Load Coincidence Study for the Integration of Wind into Tennessee Valley Authority via the Plains and Eastern Clean Line

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Clean Line Energy Partners

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Review Standard
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June 25, 2010

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KEY TO REVIEW STANDARD

Standard	Standard review level.
Senior Staff	Reviewed by senior staff.
Due Diligence	Highest level of scrutiny.

DOCUMENT HISTORY

Issue	Date	Summary
A	**June 16, 2010**	Initial Report
B	**June 25, 2010**	Version 2

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Executive Summary

AWS Truepower, LLC (AWST) was retained by Clean Line Energy Partners to complete a study to analyze the coincidence of simulated wind power output and regional load in the southeast. The wind generation, produced in southwestern Kansas, the Oklahoma panhandle, and the Texas panhandle is to be delivered to the Tennessee Valley Authority (TVA) via the proposed Plains and Eastern Clean Line project, and potentially exported to other southeastern balancing authorities, such as Southern Company, Duke Energy, and Entergy.

The potential impacts on the grid were assessed for four production and exportation scenarios. Diurnal and seasonal graphs and statistical calculations were evaluated to determine the coincidence of wind and the southeastern balancing authority loads. Further statistics were calculated to understand the impact of wind energy on system operations, such as generation ramp rate, baseload impact, and capacity value.

Load data was acquired from TVA and through the publicly available FERC Form 714. Generation was established using AWS Truepower's ***windTrends***® database, a simulated hourly time series Mesoscale Atmospheric Simulation System (MASS) model output. The model output was interpolated to the selected sites, and production was created using the IEC class specific composite power curve from the Eastern Wind Integration and Transmission Study (EWITS).

AWST looked at the coincidence of the load and wind generation diurnally by year as well as using an 11-year mean typical diurnal pattern. To further understand the coincidence of wind with the load, AWST looked at the seasonal and monthly patterns. Additionally, AWST looked at the minimum and maximum statistics for load, wind, and net load. Statistics for the top 100 load hours by season and annually were created to further illustrate wind and load coincidence.

To determine the impact the addition of wind has on the variability within the system, AWST evaluated the maximum hourly up ramps and down ramps that occurred for each balancing authority load, the simulated wind production, and the net load (load – wind). Incremental variation helps to identify the additional magnitude that swings may have within the system. Much, and potentially all, of the increased variance is already accounted for in the reserve margin, especially if the reserve margin is higher than the required reserve margin (which is typical of most balancing authorities).

For systems with wind generation, periods of high wind output can result in a net load less than the minimum power output level required to keep all baseload units online. During these events, baseload units (nuclear and/or large coal) must be shut down or wind plants curtailed. AWST completed an analysis based on two baseload scenarios to identify the impact of wind on the baseload unit operation.

Capacity value is the amount of generation that can be relied upon to support system reliability. AWST researched current operator methods for determining capacity value and applied the methods to give an estimated capacity value for the Clean Line project.

Although the coincidence of the wind generation with the load in the southeast is not strong, the overall impact of integrating wind is mitigated by load variability, which is consistent with the findings of other studies with similar wind penetrations. Hourly ramps of simulated wind are largely uncorrelated with hourly load ramps, which mitigate the impacts of wind on net load variability. Therefore, incremental variability to the system, due to wind, is overall low and can be significantly reduced in the export scenarios. Furthermore, the export scenarios have few (or no) baseload impact issues that are likely to cause curtailments to occur. AWST believes that further research should be carried out to evaluate impacts on ancillary services and to model the effects of wind integration on reserve requirements.

1. Introduction

AWS Truepower, LLC (AWST) was retained by Clean Line Energy Partners to complete a study to analyze the coincidence of simulated wind power output and regional load in the southeast. The wind generation, produced in southwestern Kansas, the Oklahoma panhandle, and the Texas panhandle is to be delivered to the Tennessee Valley Authority (TVA) via the proposed Plains and Eastern Clean Line project, and potentially exported to other southeastern balancing authorities such as Southern Company, Duke Energy, and Entergy. Production scenarios were created utilizing the Wind Generation Scenario Summary Statistics Report completed in October of 2009.

The potential impacts on the grid were assessed for four production and exportation scenarios as described further in this report. Diurnal and seasonal graphs and calculations were evaluated to determine coincidence of wind and balancing authority loads. Further statistics were calculated to understand the impact of wind energy on system operations, such as generation ramp rate, baseload impact, and capacity value.

2. Collect and Validate Load Data

TVA supplied AWST with hourly load data for the time period ranging from 1997 to 2006. AWST acquired the same hourly load data from the FERC form 714, along with the data for 2007 and 2008. Upon evaluation of the data, it was determined that the FERC Form 714 data was essentially equivalent to the data supplied by TVA. FERC Form 714 data was also used for Southern Company, Duke Energy and Entergy to assess exportation of portions of the simulated wind production into other southeastern markets. Data was acquired for the time period from 1998 to 2008 (2009 data has not yet been released).

The FERC Form 714 is a required submission of data authorized by the Federal Power Act. The publicly available data is offered by FERC to assist in educating the general public and allowing a broader picture of balancing authority operations.

Load data was analyzed to filter and correct data issues (e.g. missing data, erroneous data, daylight savings (DST) shifts, and time zone alignment). Missing and erroneous (e.g. negative load) hours were replaced with the average of the prior and following hours. Additionally, hours showing load levels well below the typical system wide minimum loads were replaced with the same averaging method. These data replacements allowed AWST to maintain a full record set without biasing the variation studies. For the Duke Energy data, the ending hour of DST contained a double record, which was split into single records during the data shift. Figure 1, below, shows the mean diurnal pattern for each of the load data sets collected; each of the studied balancing authorities has similar diurnal patterns.

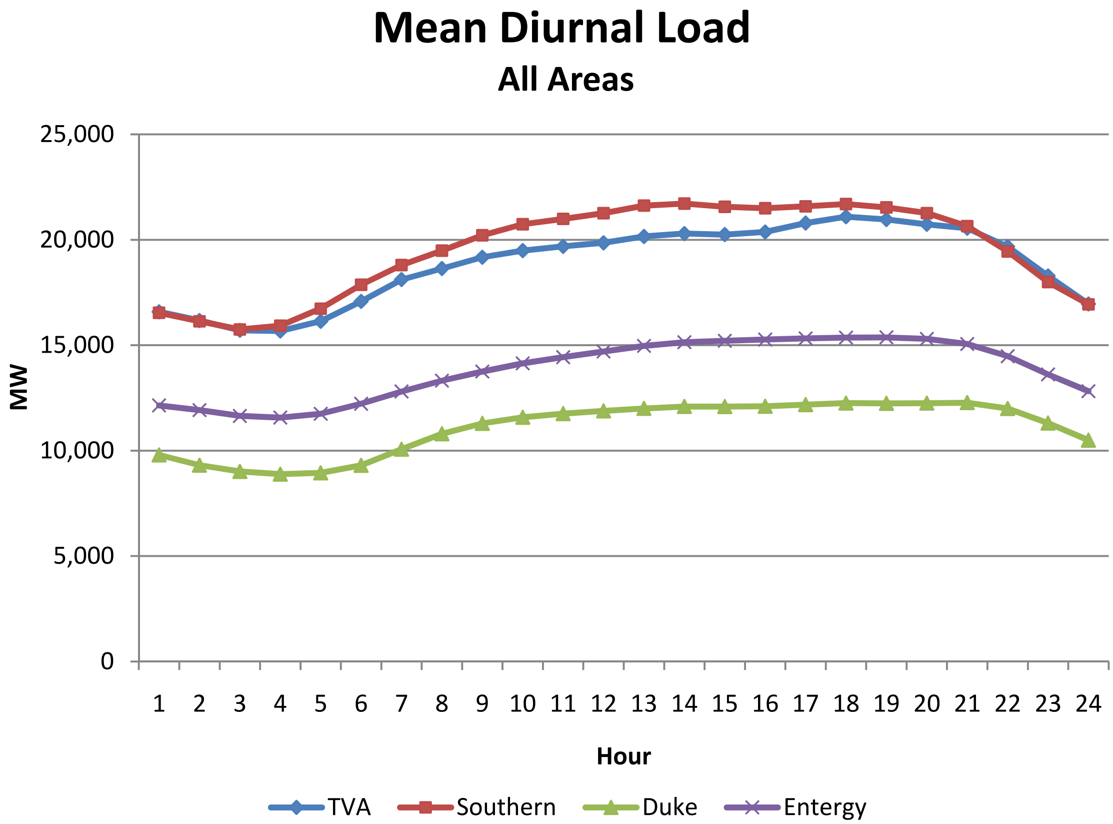

Figure 1. Mean Diurnal Load Patterns within the Study Region

3. EWITS Scenarios and *windTrends*® dataset

AWST created hourly time series production data sets, utilizing the windTrends dataset to simulate production from the selected projects within the Texas and Oklahoma panhandles and southwestern Kansas based on the EWITS study sites. The data were produced for two subsets of the "core sites" and "expanded sites" identified in the October 2009 study.

A 7000 MW subset was created from the expanded project sites and a 3500 MW subset from the core project sites. The subsets were chosen based on the capacity factor estimated for the identified projects. The sites selected for each subset can be seen in Table 1 and Table 2. Note that the total rated capacity in each subset exceeds the nominal capacity. For the 3500 MW subset, the total installed capacity is approximately 4090 MW. For the 7000 MW subset, the aggregate installed capacity is approximately 8430 MW. The purpose of this is to increase the average utilization of the transmission line. It is assumed that any excess generation beyond the nominal maximum will not be transmitted through the line.

Table 1. EWITS Site IDs and Rated Capacities for 3500 MW Subset

Sites From Core Area	Site Capacity (MW)
215	450.6
365	557.5
473	261.8
503	308.1
540	306.7
573	373
620	455.7
754	436.1
797	247
1021	264
1476	427.6
Total	4088.1

Table 2. EWITS Site IDs and Rated Capacities for 7000 MW Subset

Sites From Expanded Area	Site Capacity (MW)
53	427.5
105	410.9
115	289.1
150	350.7
215	450.6
238	442.6
239	333.8
283	461.4
324	566.1
363	505.6
365	557.5
438	352.3
473	261.8
502	463
620	455.7
754	436.1
797	247
1021	264
1476	427.6
1720	376.7
1792	347.8
Total	8427.8

windTrends

Simulated production data were created for each site using AWS Truepower's *windTrends* database. *windTrends* is a simulated hourly time series, beginning in 1997, of Mesoscale Atmospheric Simulation System (MASS) model output covering the conterminous United States and southern Canada. It is essentially a controlled regional reanalysis dataset developed by AWS Truepower that differs from the conventional reanalysis data because it is computed at a finer resolution (20 km) and it relies on fixed observational data (rawinsonde).[i] The model output can be interpolated to the location of a given project. The *windTrends* dataset has been validated against operational plants as well as long term reference meteorological stations and internal tall tower data.

For this analysis, the model output was interpolated to each of the sites identified in the October 2009 report from the EWITS dataset. To determine the power output at each site, an IEC-class-specific composite power curve was used for each of the sites within the area subsets. The IEC Class I and Class II curves are based on a composite of three class-specific turbines commercially available at the time of the EWITS study (GE, Vestas, and Gamesa brands). The same power curves were used in the EWITS study. The power curves are scaled to a rated capacity of 2 MW and are valid for the standard sea-level air density of 1.225 kg/m^3. IEC approved extrapolation and interpolation techniques were used to create multiple air density power curves. It is likely that, due to improvements in turbine technology, the capacity factors produced by wind projects will increase in the future.

Scenarios

Two scenarios were analyzed for each subset of project sites described above, resulting in four scenarios in all. The scenarios are described in Table 3. For each subset, one scenario envisions integrating all of the wind generation into the TVA system, while the other envisions half of the generation being exported to neighboring systems (Southern Company, Duke, and Entergy).

Table 3. Description of Scenarios

Scenario	Description
1	7000 MW, all integrated into TVA
2	7000 MW, 3500 MW integrated into TVA and 3500 MW integrated into Southern Company, Duke and Entergy, divided pro rata each hour based on hourly load.
3	3500 MW, all integrated into TVA
4	3500 MW, 1750 MW integrated into TVA and 1750 MW integrated into Southern Company, Duke and Entergy, divided pro rata each hour based on hourly load.

4. Diurnal, Monthly and Seasonal Patterns

Wind product varies through time, thus the coincidence of loads and wind generation must be taken into consideration. Using the simulated wind data sets and the acquired historical load data sets, AWST looked at the coincidence of the load and wind generation. Because the impact of wind generation may differ diurnally, AWST looked at 11 years of data, both yearly and as an 11 year mean diurnal. The diurnal plots in Figure 2 - Figure 20 are based on the 11 year mean diurnal patterns for each of the production and balancing area scenarios. Year specific diurnal plots for the TVA and 3500 MW of wind scenario can be seen in Appendix A.

To further examine coincidence of wind energy with seasonal load, seasonal and mean monthly analyses were completed. Figure 22 and Figure 23 illustrate the difference in load and wind patterns seasonally, while Figure 24 and Figure 25 show the mean load and production for the 3500 MW scenario. For TVA, a summer peaking system, the coincidence of the wind is lower during the peak season than the off-peak season.

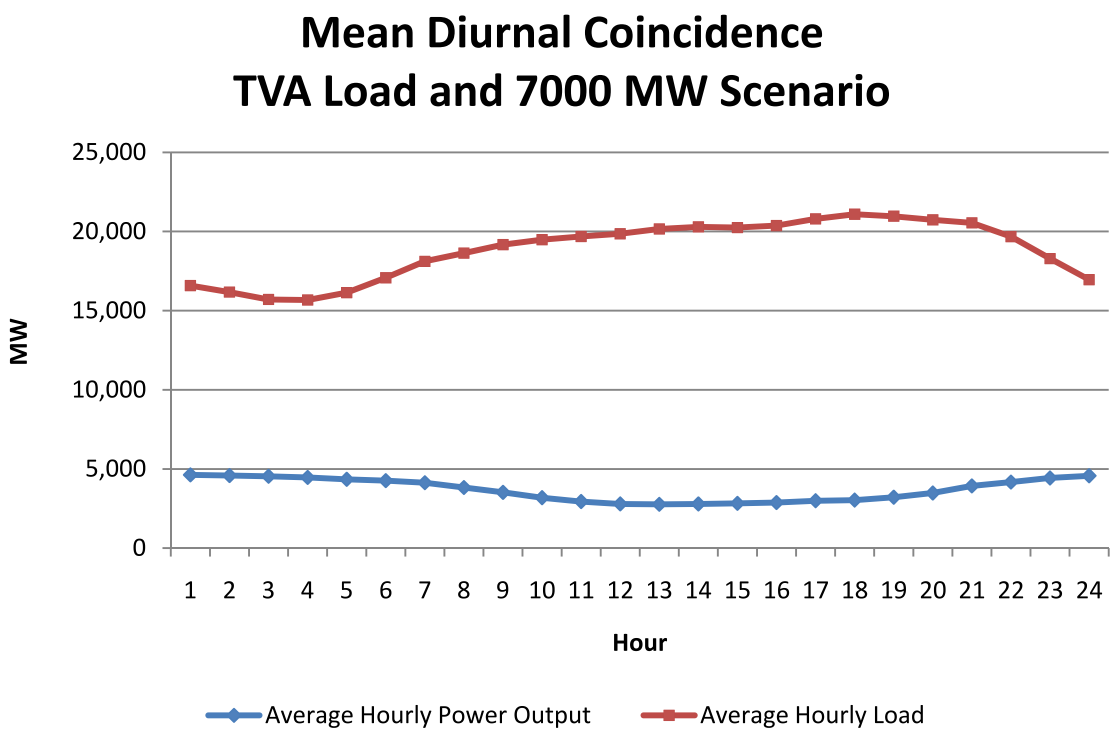

Figure 2. Coincidence of TVA load with 100% of the 7000 MW wind Scenario

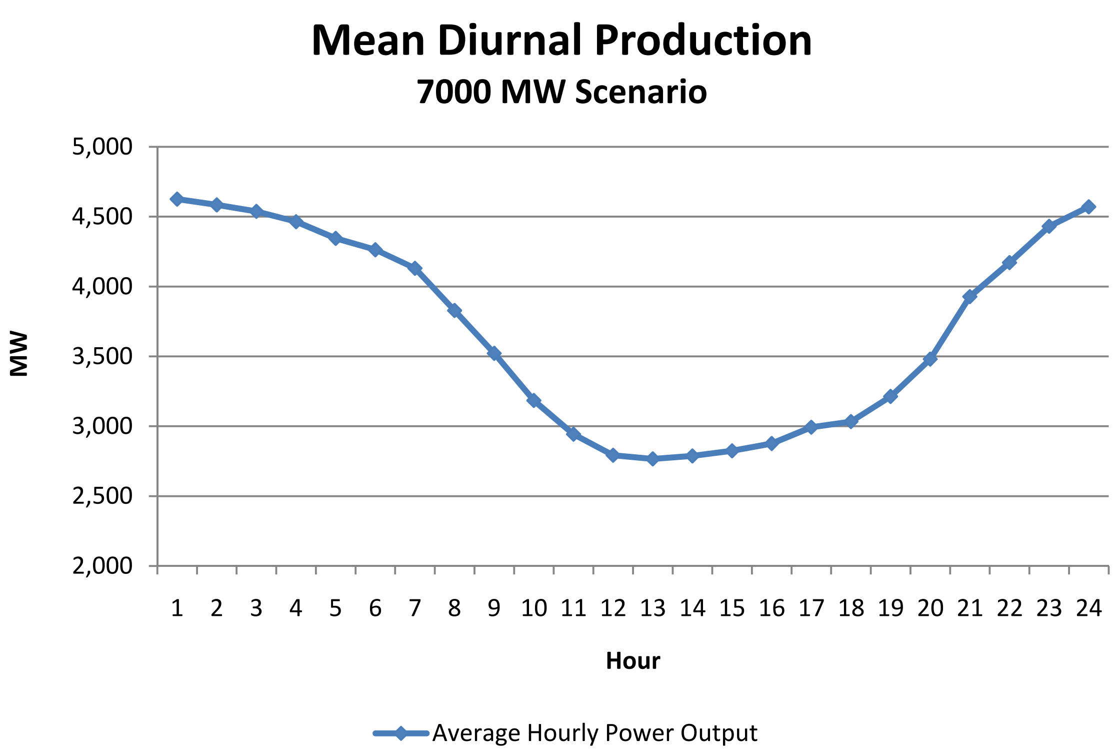

Figure 3. 7000 MW Wind Scenario Diurnal Production Profile

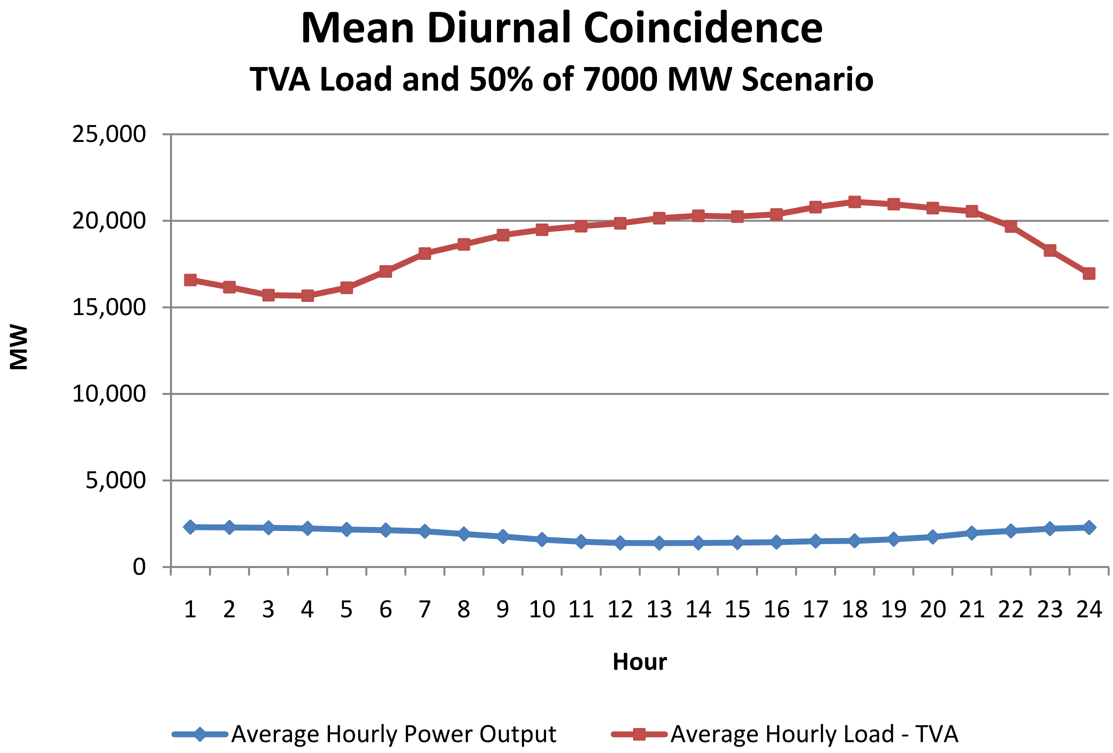

Figure 4. Coincidence of TVA load with 50% of the 7000 MW wind Scenario

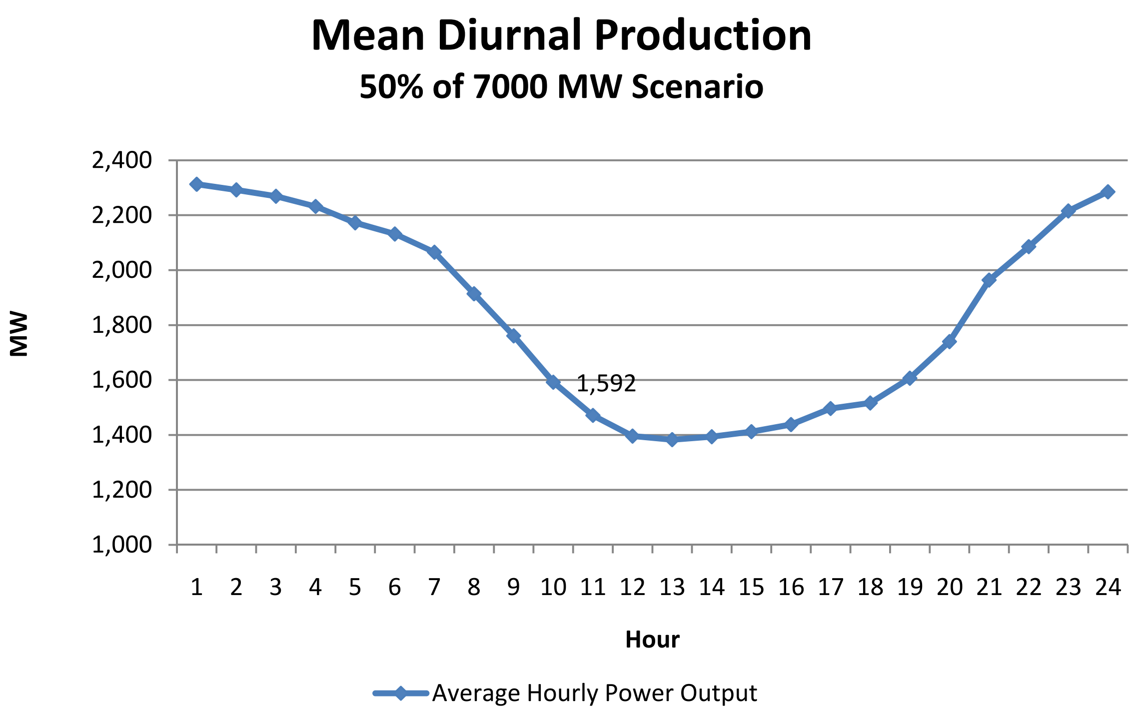

Figure 5. 50% of 7000 MW Wind Scenario Diurnal Production Profile

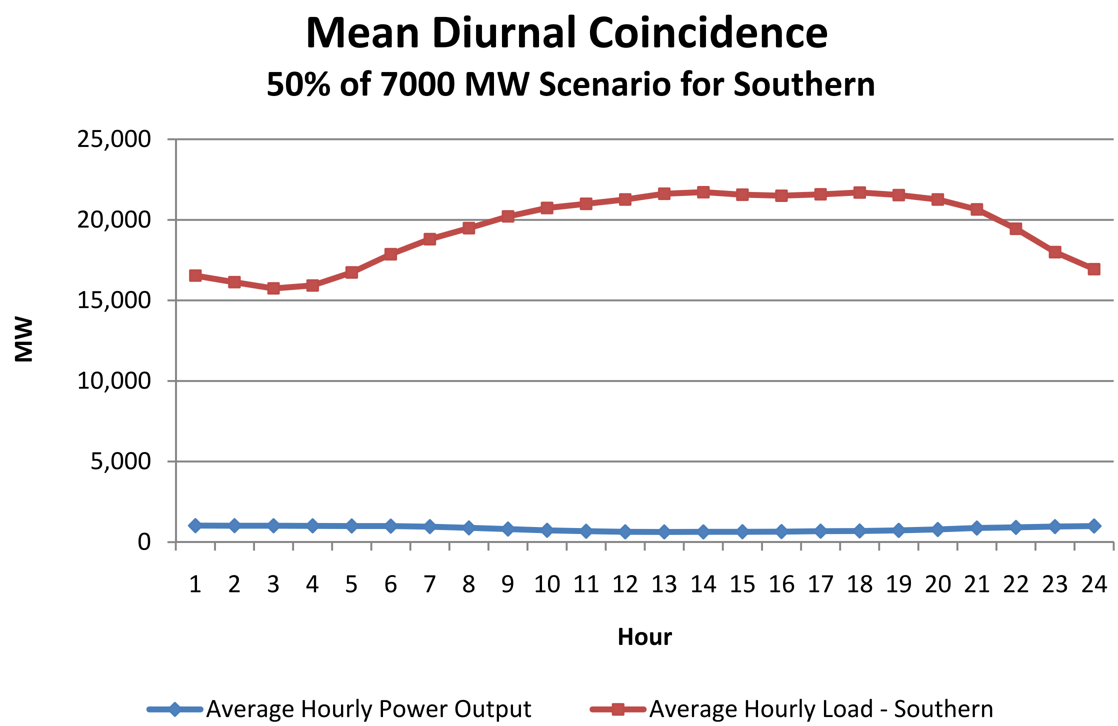

Figure 6. Coincidence of Southern load with Pro-Rata Share of the 50% of 7000 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

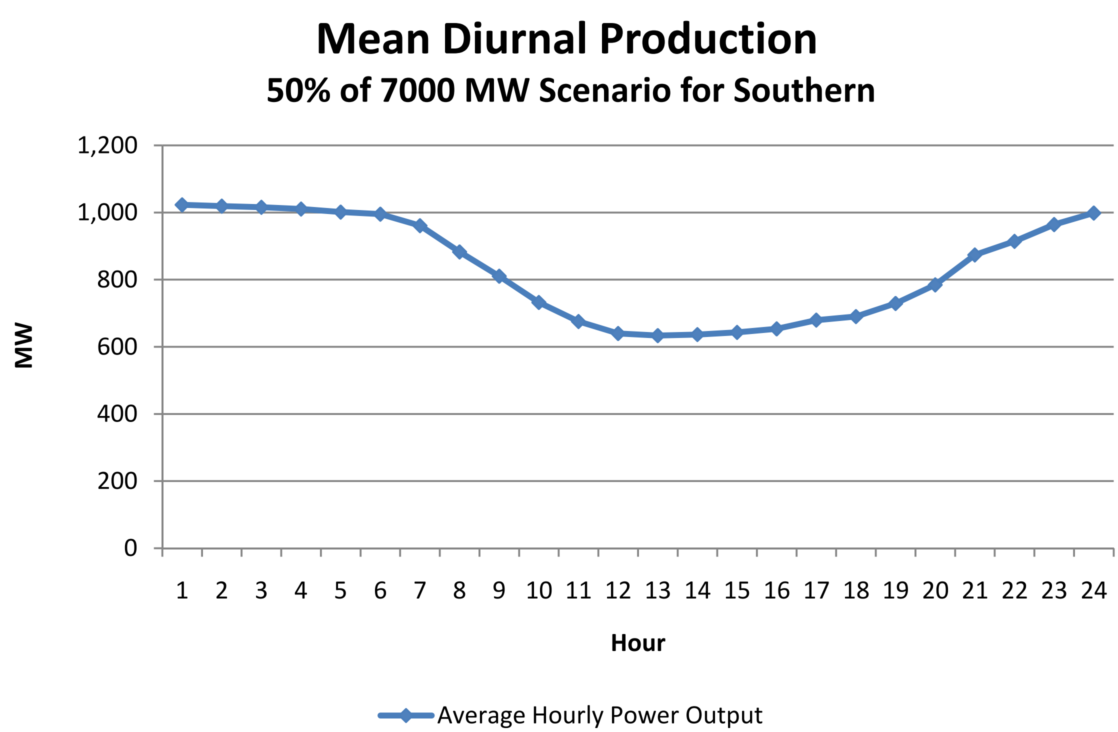

Figure 7. Southern Pro-Rata Share of the 50% of 7000 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy

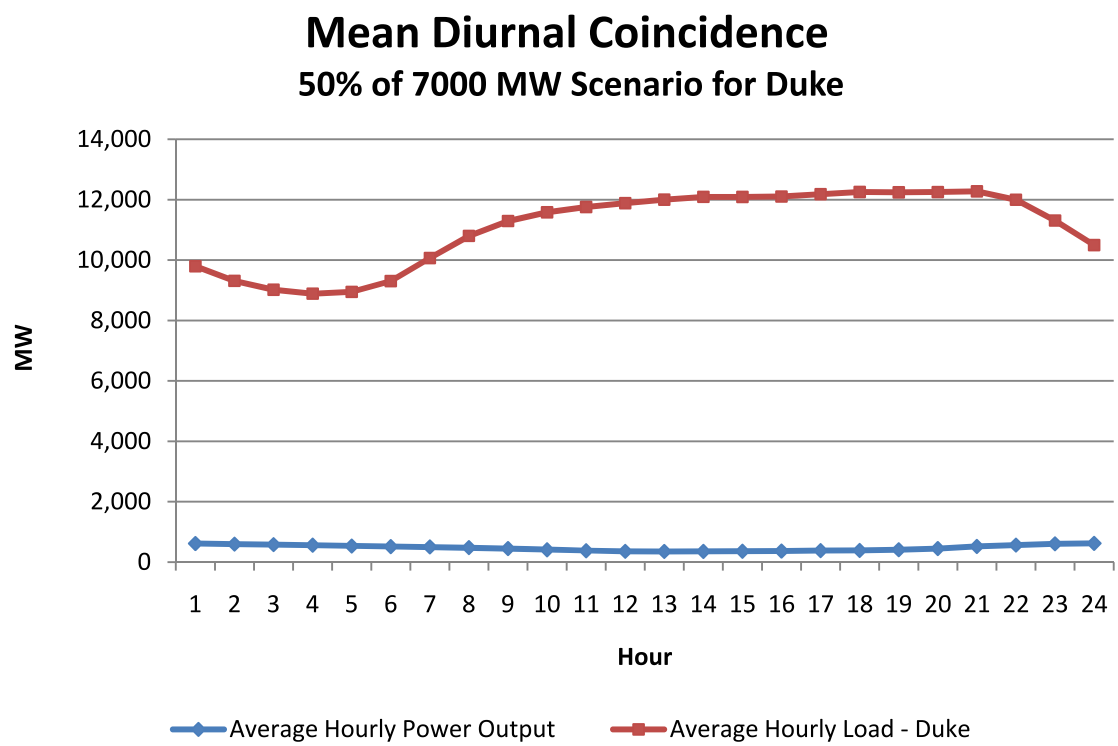

Figure 8. Coincidence of Duke load with Pro-Rata Share of the 7000 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

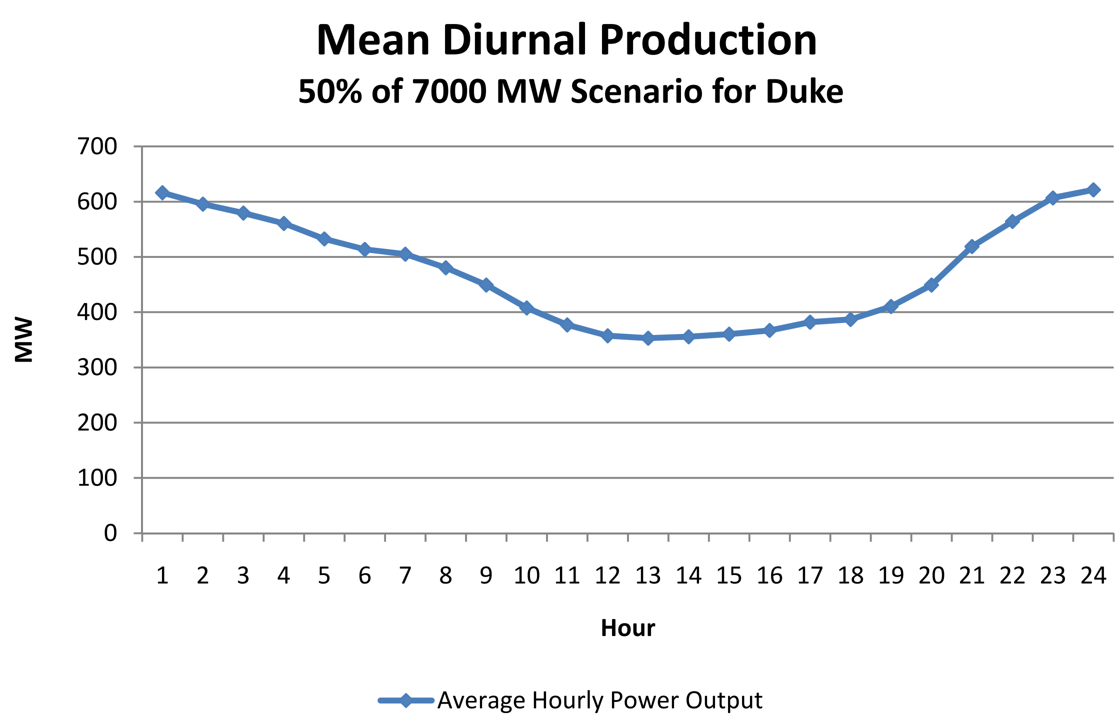

Figure 9. Duke Pro-Rata Share of the 50% of 7000 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy

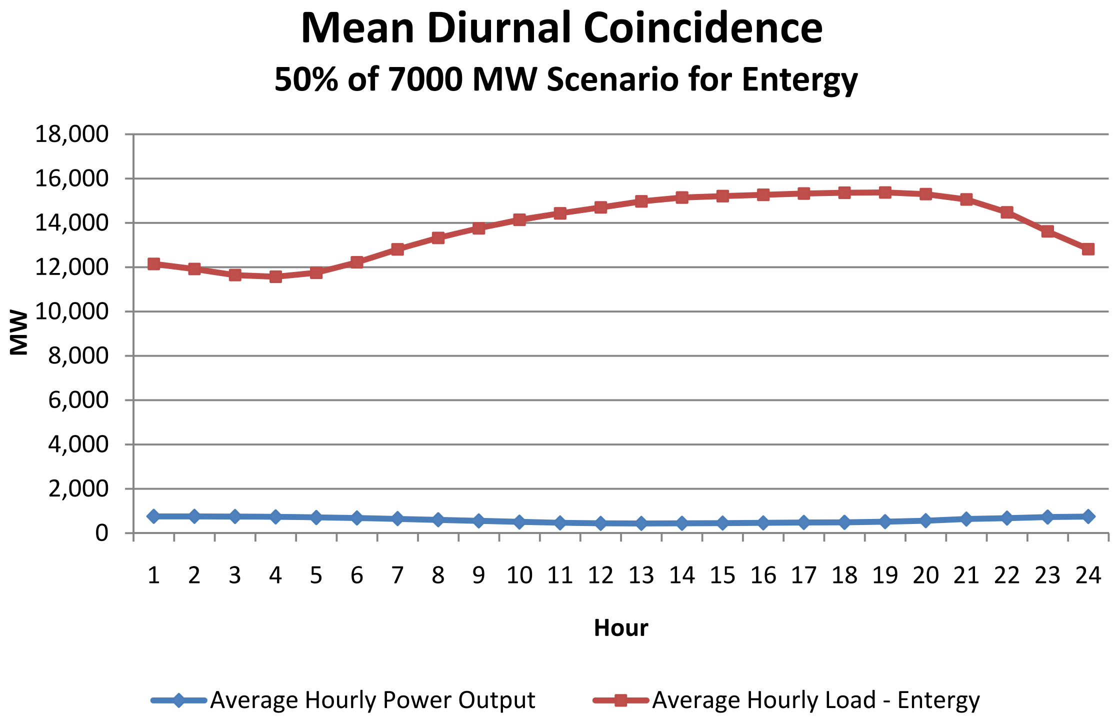

Figure 10. Coincidence of Entergy load with Pro-Rata Share of the 7000 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

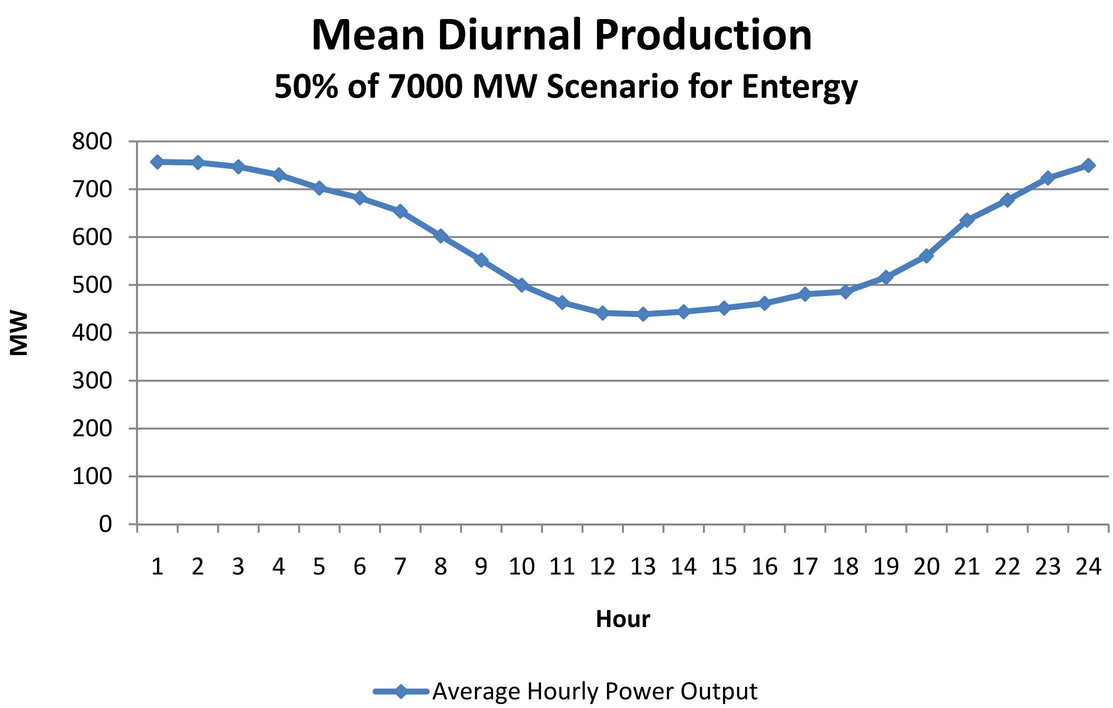

Figure 11. Entergy Pro-Rata Share of the 50% of 7000 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

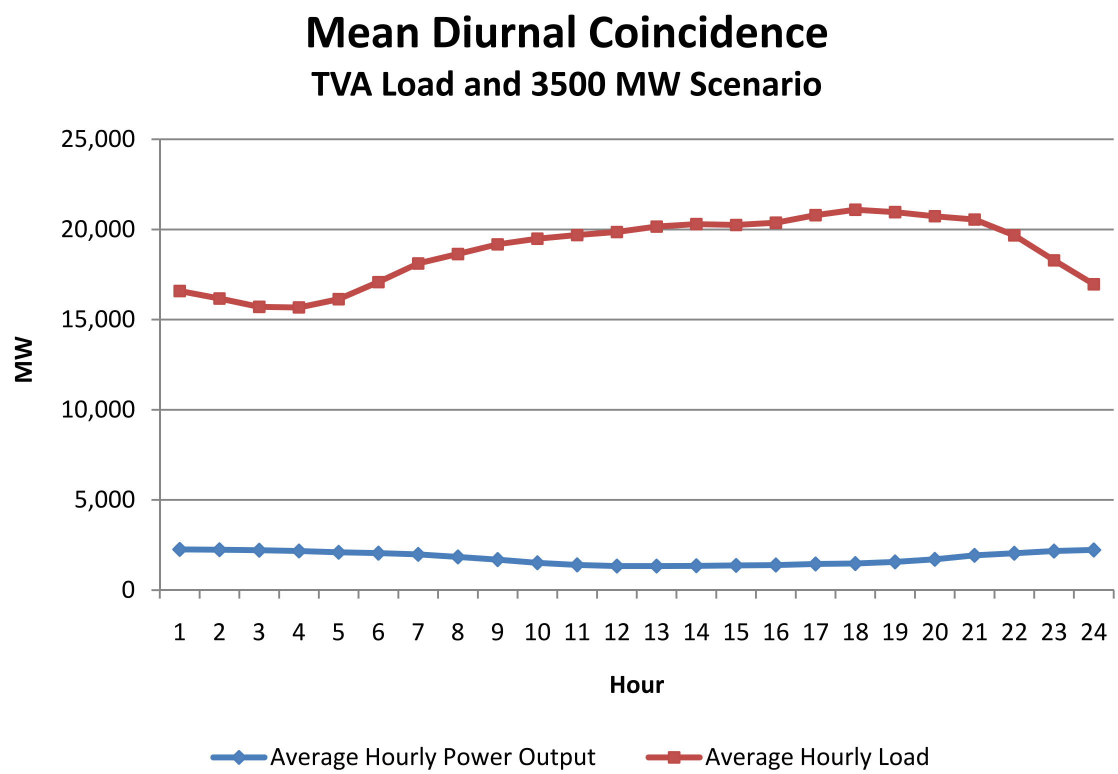

Figure 12. Coincidence of TVA load with 100% of the 3500 MW wind Scenario

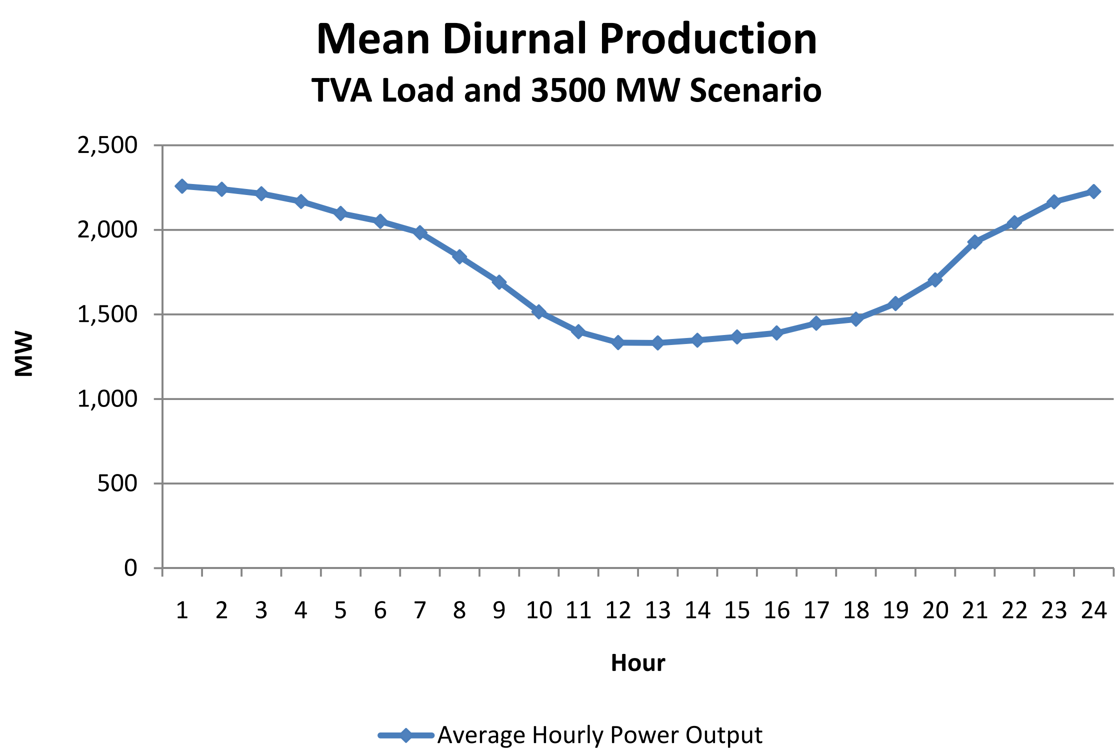

Figure 13. 3500 MW Wind Scenario Diurnal Production Profile

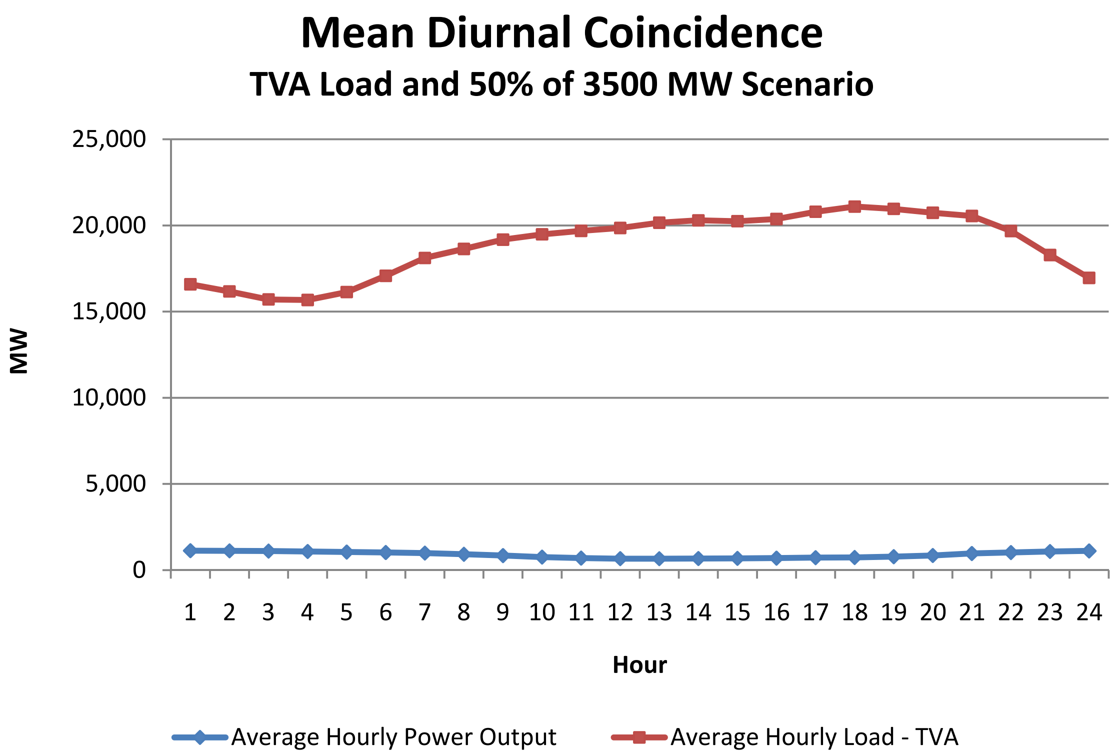

Figure 14. Coincidence of TVA load with 50% of the 3500 MW wind Scenario

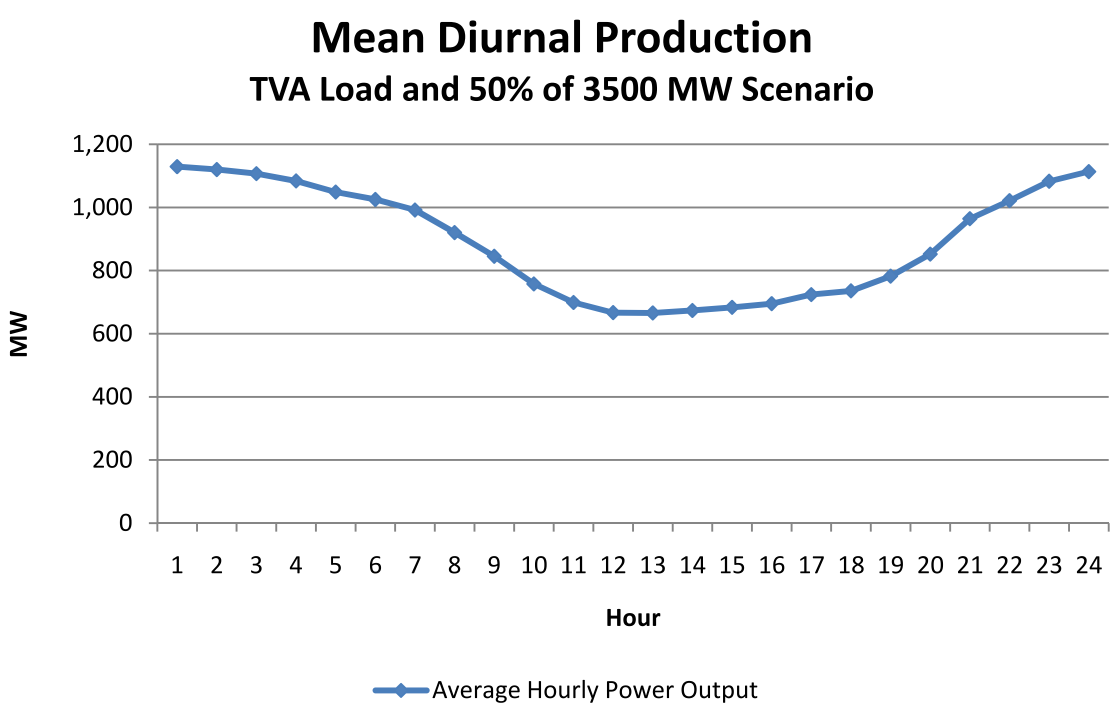

Figure 15. 50% of 3500 MW Wind Scenario Diurnal Production Profile

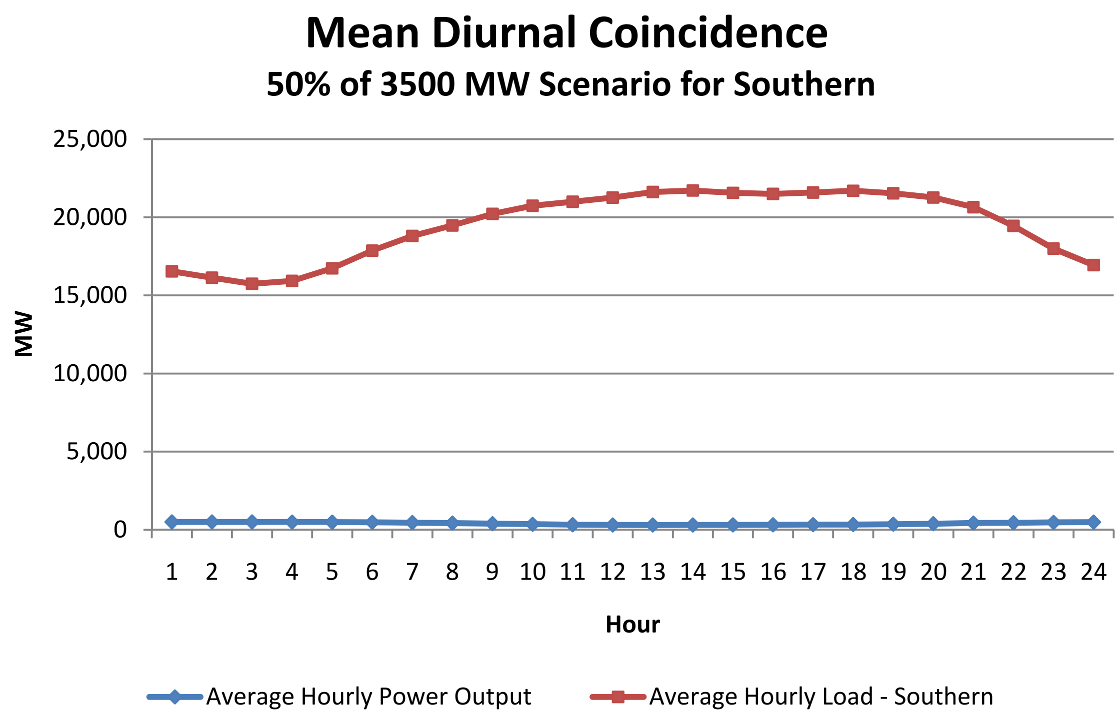

Figure 16. Coincidence of Southern load with Pro-Rata Share of the 3500 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

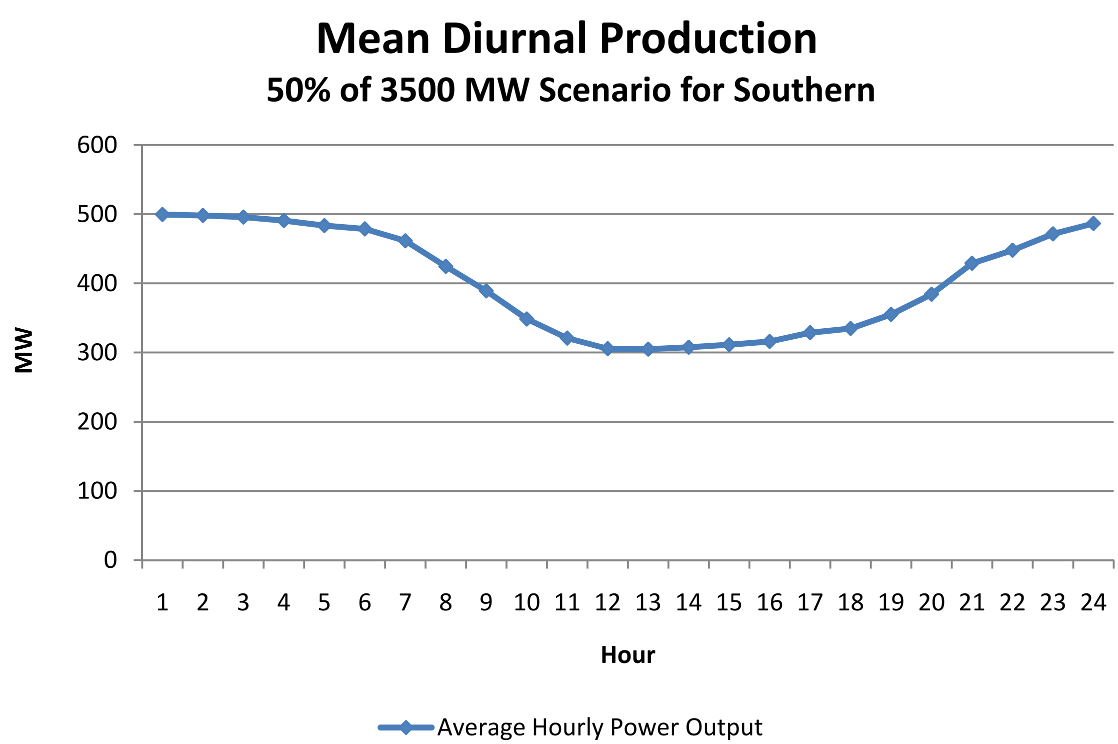

Figure 17. Southern Pro-Rata Share of the 50% of 3500 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy

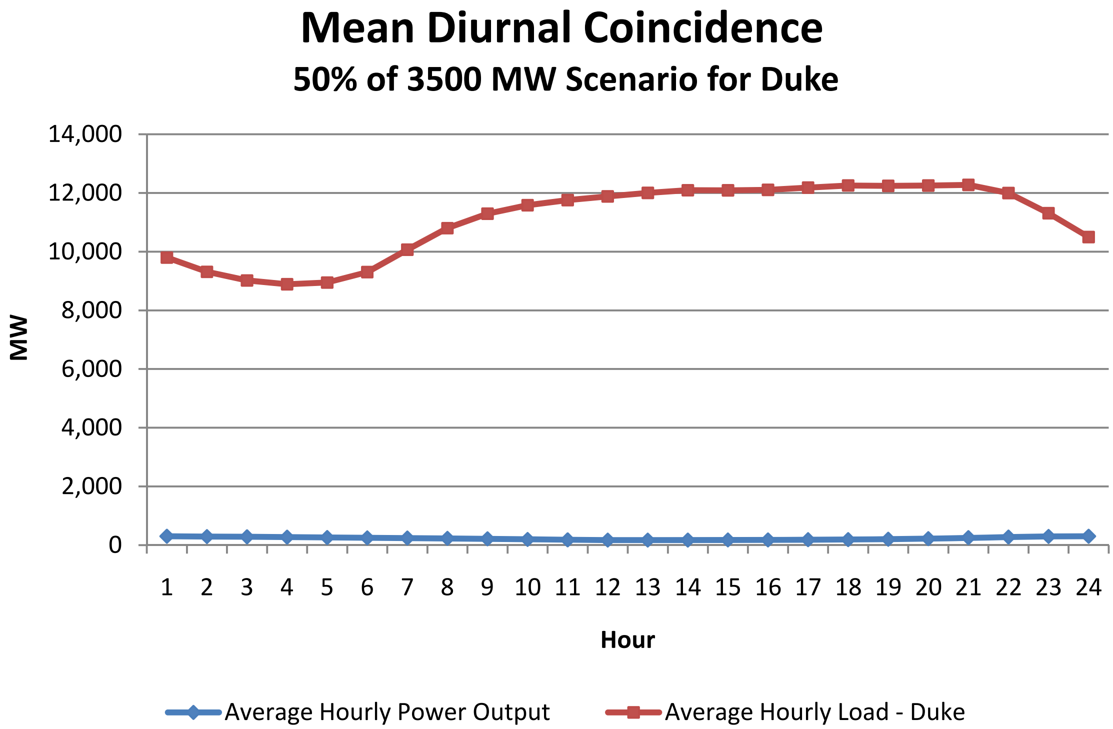

Figure 18. Coincidence of Duke load with Pro-Rata Share of the 3500 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

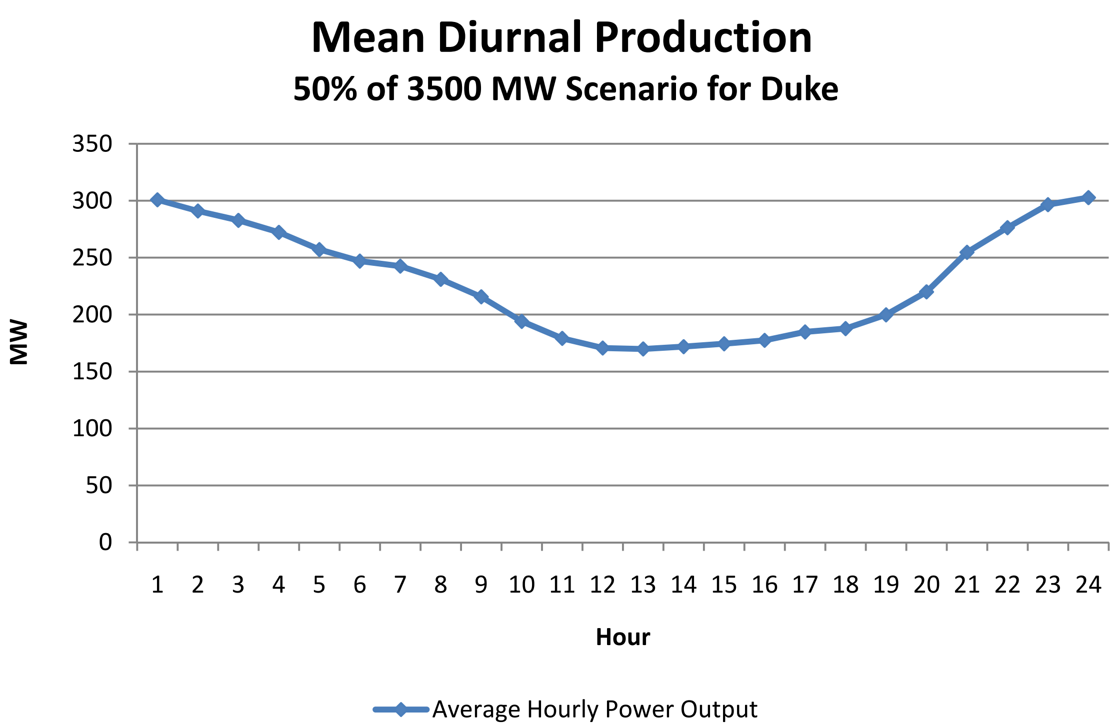

Figure 19. Duke Pro-Rata Share of the 50% of 3500 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy

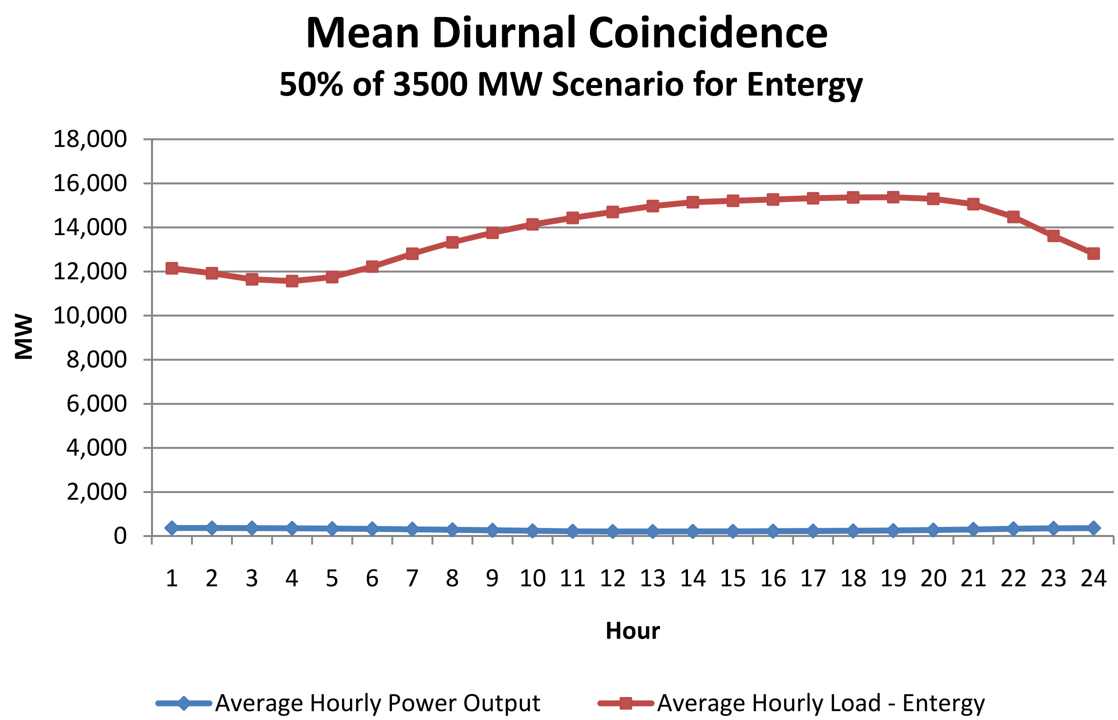

Figure 20. Coincidence of Entergy load with Pro-Rata Share of the 3500 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy.

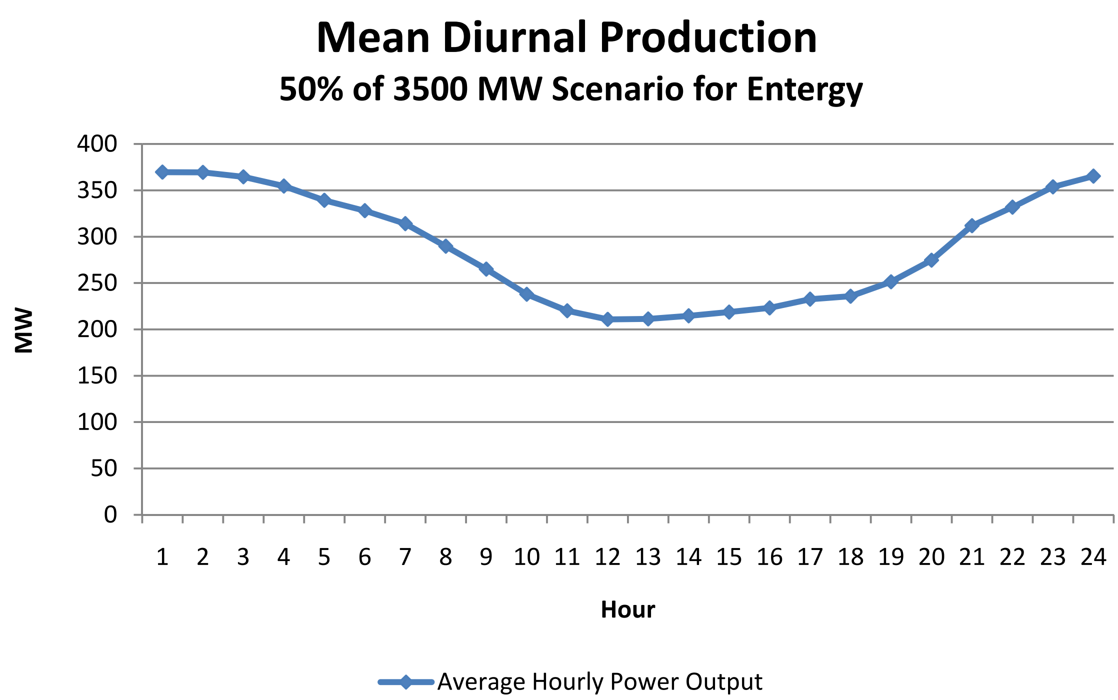

Figure 21. Entergy Pro-Rata Share of the 50% of 3500 MW wind Scenario, division based on hourly load of Southern, Duke and Entergy

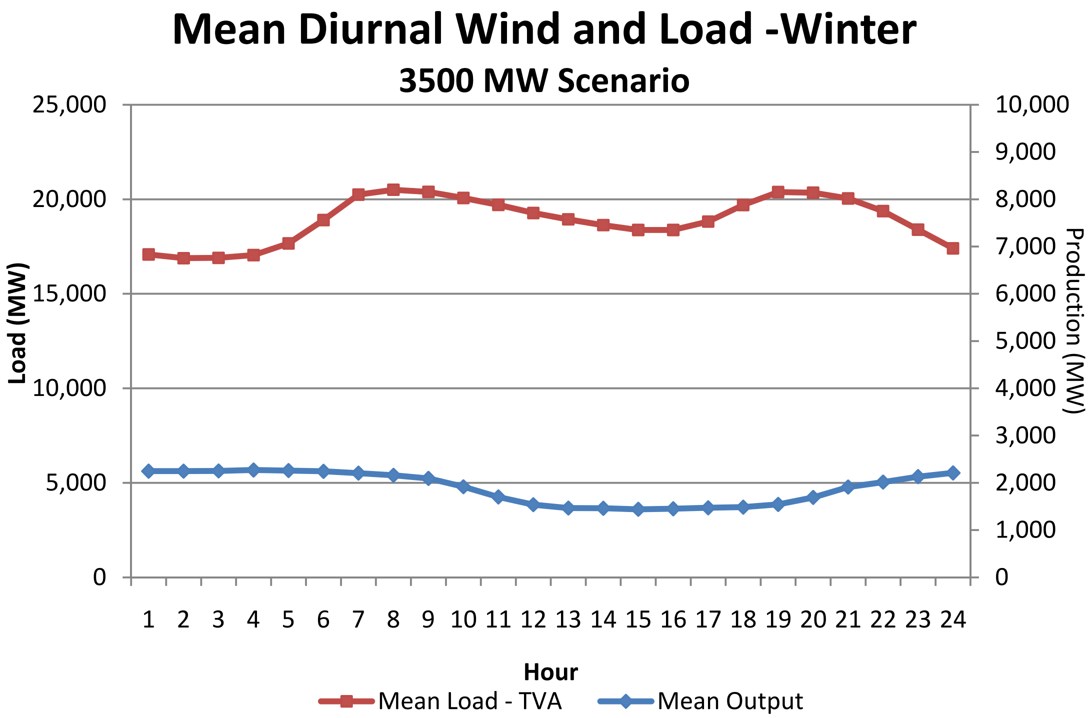

Figure 22. Winter Diurnal Load for TVA and 3500 MW production Scenario

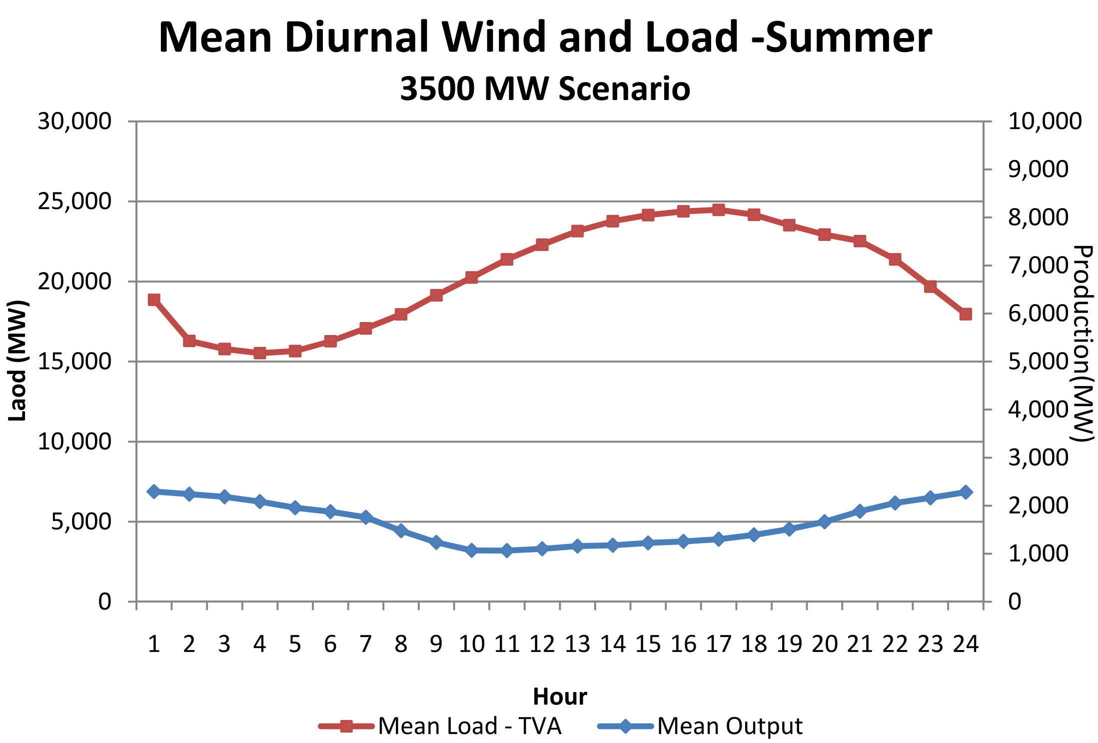

Figure 23. Summer Diurnal Load for TVA and 3500 MW production Scenario

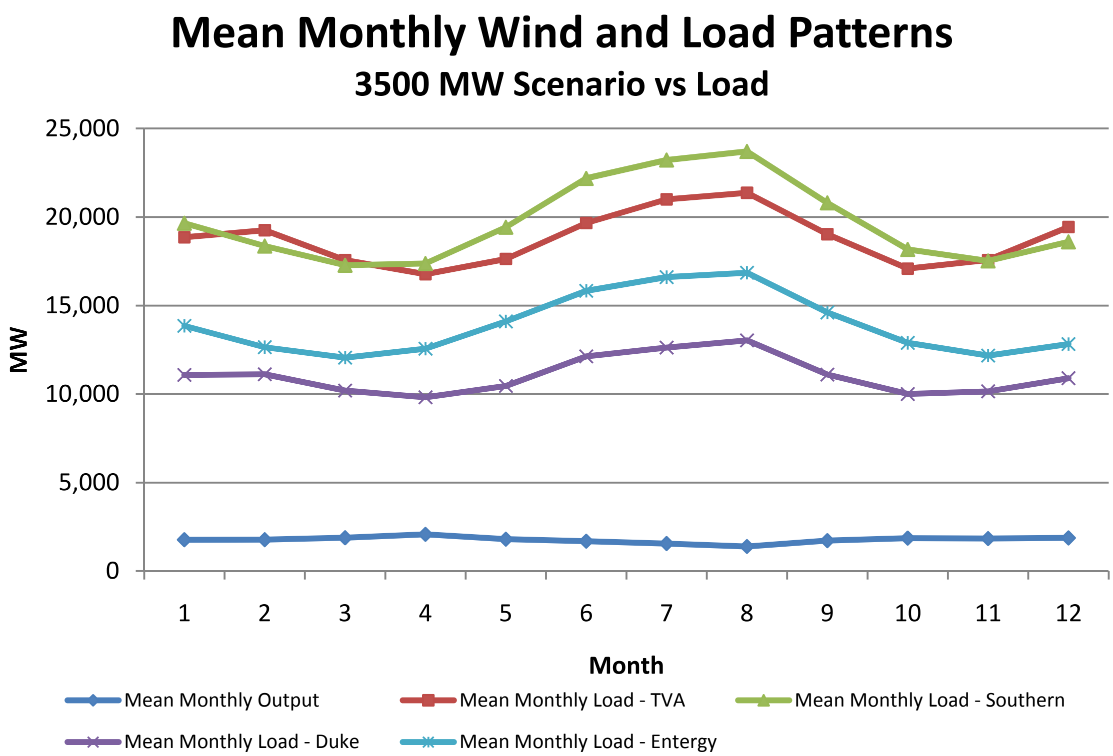

Figure 24. Monthly Average Wind and Load Patterns for 3500 MW and All Studied Balancing Authorities

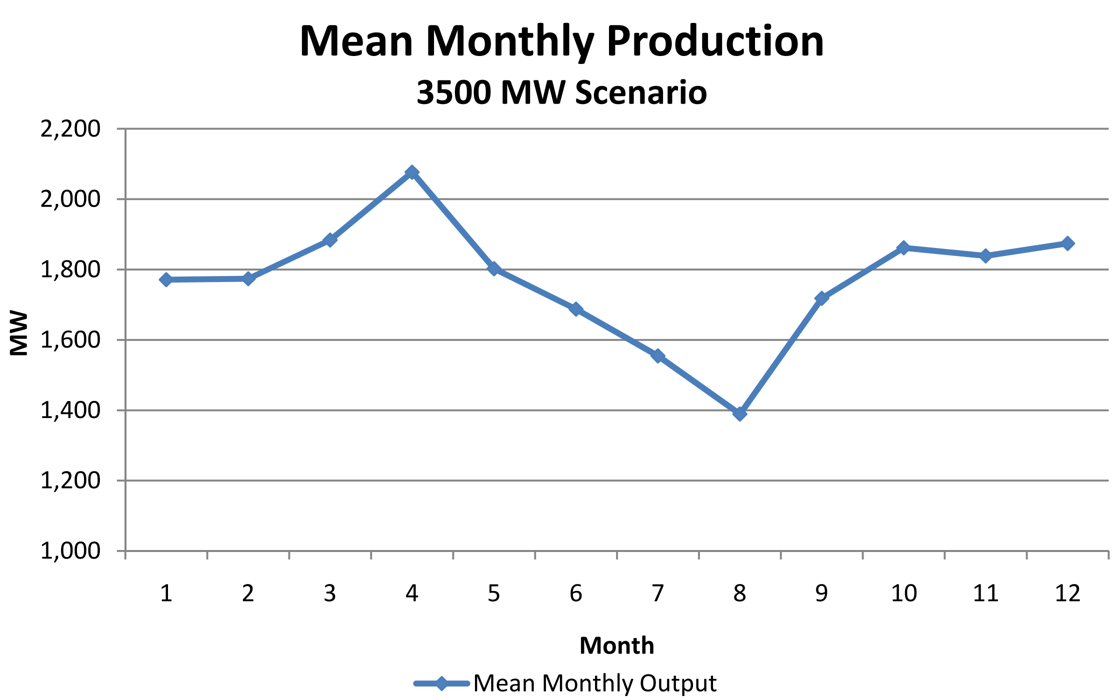

Figure 25. Mean Monthly Production for the 3500 MW Scenario

5. Analysis of Maximum and Minimum Statistics for Load, Generation, and Net Load

Full Dataset Statistics

AWST completed a set of maximum and minimum statistics for each of the studied balancing authority loads, each of the generation scenarios, and each of the associated net loads. Table 4 shows the statistics for the full 11-year study period.

Table 4. Maximum and Minimum Statistics for Full 11-year Dataset

Maximum and Minimum Load, Generation, and Net Load Values	Load Only	7000 MW Wind	50% of 7000 MW Wind	3500 MW Wind	50% of 3500 MW Wind	Net Load - 7000 MW (All TVA)	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 3500 MW (All TVA)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max									
Wind		7000	3500	3500	1750				
TVA	33482					33259	33371	33354	33418
Southern	35515						35206		35310
Duke	20628						20536		20597
Entergy	23646						23227		23420
Min									
Wind		0	0	0	0				
TVA	10681					3902	7402	7270	8976
Southern	8079						6953		7707
Duke	6275						5492		5886
Entergy	7854						7103		7516

Top 100 Hours Statistics

AWST completed a set of maximum and minimum statistics on the top 100 load hours of each season and each year. Table 5 - Table 8 shows the annual statistics for the top 100 load hours of a given year and their associated wind generation and net load. Table 9 - Table 12 show the top 100 load hours for each season over the 11-year period, again with their associated wind generation and net load.

Table 5. Top 100 Load Hour Analysis for TVA

TVA Top 100 Load Hours	Load Only	7000 MW Wind	50% of 7000 MW Wind	3500 MW Wind	50% of 3500 MW Wind	Net Load - 7000 MW (All TVA)	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 3500 MW (All TVA)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max									
1998	27127	6980	3490	3500	1750	20148	23637	23627	25377
1999	28356	3829	1915	2147	1073	24527	26441	26209	27283
2000	29344	540	270	97	48	28804	29074	29247	29296
2001	27368	6581	3290	3443	1721	20787	24078	23925	25647
2002	29052	1309	654	494	247	27744	28398	28558	28805
2003	29866	5402	2701	2897	1448	24464	27165	26969	28418
2004	29966	367	183	126	63	29599	29783	29840	29903
2005	31924	3811	1906	1921	961	28113	30019	30003	30964
2006	32008	3144	1572	1469	735	28864	30436	30539	31274
2007	33482	223	111	128	64	33259	33371	33354	33418
2008	32027	6969	3484	3500	1750	25058	28543	28527	30277
Min									
1998	25393	6900	3450	3393	1696	18493	21943	22001	23697
1999	26581	481	241	184	92	26100	26340	26397	26489
2000	26600	3392	1696	1485	743	23208	24904	25115	25857
2001	25407	4296	2148	3231	1615	21111	23259	22176	23792
2002	27089	3132	1566	1472	736	23957	25523	25618	26353
2003	26757	3456	1728	1373	687	23302	25029	25384	26070
2004	26780	7000	3500	3500	1750	19780	23280	23280	25030
2005	29196	2138	1069	806	403	27058	28127	28389	28792
2006	29963	1700	850	1069	535	28262	29112	28893	29428
2007	31011	3576	1788	2030	1015	27435	29223	28981	29996
2008	28787	4405	2203	1783	892	24382	26585	27004	27896

Table 6. Top 100 Load Hour Analysis for Southern Company

Southern Top 100 Load Hours	Load Only	50% of 7000 MW Wind	50% of 3500 MW Wind	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max					
1998	28920	1271	490	27649	28430
1999	31025	166	40	30859	30985
2000	31702	152	18	31550	31684
2001	30140	28	8	30111	30132
2002	32926	167	103	32760	32823
2003	31034	172	27	30862	31007
2004	32327	37	9	32289	32318
2005	33308	887	425	32422	32883
2006	33984	94	69	33890	33915
2007	35515	1718	829	33797	34686
2008	33999	309	174	33690	33825
Min					
1998	27737	213	86	27524	27651
1999	28805	48	14	28756	28791
2000	29115	1347	656	27768	28459
2001	27780	335	151	27445	27629
2002	30698	210	127	30487	30571
2003	28908	586	377	28322	28531
2004	29683	711	225	28972	29459
2005	30825	454	178	30371	30647
2006	32486	659	319	31827	32167
2007	32535	944	439	31591	32096
2008	30526	899	209	29627	30317

Table 7. Top 100 Load Hour Analysis for Duke Energy

Duke Top 100 Load Hours	Load Only	50% of 7000 MW Wind	50% of 3500 MW Wind	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max					
1998	17657	843	419	16814	17238
1999	18426	239	89	18187	18337
2000	18773	352	171	18421	18602
2001	18105	73	36	18032	18069
2002	18664	70	19	18594	18645
2003	18074	351	116	17723	17958
2004	17926	83	48	17843	17878
2005	16954	292	133	16662	16821
2006	19725	226	96	19499	19629
2007	20628	92	31	20536	20597
2008	19762	11	3	19751	19759
Min					
1998	16386	617	288	15769	16098
1999	17204	79	41	17125	17163
2000	16903	257	100	16646	16803
2001	16118	84	1	16034	16117
2002	17104	97	49	17007	17055
2003	16358	75	21	16283	16337
2004	16516	248	139	16268	16377
2005	16026	291	148	15735	15878
2006	18039	142	74	17897	17965
2007	18536	676	342	17860	18194
2008	17854	988	490	16866	17364

Table 8. Top 100 Load Hour Analysis for Entergy

Entergy Top 100 Load Hours	Load Only	50% of 7000 MW Wind	50% of 3500 MW Wind	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max					
1998	21,856	54	15	21,802	21,841
1999	21,853	204	40	21,649	21,813
2000	23,384	1,045	484	22,339	22,900
2001	21,609	327	168	21,282	21,441
2002	21,732	194	73	21,538	21,659
2003	21,630	55	2	21,575	21,628
2004	22,670	29	6	22,641	22,664
2005	22,788	38	4	22,750	22,784
2006	22,505	313	179	22,192	22,326
2007	23,646	755	398	22,891	23,248
2008	22,822	572	299	22,250	22,523
Min					
1998	20,623	372	137	20,251	20,486
1999	20,469	27	17	20,442	20,452
2000	21,587	186	106	21,401	21,481
2001	20,227	620	414	19,607	19,813
2002	20,316	166	73	20,150	20,243
2003	20,373	625	235	19,748	20,138
2004	20,691	165	96	20,526	20,595
2005	21,374	271	22	21,103	21,352
2006	21,070	370	208	20,700	20,862
2007	21,398	164	80	21,234	21,318
2008	20,486	614	321	19,872	20,165

Table 9. Seasonal Analysis for TVA Top 100 Load Hours

TVA Top 100 Load Hours	Load Only	7000 MW Wind	50% of 7000 MW Wind	3500 MW Wind	50% of 3500 MW Wind
Max					
Spring	28281	54	27	17	8
Summer	33482	223	111	128	64
Winter	32027	6969	3484	3500	1750
Fall	30533	7000	3500	3500	1750
Min					
Spring	25277	3473	1737	1674	837
Summer	31513	764	382	418	209
Winter	27811	7000	3500	3500	1750
Fall	26337	1571	785	444	222

TVA Top 100 Load Hours	Net Load - 7000 MW (All TVA)	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 3500 MW (All TVA)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max				
Spring	28227	28254	28264	28273
Summer	33259	33371	33354	33418
Winter	25058	28543	28527	30277
Fall	23533	27033	27033	28783
Min				
Spring	21804	23541	23604	24440
Summer	30750	31131	31095	31304
Winter	20811	24311	24311	26061
Fall	24766	25551	25892	26114

Table 10. Seasonal Analysis for Southern Company to 100 Load Hours

Southern Top 100 Load Hours	Load Only	50% of 7000 MW Wind	50% of 3500 MW Wind	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max					
Spring	31624	13	4	31611	31620
Summer	35515	1718	829	33797	34686
Winter	30969	1303	699	29665	30270
Fall	28974	1691	903	27283	28071
Min					
Spring	27654	226	95	27428	27559
Summer	33404	689	339	32715	33065
Winter	26419	1317	696	25103	25723
Fall	26075	1546	735	24529	25340

Table 11. Seasonal Analysis for Duke Energy Top 100 Load Hours

Duke Top 100 Load Hours	Load Only	50% of 7000 MW Wind	50% of 3500 MW Wind	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max					
Spring	17525	362	63	17163	17462
Summer	20628	92	31	20536	20597
Winter	17593	1059	522	16534	17071
Fall	16978	1021	519	15957	16459
Min					
Spring	15148	124	68	15024	15080
Summer	19101	107	49	18994	19052
Winter	15623	606	295	15017	15328
Fall	15016	526	250	14490	14766

Table 12. Seasonal Analysis for Entergy Top 100 Load Hours

Entergy Top 100 Load Hours	Load Only	50% of 7000 MW Wind	50% of 3500 MW Wind	Net Load - 50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	Net Load - 50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
Max					
Spring	20372	156	61	20216	20311
Summer	23646	755	398	22891	23248
Winter	18553	1099	533	17454	18020
Fall	19539	671	204	18868	19335
Min					
Spring	18838	1267	615	17571	18223
Summer	22306	2	0	22304	22306
Winter	17026	1144	552	15882	16474
Fall	17998	227	96	17771	17902

6. Ramping Analysis

Wind, as well as electrical power system load, has hourly variations that must be balanced with the generation mix. Wind variations are conventionally assessed as a negative load, which in combination with the normal load must be balanced by system operators. Figure 26, a plot of load, wind, and net load for June 2004, shows typical variation within the system and resource.

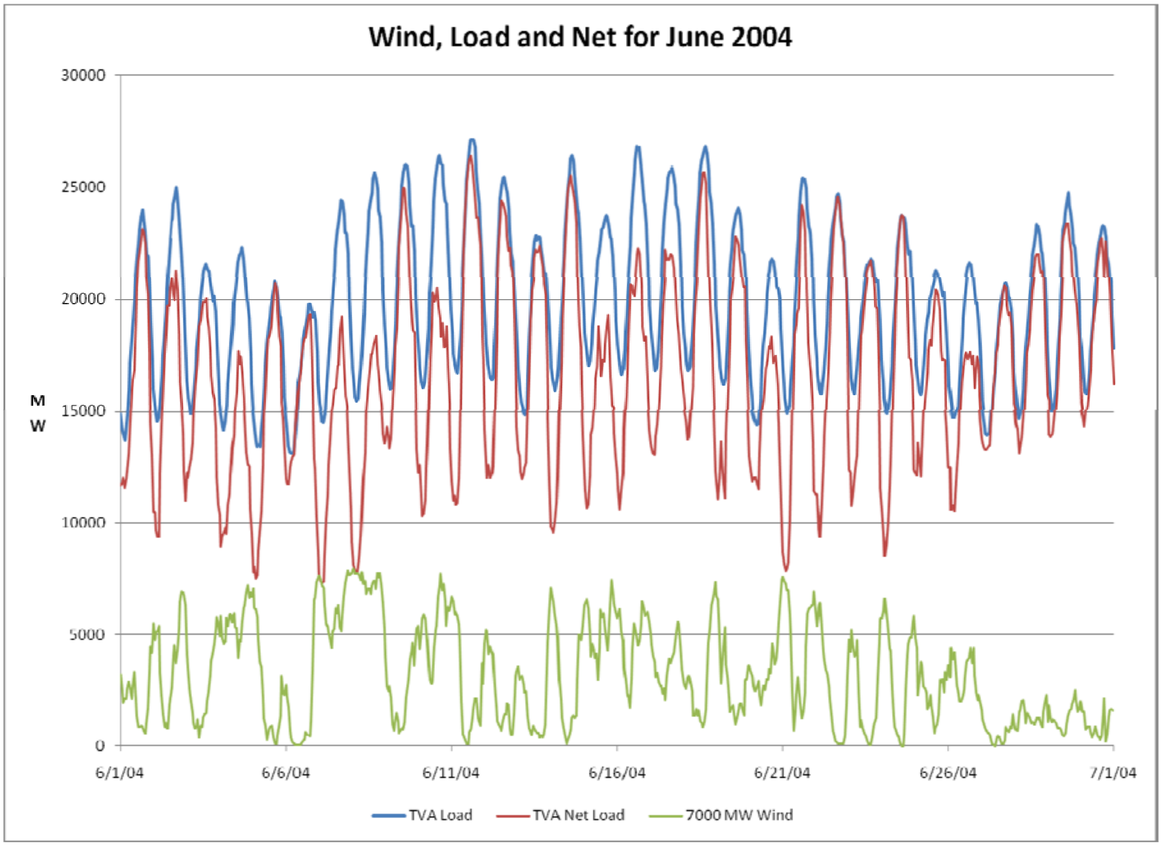

Figure 26. Typical System Variations – June 2004

To determine the impact the addition of wind has on the variability within the system, AWST evaluated the maximum hourly up ramps and down ramps that occurred for each balancing authority load, as well as the simulated wind production, and the net load (load – wind).

Figure 27 shows duration curves of the variability of net load on the TVA system, for 2004, without wind and for each of the wind generation scenarios. The duration curves illustrate the frequency with which ramps of different magnitudes occur in an average year. The blue line is the base TVA variability. The 0 hour represents the highest up ramp within the system, while the 8760 hour represents the highest down ramp within the system. Table 13 lists some points along the duration curves to help clarify the differences in system ramps among the scenarios.

The maximum up ramp and down ramp events are increased with the addition of wind, and the magnitude of that increase depends on the penetration of wind generation. For 7000 MW of wind generation fully used within TVA, the additional net load variability is substantial relative to normal loads.

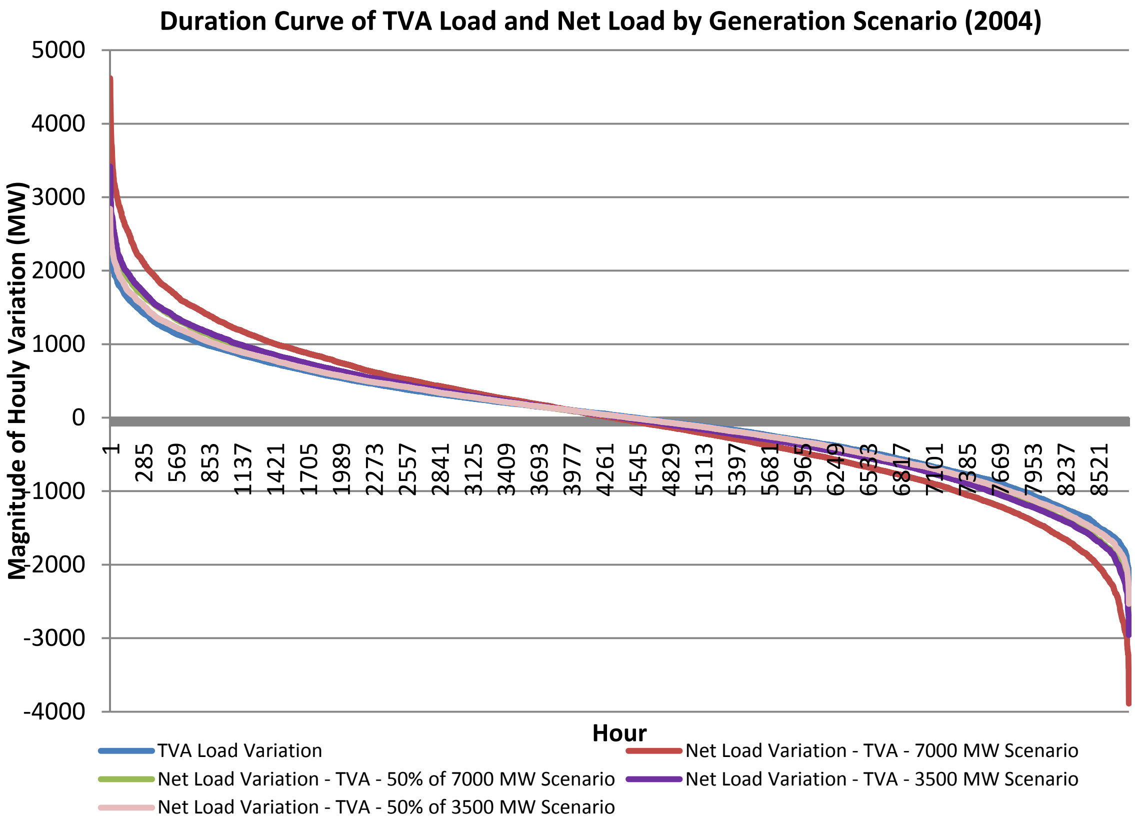

Figure 27. 2004 TVA Duration Curves – Smoothes Variation to Illustrate the Impact of Wind Generation on Variation within the System.

Table 13. Points on TVA Duration Curves

Duration Curve Points for TVA System (from Fig 27)	Load Only	Net 7000 MW	Net 50% of 7000 MW	Net 3500 MW	Net 50% of 3500 MW
Maximum Up Ramp	2544	4618.6	3260.25	3416	2841.05
Maximum Down Ramp	-2331	-3888.6	-2645.75	-2957	-2533.5
Up Ramp at 100th highest hour	1759	2752.6	2084.7	2112.1	1875.55
Down Ramp at 100th lowest hour	-1671	-2434.4	-1919.15	-1981.9	-1783.45

The 11-year maximum (extreme) and typical system swings are listed in Table 14. The 11 year typical swings are calculated by averaging the maximum swings in each year. In the wind only section of Table 14, the wind production effectively reduces the load, so the wind variability is assessed as negative load swings. Increased up ramps in net load will therefore occur with decreases in wind production, while increased down ramps will occur with increases in wind production.

Table 14. Maximum and Minimum One-Hour Ramping Events

LOAD ONLY	TVA	Southern	Duke	Entergy
Maximum 11-Year Up Ramp (MW)	4666	5460	1997	3144
Average Maximum Annual Up Ramp (MW)	3257	3423	1656	2105
Maximum 11-Year Down Ramp (MW)	-3913	-5429	-2184	-2994
Average Maximum Annual Down Ramp (MW)	-2712	-3107	-1828	-1947

WIND ONLY (as Negative Load)	7000 MW	3500 of 7000 MW	3500 MW	1750 of 3500 MW
Maximum 11-Year Up Ramp (MW)	-4554	-2277	-2621	-1310
Average Maximum Annual Up Ramp (MW)	-3941	-1970	-2329	-1165
Maximum 11-Year Down Ramp (MW)	3995	1998	2937	1469
Average Maximum Annual Down Ramp (MW)	3561	1780	2206	1103

NET LOAD (Load - Wind) 7000 MW to TVA	TVA
Maximum 11-Year Up Ramp (MW)	5358
Average Maximum Annual Up Ramp (MW)	4780
Maximum 11-Year Down Ramp (MW)	-4833
Average Maximum Annual Down Ramp (MW)	-4139

NET LOAD (Load - Wind) 3500 MW to TVA and 3500 MW to Neighbors	TVA	Southern	Duke	Entergy
Maximum 11-Year Up Ramp (MW)	4666	5426	2108	3286
Average Maximum Annual Up Ramp (MW)	3514	3490	1705	2293
Maximum 11-Year Down Ramp (MW)	-3820	-5309	-2079	-3006
Average Maximum Annual Down Ramp (MW)	-3049	-3173	-1859	-2002

NET LOAD (Load - Wind) 3500 MW to TVA	TVA
Maximum 11-Year Up Ramp (MW)	4690
Average Maximum Annual Up Ramp (MW)	3710
Maximum 11-Year Down Ramp (MW)	-4089
Average Maximum Annual Down Ramp (MW)	-3407

NET LOAD (Load - Wind) 1750 MW to TVA and 1750 MW to Neighbors	TVA	Southern	Duke	Entergy
Maximum 11-Year Up Ramp (MW)	4678	5151	1985	3202
Average Maximum Annual Up Ramp (MW)	3368	3411	1657	2215
Maximum 11-Year Down Ramp (MW)	-3748	-5399	-2151	-2990
Average Maximum Annual Down Ramp (MW)	-2838	-3141	-1841	-1967

7. Incremental Variation Analysis

The incremental variation analysis describes, on a statistical basis, the added variability of system net loads due to wind. It helps system operators to estimate the impact wind power may have on reserve requirements. Load variability is measured in this study by either the standard deviation (sigma) or three times the standard deviation (three-sigma) of the hourly load or net load changes. Three-sigma variation is frequently used to approximate the reserve requirement, as it covers 99% of the normal distribution[ii].

Table 15 and Table 16 show the variations in the load and wind separately, while Table 17 and Table 18 show the associated variations in net load. Table 19 shows the difference in three-standard-deviation variability between the load (without wind) and the net load (with wind). This is, approximately, the change in the reserve requirement.

For the 7000 MW scenario, the three-sigma variation in TVA net load increases by 941 MW, compared to 2326 MW without wind. Although significant, the increase is far smaller than the three-sigma variation in the wind alone (2058 MW). This is because fluctuations in wind are largely uncorrelated with fluctuations in load. The impacts in the other scenarios are considerably smaller in proportion to the base variability of each system, because the wind is spread over a proportionately larger load. For example, for the scenario in which 50% of the 7000 MW is exported, the impact on TVA variability is 317 MW, about one-third that of the full 7000 MW scenario.

It should be stressed that a change in the three-sigma variation may not correspond to a similar change in the reserve margin (the actual capacity over peak load). Some, and potentially all, of the increased reserve requirement may already be covered in the system's existing or planned reserve margin. The precise impact on the system reserve margin should be determined through more detailed study.

Table 15. One-Sigma Variation of Load and Wind Scenarios

1 Standard Deviation	Load Only	7000 MW Wind	50% of 7000 MW	3500 MW Wind	50% of 3500 MW
TVA	775	686	343	398	199
Southern	836		155		90
Duke	522		92		53
Entergy	543		112		65

Table 16. Three-Sigma Variation of Load and Wind Scenarios

3 Standard Deviation	Load Only	7000 MW Wind	50% of 7000 MW	3500 MW Wind	50% of 3500 MW
TVA	2326	2058	1029	1195	597
Southern	2510		466		270
Duke	1570		275		159
Entergy	1631		335		195

Table 17. One-Sigma Variation of Net Loads

1 Standard Deviation	7000 MW All TVA	50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	3500 MW All TVA	50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
TVA	1089	881	903	818

Southern		868		850
Duke		529		524
Entergy		566		553

Table 18. Three-Sigma Variation of Net Loads

3 Standard Deviation	7000 MW All TVA	50% of 7000 MW (3500 - TVA, 3500 split to Neighbors)	3500 MW All TVA	50% of 3500 MW (1750 - TVA, 1750 split to Neighbors)
TVA	3267	2643	2709	2453
Southern		2605		2550
Duke		1587		1573
Entergy		1699		1659

Table 19. Incremental Three-Sigma Variation of Net Load Scenarios

Incremental Variations	7000 MW All TVA Incremental Variation	50% of 7000 MW (3500 - TVA, 3500 split to Neighbors) Incremental Variation	3500 MW All TVA Incremental Variation	50% of 3500 MW (1750 - TVA, 1750 split to Neighbors) Incremental Variation
TVA	941	317	383	127
Southern		98		42
Duke		20		6
Entergy		69		29

8. Impact of Wind Generation on Operation of Baseload Generation

Nuclear, coal and combined cycle gas plants have high startup and shutdown costs. These costs plus low fuel costs make coal and nuclear units preferred for continuous baseload operation. For systems with large amounts of wind generation relative to baseload generation, periods of high wind output can result in a net load less than the minimum power output level required to keep all baseload units online. During these events, baseload units must be temporarily derated or shutdown, or the wind production must be curtailed.

Two scenarios were examined to quantify the impact of the proposed project on TVA baseload operation. In the first scenario, all coal units above 500 MW as well as all nuclear units were designated as baseload. The total existing capacity for such units within the TVA system is 12,246 MW. [iii] Historical generation data for these units shows they are typically operated at capacity factors of 70-90%.[iv] Based on operational data for other large coal units in the US, a minimum output power of 20% was assumed for coal plants and 95% for nuclear plants. This results in a required net load of at least 7,472 MW to keep all base units online and avoid wind curtailment.

The second scenario considered only nuclear units as baseload. Existing nuclear units have a nameplate capacity of 6,697 MW. Adjusting for a minimal output level of 95% results in a required net load of 6,362 MW to avoid unit shutdown or wind curtailment.

For both scenarios, the following statistics were generated:

- The average number of events per year during which minimum baseload capacity exceeded net load
- A distribution of the duration of events during which baseload capacity exceeded net load

The results indicate few or no impacts under either minimum baseload criterion except in the 7000 MW TVA scenario, where approximately 3.4% of hours are affected under the coal + nuclear standard and 1.3% of hours under the nuclear only standard.

Table 20. Baseload Scenario Statistics for TVA

Baseload Scenario Description	Nuclear + Large Coal			Nuclear		
	# of Occurrences	# of 1 hr duration occurrences	Maximum Duration (hr)	# of Occurrences	# of 1 hr duration occurrences	Maximum Duration (hr)
Net TVA and 7000 MW	832	166	33	366	94	11
Net TVA and 50% of 7000 MW	6	3	3	0	0	0
Net TVA and 3500 MW	6	5	3	0	0	0
Net TVA and 50% of 3500 MW	0	0	0	0	0	0

9. Evaluation of Capacity Value

The capacity value of a power plant is the amount of generation that can be relied upon to meet system loads according to certain standards. A number of techniques have been developed to evaluate the capacity value of wind generation. The NERC Integration of Variable Generation Task Force (IVGTF) surveyed the techniques and classified them into two categories:[v]

- Monte-Carlo based Effective Load Carrying Capability (ELCC) technique
- Evaluation of plant capacity factor during high-risk periods

IVGTF is currently working with the NERC Resource Issues Subcommittee (RIS) on Activity 141.1 to produce a handbook of suggested capacity evaluation methods. Expected completion date is July 2010.

Taking the capacity factor during high-risk periods as a proxy for ELCC does not require system specific information such as outage rates, maintenance schedules, and load. IVGTF found the capacity factor techniques to be a good approximation for Monte Carle techniques, although Monte Carlo is preferred. At Clean Line's request, AWST can perform a Monte Carlo ELCC capacity evaluation using typical or utility-specific outage rates and maintenance schedules.
Four major electricity regions use the capacity factor technique:

- PJM – average capacity factor between 3pm and 7p for June through August.
- NYISO – *Summer*: average capacity factor between 2p and 6p for June through August. *Winter:* average capacity factor between 4p and 8p for December through February.
- California (CPUC) – average capacity factor between 12p and 6p for May through December.
- ISO New England – *Summer:* average capacity factor from 2 to 6p for June through September.

Capacity values for the proposed 3500 MW and 7000 MW scenarios were evaluated based on the techniques used in these four regions. The results for 1997-2008, shown in Table 21, range from 43% to 44% of nameplate capacity for winter metrics and 36.5% to 40.4% for summer metrics. The PJM and CPUC techniques use 3 years of data but this analysis used 11 years of data. Figure 28 and Figure 29 present the capacity values by year for each technique.

Table 21. Capacity Value Estimates for the Proposed CLE Project based on Capacity Evaluation Techniques Used in other Regions of the US

Technique Used	Capacity - 3500 MW core scenario	Capacity - 7000 MW scenario
PJM	1371 MW (39.2%)	2831 MW (40.4%)
NYISO - Summer	1276 MW (36.5%)	2654 MW (37.9%)
NYISO - Winter	1511 MW (43.2%)	3122 MW (44.6%)
CPUC	1314 MW (37.5%)	2764 MW (39.5%)
ISO New England - Summer	1299 MW (37.1%)	2710 MW (38.7%)

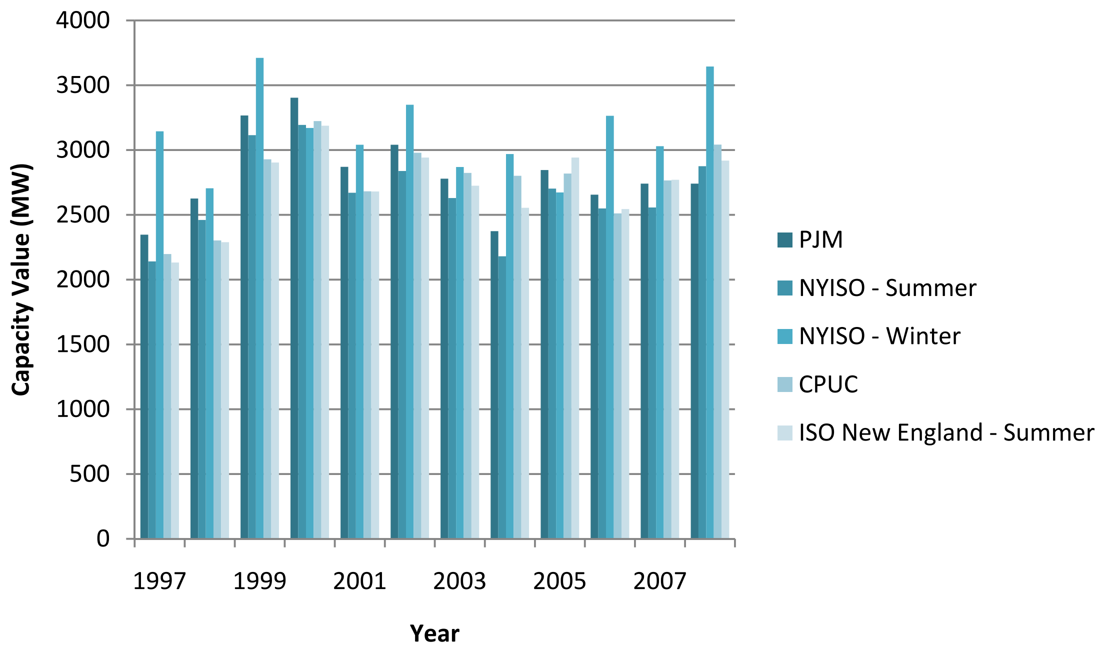

Figure 28. Capacity Value by Year for each Regional Technique, 7000 MW Case

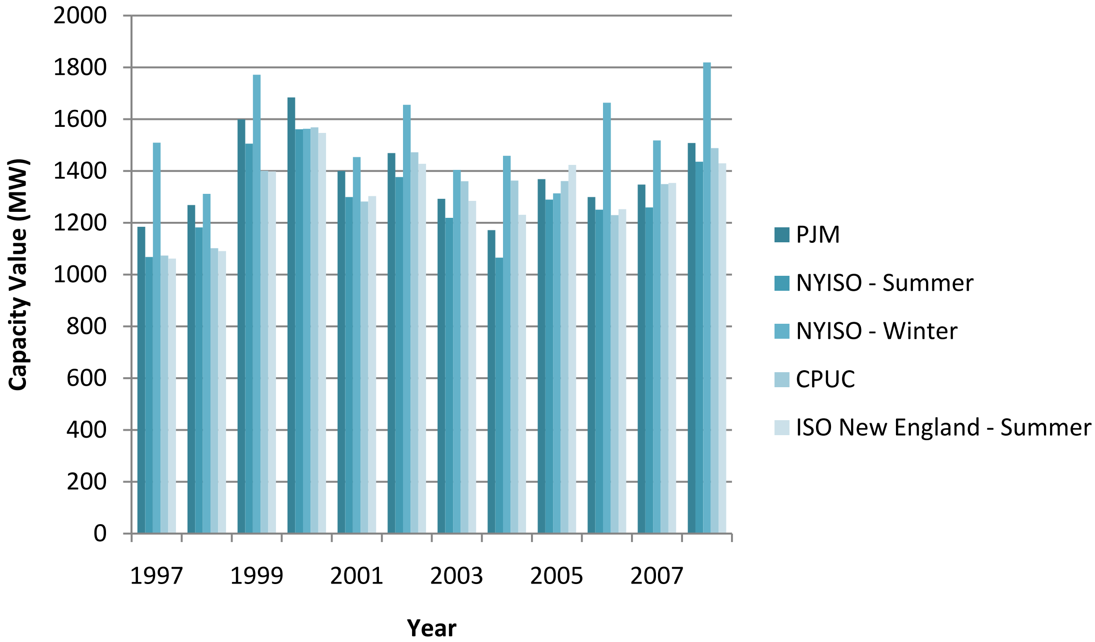

Figure 29. Capacity Value by Year for each of the Regional Technique, 3500 MW Case

10. Summary

AWST assessed the impacts on TVA and the neighboring grid systems Southern Company, Duke Energy, and Entergy, of up to 7000 MW of wind generation from southwestern Kansas and the Texas and Oklahoma panhandles, to be delivered by the proposed Plains and Eastern Clean Line project. The key findings of the study are as follows:

- Hourly maximum up and down ramps will be increased with the addition of wind generation, depending on wind penetration levels. However, the impacts will be mitigated by the lack of correlation between wind and load fluctuations. The incremental three-sigma hourly variation due to wind is 941 MW for TVA under the 7000 MW scenario with no exports, and less than 400 MW in the export scenarios and the 3500 MW TVA scenario.

- In the highest wind penetration scenario, with no exports, the wind generation could cause TVA's net load to dip below baseload (coal and nuclear) generation levels approximately 3.4% of the time. These events could result in curtailments of the wind generation or non-economic reduction in baseload generation. Other scenarios have few (or no) baseload impact issues.

- The diurnal patterns of the load and wind generation do not coincide well, although there is some coincidence with the winter peak. Nevertheless, based on projected wind capacity factors during high risk periods, a capacity value of 43%-44% is estimated, depending on the scenario. In summer, the capacity value range is 36.5% - 40.4%.

Overall, AWST finds the impacts of the wind generation envisioned under the Clean Line project to be manageable and within expected bounds based on studies of other utility systems. However, AWST believes that further research should be carried out to evaluate impacts on ancillary services and to model the effects of wind integration on reserve requirements. We also suggest a rigorous evaluation of Effective Load Carrying Capacity, ELCC.

Author: Whitney Wilson and Frank Kreikebaum
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Appendix A

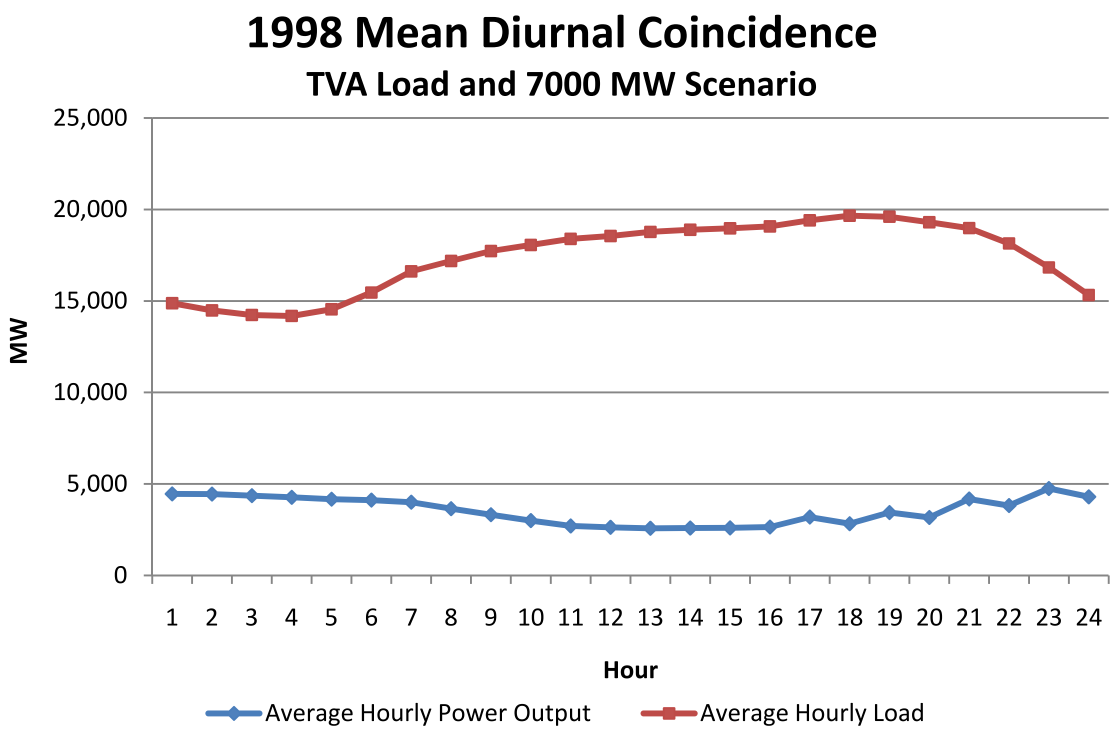

Figure 30. 1998 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

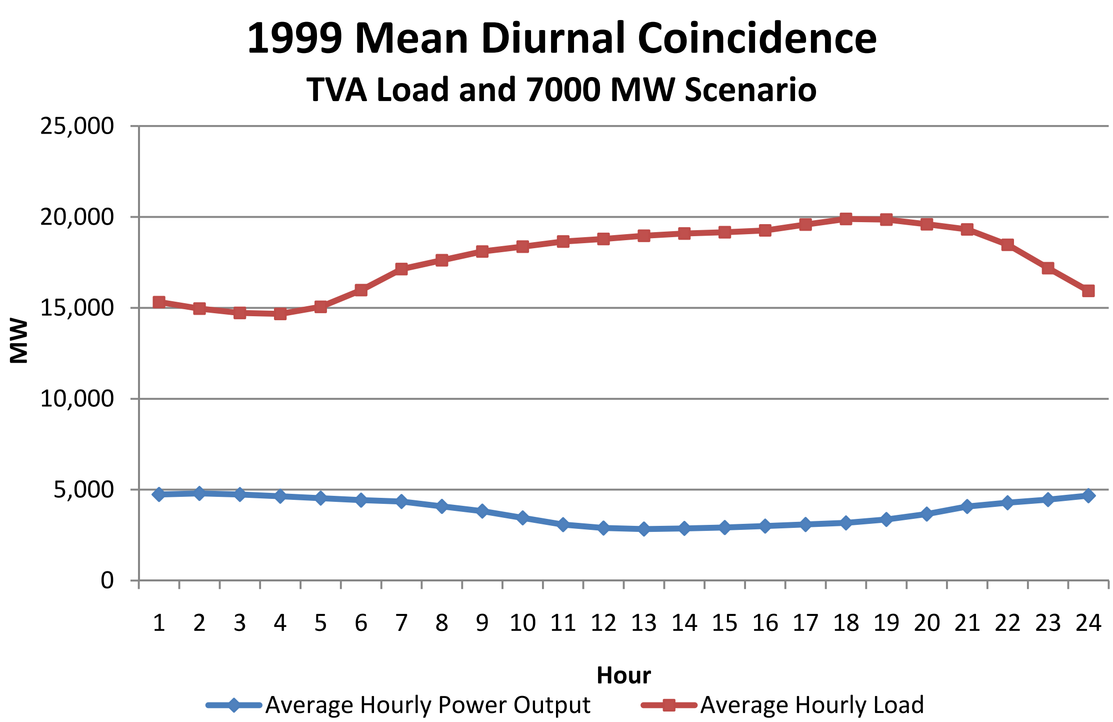

Figure 31. 1999 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

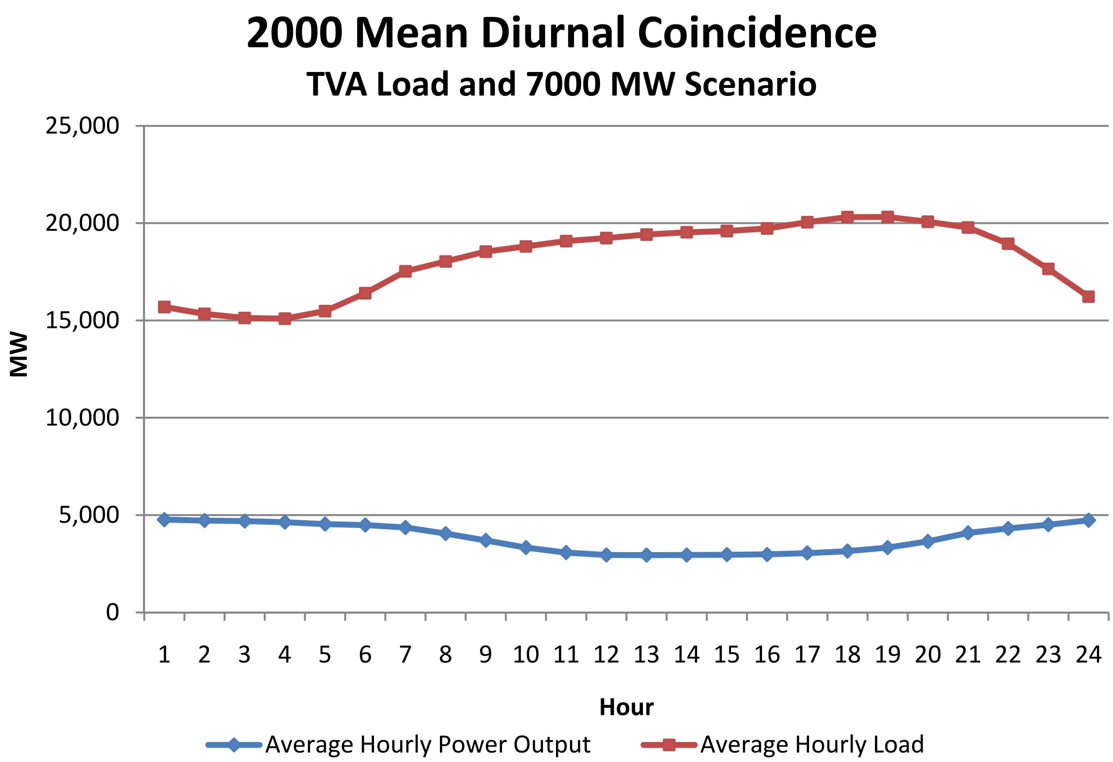

Figure 32. 2000 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

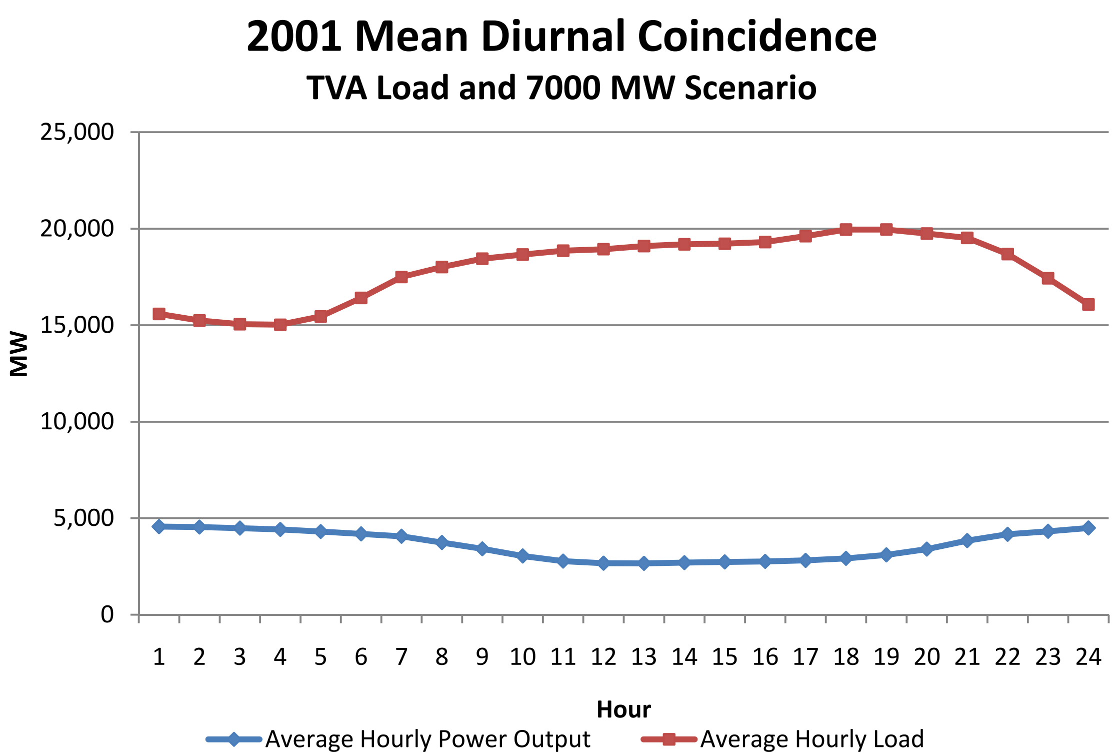

Figure 33. 2001 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

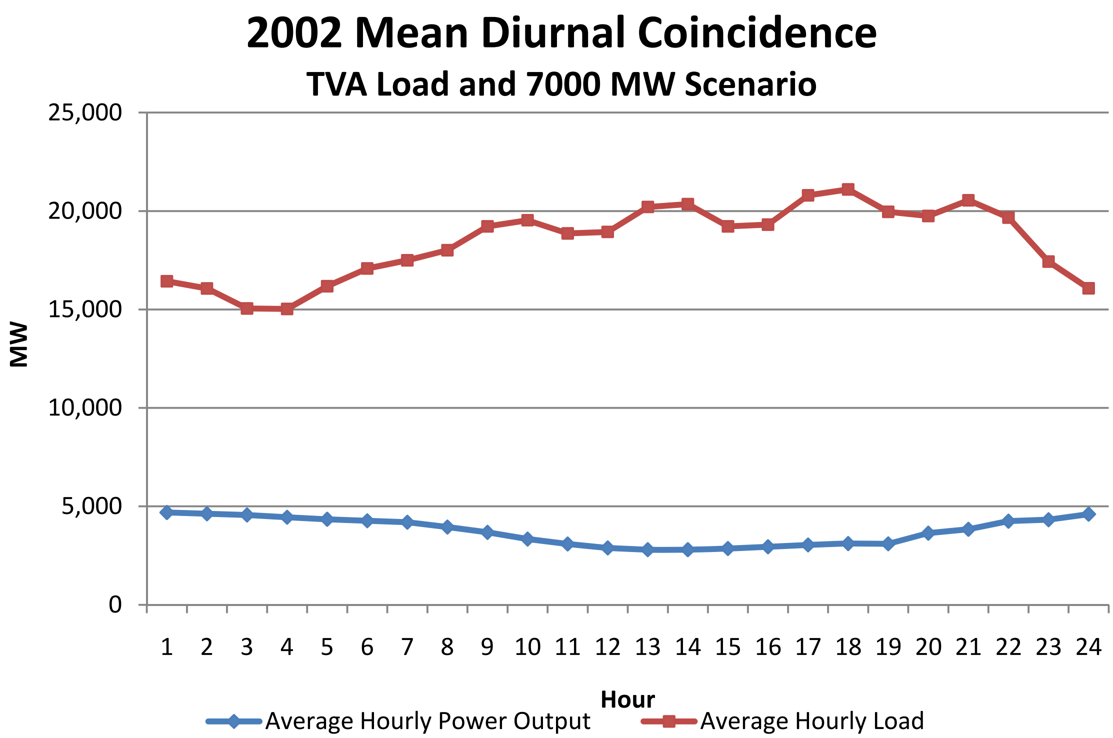

Figure 34. 2002 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario - Although the pattern does not match the typical diurnal patter, AWST does not see any issues with the load data from the FERC 714 used to create the diurnal load.

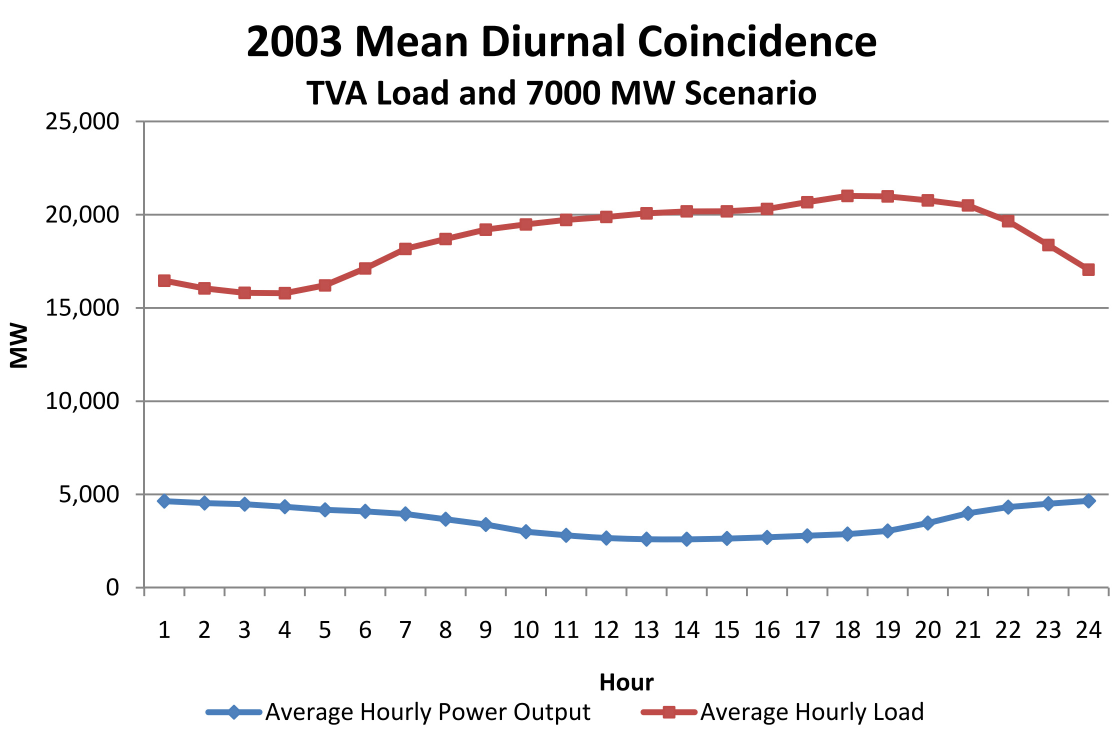

Figure 35. 2003 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

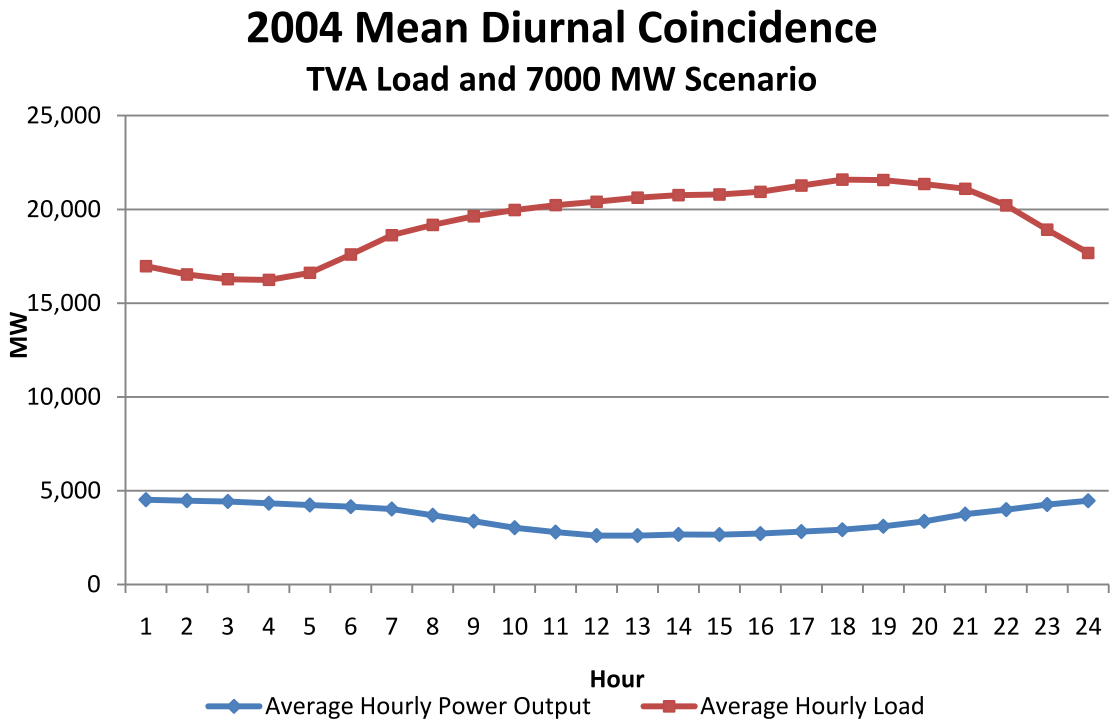

Figure 36. 2004 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

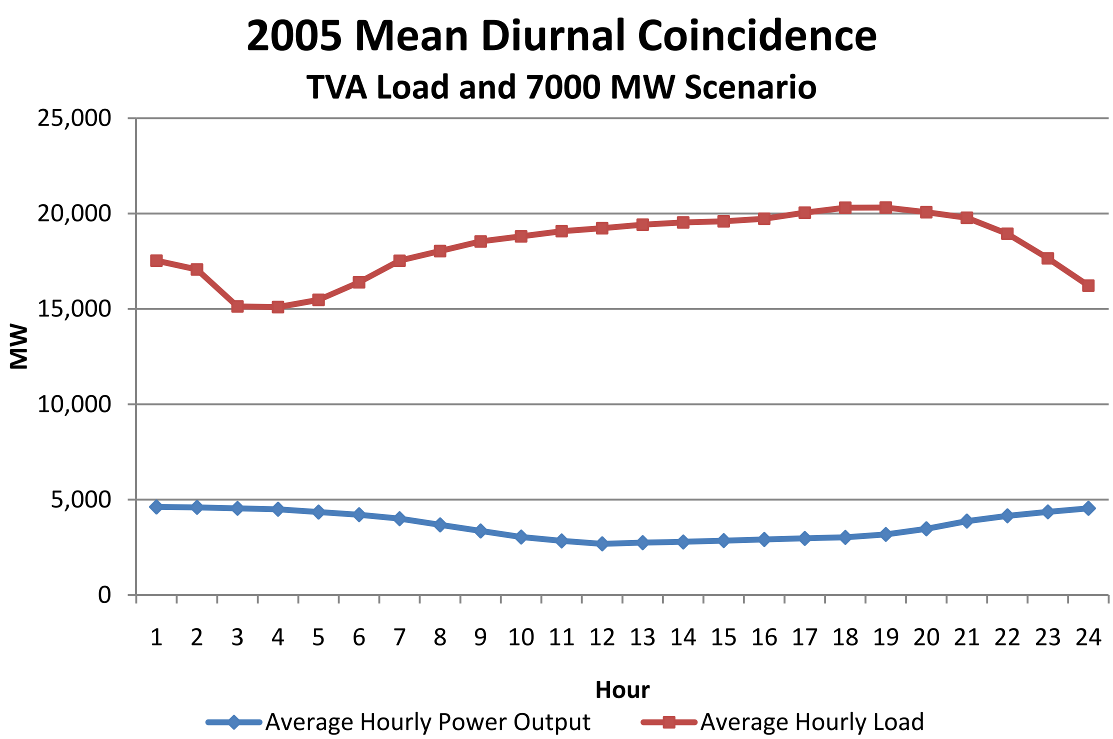

Figure 37. 2005 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

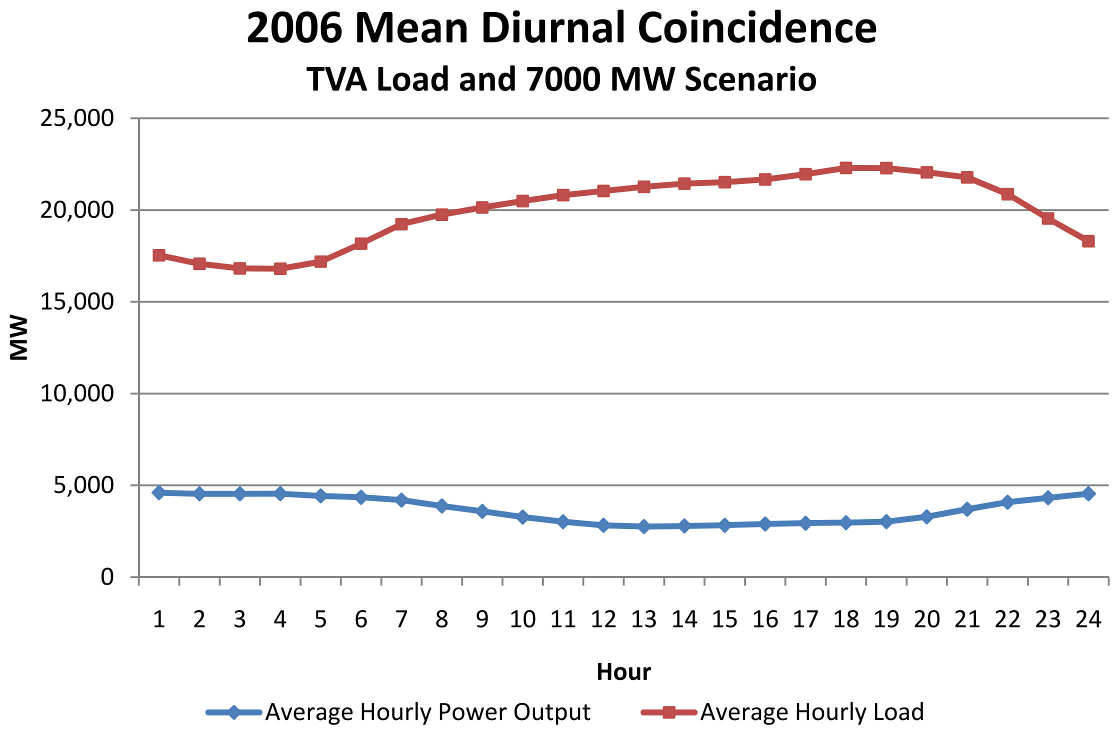

Figure 38. 2006 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

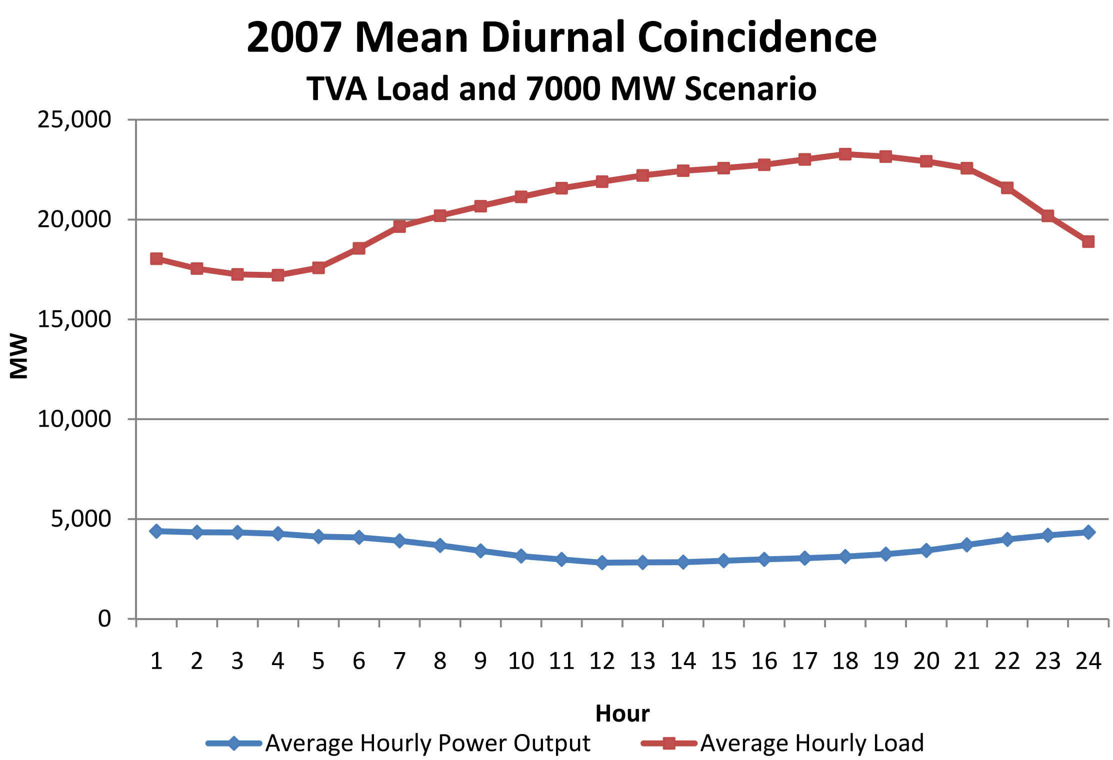

Figure 39. 2007 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

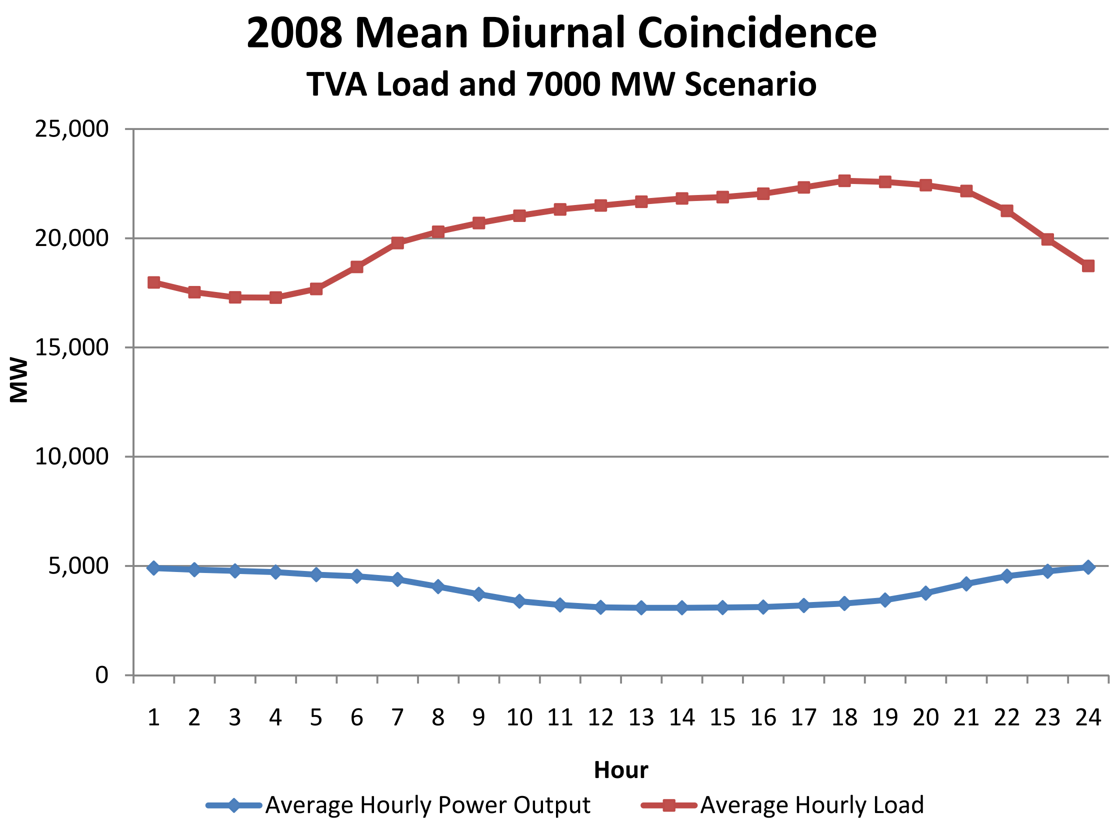

Figure 40. 2008 Mean Diurnal Coincidence for TVA and 7000 MW Wind Scenario

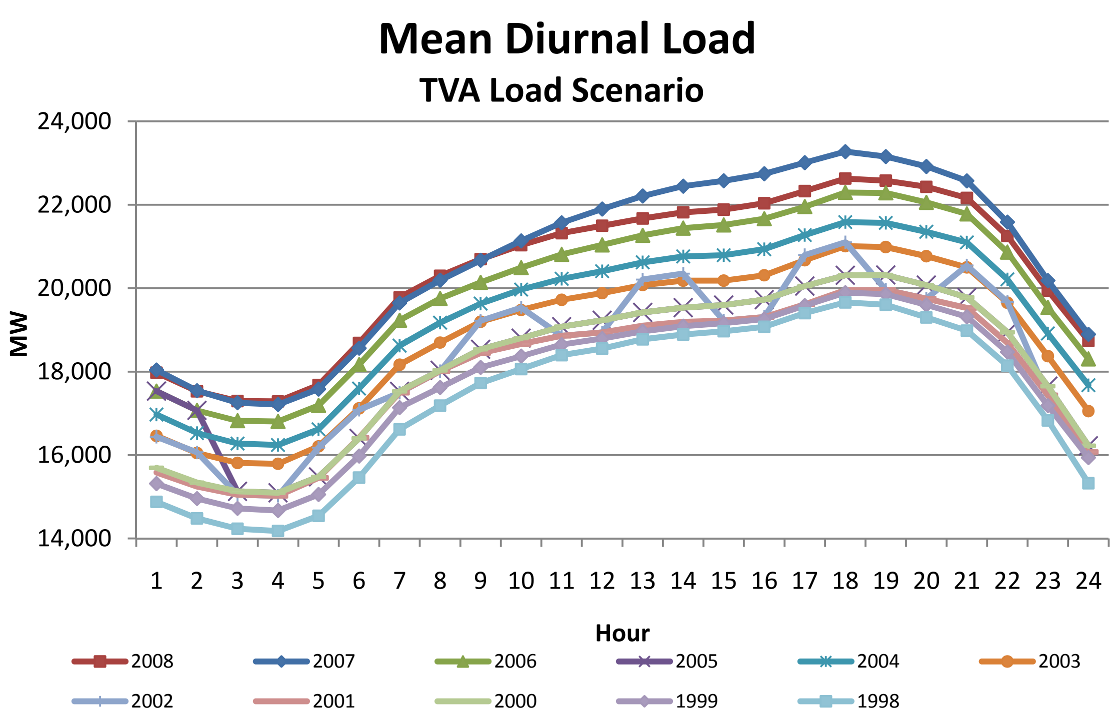

Figure 41. Mean Diurnal Pattern of Load for TVA System Over the Previous 11-years

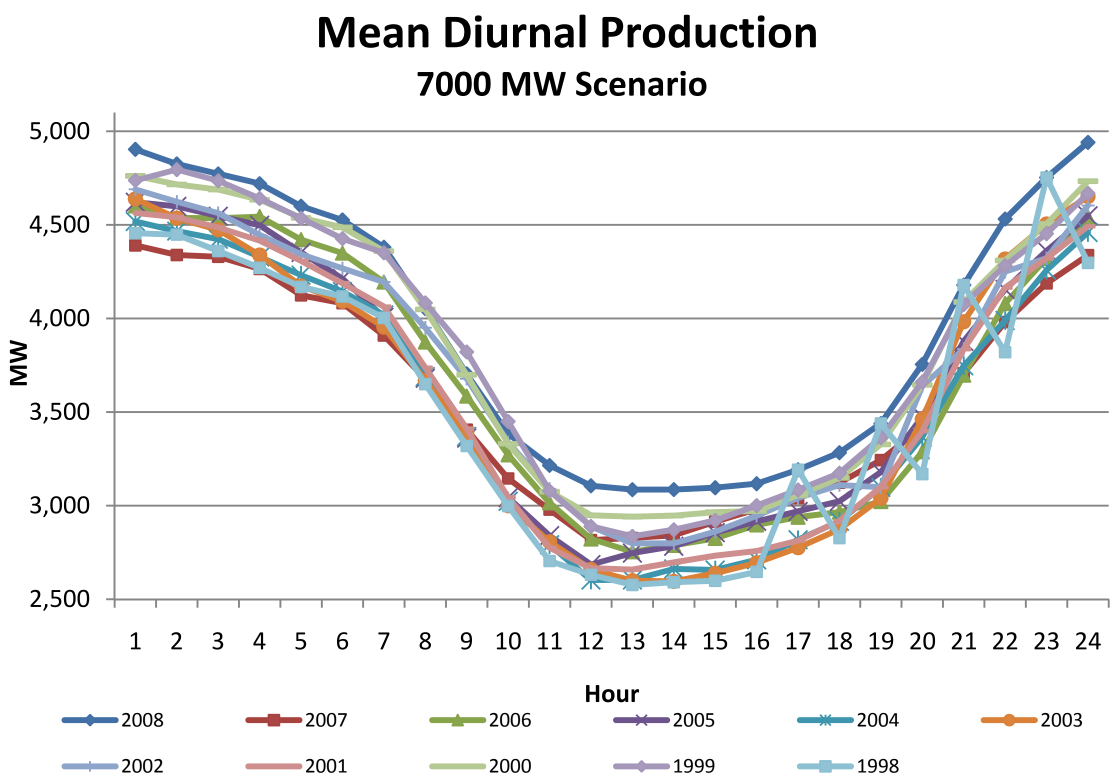

Figure 42. Mean Diurnal Wind Patter for the 7000 MW Scenario Over the Previous 11-years

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[i] The rawinsonde station provides twice-daily wind speed and direction, temperature, and moisture profiles of the atmosphere (7 am and 7 pm local time). The wind speed and direction are determined from a ground-based antenna that tracks the instrument package as it is transported by the wind during the ascent of the balloon. By international convention, the parameters are reported at a number of "mandatory" levels including 1000 millibars (mb), 925 mb, and 850 mb. Data are also collected from "significant" levels where abrupt changes in the vertical temperature or moisture profile are found. The two main advantages of rawinsonde data are, first, they can provide a consistent, decades-long climate record from the same location, and second, the observations are taken well above ground level where the influence of changing surface conditions such as tree growth and urbanization are minimized.

[ii] Ackermann, Thomas. "Wind Power in Power Systems." John Wiley & Sons, Ltd West Sussex, England: 2005.

[iii] Ventyx Energy Velocity Suite, Dataset: April 2010

[iv] EIA Form 923, December 2008

[v] http://www.nerc.com/files/IVGTF_Report_041609.pdf