



MARKET EFFICIENCY ANALYSIS ASSUMPTIONS

Overview of Market Efficiency Analysis

Market Efficiency Analysis will be performed as part of the overall Regional Transmission Planning Process (RTEP) to accomplish the following objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified.
2. Identify new transmission upgrades that may result in economic benefits.
3. Identify economic benefits associated with “hybrid” transmission upgrades. Hybrid transmission upgrades include proposed solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

Market Efficiency analysis is conducted using a market simulation tool which models the hourly security-constrained commitment and dispatch of generation over a future annual period. Economic benefits of transmission upgrades are determined by comparing results of simulations which include the study upgrade to results of simulations which do not include the study upgrade. Market simulations will be made for the following years: 2007, 2010, 2013 and 2016. A forecast of annual benefits for years beyond 2016 will be based on an extrapolation of the year 2007, 2010, 2013 and 2016 simulation results. Higher-level market simulations with a less detailed model of the transmission system below the 500 kV level will be made for the year 2021 to validate the extrapolation results.

The primary analytical tool used in the analysis is the PROMOD model from New Energy Associates (NEA). PROMOD is a market simulation tool which simulates the hourly commitment and dispatch of generation to meet load while recognizing and maintaining transmission system security limits. The underlying source of PROMOD data is contained in Powerbase which is a separately licensed tool from NEA that contains the data necessary to run PROMOD. The data includes generating units and generating unit characteristics, fuel costs, emissions costs, load forecasts and a power flow case.

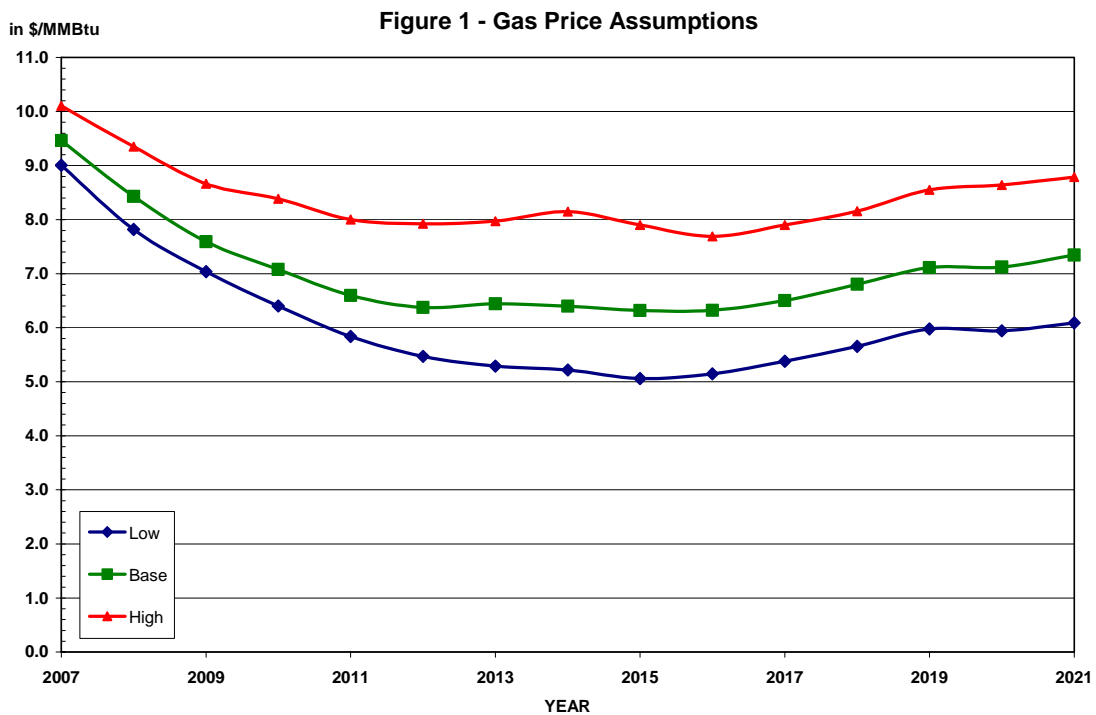
This document serves to present to the Transmission Expansion Advisory Committee (TEAC) the key assumptions and sensitivity analysis parameters to be used in the Market Efficiency analysis. The parameters around which high and low sensitivity analysis is to be conducted include fuel cost, load growth, emission costs, discount rate(s), and potential future new generation and generation retirements.

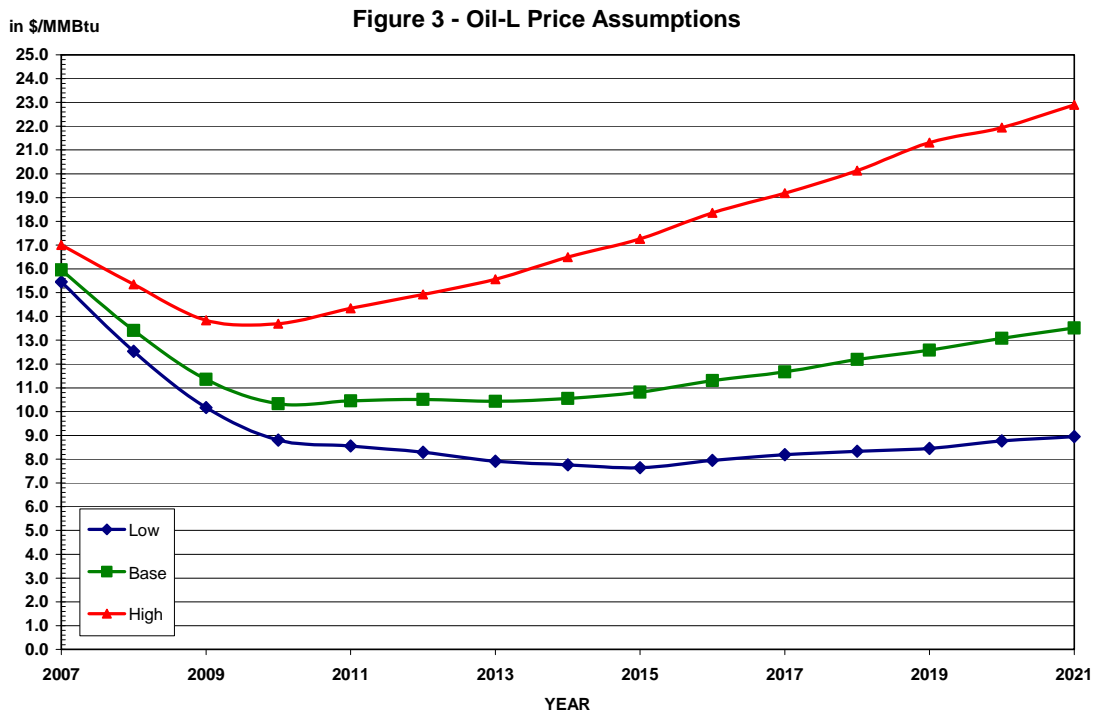
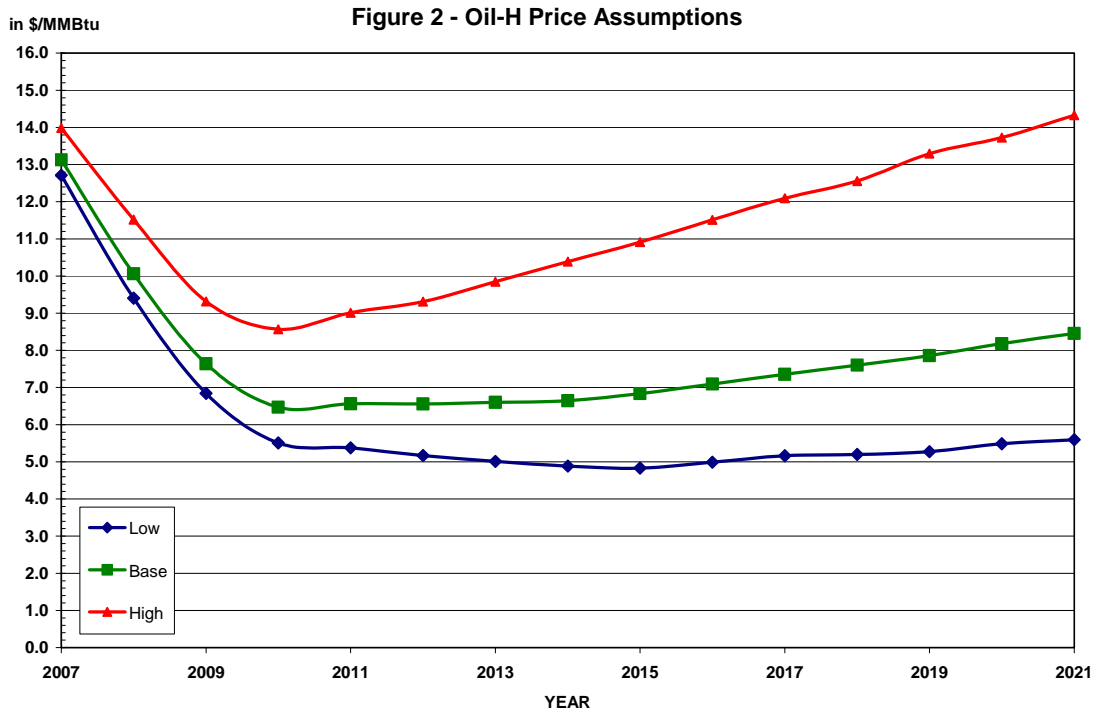


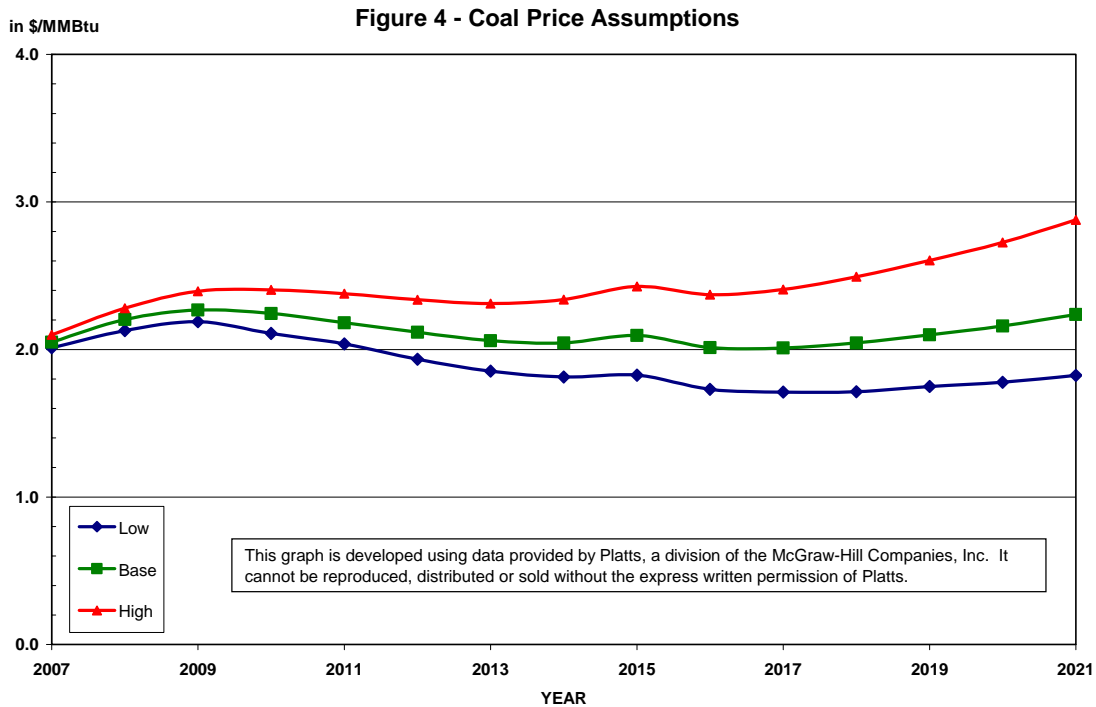
Fuel Cost Assumptions

The Powerbase database contains a base fuel cost forecast for each fuel type. The base forecast for gas and oil prices is based on NYMEX futures prices and long-run forecasts from Platts and the Energy Information Administration (EIA). The base forecast for coal prices are from Platts directly.

To develop high and low fuel cost scenarios, PJM relied on high and low forecast information from the EIA's Annual Energy Outlook 2006. The ratios of high and low price cases to the reference price case were obtained from the EIA forecast and applied to the base fuel costs from NEA's Powerbase. Figures 1 through 4 show the high, base and low fuel cost forecasts for gas, heavy oil, light oil and coal, respectively. Appendix A contains monthly fuel prices for each study year.







Load and Energy Assumptions

Load and energy forecasts for the PJM RTO were developed by PJM’s Capacity Adequacy Planning Department. These forecasts will be used to model hourly PJM load while hourly load data from the Powerbase database will be used for all regions outside of PJM. High, base and low load and energy forecasts have been developed for each PJM transmission zone. The forecasts are aggregated for the entire PJM RTO and are shown in Tables 1 and 2.

The base scenario is a 50/50 forecast which represents a load (or energy) which has equal probability of not being met as being exceeded. The high scenario is a high weather forecast. The high scenario is a 90/10 forecast which represents a load (or energy) which is expected to be met or exceeded, on average once every ten years. The low scenario is a low weather forecast. The low scenario is a 10/90 forecast which represents a load (or energy) which is expected to not be met, on average once every ten years. The load and energy forecasts are at the generation level which means that they include transmission and distribution system losses.

Base case generation levels will not be adequate to meet the high load forecast in the simulations of the years 2016 and 2021. For these years, new generation additions will be modeled under the high load scenarios. Generation capacity additions totaling about 11,000 MW will be needed to maintain the installed reserve margin level of the base case. This new generation will be added to the western, eastern and southern regions of



the PJM system in proportion to the regional location and regional generation type of future generation projects in Generation Interconnection Queues M through Q.

Table 1 – Forecast PJM Peak Loads (MW)

Scenario	2007	2010	2013	2016	2021
High	144,542	152,934	160,390	167,058	175,813
Base	135,747	143,628	150,630	156,893	165,117
Low	124,888	132,138	138,580	144,342	151,906

Table 2 – Forecast PJM Energy (GWh)

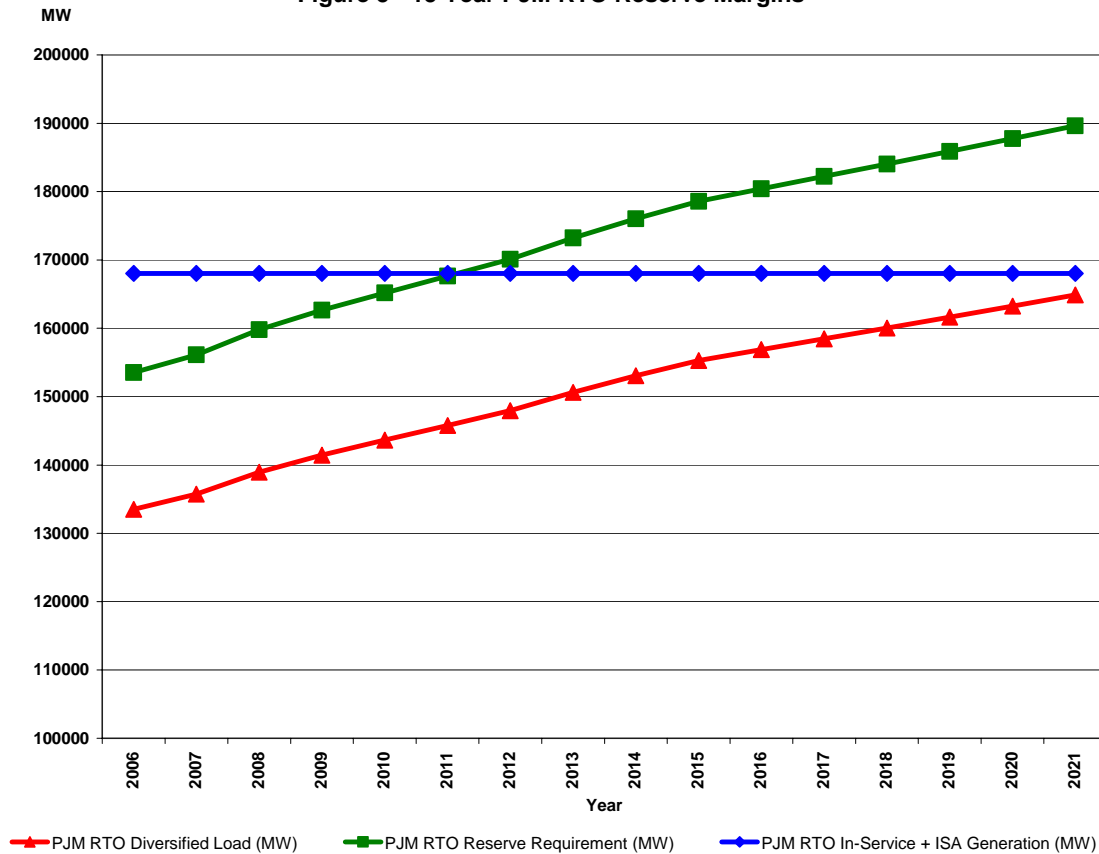
Scenario	2007	2010	2013	2016	2021
High	733,670	765,559	795,241	826,420	872,942
Base	722,549	754,156	783,476	814,337	860,336
Low	713,000	744,319	773,506	804,047	849,760

Future Generation Scenarios

Figure 5 shows that the total installed PJM generation MW (in-service generation plus generation with an executed Interconnection Service Agreement (ISA)) exceeds the forecasted PJM peak load through 2021; however, the total installed generation MW falls below the PJM Installed Reserve Requirement beginning in 2012. The PJM installed reserve requirement exceeds the PJM installed generation MW amount by approximately 5,200 MW, 12,400 MW and 21,600 MW in the years 2013, 2016 and 2021, respectively.



Figure 5 - 15 Year PJM RTO Reserve Margins



The base generation assumption used in the Market Efficiency Analysis will include all in-service generation plus generation with an executed ISA. This level of generation will be adequate to meet PJM peak load through the entire study period.

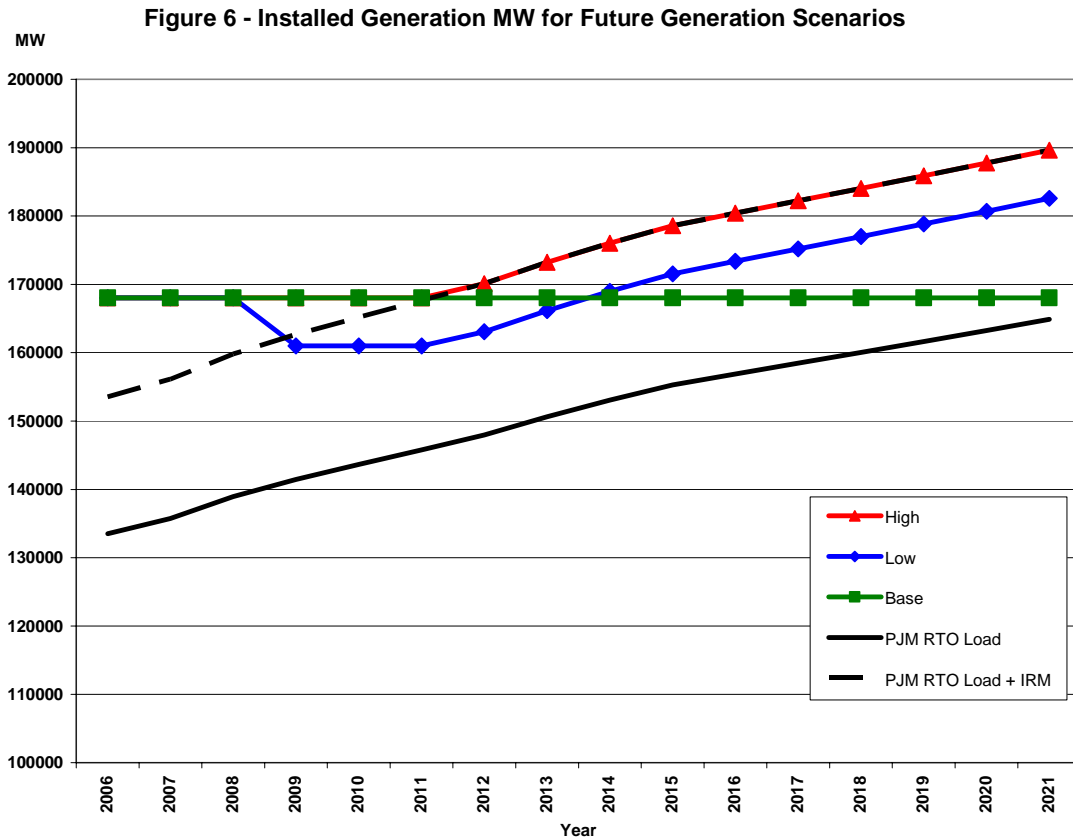
A high generation scenario will include new generation additions needed to maintain the PJM Installed Reserve Requirement. For the high generation scenario, generation capacity additions of 5,200 MW, 12,400 MW and 21,600 MW will be added to the 2013, 2016 and 2021 base cases, respectively. This new generation will be added to the western, eastern and southern regions of the PJM system in proportion to the regional location and regional generation type of future generation projects in Generation Interconnection Queues M through Q. The high generation scenario will be the same as the base generation scenario for the year 2007 and 2010 simulations but will deviate from the base generation scenario beginning with the year 2013 simulations.

A low generation scenario will include a removal of generating units in system locations where PJM believes there is a potential reliability risk if generation retires. This estimate of units that are candidates to retire is based on an assessment of three categories: unit age, units that may be impacted by future environmental regulations and units that have announced or are rumored to be considering retirement. A preliminary assessment has identified approximately 7,000 MW of generation (5,000 MW in eastern PJM and 2,000



MW in western PJM) that could be retired by 2010. The low generation scenario case will be created by removing these units from the high generation scenario case. The low generation scenario will be the same as the base generation scenario for the year 2007 but will deviate from the base generation scenario beginning with the year 2010 simulations.

Figure 6 shows the total PJM installed generation MW capability assumed in the base, high and low future generation scenarios. The PJM RTO peak load and the PJM RTO peak load plus the PJM installed reserve margin is also shown on Figure 6.



Emission Allowance Price Assumptions

The Powerbase database models 3 three major effluents: SO₂, NO_x and Hg. Effluents (by trading program) are assigned to generators based on generator location (county/state) and release rates are from a variety of sources including Platt’s BASECASE, EPA CEMS data and certain EPA studies. Emissions allowance prices are also from a variety of sources including Platt’s BASECASE, Evomarkets.com and EPA studies.

To develop high and low emissions cost scenarios, PJM conducted a statistical analysis of daily SO₂ and NO_x spot prices from January 1, 1999 through September 30, 2006. Based on this analysis, it was determined that a doubling of the base costs and a halving of the base costs would provide reasonable estimates of high and low costs scenarios, respectively. Figures 7, 8 and 9 show the high, base and low emissions allowance prices for SO₂, NO_x and Hg, respectively.

Figure 7 - SO₂ Emission Allowance Price Assumptions

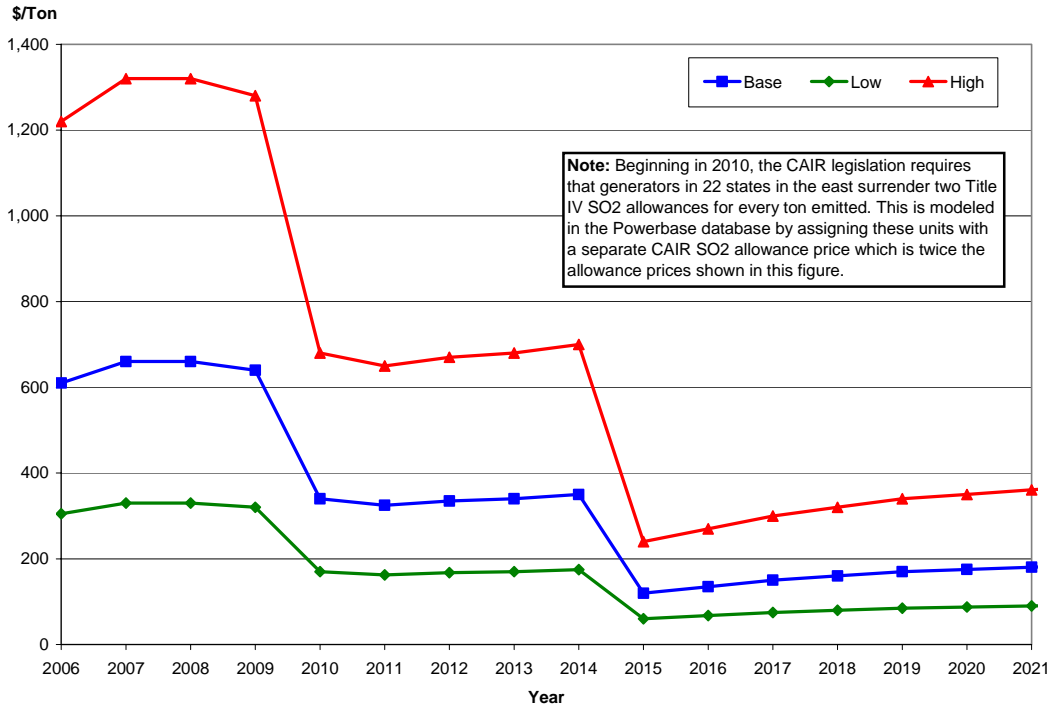


Figure 8 - NO_x Emission Allowance Price Assumptions

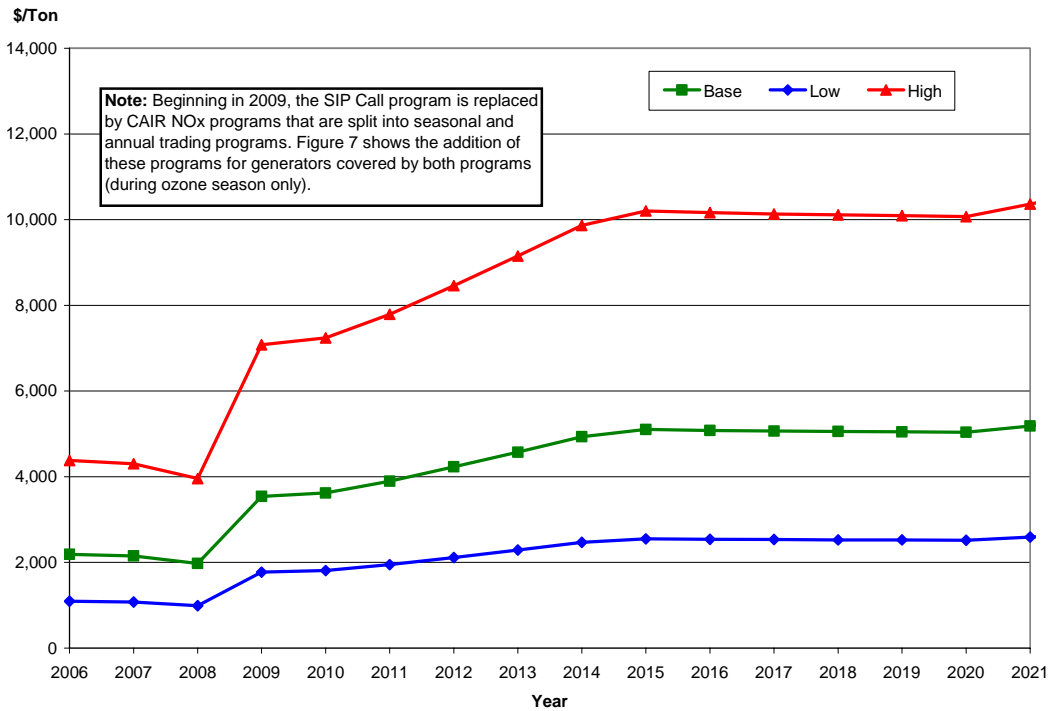
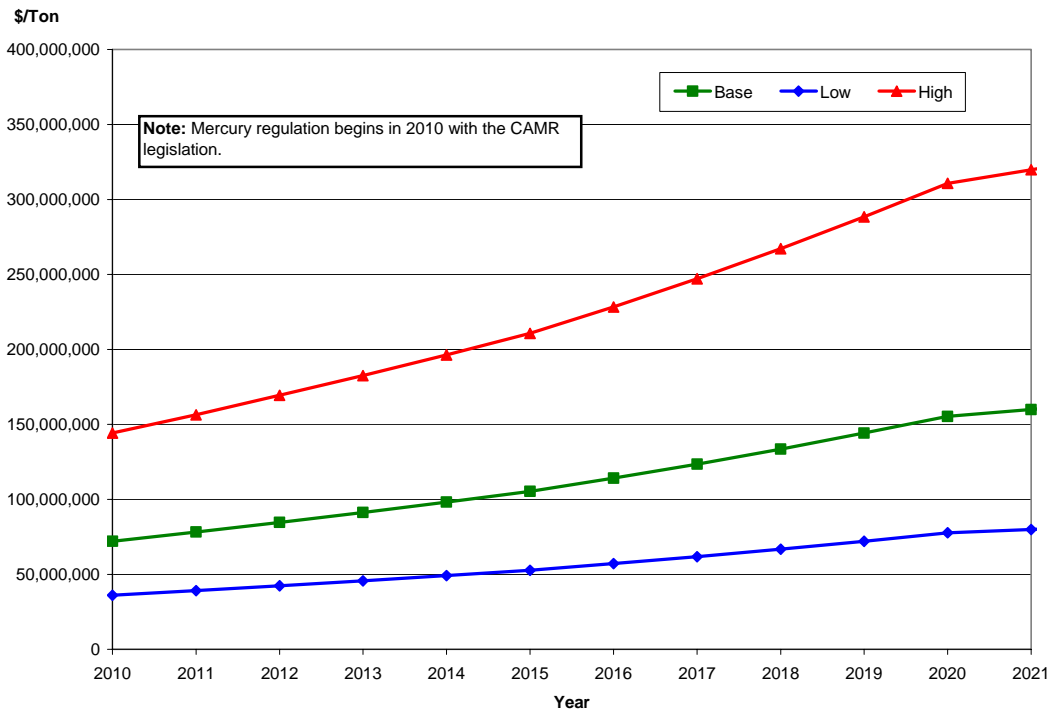


Figure 9 - Hg Emission Allowance Price Assumptions



Discount Factor Assumptions

The economic benefit of upgrades will be determined by comparing market simulation results from simulations made with the upgrade modeled to simulations made without the upgrade modeled. These simulations will be made for years 2007, 2010, 2013 and 2016. Annual benefits within the 10-year time frame for years which are not simulated will be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results for years 2007, 2010, 2013 and 2016. A higher-level annual market simulation will be made for year 2021 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.

The net present value of annual benefits for 10, 20 and 30 years will be compared to the net present value of the upgrade revenue requirement for 10, 20 and 30 years to determine if the upgrade is cost beneficial. A sensitivity of this comparison to the discount rate used to calculate the net present value of annual project benefits will be conducted. The high, base and low discount rate will be 10%, 9% and 8%, respectively.

Power Flow Base Case Assumptions

Generators in the PROMOD model will be mapped to the RTEP 2011 Base Case powerflow case. Key RTEP upgrades will be removed or added to this case to develop the powerflow base cases for the study years: 2007, 2010, 2013, 2016 and 2021.



APPENDIX A - Monthly Fuel Prices for Study Years (\$/MMBtu)

Year	Month	GAS LOW	GAS BASE	GAS HIGH	OIL-L LOW	OIL-L BASE	OIL-L HIGH	OIL-H LOW	OIL-H BASE	OIL-H HIGH
2007	Jan	10.339	10.868	11.606	15.649	16.161	17.218	12.695	13.110	13.968
2007	Feb	10.349	10.878	11.616	15.785	16.301	17.368	12.725	13.140	14.000
2007	Mar	10.120	10.638	11.360	15.736	16.251	17.314	12.745	13.161	14.022
2007	Apr	8.246	8.668	9.256	15.447	15.952	16.996	12.753	13.170	14.031
2007	May	8.056	8.468	9.043	15.148	15.643	16.667	12.751	13.168	14.030
2007	Jun	8.134	8.550	9.130	15.022	15.513	16.529	12.740	13.156	14.017
2007	Jul	8.231	8.652	9.239	15.078	15.571	16.590	12.726	13.142	14.002
2007	Aug	8.307	8.732	9.325	15.207	15.704	16.732	12.713	13.128	13.988
2007	Sep	8.399	8.828	9.427	15.357	15.859	16.896	12.700	13.115	13.973
2007	Oct	8.555	8.993	9.603	15.507	16.013	17.061	12.683	13.098	13.955
2007	Nov	9.283	9.758	10.420	15.684	16.197	17.257	12.662	13.075	13.931
2007	Dec	10.035	10.548	11.264	15.862	16.380	17.452	12.640	13.053	13.907
2007	AVERAGE	9.005	9.465	10.108	15.457	15.962	17.007	12.711	13.126	13.985
2010	Jan	6.632	7.331	8.685	8.998	10.561	13.991	5.632	6.610	8.757
2010	Feb	6.691	7.396	8.762	8.999	10.562	13.993	5.633	6.611	8.758
2010	Mar	6.771	7.485	8.868	8.935	10.488	13.894	5.594	6.566	8.698
2010	Apr	6.702	7.409	8.778	8.688	10.198	13.510	5.439	6.384	8.457
2010	May	6.227	6.883	8.155	8.691	10.201	13.515	5.440	6.385	8.459
2010	Jun	6.274	6.935	8.216	8.681	10.189	13.498	5.432	6.376	8.446
2010	Jul	6.297	6.961	8.247	8.718	10.233	13.557	5.458	6.406	8.487
2010	Aug	6.351	7.020	8.317	8.734	10.252	13.582	5.467	6.417	8.501
2010	Sep	6.362	7.033	8.332	8.737	10.255	13.586	5.468	6.418	8.502
2010	Oct	6.391	7.065	8.370	8.725	10.241	13.568	5.459	6.407	8.488
2010	Nov	6.026	6.661	7.891	8.824	10.357	13.721	5.522	6.481	8.586
2010	Dec	6.095	6.737	7.982	8.926	10.477	13.880	5.587	6.558	8.688
2010	AVERAGE	6.402	7.076	8.384	8.805	10.334	13.691	5.511	6.468	8.569
2013	Jan	5.434	6.621	8.193	8.092	10.663	15.908	5.118	6.744	10.062
2013	Feb	5.482	6.679	8.265	8.093	10.664	15.910	5.119	6.745	10.063
2013	Mar	5.554	6.768	8.374	8.035	10.587	15.795	5.083	6.698	9.993
2013	Apr	5.462	6.655	8.235	7.811	10.292	15.355	4.943	6.513	9.717
2013	May	5.119	6.237	7.717	7.818	10.301	15.368	4.944	6.515	9.719
2013	Jun	5.160	6.288	7.780	7.808	10.288	15.349	4.941	6.510	9.712
2013	Jul	5.184	6.317	7.817	7.843	10.334	15.417	4.961	6.537	9.752
2013	Aug	5.241	6.386	7.902	7.854	10.348	15.438	4.969	6.548	9.768
2013	Sep	5.246	6.393	7.910	7.860	10.356	15.450	4.970	6.549	9.770
2013	Oct	5.271	6.422	7.947	7.845	10.337	15.422	4.962	6.538	9.753
2013	Nov	5.118	6.236	7.716	7.932	10.452	15.593	5.020	6.615	9.868
2013	Dec	5.187	6.321	7.821	8.027	10.577	15.779	5.081	6.695	9.988
2013	AVERAGE	5.288	6.444	7.973	7.918	10.433	15.565	5.009	6.601	9.847
2016	Jan	5.267	6.470	7.870	8.126	11.550	18.753	5.097	7.245	11.764
2016	Feb	5.313	6.527	7.939	8.130	11.556	18.763	5.101	7.251	11.773
2016	Mar	5.400	6.634	8.070	8.072	11.473	18.628	5.062	7.196	11.683
2016	Apr	5.325	6.541	7.956	7.847	11.154	18.111	4.923	6.998	11.362
2016	May	4.972	6.108	7.429	7.850	11.159	18.118	4.924	6.999	11.364
2016	Jun	5.011	6.156	7.488	7.840	11.145	18.095	4.921	6.994	11.356
2016	Jul	5.035	6.185	7.523	7.875	11.194	18.175	4.941	7.023	11.403
2016	Aug	5.089	6.252	7.604	7.890	11.215	18.209	4.949	7.035	11.422
2016	Sep	5.103	6.269	7.626	7.892	11.218	18.215	4.950	7.036	11.424
2016	Oct	5.128	6.299	7.663	7.882	11.203	18.190	4.942	7.024	11.405
2016	Nov	5.017	6.163	7.497	7.969	11.327	18.390	4.999	7.106	11.538
2016	Dec	5.093	6.257	7.611	8.063	11.462	18.610	5.060	7.192	11.677
2016	AVERAGE	5.146	6.322	7.690	7.953	11.305	18.355	4.989	7.092	11.514
2021	Jan	6.201	7.481	8.951	9.145	13.810	23.406	5.719	8.636	14.637
2021	Feb	6.274	7.569	9.056	9.146	13.812	23.409	5.723	8.643	14.648
2021	Mar	6.374	7.690	9.201	9.081	13.714	23.242	5.682	8.580	14.542
2021	Apr	6.260	7.553	9.036	8.827	13.330	22.591	5.524	8.343	14.140
2021	May	5.878	7.092	8.485	8.833	13.340	22.609	5.525	8.344	14.142
2021	Jun	5.927	7.151	8.555	8.823	13.324	22.582	5.518	8.333	14.123
2021	Jul	5.956	7.186	8.597	8.860	13.380	22.676	5.543	8.371	14.188
2021	Aug	6.023	7.267	8.694	8.875	13.403	22.716	5.552	8.384	14.210
2021	Sep	6.065	7.318	8.755	8.881	13.412	22.731	5.556	8.391	14.221
2021	Oct	6.094	7.353	8.797	8.866	13.389	22.693	5.544	8.372	14.190
2021	Nov	5.956	7.186	8.597	8.965	13.539	22.946	5.608	8.470	14.354
2021	Dec	6.054	7.304	8.739	9.072	13.701	23.220	5.676	8.571	14.527
2021	AVERAGE	6.089	7.346	8.788	8.948	13.513	22.902	5.598	8.453	14.327