Appendix A

This appendix summarizes the data that was provided to GE for use in this project.

A.1 Historical Data from NYISO

NYISO provided data derived from their archives of operational records. Data included the following:

- Hourly total NYISO system load MW for years 2001, 2002, and 2003
- Hourly load MW by zone for years 2001 and 2002
- Hourly load MW by zone for summer months, 1999-2003
- Day-ahead forecast and actual hourly load MW by zone for 11 months, as follows:
  - January, April, August, and October of year 2001
  - January, April, August, October of year 2002
  - January, April, August of year 2003
- Six-second load MW by zone, tie-flow, and ACE data for five months, as follows:
  - January 2003, April 2003, August 2003, October 2003, and January 2004

A.2 Wind Data for AWS TrueWind

AWS TrueWind provided wind data for this project. The data were for the same periods as the NYISO historical data described above. The wind generation scenario for this project included a total of 3300 MW of wind power divided among 33 individual sites across New York State. The data provided by AWS TrueWind represented the amount of wind power that would have been produced at each of those 33 sites if the wind plants had been in operation, given the historical weather records for those years. Specific items of data are explained below.

A.2.1 Hourly Actual Wind MW by Site

Hourly wind megawatt production by site was provided for years 2001, 2002, 2003, and for the summer months of years 1999 and 2000. The data represented the “actual” power that would have been generated at each site, given weather conditions that existed at each site for each hour of each day.

The data were produced using AWS TrueWind’s MesoMap system. MesoMap consists of an integrated set of atmospheric models, computer systems, and meteorological and geophysical databases. The two main models are a mesoscale numerical weather prediction model (MASS) and a mass-conserving microscale wind flow model (WindMap). The main source of meteorological data is the reanalysis database produced by the National Centers for Environmental Prediction (NCEP); reanalysis data provide a snapshot of global weather conditions (including temperature, pressure, wind, atmospheric moisture, and other parameters) every six hours at multiple levels above the surface over the past 50 years.

In the first stage of the analysis, the reanalysis data for the historical years of interest were used to drive the MASS model in simulations over the state of New York at a grid resolution of 8 km. For every hour of simulated time, multi-level wind and temperature data were stored in data files. Once the simulations were complete, the hourly wind and temperature data were extracted as time series for each of the prospective wind project sites. The wind speeds were then scaled to match the predicted mean annual wind speed at 65 m height for each site from a high-resolution wind speed map of New York State produced by AWS TrueWind in a previous project. Next, the scaled hourly wind speeds were applied to a power curve for a generic 1.5 MW wind turbine; the power curve was adjusted to the site air density for each hour derived from the elevation and simulated temperature. Lastly, a moving-average filter was applied to simulate the smoothing effect of the turbines within each project, which slightly reduces the variability of the plant output.

A.2.2 Hourly Forecast Wind MW by Site

Both day-ahead and hour-ahead wind forecast data was provided for years 2001, 2002, and 2003. The wind forecast methodology and timing are consistent with NYISO's existing operating practices for day-ahead and hour-ahead markets.

Weather forecast data are normally made available at 0:00 and 12:00 hours GMT (7:00 pm and 7:00 am EST). AWS TrueWind used this type of historical weather data to produce day-ahead wind generation forecasts for the 33 sites. Consider, for example, a day-ahead wind generation forecast for January 10. Using weather forecast data collected at 7:00 pm on January 8, an hourly wind generation forecast for January 10 would be produced and submitted to NYISO by 5:00 am on January 9. AWS TrueWind applied this process to all 33 wind generation sites for each day of years 2001, 2002, 2003.

AWS TrueWind followed a similar process for the hour-ahead forecasts. Hour-ahead forecasts must be submitted to the NYISO at 75 minutes prior to the beginning of the forecasted hour. Therefore, the wind generation forecast would be developed from weather forecast data available 80 minutes before the beginning of the forecasted hour. For example, the hour-ahead wind generation forecast for the 6:00-7:00 pm hour would be derived from 4:40 pm weather data, and sent to the NYISO at 4:45 pm. AWS TrueWind applied this process to all 33 wind generation sites for each hour of each day of years 2001, 2002, 2003.

Normally wind forecasts would be produced by a mesoscale weather model as well as statistical models. Since a mesoscale model was already used to simulate the actual plant production, however, an alternative method was required. AWS TrueWind adopted a Markov chain approach. In a Markov chain, the next value in a time series is a function of the current value and some random change drawn from a probability distribution. The values in the time series in this case represent forecast errors, i.e., the difference between the forecasted plant output and actual plant output. To produce realistic forecast error behavior, the probability distribution should depend on the previous forecast error and current forecasted plant output, so that, for example, when the forecasted plant output is high, the error distribution will be skewed towards zero and negative values (since the forecasted output could never be higher than the maximum rated capacity of the plant).

To create realistic probability distributions and error patterns for New York State, AWS TrueWind ran a year of historical wind forecasts for the Madison wind project using its eWind system. Exactly the same method was applied in generating these forecasts as would actually be used for wind projects. Following the usual eWind process, for each historical day, weather data were used to initialize the MASS model, which then stepped forward in time to produce forecasts of weather for the next several days. As the process was repeated through the year, the previous errors were tracked, and a statistical model was used to tune the subsequent forecasts to minimize errors. At the end of the year, the error distributions were calculated and applied to the simulated hourly generation data the 33 sites to produce the synthesized forecasts.

A.2.3 One-Minute Wind MW by Site

AWS TrueWind provided one-minute wind MW by site for 108 three-hour events as follows:

- Normal operation (45 events, three-hours each)
- High wind variability (45 events, three-hours each)
- Large wind shifts (18 events, three-hours each)

The "large wind shift" data is for 18 selected periods from 2001-2003 experiencing the largest increase or decrease in total wind plant output across the whole state. The times of day tend to fall in a narrow range for large decreases, and likewise for large increases. The data indicate that these are not "storm events," but are extreme cases of the normal diurnal pattern. It makes sense that the largest three-hour changes in output across the whole state would occur as part of the diurnal cycle, because diurnal changes in atmospheric stability tend to affect all plants more or less simultaneously. Storm fronts, in contrast, move across the state. Even if a front moved at 30 mph, it would take about six hours to affect the bulk of the Western New York sites, and that would still leave a lot of capacity in the rest of the state unaffected. Therefore it seems sensible that the largest three-hour shifts are diurnal cycles, not storms.

The one-minute plant output data were generated by AWS TrueWind in the following steps. First, one-minute-resolution plant data was obtained for a 105 MW wind project in northwestern Iowa from the National Renewable Energy Laboratory (NREL). Next, a computer program was written to extract 1-minute deviations from the hourly trends in these data. Third, three-hour blocks of one-minute deviations were selected on a random basis for each of the 33 sites. Fourth, the deviations for each site were scaled up or down to imitate the temporal smoothing by the turbines in each project. (Since individual turbines in a project experience different fluctuations, the combined output of numerous turbines has a lower overall variability, as a fraction of rated capacity, than a single turbine; sites with a smaller number of turbines than the Iowa project therefore should experience somewhat greater fluctuations than sites with a larger number of turbines.) Finally, the scaled fluctuations were applied to the hourly data generated previously to produce three-hour blocks of simulated one-minute wind plant data for each site.

For the high-variability cases, the one-minute fluctuations were scaled up to match the average variability plus two standard deviations. For the large wind-shift cases, the hourly data record was scanned to select the three-hour periods with the largest positive and negative changes in statewide wind plant output.

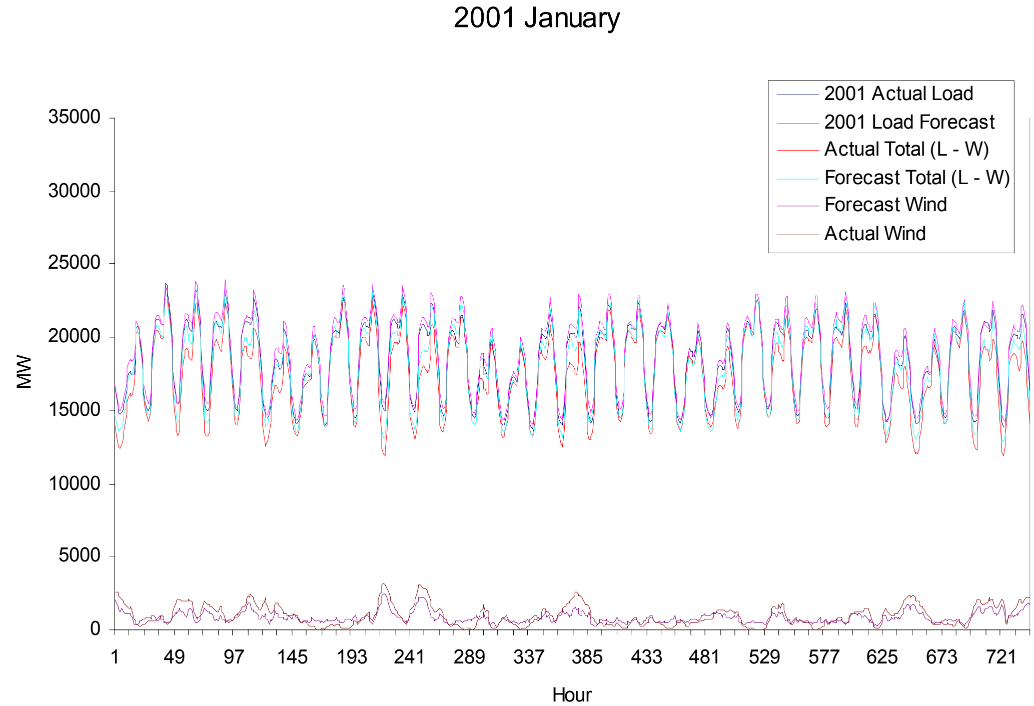
A.2.4 One-Second Wind MW by Site

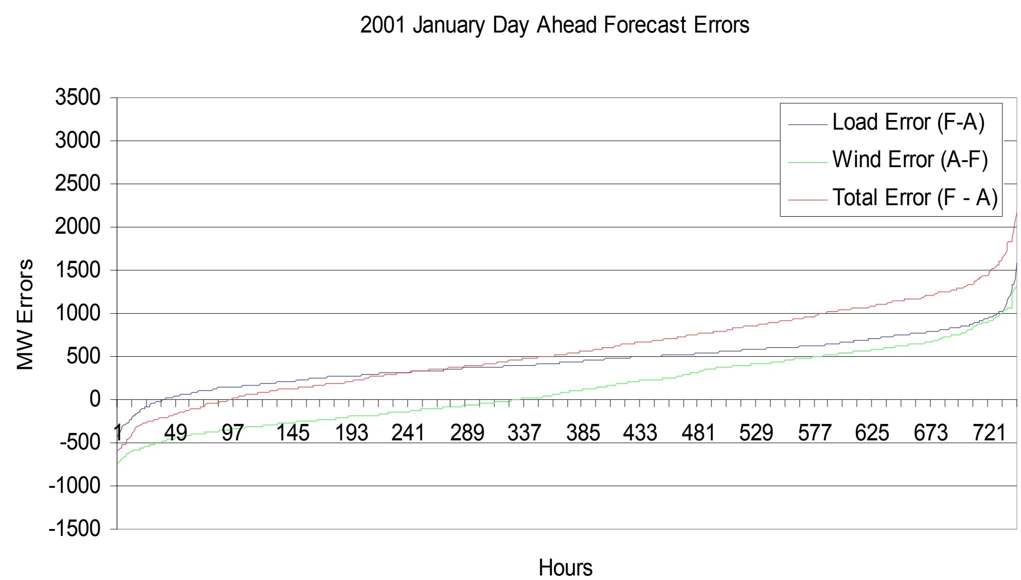
AWS TrueWind provided one-second wind MW by site for six events, each of 10-minute duration, representing high wind volatility as would be expected on a gusty day. The data accounts for spatial diversity in each wind farm. That is, the individual wind turbines in a given wind farm are spread over a wide geographic area, and hence wind gusts affect different turbines at different times and in different manners.

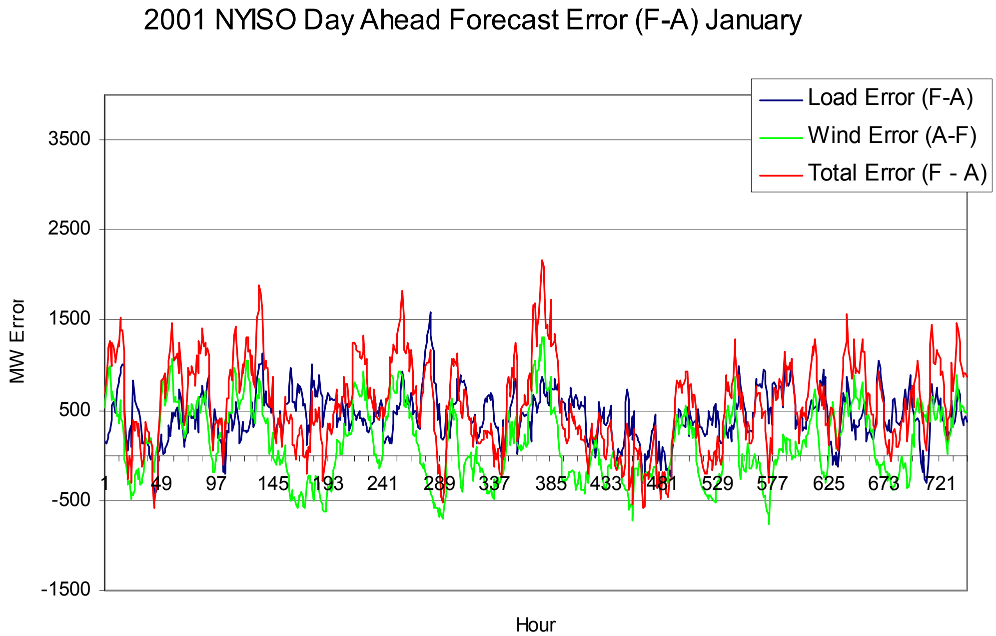
The data were produced in a manner very similar to that used to generate the one-minute data, except, of course, that the one-second fluctuations were derived from one-second data, which were obtained from NREL for the same northwestern Iowa wind project.

Appendix B

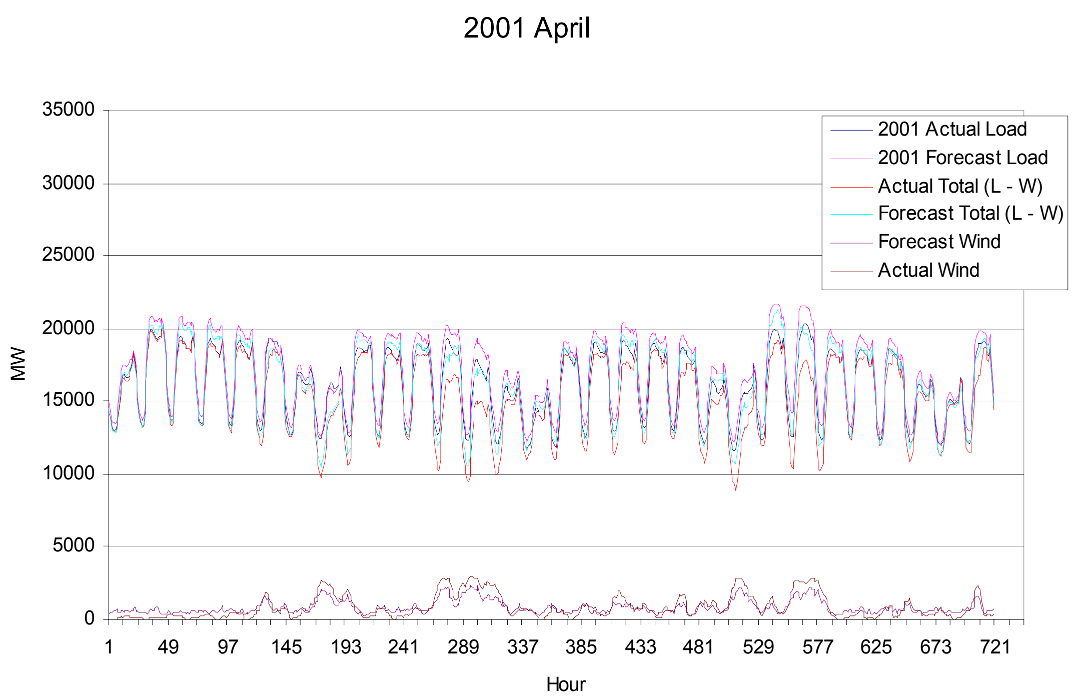
B.1 Day Ahead Forecast Analysis for 11 Months

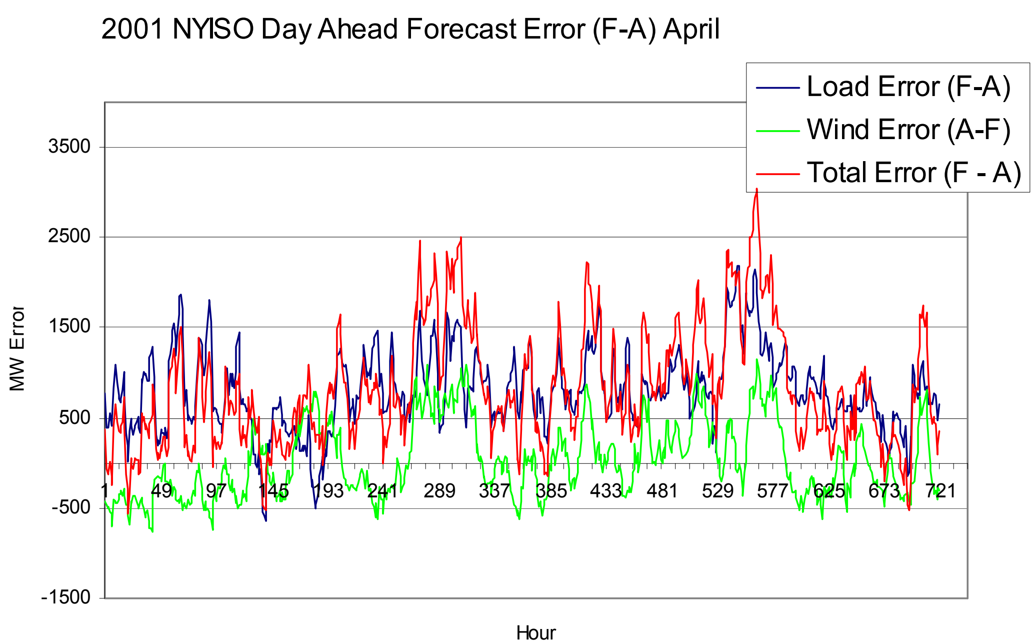


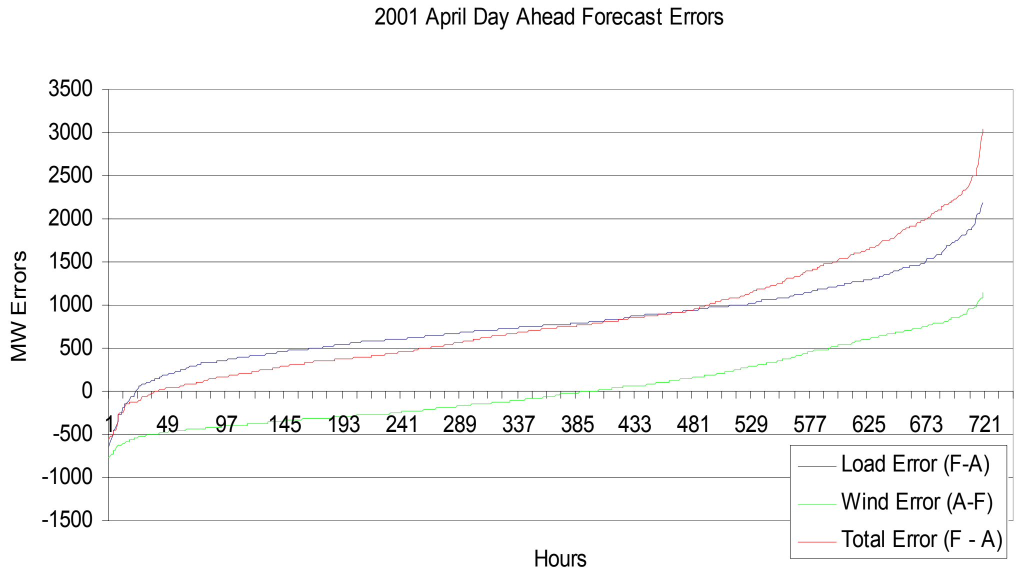




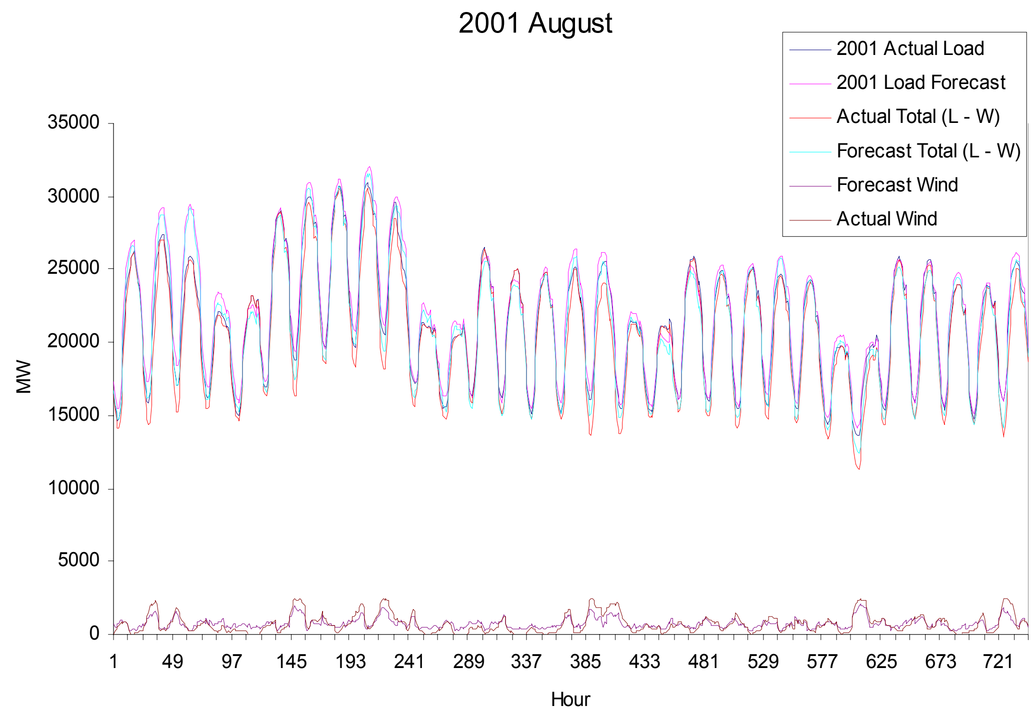
2001 Jan Day Ahead	Load	Wind	Load - Wind
Hours Negative	39	329	94
Hours Positive	705	415	650
Negative Energy Error (MWh)	-6,058	-85,645	-18,655
Positive Energy Error(MWh)	332,772	180,573	440,297
Net Energy Error (MWh)	326,714	94,928	421,642
Worst Negative Error (MW)	-433	-753	-581
Worst Positive Error (MW)	1,581	1,310	2,174
Peak (MW)	23,720	3,149	23,273
Energy (MWh)	13,719,259	723,591	12,995,668
Negative Energy Error(% of LE)	-0.04	-0.62	-0.14
Positive Energy Error(% of LE)	2.43	1.32	3.21
MAE (MW)	455	358	617
MAE (% of Rating Wind)	13.80	10.84	18.69


2001 April
35000
30000
25000
20000
15000
10000
5000
0
MW
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour
2001 Actual Load
2001 Forecast Load
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind


2001 NYISO Day Ahead Forecast Error (F-A) April
3500
2500
1500
500
-500
-1500
MW Error
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)



2001 Apr Day Ahead Error	Load	Wind	Load - Wind
Hours Negative	22	395	39
Hours Positive	698	325	681
Negative Energy Error (MWh)	-6,008	-114,048	-7,295
Positive Energy Error(MWh)	582,225	133,702	603,166
Net Energy Error (MWh)	576,217	19,654	595,871
Worst Negative Error (MW)	-653	-770	-568
Worst Positive Error (MW)	2,182	1,141	3,037
Peak (MW)	20,337	2,985	19,894
Energy (MWh)	11,634,608	621,205	11,013,403
Negative Energy Error(% of LE)	-0.05	-0.98	-0.06
Positive Energy Error(% of LE)	5.00	1.15	5.18
MAE (MW)	791	344	848
MAE (% of Rating Wind)	23.96	10.43	25.69


2001 August
2001 Actual Load
2001 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
35000
30000
25000
20000
15000
10000
5000
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MW
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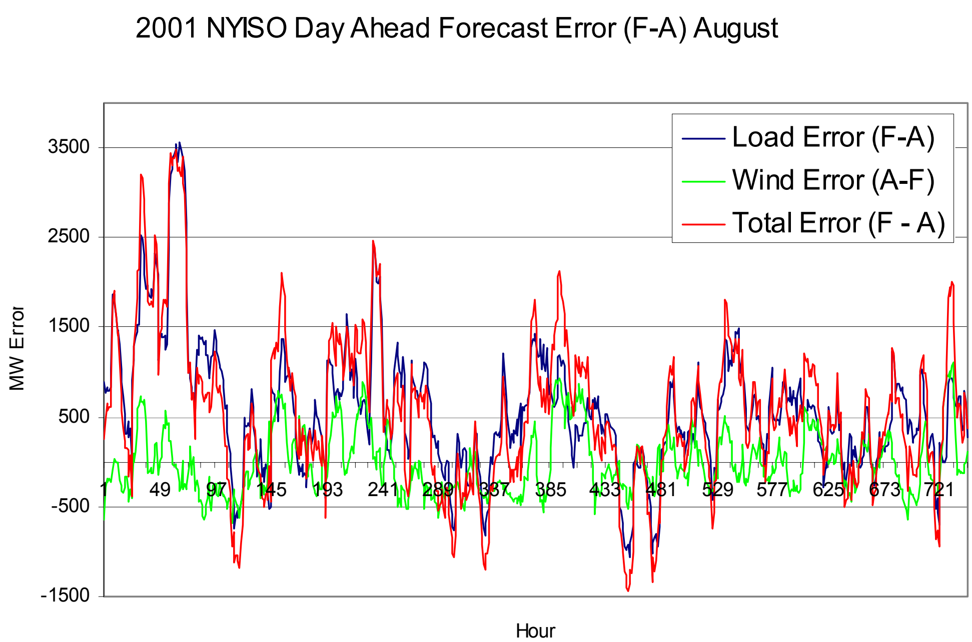
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2001 NYISO Day Ahead Forecast Error (F-A) August
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
3500
2500
1500
500
-500
-1500
MW Error
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241
289
337
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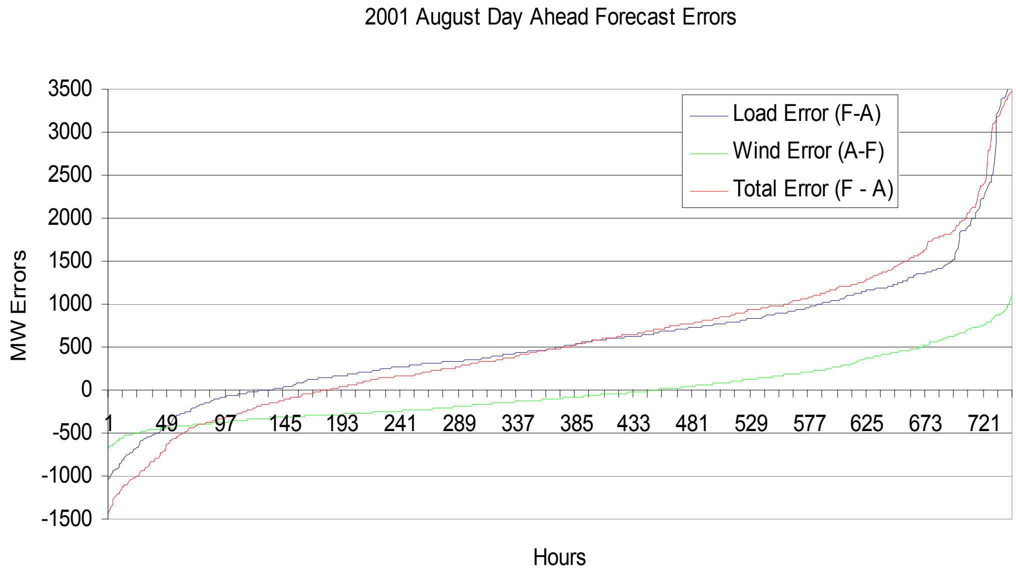
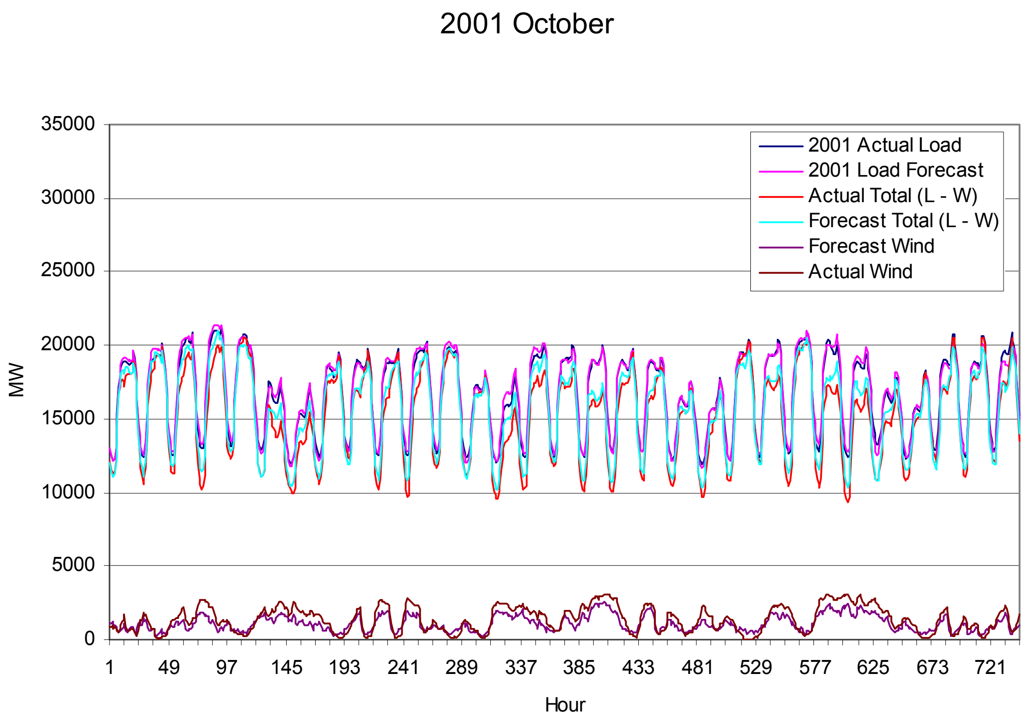
625
673
721
Hour



2001 Aug Day Ahead	Load	Wind	Load - Wind
Hours Negative	128	451	179
Hours Positive	616	293	565
Negative Energy Error (MWh)	-44,094	-113,346	-81,734
Positive Energy Error(MWh)	473,645	98,650	496,588
Net Energy Error (MWh)	429,551	-14,696	414,855
Worst Negative Error (MW)	-1,052	-688	-1,446
Worst Positive Error (MW)	3,569	1,106	3,485
Peak (MW)	30,982	2,503	30,596
Energy (MWh)	15,867,346	537,309	15,330,037
Negative Energy Error(% of LE)	-0.28	-0.71	-0.52
Positive Energy Error(% of LE)	2.99	0.62	3.13
MAE (MW)	696	285	777
MAE (% of Rating Wind)	21.09	8.63	23.55


2001 October
35000
30000
25000
20000
15000
10000
5000
0
MW
2001 Actual Load
2001 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
1
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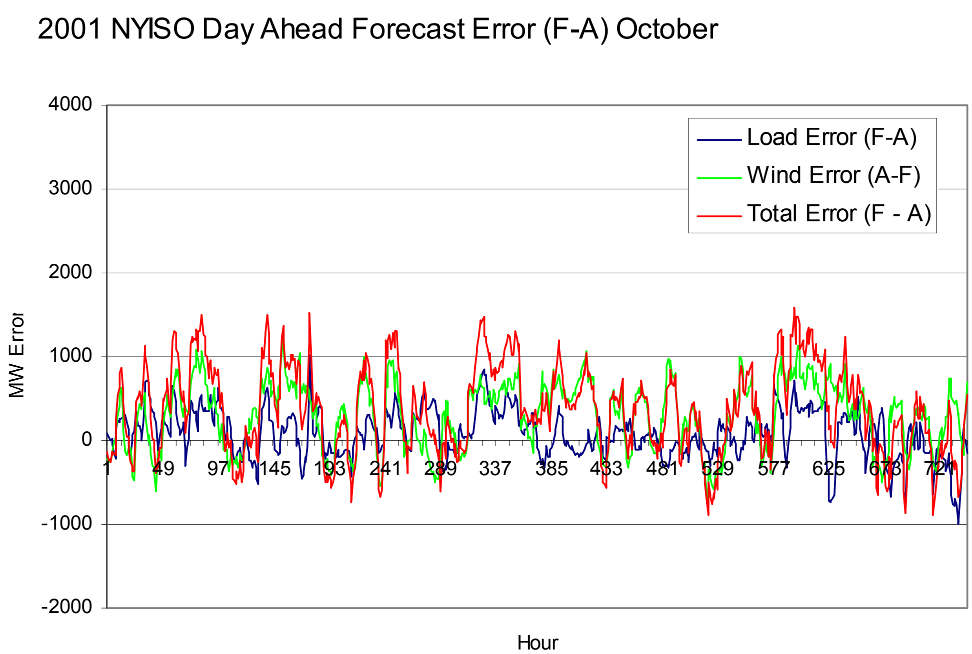
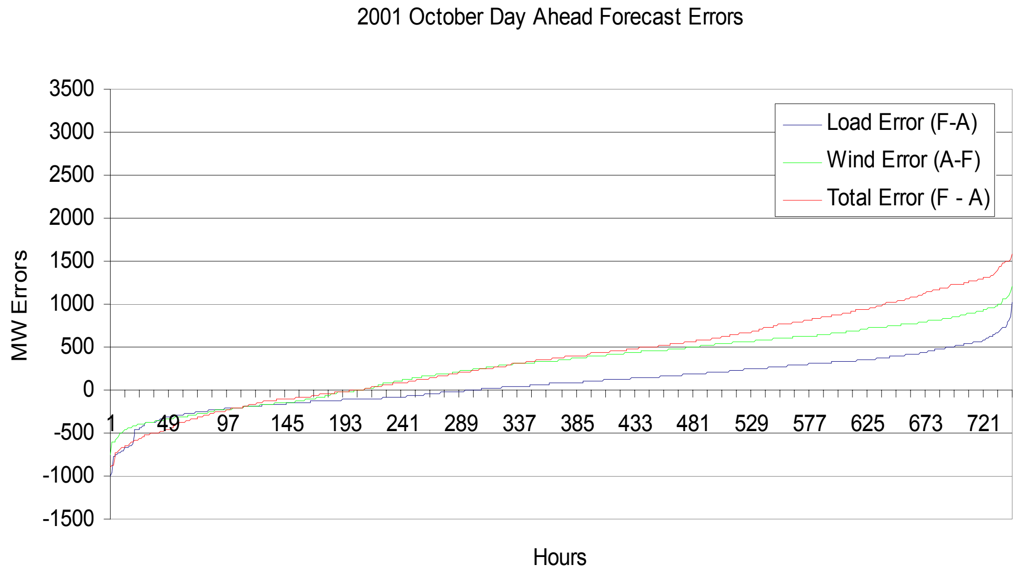
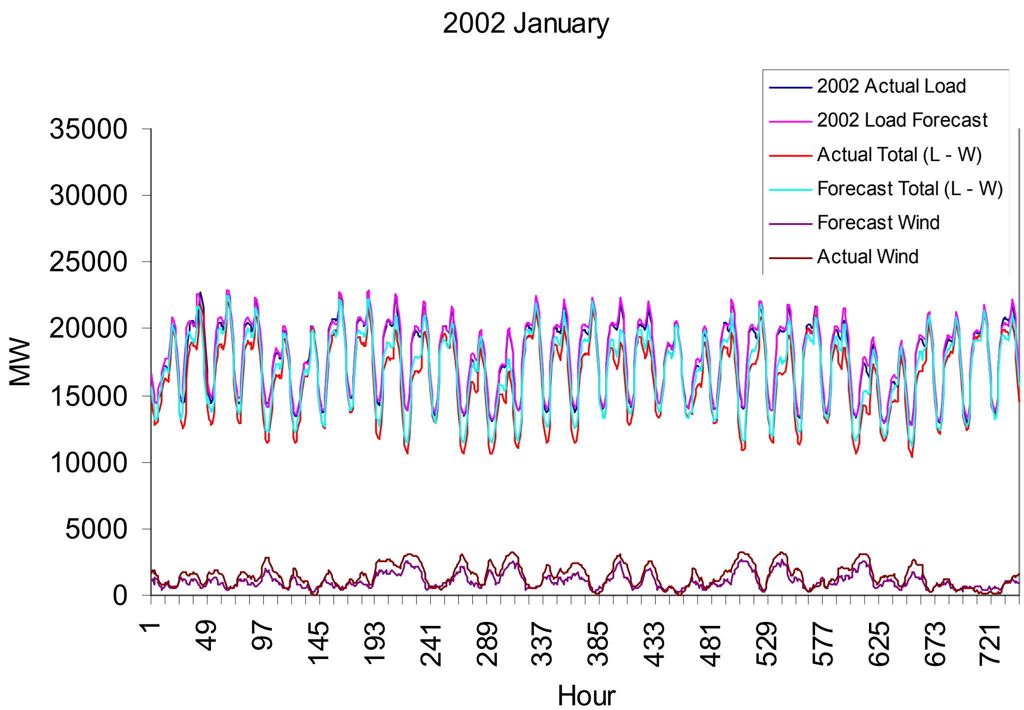
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2001 NYISO Day Ahead Forecast Error (F-A) October
4000
3000
2000
1000
0
-1000
-2000
MW Error
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



2001 Oct Day Ahead	Load	Wind	Load - Wind
Hours Negative	301	205	204
Hours Positive	443	539	540
Negative Energy Error (MWh)	-59,554	-47,258	-55,104
Positive Energy Error(MWh)	116,567	268,574	333,433
Net Energy Error (MWh)	57,013	221,316	278,329
Worst Negative Error (MW)	-997	-757	-894
Worst Positive Error (MW)	1,024	1,218	1,588
Peak (MW)	21,152	3,130	20,551
Energy (MWh)	12,397,862	1,035,844	11,362,019
Negative Energy Error(% of LE)	-0.48	-0.38	-0.44
Positive Energy Error(% of LE)	0.94	2.17	2.69
MAE (MW)	237	425	522
MAE (% of Rating Wind)	7.17	12.86	15.83


2002 January
2002 Actual Load
2002 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
35000
30000
25000
20000
15000
10000
5000
0
MW
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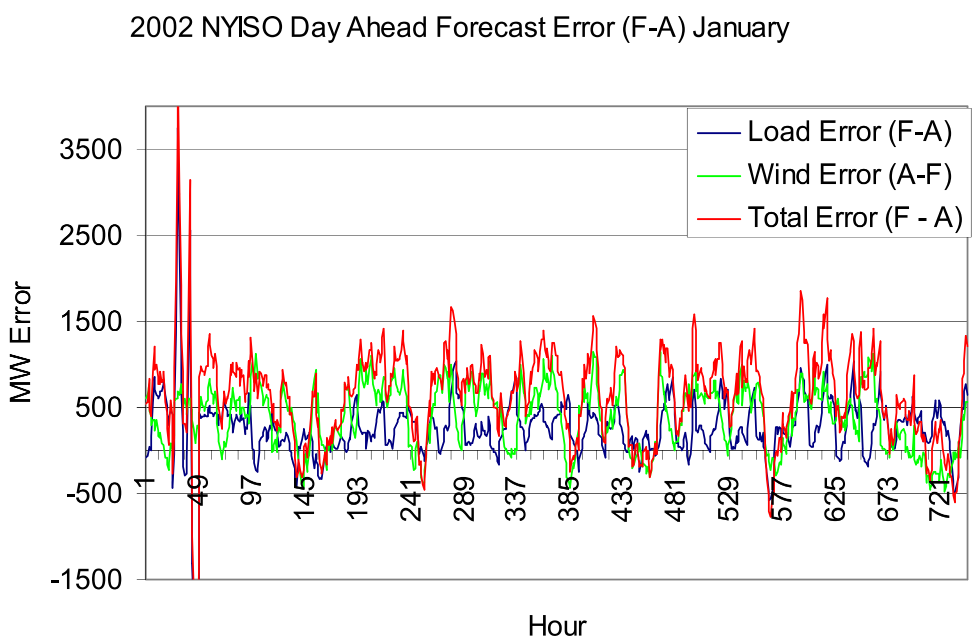
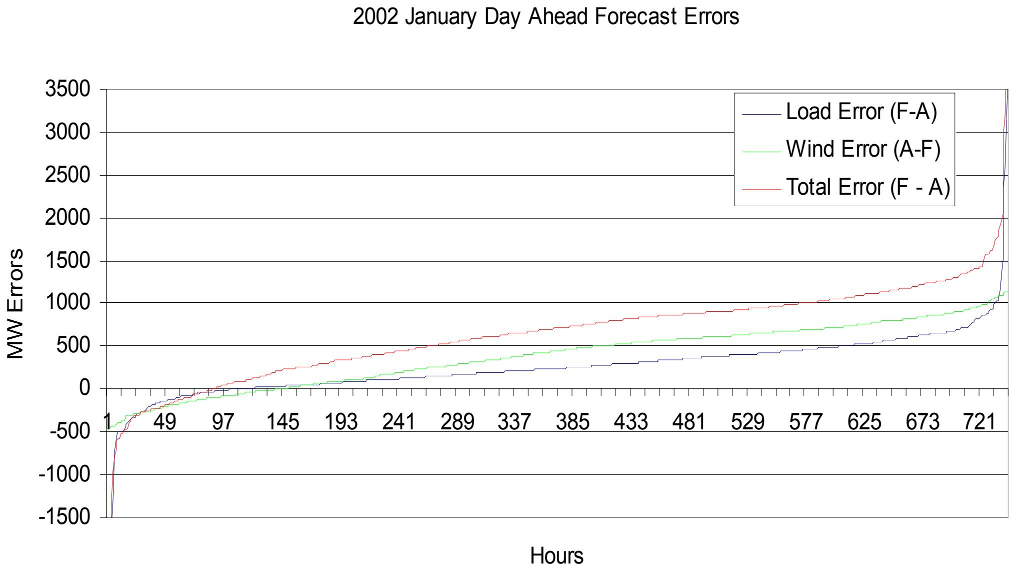
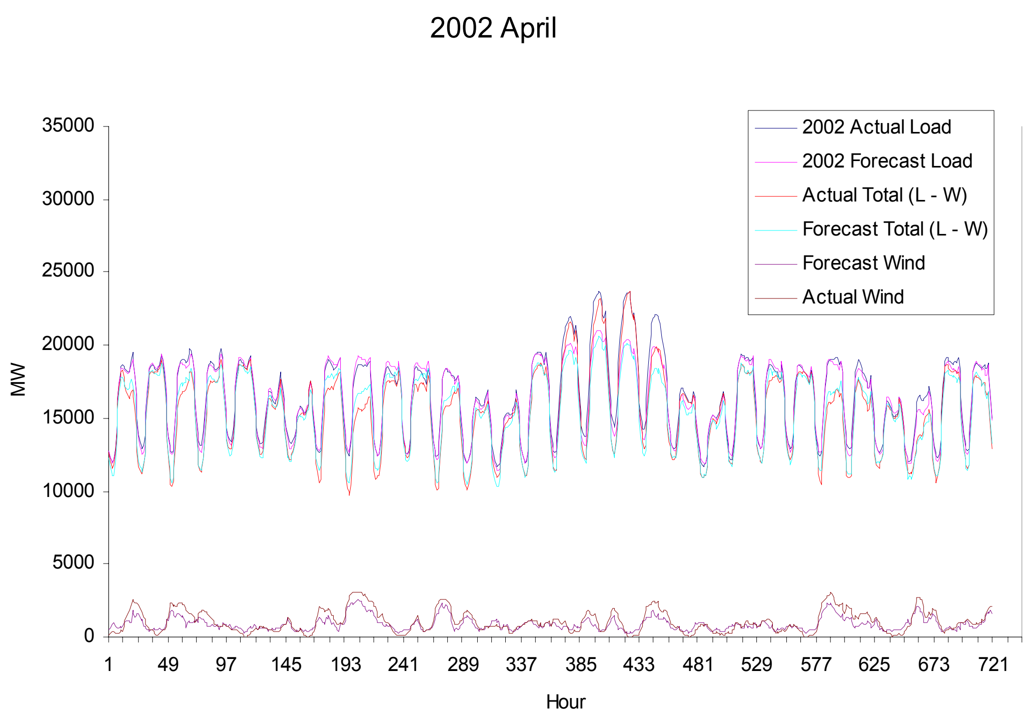
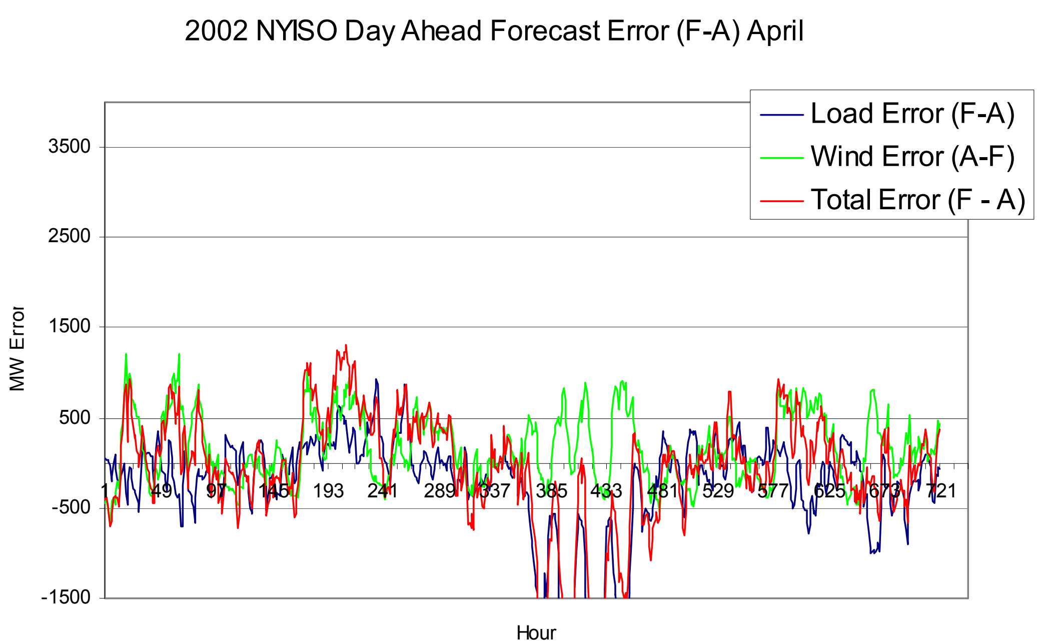
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour

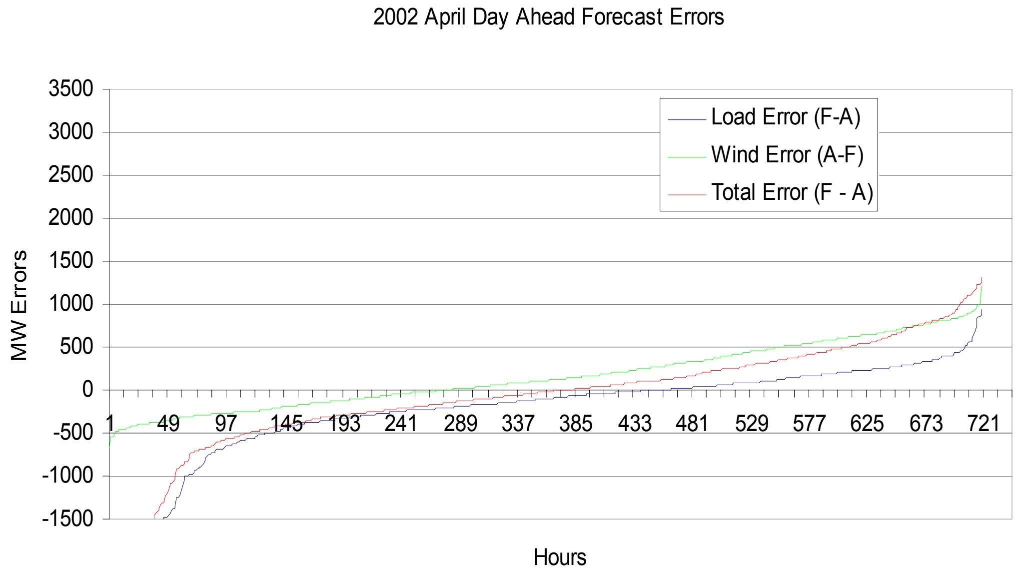

2002 NYISO Day Ahead Forecast Error (F-A) January
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
3500
2500
1500
500
-500
-1500
MW Error
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



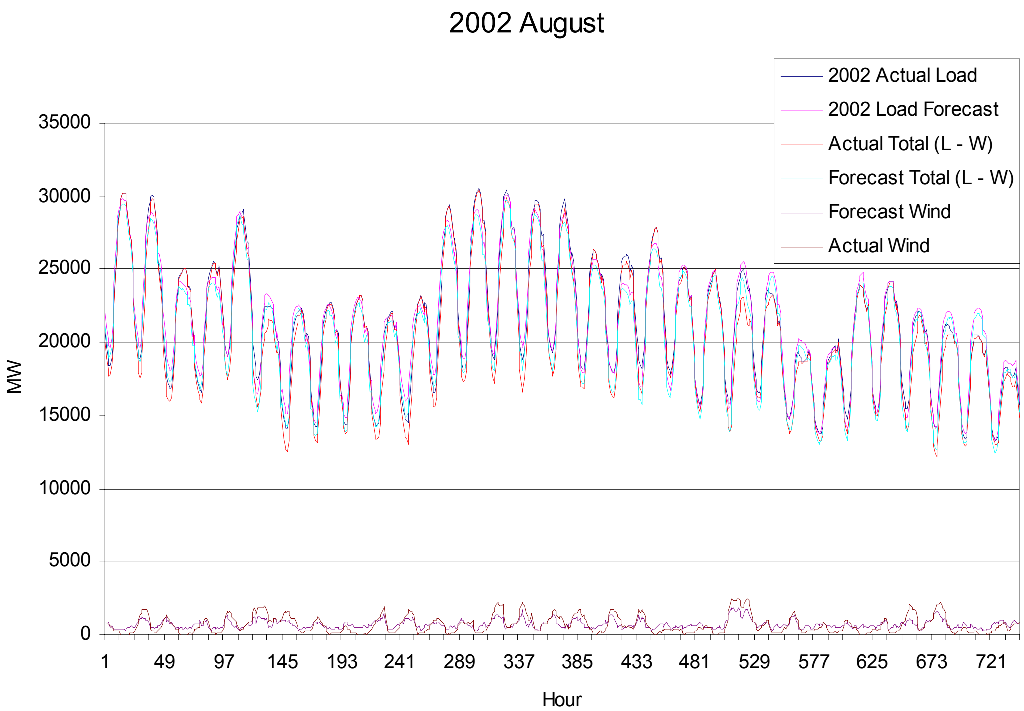
2002 Jan Day Ahead	Load	Wind	Load - Wind
Hours Negative	105	142	89
Hours Positive	639	602	655
Negative Energy Error (MWh)	-29,686	-23,259	-30,268
Positive Energy Error(MWh)	219,515	311,007	507,844
Net Energy Error (MWh)	189,829	287,747	477,576
Worst Negative Error (MW)	-3,217	-472	-3,115
Worst Positive Error (MW)	3,755	1,146	4,436
Peak (MW)	22,798	3,215	22,299
Energy (MWh)	13,247,192	1,089,858	12,157,334
Negative Energy Error(% of LE)	-0.22	-0.18	-0.23
Positive Energy Error(% of LE)	1.66	2.35	3.83
MAE (MW)	335	449	723
MAE (% of Rating Wind)	10.15	13.61	21.92


2002 April
35000
30000
25000
20000
15000
10000
5000
0
MW
2002 Actual Load
2002 Forecast Load
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour


2002 NYISO Day Ahead Forecast Error (F-A) April
3500
2500
1500
500
-500
-1500
MW Error
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour



2002 Apr Day Ahead Error	Load	Wind	Load - Wind
Hours Negative	450	274	376
Hours Positive	270	446	344
Negative Energy Error (MWh)	-236,487	-58,641	-201,161
Positive Energy Error(MWh)	54,886	175,979	136,898
Net Energy Error (MWh)	-181,601	117,338	-64,263
Worst Negative Error (MW)	-3,398	-670	-3,654
Worst Positive Error (MW)	932	1,215	1,306
Peak (MW)	23,713	3,088	23,707
Energy (MWh)	11,924,420	759,329	11,165,091
Negative Energy Error(% of LE)	-1.98	-0.49	-1.69
Positive Energy Error(% of LE)	0.46	1.48	1.15
MAE (MW)	392	326	470
MAE (% of Rating Wind)	11.87	9.87	14.23


2002 August
2002 Actual Load
2002 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
35000
30000
25000
20000
15000
10000
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MW
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145
193
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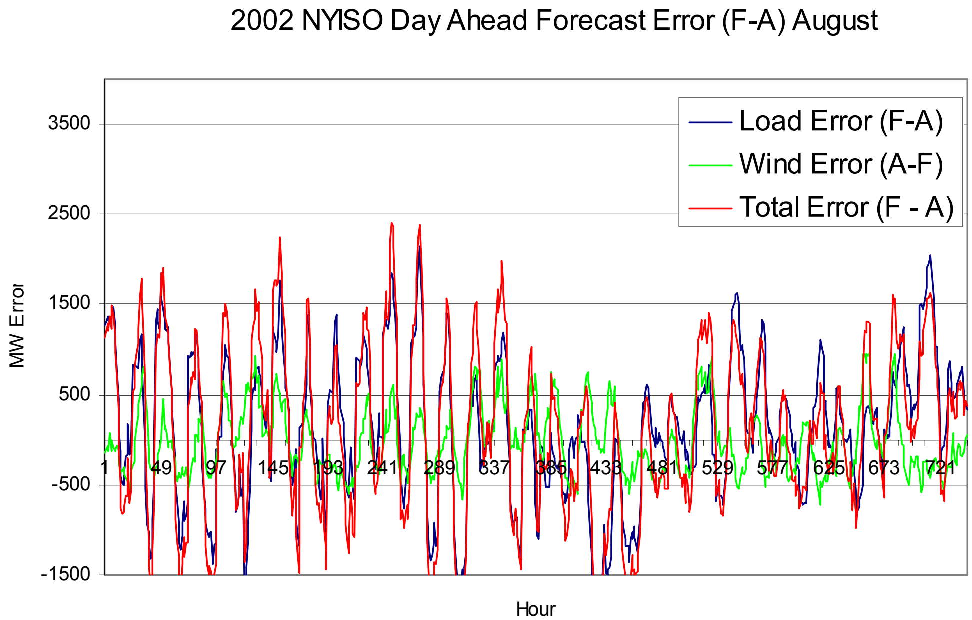
289
337
385
433
481
529
577
625
673
721
Hour


2002 NYISO Day Ahead Forecast Error (F-A) August
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
3500
2500
1500
500
-500
-1500
MW Error
1
49
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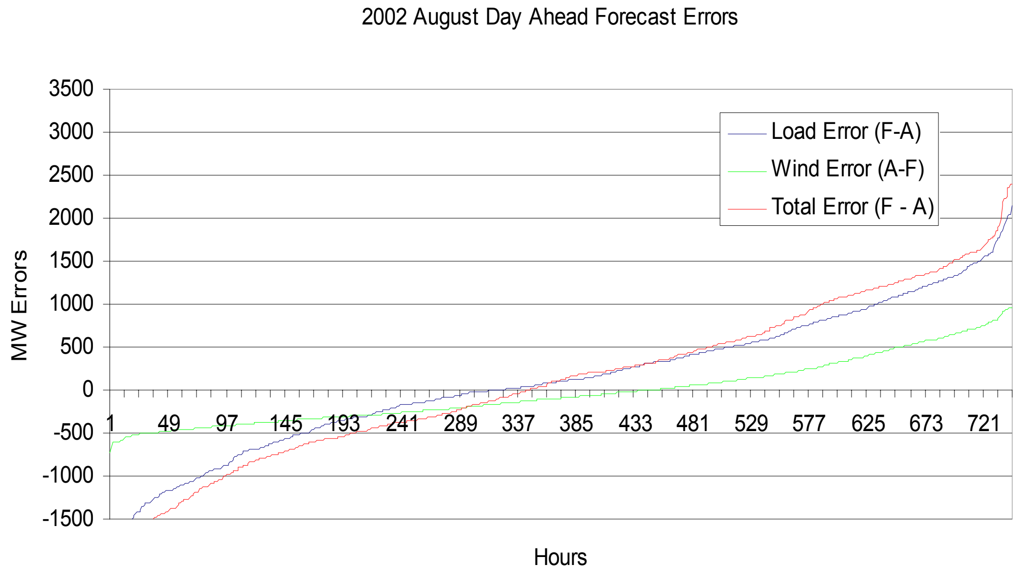
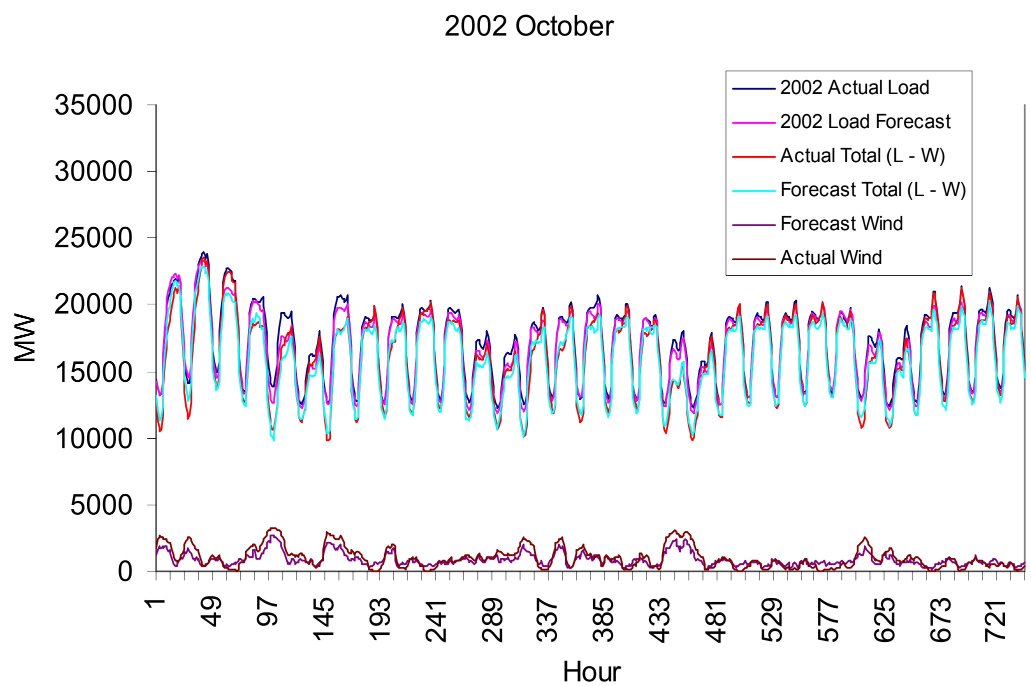
721
Hour



2002 Aug Day Ahead	Load	Wind	Load - Wind
Hours Negative	317	440	344
Hours Positive	427	304	400
Negative Energy Error (MWh)	-195,205	-121,950	-251,639
Positive Energy Error(MWh)	283,520	105,119	323,122
Net Energy Error (MWh)	88,315	-16,831	71,484
Worst Negative Error (MW)	-2,100	-728	-2,260
Worst Positive Error (MW)	2,138	968	2,399
Peak (MW)	30,596	2,464	30,476
Energy (MWh)	15,847,550	505,408	15,342,142
Negative Energy Error(% of LE)	-1.23	-0.77	-1.59
Positive Energy Error(% of LE)	1.79	0.66	2.04
MAE (MW)	643	305	773
MAE (% of Rating Wind)	19.50	9.25	23.41


2002 October
2002 Actual Load
2002 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
MW
35000
30000
25000
20000
15000
10000
5000
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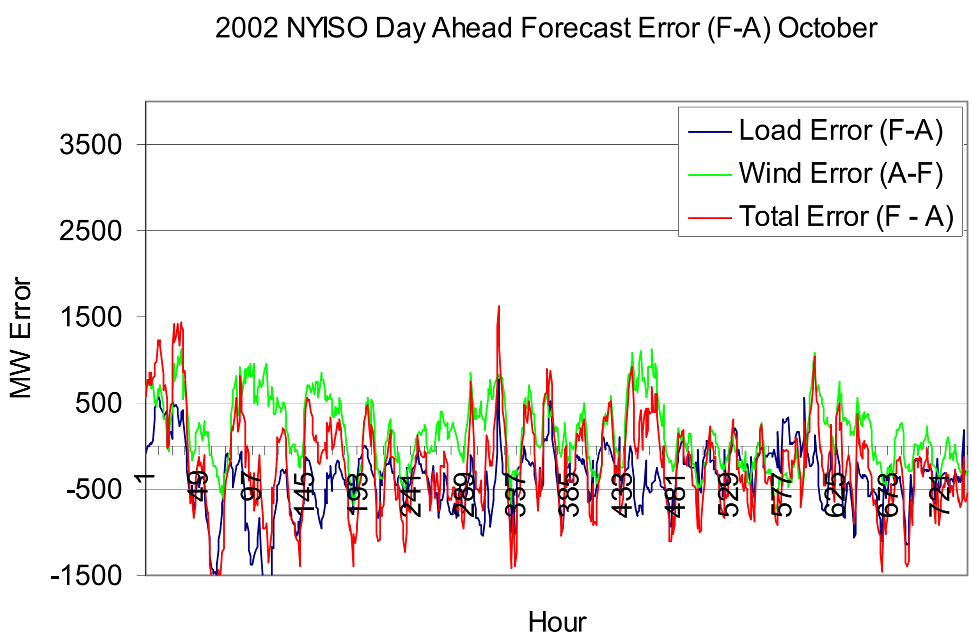
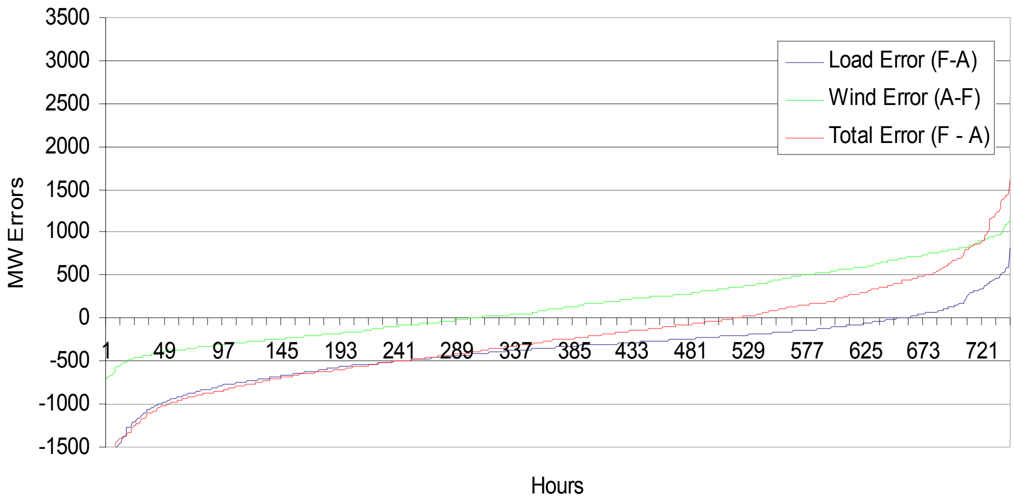
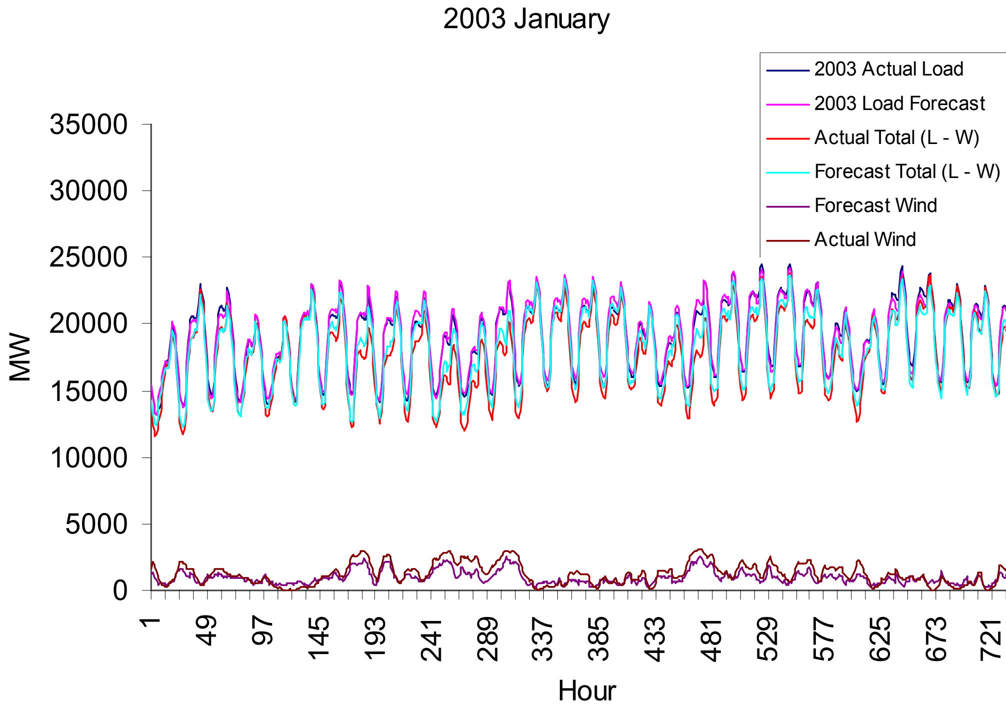
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour

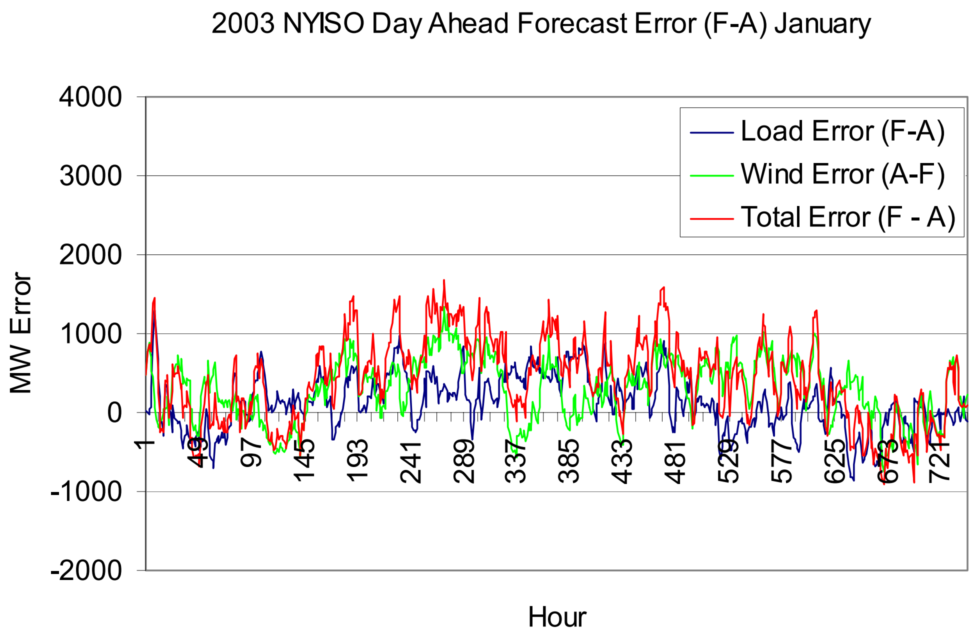

2002 NYISO Day Ahead Forecast Error (F-A) October
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
MW Error
3500
2500
1500
500
-500
-1500
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



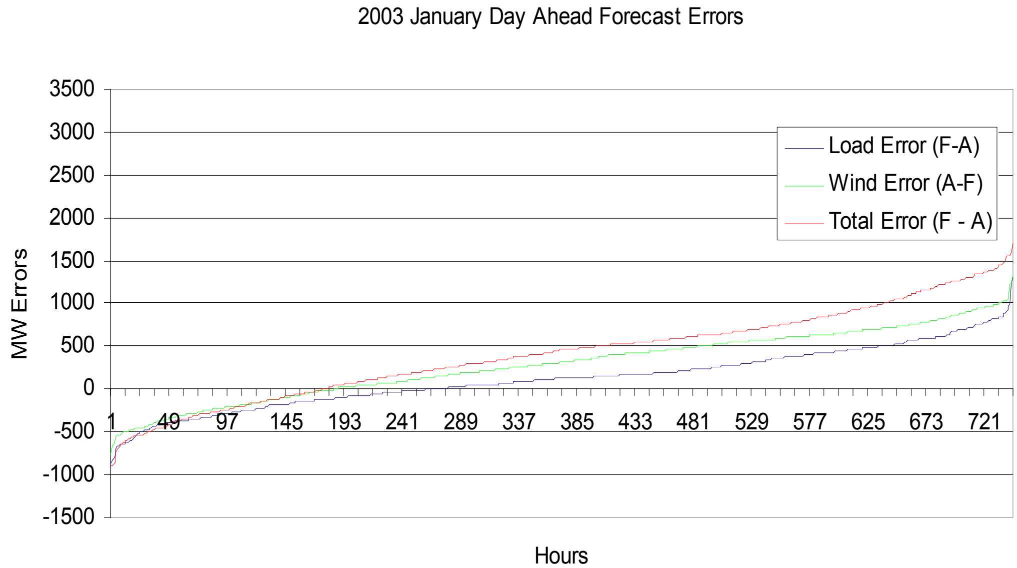
2002 Oct Day Ahead	Load	Wind	Load - Wind
Hours Negative	653	301	515
Hours Positive	91	443	229
Negative Energy Error (MWh)	-304,154	-72,614	-268,512
Positive Energy Error(MWh)	19,567	183,869	95,180
Net Energy Error (MWh)	-284,587	111,255	-173,332
Worst Negative Error (MW)	-1,872	-726	-1,778
Worst Positive Error (MW)	818	1,133	1,619
Peak (MW)	23,920	3,227	23,540
Energy (MWh)	12,765,254	761,616	12,003,638
Negative Energy Error(% of LE)	-2.38	-0.57	-2.10
Positive Energy Error(% of LE)	0.15	1.44	0.75
MAE (MW)	435	345	489
MAE (% of Rating Wind)	13.19	10.45	14.81



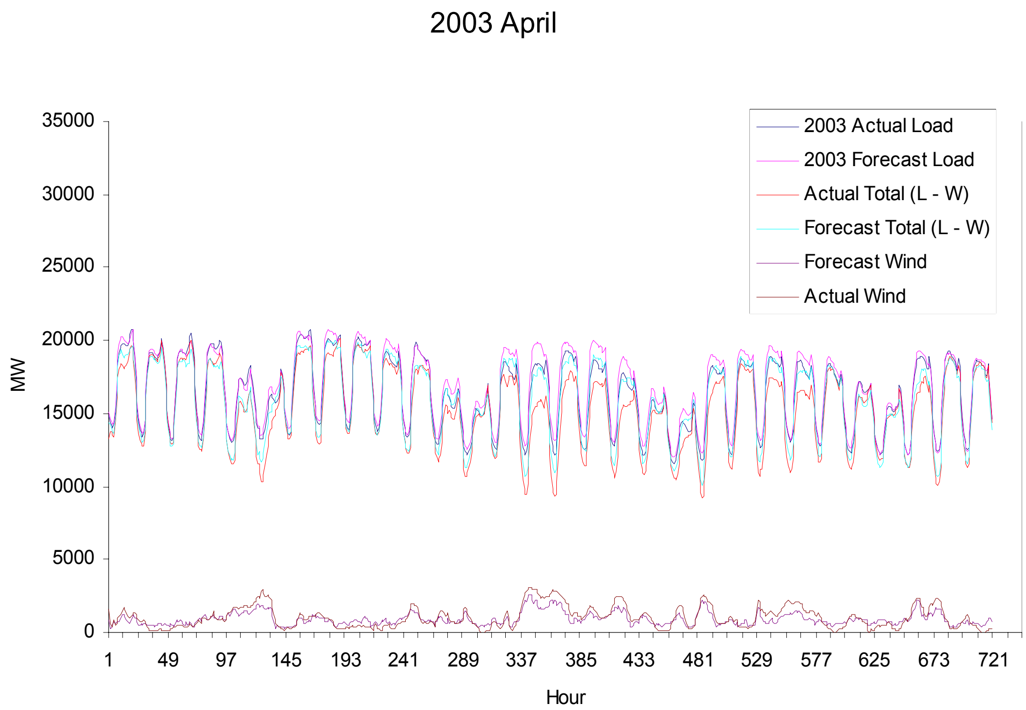
2003 January
2003 Actual Load
2003 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
35000
30000
25000
20000
15000
10000
5000
0
MW
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour

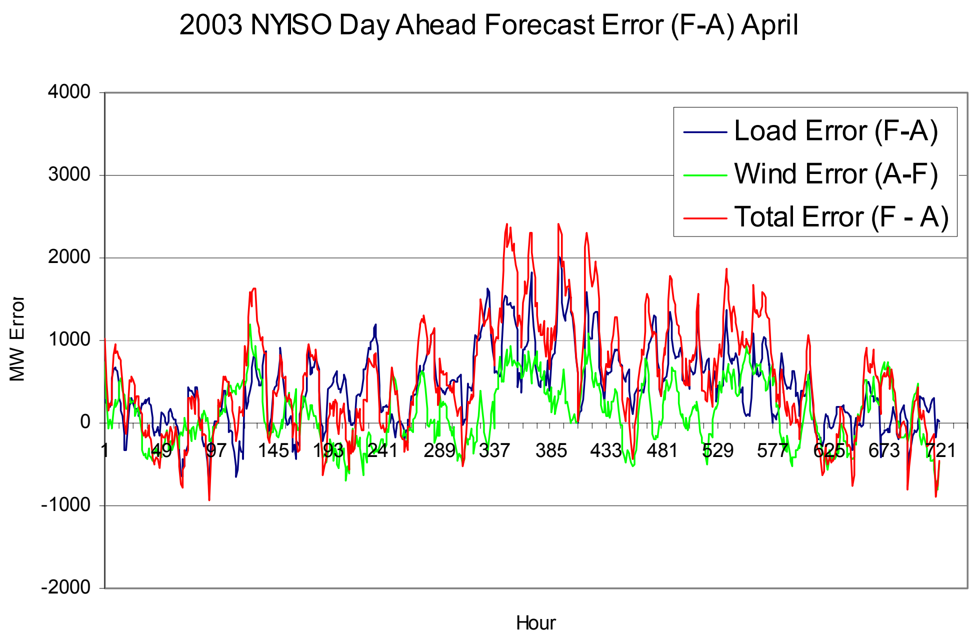


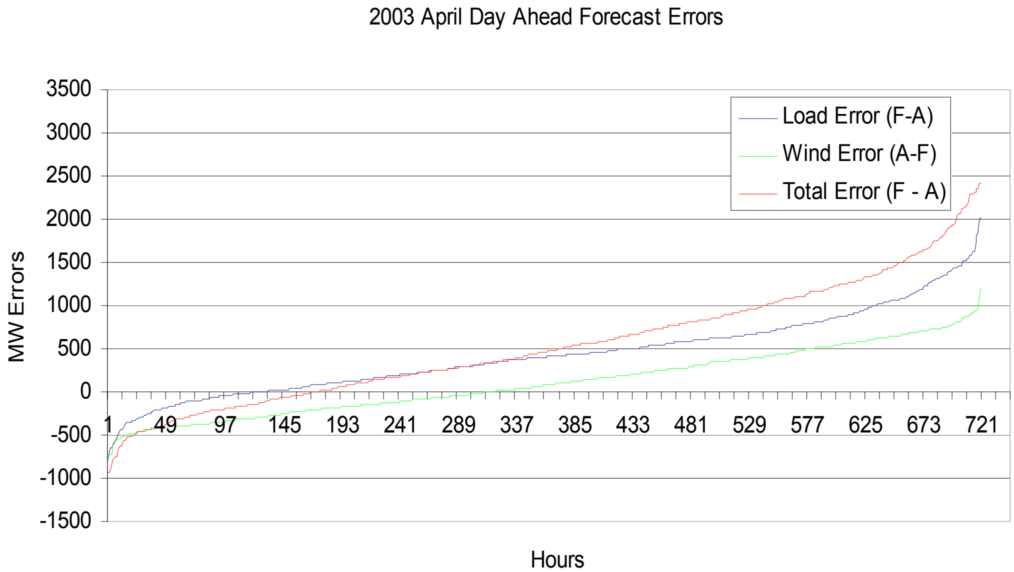
2003 NYISO Day Ahead Forecast Error (F-A) January
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
4000
3000
2000
1000
0
-1000
-2000
MW Error
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



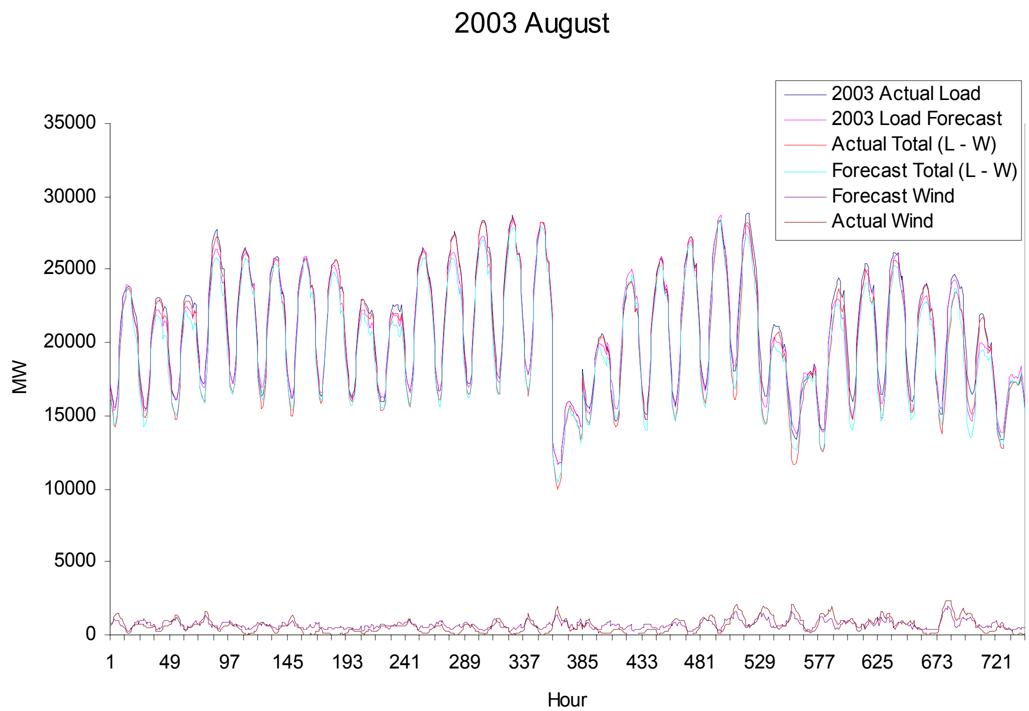
2003 Jan Day Ahead	Load	Wind	Load - Wind
Hours Negative	263	185	176
Hours Positive	481	559	568
Negative Energy Error (MWh)	-62,596	-44,503	-51,122
Positive Energy Error(MWh)	155,131	260,806	359,960
Net Energy Error (MWh)	92,535	216,303	308,838
Worst Negative Error (MW)	-865	-758	-903
Worst Positive Error (MW)	1,303	1,332	1,691
Peak (MW)	24,454	3,160	23,812
Energy (MWh)	14,184,906	928,510	13,256,396
Negative Energy Error(% of LE)	-0.44	-0.31	-0.36
Positive Energy Error(% of LE)	1.09	1.84	2.54
MAE (MW)	293	410	553
MAE (% of Rating Wind)	8.87	12.44	16.74

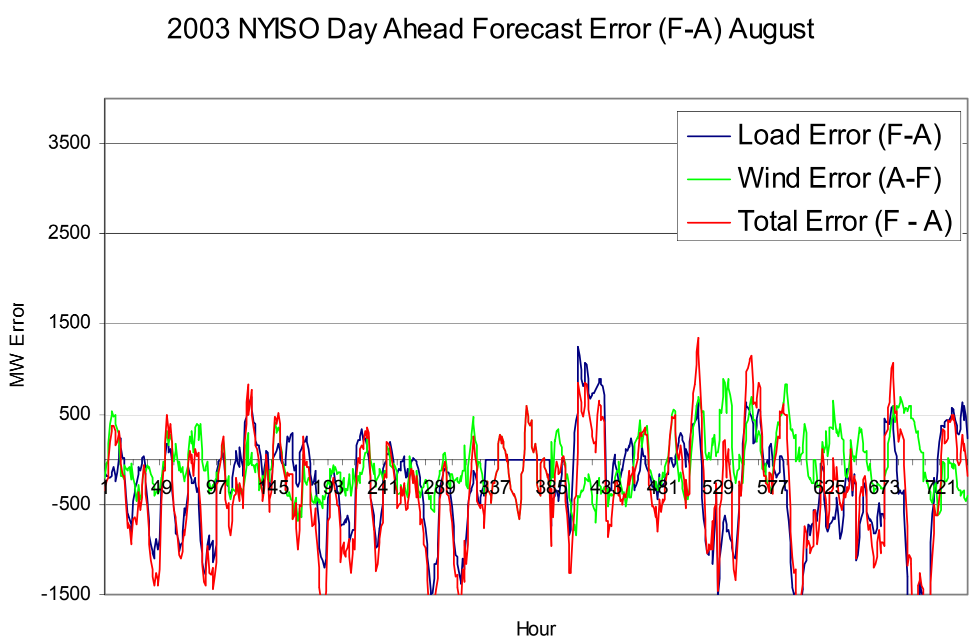

2003 April
35000
30000
25000
20000
15000
10000
5000
0
MW
2003 Actual Load
2003 Forecast Load
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour

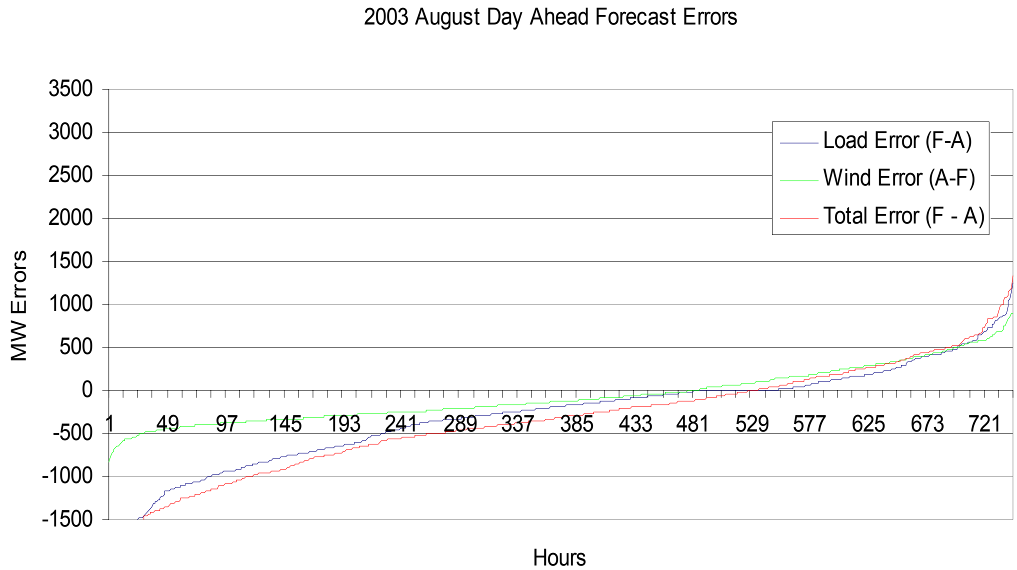

2003 NYISO Day Ahead Forecast Error (F-A) April
4000
3000
2000
1000
0
-1000
-2000
MW Error
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour



2003 Apr Day Ahead Error	Load	Wind	Load - Wind
Hours Negative	125	312	171
Hours Positive	595	408	549
Negative Energy Error (MWh)	-22,870	-78,023	-46,547
Positive Energy Error(MWh)	332,439	156,910	435,003
Net Energy Error (MWh)	309,569	78,887	388,456
Worst Negative Error (MW)	-822	-814	-937
Worst Positive Error (MW)	2,030	1,199	2,415
Peak (MW)	20,795	3,067	20,141
Energy (MWh)	11,792,616	740,013	11,052,603
Negative Energy Error(% of LE)	-0.19	-0.66	-0.39
Positive Energy Error(% of LE)	2.82	1.33	3.69
MAE (MW)	478	326	669
MAE (% of Rating Wind)	14.47	9.89	20.27


2003 August
2003 Actual Load
2003 Load Forecast
Actual Total (L - W)
Forecast Total (L - W)
Forecast Wind
Actual Wind
35000
30000
25000
20000
15000
10000
5000
0
MW
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour

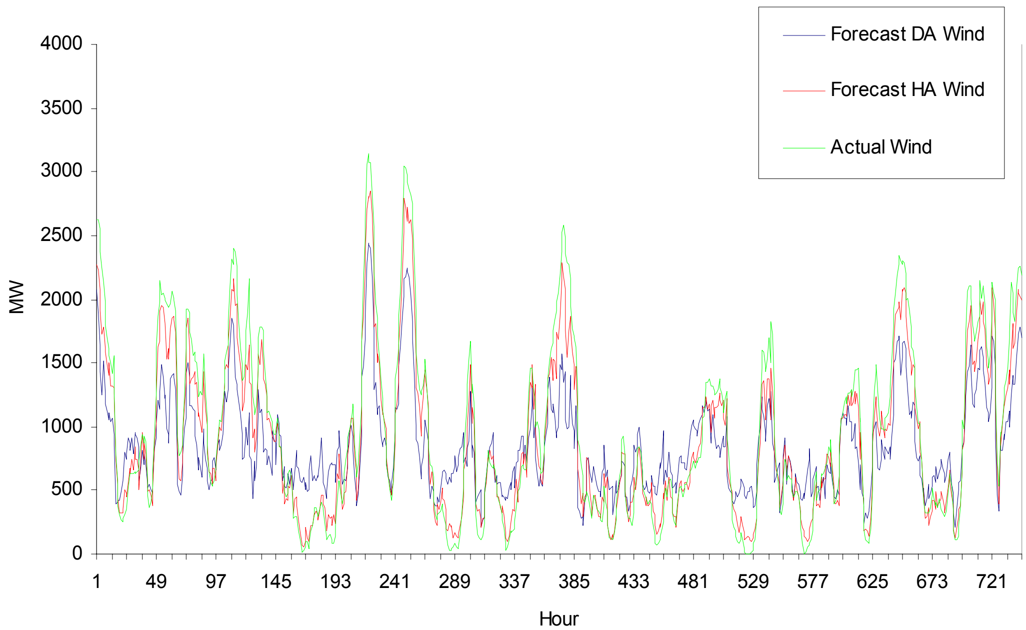

2003 NYISO Day Ahead Forecast Error (F-A) August
Load Error (F-A)
Wind Error (A-F)
Total Error (F - A)
3500
2500
1500
500
-500
-1500
MW Error
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



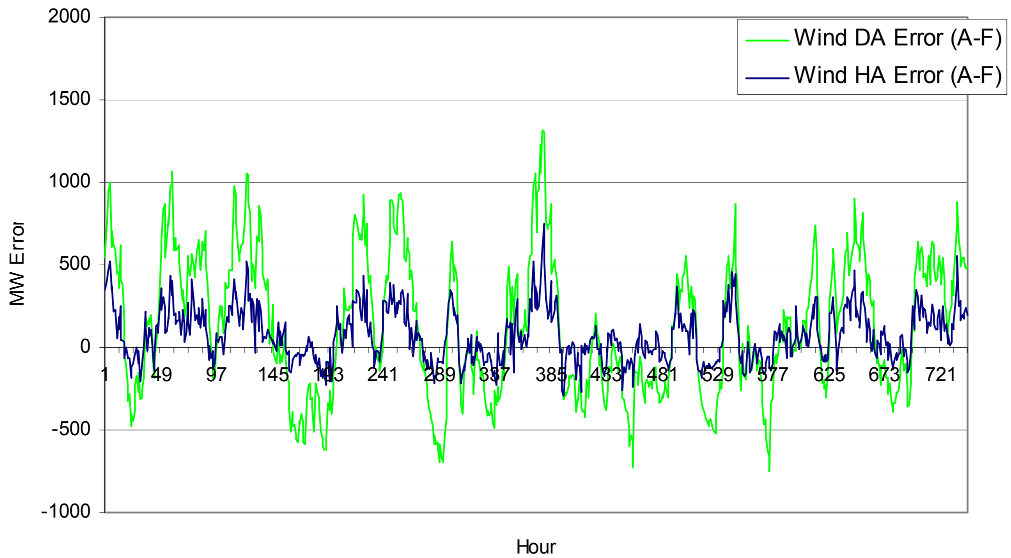
2003 Aug Day Ahead	Load	Wind	Load - Wind
Hours Negative	490	482	531
Hours Positive	254	262	213
Negative Energy Error (MWh)	-277,562	-123,654	-336,695
Positive Energy Error(MWh)	64,835	77,439	77,754
Net Energy Error (MWh)	-212,727	-46,215	-258,942
Worst Negative Error (MW)	-2,327	-842	-2,331
Worst Positive Error (MW)	1,259	896	1,342
Peak (MW)	28,855	2,388	28,657
Energy (MWh)	15,580,596	466,272	15,114,325
Negative Energy Error(% of LE)	-1.78	-0.79	-2.16
Positive Energy Error(% of LE)	0.42	0.50	0.50
MAE (MW)	460	270	557
MAE (% of Rating Wind)	13.95	8.19	16.88

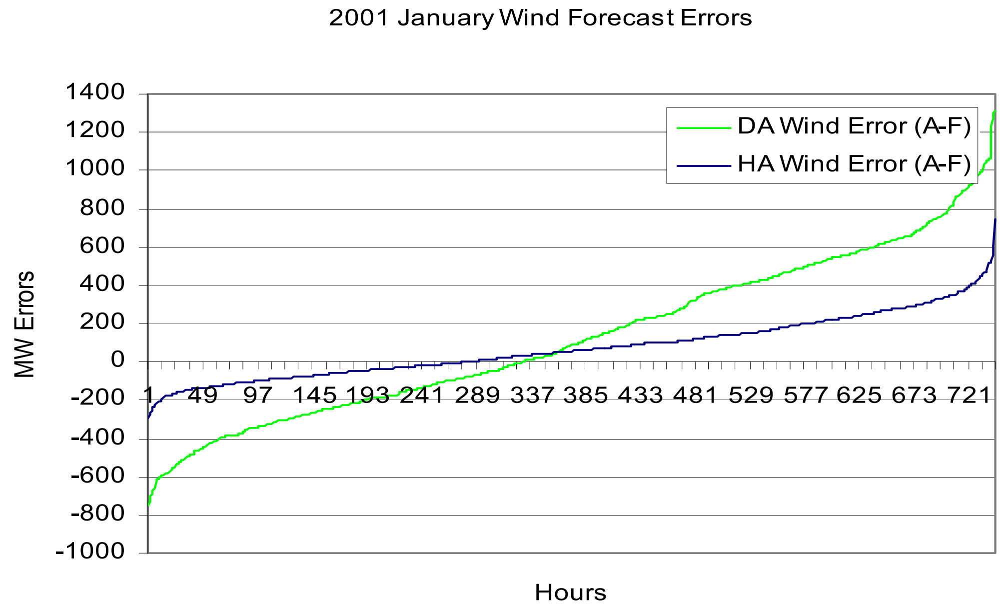
B.2 Day and Hour Ahead Forecast Analysis for 11 Months

2001 January Wind

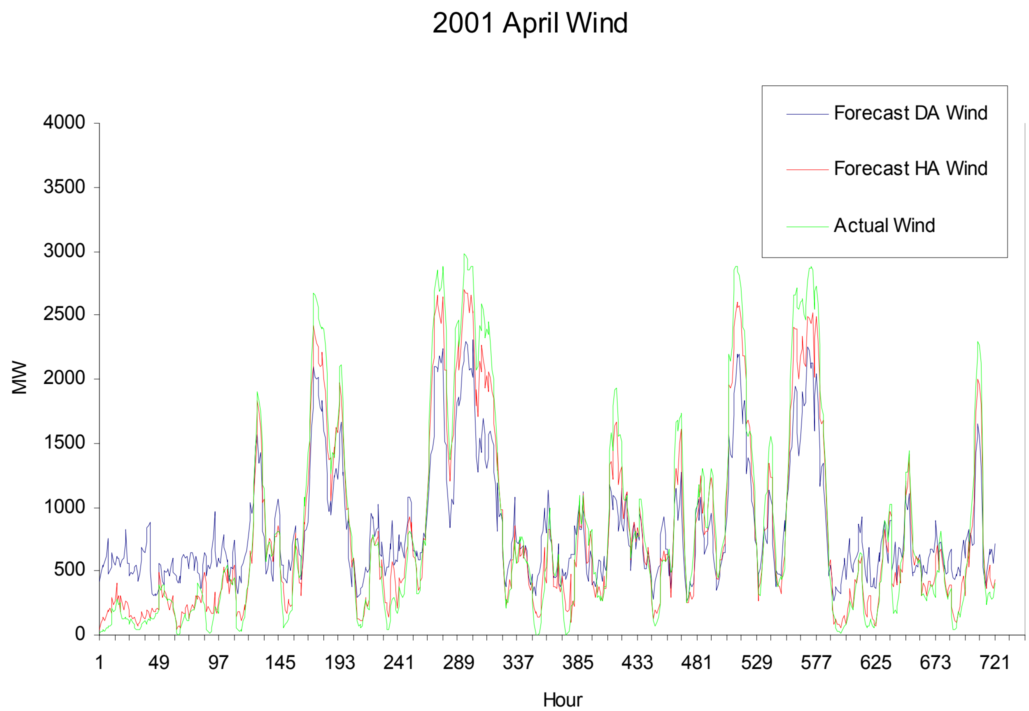


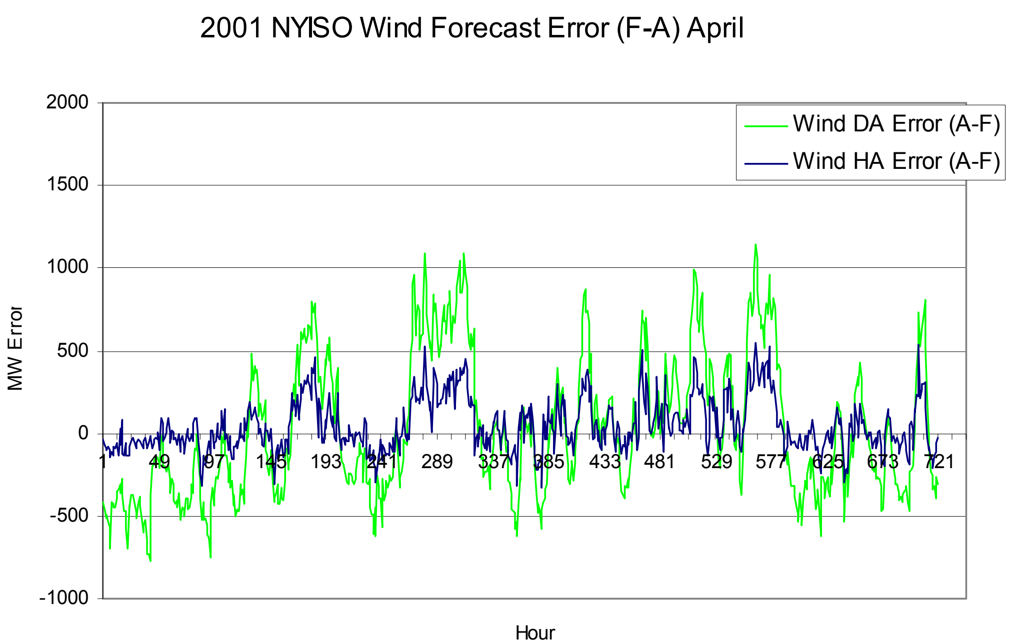
2001 NYISO Wind Forecast Error (F-A) January





2001 Jan Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	329	280
Hours Positive	415	464
Negative Energy Error (MWh)	-85,645	-23,098
Positive Energy Error(MWh)	180,573	77,491
Net Energy Error (MWh)	94,928	54,393
Worst Negative Error (MW)	-753	-295
Worst Positive Error (MW)	1,310	747
Peak (MW)	3,149	3,149
Energy (MWh)	723,591	723,591
Negative Energy Error(% of LE)	-0.62	-0.17
Positive Energy Error(% of LE)	1.32	0.56
MAE (MW)	358	135
MAE (% of Rating Wind)	10.84	4.10


2001 April Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
0
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2001 NYISO Wind Forecast Error (F-A) April
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
1
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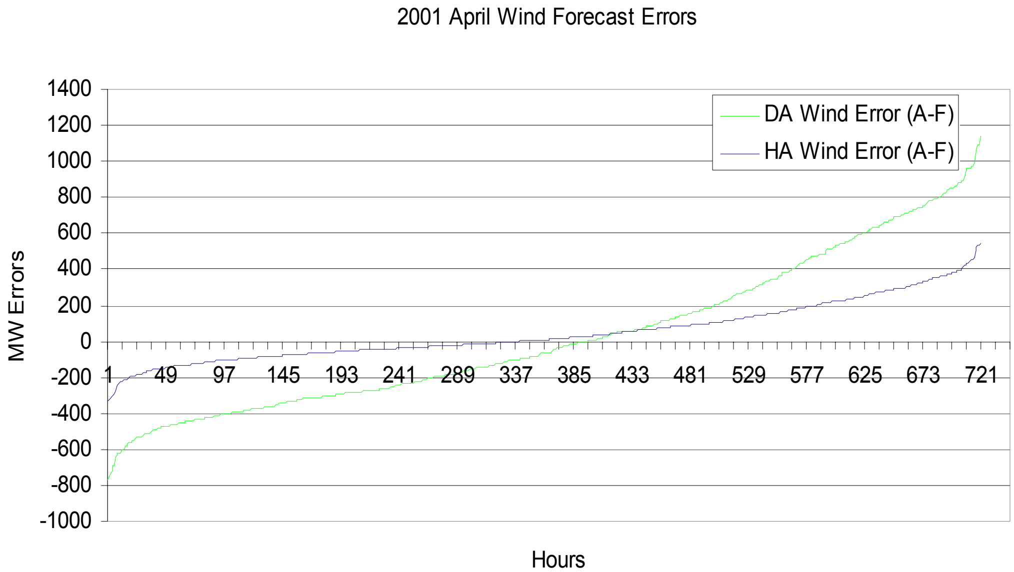
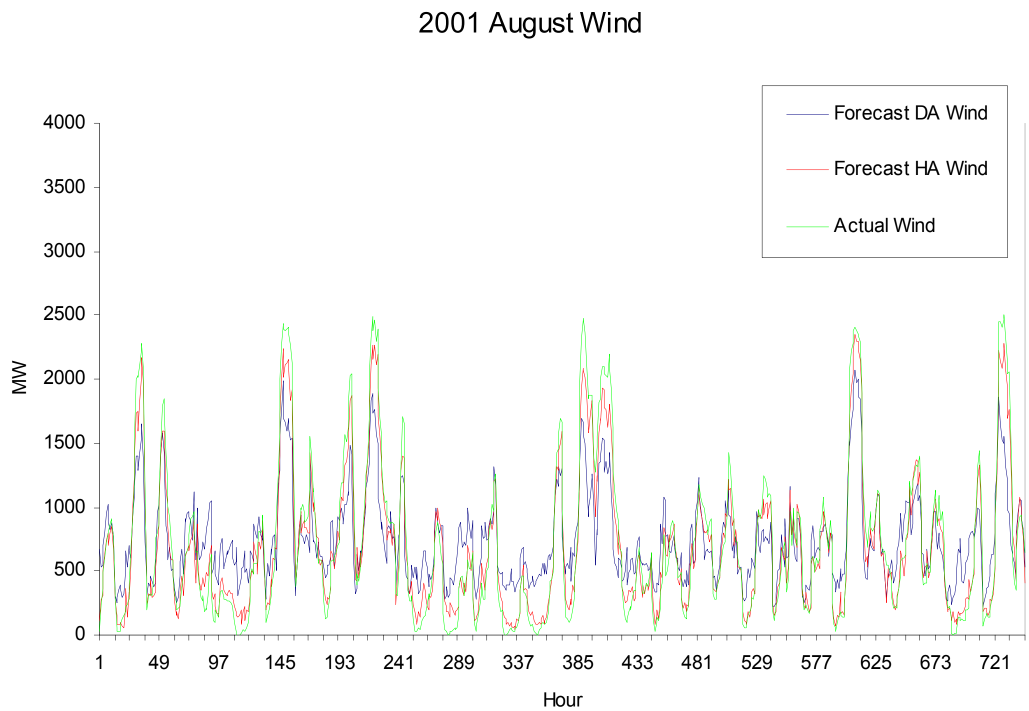
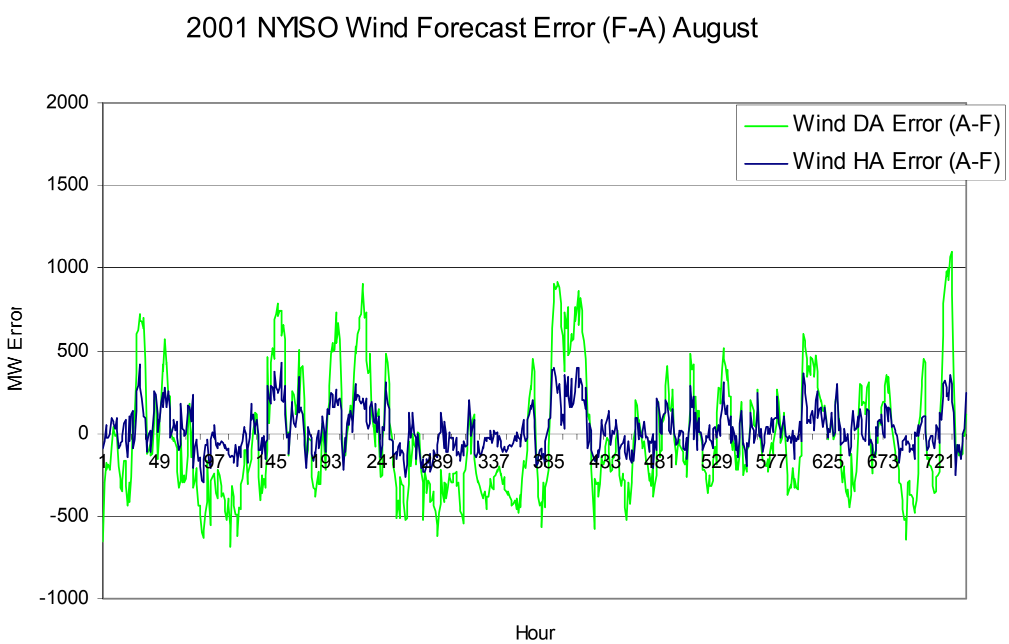
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



2001 Apr Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	395	334
Hours Positive	325	386
Negative Energy Error (MWh)	-114,048	-27,443
Positive Energy Error(MWh)	133,702	62,352
Net Energy Error (MWh)	19,654	34,909
Worst Negative Error (MW)	-770	-334
Worst Positive Error (MW)	1,141	546
Peak (MW)	2,985	2,985
Energy (MWh)	621,205	621,205
Negative Energy Error(% of LE)	-0.98	-0.24
Positive Energy Error(% of LE)	1.15	0.54
MAE (MW)	344	125
MAE (% of Rating Wind)	10.43	3.78


2001 August Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
0
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2001 NYISO Wind Forecast Error (F-A) August
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
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193
241
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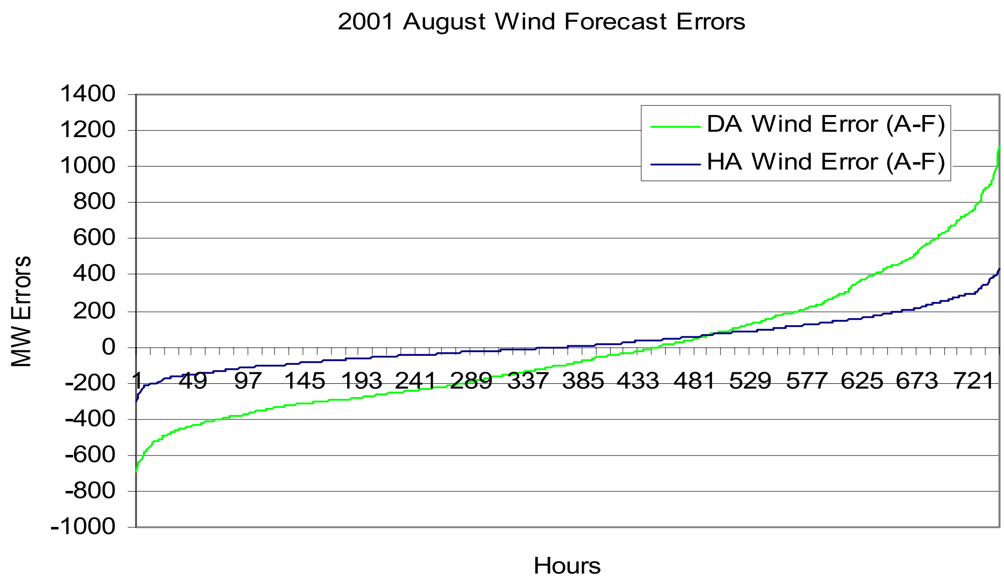
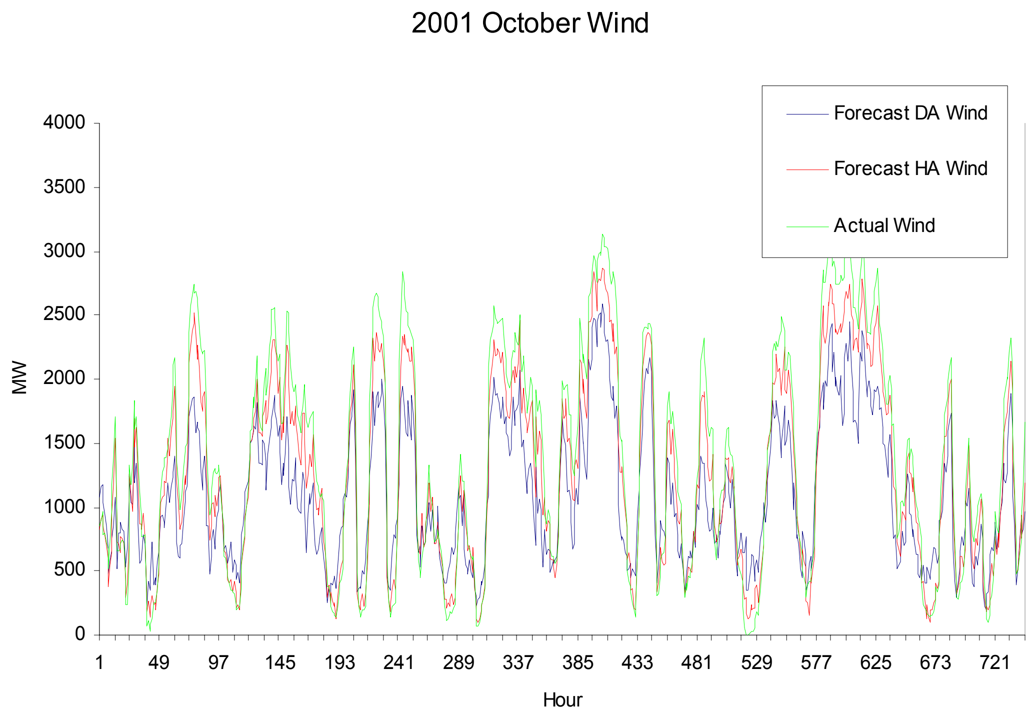
385
433
481
529
577
625
673
721
Hour



2001 Aug Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	451	369
Hours Positive	293	375
Negative Energy Error (MWh)	-113,346	-29,468
Positive Energy Error(MWh)	98,650	47,744
Net Energy Error (MWh)	-14,696	18,276
Worst Negative Error (MW)	-688	-298
Worst Positive Error (MW)	1,106	430
Peak (MW)	2,503	2,503
Energy (MWh)	537,309	537,309
Negative Energy Error(% of LE)	-0.71	-0.19
Positive Energy Error(% of LE)	0.62	0.30
MAE (MW)	285	104
MAE (% of Rating Wind)	8.63	3.14


2001 October Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
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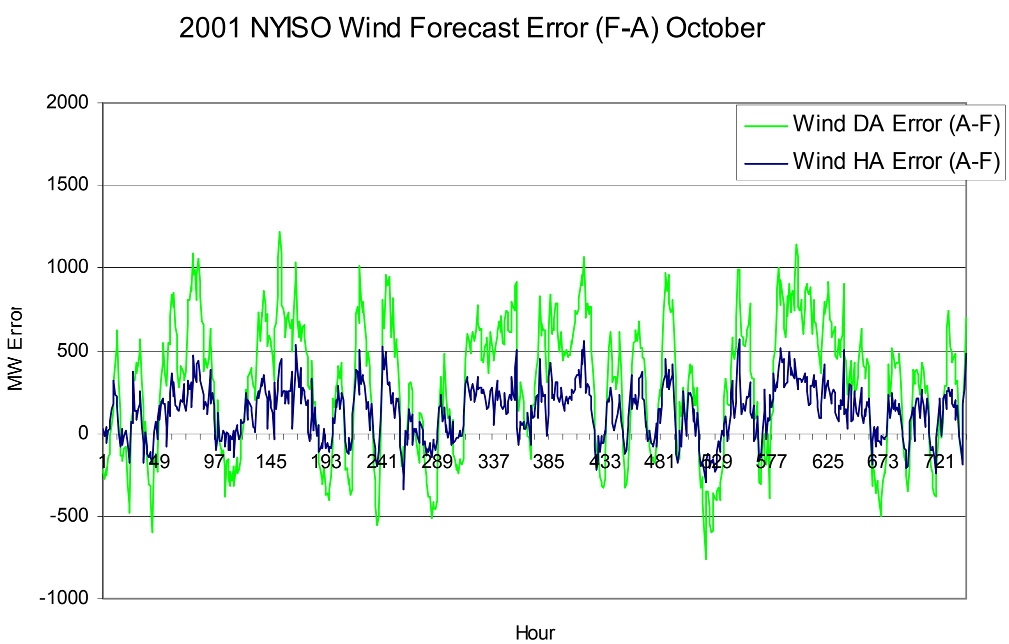
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2001 NYISO Wind Forecast Error (F-A) October
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
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145
193
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481
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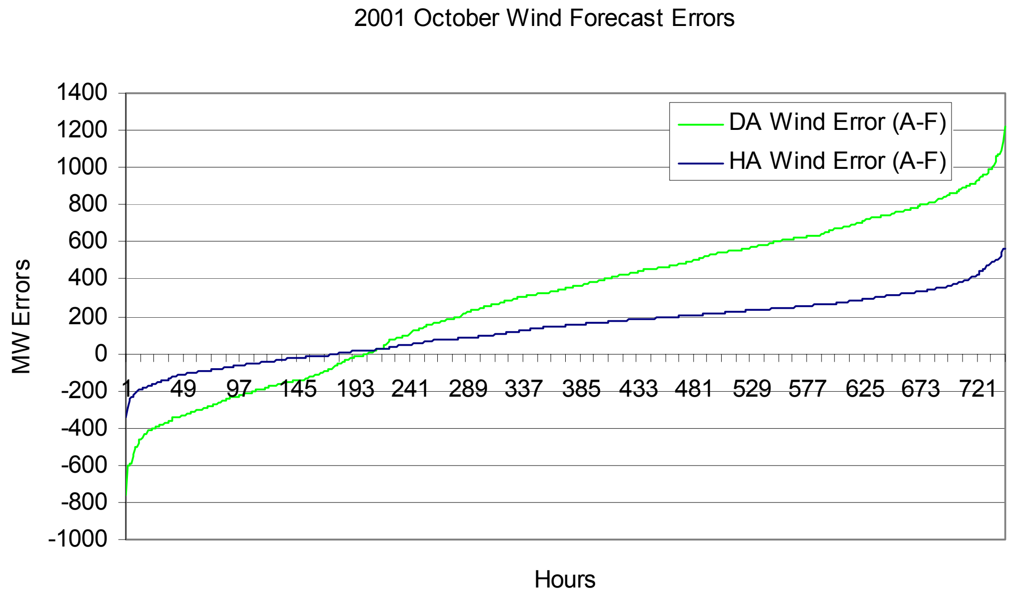
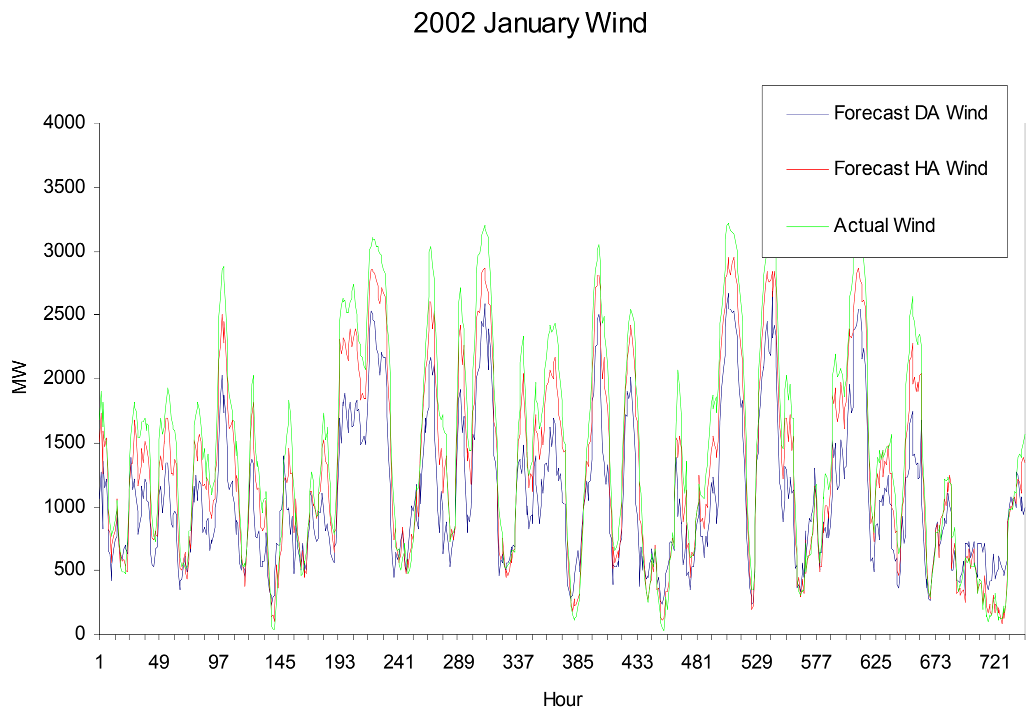
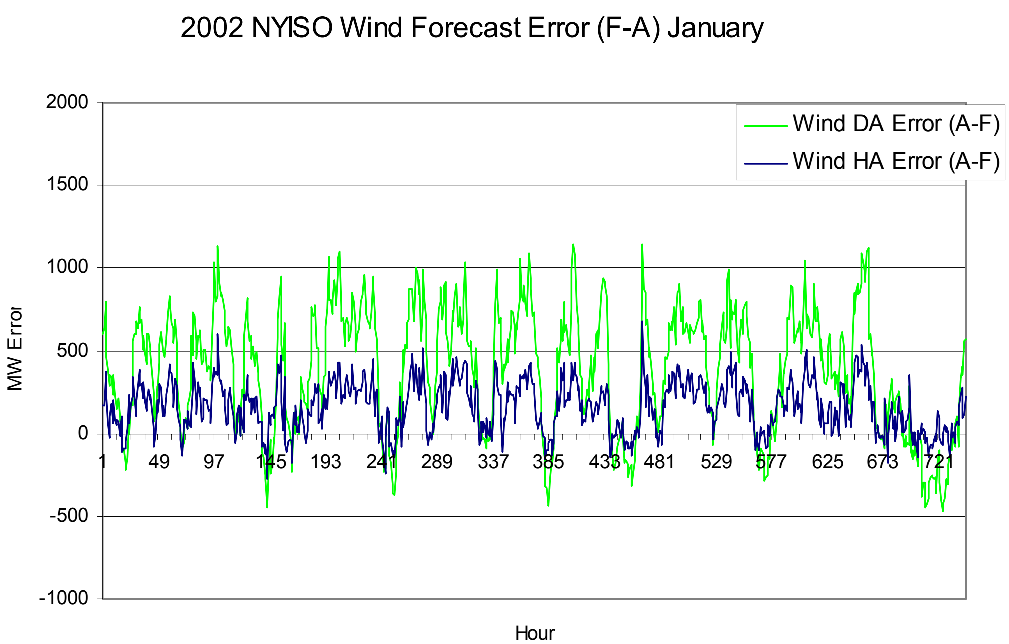
625
673
721
Hour



2001 Oct Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	205	178
Hours Positive	539	566
Negative Energy Error (MWh)	-47,258	-15,080
Positive Energy Error(MWh)	268,574	113,573
Net Energy Error (MWh)	221,316	98,493
Worst Negative Error (MW)	-757	-343
Worst Positive Error (MW)	1,218	566
Peak (MW)	3,130	3,130
Energy (MWh)	1,035,844	1,035,844
Negative Energy Error(% of LE)	-0.38	-0.12
Positive Energy Error(% of LE)	2.17	0.92
MAE (MW)	425	173
MAE (% of Rating Wind)	12.86	5.24


2002 January Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
0
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2002 NYISO Wind Forecast Error (F-A) January
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
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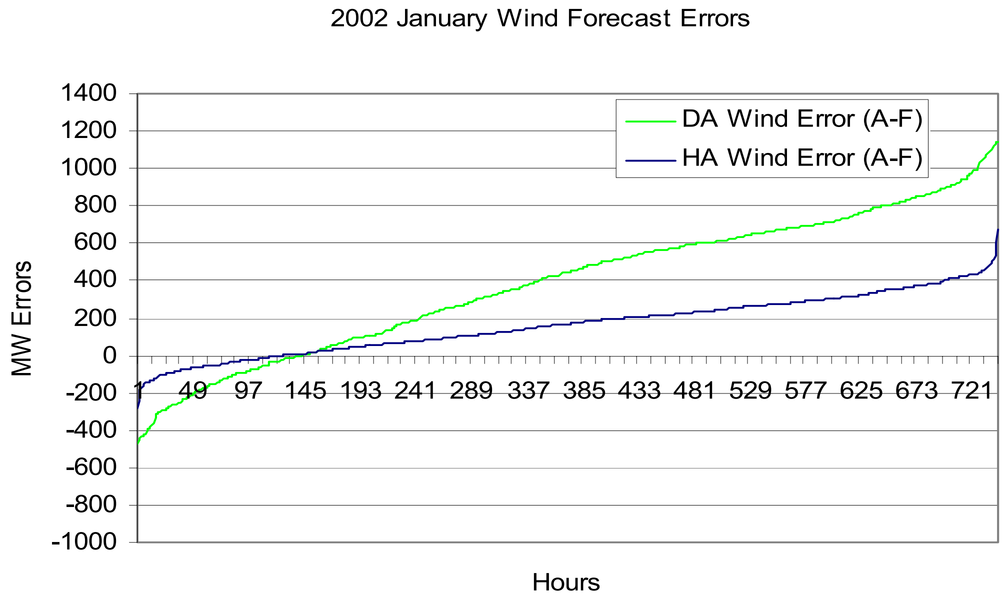
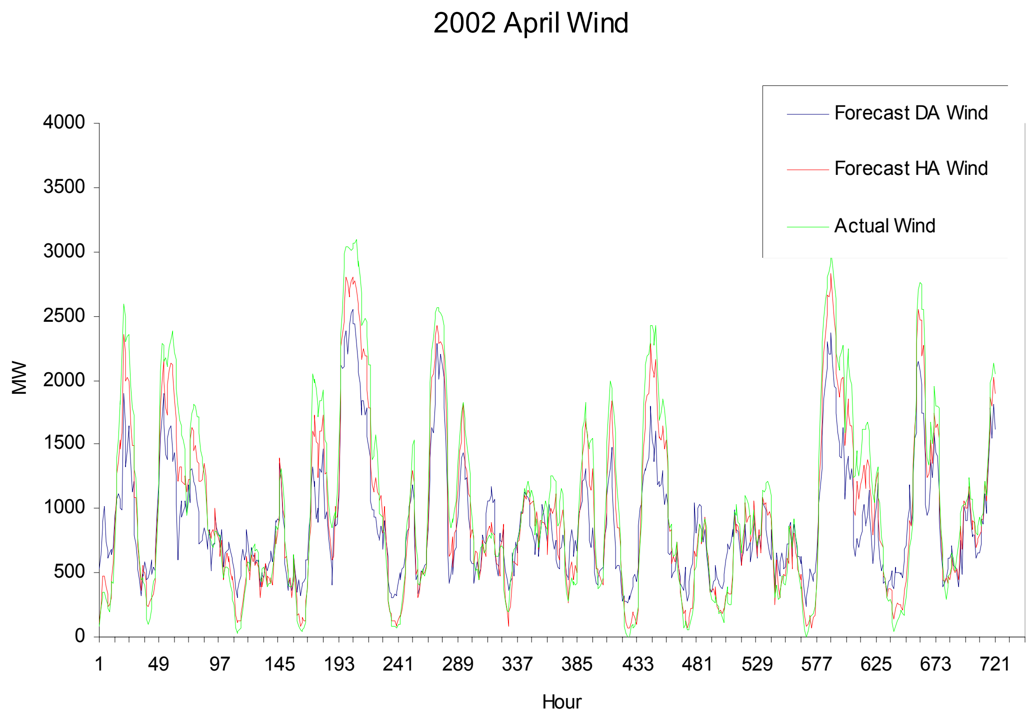
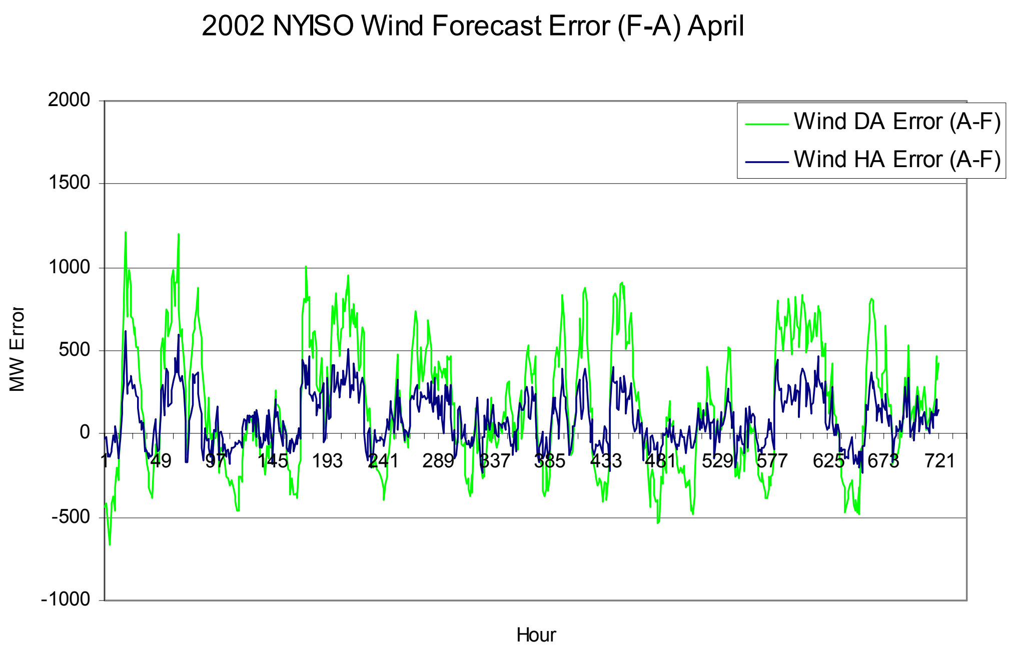
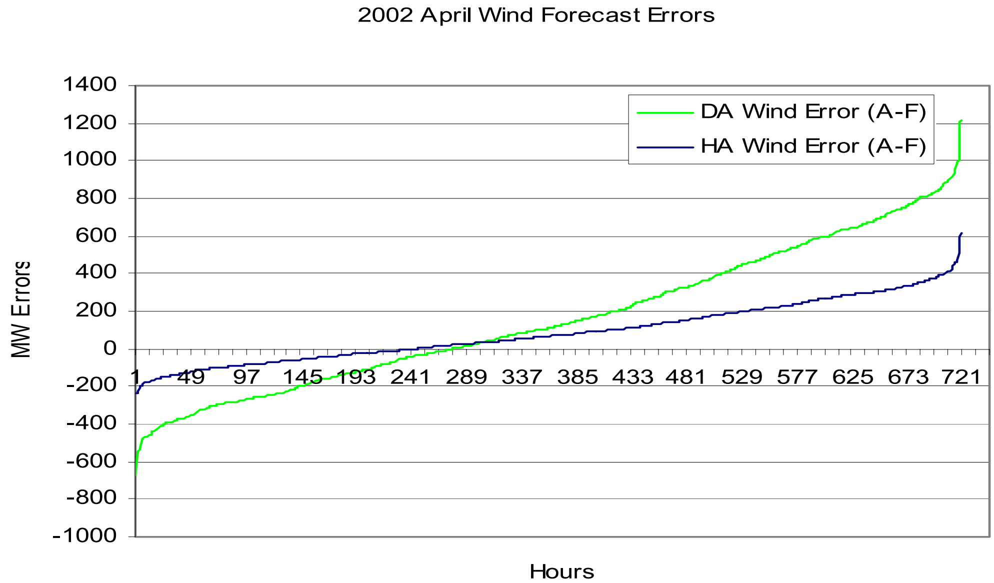
721
Hour



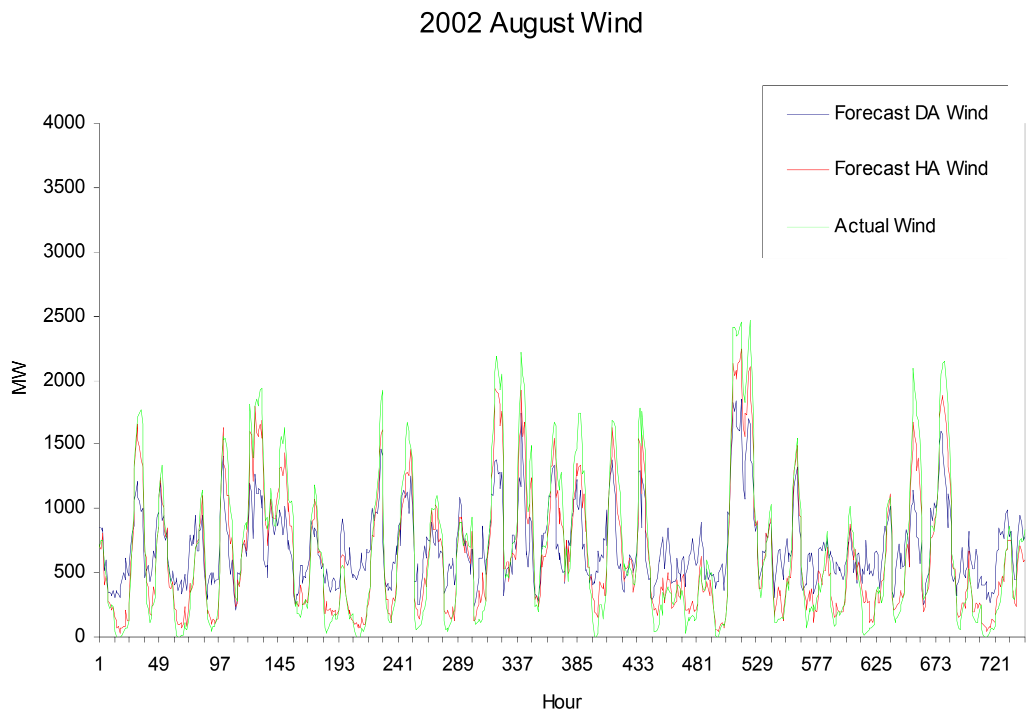
2002 Jan Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	142	126
Hours Positive	602	618
Negative Energy Error (MWh)	-23,259	-7,980
Positive Energy Error(MWh)	311,007	128,902
Net Energy Error (MWh)	287,747	120,922
Worst Negative Error (MW)	-472	-280
Worst Positive Error (MW)	1,146	676
Peak (MW)	3,215	3,215
Energy (MWh)	1,089,858	1,089,858
Negative Energy Error(% of LE)	-0.18	-0.06
Positive Energy Error(% of LE)	2.35	0.97
MAE (MW)	449	184
MAE (% of Rating Wind)	13.61	5.58


2002 April Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
0
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour


2002 NYISO Wind Forecast Error (F-A) April
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour



2002 Apr Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	274	244
Hours Positive	446	476
Negative Energy Error (MWh)	-58,641	-18,571
Positive Energy Error(MWh)	175,979	82,024
Net Energy Error (MWh)	117,338	63,453
Worst Negative Error (MW)	-670	-236
Worst Positive Error (MW)	1,215	615
Peak (MW)	3,088	3,088
Energy (MWh)	759,329	759,329
Negative Energy Error(% of LE)	-0.49	-0.16
Positive Energy Error(% of LE)	1.48	0.69
MAE (MW)	326	140
MAE (% of Rating Wind)	9.87	4.23


2002 August Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
4000
3500
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MW
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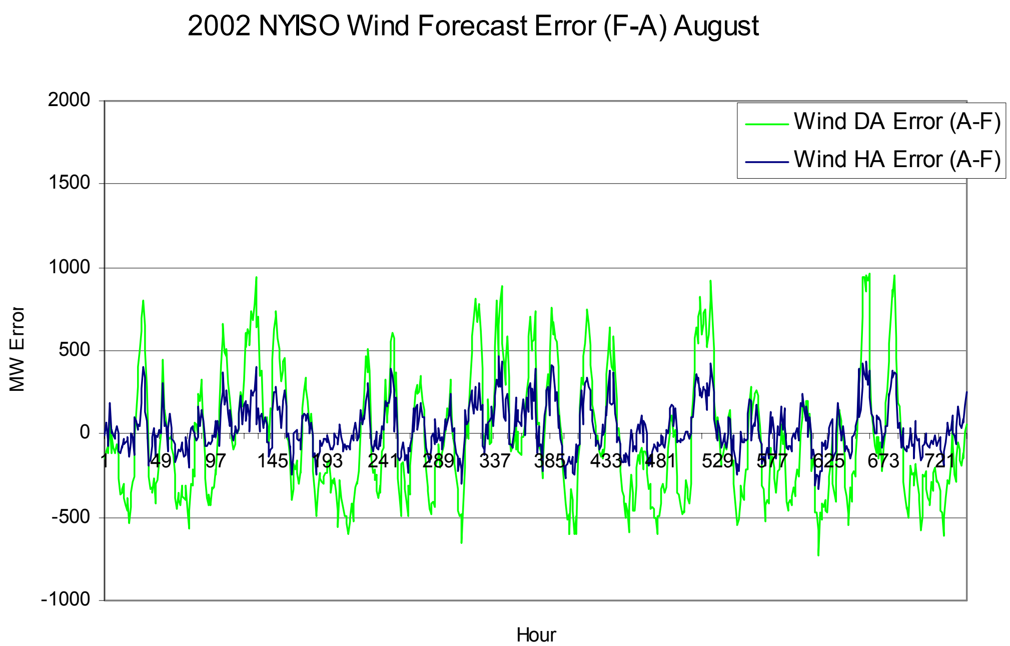
673
721
Hour


2002 NYISO Wind Forecast Error (F-A) August
Wind DA Error (A-F)
Wind HA Error (A-F)
2000
1500
1000
500
0
-500
-1000
MW Error
1
49
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145
193
241
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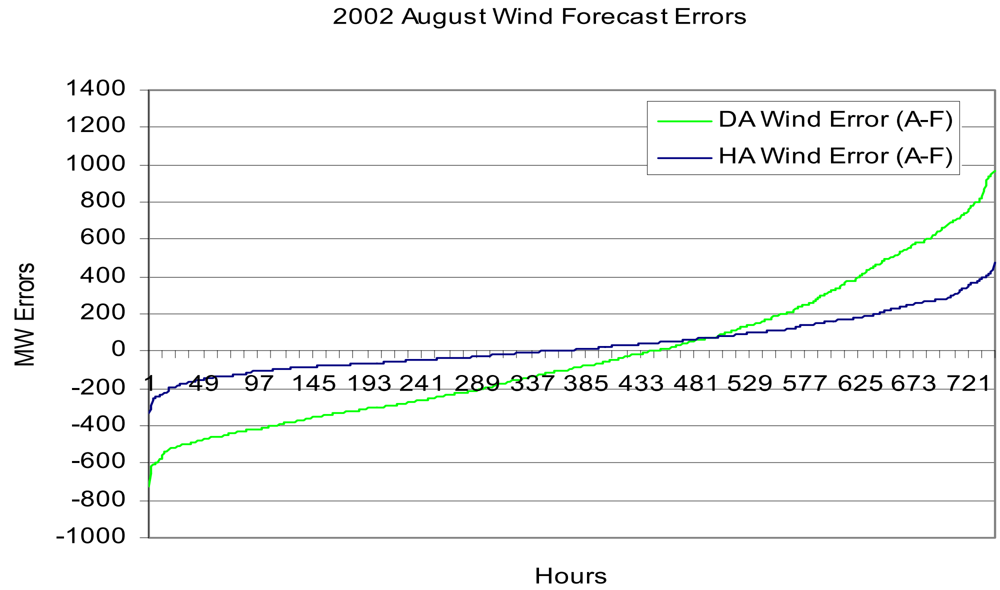
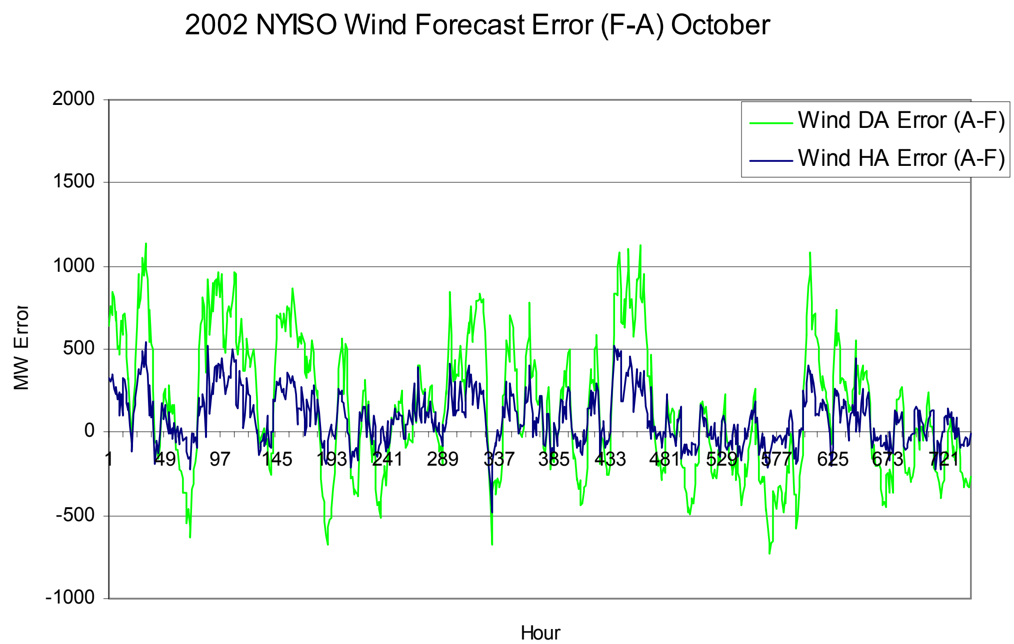
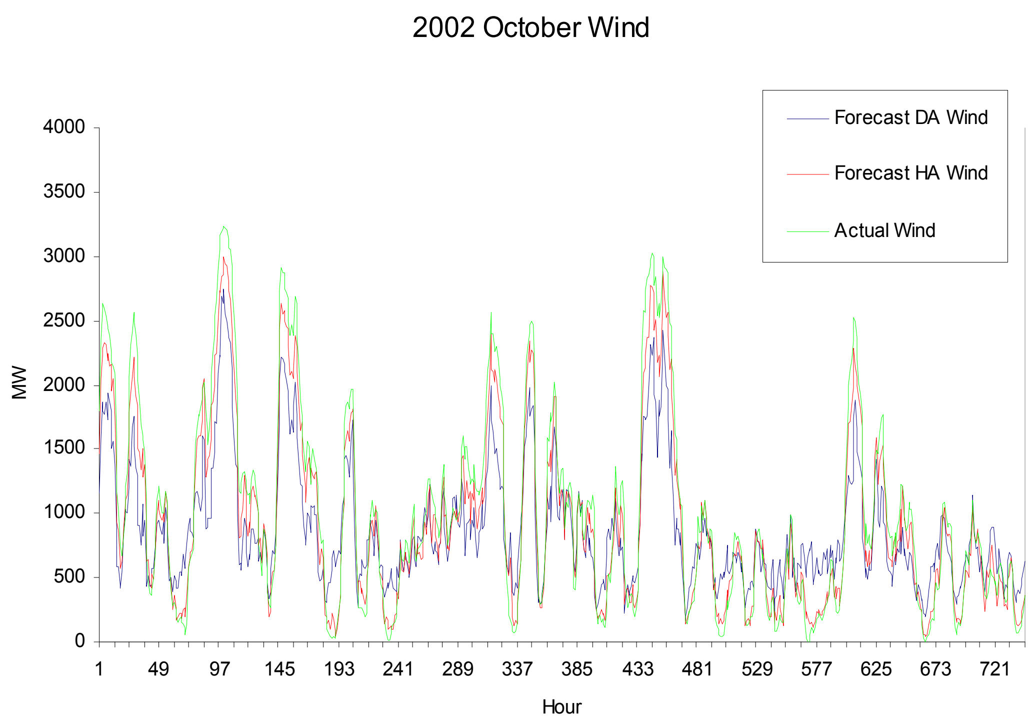
Hour



2002 Aug Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	440	349
Hours Positive	304	395
Negative Energy Error (MWh)	-121,950	-29,178
Positive Energy Error(MWh)	105,119	54,334
Net Energy Error (MWh)	-16,831	25,155
Worst Negative Error (MW)	-728	-333
Worst Positive Error (MW)	968	471
Peak (MW)	2,464	2,464
Energy (MWh)	505,408	505,408
Negative Energy Error(% of LE)	-0.77	-0.18
Positive Energy Error(% of LE)	0.66	0.34
MAE (MW)	305	112
MAE (% of Rating Wind)	9.25	3.40


2002 NYISO Wind Forecast Error (F-A) October
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour


2002 October Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
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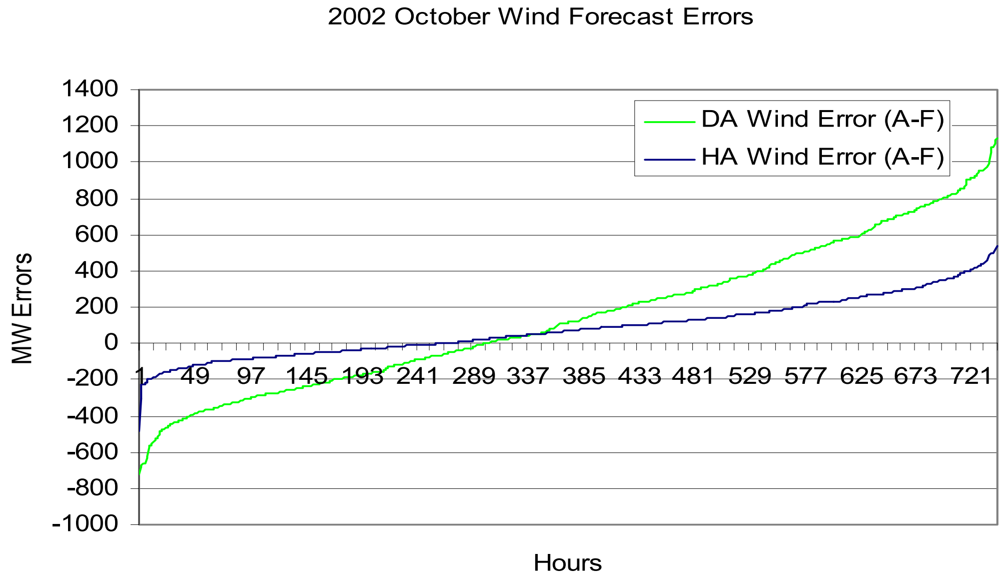
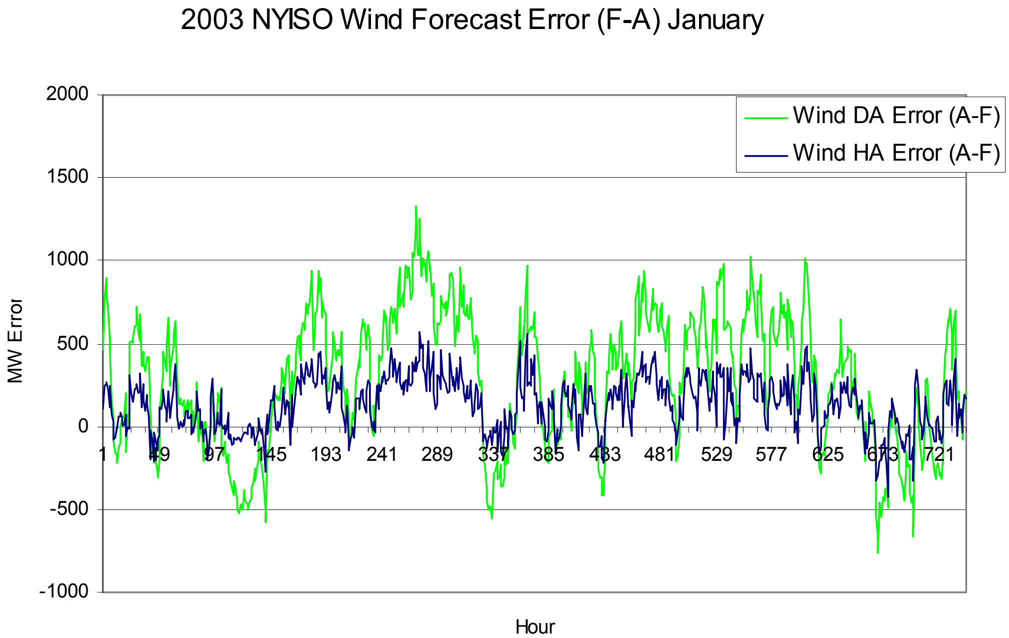
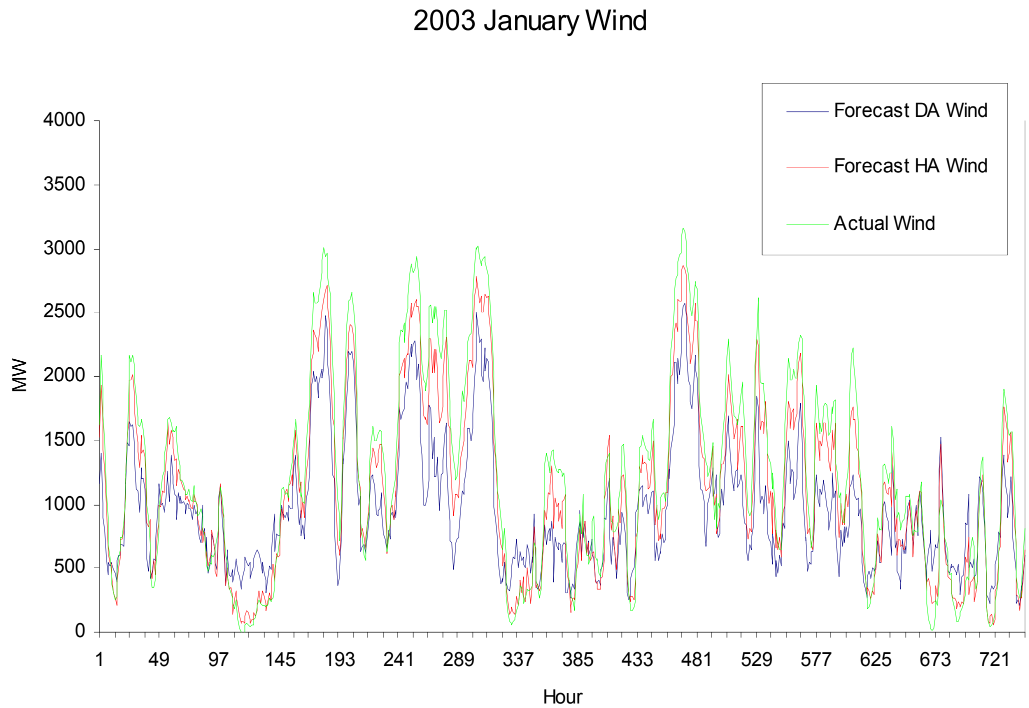
500
0
1 49 97 145 193 241 289 337 385 433 481 529 577 625 673 721
Hour



2002 Oct Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	301	263
Hours Positive	443	481
Negative Energy Error (MWh)	-72,614	-19,745
Positive Energy Error(MWh)	183,869	82,337
Net Energy Error (MWh)	111,255	62,592
Worst Negative Error (MW)	-726	-487
Worst Positive Error (MW)	1,133	540
Peak (MW)	3,227	3,227
Energy (MWh)	761,616	761,616
Negative Energy Error(% of LE)	-0.57	-0.15
Positive Energy Error(% of LE)	1.44	0.65
MAE (MW)	345	137
MAE (% of Rating Wind)	10.45	4.16


2003 NYISO Wind Forecast Error (F-A) January
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2003 January Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
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0
1
49
97
145
193
241
289
337
385
433
481
529
577
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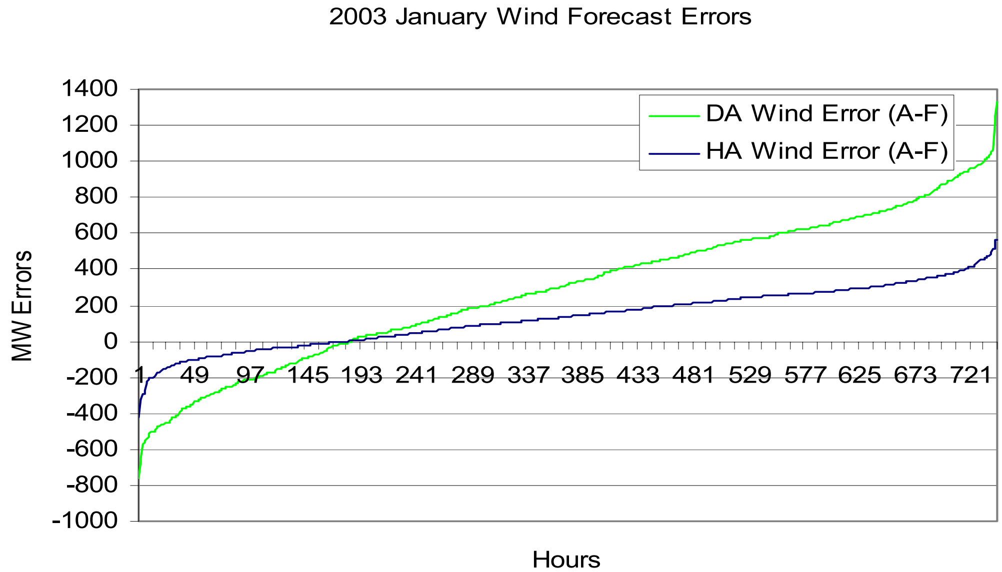
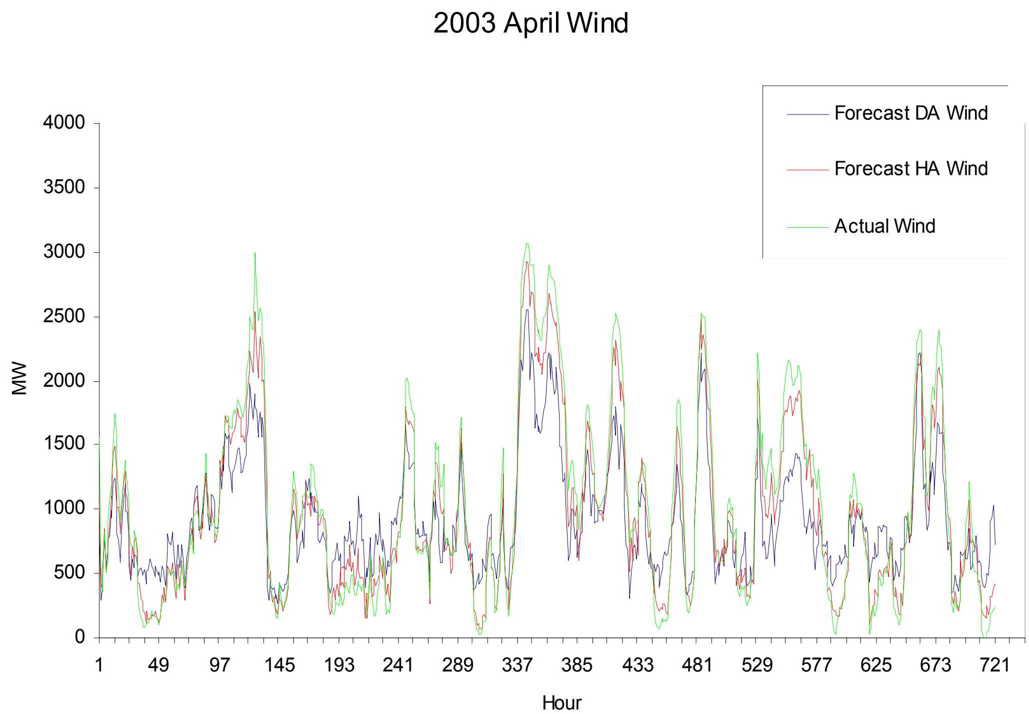
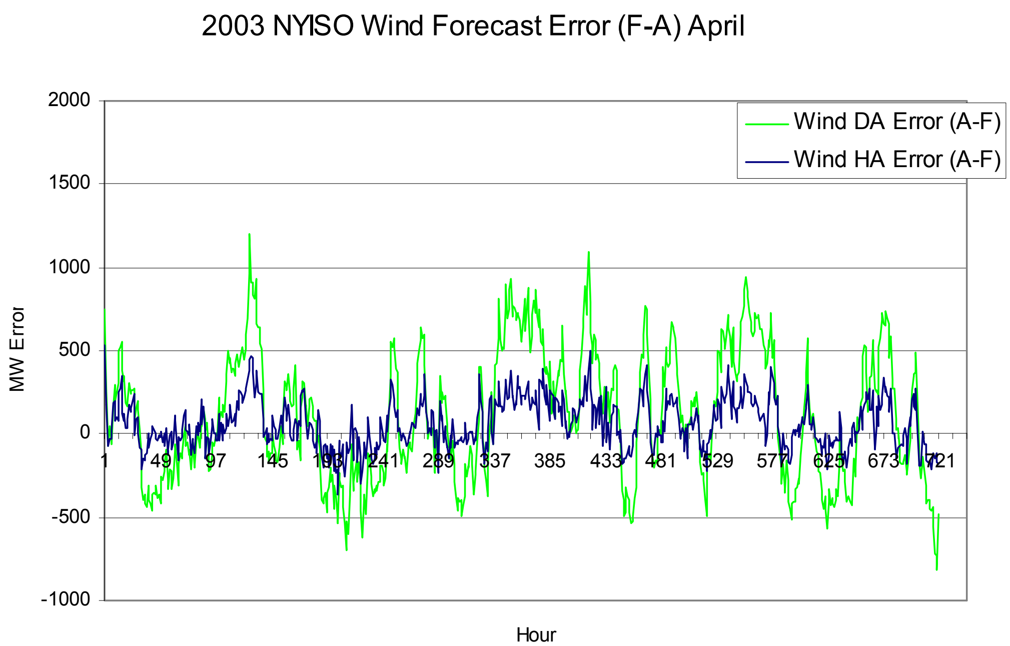
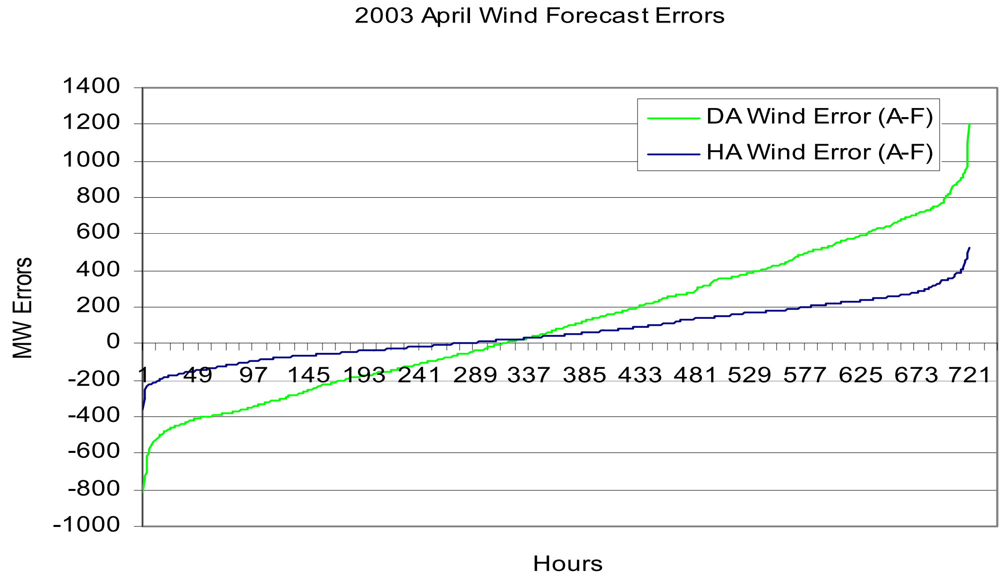
721
Hour



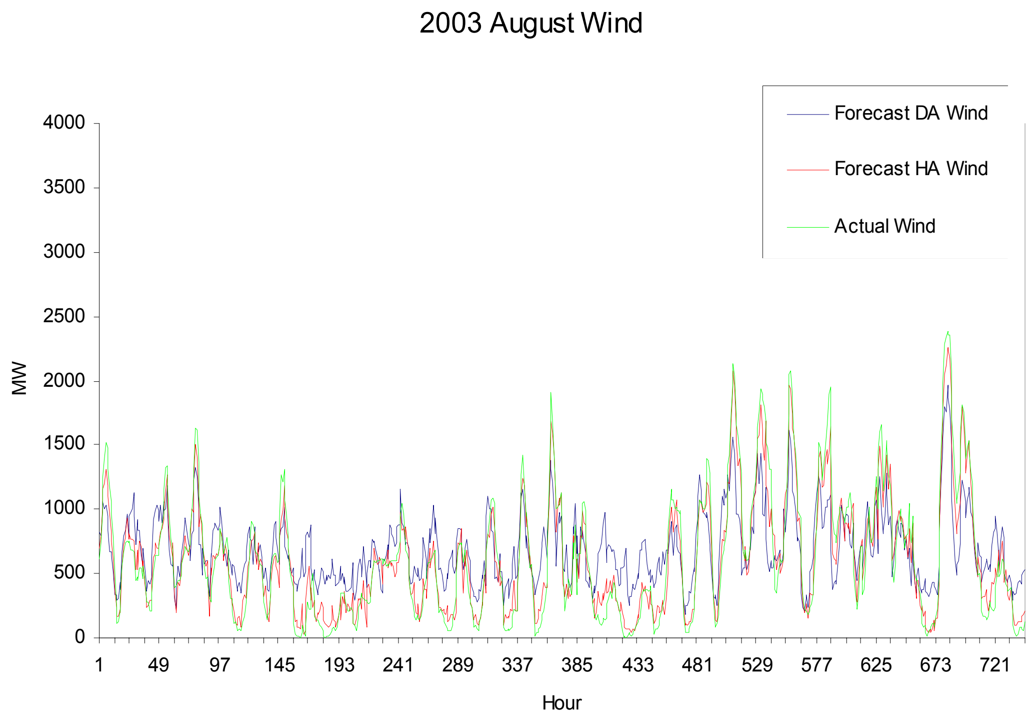
2003 Jan Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	185	182
Hours Positive	559	562
Negative Energy Error (MWh)	-44,503	-14,169
Positive Energy Error(MWh)	260,806	112,903
Net Energy Error (MWh)	216,303	98,734
Worst Negative Error (MW)	-758	-425
Worst Positive Error (MW)	1,332	565
Peak (MW)	3,160	3,160
Energy (MWh)	928,510	928,510
Negative Energy Error(% of LE)	-0.31	-0.10
Positive Energy Error(% of LE)	1.84	0.80
MAE (MW)	410	171
MAE (% of Rating Wind)	12.44	5.18

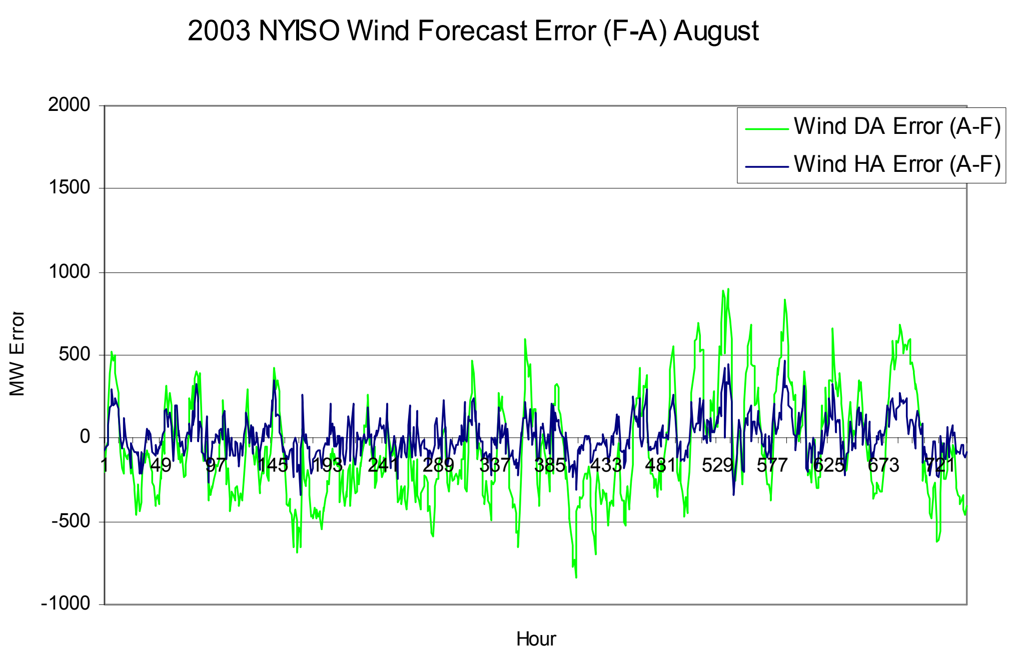

2003 April Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
0
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2003 NYISO Wind Forecast Error (F-A) April
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour



2003 Apr Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	312	274
Hours Positive	408	446
Negative Energy Error (MWh)	-78,023	-22,716
Positive Energy Error(MWh)	156,910	67,360
Net Energy Error (MWh)	78,887	44,644
Worst Negative Error (MW)	-814	-363
Worst Positive Error (MW)	1,199	529
Peak (MW)	3,067	3,067
Energy (MWh)	740,013	740,013
Negative Energy Error(% of LE)	-0.66	-0.19
Positive Energy Error(% of LE)	1.33	0.57
MAE (MW)	326	125
MAE (% of Rating Wind)	9.89	3.79


2003 August Wind
Forecast DA Wind
Forecast HA Wind
Actual Wind
MW
4000
3500
3000
2500
2000
1500
1000
500
0
1
49
97
145
193
241
289
337
385
433
481
529
577
625
673
721
Hour


2003 NYISO Wind Forecast Error (F-A) August
Wind DA Error (A-F)
Wind HA Error (A-F)
MW Error
2000
1500
1000
500
0
-500
-1000
1
49
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145
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337
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481
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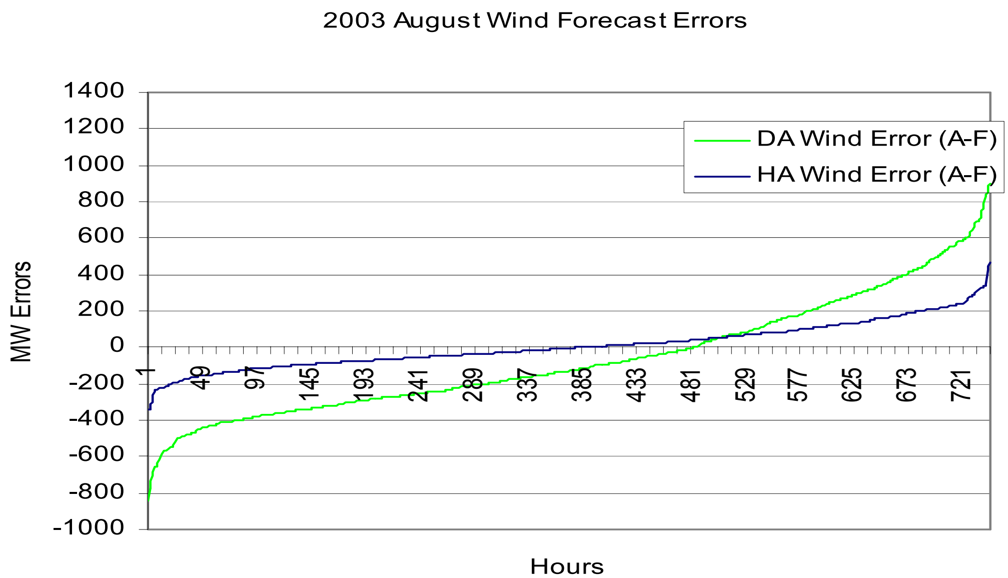
Hour



2003 Aug Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	482	383
Hours Positive	262	361
Negative Energy Error (MWh)	-123,654	-32,262
Positive Energy Error(MWh)	77,439	39,372
Net Energy Error (MWh)	-46,215	7,110
Worst Negative Error (MW)	-842	-338
Worst Positive Error (MW)	896	469
Peak (MW)	2,388	2,388
Energy (MWh)	466,272	466,272
Negative Energy Error(% of LE)	-0.79	-0.21
Positive Energy Error(% of LE)	0.50	0.25
MAE (MW)	270	96
MAE (% of Rating Wind)	8.19	2.92

Appendix C

C.1 Hourly Variability Statistics by Month

This section shows statistics for hourly change by state, superzone and zone K, for 11 months.

Delta (1Hr) State 2001 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.60	-0.58	-0.02
Standard Error	31.48	5.53	33.26
Median	-78.00	-1.50	-46.20
Mode	-95.00	-173.00	-46.20
Standard Deviation	858.07	150.83	906.51
Sample Variance	736,284.44	22,750.84	821,761.45
Kurtosis	0.15	2.29	0.04
Skewness	0.44	-0.10	0.31
Range	4,075.00	1,260.10	4,560.50
Minimum	-1,787.00	-680.00	-2,101.50
Maximum	2,288.00	580.10	2,459.00
Sum	-446.00	-431.60	-14.40
Count	743.00	743.00	743.00

Delta (1Hr) Superzone (a-e) 2001 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.25	-0.48	0.74
Standard Error	10.34	4.28	11.98
Median	-39.00	-2.70	-30.20
Mode	-7.00	-30.30	-231.00
Standard Deviation	281.85	116.69	326.62
Sample Variance	79,439.43	13,617.20	106,679.45
Kurtosis	0.73	2.25	0.44
Skewness	0.72	-0.23	0.44
Range	1,452.00	894.40	1,958.70
Minimum	-581.00	-516.10	-917.00
Maximum	871.00	378.30	1,041.70
Sum	189.00	-357.30	546.30
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2001 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.36	0.00	-0.35
Standard Error	5.28	1.90	5.83
Median	-6.00	0.00	-4.00
Mode	21.00	0.00	29.00
Standard Deviation	144.04	51.83	158.89
Sample Variance	20,746.52	2,686.76	25,246.35
Kurtosis	0.07	6.91	0.08
Skewness	0.24	0.96	0.16
Range	717.00	596.00	907.90
Minimum	-318.00	-231.10	-401.00
Maximum	399.00	364.90	506.90
Sum	-264.00	-0.70	-263.30
Count	743.00	743.00	743.00

Delta (1Hr) State 2001 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.83	0.56	0.27
Standard Error	28.25	5.69	29.06
Median	-60.00	4.40	-7.30
Mode	-90.00	7.50	-3.90
Standard Deviation	757.39	152.47	779.29
Sample Variance	573646.96	23248.23	607291.41
Kurtosis	0.39	3.34	0.22
Skewness	0.23	-0.19	0.05
Range	3867.00	1554.20	4091.30
Minimum	-1778.00	-843.10	-1999.90
Maximum	2089.00	711.10	2091.40
Sum	598.00	403.90	194.10
Count	719.00	719.00	719.00

Delta (1Hr) Superzone (a-e) 2001 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.16	0.10	0.06
Standard Error	8.77	4.45	9.72
Median	-32.00	2.00	-10.10
Mode	-68.00	10.10	-78.30
Standard Deviation	235.07	119.35	260.56
Sample Variance	55256.84	14244.45	67890.52
Kurtosis	0.89	5.11	0.39
Skewness	0.45	-0.56	0.12
Range	1320.00	1170.70	1612.20
Minimum	-558.00	-740.20	-716.50
Maximum	762.00	430.50	895.70
Sum	117.00	71.40	45.60
Count	719.00	719.00	719.00

Delta (1Hr) Zone K 2001 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.10	0.45	-0.35
Standard Error	4.52	2.60	5.26
Median	1.00	0.00	8.60
Mode	-21.00	0.00	2.00
Standard Deviation	121.08	69.80	141.03
Sample Variance	14660.87	4872.68	19888.23
Kurtosis	0.05	4.79	0.71
Skewness	-0.26	0.50	-0.54
Range	584.00	661.70	982.20
Minimum	-309.00	-299.70	-605.00
Maximum	275.00	362.00	377.20
Sum	71.00	323.90	-252.90
Count	719.00	719.00	719.00

Delta (1Hr) State 2001 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	3.31	0.72	2.59
Standard Error	35.89	6.56	38.30
Median	4.00	9.90	2.20
Mode	-1712.00	-4.90	-406.10
Standard Deviation	962.31	175.99	1026.85
Sample Variance	926034.00	30971.49	1054424.55
Kurtosis	-0.41	4.25	-0.61
Skewness	0.12	-0.83	0.06
Range	4685.00	1548.60	5023.50
Minimum	-2260.00	-925.60	-2522.30
Maximum	2425.00	623.00	2501.20
Sum	2382.00	519.20	1862.80
Count	719.00	719.00	719.00

Delta (1Hr) Superzone (a-e) 2001 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.21	0.13	-0.34
Standard Error	10.18	5.39	12.30
Median	-7.00	2.70	-13.40
Mode	47.00	0.00	28.80
Standard Deviation	277.50	146.87	335.23
Sample Variance	77004.15	21571.74	112382.45
Kurtosis	-0.24	5.50	-0.44
Skewness	-0.01	-0.70	-0.01
Range	1418.00	1350.30	1794.00
Minimum	-712.00	-764.60	-862.40
Maximum	706.00	585.70	931.60
Sum	-159.00	95.70	-254.70
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2001 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	1.15	0.55	0.60
Standard Error	6.65	2.64	7.51
Median	0.00	0.00	9.90
Mode	-59.00	0.00	61.00
Standard Deviation	181.31	71.91	204.57
Sample Variance	32874.37	5171.60	41850.24
Kurtosis	-0.40	10.03	-0.39
Skewness	-0.06	-0.63	-0.09
Range	951.00	828.60	1173.90
Minimum	-496.00	-441.40	-554.80
Maximum	455.00	387.20	619.10
Sum	858.00	410.80	447.20
Count	743.00	743.00	743.00

Delta (1Hr) State 2001 Oct	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	2.96	1.09	1.88
Standard Error	30.55	7.40	32.97
Median	-19.00	0.70	58.10
Mode	78.00	122.70	237.10
Standard Deviation	832.76	201.82	898.81
Sample Variance	693493.85	40729.46	807861.32
Kurtosis	0.38	2.84	0.22
Skewness	0.30	-0.27	0.10
Range	4095.00	1731.90	4678.20
Minimum	-1747.00	-926.00	-2128.10
Maximum	2348.00	805.90	2550.10
Sum	2202.00	808.10	1393.90
Count	743.00	743.00	743.00

Delta (1Hr) Superzone (a-e) 2001 Oct	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	1.02	1.31	-0.29
Standard Error	9.93	5.99	12.17
Median	-17.00	-0.10	7.40
Mode	-57.00	-9.10	-41.20
Standard Deviation	270.69	163.31	331.60
Sample Variance	73273.53	26669.34	109961.46
Kurtosis	1.16	3.84	0.43
Skewness	0.60	-0.46	0.11
Range	1442.00	1398.50	1930.30
Minimum	-580.00	-843.30	-863.00
Maximum	862.00	555.20	1067.30
Sum	761.00	976.90	-215.90
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2001 Oct	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.37	-0.29	0.66
Standard Error	4.96	1.96	5.68
Median	10.00	0.00	9.60
Mode	16.00	0.00	-7.10
Standard Deviation	135.08	53.46	154.94
Sample Variance	18245.34	2858.50	24005.61
Kurtosis	-0.13	3.04	-0.16
Skewness	-0.17	0.08	-0.15
Range	696.00	454.50	862.10
Minimum	-343.00	-241.50	-401.20
Maximum	353.00	213.00	460.90
Sum	275.00	-213.00	488.00
Count	743.00	743.00	743.00

Delta (1Hr) State 2002 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.94	-0.16	-0.78
Standard Error	31.77	6.64	34.28
Median	-67.00	4.20	-30.20
Mode	-432.00	-260.80	-922.30
Standard Deviation	865.95	181.06	934.28
Sample Variance	749,877.66	32,781.46	872,887.05
Kurtosis	0.15	0.62	0.01
Skewness	0.41	0.08	0.25
Range	4,116.00	1,208.10	4,739.30
Minimum	-1,797.00	-597.40	-2,163.80
Maximum	2,319.00	610.70	2,575.50
Sum	-698.00	-115.90	-582.10
Count	743.00	743.00	743.00

Delta (1Hr) Superzone (a-e) 2002 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.08	-0.03	-0.05
Standard Error	10.47	4.82	12.36
Median	-29.00	-1.40	-26.50
Mode	-26.00	-13.40	-86.30
Standard Deviation	285.47	131.40	336.81
Sample Variance	81,491.09	17,266.49	113,437.90
Kurtosis	0.78	0.94	0.44
Skewness	0.69	0.10	0.36
Range	1,486.00	965.90	2,094.30
Minimum	-588.00	-437.00	-919.40
Maximum	898.00	528.90	1,174.90
Sum	-61.00	-21.10	-39.90
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2002 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.42	-0.03	-0.39
Standard Error	5.37	2.55	6.51
Median	-6.00	-0.30	-1.40
Mode	26.00	0.00	-10.00
Standard Deviation	146.45	69.52	177.56
Sample Variance	21,447.90	4,832.55	31,526.02
Kurtosis	0.08	5.25	-0.20
Skewness	0.27	0.83	-0.01
Range	765.00	750.30	946.70
Minimum	-327.00	-304.80	-470.60
Maximum	438.00	445.50	476.10
Sum	-309.00	-18.90	-290.10
Count	743.00	743.00	743.00

Delta (1Hr) State 2002 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	3.03	2.73	0.30
Standard Error	29.27	6.01	30.58
Median	-22.00	1.30	28.90
Mode	155.00	8.50	40.50
Standard Deviation	784.74	161.12	820.10
Sample Variance	615,811.83	25,960.96	672,571.31
Kurtosis	0.26	1.94	0.17
Skewness	0.14	0.29	0.06
Range	4,171.00	1,305.70	4,453.30
Minimum	-2,002.00	-621.90	-2,136.30
Maximum	2,169.00	683.80	2,317.00
Sum	2,181.00	1,962.70	218.30
Count	719.00	719.00	719.00

Delta (1Hr) Superzone (a-e) 2002 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	1.18	1.86	-0.67
Standard Error	9.25	4.55	10.45
Median	-23.00	0.50	-1.60
Mode	59.00	-23.60	-185.00
Standard Deviation	247.96	122.12	280.34
Sample Variance	61,484.11	14,912.64	78,587.99
Kurtosis	0.68	3.14	0.23
Skewness	0.32	0.37	0.06
Range	1,358.00	1,037.40	1,646.10
Minimum	-573.00	-469.90	-776.50
Maximum	785.00	567.50	869.60
Sum	852.00	1,333.80	-481.80
Count	719.00	719.00	719.00

Delta (1Hr) Zone K 2002 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.34	0.81	-0.46
Standard Error	4.85	2.70	5.74
Median	2.00	0.00	9.00
Mode	-13.00	0.00	12.00
Standard Deviation	130.17	72.27	154.03
Sample Variance	16,944.72	5,222.48	23,725.19
Kurtosis	0.12	7.94	0.88
Skewness	-0.30	0.22	-0.32
Range	705.00	894.00	1,090.70
Minimum	-373.00	-443.90	-646.40
Maximum	332.00	450.10	444.30
Sum	248.00	580.40	-332.40
Count	719.00	719.00	719.00

Delta (1Hr) State 2002 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-6.28	-0.87	-5.41
Standard Error	35.71	6.50	38.25
Median	-21.00	10.00	-17.90
Mode	-809.00	-15.00	-970.40
Standard Deviation	957.60	174.31	1,025.56
Sample Variance	916,990.34	30,385.16	1,051,766.77
Kurtosis	-0.49	2.93	-0.60
Skewness	0.14	-0.62	0.07
Range	4,498.00	1,394.40	4,780.50
Minimum	-2,260.00	-801.30	-2,437.00
Maximum	2,238.00	593.10	2,343.50
Sum	-4,516.00	-626.20	-3,889.80
Count	719.00	719.00	719.00

Delta (1Hr) Superzone (a-e) 2002 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-1.14	-0.06	-1.08
Standard Error	10.37	5.21	12.56
Median	-13.00	3.00	-6.20
Mode	-29.00	0.00	-124.00
Standard Deviation	282.78	141.92	342.30
Sample Variance	79,965.34	20,142.03	117,171.47
Kurtosis	-0.38	4.24	-0.58
Skewness	-0.02	-0.71	0.01
Range	1,333.00	1,273.70	1,656.70
Minimum	-680.00	-727.00	-804.70
Maximum	653.00	546.70	852.00
Sum	-847.00	-41.20	-805.80
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2002 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-1.31	0.27	-1.58
Standard Error	6.77	2.16	7.37
Median	0.00	0.00	3.30
Mode	9.00	0.00	170.10
Standard Deviation	184.47	58.78	200.78
Sample Variance	34,027.75	3,455.60	40,313.75
Kurtosis	-0.38	8.47	-0.14
Skewness	0.00	0.62	-0.10
Range	934.00	804.10	1,264.70
Minimum	-504.00	-372.60	-663.30
Maximum	430.00	431.50	601.40
Sum	-977.00	197.10	-1,174.10
Count	743.00	743.00	743.00

Delta (1Hr) State 2002 Oct	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	1.46	-1.93	3.39
Standard Error	30.73	6.32	32.69
Median	-33.00	-2.80	52.10
Mode	-139.00	-149.50	-207.30
Standard Deviation	837.58	172.21	890.94
Sample Variance	701,536.16	29,656.49	793,765.97
Kurtosis	0.38	2.68	0.18
Skewness	0.30	0.04	0.10
Range	4,173.00	1,533.00	4,697.00
Minimum	-1,870.00	-668.90	-2,231.00
Maximum	2,303.00	864.10	2,466.00
Sum	1,083.00	-1,436.00	2,519.00
Count	743.00	743.00	743.00

Delta (1Hr) Superzone (a-e) 2002 Oct	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.66	-1.04	1.70
Standard Error	9.88	4.74	11.43
Median	-23.00	-0.10	3.10
Mode	64.00	-3.20	-94.70
Standard Deviation	269.24	129.16	311.66
Sample Variance	72,488.86	16,682.97	97,132.79
Kurtosis	1.22	4.55	0.50
Skewness	0.64	0.27	0.10
Range	1,529.00	1,267.90	1,979.20
Minimum	-574.00	-619.00	-951.00
Maximum	955.00	648.90	1,028.20
Sum	490.00	-775.90	1,265.90
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2002 Oct	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.22	-0.58	0.80
Standard Error	5.17	2.35	5.94
Median	3.00	-0.70	15.10
Mode	-13.00	0.00	51.00
Standard Deviation	140.85	64.17	161.97
Sample Variance	19,838.38	4,117.42	26,234.18
Kurtosis	-0.14	7.30	0.36
Skewness	-0.13	0.53	-0.32
Range	674.00	778.20	1,147.60
Minimum	-356.00	-376.90	-685.30
Maximum	318.00	401.30	462.30
Sum	162.00	-429.90	591.90
Count	743.00	743.00	743.00

Delta (1Hr) State 2003 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	2.09	-1.09	3.19
Standard Error	30.94	6.02	33.00
Median	-73.00	-2.00	-7.40
Mode	548.00	-78.00	-1,662.70
Standard Deviation	843.35	164.03	899.61
Sample Variance	711,245.00	26,905.42	809,292.38
Kurtosis	0.03	1.49	-0.15
Skewness	0.37	0.19	0.21
Range	3,978.00	1,282.00	4,539.40
Minimum	-1,735.00	-512.90	-2,007.30
Maximum	2,243.00	769.10	2,532.10
Sum	1,554.00	-813.40	2,367.40
Count	743.00	743.00	743.00

Delta (1Hr) Superzone (a-e) 2003 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.97	-0.81	1.77
Standard Error	10.14	4.50	11.98
Median	-35.00	1.00	-10.10
Mode	-19.00	91.90	57.00
Standard Deviation	276.26	122.59	326.59
Sample Variance	76,320.60	15,029.21	106,659.10
Kurtosis	0.64	2.74	0.05
Skewness	0.62	0.06	0.24
Range	1,427.00	1,162.30	1,869.80
Minimum	-576.00	-537.20	-829.20
Maximum	851.00	625.10	1,040.60
Sum	718.00	-599.10	1,317.10
Count	743.00	743.00	743.00

Delta (1Hr) Zone K 2003 Jan	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.11	-0.04	0.15
Standard Error	5.34	2.19	6.07
Median	-6.00	0.00	2.00
Mode	41.00	0.00	-42.00
Standard Deviation	145.49	59.70	165.38
Sample Variance	21,167.29	3,563.97	27,349.09
Kurtosis	-0.12	2.63	-0.02
Skewness	0.15	0.45	-0.01
Range	754.00	481.10	1,055.60
Minimum	-352.00	-221.50	-521.10
Maximum	402.00	259.60	534.50
Sum	84.00	-28.70	112.70
Count	743.00	743.00	743.00

Delta (1Hr) State 2003 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.38	-1.85	1.47
Standard Error	27.78	6.15	29.07
Median	-38.00	0.50	27.70
Mode	-102.00	-79.00	292.00
Standard Deviation	744.83	164.96	779.51
Sample Variance	554,774.63	27,212.98	607,628.40
Kurtosis	0.26	4.17	0.14
Skewness	0.14	-0.18	0.01
Range	3,790.00	1,763.00	4,369.10
Minimum	-1,730.00	-1,004.70	-2,171.10
Maximum	2,060.00	758.30	2,198.00
Sum	-272.00	-1,327.70	1,055.70
Count	719.00	719.00	719.00

Delta (1Hr) Superzone (a-e) 2003 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.56	-1.12	0.56
Standard Error	8.57	4.61	9.81
Median	-17.00	0.20	8.00
Mode	-42.00	0.00	62.80
Standard Deviation	229.80	123.48	263.14
Sample Variance	52,809.54	15,247.54	69,240.81
Kurtosis	0.65	4.28	0.19
Skewness	0.30	-0.04	0.06
Range	1,338.00	1,192.60	1,503.20
Minimum	-609.00	-571.40	-698.20
Maximum	729.00	621.20	805.00
Sum	-401.00	-804.90	403.90
Count	719.00	719.00	719.00

Delta (1Hr) Zone K 2003 Apr	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	0.08	-0.56	0.64
Standard Error	4.65	2.97	5.66
Median	3.00	-0.40	10.60
Mode	16.00	0.00	-3.00
Standard Deviation	124.59	79.59	151.78
Sample Variance	15,521.51	6,335.03	23,035.70
Kurtosis	0.02	9.74	1.46
Skewness	-0.27	0.59	-0.57
Range	608.00	956.50	1,228.50
Minimum	-314.00	-453.00	-757.50
Maximum	294.00	503.50	471.00
Sum	61.00	-399.50	460.50
Count	719	719	719

Delta (1Hr) State 2003 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-2.15	-0.67	-1.49
Standard Error	36.61	5.21	38.77
Median	-7.00	3.00	4.70
Mode	-386.00	39.00	#N/A
Standard Deviation	998.04	141.97	1,056.71
Sample Variance	996,079.48	20,156.05	1,116,642.49
Kurtosis	6.65	2.25	5.73
Skewness	-0.66	-0.12	-0.65
Range	12,514.00	1,093.80	12,527.20
Minimum	-8,555.00	-548.30	-8,824.70
Maximum	3,959.00	545.50	3,702.50
Sum	-1,601.00	-495.90	-1,105.10
Count	743.00	743.00	743.00

Delta (1Hr) Superzone (a-e) 2003 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-1.02	-0.35	-0.67
Standard Error	10.73	3.95	12.26
Median	-4.00	0.00	-4.80
Mode	-75.00	0.00	464.20
Standard Deviation	292.48	107.70	334.31
Sample Variance	85,541.66	11,599.22	111,764.48
Kurtosis	6.71	4.09	4.99
Skewness	-0.76	0.14	-0.67
Range	3,656.00	949.40	3,900.40
Minimum	-2,498.00	-434.20	-2,706.80
Maximum	1,158.00	515.20	1,193.60
Sum	-758.00	-261.20	-496.80
Count	743.00	743.00	743.00

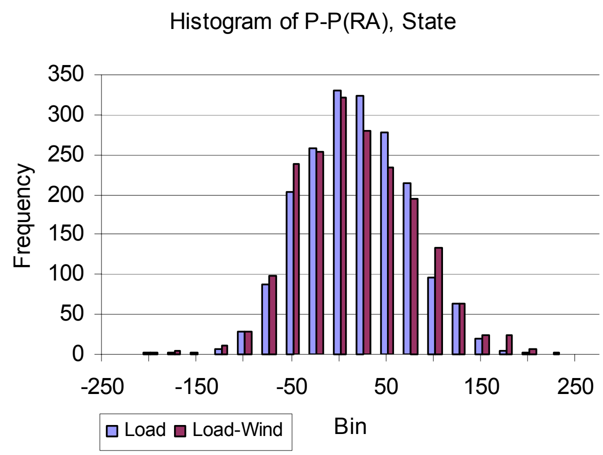
Delta (1Hr) Zone K 2003 Aug	Load(MW)	Wind (MW)	Load -Wind (MW)
Mean	-0.22	-0.33	0.11
Standard Error	6.89	2.66	7.81
Median	-2.00	-0.10	6.80
Mode	-18.00	0.00	-278.00
Standard Deviation	187.83	72.64	213.02
Sample Variance	35,281.93	5,275.97	45,376.30
Kurtosis	2.47	9.22	1.36
Skewness	-0.45	-0.02	-0.39
Range	1,848.00	939.70	1,888.90
Minimum	-1,318.00	-494.60	-1,338.20
Maximum	530.00	445.10	550.70
Sum	-164.00	-245.10	81.10
Count	743.00	743.00	743.00

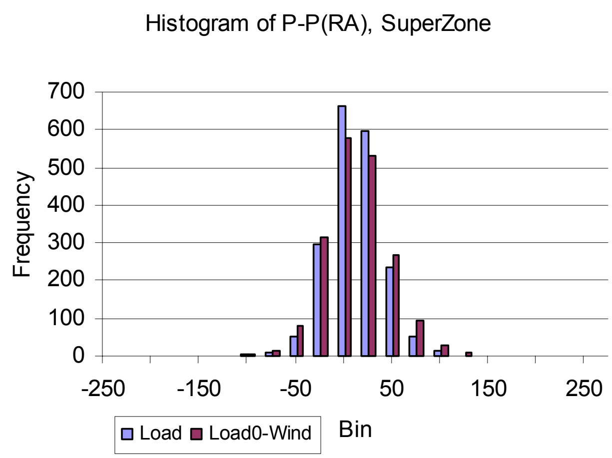
C.2 Hourly Variability Statistics for Rapid Load Rise Periods

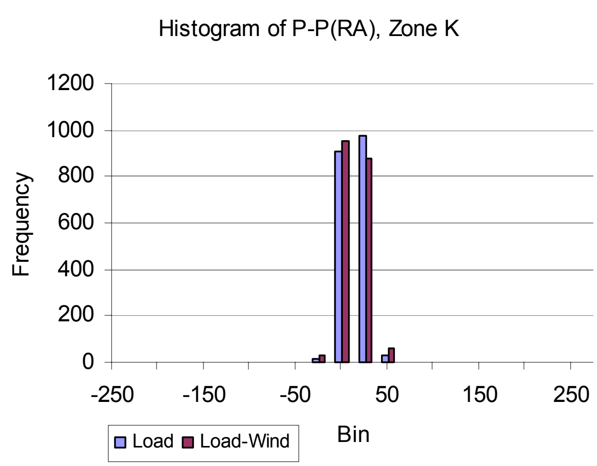
2001-2003 Jun-Sep 7AM-9AM	Load 1hr delta	Wind 1hr delta	Load-Wind 1hr delta
Mean	1,431.12	-41.42	1,472.54
Standard Error	17.96	4.28	18.43
Median	1,500.00	-41.75	1,542.55
Mode	1,797.00	-105.50	1,798.70
Standard Deviation	595.04	141.70	610.54
Sample Variance	354,076.69	20,079.63	372,763.26
Kurtosis	-0.11	1.06	-0.05
Skewness	-0.68	0.23	-0.65
Range	2,717.00	1,136.00	3,109.90
Minimum	-142.00	-517.00	-353.90
Maximum	2,575.00	619.00	2,756.00
Sum	1,571,372.00	-45,476.50	1,616,848.50
Count	1,098.00	1,098.00	1,098.00

2001-2003, Dec-Mar, 4PM-6PM	Load 1hr delta	Wind 1hr delta	Load-Wind 1hr delta
Mean	551.84	-97.86	649.69
Standard Error	17.41	4.70	18.19
Median	367.50	-86.00	501.00
Mode	987.00	-18.40	360.60
Standard Deviation	575.29	155.27	601.09
Sample Variance	330,960.84	24,109.60	361,303.24
Kurtosis	-0.82	1.00	-0.70
Skewness	0.62	-0.15	0.56
Range	2,623.00	1,314.60	3,185.40
Minimum	-536.00	-766.90	-688.70
Maximum	2,087.00	547.70	2,496.70
Sum	602,604.50	-106,857.80	709,462.30
Count	1,092.00	1,092.00	1,092.00

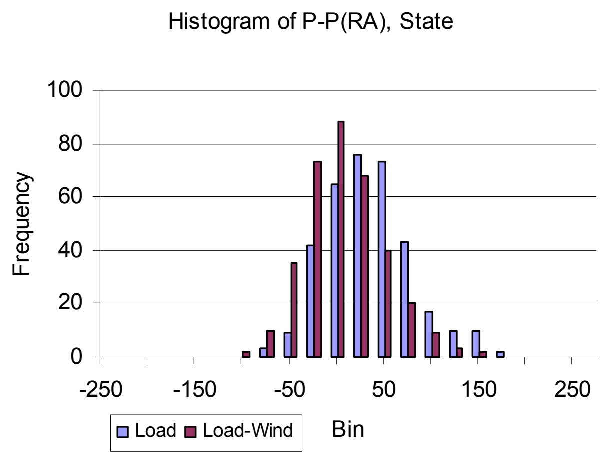
C.3 5-MinuteVarability with High Volatility Wind

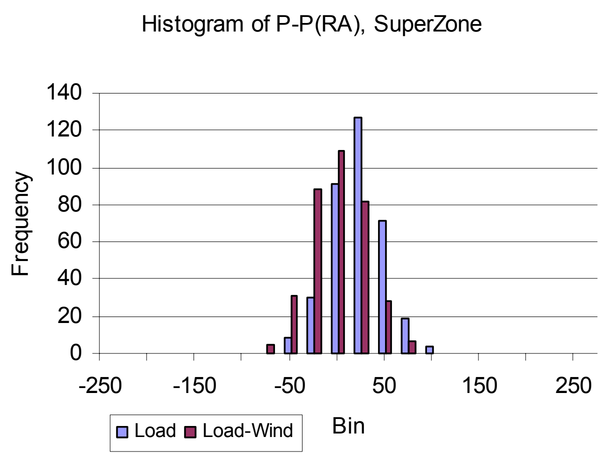


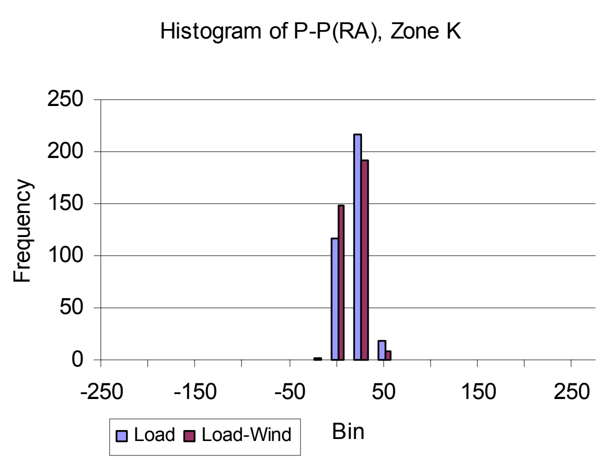




C.4 5-MinuteVarability with Large Shift Wind







C.5 Year 2003 Fast Load Variability Statistics Tables for 8 Days

1/8/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	-0.07	-0.06	-0.12	0.03	-0.03	0.02	-0.11	-0.05	-0.05	-0.31	-0.19	-0.26	-0.94
Standard Error	0.13	0.05	0.13	0.07	0.10	0.10	0.08	0.03	0.07	0.15	0.07	0.22	0.42
Median	-0.32	-0.06	-0.26	0.02	-0.06	-0.16	0.00	-0.16	-0.26	-1.26	-0.66	-1.60	-3.82
Mode	-1.62	1.76	-3.54	-0.38	-0.54	-2.52	3.46	-1.24	0.10	0.80	-2.08	5.00	3.04
Standard Deviation	15.23	5.76	15.18	8.97	12.10	11.60	9.96	3.88	8.43	18.06	8.83	25.79	50.54
Sample Variance	232.01	33.13	230.58	80.51	146.34	134.57	99.15	15.02	71.13	326.16	77.98	665.32	2554.68
Kurtosis	9.82	5.47	15.44	8.60	101.36	113.26	4.85	4.65	4.20	5.90	1.54	5.00	2.51
Skewness	-0.39	-0.26	1.53	-0.44	-6.06	-3.33	-0.23	0.46	0.46	0.12	0.38	0.53	0.67
Range	352.80	84.76	243.80	143.94	326.00	392.14	174.30	69.76	119.06	372.66	113.54	488.40	635.24
Minimum	-259.96	-47.06	-68.42	-80.44	-233.92	-224.06	-82.74	-33.20	-55.70	-263.98	-39.08	-237.40	-270.48
Maximum	92.84	37.70	175.38	63.50	92.08	168.08	91.56	36.56	63.36	108.68	74.46	251.00	364.76
Sum	-1054.44	-850.04	-1656.72	383.78	-502.16	312.70	-1597.52	-663.00	-734.18	-4392.22	-2696.86	-3679.58	-13450.66
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

1/20/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	0.19	0.09	0.20	0.08	0.08	0.21	-0.02	-0.05	0.09	0.27	0.21	0.64	1.35
Standard Error	0.11	0.04	0.11	0.11	0.07	0.08	0.10	0.05	0.25	0.19	0.13	0.21	0.40
Median	0.00	-0.02	0.48	0.00	0.00	0.30	0.00	-0.04	-0.16	-0.32	-0.30	0.54	0.14
Mode	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Deviation	13.63	5.03	13.46	12.93	7.81	9.03	12.08	5.47	29.64	22.56	15.28	25.11	47.51
Sample Variance	185.70	25.27	181.30	167.31	61.00	81.60	145.91	29.91	878.79	509.01	233.47	630.68	2257.35
Kurtosis	1.45	4.65	0.66	69.90	6.45	137.22	6.55	50.91	206.33	43.06	104.22	3.91	1.76
Skewness	-0.04	0.51	-0.21	-0.32	0.10	-5.43	-0.28	3.33	-0.11	-0.57	-2.02	0.24	0.10
Range	145.20	89.52	128.38	363.90	134.30	340.92	219.34	132.48	1117.38	554.62	494.94	351.20	609.12
Minimum	-78.82	-21.62	-74.08	-196.94	-58.72	-230.82	-106.68	-45.54	-546.90	-306.32	-267.36	-179.50	-307.68
Maximum	66.38	67.90	54.30	166.96	75.58	110.10	112.66	86.94	570.48	248.30	227.58	171.70	301.44
Sum	2716.54	1254.96	2890.92	1122.24	1210.68	2949.14	-279.86	-749.22	1241.50	3941.70	3011.82	9195.34	19310.42
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

4/1/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	-0.06	-0.03	-0.06	-0.04	-0.04	-0.02	0.01	-0.21	0.23	-0.02	-0.10	-0.22	-0.32
Standard Error	0.13	0.05	0.11	0.10	0.06	0.15	0.08	0.04	0.06	0.26	0.07	0.20	0.45
Median	-0.46	0.42	0.34	-0.18	-0.06	0.22	0.16	-0.16	-0.04	-1.04	0.06	0.18	0.80
Mode	-1.50	0.44	0.50	3.14	-0.56	-0.04	2.02	-0.32	-1.52	-4.02	4.00	1.34	-6.54
Standard Deviation	15.42	6.18	13.27	11.43	7.05	17.41	9.82	4.54	7.31	31.68	7.82	24.38	54.46
Sample Variance	237.78	38.16	176.10	130.57	49.76	303.28	96.38	20.63	53.40	1003.74	61.08	594.20	2965.69
Kurtosis	1.91	7.88	1.58	14.46	2.27	293.35	3.30	27.83	2.21	494.27	0.55	1.05	63.49
Skewness	0.20	-1.63	-0.34	0.68	0.07	-13.61	-0.41	0.02	0.45	15.52	-0.07	0.05	2.69
Range	204.92	93.90	119.06	208.20	111.14	655.62	140.34	128.24	93.26	1250.50	76.30	233.22	1571.54
Minimum	-88.82	-63.42	-62.44	-82.12	-61.84	-451.74	-84.66	-58.06	-37.16	-206.76	-43.58	-96.40	-504.20
Maximum	116.10	30.48	56.62	126.08	49.30	203.88	55.68	70.18	56.10	1043.74	32.72	136.82	1067.34
Sum	-863.74	-369.60	-850.08	-546.06	-503.18	-248.86	200.30	-3029.50	3261.80	-226.98	-1376.98	-3132.66	-4552.88
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

4/12/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	-0.23	-0.07	-0.16	0.01	-0.08	-0.14	-0.09	-0.05	-0.03	-0.22	-0.14	-0.54	-1.21
Standard Error	0.13	0.06	0.13	0.08	0.11	0.12	0.07	0.05	0.05	0.10	0.05	0.21	0.31
Median	-0.74	0.84	0.40	0.00	-0.14	-0.06	-0.08	-0.06	-0.02	-0.68	-0.60	-0.46	-2.52
Mode	-3.04	2.24	-2.90	0.00	-4.76	0.52	-0.72	-1.82	-1.02	5.70	-0.12	-1.74	-2.30
Standard Deviation	15.79	7.31	15.00	9.40	13.35	14.67	8.79	5.93	6.58	12.31	6.52	25.34	36.78
Sample Variance	249.36	53.45	225.13	88.30	178.11	215.32	77.32	35.15	43.24	151.63	42.47	642.10	1352.84
Kurtosis	2.04	9.55	0.62	8.05	403.55	384.50	3.20	4.16	2.56	1.03	0.43	35.08	2.78
Skew ness	0.35	-2.14	-0.31	0.24	14.02	-9.07	-0.12	0.54	-0.29	0.17	0.37	2.36	0.28
Range	178.60	132.58	152.74	152.42	492.16	782.46	156.22	74.80	76.34	136.58	55.52	504.12	640.56
Minimum	-69.26	-95.44	-74.04	-64.84	-108.62	-389.60	-95.02	-25.98	-44.98	-80.78	-28.38	-115.44	-239.98
Maximum	109.34	37.14	78.70	87.58	383.54	392.86	61.20	48.82	31.36	55.80	27.14	388.68	400.58
Sum	-3259.82	-1054.42	-2339.52	93.34	-1161.26	-1994.68	-1359.00	-692.28	-404.82	-3179.44	-1964.94	-7721.68	-17316.84
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

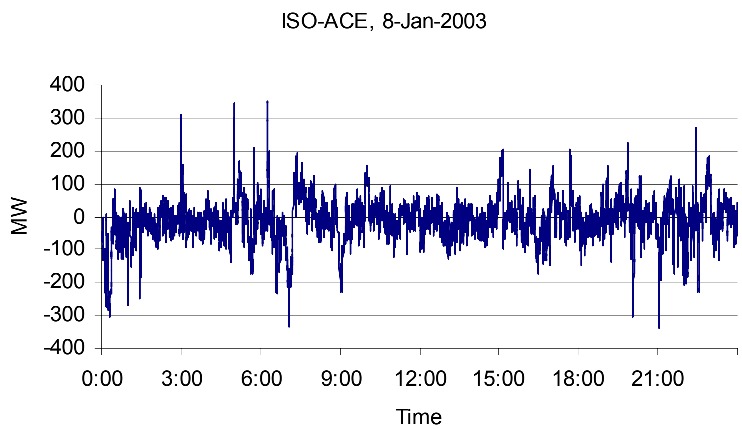
8/1/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	-0.04	-0.09	-0.16	-0.03	-0.06	-0.25	0.10	0.06	0.14	0.82	0.52	-0.39	1.01
Standard Error	0.11	0.04	0.08	0.07	0.06	0.08	0.09	0.03	0.08	0.16	0.08	0.17	0.37
Median	0.18	-0.10	-0.08	-0.06	0.04	-0.28	0.14	-0.02	-0.26	-0.58	0.12	-0.22	-0.68
Mode	1.48	-0.20	1.92	-3.08	-2.48	-2.26	-1.00	-0.86	-1.22	-2.00	3.36	-2.26	0.64
Standard Deviation	12.78	4.58	9.11	8.86	7.39	9.47	11.28	3.55	9.02	19.06	9.52	20.16	44.08
Sample Variance	163.37	20.99	83.00	78.57	54.56	89.74	127.32	12.61	81.41	363.34	90.63	406.58	1943.16
Kurtosis	1.55	3.54	0.73	6.29	2.37	55.11	138.33	2.37	526.24	28.15	2.10	0.39	0.68
Skew ness	-0.14	0.28	-0.19	-0.42	0.18	1.82	3.69	0.21	11.73	-1.02	0.22	-0.07	0.32
Range	161.28	85.72	99.10	136.86	102.90	309.06	522.00	61.10	496.88	564.92	112.50	186.58	598.80
Minimum	-83.90	-23.30	-60.88	-79.90	-44.34	-139.08	-109.40	-26.78	-45.58	-457.88	-58.64	-96.46	-231.00
Maximum	77.38	62.42	38.22	56.96	58.56	169.98	412.60	34.32	451.30	107.04	53.86	90.12	367.80
Sum	-630.18	-1347.80	-2308.16	-369.88	-879.84	-3553.40	1467.68	856.28	2066.14	11767.92	7412.08	-5535.86	14480.84
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

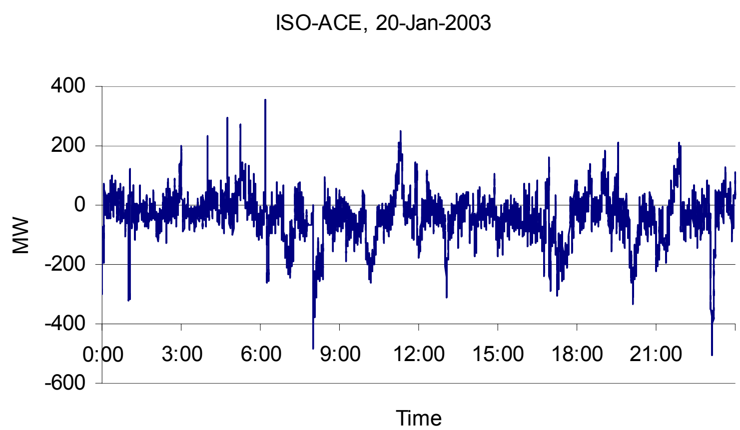
8/9/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	-0.17	-0.08	-0.17	0.00	-0.02	-0.07	0.00	0.03	0.04	-0.34	0.07	-0.44	-0.71
Standard Error	0.11	0.04	0.14	0.07	0.06	0.08	0.08	0.03	0.06	0.13	0.07	0.20	0.35
Median	-0.18	-0.08	0.22	-0.08	0.10	0.02	0.00	0.00	-0.06	-0.82	-0.40	-0.46	-2.72
Mode	-1.50	-2.24	-1.06	-2.16	-3.46	-2.94	1.82	0.50	1.44	-3.22	-4.98	2.58	-15.88
Standard Deviation	12.89	4.42	17.14	8.13	7.19	9.66	9.47	3.99	6.97	15.62	8.92	24.15	41.98
Sample Variance	166.03	19.55	293.94	66.04	51.76	93.24	89.66	15.95	48.60	244.02	79.50	583.32	1762.29
Kurtosis	9.85	0.44	7.46	9.50	1.25	14.44	6.77	1.52	2.85	3.20	4.28	3.44	0.79
Skew ness	0.19	-0.03	0.61	-0.39	-0.01	0.02	0.18	-0.03	0.25	-0.13	0.63	0.32	0.31
Range	246.22	43.20	231.30	155.10	87.30	234.68	176.12	58.04	89.22	228.56	119.98	324.54	392.68
Minimum	-117.36	-22.02	-85.66	-85.92	-36.66	-102.74	-70.64	-31.56	-38.86	-112.84	-54.64	-142.00	-170.80
Maximum	128.86	21.18	145.64	69.18	50.64	131.94	105.48	26.48	50.36	115.72	65.34	182.54	221.88
Sum	-2375.40	-1204.62	-2397.94	-43.34	-290.52	-1011.90	-21.98	478.70	555.64	-4815.70	935.94	-6311.82	-10191.12
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

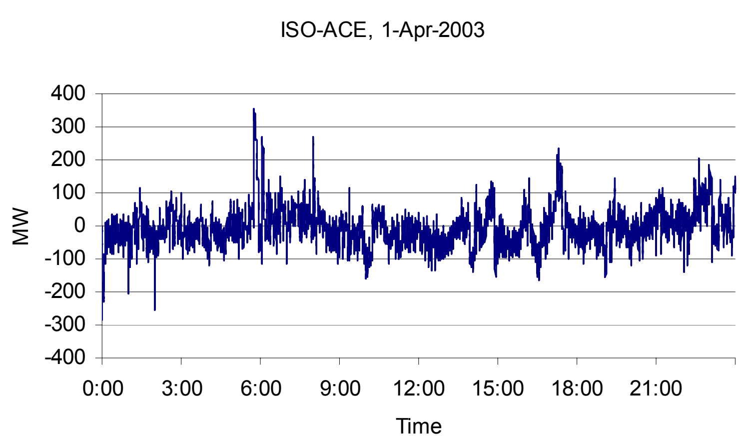
10/1/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	0.05	0.02	0.01	0.04	0.01	0.01	0.04	0.01	0.03	0.06	0.08	0.13	0.37
Standard Error	0.12	0.04	0.11	0.07	0.06	0.27	0.27	0.03	0.09	0.16	0.07	0.20	0.39
Median	-0.02	-0.04	0.86	-0.10	-0.06	-0.38	0.38	0.02	-0.16	-0.82	-0.14	-0.14	-0.76
Mode	-0.96	1.66	1.92	-2.72	2.24	-0.78	-0.44	1.68	-3.22	-5.30	2.04	3.10	-1.82
Standard Deviation	14.44	5.34	13.14	8.30	7.15	32.76	31.94	3.82	10.55	18.78	8.92	23.70	47.29
Sample Variance	208.48	28.47	172.68	68.89	51.07	1073.40	1020.11	14.58	111.36	352.61	79.62	561.57	2236.18
Kurtosis	1.77	6.16	1.44	6.13	2.75	410.34	457.41	3.90	6.23	2.83	80.36	1.11	0.98
Skew ness	0.11	-0.37	-0.48	0.27	0.18	15.84	-17.34	0.33	-0.23	0.10	-2.67	0.20	0.18
Range	177.64	82.20	107.68	150.80	116.86	1119.40	1113.50	63.12	169.68	259.16	309.84	214.78	467.20
Minimum	-83.58	-49.22	-57.22	-61.22	-53.00	-239.78	-886.78	-19.72	-106.86	-134.70	-266.46	-101.52	-274.16
Maximum	94.06	32.98	50.46	89.58	63.86	879.62	226.72	43.40	62.82	124.46	43.38	113.26	193.04
Sum	755.02	277.88	127.22	594.46	72.58	118.14	583.16	206.44	422.50	930.00	1162.16	1827.16	5249.56
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

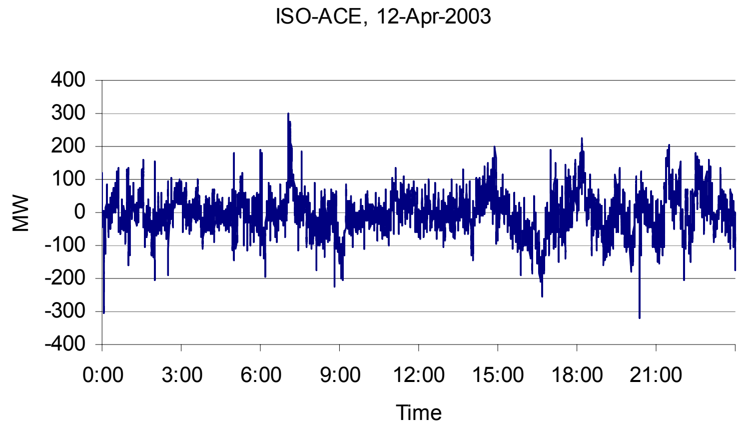
10/18/2003	zone_a	zone_b	zone_c	zone_d	zone_e	zone_f	zone_g	zone_h	zone_I	zone_j	zone_k	superzone(A-E)	state
00:05 - 23:59	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)	P-P(RA)
Mean	-0.15	0.00	0.00	0.04	0.00	0.23	-0.06	0.06	0.03	-0.01	0.05	-0.11	0.19
Standard Error	0.13	0.04	0.13	0.07	0.06	0.08	0.08	0.03	0.07	0.11	0.06	0.20	0.32
Median	0.06	0.08	1.26	0.00	0.00	0.28	-0.24	0.08	-0.02	-0.26	-0.16	0.26	-1.10
Mode	0.74	0.26	0.80	-0.86	0.36	0.06	0.70	0.56	1.14	11.30	-2.48	-0.88	-1.64
Standard Deviation	16.07	4.82	15.24	8.35	6.76	9.97	9.78	3.46	8.68	12.94	7.33	23.88	38.14
Sample Variance	258.25	23.22	232.31	69.64	45.72	99.36	95.61	11.97	75.33	167.39	53.69	570.21	1454.93
Kurtosis	5.02	784.93	0.46	21.52	10.84	138.59	24.58	28.09	6.59	2.47	0.89	1.14	1.04
Skew ness	-0.38	15.24	-0.45	-1.32	0.71	-3.05	0.34	-1.42	-0.06	0.47	0.17	-0.18	0.02
Range	273.96	330.52	141.16	199.38	169.52	442.40	375.20	106.08	165.50	181.80	81.08	297.62	412.82
Minimum	-157.72	-57.24	-87.90	-152.20	-58.56	-245.96	-171.16	-81.16	-96.98	-58.98	-43.54	-150.28	-233.84
Maximum	116.24	273.28	53.26	47.18	110.96	196.44	204.04	24.92	68.52	122.82	37.54	147.34	178.98
Sum	-2100.42	-1.00	29.08	534.50	-51.74	3240.28	-906.96	840.96	499.42	-94.80	729.04	-1589.58	2718.36
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

C.6 Year 2003 ACE for 8 Days





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0
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MW
0:00
3:00
6:00
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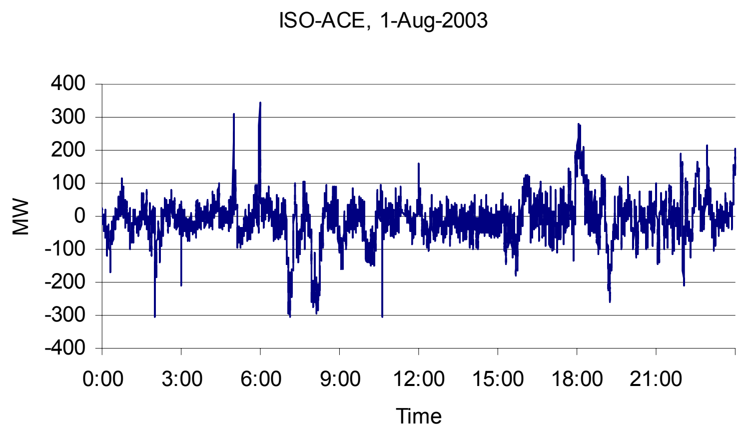
18:00
21:00
Time


ISO-ACE, 1-Aug-2003
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200
100
0
-100
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MW
0:00
3:00
6:00
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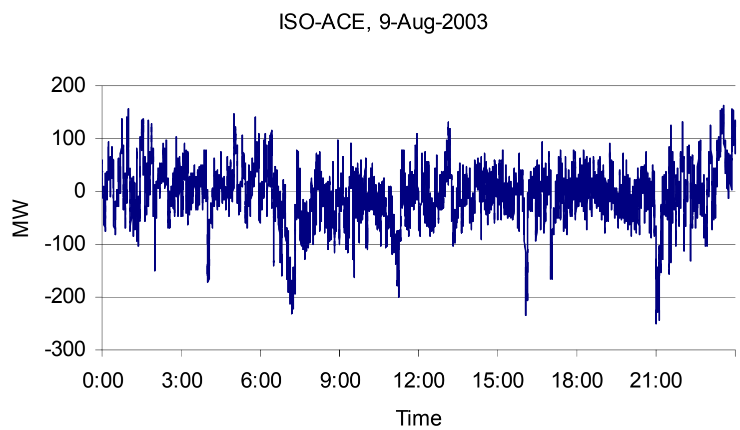
12:00
15:00
18:00
21:00
Time


ISO-ACE, 9-Aug-2003
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-100
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MW
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6:00
9:00
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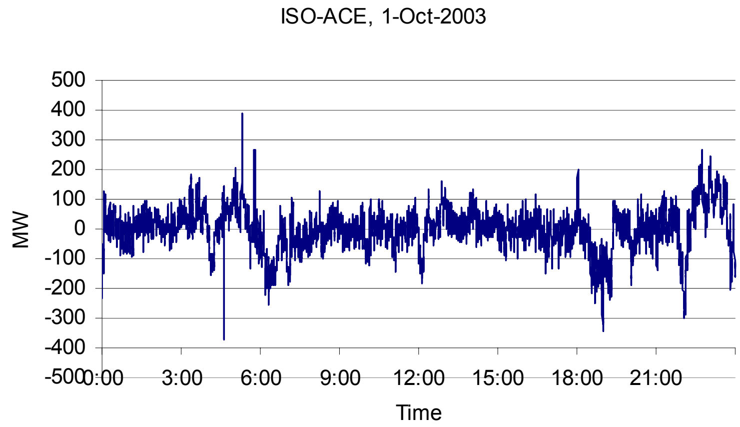
18:00
21:00
Time


ISO-ACE, 1-Oct-2003
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300
200
100
0
-100
-200
-300
-400
-500
MW
0:00
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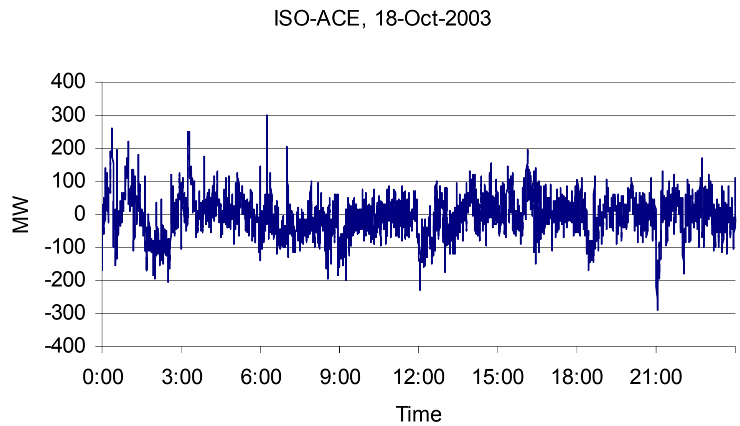
18:00
21:00
Time


ISO-ACE, 18-Oct-2003
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100
0
-100
-200
-300
-400
MW
0:00
3:00
6:00
9:00
12:00
15:00
18:00
21:00
Time

Appendix D. Wind Turbine-Generator (WTG) Models

This appendix contains a discussion of appropriate wind turbine-generator models for both steady-state and stability analyses. Significant technology-dependent differences between types of WTGs are also discussed, as well as the specific dynamic WTG models added to the databases provided by NYISO and used in the stability analysis.

D.1 WTG Technology

There are three classes of WTGs described in the "Technical Characteristics" document[i]: stall regulated, scalar controlled and vector controlled. Of these three types, only vector controlled WTGs have the inherent ability to control reactive power output from the generator, and therefore to regulate voltage. For the other types of WTGs, additional equipment, such as mechanically switched capacitors, are required to compensate the generator reactive power consumption and to meet the reactive power needs of the host grid. In applications with relatively weak systems, wind farms with these types of machines may require the addition of fast-acting solid-state reactive power equipment to meet the voltage regulation requirements.

The power factor range of a wind farm is a function of the characteristics of the component WTGs, the collector system and other equipment in the farm. From a systems perspective, the available power factor range as measured at the POI is important. In the U.S., most wind farm interconnection agreements specify a required power factor range. In many cases, the power factor range requirement is determined by the particular needs of the site (i.e., grid characteristics at the POI). The emerging consensus in the U.S. on required power factor range appears to be headed toward ± 0.95.

D.2 Steady-State WTG Models

For steady-state studies, a wind farm may be represented as a single equivalent generator connected either directly to the interconnection bus or via a transformer. The need for a transformer model depends on the type of analysis to be performed. For screening level studies, it is not necessary. For detailed system impact studies, a transformer model is recommended.

The capabilities of the entire wind farm may be represented in the equivalent generator, making the model technology-independent. It is recommended that a power factor range of +/-0.95 and voltage regulation capability be assumed for all wind farms. Depending upon the application, the power factor range may be extended, and the regulated bus may be either the terminal bus of transmission level interconnection bus. Whether the reactive power capability and voltage regulation are inherent in the WTGs themselves or provided by auxiliary equipment (e.g., mechanically switched capacitors or static var compensator) is irrelevant for a strictly steady-state study. However, if the power flow developed for the steady-state analysis will also be used in a stability analysis, any auxiliary equipment that provides either reactive power range or voltage regulation capability should be modeled separately.

The recommendation that wind farms be represented as a single equivalent does not mean that details within the farm are unimportant to the wind farm design. However, it is incumbent on the wind farm designer, and not the host utility or NYISO, to ensure that the wind farm is designed to satisfy power factor and voltage requirements at the point of interconnection. Thus, detailed representation of collection feeders and individual wind turbines is neither required nor appropriate for power system studies.

The equivalent generator may be represented by the following generator data:

Base MVA = Maximum Power Output of Wind Farm

Pmax = Maximum Power Output of Wind Farm

Qmax/Qmin = +/- 0.95 power factor

Voltage Regulation = Either Terminal or Point of Interconnection Bus

If data is not available for the interconnection transformer, the following data represents reasonable assumptions:

Rated MVA = 1.2 * Maximum Power Output of Wind Farm

Base MVA = Maximum Power Output of Wind Farm

Reactance = 0.10pu on Base MVA

X/R Ratio = 50

Low-side Voltage Level = 34.5kV

D.3 Dynamic WTG Models

For a stability analysis of the impact of wind generation, standard system fault disturbances can be examined, as for any other type of generation. The transient and dynamic stability of wind farms is generally superior to conventional generation. In the case of vector controlled type WTGs, it is essentially impossible for the machines to exhibit first swing or transient instability. In this regard, transient stability analysis of wind farms can be quite uninteresting. However, incremental power transfer resulting from added generation (of any type) can create stability problems, and must be examined. One important consideration for stability analysis of wind farms is to examine the vulnerability of the farm to tripping due to low voltages. The LVRT characteristics of the WTGs in a farm will tend to dominate performance evaluations, and should always be confirmed with the developer and/or equipment supplier before performing system studies.

For stability studies, a wind farm may also be represented as a single equivalent WTG connected to the interconnection bus via a transformer. However, any auxiliary equipment that provides either reactive power range or voltage regulation capability should be modeled separately in the power flow used to set initial conditions for the stability analysis. Then appropriate dynamic models (e.g., mechanically switched capacitor or static var compensator) can be associated with that equipment.

The block diagrams and associated data for dynamic WTG models used in the stability analysis for this study are shown in the following sections. All are PSLF models.

D.3.1 Vector Controlled WTG

Block diagrams for the generator, excitation and turbine models appropriate for representing a vector controlled WTG, such as GE's 1.5MW machine, are shown in Figure D-1, Figure D-2, and Figure D-3, respectively. The data associated with these models, including parameter identifier, value and description, are shown in Table D-1, Table D-2, and Table D-3, respectively.

Note that there is more data shown in Table D-1 than can be observed in the associated figure (Figure D-1). The parameter X" shown in the figure is equivalent to the parameter lpp in the table. The remaining data shown in the table is related to voltage trip thresholds and timers, and is not shown in the figure.

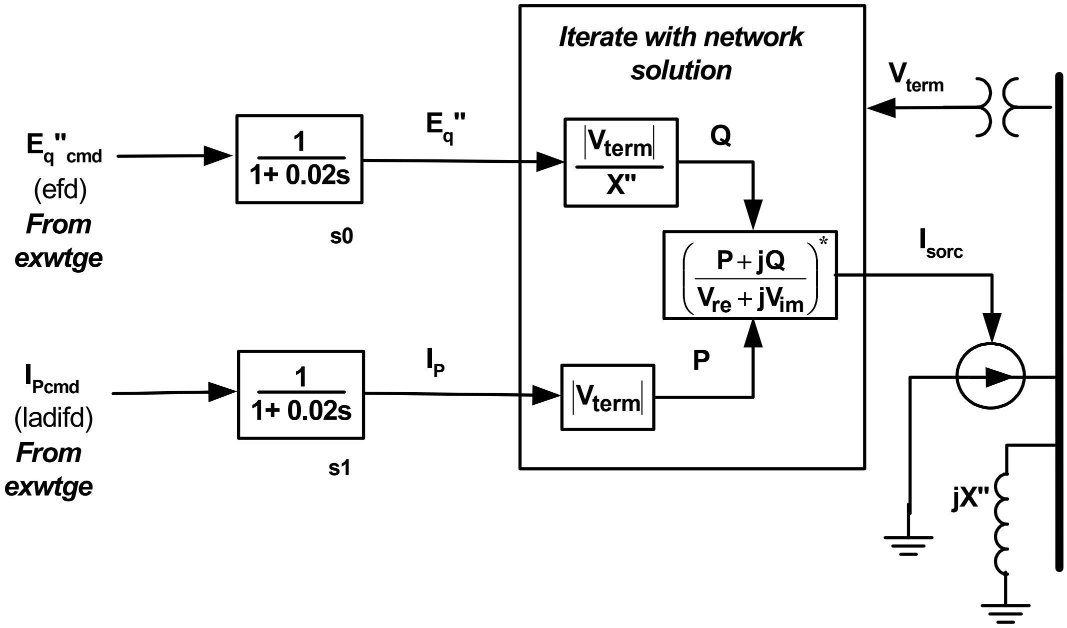


Figure D-1. GE Wind Generator/Converter Model (gewtg) Block Diagram.

Table D-1. GE Wind Generator/Converter Model (gewtg) Data.

Parameter	Value	Description
lpp	0.55	Generator subtransient reactance, pu
dVtrp1	-0.15	Delta voltage trip level 1, pu
dVtrp2	-0.25	Delta voltage trip level 2, pu
dVtrp3	-0.7	Delta voltage trip level 3, pu
dVtrp4	0.1	Delta voltage trip level 4, pu
dVtrp5	0.15	Delta voltage trip level 5, pu
dVtrp6	0.3	Delta voltage trip level 6, pu
dTtrp1	10.	Voltage trip time 1, sec
dTtrp2	1.	Voltage trip time 2, sec
dTtrp3	0.1	Voltage trip time 3, sec
dTtrp4	1.	Voltage trip time 4, sec
dTtrp5	0.1	Voltage trip time 5, sec
dTtrp6	0.02	Voltage trip time 6, sec

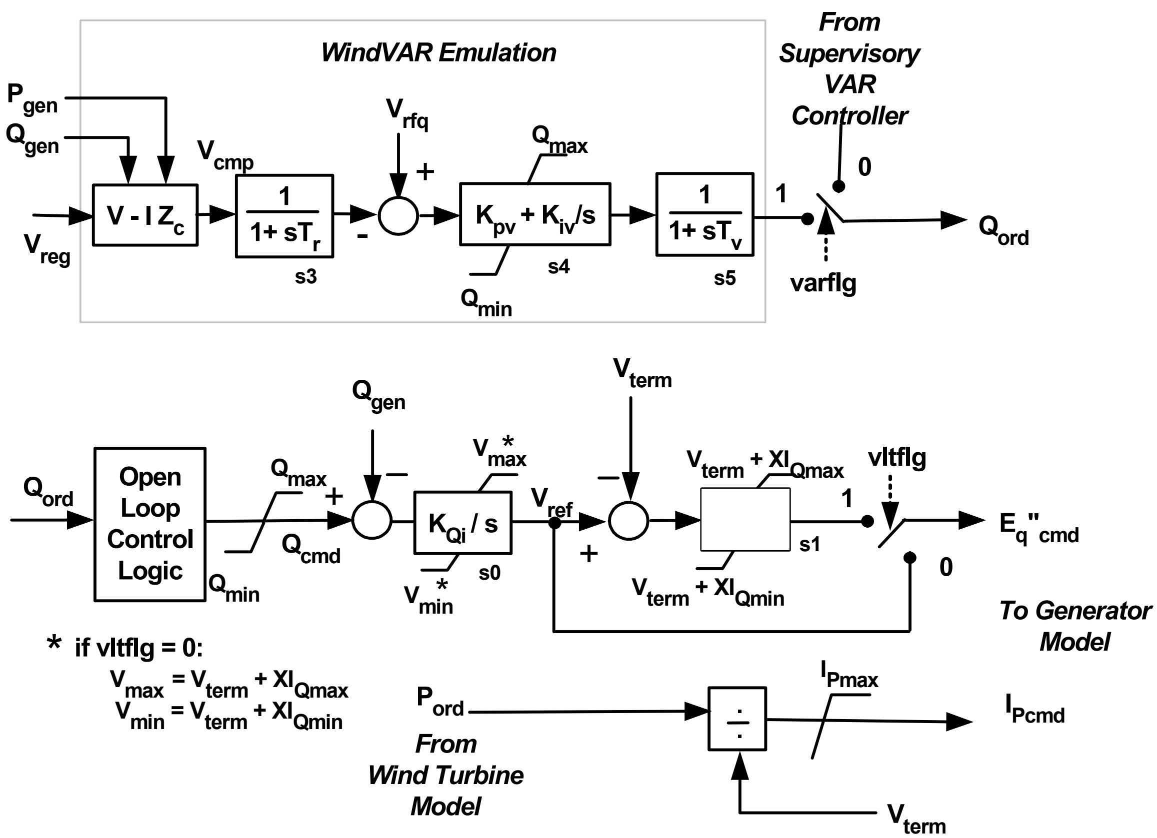


Figure D-2. Excitation (Converter) for GE WTG Model (exwtge) Block Diagram.

Table D-2. Excitation (Converter) for GE WTG Model (exwtge) Data.

Parameter	Value	Description
varflg	1	0 = Qord from vref; 1 = Qord from WindVar
vltflg	1	0 = open loop V control; 1 = closed loop V control
Kqi	0.05	Q control integral gain
Kvi	20.	V control integral gain
Tvz	-	Not used
Vmax	1.1	Maximum voltage at regulated bus, pu
Vmin	0.9	Minimum voltage at regulated bus, pu
Qmax	0.436	Maximum Q command, pu
Qmin	-0.436	Minimum Q command, pu
XIQmax	0.30	(+Vterm) = maximum Eq” (flux) command, pu
XIQmin	-0.35	(+Vterm) = minimum Eq” (flux) command, pu

Parameter	**Value**	**Description**
Tr	0.05	WindVar voltage measurement lag time constant, sec
Tv	0.15	WindVar regulator lag time constant, sec
Kpv	20.	WindVar regulator proportional gain
Kiv	2.	WindVar regulator integral gain
Vl1	0	First low voltage limit, pu
Vh1	0	First high voltage limit, pu
Tl1	0	First low voltage time, sec
Tl2	0	Second low voltage time, sec
Th1	0	First high voltage time, sec
Th2	0	Second high voltage time, sec
Ql1	0	First low voltage Q command, pu
Ql2	0	Second low voltage Q command, pu
Ql3	0	Third low voltage Q command, pu
Qh1	0	First high voltage Q command, pu
Qh2	0	Second high voltage Q command, pu
Qh3	0	Third high voltage Q command, pu
Vhyst	0.05	Voltage hysteresis, pu
pfflag	0	1 = regulate power factor angle; 0 = regulate Q

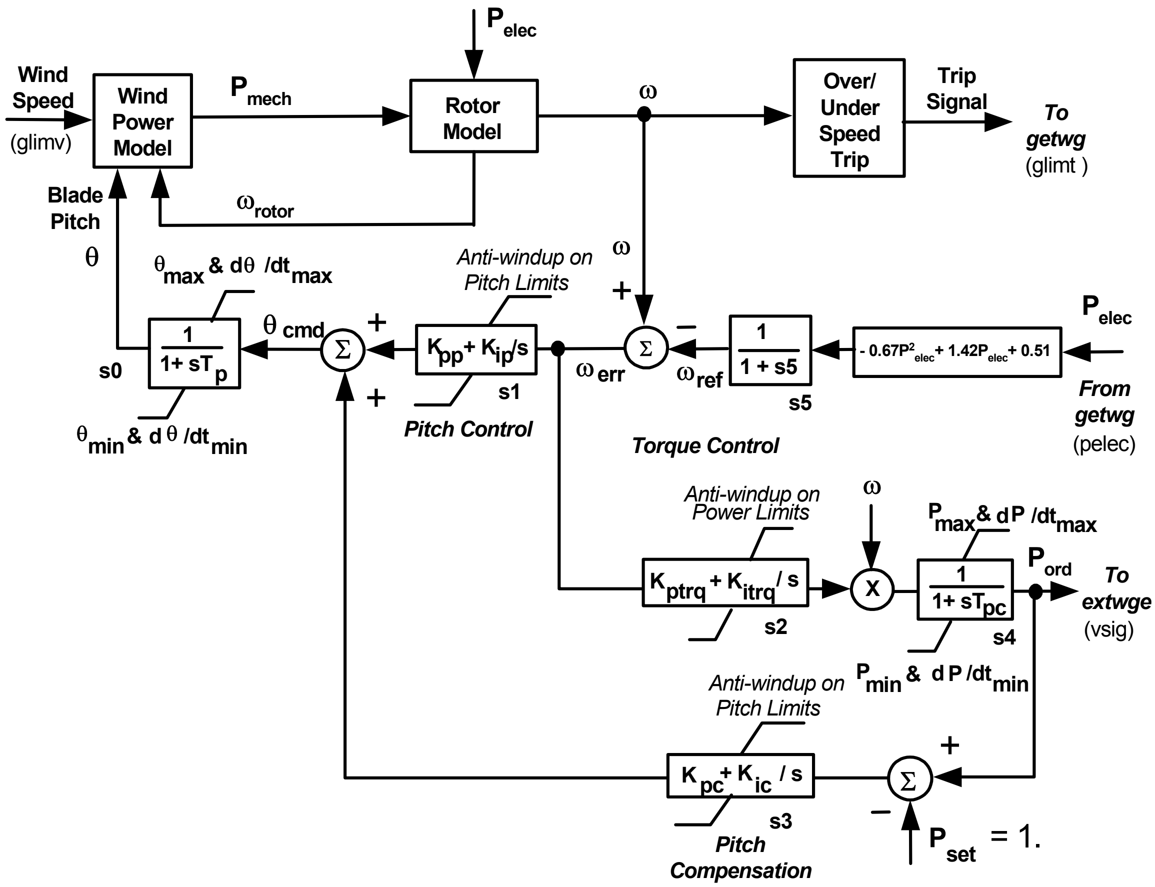


Figure D-3. Wind Turbine Model (wndtge) Block Diagram.

Table D-3. Wind Turbine Model (wndtge) Data.

Parameter	Value	Description
usize	1.5	WTG unit size (1.5 or 3.6)
spdw1	14	Initial wind speed, m/s
Tp	0.2	Pitch control constant, sec.
Tpc	0.05	Power control time constant, sec
Kpp	150.	Pitch control proportional gain
Kip	25.	Pitch control integral gain
Kptrq	3.	Torque control proportional gain
Kitrq	0.6	Torque control integral gain
Kpc	3.	Pitch compensation proportional gain
Kic	30.	Pitch compensation integral gain
PImax	27.	Maximum blade pitch

Parameter	Value	Description
PImin	0	Minimum blade pitch
PIrat	10.	Blade pitch rate limit
PWmax	1.	Maximum power order
PWmin	0	Minimum power order
PWrat	0.45	Power order rate limit
H	4.94	Rotor inertia constant

D.3.2 Stall Regulated WTG

Block diagrams for the generator and turbine models appropriate for representing WTG induction (stall regulated) machines are shown in Figure D-4 and Figure D-5, respectively. The data associated with these models, including parameter identifier, value and description, are shown in Table D-4 and Table D-5, respectively. No excitation model is required unless an automatic external resistor needs to be represented.

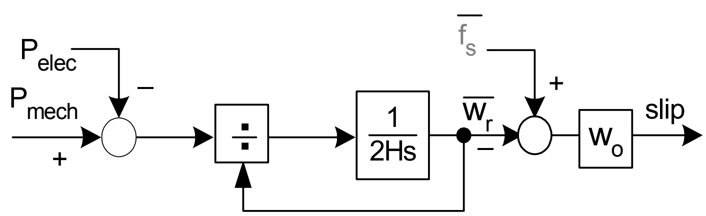


Figure D-4. Wound-rotor Induction Generator Model (genwri) Block Diagram.

Table D-4. Wound-rotor Induction Generator Model (genwri) Data.

Parameter	Value	Description
ls	6.45	Synchronous reactance, pu
lp	0.28	Transient reactance, pu
ll	0.1167	Stator leakage reactance, pu
ra	0.0045	Armature (stator) resistance, pu
Tpo	4.21	Open-circuit transient time constant, sec
H	3.03	Inertia constant, sec
D	-	Not used
s1	0.03	Saturation factor at 1pu flux

Parameter	Value	Description
s12	0.29	Saturation factor at 1.2pu flux
spdrot	1.04	Initial electrical rotor speed, pu of system frequency

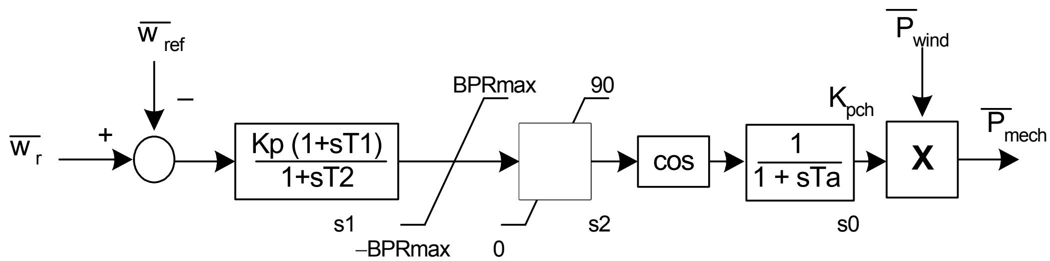


Figure D-5. Wind Turbine Control Model (wndtrb) Block Diagram.

Table D-5. Wind Turbine Control Model (wndtrb) Data..

Parameter	Value	Description
Ta	0.05	Actuator time constant, sec
Kp	100.	Speed regulator gain
T1	0.2	Speed regulator TGR numerator time constant, sec
T2	0.5	Speed regulator TGR denominator time constant, sec
BPRMx	12.	Blade pitch maximum rate, deg/sec
Pwo	Pmech	Initial wind power, pu

D.3.3 Scalar Controlled WTG

Only vector controlled and stall regulated machines, which bound the region of WTG performance, were evaluated in the study. However, a scalar controlled machine could be modeled using the wound-rotor induction generator (genwri) and wind turbine control (wndtrb) models, discussed in the previous section, as well as an appropriate excitation system (exwtg1). The block diagram and data for such an excitation system are shown in Figure D-6 and Table D-6, respectively.

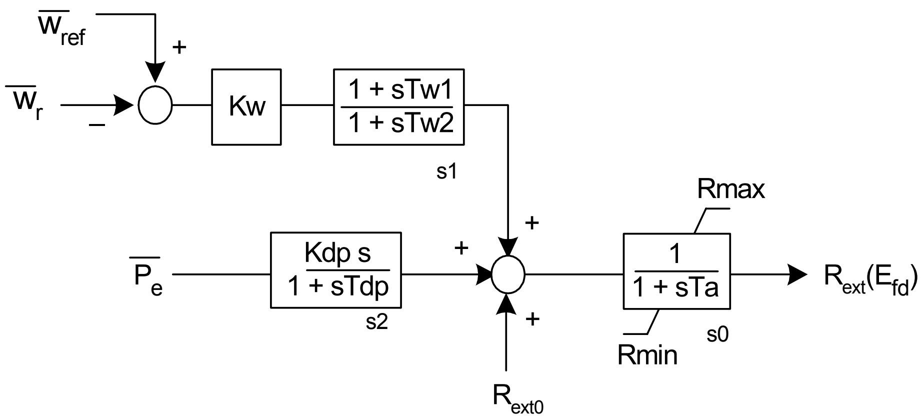


Figure D-6. Excitation System for Wound-Rotor Induction Generator (exwtg1) Block Diagram.

Table D-6. Excitation System for Wound-Rotor Induction Generator (exwtg1) Data.

Parameter	Value	Description
Ta	0.02	Time constant, sec
Kdp	0.1	Power derivative gain
Tdp	1.	Power derivative washout time constant, sec
Kw	-1.	Speed regulator gain
Tw1	2.	Speed regulator TGR numerator time constant, sec
Tw2	4.	Speed regulator TGR denominator time constant, sec
Rmax	0.0977	Maximum external rotor resistance, pu
Rmin	0.0061	Minimum external rotor resistance, pu

D.3.4 Model Evolution

The models presented in this document represent a snapshot of a varying suite of models. The industry is in a state of rapid change, and models are continuously being modified, refined and updated. Model development and validation are the subject of intense scrutiny and debate throughout the industry. Thus, it is essential that the specific characteristics and parameters for each individual project be confirmed before system reliability impact studies are performed.

[i] Reference 'Techncial Characteristics" document prepared for NYSERDA by Enernex.

Appendix E. Other Dynamic Models

The block diagrams and associated data for any dynamic models, other than wind turbine-generator models, added to the databases provided by NYISO and used in the stability analysis are included in this appendix.

E.1 Automatic Generation Control (AGC)

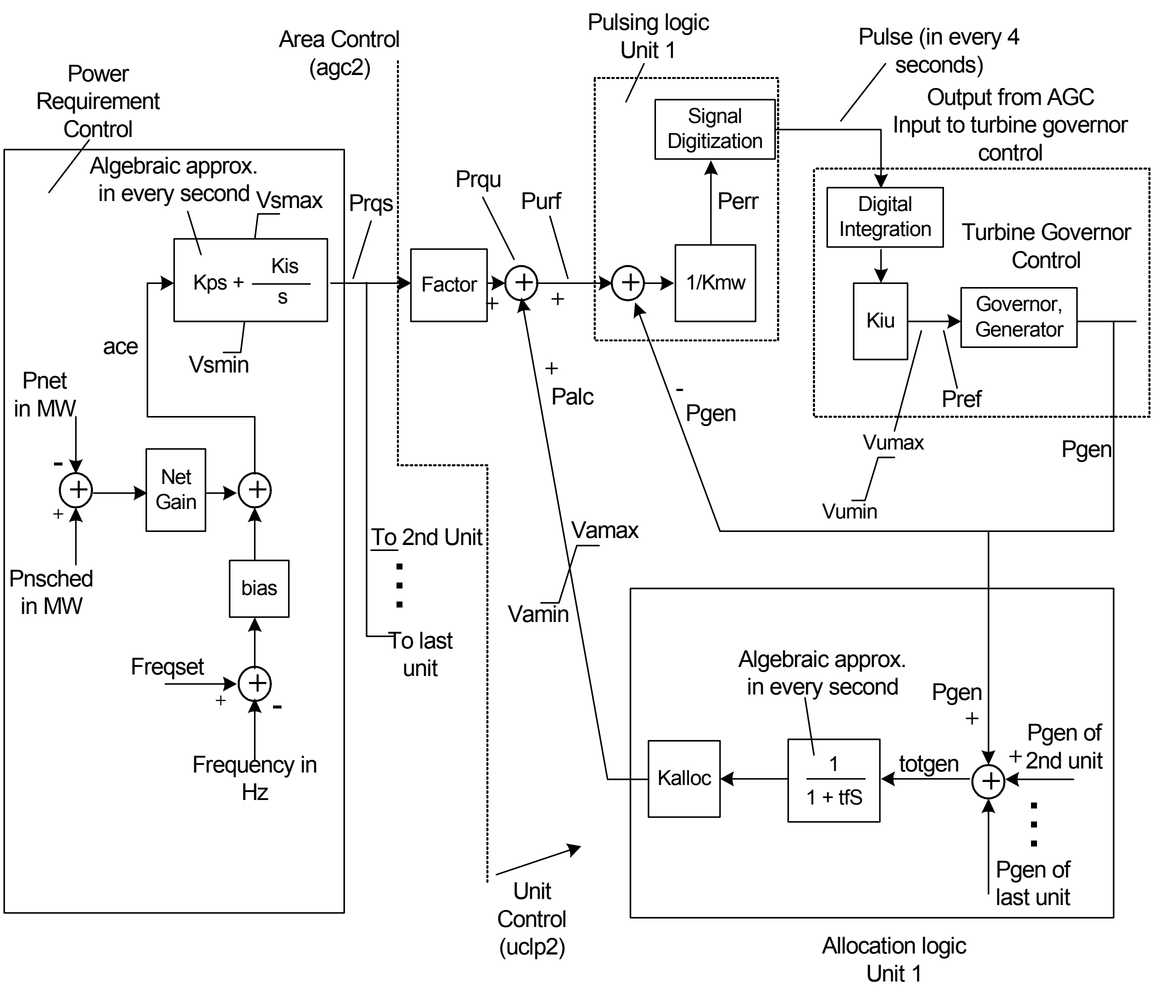


Figure E-1. AGC Model (agc2) and Unit Control Loop Model (uclp2) Block Diagram.

Table E-1, AGC Model (agc2) Data.

Parameter	Value	Description
Fset	60.	Desired Frequency Setpoint, Hz
Kps	5.0	Proportional gain in the power requirement control
Kis	0.005	Integral gain in power requirement control
Vsmax	9999.	Upper limit on the output of the power requirement control, MW
Vsmin	-9999.	Lower limit on the output of the power requirement control, MW
Netgain	1.	Gain for the tie flow error signal
Bias	0	Gain for the speed error signal
Pnsched	Σ Initial Tie Flows	Scheduled tie flow, MW
Areanum	99	Area number of which AGC controls generations
Zonenum	99	Zone number of which AGC controls generations
Tf	0.02	Filter time constant for filtering total generation

Table E-2. Unit Control Loop Model (uclp2) Data.

Parameter	Value	Description
Factor	Pgen/ΣPgen on AGC	Contribution factor of the controlled unit
Kmw	Pmax	Rating of unit, MW
Kiu	0.001	Integral gain in unit control
Vumax	1.1	Upper limit on the output of the unit control, pu
Vumin	0	Lower limit on the output of the unit control, pu
Kalloc	Pgen/ΣPgen on AGC	Allocation factor in the allocation logic
Vamax	Pmax	Upper limit on the allocation power, MW
Vamin	0.001	Lower limit on the allocation power, MW
Tz	0.02	Time constant for sensing rate of change in unit generation
cz	999	Maximum limit on the rate of change in unit generation

Appendix F– MAPS™* Program Description

* Trademark of General Electric Company

Appendix F– MAPS™* Program Description

* Trademark of General Electric Company

GE Energy

Multi-Area Production Simulation

(MAPS™)

Program Description

January 2002

General Electric Company
One River Road
Schenectady, NY 12345
USA

Table of Contents

Multi-Area Production Simulation (MAPS)

I. MAPS' Unique Capabilities

MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. When the program was initially developed over twenty years ago, its primary use was as a generation and transmission planning tool to evaluate the impacts of transmission system constraints on the system production cost. In the current deregulated utility environment, the acronym MAPS may more also stand for Market Assessment & Portfolio Strategies because of the model's usefulness in studying issues such as market power and the valuation of generating assets operating in a competitive environment.

The unique modeling capabilities of MAPS use a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints.

Separate dispatches of the interconnected system and the individual companies' own load and generation are performed to determine the economic interchange of energy between companies. Several methods of cost reconstruction are available to compute the individual company costs in the total system environment. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus.

In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and on the flows on selected transmission lines for all hours in the year, as well as identifying the companies responsible for the flows on a given line.

Because of its detailed representation of the transmission system, MAPS can be used to study issues that often cannot be adequately modeled with conventional production costing software. These issues include:

- **Market Structures –** MAPS is being used extensively to model emerging market structures in different regions of the United States. It has been used to model the New York, New England, PJM and California ISOs for market power studies, stranded cost estimates, and project evaluations.
- **Transmission Access –** MAPS calculates the hour spot price ($/MWh) at each bus modeled, thereby defining a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.
- **Loop Flow or Uncompensated Wheeling –** The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify the companies contributing to the flow on a given transmission line and to define the production cost impact of that loading.
- **Transmission Bottlenecks –** MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year these lines are limiting. Next, the program can be used to assess, from an economic point of view, the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators for alleviating bottlenecks.
- **Evaluation of New Generation, Transmission, or Demand-Side Facilities –** MAPS can evaluate which of the available alternatives under consideration has the most favorable impact on system operation in terms of production costs and transmission system loading.
- **Power Pooling –** The cost reconstruction algorithms in MAPS allow individual company performance to be evaluated with and without pooling arrangements, so that the benefits associated with pool operations can be defined.

Table 1 shows how MAPS models the bulk power system and yields an accurate through-time simulation of system operation.

Table 1

MAPS Models the Bulk Power System

Generation	Transmission	Loads	Transactions
– Detailed Representation	– Tracks Individual Flows	– Chronological by Bus	– Automatic Evaluation
– Secure Dispatch	– Obeys Real Limits	– Varying Losses	– Location Specific

II. Modeling Capabilities

MAPS has evolved to study the management of a power system's generation and transmission resources to minimize generation production costs while considering transmission security. The modeling capabilities of MAPS are summarized below:

- **Time Frame –** One year to several years with ability to skip years.
- **Company Models –** Up to 175 companies.
- **Load Models –** Up to 175 load forecasts. The load shapes can include all 365 days or automatically compress to a typical week (seven different day shapes) per month. The day shapes can be further compressed from 24 to 12 hours, with bi-hourly loads.
- **Generation** – Up to 7,500 thermal units, 500 pondage plants, 300 run-of-river plants, 50 energy-storage plants, 15 external contracts, 300 units jointly owned, and 2,000 fuel types. Thermal units have full and partial outages, daily planned maintenance, fixed and variable operating and maintenance costs, minimum down-time, must-run capability, and up to four fuels at a unit.
- **Network Model** – 30,000 buses, 60,000 lines, 100 phase-angle regulators and 10 multi-terminal High-Voltage Direct Current lines. Line or interface transmission limits may be set using operating nomograms as well as thermal, voltage and stability limits. Line or interface limits may be varied by generation availability. Transmission losses may vary as generation and loads vary, approximating the ac power flow behavior, or held constant, which is the usual production simulation assumption.
- **Marginal Costs** – Marginal costs for an increment such as 100 MW can be identified by running two cases, one 100 MW higher, with or without the same commitment and pumped-storage hydro schedule. A separate routine prepares the cost difference summaries. Hourly bus spot prices are also computed.
- **Operating Reserves –** Modeled on an area, company, pool and system basis.
- **Secure Dispatch** – Up to 5,000 lines and interfaces and nomograms may be monitored. The effect of hundreds of different network outages are considered each study hour.
- **Report Analyzer –** MAPS allows the simulation results to be analyzed through a powerful report analyzer program, which incorporates full screen displays, customizable output reports, graphical displays and databases. The built-in programming language allows the user to rapidly create custom reports.

- **Accounting –** Separate commitment and dispatches are done for the system and for the company own-load assumptions, allowing cost reconstruction and cost splitting on a licensee-agreed basis. External economy contracts are studied separately after the base dispatch each hour.
- **Bottom Line –** Annual fuel plus O&M costs for each company, fuel consumption, and generator capacity factors.

III. MAPS Applications

The program's unique combination of generation, transmission, loads and transaction details has broadened the potential applications of a production simulation model. Since both generation and transmission are available simultaneously with MAPS, the user can easily evaluate the system and company impacts of non-utility generation siting and transmission considerations.

In addition to calculating the usual production cost quantities, MAPS is able to calculate the market clearing prices (marginal costs or bus spot prices) at each load and generation bus throughout the system. For the load buses, the price reflects the cost of generating the next increment of energy somewhere on the system, and the cost of delivering it from its source of generation to the specific bus. Because the production simulation in MAPS recognizes the constraints imposed by the transmission system, the market clearing prices include the costs associated with the incremental transmission losses as well as the costs incurred in redispatching the generation because of transmission system overloads. Figure 1 shows the

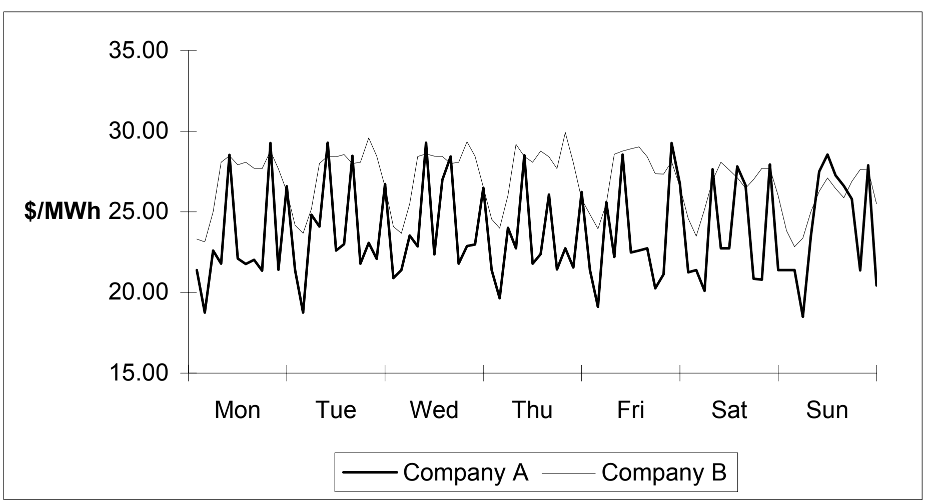


Figure 1. Market clearing prices vary with time and location.

variation in market clearing prices of two separate companies. The company wide clearing price is the weighted average of the clearing prices at the load buses.

MAPS is also able to calculate and constrain both the actual electrical flows on the transmission system and the scheduled flows assigned to individual contract paths. The actual real power flows on the network are based on the bus-specific location of the load and on the generation being dispatched to serve the load. The scheduled flows include firm company-to-company transactions that are delivered from the seller to the buyer over a negotiated path. The scheduled flows also include the generation from remotely owned units, which is delivered to the owning company over an assigned path, and generation that is delivered to remotely owned load.

The simultaneous modeling of actual and scheduled flows is especially important in modeling the Western region of the US where the scheduled flows often have a major impact on the operation of the system. Figure 2 shows the hourly flows on one of the WSCC interchange paths where the scheduled flows on the path are limiting while the actual flows are not,

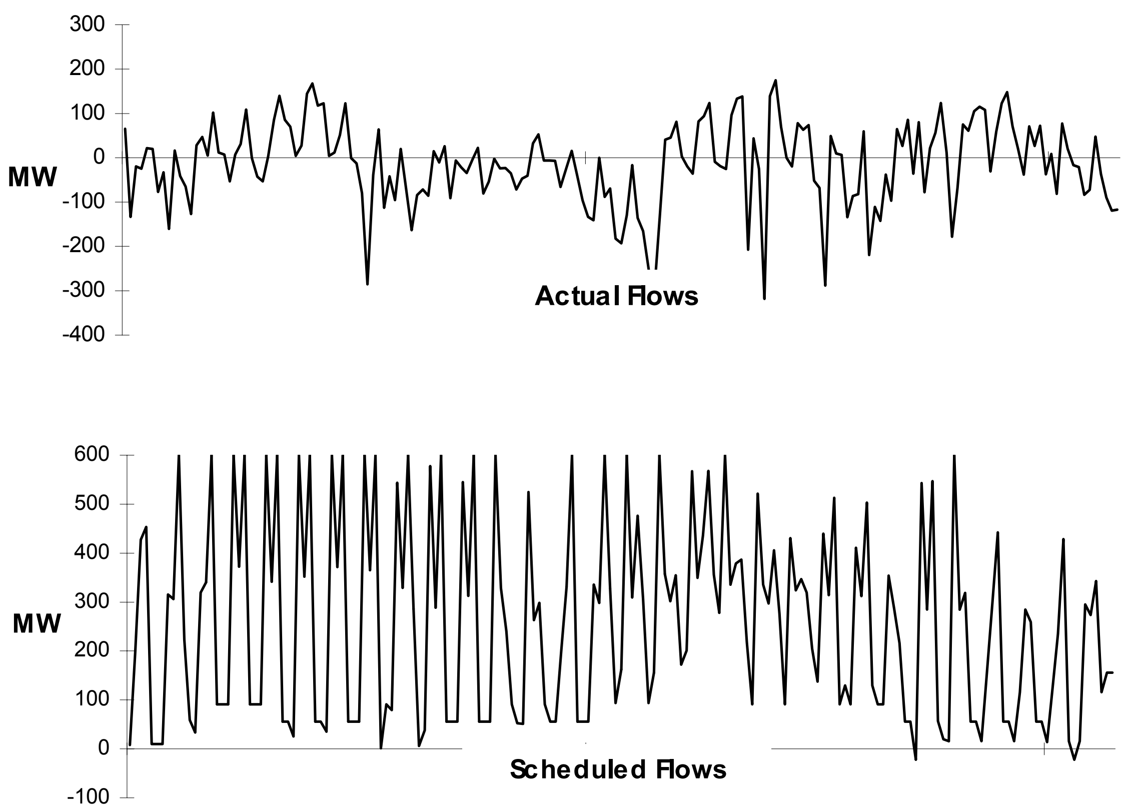


Figure 2. Example of hourly actual and scheduled flows.

resulting in the generation dispatch being constrained by scheduled rather than actual physical limits. This is important in identifying the contract paths that have available transfer capability and could be used to deliver power from potential new development sites.

IV. Production Costing

MAPS models the system chronologically on an hourly basis, dispatching the generation to serve the load for all hours in a year. As a result, MAPS captures the diversity that may exist throughout the system, and accurately models resources such as energy storage and demand-side management.

Load Data

The hourly load data is input to the program in EEI (Edison Electric Institute) format for each load forecast area. These hourly load profiles are then adjusted to meet the peak and energy forecasts input to the model on a monthly or annual basis. To accurately calculate the electrical flows on the transmission system, MAPS requires information on the hourly loads at each bus in the system. This is specified by assigning one, or a combination of several hourly load profiles to each load bus.

In addition to studying all the hours in the year, MAPS can study all the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. With these modeling options, MAPS simulates the loads in chronological order and does not sort them into load duration curves.

Thermal Unit Characteristics

Essentially all the thermal unit characteristics input to MAPS can be changed on a weekly, monthly or annual basis. The following are the characteristics that can be modeled:

- Each unit can have up to seven loading segments (power points).
- Generating units can burn a blend of up to three fuel types in addition to the start-up fuel. The percentage of each fuel burned can vary by unit power point. Minimum fuel usage and maximum fuel limits are modeled and enforced on a monthly basis. If the maximum fuel limit is reached, the affected units will be switched to an alternate fuel.
- MAPS models fixed O&M in $/kW/year and variable O&M in $/MWh and $/fired hour. The user controls whether the variable O&M is included in determining the order for unit commitment and dispatch. A separate bidding adder in $/MWh can

also be input for each unit. This cost is added to the costs used to determine the commitment and dispatch order of the units, but is ignored when computing actual unit costs.

- MAPS calculates start-up costs as a function of the number of hours that the unit has been off-line. The user can specify whether the start-up should be included in the full-load costs used to determine the order in which the units are committed.
- In the unit commitment process, MAPS models the minimum downtime and uptime on thermal units. Units can also be identified as must-run with the user specifying that the entire unit is must-run, or only the minimum portion, with the remainder of the unit committed on an economic basis as needed.
- MAPS allows the user to specify the portion of each thermal unit that can be counted toward meeting the load plus spinning reserve requirements, and the portion that can be considered as quick-start capacity. A spinning reserve credit can also be taken for unused pondage hydro and energy-storage generating capacity.
- Full and partial forced outage information is specified to MAPS in terms of forced outage rates.
- Maintenance can be specified on a daily basis for any number of maintenance periods during the year. The user can also identify units as unavailable for specific hours during the day.
- The thermal generating units bid into the system at their costs, based on fuel prices, O&M and emission costs, bid adders, and heat rates. Alternatively, the user can input the bid price in $/MWh by unit power point. This price will then be used in the commitment and dispatch to determine the way in which the units operate.
- MAPS allows all types of generating units (thermal, pondage, and energy storage) to be owned by more than one company in a multi-utility simulation. The output and cost of these units are allocated to the owning companies based on the user-specified percentages.
- Nearly all unit characteristics including rating, heat rates, and costs, can change on a weekly basis.

Models for Production Costing

The following sections describe various portions of the production simulation process in MAPS.

Hydro and energy-storage scheduling - MAPS offers three distinct representations for modeling hydro plants: hourly modifiers, pondage modifiers or energy-storage devices. This flexibility allows the program to accurately model each hydro plant based on its operating characteristics.

Hourly modifiers allow the user to specify the actual hour-by-hour operation of the plant in MW. This data can be specified for the 168 hours of a typical week of operation, with the option to change this data on a monthly basis. Alternatively, the hourly operation for the entire year (8,760 or 8,784 hours) can be input. This feature can also be used to model firm company transactions that can be specified on an hourly basis.

Hydro plants can also be modeled as *pondage modifiers*. Each pondage modifier is defined by a monthly minimum and maximum capacity (MW) and a monthly available energy (MWh). The minimum capacity is base-loaded for all hours in the month, representing the run-of-river portion of the plant. The remaining capacity and energy are scheduled in a peak-shaving or valley-filling mode over the month. The user identifies the specific load shape to use for scheduling the plant; options include the system load, combinations of selected company loads, or combinations of selected area loads. If several pondage units are located at sequential dams on the same river, they can be scheduled as a group to coordinate the operation of the units.

MAPS allows the user to develop scenarios for different water conditions (e.g., low, average, or high stream flows) through simple modifications to the available energy specified for the pondage modifiers.

For *energy-storage* devices, which include pumped-storage hydro and batteries, MAPS automatically schedules the operation based on economics and the characteristics of the storage device. The characteristics specified include the charging (or pumping) and generating ratings, the maximum storage capacity in MWh, the full-cycle efficiency (which recognizes losses in the pump/generate cycle), and the scheduling period (daily or weekly). The program examines the initial thermal unit commitment to develop a cost curve for the week. This cost curve is then combined with the appropriate chronological load profile to develop an hourly schedule, which minimizes costs without violating the storage constraints. This schedule is locked-in and the thermal unit commitment process is repeated to develop the final commitment schedule.

For all three hydro representations, the user also specifies the ownership of the plant, energy costs in $/MWh, and the transmission system bus or buses at which the plant is located. For each hourly modifier and pondage plant, you can also specify an economic dispatch price in $/MWh. If, during the dispatch of the thermal generation, the spot price at the unit's bus drops below the specified value, the unit's output will be backed down to its minimum rating (or 0 in the case of hourly modifiers) and the energy will be shifted to hours later in the week when the spot price is higher.

Dispatchable load management and non-dispatchable renewable - MAPS can model some types of dispatchable DSM and load control as thermal generating units with the appropriate characteristics and costs. Load management strategies such as batteries or thermal energy storage can be modeled as energy-storage devices.

MAPS models non-dispatchable DSM and load control and renewables such as photovoltaic or wind energy as hourly modifications to the load. This modification can be specified for the 168 hours of a typical week, with the option to change this data on a monthly basis, or by specifying the data for the entire year (8,760 or 8784 hours).

The generating units used to represent DSM, load control, and renewables can be assigned to the appropriate areas and buses throughout the system to accurately capture the dispersed nature of such resources.

Maintenance scheduling - The unit planned outages can be specified by the user, in terms of the starting and stopping dates of the maintenance period, or automatically scheduled by the program. If being scheduled by the program, the maintenance requirements can be specified as weeks of maintenance or a planned outage rate. The program schedules the maintenance on a weekly basis so as to levelize reserves (the difference between installed capacity and the sum of load plus MW on maintenance) on an area, company, pool, or system basis.

Forced outages - MAPS models the forced outages through either a Monte Carlo or recursive convolution approach. In the Monte Carlo approach, the forced outages on generating units are modeled through the use of random outages. This method is stochastic over the course of the entire year and results in the units being on forced outage for randomly selected periods during the year. The total outage time for each unit is determined by the forced outage rate, and the duration of each outage period, also known as the "mean-time-to-repair," can be specified by unit in days. Partial outages on the generating units can also be modeled, on a weekly basis. The random outage method permits accurate treatment of forced outages over the course of the year while allowing each hour to be deterministically dispatched, thus providing for the most accurate treatment of transmission limits when operating with the detailed electrical representation.

MAPS also has the capability of using the more traditional recursive convolution technique when run in the transportation mode. This technique convolves the forced outages of the units with the loads to develop an equivalent load curve each hour, allowing the calculation of expected output for each of the generating units. In this manner, a unit with a 10% forced outage rate will have a 10% probability of being unavailable for each hour of the year. This methodology is not compatible with the more detailed transmission constrained logic, but can be used with the transportation model and the transfer limits between areas.

Hourly commitment and dispatch - The objective of the commitment and dispatch algorithms in MAPS is to determine the most economic operation of the generating units on the system, subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and other operational considerations such as operating and spinning reserve requirements. The economics used for commitment and dispatch can be adjusted through the use of penalty factors that can move a unit within the commitment and dispatch ordering.

MAPS models the system chronologically on an hourly basis, committing and dispatching the generation to serve the load for all hours of the year. The unit commitment process in MAPS begins by developing a priority list of the available thermal units based on their full-load operating costs. The full-load cost is calculated from the fuel price and full-load heat rate, and can optionally include the variable O&M costs, start-up costs, and a bid adder. Alternatively, the full-load cost can be based on the bid prices that were input by unit section. This priority ordering of the thermal units is used for the entire week.

The units are then committed in order of increasing full-load costs to meet the load plus spinning reserve requirements on an hourly basis, recognizing transmission constraints. This preliminary commitment for the entire week is then checked to see if any units need to be kept on-line because of minimum downtime or minimum run-time constraints.

One potential shortcoming of this process is that baseload units, which tend to be committed first because of their lower full-load costs, may be committed for just a few hours during the week to meet load plus spinning reserve, but are then kept on-line, usually at part-load, because of the minimum downtime constraints. Consequently, the average cost of these units over the course of the week is much higher than the full-load costs that were used in determining their commitment ranking. A more economic commitment might be obtained by skipping over these units and committing intermediate or peaking units, that while they have a higher full-load cost, they can be more easily cycled from hour to hour.

The multi-pass unit commitment option is designed to commit the units based on their expected operating costs rather than their full-load costs. This is accomplished by doing the commitment in up to four passes and adjusting the daily priority costs of those units that are not committed for a specified number of hours during the day. The cost adjustment is based on the unit type (i.e., baseload, intermediate, or peaking) and an input number of hours at full, part, and minimum load operation. The type for each unit is determined from the unit's minimum downtime and input cutoff values for the minimum downtimes of baseload and peaking units. Any unit whose minimum downtime falls between these cutoff values will be modeled as an intermediate unit.

Upon completion of the commitment process for the week, the program begins the dispatch process. All of the committed units are loaded to their minimum power point, and then the program dispatches the remaining unit sections, in order of increasing incremental cost, to meet the hourly bus loads, once again recognizing the constraints imposed by the transmission system and other user-specified operating considerations.

Operational constraints - In MAPS, the production simulation is formulated as a linear programming (LP) problem where the objective function is to minimize the production costs subject to electrical and business constraints. MAPS models each security constraint as a single constraint in the LP formulation. MAPS derives these constraints from the production costing input data (for example, identified must-run units and minimum down-time for generation units) and from user-specified operating nomograms, such as those often used by system operators to represent voltage and transient stability limits. MAPS monitors the flows on individual transmission lines and interfaces on an hourly basis to ensure that the line or interface limits, or other security constraints such as import limits, are not violated while dispatching the generation system.

MAPS can also consider other user-specified contingencies such as the tripping of lines or groups of lines, or the tripping of load or generation at specified buses. The final generation dispatch developed by MAPS will be secure in the sense that the system will be operating within all its limits even under the contingency conditions.

Operating and spinning reserves - During both the unit commitment and dispatch, MAPS models operating reserve requirements for areas, companies, pools, and the entire system. The operating reserves are calculated based on a percentage of the load, a fixed MW reserve, and a percentage of continuous rating of the largest committed unit.

The total operating reserves can be met by a combination of quick-start reserves (units not actually running but which can be brought on line very quickly) and spinning reserves. The portion of operating reserves that can be met by quick-start reserves can be specified by area, company, pool, or system. The user identifies which units have quick-start capability.

A spinning reserve credit can be taken for unused generation from energy-storage units. The user can also specify the portion of each committed thermal unit that can be applied toward the spinning reserve requirements.

Emissions - MAPS models two general types of emissions. The first type of emission is a function of the amount of fuel being used. This type would typically be used to model sulfur and particulate emission. The second type of emission is a function of the unit operation, but is not directly related to the amount of fuel. This type could be used to model NOx emissions, which can decrease with increased power output.

In addition to the emission rates modeled by fuel type or by unit, the user can input, by thermal unit and emission type, the removal efficiency (in per unit) of the emission control equipment, and the removal and trading costs in dollars per ton of emission. The removal cost represents the operating costs associated with emission control equipment. The trading cost can be used to model the costs associated with the emissions that are not removed by the control equipment. These costs could include the costs related to the purchase of emission allowances.

Penalty factors on the removal and trading costs can also be input to control the extent to which these costs are included in the full-load and incremental costs used to determine the order in which the units are committed and dispatched

Representation of various power market participants - Through the appropriate assignment of loads and generation, the various participants in the power market can be represented in MAPS. Integrated utilities would have generation, transmission, and be responsible for serving load. Separate distribution entities would not own any generation but would purchase all of the energy they need to meet their load obligations. Independent power producers would be modeled as companies with generation but no transmission or load. The commitment, dispatch, and cost allocation functions in MAPS itself would represent the independent system operator. The wholesale power broker would be modeled as a company with firm contracts to buy energy from other companies, which would then be resold on a firm or economy basis.

MAPS models bilateral contracts between market participants as firm transactions between the selling and buying companies. These contracts can be specified in terms of hourly MW values, or as minimum and maximum MW ratings and available monthly energy that would be scheduled by the program.

Purchase and sale contracts - MAPS can model internal transactions (purchases and sales contracts) between companies with the system, and external transactions with companies outside the study system.

The internal transactions can be either "firm" or "economy." Firm transactions between companies can be specified in MW on an hourly basis, or as a minimum and maximum rating (MW) and a monthly energy (MWh), which can be scheduled by MAPS. The firm transactions occur regardless of economics. The economy transactions occur between companies in the system dispatch when it is cheaper for a company to purchase energy to serve its load than to generate load with its own units.

The external contracts can also be categorized as "firm" and "economy." The primary difference is that firm external contracts are evaluated as part of the base dispatch each hour, while economy external contracts involve multiple dispatches each hour to evaluate the price paid for the energy.

Firm external contracts are modeled as unit modifiers located outside the study system, but in all other respects they are treated the same as any other system generation. Company ownerships are assigned to the units, and they are modeled in the commitment and dispatch along with the local generation.

The special feature of the economy external contract logic in MAPS is that multiple dispatches are performed each hour (both with and without each economy external contract) and the price paid for the energy is a function of the change in system operating costs. This total savings is also referred to in MAPS as the delta costs. These total savings from the transactions are divided between the system and the outside world according to a specified percentage. The system savings resulting from an external economy purchase are allocated to those companies that are net buyers of energy. Similarly, any savings from an external economy sale are allocated to those companies that are net sellers of energy.

Cost reconstruction - Within a single run of the program, MAPS can perform two separate dispatches of the system generation. In the system dispatch, the entire system is dispatched to serve the load as economically as possible, subject to the constraints imposed by the transmission system. In the company own-load dispatch, each company's resources (including its firm transactions with other companies) are economically dispatched to serve its own load. The results of the two dispatches are then used to calculate the savings that result from the coordinated system dispatch versus the isolated company dispatches. Several methods of cost reconstruction are available to allocate these savings between the buyers and sellers and to compute the individual company costs in the system environment.

Furthermore, multiple pools within a system can be modeled in MAPS. MAPS has the capability to model economic energy transaction within a company's power pool, if desired in the simulation.

Hourly bus spot prices - MAPS computes hourly spot prices at individual buses. The bus spot price is the cost of supplying an additional MW of load at the bus and includes the cost of generating the energy, the cost of the incremental transmission losses, and any costs associated with re-dispatching the generation if this additional increment of load caused overloads on the transmission system. The difference in spot prices at two buses is the short-run marginal wheeling cost between these buses.

MAPS can also develop marginal costs on a company and pool basis. There are two types of marginal cost calculations in MAPS: incremental and delta. Incremental marginal costs are calculated from a single dispatch and are equal to the cost of the last increment of power generated. Delta costs are calculated from two dispatches and equal the average cost of the change in energy dispatched. The hourly marginal costs can be summarized for on-, mid-, and off-peak periods by month, season and year.

V. Transmission Network

MAPS contains two distinct models for representing the transmission system. The original approach uses a transportation model to limit the transfer between interconnected areas during the dispatch of the system generation. The second approach performs a transmission-constrained production simulation, using a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This makes it possible to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints. In the electrical representation, all physical components of the transmission system are modeled, including transmission lines, phase-angle regulators, and HVDC lines.

MAPS can also operate in the mode in which both methodologies are used simultaneously. For example, MAPS can operate the system so that both the scheduled contract flows (transportation model) and actual electrical flows are calculated, with the more restrictive limits applying. Similarly, MAPS can constrain the system based only on the transfer limits between areas while calculating the actual electrical flows throughout the system.

Most discussions about the future of power systems agree that networks will be stressed more than ever before, and the utilities will not have the luxury of observing artificial constraints. For this reason, it is important to model the actual electrical flows on the lines in addition to the transportation flows between the control areas. MAPS, with both models available, is perfectly suited to model both the current operation of a system and to examine the various ways in which the system might be operated in the future.

In both the transportation and electrical representations, MAPS calculates and limits the transmission flows on an hourly basis. In the transportation mode, the utility system is modeled as discrete operating areas containing generation and load. The transmission system is represented in terms of transfer limits on the interfaces between the interconnected areas. These limits can be different for the two directions of interface flow, and can be specified on an hourly basis. These limits can also vary on an hourly basis in response to user-specified conditions as to whether or not specified units are available (for commitment) or have been committed (for dispatch).

In the electrical representation, the load and generation are assigned to individual buses and the transmission system is modeled in terms of the individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Limits can be specified for the flow on the lines and the operation of the PARs. These limits can change on an hourly basis as a function of loads, generation, and flows elsewhere on the system. Examples of the types of operating nomograms that can be modeled in MAPS include:

- transmission line or interface limit as a function of area or company load
- net imports to an area as a function of load
- simultaneous imports into an area
- minimum generation by area.

The user can control the extent to which MAPS will enforce the limits assigned to an interchange path, transmission line, or other system element. Each monitored element is assigned an overload cost in $/MWh. If violating the limit will result in production cost savings greater than or equal to the overload cost, the limit will be ignored. If the monitored element has a small overload cost, it has “soft” limits that will be monitored but will most likely not result in a significant redispatch of the generation. An element with a large overload cost will be modeled with “hard” limits that are strictly enforced and rarely, if ever, violated, necessitating a redispatch of the generation to correct the violations.

VI. Data Input/Output

The MAPS data is input through data tables that are stored as text files, which can be easily accessed and edited through standard text editors. The table structure is essentially free-format with no stringent requirements that data can be input in specific positions within a line.

The table structure in MAPS is self-documenting and allows the user to freely insert comments in the data to aid in documentation.

All MAPS output is stored in binary files to allow for report generation and customization at a later date. Among the results stored in binary files are the individual unit quantities on an hourly, monthly, annual, and study period basis for the system and own-load dispatches, and the hourly interface flows. The stored results of the transmission analysis, when MAPS is run in with the detailed electrical representation, include the hourly flows and plant outputs, the limiting elements for each hour and the marginal benefit of relaxing each limiting constraint, and the hourly spot prices at specified buses.

The MAPS Report Analyzer (MRA) is an extremely powerful tool for analyzing the vast quantities of generation- and transmission-related data produced by MAPS. The MRA loads the data from the binary files into a very efficient database and allows the user to easily create customized reports and graphs through the use of built-in commands and a simple programming language.

The MRA is completely menu driven and includes several on-line help function to guide the user. The MRA has several options for plotting study results. The first option is intended to give the user a quick look at the data but does not offer all of the flexibility, such as changing scale divisions or adding text to the graphs, that is sometimes needed. The MRA also contains a separate plotting package that can be used to fine tune the appearance of plots. The third option allows the user to export the data for use with other plotting software.

The following pages show some of the reports and graphs that are readily available from the MRA or can be easily generated from data accessible through the MRA.

Example 1 – MRA Unit Edit Table

NO	--NAME--	G	H	TYPE	COMPANY	--AREA--	MAX-RTG	CON-RTG	F-O-R	MN-DT	P	TOTAL-GWH	CF	P	FC(k$)	P	OMT(k$)	P	SPMIN	SPMAX
1	Unit-01	0	0	THE	Company A	ATCE_AR	36.00	36.00	0.1040	4	0	0.774	0.0024	0	103	0	1.28	0	11.04	39.81
2	Unit-02	0	0	THE	Company A	ATCE_AR	37.00	37.00	0.1040	4	0	0.777	0.0024	0	102	0	1.29	0	11.04	39.81
3	Unit-03	0	0	THE	Company A	ATCE_AR	46.00	46.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
4	Unit-04	0	0	THE	Company A	ATCE_AR	22.00	22.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
5	Unit-05	0	0	THE	JOINT	ATCE_AR	838.78	838.78	0.0610	48	0	4105.661	0.5572	0	73479	0	9063.78	0	11.04	39.81
6	Unit-06	0	0	THE	JOINT	ATCE_AR	838.78	838.78	0.0610	48	0	3974.200	0.5394	0	71273	0	8773.56	0	11.04	39.81
7	Unit-07	0	0	THE	Company B	ATCE_AR	84.00	84.00	0.1040	4	0	13.198	0.0179	0	718	0	21.85	0	11.04	39.81
8	Unit-08	0	0	THE	Company B	ATCE_AR	19.00	19.00	0.1040	4	0	0.821	0.0049	0	76	0	1.36	0	11.04	39.81
9	Unit-09	0	0	THE	Company B	ATCE_AR	86.00	86.00	0.0840	48	0	150.891	0.1997	0	5144	0	208.19	0	11.04	39.81
10	Unit-10	0	0	THE	Company B	ATCE_AR	54.00	54.00	0.0980	48	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
11	Unit-11	0	0	THE	Company B	ATCE_AR	80.00	80.00	0.0760	48	0	343.647	0.4890	0	6535	0	758.64	0	11.04	39.81
12	Unit-12	0	0	THE	Company B	ATCE_AR	9.00	9.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
13	Unit-13	0	0	THE	Company B	ATCE_AR	129.00	129.00	0.0760	48	0	555.595	0.4903	0	10386	0	1226.55	0	11.04	39.81
14	Unit-14	0	0	THE	Company B	ATCE_AR	160.00	160.00	0.0760	48	0	699.189	0.4975	0	13058	0	1543.55	0	11.04	39.81
15	Unit-15	0	0	THE	Company B	ATCE_AR	155.00	155.00	0.0980	48	0	12.013	0.0088	0	653	0	25.46	0	11.04	39.81
16	Unit-16	0	0	THE	JOINT	ATCE_AR	1031.00	1031.00	0.1660	168	0	6268.466	0.6922	0	41312	0	4151.52	0	11.04	39.81
17	Unit-17	0	0	THE	JOINT	ATCE_AR	847.20	847.20	0.0610	48	0	4478.840	0.6019	0	79801	0	9887.49	0	11.04	39.81
18	Unit-18	0	0	THE	JOINT	ATCE_AR	847.20	847.20	0.0610	48	0	4304.070	0.5784	0	76858	0	9501.69	0	11.04	39.81
19	Unit-19	0	0	THE	Company C	ATCE_AR	59.00	59.00	0.1040	4	0	1.304	0.0025	0	175	0	2.16	0	11.04	39.81
20	Unit-20	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
21	Unit-21	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
22	Unit-22	0	0	THE	Company C	ATCE_AR	37.00	37.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
23	Unit-23	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
24	Unit-24	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
25	Unit-25	0	0	THE	Company C	ATCE_AR	20.00	20.00	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81
26	Unit-26	0	0	THE	JOINT	ATCE_AR	1051.00	1051.00	0.1660	168	0	6390.057	0.6922	0	42114	0	4232.06	0	11.04	39.81
27	Unit-27	0	0	THE	JOINT	ATCE_AR	1035.00	1035.00	0.1660	168	0	6292.781	0.6922	0	41474	0	4167.63	0	11.04	39.81
28	Unit-28	0	0	THE	JOINT	ATCE_AR	1106.00	1106.00	0.1660	168	0	6724.443	0.6922	0	44318	0	4453.52	0	11.04	39.81
29	Unit-29	0	0	THE	JOINT	ATCE_AR	1106.00	1106.00	0.1660	168	0	6724.454	0.6922	0	44319	0	4453.52	0	11.04	39.81
30	Unit-30	0	0	THE	JOINT	ATCE_AR	37.93	37.93	0.1040	4	0	0.000	0.0000	0	0	0	0.00	0	11.04	39.81

NAME	Unit name
TYPE	Unit type
COMPANY	Unit company
AREA	Unit area
MAX-RTG	Maximum rating in MW
CON-RTG	Continuous rating in MW
F-O-R	Forced outage rate
MN-DT	Minimum downtime (hours)

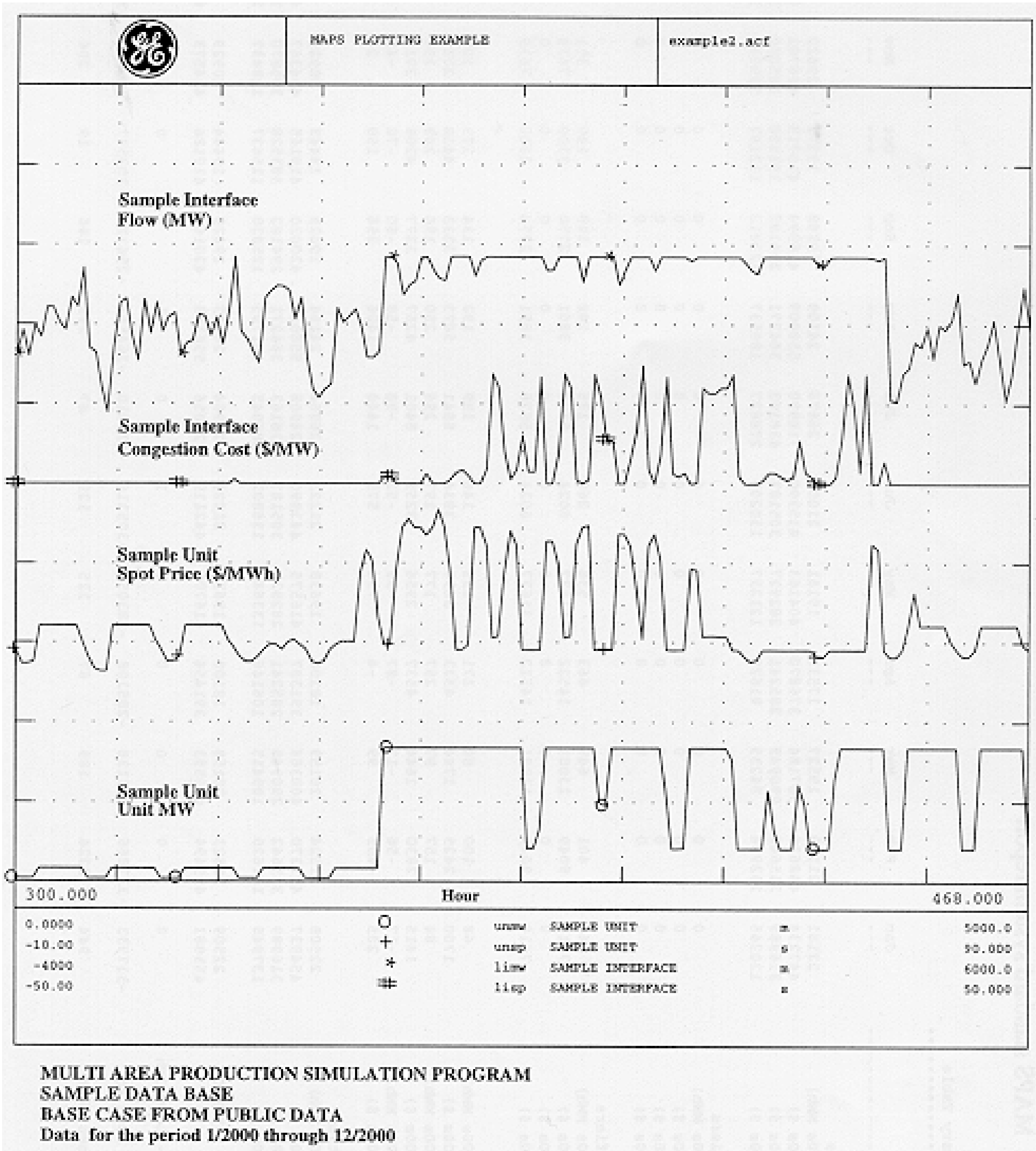
TOTAL-GWH	Annual GWH operation
CF	Capacity Factor
FC (k$)	Fuel Cost
OMT (k$)	Total O&M Cost
SPMIN	Spot price minimum
SPMAX	Spot price maximum
SPAVG	Spot price average

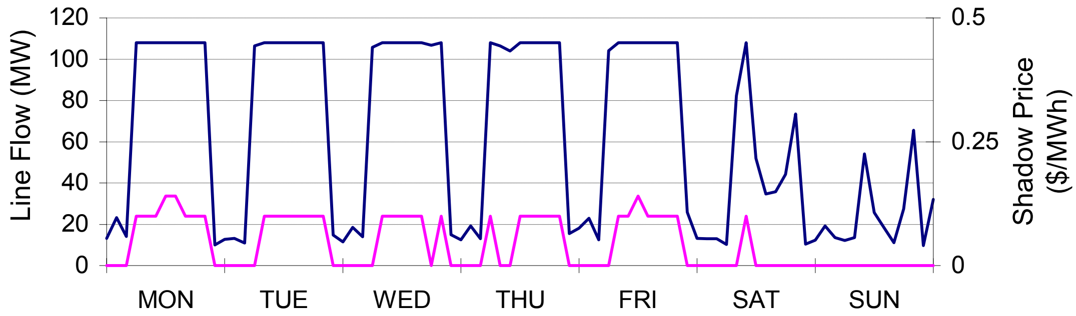
Example 2 – MAPS Standard System Report

Year -- 2000
Monthly Summary Table
****

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
SYSTEM													
Thermal Units													
ENERGY (1000s MWh)	22181	21179	19527	17531	19141	21007	26876	24109	19369	19371	20622	23239	254153
REVENUE (1000s $)	447234	448626	387184	376870	404163	435390	716990	550809	416994	415715	426702	474828	5501506
COST (1000s $)	316989	315642	290949	285241	282927	305187	438163	364271	294182	303528	305870	334249	3837198
NET $ (1000s $)	130245	132984	96235	91629	121237	130203	278827	186537	122812	112187	120831	140579	1664308
Hourly Modifiers													
ENERGY (1000s MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
REVENUE (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
COST (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
NET $ (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
Pondage Modifiers													
ENERGY (1000s MWh)	344	401	649	663	536	268	185	142	120	149	351	438	4250
REVENUE (1000s $)	7418	9049	13081	14522	11677	6024	5578	3851	2770	3300	7639	9388	94297
COST (1000s $)	0	0	0	0	0	0	0	0	0	0	0	0	0
NET $ (1000s $)	7418	9049	13081	14522	11677	6024	5578	3851	2770	3300	7639	9388	94297
P.S. Hydro													
GEN EGY (1000s MWh)	68	100	80	171	139	146	199	192	134	173	109	92	1601
REVENUE (1000s $)	1700	2425	1744	4533	3690	3834	6841	5673	3533	4418	2738	2252	43380
PUMP EGY (1000s MWh)	84	157	97	257	177	197	296	250	194	249	154	135	2248
NEG REV (1000s $)	1415	2830	1644	4537	2956	3259	5401	4267	3277	4268	2711	2342	38907
NET EGY (1000s MWh)	-17	-56	-17	-87	-39	-52	-98	-58	-60	-76	-45	-43	-648
NET $ (1000s $)	285	-405	99	-4	734	575	1440	1406	256	150	26	-90	4473
Total Generation													
ENERGY (1000s MWh)	22509	21524	20159	18108	19638	21223	26964	24194	19429	19443	20929	23635	257756
REVENUE (1000s $)	454937	457270	400364	391387	416575	441990	724008	556066	420020	419165	434367	484126	5600276
COST (1000s $)	316989	315642	290949	285241	282927	305187	438163	364271	294182	303528	305870	334249	3837198
NET $ (1000s $)	137948	141629	109415	106146	133648	136802	285845	191795	125838	115637	128497	149877	1763078
Load ENERGY	22509	21523	20159	18108	19638	21223	26964	24193	19429	19444	20929	23634	257754
REVENUE	455881	459494	400553	391454	416700	442119	724056	556358	420166	419184	434573	484156	5604694
Net Gen GWh - Load GWh	0	0	0	0	0	1	0	1	0	0	0	0	2
Net Gen k$ - Load k$	-317933	-317866	-291138	-285308	-283052	-305316	-438210	-364563	-294328	-303547	-306076	-334278	-384161
Congestion Cost (k$)	944	2224	189	67	125	129	47	292	146	19	206	29	4417

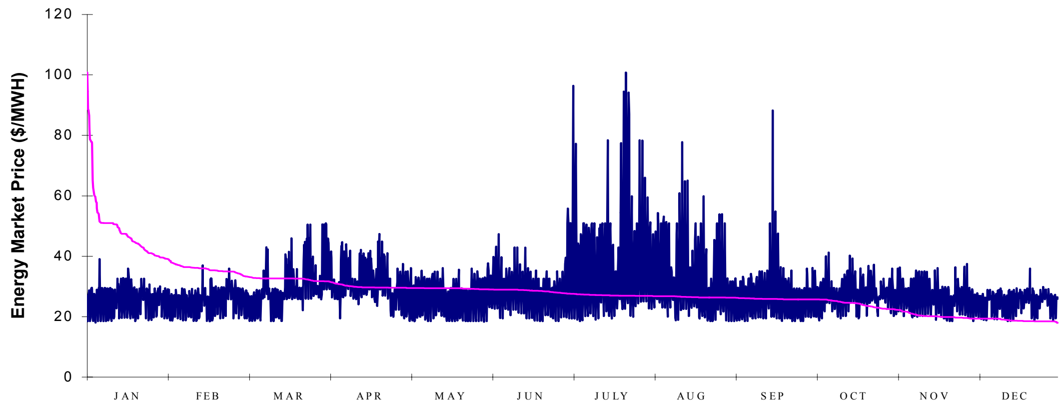
Example 3 – Typical Plots Available from MRA



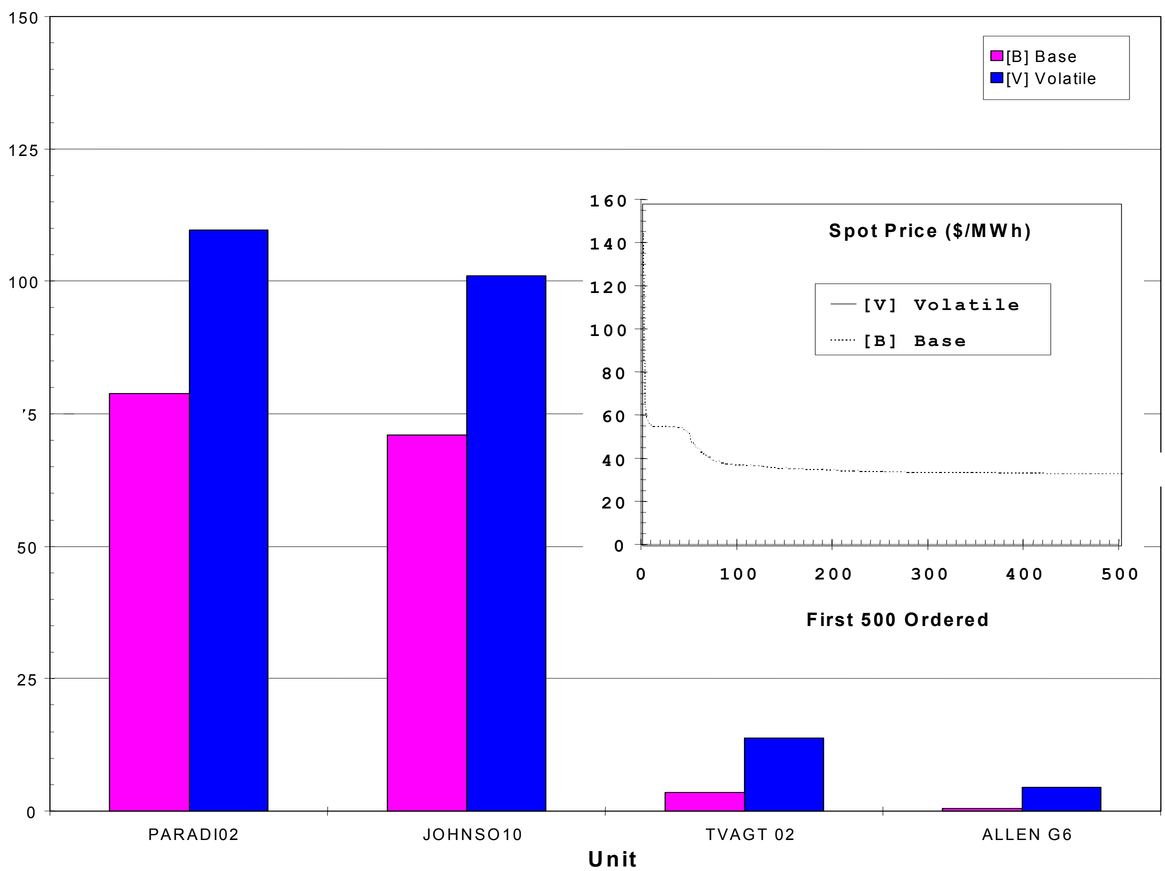


Example 4 – Line Flows and Line Shadow Prices

Example 5 – Merchant Plant Net Revenues



Example 6 – Hourly Market Energy Prices



Example 7 - Effect of Market Volatility on Spot Price and Net Revenue

VII. Hardware Specifications for Running MAPS and MRA

	PENTIUM PC
System	Pentium IV 900 MHz 512 MB RAM 40 GB Disk 2 Button Mouse 101 Keys (US) Floppy Disk Drive CD-ROM 56 kB Modem
Monitor	20" Color Display
Backup	CD-Writer
Op Sys	Windows NT, 95, 98, or 2000
Aux Software	Exceed 7.0 from Hummingbird

VIII. MAPS Licensees

A list of current MAPS licensees is available on request.

IX. MAPS Pricing Information

Pricing information for licensing MAPS, MAPS training, and MAPS studies conducted by GE personnel is available on request.

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Appendix G – MARS Program Description

MARS Program Description

The Multi-Area Reliability Simulation program (MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

MARS MODELING TECHNIQUE

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

RELIABILITY INDICES AVAILABLE FROM MARS

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

DESCRIPTION OF PROGRAM MODELS

Loads

The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

Generation

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units. In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

Energy-Limited Units. Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration. MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM. Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

Emergency Operating Procedures

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.