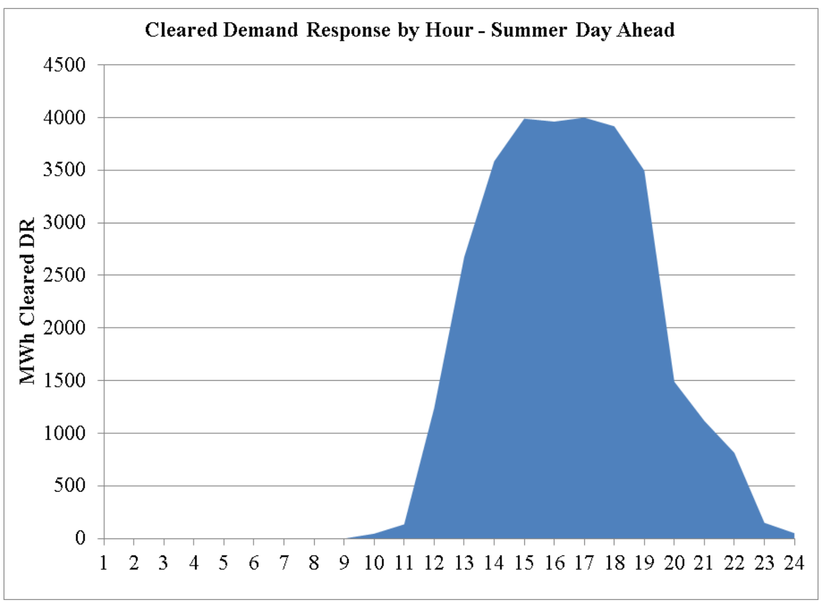


Figure 8: Cleared Demand Response in the Day-ahead Summer Model

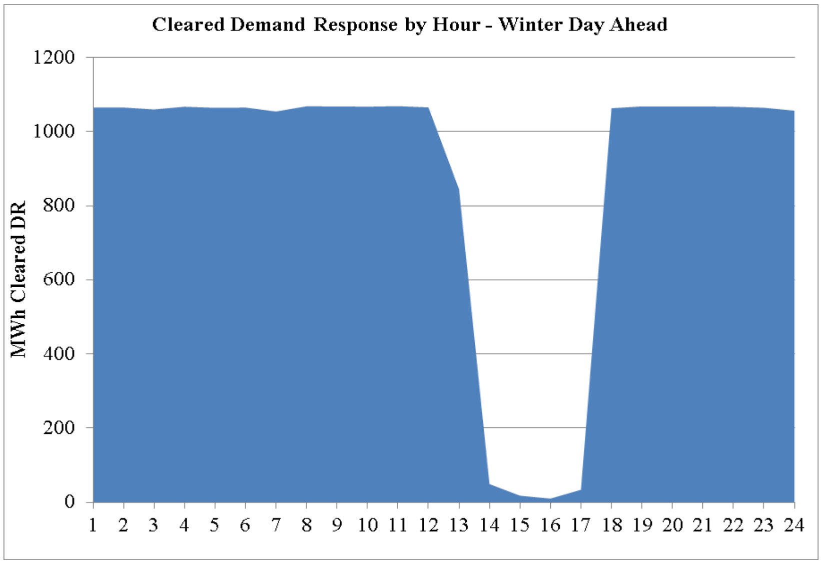


Figure 9: Cleared Demand Response in the Day-ahead Winter Model

Locational Marginal Prices (LMPs)

LMPs can be derived from the dual variables in the previously described mathematical formulation of the unit commitment problem. For the purposes of this report, dual variablesare obtained after the optimal integer solution is obtained, by solving a restricted linear program with constraints that hold the integer variables equal to their values in the optimal solution. Since the values are the duals to a mixed integer program, the costs on the binary variables are able to impact the prices. Thus, the "LMPs" shown here may not match the LMPs produced by a pricing algorithm in a given electricity market. In many pricing algorithms, the costs associated with binary variables receive different treatment and often do not impact prices (or impact prices only in limited circumstances).

The LMP at each bus is found from the dual variable on system power balance, and the dual variables on the transmission constraints which are sensitive to injections from that bus. The formula for a bus LMP is expressed as:

$$LMP_{tn} = -\lambda_t - \sum_k (\xi_{tk} + o_{tk})\delta_{nk}$$

The following figures show the average LMPs across all buses for the two days modeled.

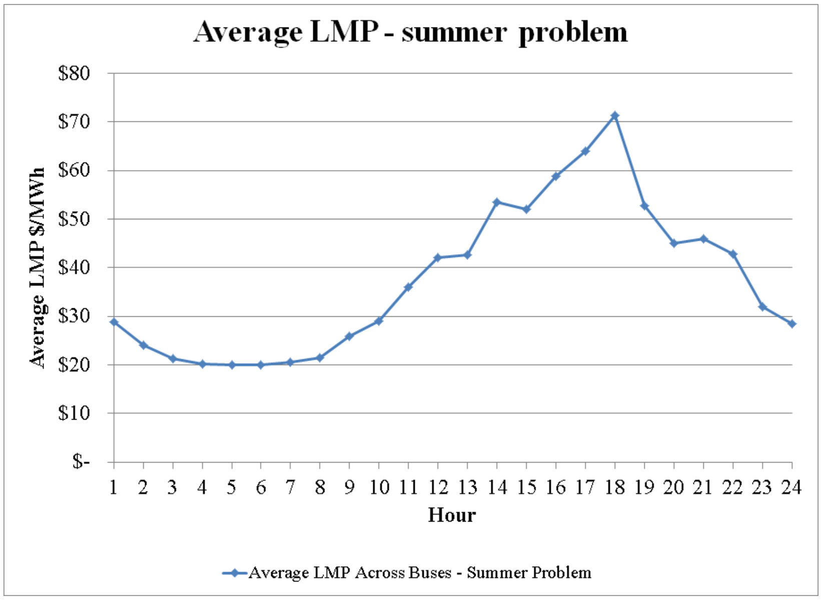


Figure 10: Average LMPs by Hour in the Summer Model

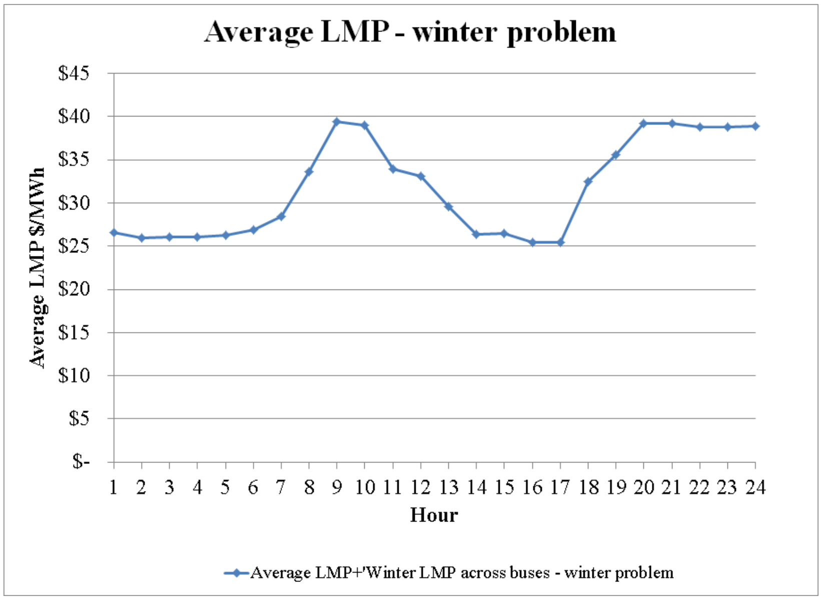


Figure 11: Average LMPs by Hour in the Winter Model

The average prices ranging from $20/MWh to $60/MWh are reasonable and suggest that the test system is realistic.

Taking the load weighted LMPs by zone for the summer problem reveals that the higher prices tended to be in zones where higher prices are expected in the actual RTO; similarly for lower prices.

Table 4: 5 Highest Priced Zones in the Summer Day-ahead model (load weighted)

Average	Zone
$ 75.35	Zone 68
$ 67.25	Zone 71
$ 54.21	Zone 58
$ 54.01	Zone 63
$ 53.90	Zone 72

Table 5: 5 Highest Priced Zones in the Winter Day-ahead model

Average	Zone
$ 36.97	Zone 69
$ 34.19	Zone 73
$ 33.58	Zone 58
$ 32.74	Zone 64
$ 32.69	Zone 66

Table 6: 5 Lowest Priced Zones in the Summer Day-ahead model

Average	Zone Number
$ 28.33	Zone 91
$ 29.73	Zone 104
$ 30.69	Zone 90
$ 31.77	Zone 82
$ 31.96	Zone 92

Table 7: 5 Lowest Priced Zones in the Winter Day-ahead model

Average	Zone Number
$ 31.21	Zone 105
$ 31.27	Zone 91
$ 31.31	Zone 75
$ 31.35	Zone 79
$ 31.40	Zone 85

8. Summary

By providing a single, RTO-sized test set it is staff's hope that the power systems optimization community will be equipped with a tool for identifying best practices in unit commitment and economic dispatch algorithms, and for comparing performance on difficult power systems optimization problems. The test set and data sources are described in detail. A suggested template which contains important solution information for benchmarking algorithms is contained in Appendix G. The examples of base case results are intended to provide a general guide for users who are trying to validate that they have constructed the various pieces of the data set properly in order to run optimization experiments. Staff anticipate that users will want to see changes and updates to the data set to reflect a changing power industry. As such users in the optimization community are encouraged to document their own modifications and ideas so that the data set can evolve over time. Additionally, we have begun the process of obtaining two additional, even more detailed data sets which can be used for not only integer-linear unit commitment algorithms but also for non-linear AC optimal power flow modeling.

The network components of the data set have CEII restrictions. Other data, such as the generator data, was obtained without any restriction from public sources like the EIA, EPA and PJM websites, as well as statistical estimation. The data is contained in eLibrary under AD10-12. The public portions of the data set are available, and the network portions are considered CEII and classified appropriately in eLibrary. For additional information about CEII information filed at the Commission, please visit this section of the FERC website: **http://www.ferc.gov/legal/ceii-foia.asp**, or contact: foia-ceii@ferc.gov.

Appendix A: Generator Data

Data in the Generator_data_Summer(Winter).xls spreadsheets

Generator Characteristics Tab:

Field	Description	Source
Generic Name	Generic name of the generator	
Ramp Up	Ramp Up	Statistical Study
Ramp Down	Ramp Down	Statistical Study
PRIMEMOVER	Primemover Code	EIA 411
NAMEPLATE (MWs)	Nameplate MWs	EIA 411
SUMMER_CAPABILITY (MWs)	Summer Capability MWs	EIA 411
WINTER_CAPABILITY (MWs)	Winter Capability MWs	EIA 411
Energy_Source_1 (Fuel)	Energy Source 1	EIA 411
EFORD	Forced Outage Rate	PJM website
CITY	City where plant resides	EIA 411
STATE	State where plant resides	EIA 411
Economic Minimum (MWs)	Generator Eco Min	Statistical Study
MIN_DOWN_TIME	Default Minimum Down Time in hours	PJM Default Parameters
MIN_RUN_TIME	Default Minimum Run Time in hours	PJM Default Parameters
CO2 rate	CO2 Emissions rate in lbs/MWh	EPA eGrid Data
NOx rate	NOx emissions rate in lbs/MWh	EPA eGrid Data
SO2 rate	SO2 emissions rate in lbs/MWh	EPA eGrid Data

Default Generator Parameters

In addition to the parameters obtained from EIA and EPA, and those that were estimated, some default parameters were assumed. For example, for minimum run time and minimum down time.

These defaults are taken from the PJM Parameter Matrix and the GE MAPS assumptions as listed in the report that can be found at:

http://www.oe.energy.gov/DocumentsandMedia/Appendix_6_MAPS_Assumptions_3-13.pdf (accessed late 2010), and Appendix B of the report at : http://www.spp.org/publications/CRA%20SPP-Entergy%20Rate%20Pancaking%20Study.pdf (accessed September, 2011) http://www.pjm.com/~/media/committees-groups/working-groups/rmwg/20070424/20070424-item-03-parameters-matrix-revised.ashx

Generator Offer Curve Tab:
Note that generator offer curves are derived from data on PJM historical bids as well as estimated data in the heat rate tab. Since it was not known which generator was represented in the masked PJM historical data, the curves for each generator were assigned after dividing generators into categories and looking for bid data that had a similar upper limit as a generator's nameplate capacity. When no match could be obtained, the estimated heat rate curves from the heat rate tab were multiplied by fuel prices obtained from EIA data to create the offer curve. As such, the offer curves, while representative of realistic curves, are fictional and entirely derived from publicly available sources.

Field	Description	Source
Generic Name	Generic name of the generator	
MW 1		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 1 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 2		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 2 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 3		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 3 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 4		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 4 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 5		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 5 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 6		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 6 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 7		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 7 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 8		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 8 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 9		PJM Historical Generator Bids & Data from Heat Rate Tab
BID 9 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
MW 10		PJM Historical Generator Bids & Data from Heat Rate Tab

BID 10 ($/MW)		PJM Historical Generator Bids & Data from Heat Rate Tab
No Load Cost ($)	No Load Cost in Dollars	PJM Historical Bid Data
Cold Start Cost ($)	Cold Start Cost in Dollars	PJM Historical Bid Data
	Hot Start Cost in Dollars	PJM Historical Bid Data

Generator Heat Rate Tab:

This tab lists the nominal heat rate for those units reporting on the 2008 EIA Form 923. The nominal heat rates came from the EPA eGrid datasets, curves were derived by using the default shape listed in the GE MAPS assumptions.

Field	Description	Source
Generic Name	Generic name of the generator	
Nominal Heat Rate	Nominal Heat Rate	EPA eGrid
MW_OUTPUT_1		
MMBTU_PER_MWH1		
MW_OUTPUT_2		
MMBTU_PER_MWH2		
MW_OUTPUT_3		
MMBTU_PER_MWH3		
MW_OUTPUT_4		
MMBTU_PER_MWH		

Appendix B: Shift Factor Calculation

The calculation of shift factors for the base case model makes assumptions to create a simplified real power flow to be used in linear and mixed-integer linear programming algorithms (aka DC power flow, linearized power flow, etc): 1) Voltage magnitudes equal to 1.0, 2) branch resistance is assumed to be very small such that susceptance of a branch from bus i to bus j is $-\frac{1}{x_{ij}}$, where x_{ij} is the branch reactance. The angle difference at the two ends of the branch is assumed to be small so that $\sin \theta_{ij} = \theta_i - \theta_j$ and $\cos \theta_{ij} = 1$. The real power flow on each branch and transformer using these assumptions is: $P_{ij} = -\frac{1}{x_{ij}}(\theta_i - \theta_j)$. The angle at the reference bus is set equal to 0. Shift factors are the change in flow on a transmission element k for a change in injection at a bus i, or $s_{ki} = \frac{\Delta P_k}{\Delta P_i}$. These can be calculated from:

$$\mathbf{Sf} = \mathbf{D}[\mathbf{B'}]^{-1}$$

The solution gives **Sf**, the matrix of shift factors from buses to branches in the network. The **B'** matrix is n-1 x n-1, where n is the number of buses and the row and column for the reference bus are removed. $B'_{ij} = -\frac{1}{x_{ij}}$ and $B'_{ii} = \sum_{j \neq i} B'_{ii}$.. **D** is a matrix where $D_{ki} = 1/x_{ij}$ and $D_{kj} = -1/x_{ij}$ for branch k from bus i to bus j and $D_{kp} = 0$ for $p \neq i$ or j. There are many methods for calculating shift factors, including the use of distributed slack buses. We did not use a distributed slack bus here, but calculated our shift factors using methods found in a textbook.[12] For a large network such as the one in this test set, software with built in methods to calculate shift factors, or tools such as Matlab which quickly perform matrix calculations, are beneficial.

[12] We consulted the following book in calculating shift factors: Zhu, J., *Optimization of Power System Operation*, IEEE/Wiley (2009).

Appendix C: RUC Solution Statistics

Problem Summary	
Test Problem	Summer Day Ahead RUC
Formulation Type	DCOPF
Solver	Gurobi 4.0
CPU	8x Intel Xeon E7458 2.4GHz
Memory	64 GB RAM
Shift Factor Cutoff	0.05
Monitored Lines and Transformers kV Cutoff	subset of lines above 115
Algorithm	Mixed Integer Program
MIP Gap Tolerance	0.05
Solution	
Objective	$3,852,687
Best Bound	$3,692,130
Gap	4.16%
Time	
Presolve + Root Linear Program	250
MIP Search	23

Problem Summary	
Test Problem	Winter Day Ahead RUC
Formulation Type	DCOPF
Solver	Gurobi 4.0
CPU	8x Intel Xeon E7458 2.4GHz
Memory	64 GB RAM
Shift Factor Cutoff	0.05
Monitored Lines and Transformers kV Cutoff	subset of lines above 115
Algorithm	Mixed Integer Program
MIP Gap Tolerance	0.05
Solution	
Objective	$1,535,989
Best Bound	$1,489,791
Gap	3.00%
Time	
Presolve + Root Linear Program	395
MIP Search	15

Appendix D: Real-time Model Results

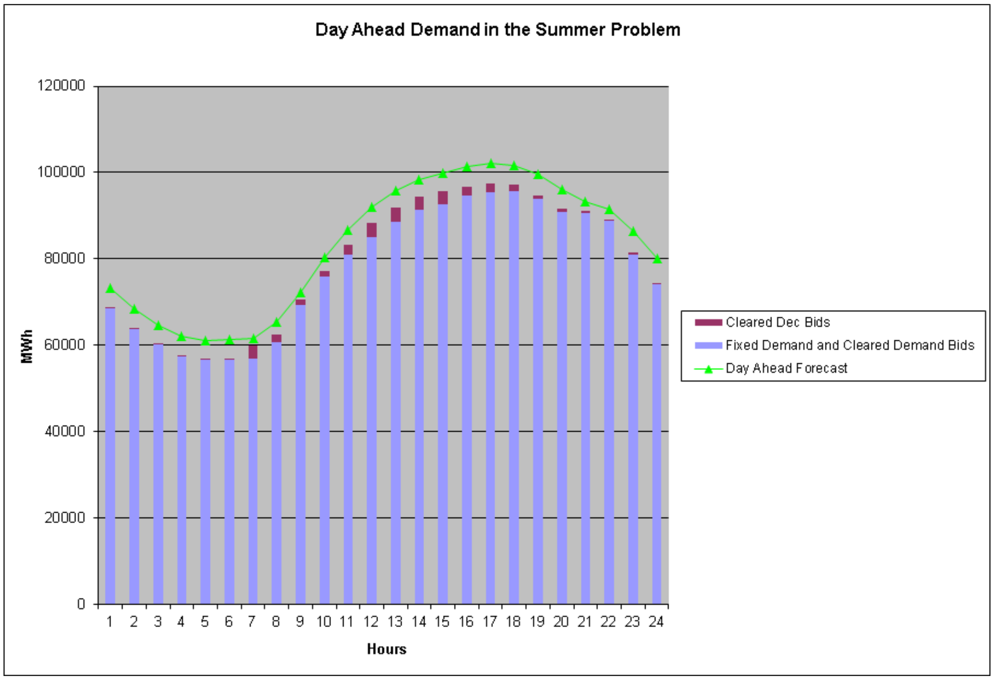
As discussed previously, the test system is primarily a day-ahead test system. The limited sample of updated real-time load and wind data can be used to model discrete intervals. Data exists for 6 such intervals in each of the summer and winter data sets. The intervals are from the real-time hours ending 1, 5, 9, 13, 17 and 22. The data could be extrapolated, in theory, to construct a real-time look ahead commitment. However, here we only report on the single interval dispatch solution time. We only report on one interval because all solve in essentially the same amount of time and display the same characteristics.

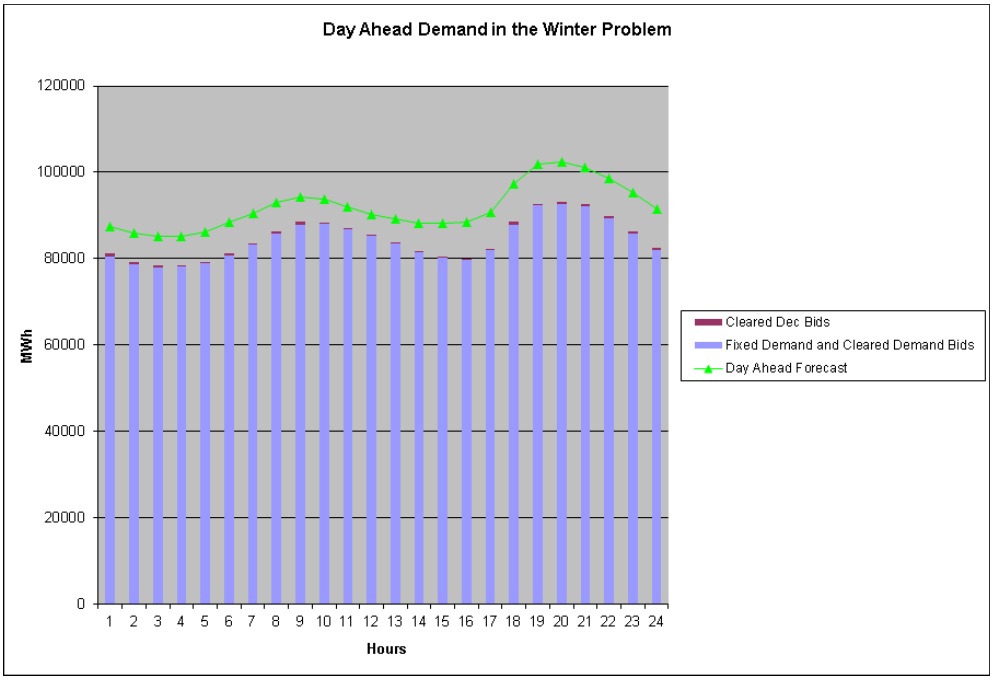
We report on the first interval (HE1) from the Winter problem.

Problem Summary	
Test Problem	Winter Real Time Interval 1
Formulation Type	DCOPF
Solver	Gurobi 4.0
CPU	8x Intel Xeon E7458 2.4GHz
Memory	64 GB RAM
Shift Factor Cutoff	0.05
Monitored Lines and Transformers kV Cutoff	subset of lines above 115
Algorithm	Linear Program
MIP Gap Tolerance	0.05
Solution	
Objective	$124,902
Best Bound	N/A
Gap	N/A
Time	
Presolve + Root Linear Program	58
MIP Search	N/A

Appendix E: Day-ahead Demand and Virtual Demand

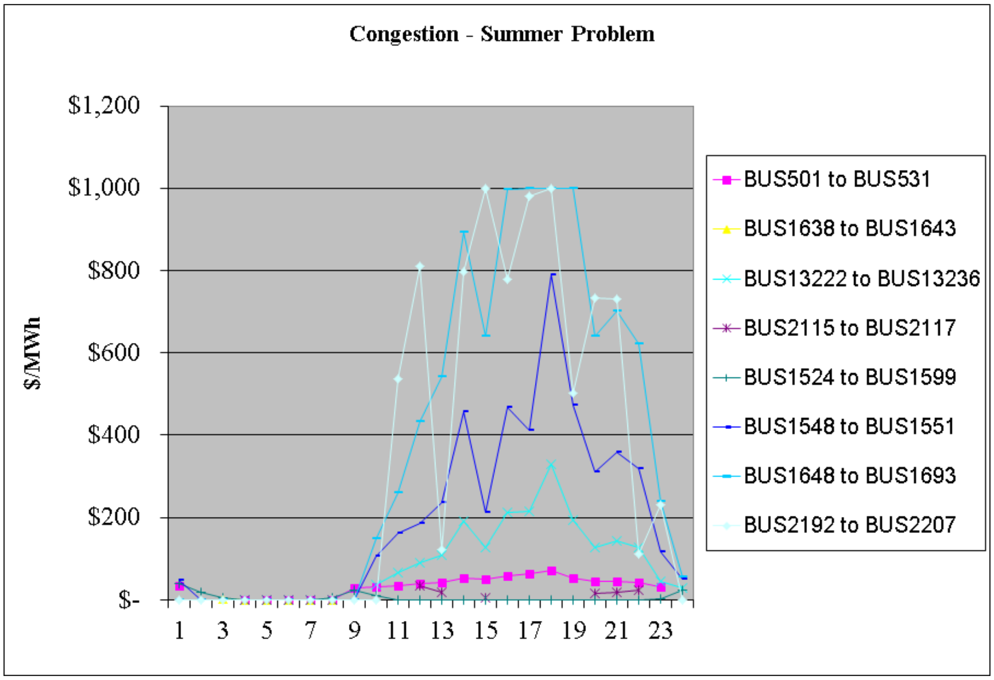
This appendix includes information on the fixed demand, demand bids and virtual bids which cleared in the base case day-ahead market problem for each day.

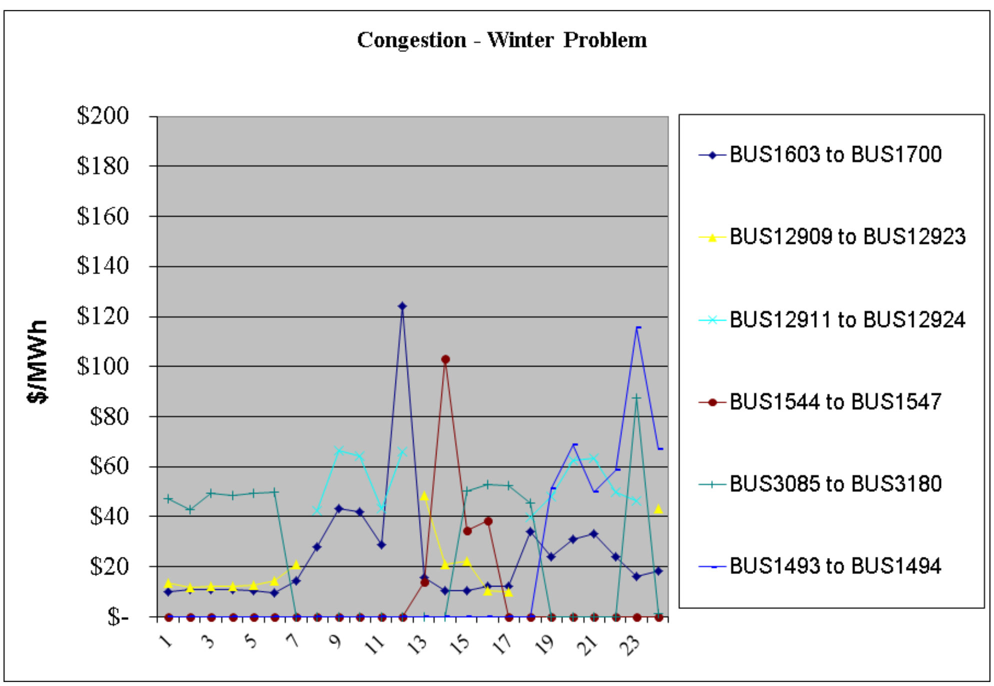




Appendix F: Congestion

This appendix illustrates the congestion shadow prices associated with constraints in the day-ahead solutions.





Appendix G: Suggested Reporting Template

Because one of the purposes of the test system is for benchmarking unit commitment solution algorithms, staff suggests a reporting template which could be used to compare solution statistics from different methods. Reporting a common set of information could aid in the identification of best practices for solving unit commitment.

RTO Unit Commitment Test Problem Reporting Template	
Name:	Date: *7/2/2012*
Data Set (Summer/Winter; Day Ahead/Real Time)	
Summer Day Ahead	
Model Description	
24 period Day Ahead unit commitment, monitoring limits on a reduced set of branches and transformers 115 kV and above. Shift factors below 0.05 are not modeled (Shift factor cutoff 0.05). Lossless, linearized powerflow without contingencies.	
Solution Summary	
Objective Function Value	*17977310*
Best Possible Objective	*17225488*
Gap	*4.18%*
Gap Tolerance	*5.0%*
Algorithm	*Mixed Integer Program*
Solution Time (seconds)	
Total	*1176*
LP relaxation	*502*
Branch and Bound	*674*
Other (Describe)	
Time:	
Computer	
CPU(s)	*8x Intel Xeon E7458 2.4GHz*
Memory	*64 GB*
Software	
Program	*GAMS 23.6*
Solver	*Gurobi 4.0*
Solver Options (Summarize)	
8 threads, Presolve on, default presolve and cuts options.	
Additional Information	
Reduced set of constraints to monitor determined by running the model with only interface constraints enforced, and choosing lines that had flows within 20% of normal limits. This was found to lead to a close approximation of the optimal solution with very close to the same set of congested constraints, in a much shorter amount of time than solving the problem with every line monitored.	

Appendix H: References

References

In addition to this documentation, useful references include the following PJM Manuals:

- M-10: Pre-Scheduling Operations describes PJM and PJM Member pre-scheduling activities
- M-11: Scheduling Operations provides information on the day-ahead and hourly scheduling
- M-35: Definitions and Acronyms

All of which can be found on the PJM website at:

http://www.pjm.com/documents/manuals.aspx

In addition to the above manuals, the PJM Market Database Data Dictionary can be found at:

http://www.pjm.com/~/media/etools/emkt/market-database-data-dictionary.ashx

Information on the PJM FTR model can be found at:

http://pjm.com/markets-and-operations/ftr.aspx

Additional PJM historical data can be found at:
http://pjm.com/markets-and-operations/ops-analysis.aspx

http://pjm.com/markets-and-operations/energy.aspx

EIA documentation for EIA forms:

- Form EIA-860 Database Annual Electric Generator Report
- Form EIA-411 Coordinated Bulk Power Supply Program Report
- Form EIA-906, EIA-920 and EIA-923 Databases

Can be found on the EIA website at:

http://www.eia.doe.gov/cneaf/electricity/page/data.html

EPA documentation for EPA forms:

http://www.epa.gov/cleanenergy/energy-resources/egrid

The National Renewable Research Lab (NREL) report “A Method and Case Study for Estimating the Ramping May 2005 Capability of a Control Area or Balancing Authority and Implications for Moderate or High Wind Penetration” can be found at:

http://www.nrel.gov/docs/fy05osti/38153.pdf

Appendix I: GAMS Code for the Day-ahead Unit Commitment

Below is the code used to solve the unit commitment test problem in GAMS, to create the base case results.

```
$ontext
Day Ahead Unit Commitment Test Problem;
$offtext

$OFFListing
$ONUELLIST
$ONINLINE
$ONEMPTY

$ontext
choose the season to solve:
If you want to solve the Summer problem, comment out the 'Winter' line and
leave the 'Summer' line un-commented
vice versa to solve the Winter problem
$offtext

$set season 'Summer'
*$set season 'Winter'

*place the path for your GAMS project in my_data_root
$set my_data_root 'insert path for GAMS project file'

*place the path for your GDX input and output files in cgdxpath
$set cgdxpath 'insert path for GDX files'

$set ceiifile ceii_input_%season%_model
$set outfile  ceii_DAUC_%season%


scalar  SFcutoff                Shift Factor cutoff
/0.05/;
scalar kVcutoff                 kV cutoff for monitored Tx limits
/115/;
scalar ThermalLimViol           Thermal Limit violation penalty
/1000/;
scalar InterfaceLimViol         Interface Limit violation penalty
/5000/;
```

```
scalar GlobalViol              Global energy shortage or surplus penalty
/10000/;

sets     sHour(*)              Hours in the day ahead market
         sGen(*)               all generators
         sPrimeMover           Generator prime mover set
         sGenPrimeMover(sGen,sPrimeMover)       Prime mover mapping
         sStep                 Steps in generator offer curve
         sWind                 Wind generators
         sWindBus              Wind generator bus
         sSource               Fuel Sources
         sGenSource            Fuel source to generator

         sBus(*)               CEII Do Not Release - all network buses
         sZone                 CEII Do Not Release - network zones
         sGenBus(sGen,sBus)      CEII Do Not Release - generator bus mapping
         sGenZone(sGen,sZone)    CEII Do Not Release - generator to zone mapping

         sBusZone(sBus,sZone)    CEII Do Not Release - bus to zone mapping
         sActiveBus(sBus)        CEII Do Not Release - dynamic set to select certain buses

         sTrans(*)             CEII Do Not Release - all network transmission elements
         sBranch(sTrans)         CEII Do Not Release - network branches
         sXFMR(sTrans)           CEII Do Not Release - network transformers
         sActiveTrans(sTrans)    CEII Do Not Release - dynamic set to select elements to be
in network
         sMonitorTrans(sTrans)   CEII Do Not Release - dynamic set to select elements to
monitor
         sFBus(sTrans,sBus)      CEII Do Not Release - From Bus mapping for transmission
elements
         sTBus(sTrans,sBus)      CEII Do Not Release - To Bus mapping for transmission
elements

         sDRBid(*)                          Set of DR resources
         sDRBidBus(sDRBid,sBus)                   Map DR to bus

         sDecBid(*)                         Dec bids
         sDecBidBus(sDecBid,sBus)                 Dec bid Bus mapping
         sDecBus(sDecBid,sBus)
         sIncBid(*)                         Inc bids
         sIncBidBus(sIncBid,sBus)                 Inc bid Bus mapping
         sIncBus(sIncBid,sBus)
```

sPriceDem(*)   Price responsive demands
sPriceDemBus(sPriceDem,sBus)   Price responsive demand bus
sDemandbid(*)
sDemandbidBus(sDemandbid,sBus)

sForecastDem(*)   Forecast Demands
sForecastDemBus(sForecastDem,sBus)   Forecast Demand Bus

sLoopFlow   Loop flows
sLoopFlowBus(sLoopFlow,sBus)   Loop flow bus mapping

sTie   Ties
sTieBus(sTie,sBus)   Tie Bus Mapping

sInterfaces   interfaces or flowgates;

parameters
pBranchR(sTrans)   CEII Do Not Release - per unit resistance of tx element
pBranchX(sTrans)   CEII Do Not Release - per unit reactance of tx element
pThermalRateA(sTrans)   CEII Do Not Release - normal thermal rating of tx element
pThermalRateB(sTrans)   CEII Do Not Release - emergency rating of tx element
pTranskV(sTrans)   CEII Do Not Release - Tx element kV
pBranchkV(sTrans)   CEII Do Not Release - Branch kV
pXFMRkV(sTrans)   CEII Do Not Release - XFMR kV
pBuskV(sBus)   CEII Do Not Release - Bus Base kV
ptdfmat(sBus,sTrans)   CEII Do Not Release matrix of shift factors branch & xfmr

pColdStart(sGen)   cold startup cost
pHotStart(sGen)   hot startup cost
pGenFuelCost(sGen)   generator fuel cost based on EIA data
pMWbid(sGen,sStep)   generator offer curve output level
pPricebid(sGen,sStep)   generator offer curve price level
pWinterCapability(sGen)   generator Winter Rating in MW
pSummerCapability(sGen)   generator Summer Rating in MW
pEcoMin(sGen)   generator Economic Minimum
pEcoMax(sGen)   generator Economic Maximum
pGenMax(sGen)   generator maximum
pGenMin(sGen)   generator minimum
pGenNameplateCap(sGen)   Nameplate capacity

```
        pNoLoadCost(sGen)              no-load cost
        pMinRunTime(sGen)              minimum run time
        pMinDnTime(sGen)               minimum down time
        pRampUp(sGen)                  ramp rate up
        pRampDn(sGen)                  ramp rate down
        pWindInjection(sWind,sHour)    Wind injection

        pTieScheduleMW(sTie,sHour)     Tie Schedules Hourly
        pSysReserves(sHour)            System Wide reserves requirement
        pWinterReserves(sHour)         Winter problem Scheduling Reserves
        pSummerReserves(sHour)         Summer Problem Reserves
        pReserves(sHour)               Reserves
        pLoopFlow(sLoopFlow)           Loop flow injection or withdrawal

        pInterfaceLimit                interface base thermal limit

        pPriceDemMW(sPriceDem,sHour)    demand bid
        pPriceDemPrice(sPriceDem,sHour) demand bid price
        pFixedDemand(sBus,sHour)        fixed demand
        pDRQty(sDRBid)                  demand response bid in mw
        pDRPrice(sDRBid)                demand response bid price
        pForecastDemand(sBus,sHour)     forecast demand
        pIncBidMW(sIncBid,sHour)        Inc bid qty
        pIncBidPrice(sIncBid,sHour)     Inc bid price
        pDecBidMW(sDecBid,sHour)        Dec bid qty
        pDecBidPrice(sDecBid,sHour)     Dec bid price

        pInterfaceSF(sBus,sInterfaces)  matrix of shift factors for interfaces
        monitorind                      indicator to reduce monitored lines

        pGenStatus(sGen)                initial commit status prior to hour 1;

alias(h,sHour);
alias(sa,sStep);
alias(sb,sStep);

$gdxin  "%cgdxpath%\%ceiifile%"
$load sTrans sWind sDRBid sDecBid sIncBid sPriceDem sLoopFlow sTie
$load sHour
$load sGen
$load sZone
$load sBus sBusZone
$load sFBus sTBus sWindBus sDRBidBus sDecBidBus sIncBidBus
```

```
$load sPriceDemBus sTieBus sLoopFlowBus pForecastDemand pBuskV
$load ptdfmat
$load sInterfaces pInterfaceLimit
$load pInterfaceSF
$load sStep sPrimeMover
$load sBranch sXFMR
$load pBranchR pBranchX
$load pThermalRateA pThermalRateB
$load pTranskV
$load pColdStart pHotStart
$load pWindInjection
$load pTieScheduleMW
$load pIncBidMW pIncBidPrice
$load pLoopFlow pPriceDemMW pDRQty
$load pDRPrice
$load pPriceDemPrice
$load pDecBidMW pDecBidPrice
$load pReserves
$load pFixedDemand
$load sSource sGenSource
$load sGenBus sGenPrimeMover
$load pMWbid
$Load pPricebid pGenMax pNoLoadCost pMinRunTime pMinDnTime pGenStatus
pRampUp pRampDn
$load pEcoMin monitorind

*for units with longer than 24 hour run time, truncate to 24 hours which is the
*horizon of this problem
pMinRunTime(sGen)$(pMinRunTime(sGen) gt 24)=24;
pMinDnTime(sGen)$(pMinDnTime(sGen) gt 24)=24;

*select which branches to monitor
sActiveBus(sBus)=yes;
sActiveTrans(sTrans)=yes;
sMonitorTrans(sActiveTrans)=yes;
sMonitorTrans(sActiveTrans)$(pTranskV(sActiveTrans) lt kVcutoff or
pThermalRateA(sActiveTrans) ge 9999 or
pThermalRateA(sActiveTrans) eq 0)=no;

*apply the shift factor cutoff, used in the constrained model if shift
*factors have been calculated
ptdfmat(sBus,sTrans)$(abs(ptdfmat(sBus,sTrans)) lt SFcutoff) = 0;
ptdfmat(sBus,sTrans)$(not(sMonitorTrans(sTrans)))=0;
```

```
positive variables
        vQGen                    Qty of cleared supply mkt based gen
        vQGenRes                 Qty reserves from generator
        vQGenTot                 Total qty real power from generator
        vgen_rampplus            Ramp Up
        vgen_rampminus           Ramp Down

        vQDem                    Qty of cleared demand bid MW
        vQDR                     Qty of cleared demand response MW
        vQInc                    Qty of cleared Inc bid MW
        vQDec                    Qty of cleared Dec bid MW

        vNetInj                  Net injection at bus
        vNetWith                 Net withdrawal at bus

        vflowviolp               transmission element flow relaxation +
        vflowvioln               transmission element flow relaxation -
        vIntViolP                Interface relaxation +
        vIntViolN                Interface relaxation -
        vgendummy                system wide shortage
        vloaddummy               system wide surplus
;

free variables
        vMarketSurplus           Objective variable for market problem
        vPhaseAngle              Phase angle at bus
        vFlow                    Flow on Transmission element
;

binary variables
        vUCGen                   binary unit commitment for generator
        vSDGen                   shutdown for generaator
        vSUGen                   startup  for generator
;

equations
*********DA market objective Function************************
        eObjectiveFunctionMS     objective function market surplus

*********Global power balance hourly*************************
        eSysPowerBalance         system wide power balance
```

```
*********Dispatch Constraints for generators*****************
       eGenMaxStepUCMkt       Dispatch for offer curve step
       eGenDef                generator output is the sum of output by step
       erampplusmax           constrain ramp rate up
       erampminusmax          constrain ramp rate down
       eGenMaxUC              generator upper limit
       eGenMinUC              generator min run level

********Commitment Constraints for generators*****************
       eSUSD
       eSUSD2
       eMinUpTime
       eMinDnTime


********DR, price responsive demand and virtual bids**********
       eDRmax                 DR maximum reduction
       eIncmax                Inc bid maximum
       eDecmax                Dec bid maximum
       eDemmax                demand bid maximum


********Transmission Constraints****************************
       eNetInj                net injection at bus
       eThermalConstraint1    upper limit on transmission element
       eThermalConstraint2    lower limit on transmission element
       eInterfaceLim1         interface constraints
       eInterfaceLim2         interface constraints
       eFlowDef               definition of monitored element flow

*********Operating reserves constraints**********************
       eSysRes                system reserves
       eSpinning              spinning reserves 50% of reserves
;

*the model treats the wind output as non-dispatchable, fixed parameter
*in each hour, thus the variable for wind output is not used.
vQGenTot.fx(sGen,sHour)$(sGenPrimeMover(sGen,'WT'))=0;

*for summer problem
pSysReserves(sHour)=pReserves(sHour);

*Day Ahead Market Objective Function, max market surplus
```

```
eObjectiveFunctionMS..

vMarketSurplus =e=
sum((sPriceDem,sHour),vQDem(sPriceDem,sHour)*pPriceDemPrice(sPriceDem,sHour)
)
+sum((sDecBid,sHour),vQDec(sDecBid,sHour)*pDecBidPrice(sDecBid,sHour))
-sum((sGen,sHour,sStep),vQGen(sGen,sHour,sStep)*pPricebid(sGen,sStep))
-sum((sDRBid,sHour),vQDR(sDRBid,sHour)*pDRPrice(sDRBid))
-sum((sIncBid,sHour),vQInc(sIncBid,sHour)*pIncBidPrice(sIncBid,sHour))
-sum((sActiveTrans,sHour),ThermalLimViol*vflowviolp(sActiveTrans,sHour)
+ThermalLimViol*vflowvioln(sActiveTrans,sHour))
-sum((sActiveBus,sHour),GlobalViol*vgendummy(sHour)
+GlobalViol*vloaddummy(sHour))
-sum((sInterfaces,sHour),InterfaceLimViol*(vIntViolP(sInterfaces,sHour)
+vIntViolN(sInterfaces,sHour)))
-sum((sGen,sHour),pColdStart(sGen)*vSUGen(sGen,sHour))
-sum((sGen,sHour),pNoLoadCost(sGen)*vUCGen(sGen,sHour));

*System Wide Power Balance Constraint
eSysPowerBalance(sHour)..
sum(sActiveBus,vNetInj(sActiveBus,sHour))
=e=sum(sActiveBus,vNetWith(sActiveBus,sHour));

*Net Injection or Withdrawal at Bus
eNetInj(sActiveBus,sHour)..
vNetInj(sActiveBus,sHour)-vNetWith(sActiveBus,sHour)=e=
sum(sGen$(sGenBus(sGen,sActiveBus)),vQGenTot(sGen,sHour))
+sum(sDRBid$(sDRBidBus(sDRBid,sActiveBus)),vQDR(sDRBid,sHour))
+sum(sIncBid$(sIncBidBus(sIncBid,sActiveBus)),vQInc(sIncBid,sHour))
-sum(sDecBid$(sDecBidBus(sDecBid,sActiveBus)),vQDec(sDecBid,sHour))
-sum(sPriceDem$(sPriceDemBus(sPriceDem,sActiveBus)),vQDem(sPriceDem,sHour))
-pFixedDemand(sActiveBus,sHour)
+sum(sWind$(sWindBus(sWind,sActiveBus)),pWindInjection(sWind,sHour))
+sum(sLoopFlow$(sLoopFlowBus(sLoopFlow,sActiveBus)),pLoopFlow(sLoopFlow))
+sum(sTie$(sTieBus(sTie,sActiveBus)),pTieScheduleMW(sTie,sHour));

*Transmission Flow Definition
eFlowDef(sMonitorTrans,sHour)$(monitorind(sMonitorTrans) eq 1)..
vFlow(sMonitorTrans,sHour) =e=
sum(sActiveBus,
vNetInj(sActiveBus,sHour)*ptdfmat(sActiveBus,sMonitorTrans)
-vNetWith(sActiveBus,sHour)*ptdfmat(sActiveBus,sMonitorTrans));
```

```
* Transmission Thermal Constraint 1
*monitorind is a flag that determines which brahcnes get monitored
*it is used to indicate which branches were monitored in the base case solution
*found in the test problem report on eLibrary
eThermalConstraint1(sMonitorTrans,sHour)$(monitorind(sMonitorTrans) eq 1)..
vFlow(sMonitorTrans,sHour)
=l=pThermalRateA(sMonitorTrans)+vflowviolp(sMonitorTrans,sHour);

* Transmission Thermal Constraint 2
*monitorind is a flag that determines which brahcnes get monitored
*it is used to indicate which branches were monitored in the base case solution
*found in the test problem report on eLibrary
eThermalConstraint2(sMonitorTrans,sHour)$(monitorind(sMonitorTrans) eq 1)..
vFlow(sMonitorTrans,sHour)
=g=-pThermalRateA(sMonitorTrans)-vflowvioln(sMonitorTrans,sHour);

*Interface limits
eInterfaceLim1(sInterfaces,sHour)$(pInterfaceLimit(sInterfaces,sHour) ne 0)..
sum(sActiveBus,
vNetInj(sActiveBus,sHour)*pInterfaceSF(sActiveBus,sInterfaces)
-vNetWith(sActiveBus,sHour)*pInterfaceSF(sActiveBus,sInterfaces))
=l=pInterfaceLimit(sInterfaces,sHour)+vIntViolP(sInterfaces,sHour);

*Interface limits - constraint used in the constrained model including shift factors
eInterfaceLim2(sInterfaces,sHour)$(pInterfaceLimit(sInterfaces,sHour) ne 0)..
sum(sActiveBus,
vNetInj(sActiveBus,sHour)*pInterfaceSF(sActiveBus,sInterfaces)
-vNetWith(sActiveBus,sHour)*pInterfaceSF(sActiveBus,sInterfaces))
=g=-pInterfaceLimit(sInterfaces,sHour)-vIntViolN(sInterfaces,sHour);

*Generator dispatch constraints
*Limit for each step on the dispatch curve (requires monotonically increasing)
eGenMaxStepUCMkt(sGen,sHour,sStep)..
vQGen(sGen,sHour,sStep)=l=
pMWbid(sGen,sStep);

*generator output is the sum of output on each step of the curve
eGenDef(sGen,sHour)..
vQGenTot(sGen,sHour)=e=sum(sStep,vQGen(sGen,sHour,sStep));

*max run level
eGenMaxUC(sGen,sHour)..
```

```
vQGenTot(sGen,sHour)+vQGenRes(sGen,sHour)=l=pGenMax(sGen)*vUCGen(sGen,sH
our);

*min run level
eGenMinUC(sGen,sHour)..
vQGenTot(sGen,sHour)=g=pEcoMin(sGen)*vUCGen(sGen,sHour);

*demand response maximum
eDRmax(sDRBid,sHour)..
vQDR(sDRBid,sHour)=l=abs(pDRQty(sDRBid));

*inc bid maximum
eIncmax(sIncBid,sHour)..
vQInc(sIncBid,sHour)=l=abs(pIncBidMW(sIncBid,sHour));

*dec bid maximum
eDecmax(sDecBid,sHour)..
vQDec(sDecBid,sHour)=l=abs(pDecBidMW(sDecBid,sHour));

*price responsive demand bid maximum
eDemmax(sPriceDem,sHour)..
vQDem(sPriceDem,sHour)=l=abs(pPriceDemMW(sPriceDem,sHour));

*Ramp Rate Dn
erampminusmax(sGen,sHour)$(ord(sHour) ge 2)..
vQGenTot(sGen,sHour-1) - vQGenTot(sGen,sHour)
-pRampDn(sGen)*60*vUCGen(sGen,sHour-1)
-pGenMax(sGen)*vSDGen(sGen,sHour) =l= 0;

*Ramp Rate Up
erampplusmax(sGen,sHour)$(ord(sHour) ge 2)..
vQGenTot(sGen,sHour)-vQGenTot(sGen,sHour-1)
- pRampUp(sGen)*60*vUCGen(sGen,sHour-1)
-pGenMax(sGen)*vSUGen(sGen,sHour) =l= 0;

eSUSD(sGen,sHour)..
 vSUGen(sGen,sHour) -  vSDGen(sGen,sHour) =e= vUCGen(sGen,sHour)
 - vUCGen(sGen,sHour-1)$(ord(sHour) gt 1) - pGenStatus(sGen)$(ord(sHour) eq 1);

eSUSD2(sGen,sHour)..
        vSUGen(sGen,sHour)+vSDGen(sGen,sHour) =l= 1;

*Min uptime
```

```
eMinUpTime(sGen,sHour)$(ord(sHour) ge pMinRunTime(sGen))..
  sum(h$(ord(sHour)-pMinRunTime(sGen)+1 le ord(h) and (ord(h) le ord(sHour))),
vSUGen(sGen,h))
  =l= vUCGen(sGen,sHour);

*min downtime
eMinDnTime(sGen,sHour)$(ord(sHour) ge pMinDnTime(sGen))..
  sum(h$(ord(sHour)-pMinDnTime(sGen)+1 le ord(h) and (ord(h) le ord(sHour))),
vSDGen(sGen,h))
  =l= 1 - vUCGen(sGen,sHour);

*operating reserves
*Reserve Constraint, system wide
eSysRes(sHour)..
sum((sGen),vQGenRes(sGen,sHour))
+sum((sGen)$(sGenPrimeMover(sGen,'CT') or sGenPrimeMover(sGen,'GT')),
abs(pGenMax(sGen))*(1-vUCGen(sGen,sHour)))
=g= pSysReserves(sHour);

*at least 50% of reseves must be spinning
eSpinning(sHour)..
sum((sGen),vQGenRes(sGen,sHour))
=g= pSysReserves(sHour)*0.5;


model DAUC
/eObjectiveFunctionMS
eSysPowerBalance
eThermalConstraint1
eThermalConstraint2
eFlowDef
eNetInj
eInterfaceLim1
eInterfaceLim2
eGenMaxStepUCMkt
eGenDef
eGenMaxUC
eGenMinUC
eDRmax
eIncmax
eDecmax
eDemmax
erampminusmax
```

```
erampplusmax
eSUSD
eSUSD2
eMinUpTime
eMinDnTime
eSysRes
eSpinning
/;

DAUC.optfile=1;
DAUC.optcr=5e-2;
DAUC.reslim=9.2e5;

option limrow=1;
option limcol=1;

execute_unload "%cgdxpath%\%ceiifile%";

solve DAUC using mip maximizing vMarketSurplus;

execute_unload "%cgdxpath%\%outfile%";
```