a) **Wholesale Energy Modeling**—quantified impacts to the energy market, system dispatch, energy prices, and resulting production system costs, and provided the inputs to the allocation of impacts.

b) **Benefits (Costs) Allocation by Company and State**—provided a detailed record of cost and benefit impacts of the cases to the individual companies and to states.

c) **Qualitative Assessment of Energy Imbalance Impacts**—provided qualitative treatment of a variety of other measures of impact of the EIS not captured directly in the energy market modeling or allocations.

d) **Qualitative Assessment of Market Power Impacts**—provided qualitative treatment of the market power impacts of the EIS.

e) **Aquila Sensitivity Cases**—provided impacts on Aquila and SPP of Aquila being integrated into SPP rather than into the MISO RTO. It was decided by the CBTF that Aquila would not be modeled in SPP in the Base Case because it does not currently have its load under the SPP OATT.

A description of each of these five areas follows.

2.1.1 Wholesale Energy Modeling

The energy modeling addressed the expected impacts on the SPP energy market due to the different operational or system configuration assumptions in the various cases. The MAPS analysis included an assessment of the impact on production cost, on the dispatch of the system, and on interregional flows in the study area.

The system production cost associated with each market design alternative served as one metric for comparison among the scenarios. The energy modeling results also served as inputs to the allocation processes for further evaluation of impacts.

CRA modeled three operational market scenarios as part of the study:

- **Base Case:** SPP within its current footprint, no balancing market
- **EIS Case:** Energy Imbalance Service market (real-time) is implemented within today's SPP footprint
- **Stand-Alone Case:** SPP's FERC Order 888 compliant Open Access Transmission Tariff (OATT) is abandoned and each transmission owner operates under its own OATT.

These cases differed in their treatment of one or more of three primary characteristics: transmission wheeling rates, flowgate capacity, and dispatch of non-network generating units. The methodology and results of the wholesale energy modeling are presented in Section 3.

2.1.2 Benefits (Costs) Allocation by Company and State

Section 4 presents the sum of the impacts, including cost and energy modeling impacts. The allocation process distributed impacts across members and by state.

Whereas the wholesale energy modeling produces the system dispatch resulting from the various cases and provides some high-level regional metrics, the allocation process provided detailed company-specific and state metrics based on specific assumptions regarding regulatory policies and the sharing of trade benefits. The major categories of benefits and costs addressed in this study are as follows:

- Trade benefits
- Wheeling charges and revenues
- SPP EIS Market implementation and operating costs
- Individual utility EIS Market implementation and operating costs.

2.1.3 Qualitative Assessment of Energy Imbalance Impacts

Section 5 describes the assessment of energy imbalance market impacts other than those quantified in the modeling and allocation portions of the study. That is, while the energy market simulations addressed the energy efficiency aspects of the market design changes, there are other potential impacts that the simulation was not intended to address. The qualitative analysis results in a matrix of evaluations in which CRA consultants examined, on one hand, a number of characteristics of the markets being assessed (e.g., the real-time energy pricing policies or transmission right product design) against, on the other hand, a variety of metrics (such as volatility, risk, and competition).

2.1.4 Qualitative Assessment of Market Power Impacts

The Market Power Impacts section addresses the likelihood that the implementation of an EIS in SPP would enhance the potential for the exercise of market power in the SPP region, especially in the context of the market monitoring function and the continuation of cost-based regulation in this region.

2.1.5 Aquila Sensitivity Cases

Section 7 presents the results of the sensitivity cases in which Aquila is considered to be part of SPP rather than part of the MISO RTO. The SPP regional wholesale energy modeling results and the wholesale impacts on Aquila are provided. The sensitivity analysis is performed for the Base and EIS cases.

3 Wholesale Energy Modeling

CRA conducted a quantitative energy modeling of the SPP system under three scenarios: a Base case in which SPP continues to operate as an RTO; a Stand-Alone case, in which the members of SPP revert to operating as individual FERC Order 888 compliant transmission providers; and an EIS case in which SPP implements a formal energy imbalance market. The wholesale energy modeling used the MAPS model[12] and incorporated the operating procedures transmission constraints currently used in SPP. The analysis is intended to provide insight into the economic operation of the SPP energy market under each scenario.[13]

The results of the analysis are based on model representations and input assumptions developed through extensive discussions with the CBTF members and SPP operations and planning staff. The market design for the Base case was defined based on current operating practices. The design for the Stand-Alone case was based on input from the CBTF members about likely changes should members revert to acting alone. It was assumed that under the Stand-Alone case SPP would continue to act as a reliability coordinator and that members would participate in reserve sharing.[14] The Energy Imbalance case was modeled assuming that the system was dispatched centrally based on a least-cost representation. The final assumptions were ones that the SPP and utility members of the CBTF considered reasonably expected conditions for the years 2006 through 2015.

3.1.1 Input Assumptions

The following input assumptions were used in the wholesale energy modeling:

Company-specific load and energy forecasts based on 2004 EIA-411 data as provided by SPP for SPP companies, and most recent available EIA-411 data from the CRA data archive for areas outside of SPP

- 2002 hourly load shapes based on FERC 714 filings, as represented in the CRA data archive
- Gas and oil forecasts as described in the forecast memo
- Generation bids based on marginal cost[15] (fuel, non-fuel variable operations and maintenance, and opportunity cost of tradable emissions permits)
- Coal forecast as obtained from Resource Data International
- Transmission system configuration based on a load flow representation that includes all planned transmission upgrades, as provided by SPP

[12] MAPS is the Multi-Area Production Simulation software developed by General Electric Power Systems and proprietary to GE.

[13] MAPS does not simulate the regulation market, nor does it reflect AC system constraints such as the reactive power needs of the system.

[14] Operating Reserves are needed to adjust for load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales. The SPP Reserve Sharing Program establishes minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group. The SPP Reserve Sharing Program assures that there are available at all times capacity resources that can be used quickly to relieve stress on the interconnected electric system during an Operating Reserve Contingency. According to the SPP reserve sharing criteria, pool-wide reserve requirements are set as the size of the largest contingency plus one-half of the second-largest contingency. These requirements are then allocated among control areas in proportion to peak demand.

[15] Cost does not include any debt service, fixed O&M, or equity recovery in any of the cases' simulations.

- Environmental adders based on forecast emissions values[16]
- New generation additions already under construction based on public information and validated with the CBTF[17]

Appendix 3-1 (Input Assumptions) and Appendix 3-2 (Fuel Forecast Memo) give details of these and other inputs to the model.

3.1.2 Case Descriptions for Base case, Stand-Alone case, and EIS case

In distinguishing among these scenarios, CRA worked with three categories of modeling assumptions:

a) Application of wheeling charges
b) Effective flowgate capacity
c) Dispatch of non-network generating units

Table 3-1 indicates how these assumptions were treated in each scenario.

Table 3-1 Scenario Matrix

	Base Case	EIS Case	Stand-Alone Case
Application of wheeling charges	No wheeling charges between SPP members	No wheeling charges between SPP members	Area[18]-to-area wheeling charges (footnote the definition of Area)
Specification of flowgate capacity	Reduced flowgate capacity	Full flowgate capacity	Reduced flowgate capacity
Dispatch of non-network generating units	Sub-optimal	Optimal	Sub-optimal

Each of the three areas of distinction is discussed further below.

Wheeling charges. In MAPS, wheeling charges are calculated as a per-MW price adder for net flows from each area to each neighboring area, based on the definition of the control areas in the

[16] Emission rates are based upon EPA's Clean Air Markets database for 2002 and include future upgrades to emission control technology only if reported in this database. Future rates do not include any environmental controls likely to be required under the current Clean Air Interstate Rules, nor were any additional environmental controls included to reflect pending regulation and/or legislation

[17] Recently constructed combined cycle units were modeled with a heat rate and O&M costs characteristic of baseload combined cycle units. However, these units were not restricted to base load operational behavior, so it is possible that the production costs associated with these units may be underestimated relative to actual operations.

[18] Areas are defined in the power flow case supporting market simulations with MAPS. As a rule, areas specified in the power flow case correspond to control areas. MAPS determines tie-lines between areas and assesses user-defined wheeling charges on the net power flow across these tie-lines.

AC power flow case. MAPS automatically defines interfaces between areas, and CRA defined wheeling rates for each interface based on the scenario modeled and on the appropriate transmission tariff wheel-out rate.

Effective flowgate capacity. For the suboptimal dispatch cases (Base and Stand-Alone), transfer limits on all flowgates in the SPP region were decreased by 10% to reflect the inefficiency of congestion management through the TLR process. The 10% figure was determined in consultation with SPP based on historical tie-line flows during TLR events. Because of uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in this process, it is difficult to achieve full system utilization when congestion is managed through the TLR process.

Optimal vs. Sub-optimal dispatch of non-network generating units. MAPS models the optimal operation of an electric power system without regard to ownership or distinctions in priority and/or transmission network access rights among generating units. Under current SPP rules, however, resources designated as "network resources" for serving native load are given priority access to the transmission system in times of scarcity. It is generally assumed that network resources gain access to the transmission system and are dispatched on an economic basis. Resources that do not have network status receive access to the transmission system on a "first come, first served" basis, subject to the availability of transmission capacity. In order to simulate such a sub-optimal market outcome, the following approach is implemented:

- First, the system is simulated under conditions of optimal, security-constrained, non-discriminatory transmission access for all generating resources. This is identical to assuming the presence of an SPP-wide energy market, in which all committed generating units are dispatched to minimize system-wide production cost subject to transmission constraints. Congestion is relieved in real time on an economic basis in accordance with LMP market signals.

- Second, the system is simulated under the condition where two operational limitations are explicitly implemented in the model:
  - Generating units that do not have network status[19] but that adversely impact limiting transmission constraints are allowed to generate only to the extent that their impact on scarce transmission resources is minimal.[20] The effect is that these resources are dispatched only if they can obtain Available Transfer Capability (ATC), calculated on the basis of network resources having been dispatched first.[21] Given the modified dispatch of units that do not have network status, the rest of the system is redispatched so that the output reduction for non-network units is compensated by increased output of units that do have network status. This redispatch defines the sub-optimal case of the corresponding scenario.
  - In that second (sub-optimal) redispatch, operational limits on SPP flowgates are reduced from their operational limits by 10%, because congestion on these lines

[19] The list of non-network units was generated with extensive consultation with the CBTF.

[20] "Minimal impact" is defined as a flow of no more than 5% of the flow limit on any limiting resource.

[21] No firm economic purchases from the set of non-network units were assumed. To the extent that utilities purchase power from non-network resources to serve firm load and provide high-priority transmission access for this power under current market conditions, the savings between the Base case and the EIS case could be overstated.

is managed through the less-efficient transmission-line relief (TLR) process rather than through LMP-based generation redispatch.

Note that none of the cases included a "hurdle rate other than the tariff wheeling rates applied in the Stand-Alone case. Hurdle rates are non-tariff wheeling rates which are sometimes implemented in market simulations to represent unspecified or difficult-to-model inefficiencies or other barriers to trade. CRA and the CBTF discussed at length the use of a hurdle rate. However, CRA preferred implementing a method that emulated actual market characteristics (network access and conservative line loading under certain cases). As a result, the cases were represented by CRA as described above. Following the implementation of the methodology described above, the utility members of the CBTF reviewed the preliminary results of the simulations and found that simulated inter-control area flow patterns closely matched historical patterns. Based on this review, the addition of a simulation hurdle rate was determined to be unnecessary.

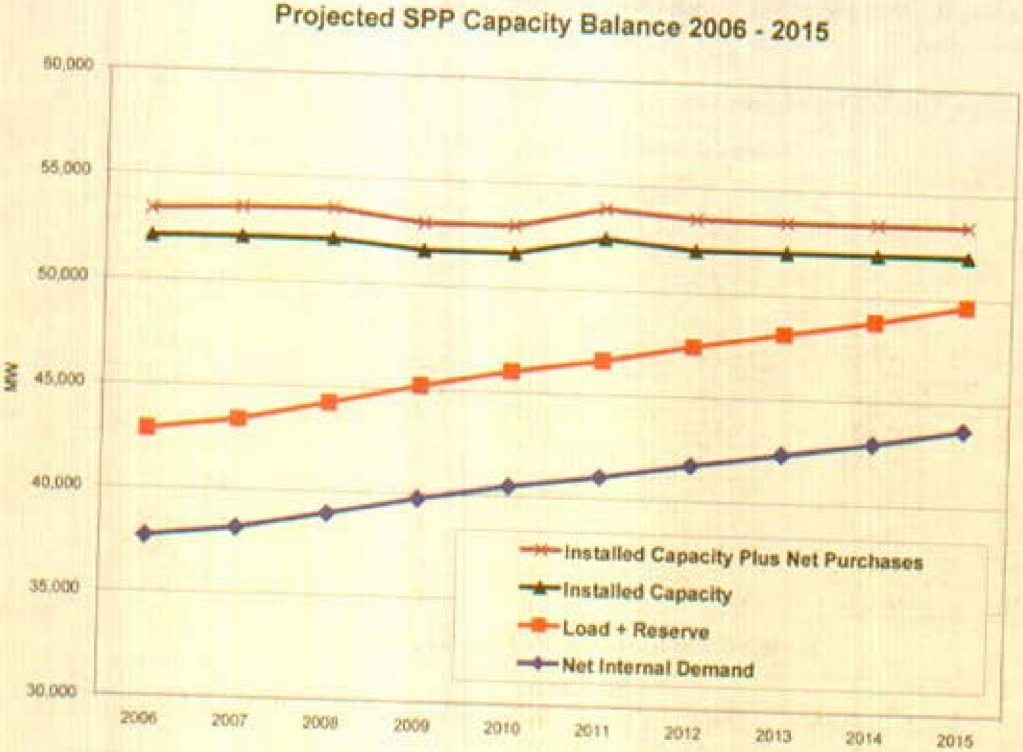
Note also that in each of modeling scenarios it is assumed that the entire volume of the market is cleared through the simulation's spot market. To the extent that transmission owners' self-dispatch and self-deployment is efficient and to the extent that the bilateral market is efficient, the results should emulate the existing market structures. However, to the extent that the bilateral markets are less efficient than the simulated result—and especially to the extent that one might expect the bilateral market efficiency to change with these cases—the actual results may deviate from the simulated results.

3.1.3 Resource Additions

Figure 3-1 summarizes the capacity balance forecast CRA prepared for the SPP region. The forecast is based on information provided by SPP companies with respect to peak demand requirements, generation capacity available to meet these requirements (including both company designated generating units and merchant power plants in SPP), and projected levels of firm purchases and sales.[22] The forecast included Cleco but not Aquila companies. The figure only reflects the addition of 30 MW of the Sunflower Windfarm in 2005 and 800 MW of Iatan 2 coal fired facility scheduled for 2010. It also reflects anticipated retirement of 430 MW of Teche generating units in 2008 and 440 MW of Rodemacher 1 generating unit in 2011. The overall projected capacity balance indicates that the capacity surplus will likely prevail over the study period. The assumed future mix of installed capacity will be more than sufficient for meeting SPP reliability requirements. That eliminated any need for modeling the entry of new generation in SPP. CRA also did not model generation retirements. A proper modeling of generation retirements would require making explicit assumptions with respect to the capacity market under each scenario considered. In absence of the capacity market model, economic retirement of generation cannot be assessed. Given that the capacity market could not be modeled consistently across all scenarios, and that the assessment of such a market is beyond the scope of this study, CRA decided not to model economic retirement of generating facilities in SPP.

[22] Net internal demand Peak demand, purchases, and sales data are per Form EIA 411 filings by SPP companies. Installed capacity in the study was based on CRA MAPS database and direct inputs by study participants.

Figure 3-1 Capacity Balance



3.2 *Wholesale Energy Modeling Results*

This section summarizes region-wide results of the MAPS wholesale energy modeling. Section 4 provides the detailed allocated results of the energy impacts. As is the case throughout this report, all financial values shown in this section are in real year-2003 U.S. dollars.

The quantification of benefits from the MAPS analysis is based on comparisons between the three cases[23] and includes generation production cost, regional generation, and the average spot market prices for energy. The comparisons are made across the SPP system.

The wholesale energy market modeling yields both high-level regional metrics and outputs that feed the detailed allocation results. Metrics include both physical metrics (generation in SPP or imports, and emissions impacts) and financial impacts such as prices.

[23] Capturing benefits in this way removes the majority of concerns regarding inaccuracies in modeling variables, because the great majority of parameters act equally in all cases. By examining differences between the cases, therefore, one can eliminate adverse impacts of a majority of modeling assumption inaccuracies.

3.2.1 Physical Metrics

This section presents both the physical market-wide impacts and the SOx and NOx production for SPP for all three cases.

Tables 3-2 through 3-6 give the physical metrics.

Table 3-2 Base Case Physical Metrics

Base Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	198,518	218,439	19,921	283,538	449,349
2007	201,109	221,942	20,834	282,606	446,861
2008	203,699	225,446	21,746	281,675	444,373
2009	206,290	228,949	22,659	280,744	441,886
2010	208,881	232,453	23,572	279,813	439,398
2011	210,828	235,843	25,016	282,211	442,057
2012	212,774	239,234	26,459	284,608	444,717
2013	214,721	242,624	27,903	287,006	447,376
2014	216,668	246,015	29,347	289,404	450,036
2015	218,615	249,405	30,791	291,802	452,695

Table 3-3 Stand-Alone Case Physical Metrics

SA Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	198,168	218,439	20,271	283,650	449,343
2007	200,825	221,942	21,117	282,903	447,162
2008	203,482	225,446	21,964	282,155	444,981
2009	206,139	228,949	22,810	281,408	442,800
2010	208,796	232,453	23,657	280,660	440,620
2011	210,686	235,843	25,158	282,954	443,094
2012	212,575	239,233	26,658	285,249	445,568
2013	214,465	242,624	28,159	287,543	448,042
2014	216,354	246,014	29,660	289,837	450,516
2015	218,244	249,405	31,161	292,131	452,991

Table 3-4 Imbalance Energy Case Physical Metrics

EIS Case					
Year	Generation (GWh)	Load (GWh)	Net Import (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	201,126	218,439	17,313	276,929	449,010
2007	204,115	221,942	17,827	275,616	446,033
2008	207,104	225,446	18,342	274,303	443,055
2009	210,092	228,949	18,857	272,990	440,077
2010	213,081	232,453	19,372	271,677	437,099
2011	215,348	235,843	20,495	273,580	439,816
2012	217,615	239,234	21,619	275,483	442,532
2013	219,881	242,624	22,743	277,385	445,249
2014	222,148	246,015	23,867	279,288	447,966
2015	224,414	249,405	24,991	281,191	450,682

Tables 3-5 and 3-6 show the differences in the physical metrics between the Stand-Alone and Base cases and between the EIS and Base cases.

Table 3-5 Impact of Stand-Alone Case - Physical Metrics

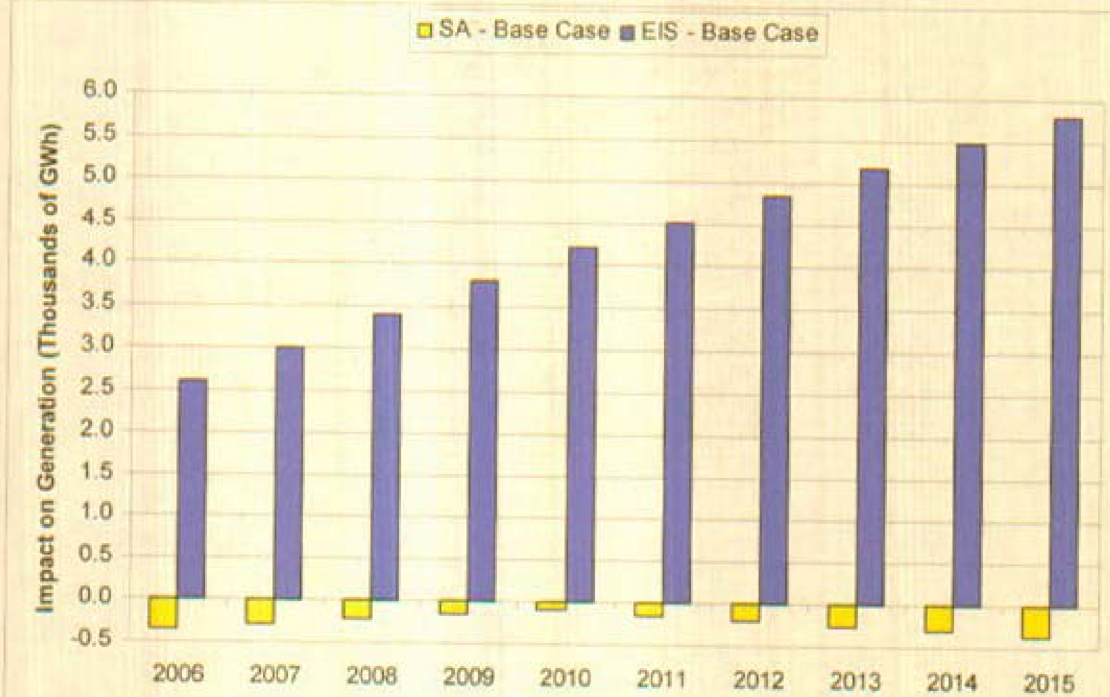
Impact (SA – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	(350)	113	(6)
2007	(284)	296	301
2008	(217)	480	608
2009	(151)	664	915
2010	(85)	848	1,222
2011	(142)	744	1,036
2012	(199)	640	851
2013	(256)	536	666
2014	(314)	433	481
2015	(371)	329	295

Table 3-6 Impact of EIS case—Physical Metrics

Impact (EIS – Base)			
Year	Generation (GWh)	NOx Emissions (T)	SOx Emissions (T)
2006	2,608	(6,608)	(338)
2007	3,006	(6,990)	(828)
2008	3,404	(7,372)	(1,318)
2009	3,802	(7,754)	(1,809)
2010	4,200	(8,136)	(2,299)
2011	4,520	(8,631)	(2,242)
2012	4,840	(9,126)	(2,185)
2013	5,160	(9,621)	(2,127)
2014	5,480	(10,116)	(2,070)
2015	5,800	(10,611)	(2,013)

Figure 3-2 shows the results of the different cases.

Figure 3-2 Impact of Stand-Alone (SA) and EIS cases on Generation in SPP Region

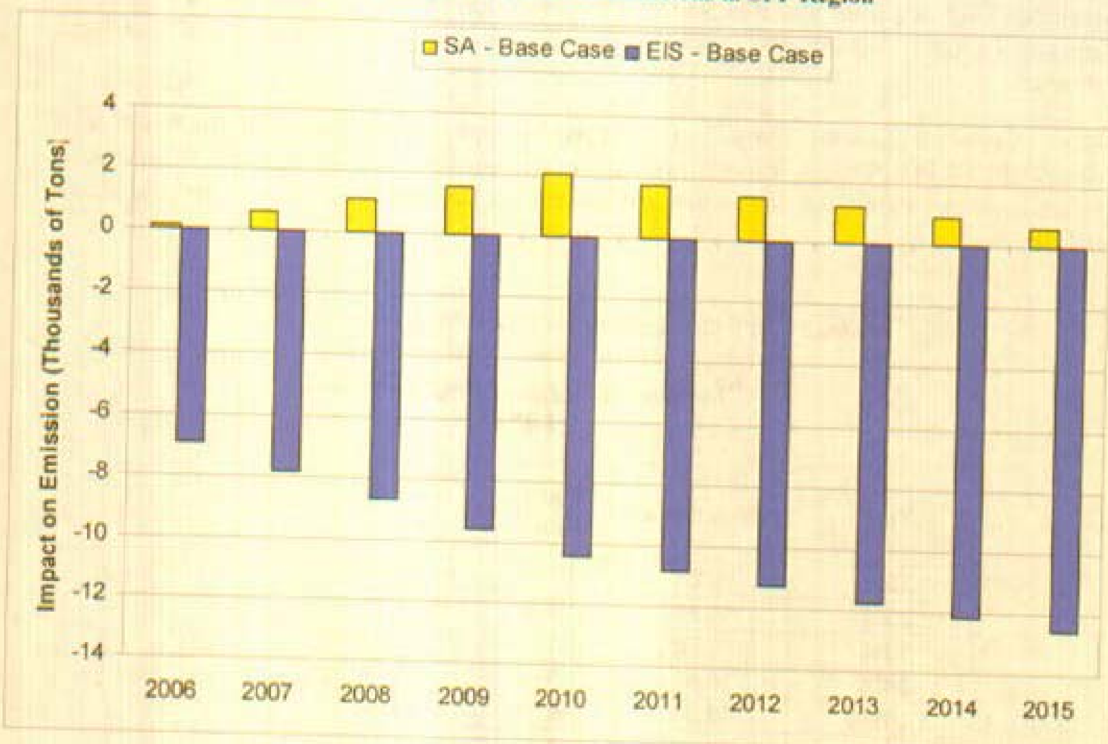


The simulations showed that generation within SPP would decrease were SPP to move from an RTO structure to a Stand-Alone structure in which wheeling rates would again exist between utilities that were previously SPP members. It is likely that with the added wheeling rates, the cost of production plus transmission renders power from SPP sources less competitive relative to generation outside of SPP, so that generation outside of SPP displaces generation within SPP.

In the EIS, case, however, an opposite result occurs. The EIS case results in a marked increase in generation in the SPP region due to the increased efficiency of the SPP dispatch as a result of the improved operation of the flowgate constraints and the increased ability for non-network units to be dispatched economically.

Figure 3-3 shows the impact of the Stand-Alone (SA) and EIS (EI) cases on regional emissions.

Figure 3-3 Impact of Cases on Emissions in SPP Region



The Stand-Alone case, given its further departure from the dispatch efficiency of the Base case due to wheeling rates, results in higher total emission in the SPP region. (Table 3-5 indicates that the increase is essentially equally spread between NOx and SOx emissions increases.) The modeling indicates that the movement to an imbalance energy market would result in a significant (up to 4%) decrease in emissions. Table 3-6 indicates the majority of the decrease is in NOx emissions. This is due to the shift in generation away from older, less efficient and higher emitting, steam-gas units in the Base case to more efficient, cleaner combined cycle units in the EIS case.

3.2.2 Annual Generation Costs—a critical economic indicator

Annual generation cost is a critical economic indicator. It is easy to interpret and it clearly represents a social gain (social welfare gain) to the region as a whole. In this study the terms "generation cost" and "production cost" are used interchangeably. The generation cost or production cost is for each generating unit includes start-up costs, variable operations and maintenance costs, fuel costs, and emissions costs.

Table 3-7 and Table 3-8 show the SPP generation costs24 by case and the impact on generation costs for the Stand-Alone and EIS cases, respectively. Figure 3-4 shows the average annual SPP generation cost for each case, and Figure 3-5 shows the cost differences between the Base case and the Stand-Alone and EIS cases.

Table 3-7 SPP Generation Cost ($/MWh) by Case

	Average Generation Cost Summary ($/MWh)		
Year	**Base Case**	**Stand-Alone**	**EIS**
2006	19.01	19.00	18.61
2007	18.88	18.88	18.51
2008	18.76	18.77	18.40
2009	18.64	18.65	18.30
2010	18.51	18.54	18.19
2011	18.72	18.74	18.38
2012	18.92	18.94	18.58
2013	19.13	19.14	18.77
2014	19.33	19.34	18.96
2015	19.54	19.54	19.15

[24] In the allocation analysis, all control areas are defined to correspond with the areas defined in the load flow case, and units are assigned to companies in accordance with their electrical locations regardless of financial ownership. This is required for alignment with tie line flows, which are defined according to the load flow case areas. In contrast, the wholesale market analysis identifies units according to ownership data provided by the CBTF. Because of this, some differences in electrical output and generation cost by company and over SPP will be found between the two analyses.

Table 3-8 Impact of Cases on Average Generation Cost in SPP ($/MWh)

	Impact on Generation Cost ($/MWh)	
Year	SA – Base	EIS – Base
2006	(0.005)	(0.39)
2007	0.002	(0.37)
2008	0.008	(0.36)
2009	0.015	(0.34)
2010	0.021	(0.32)
2011	0.016	(0.34)
2012	0.012	(0.35)
2013	0.007	(0.36)
2014	0.003	(0.37)

Figure 3-4 SPP Generation Cost ($/MW) by Case

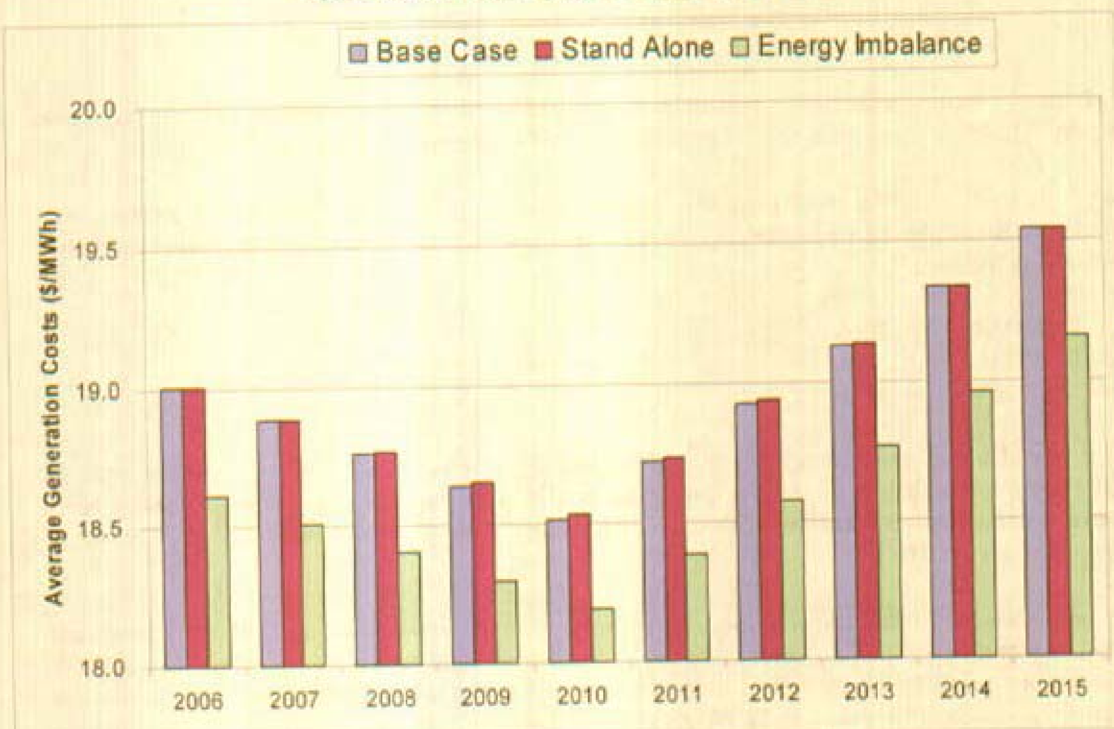
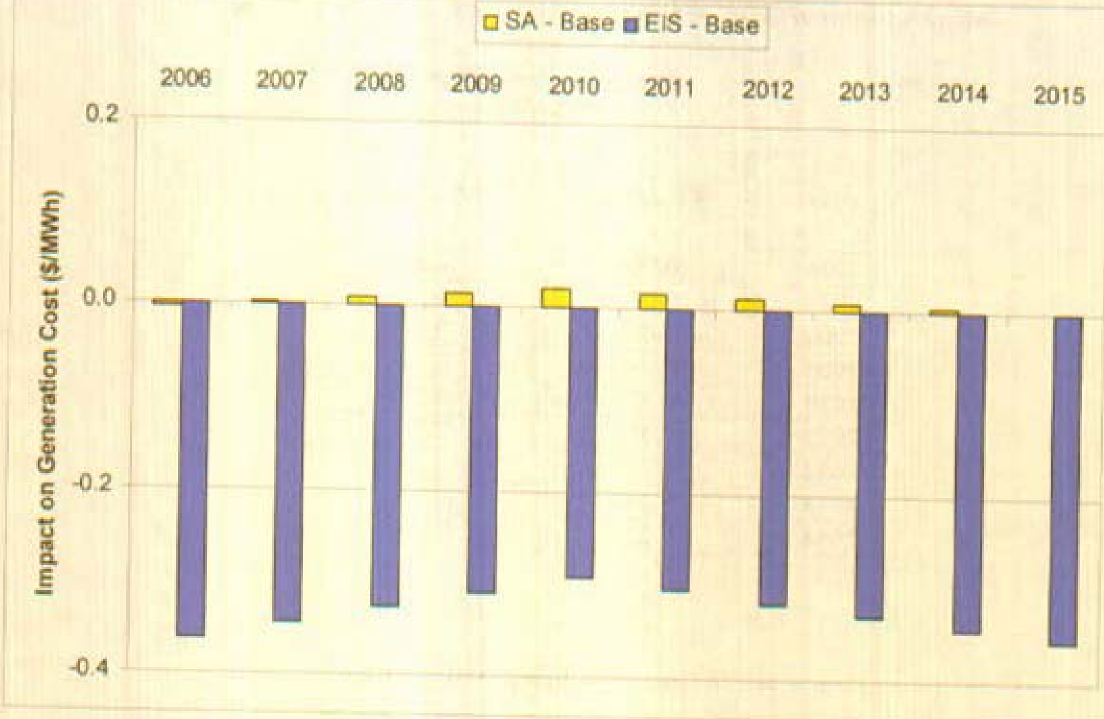


Figure 3-5 SPP Generation Cost ($/MWh) Differences



The wholesale results indicate a year-by-year pattern, as well as regular pattern in the case differences. There are three main factors behind the year-by-year trend of the cost differences.

- First, generation costs, and therefore generation cost differentials between scenarios, are significantly influenced by underlying forecast fuel prices. Assumed natural gas prices at Henry Hub are as follows:

  - $5.54/MMBtu in 2006
  - $4.24/MMbtu in 2010
  - $4.47/MMbtu in 2014

  That would imply generation costs in 2006 being higher than in 2010 and generation costs in 2010 being lower than in 2014. The same pattern will likely apply to changes in generation costs between scenarios—the change in 2006 would be higher than in 2010, then change in 2010 would be lower than in 2014.[25]

- Second, changes in the transmission system occur over the study horizon. The load flow case used to simulate years 2010 and 2014 includes transmission upgrades not available in 2006. Simulations for 2010 would reflect these transmission upgrades and therefore could exhibit less transmission congestion than in 2005. As discussed above, sub-optimal dispatch underlying the Base case modeling is primarily influenced by transmission congestion; lower congestion implies

[25] It is important to note that direct simulations were performed for 2006, 2010, and 2014 only. Results for other years are based on interpolation and/or extrapolation.

smaller differences between EIS and Base case scenarios, as can be observed in comparing years 2006 and 2010.

- Third, there is load growth requiring greater generation output but not supported by further transmission upgrades: simulations for 2010 and 2014 were made using the same load flow case. That implies higher congestion in 2014 than in 2010. Higher congestion in turn implies less efficient use of non-network generators and therefore greater difference between the Base and EIS case scenarios in 2014 than in 2010, as can be seen in Figure 3-5.

Implementation of the EIS market yields a saving of $0.36 per MWh on average. The relative magnitude of the generation cost difference between the Base and Stand-Alone cases is essentially negligible (less than 0.01%). Thus the modeling found no significant *region-wide* impact of moving from the Base case to the Stand-Alone case.

3.2.3 Wholesale Spot Energy Price Changes

This section presents the impacts on the spot price[26] of energy in SPP from the three cases. Table 3-9 shows the average annual energy cost in the SPP region under each case, and Table 3-10 shows the change in spot price, relative to the Base case, for the Stand-Alone and EIS cases.

Table 3-9 Average SPP Spot Load Energy Price

	Costs of Served Load Summary ($/MWh)		
Year	Base Case	Stand-Alone	Energy Imbalance
2006	40.85	40.95	38.32
2007	39.96	40.07	37.49
2008	39.06	39.19	36.67
2009	38.16	38.31	35.85
2010	37.27	37.43	35.03
2011	37.92	38.01	35.45
2012	38.57	38.59	35.87
2013	39.22	39.18	36.29
2014	39.87	39.76	36.71
2015	40.53	40.34	37.13

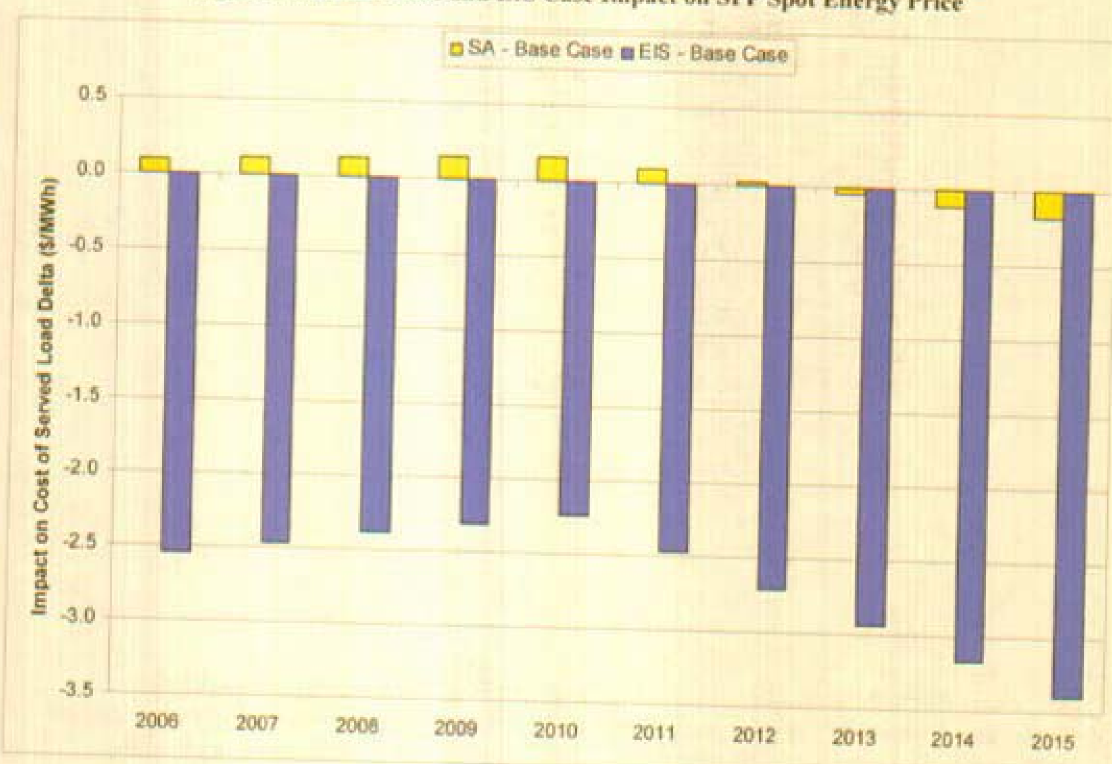
[26] The "spot price" refers to the locational price of energy (in $/MWh) as calculated under the locational marginal price (LMP) system, assuming cost-based, security constrained optimal dispatch of the system. While a spot price can be calculated for any point in the system, it is not generally reflective of the cost of production at that location, but it is reflective of the marginal cost of increasing consumption at that location.

Table 3-10 Case Impacts on SPP Spot Energy Price

Average Cost of Served Load Delta ($/MWh)		
Year	**SA - Base case**	**EIS - Base case**
2006	0.09	(2.54)
2007	0.11	(2.46)
2008	0.13	(2.39)
2009	0.14	(2.31)
2010	0.16	(2.24)
2011	0.09	(2.47)
2012	0.02	(2.70)
2013	(0.04)	(2.93)
2014	(0.11)	(3.17)
2015	(0.18)	(3.40)
Average	**0.04**	**(2.66)**

Figure 3-6 shows the impact of the Stand-Alone and Energy Imbalance cases on the average load spot energy price in SPP.

Figure 3-6 Stand-Alone and EIS Case Impact on SPP Spot Energy Price



Note that the general patterns of the impacts are similar to those shown for generation costs in Figure 3-5, but that the regional load marginal energy cost differences between the cases are significantly higher because of the model's marginal pricing of spot energy to loads. For the Energy Imbalance case, the spot price for loads is over $2.50/MWh (about 7%) less expensive than under the Base case scenario on average over the study horizon.

3.2.4 Impact on the Marginal Value of Energy Generated

Similar to Section 3.2.3, this section provides the impacts of the cases to the marginal value of energy at the generation sources. Table 3-11 shows the average marginal value of the energy for all generation in SPP and Table 3-12 shows the difference in marginal value of the generation between the cases. These results indicate how the spot value of energy at the generating locations is impacted by the cases in the simulations.[27]

Table 3-11 Average Marginal Value of Energy Generated

Average Marginal Value of Energy Generated ($/MWh)			
Year	**Base Case**	**Stand Alone**	**Energy Imbalance**
2006	37.40	37.28	35.39
2007	36.55	36.47	34.64
2008	35.73	35.68	33.91
2009	34.93	34.92	33.19
2010	34.15	34.17	32.50
2011	34.70	34.65	32.81
2012	35.35	35.22	33.21
2013	35.99	35.78	33.60
2014	36.62	36.34	33.99
2015	37.23	36.88	34.37
Average	**35.86**	**35.74**	**33.76**

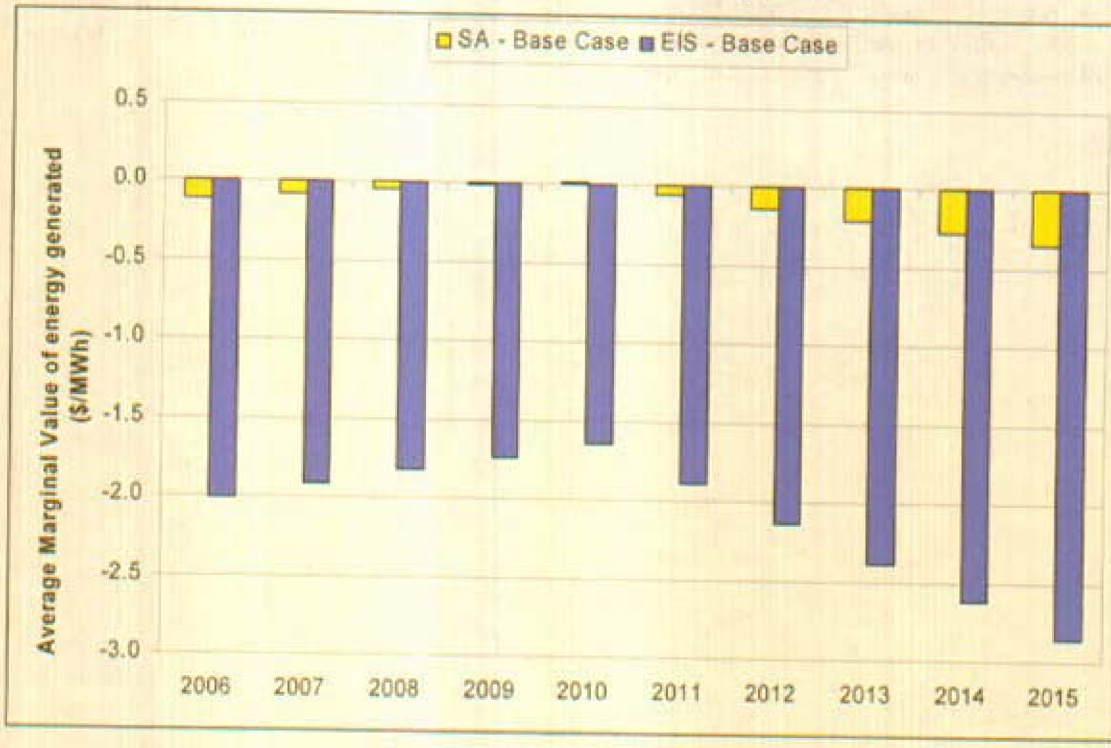
[27] Recall that the simulated values are based on the assumption that generating units bid marginal cost.

Table 3-12 Average Marginal Value Delta

Average Marginal Value Delta of Energy Generated ($/MWh)		
Year	**SA - Base Case**	**EIS - Base Case**
2006	(0.12)	(2.01)
2007	(0.08)	(1.91)
2008	(0.05)	(1.82)
2009	(0.01)	(1.74)
2010	0.02	(1.65)
2011	(0.06)	(1.90)
2012	(0.13)	(2.14)
2013	(0.21)	(2.39)
2014	(0.28)	(2.63)
2015	(0.35)	(2.86)
Average	**(0.13)**	**(2.11)**

Figure 3-7 shows the differences in marginal energy value between the cases. The figure reflects the fact that the value of energy for generators is lower in the EIS case than in the Base case (on average by $2.11). The value of energy to the generators simulated in the Stand-Alone case is also lower than in the Base case. The imposition of wheeling rates in the Stand-Alone case causes the marginal value of energy at the generators to increase for some companies and to decrease for other companies. Figure 3-7 simply shows the result of these impacts and indicates that the total average marginal generation energy value happens to be slightly lower under the Stand-Alone case.

Figure 3-7 Average Marginal Value of Energy Generated



3.2.5 Outputs to Allocation Model

In addition to providing high-level regional indicators of the impacts of each of the cases, the Wholesale Energy Modeling provided critical inputs to the allocation processes that led to company and state-specific impacts. These inputs include the following:

- Generation
- Generation cost (including emission costs)
- Nodal locational marginal prices
- Hourly tie-line flows
- Annual generating unit reports including dispatch, cost and revenue data by plant
- Load

3.3 Wholesale Energy Modeling Conclusions

The wholesale energy modeling SPP generation cost and spot energy price metrics indicate that the Energy Imbalance market increases the dispatch efficiency (reduces dispatch cost) by approximately 2% and decreases SPP spot energy prices by approximately 7%. These are significant differences. The differences between the Stand-Alone and Base case metrics were much smaller than those between the Base Case and EIS scenarios. Thus, in the absence of an Energy Imbalance Service market, reversion to a Stand-Alone mode of operation would not appear to have a significant adverse impact on regional dispatch efficiency. However, as discussed in Section 4, reversion to a Stand-Alone mode would create significant shifts in generation costs between transmission owners, merchant generators, other SPP market participants, and neighboring regions.

4 Benefits (Costs) by Company and State

4.1 Methodology for Measuring Benefits (Costs)

Welfare for regulated customers of a utility, as measured in this study, is based on the charges to local area load for generation and transmission service, assuming that any benefits to the regulated utility are passed through to its native load. If these charges decrease, regulated customer welfare increases. This study assesses the benefits and costs associated with load-serving utilities moving from base conditions to stand-alone status and from the base conditions to participation in the EIS market. To quantify this change, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation or production costs, energy purchases, wheeling charges, and O&M expenditures.

The major categories of benefits and costs addressed in this study are trade benefits, wheeling charges and revenues, SPP implementation and operating costs, and individual utility implementation and operating costs. Trade benefits and wheeling impacts were computed using the MAPS results for each case.[28] The changes in SPP costs from the Base to the Stand-Alone case and from the Base to the EIS case were estimated using projected SPP budgets. Individual company changes in operating and capital costs that would take place under stand-alone status and under participation in the EIS market were projected by each company, reviewed by CRA for consistency in approach, and converted to revenue requirements. The methodology used to estimate the impact of each major category of benefits and costs is discussed below.

4.1.1 Trade Benefits

The cases analyzed in this study (Base, Stand-Alone, and EIS) reflect varying degrees of impediments to trade between regions. In particular, the institution of intra-SPP wheeling rates in the Stand-Alone case results in greater impediments to trade between utility areas, and institution of the EIS market results in reduced impediments to trade between utility areas. Reductions in the impediments to trading between utilities should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance--an increase in imports or exports—an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation

[28] MAPS runs were completed for the years 2006, 2010 and 2014. The results for the intervening years were interpolated on a straight-line basis using the results in 2003 dollars, and then an annual inflation rate of 2.3% was applied. Results for the year 2015 were obtained by escalating 2014 results at the annual inflation rate.

cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits. While production cost changes cannot be used directly to allocate trade benefits to individual utility areas, the individual utility trade benefits will sum to the change in aggregate production cost.[29]

In this study, merchant plants are assumed to be participating in the wholesale market based upon market-driven pricing in the Stand-Alone, Base, and EIS Market cases. All utility-owned plants are assumed to have an obligation to serve native load under cost-based regulation. Benefits are therefore calculated as if all trade gains earned by utilities accrue to the benefit of native load. This means that benefits have not been separated between those that might accrue to the utility in comparison to those that that might accrue to that utility's native load.

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For the SPP region, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales. In turn, utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Allocating system-wide energy benefits to each SPP utility thus requires an analysis of both the production cost of operating utility-owned generating plants and the associated utility trading activity (purchases and sales).

In this study, trade benefits are allocated primarily among utilities within SPP and control areas with direct interties with SPP based on the change in utility generation between the base and change cases.[30] This presumes that trading margins are similar throughout the SPP region. This approach differs from that used in CRA's SEARUC cost-benefit study, which was based on using a 50-50 sharing rule and tie-line flows as a proxy for transactions between adjoining control areas. Our consideration of using a similar method within SPP indicated that loop flow effects are important within this compact region and would prevent a successful application of the SEARUC approach without substantial modification. CRA believes that the assumption of a similar trade margin throughout SPP provides a good first approximation of how aggregate trade benefits are likely to be distributed within SPP. Improving on this estimate would require additional study to determine how the loop flow issue could be addressed in greater detail.

In particular, this study assumes that trade gains are shared among control areas in proportion to the magnitude of the absolute value of the change in generation output. This means that control areas that

[29] To help understand why this must be so, consider a simple two-company example. Assume there is a $16 marginal cost to generate in Company A's control area and a $20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW' can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of $16, while Company B will generate 1 MW less at a production cost savings of $20. Thus, the total saving in production cost is $4 (i.e., $20 – $16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefits of $4 ($2 + $2) will match the total production cost saving of $4.

[30] For purposes of this study, the change in utility generation was assessed on an annual basis. This allocation could be further refined through the use of a monthly or hourly allocation.

sell more energy (those whose generation increases) and control areas that buy more energy (those whose generation decreases) share the trade benefits equally for each megawatt-hour of change in generation output. Within each control area, trade benefits associated with changes in utility-owned generation accrue to native load. This is consistent with traditional trading between utilities using a 50-50 sharing arrangement. The only difference between this approach and that used in the SEARUC study is that the 50-50 sharing rule is implemented in this study based on changes in each utility's position as a net buyer or seller, while the 50-50 sharing rule in the SEARUC study was implemented between interconnected pairs of utilities. The level of aggregation used in the allocation of the trade benefits is higher in this study, but the underlying approach is the same—a 50-50 sharing rule.

The study makes the additional assumption that merchant units participate in the EIS market in a particular way. The EIS market will provide an SPP-wide opportunity for merchant units to participate in an organized spot market for energy. However, it is expected that most merchant plants will do so through some type of contractual arrangement with utilities on behalf of their native load. CRA does not have any information about the potential nature of such contractual arrangements. However, it is unlikely that merchant plants would participate in an imbalance market for energy if that market were the sole source of merchant revenue. Merchant plants likely would seek additional revenue through contractual arrangements with native load.

Accordingly, CRA has assumed that merchants participate in the EIS under a two-part pricing arrangement. First, the merchants are paid their respective locational wholesale price for any energy that they produce. Second, the merchants in each control area are allocated a share of the control area trade benefits based on their change in generation output. That is, the control area trade benefits are allocated to utility-owned generation and merchant generation within the control area based on the absolute value of their change in generation output. Finally, the resulting merchant allocation of trade benefits is further subdivided with the merchants receiving 50 percent of these trade benefits, while native load receives the remaining 50 percent under contractual arrangements. The 50 percent native load share of these trade benefits is allocated on a pro rata basis to all of the participating load in the EIS market. In effect, CRA is using an estimate of the trade benefits allocable to the merchants as a basis for a 50-50 sharing formula between merchants and native load. This is consistent with the 50-50 sharing rule used to allocate trade benefits between control areas discussed above, except that the merchant/utility sharing arrangement would be implemented within a control area. We recognize that this approach provides only a preliminary indication (but a reasonable one, in our view) of how merchant participation might evolve in the future.

4.1.2 Wheeling Impacts

Using the MAPS outputs, wheeling charges and revenues are calculated based on hourly tie-line flows in MAPS multiplied by the applicable wheeling rate. Wheeling charges are paid on "out" transactions, i.e., exports from each control area, and are paid by the load in the importing control area. The wheeling charges are paid to the transmission provider in the exporting control area. These wheeling revenues reduce the net transmission revenue requirement to be paid by the native load in the exporting transmission provider's control area. Since each import is associated with a matching export, wheeling charges and wheeling revenues will match over the entire modeled footprint.

For the transmission owners under the SPP Tariff, wheeling revenues collected by SPP are distributed to individual SPP transmission owners based on a formula that includes MW-mile and other impacts. For purposes of this study, the wheeling revenues calculated using MAPS tie-line flows were redistributed among these transmission owners using each transmission owner's percentage share of 2003 revenue by transmission owner for point-to-point Schedule 7 and 8 external transactions.

4.1.3 Administrative and Operating Costs

A number of costs must be analyzed in addition to those directly addressed in MAPS. These include SPP implementation and operating costs that are ultimately paid by member companies and operating and implementation costs that are incurred directly by member companies.

SPP costs were analyzed using SPP budget forecasts, disaggregated as necessary to identify costs that would change in the Stand-Alone and EIS Market cases. In response to CRA requests, each company provided a projection of the implementation and operating costs it would incur. Individual company responses were compared and discussed in order to ensure a consistent approach among the respondents.

The specific categories of costs addressed in this study are discussed in detail below for each case.

4.2 Stand-Alone Case Results and Discussion

4.2.1 Trade Benefits

Implementation of intra-SPP wheeling rates in the Stand-Alone case leads to a less efficient dispatch and thereby yields additional system-wide production costs. Additional production costs for the Eastern Interconnect are $54 million over the study period. Production costs for the transmission owners under the SPP tariff increase by $165 million, while, in contrast, production costs of SPP merchants decrease by $107 million. As discussed above, these production cost impacts are shared among individual companies through trading. Using the methodology outlined above, the aggregate Stand-Alone trade impacts for the transmission owners under the SPP tariff are $21 million of lost (i.e., negative) benefits. That is, the Stand-Alone case results in a decrease in trade benefits for the transmission owners under the SPP tariff, and thus an increase in costs. Through the allocation process, transmission owners under the SPP tariff incur 39% ($21/$54) of the total loss in trade benefits across the Eastern Interconnect.

Tables 3, 4 and 5 in Appendix 4-1 give annual trading benefit results, production cost changes, and generation changes by company over the study period.

4.2.2 Transmission Wheeling Charges

Implementation of intra-SPP wheeling rates leads to significantly greater wheeling charge payments by SPP companies. As noted above, the native load in each control area was assumed to pay the charges associated with the import of power. The wheeling charges increase by $500 million over the study period for the transmission owners under the SPP tariff. Since these are payments, this is a negative benefit to the Stand-Alone case. Table 6 in Appendix 4-1 gives annual wheeling charge increases by company over the study period.

4.2.3 Transmission Wheeling Revenues

Similarly, the implementation of intra-SPP wheeling rates leads to significantly greater wheeling revenue collections by SPP transmission providers. The wheeling revenues are paid to the exporting control area's transmission provider, and then allocated to the native load in that control area. That is, wheeling revenues are used to reduce the transmission revenue requirement for native load. The wheeling revenues for the transmission owners under the SPP tariff increase by $516 million. Since these are revenues, this is a positive benefit to the Stand-Alone case.

As discussed above, the wheeling revenues were calculated using MAPS tie-line flows for the transmission owners under the SPP tariff. The revenues were redistributed among the transmission owners using each transmission owner's percentage share of 2003 revenue for point-to-point Schedule 7 and 8 external transactions. Table 7 in Appendix 4-1 gives annual wheeling revenue increases by company over the study period.

The use of tie-line flows to assess wheeling charges and wheeling revenue impacts when there are loop flows that would not represent actual transactions relies on the presumption that such loop flow impacts will be similar in the Base and alternate cases and thus will not significantly impact the change in wheeling impacts between cases. However, in the case in which there a significant change in wheeling rates between cases, for example the institution of intra-SPP wheeling charges in the Stand-Alone case, the impact of loop flow on intra-SPP tie-line flows has the potential to distort measured wheeling impacts. Given that possibility, the specific company wheeling impacts (both wheeling charges and wheeling revenues) in moving from the Base Case to the Stand-Alone case presented in this study should be viewed as representative results meriting further review and analysis.

4.2.4 Costs to Provide SPP Functions

In addition to its long-running role as a NERC reliability council, SPP performs a number of other reliability/transmission provider functions for transmission-owning members, namely reliability coordination, tariff administration, OASIS administration, available transmission capacity (ATC) and total transmission capacity (TTC) calculations, scheduling agent, and regional transmission planning. Moving to stand-alone status would require the transmission owner to procure these services from an alternative supplier or provide them internally. In turn, however, the transmission owner would avoid payment (through the assessment process) to SPP for SPP's provision of these functions.

Appendix 4-3 provides a discussion of the analysis performed to estimate the differential in costs to provide these functions. That analysis indicates that the transmission owners under the SPP tariff would incur additional costs of $46.0 million over the study period. Since this is an additional cost, this is a negative benefit to the Stand-Alone case.

Some companies would incur a decrease in the net costs for these functions, corresponding to a positive benefit. Table 8 in Appendix 4-1 presents the costs, by company, under the Base and Stand-Alone cases.

Since SPP supplies these functions in both the Base and EIS Market cases, this cost category is not relevant to the comparison of those cases.

4.2.5 FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for SPP RTO member load-serving utilities are assessed directly to SPP when SPP is an RTO (as in the Base and EIS Market cases), and then in turn assessed by SPP to member companies. Under FERC regulations, the annual FERC charge is assessed to all SPP RTO energy for load. This includes the energy transmitted to serve the load of public power companies such as municipals and cooperatives, which would not otherwise be subject to FERC charges. FERC charges for RTO members are therefore significantly higher for investor-owned utilities and are assessed for the first time to publicly owned utilities.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge under a non-RTO (Stand-Alone) basis, there will be higher FERC charges to RTO members than non RTO-members, all else being equal.

For purposes of this study, the impact of the FERC charges between the Base and Stand-Alone cases was estimated by comparing the FERC charges to be assessed to SPP (and then allocated to each SPP member) in 2005 to the average inflation-adjusted FERC charges paid by each individual company in the 1999–2003 period. This impact was then escalated and discounted over the 10-year study period. The 1999–2003 data were used as a source of actual FERC charges paid by SPP member companies when assessed charges on a stand-alone basis. An average over the 1999–2003 period was applied, as the charges vary by year depending on the volume of wholesale transactions. As RTOs continue to form, an increasingly larger share of FERC's total annual charges are being allocated to RTO members than the average over the 1999–2003 period. This approach therefore likely provides a conservative estimate of the savings in FERC charges that would result from stand-alone status in the future. However, it also may overestimate the savings if FERC begins to apply these charges to energy transmitted to native load by utilities that are not part of an RTO and thus puts non-RTO and RTO members on an equal footing.

Using this approach, the decrease in FERC fees under the Stand-Alone case is $47 million for the transmission owners under the SPP tariff over the study period. Since this is a reduction in costs, it is a benefit to the Stand-Alone case. Table 9 in Appendix 4-1 gives the estimated FERC charges, by company, under the Base and Stand-Alone cases.

Since the FERC charges by company would be the same in the Base and EIS cases, this cost category is not relevant to the comparison of those cases.

4.2.6 Transmission Construction Costs

Beginning in 2006, SPP will implement a new cost allocation procedure to assign costs for new transmission projects to the transmission owners under the SPP tariff. The existing cost-allocation method directly assigns the cost to the transmission owner in whose control area the project is placed in service. The new cost allocation will use a combination of direct cost assignment, MW-mile impacts, and load ratio shares to assign transmission project capital costs to individual transmission owners under the SPP tariff.

In the Stand-Alone case, the existing direct-assignment cost allocation is assumed to continue. A comparison of the new and existing cost allocation methods was therefore performed to capture the difference in new transmission project revenue requirements for individual companies under the SPP tariff. Only new transmission investment in the 2006–2010 period was considered. Since the total transmission investment is the same in both the Base and Stand-Alone cases, the aggregated impact over all transmission owners under the SPP tariff is zero.[31] For individual company impacts, see Table 10 in Appendix 4-1.

[31] While it is possible that Stand-Alone transmission investment could differ from transmission investment in the Base case, such a difference was not considered in this study. To the extent that transmission providers are

Since the new cost allocation method would be used in both the Base and EIS cases, this cost category is not relevant to the comparison of those cases.

4.2.7 Withdrawal Obligations

Moving to stand-alone status would likely require withdrawal from SPP and the payment of an exit fee or withdrawal obligation payment to SPP. The withdrawal obligation for each company was obtained from a recent (July 2004) SPP Finance Committee analysis of this issue. The withdrawal obligation payment is assumed to take place on January 1, 2006. For individual company obligations, see Table 11 in Appendix 4-1.

4.2.8 Total Benefits (Costs)

4.2.8.1 For Transmission Owners under the SPP Tariff

Table 4-1 gives the results by category for the transmission owners under the SPP tariff. The aggregate benefit is ($70.5) million over the study period, i.e., the aggregate benefits of moving to Stand-Alone status are negative. This $70.5 million figure can be thought of as the additional costs incurred by moving to Stand-Alone status.

Table 4-1 Stand-Alone Case Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	(20.9)
Transmission Wheeling Charges	(499.8)
Transmission Wheeling Revenues	515.6
Costs to Provide SPP Functions	(46.0)
FERC Charges	27.3
Transmission Construction Costs	0.5
Withdrawal Obligations	(47.2)
Total	(70.5)

Table 4-2 gives the total impact of moving to Stand-Alone status for each transmission owner under the SPP tariff. Table 1 in Appendix 4-1 gives results by company and by category. The results in Table 4-2 are shown with and without the impact of wheeling revenues and charges. As shown, excluding wheeling impacts, the benefit of moving to Stand-Alone status for each individual transmission owner is either close to zero or somewhat negative (i.e., an increase in costs).

While the aggregate benefit for the transmission owners under the SPP tariff is negative, some individual companies show a moderately positive benefit when wheeling impacts are included. For those companies, the positive result is driven by a significant increase in wheeling revenues when through-and-out wheeling charges to other SPP companies are instituted in the Stand-Alone case. In practice, the increase in wheeling revenues would be associated with a utility that exports significant

affected by the change in cost allocation, network customers of these transmission providers are also be affected.

amounts of power to other SPP companies. Since there are no intra-SPP wheeling charges in the Base case, utilities that export significant amounts of power to other SPP companies would collect considerably more in wheeling revenue in the Stand-Alone case than in the Base case.

However, as discussed above, the change in wheeling rates in the Stand-Alone and the existence of loop flow together result in considerable uncertainty regarding wheeling impacts assessed to individual SPP companies. The collective Stand-Alone impact across SPP is a better measure than the individual company results, as the intra-SPP wheeling charges paid to/from SPP members offset one another in the collective calculation. The individual company Stand-Alone results with wheeling impacts included should therefore be viewed as representative, subject to further investigation into loop flow on individual company wheeling impacts.

Table 4-2 Stand-Alone Case Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefits excl. Wheeling	Wheeling Impacts	Total Benefits
AEP	IOU	(19.8)	(3.0)	(22.8)
Empire	IOU	(5.8)	(19.8)	(25.6)
KCPL	IOU	(17.8)	68.7	50.9
OGE	IOU	(8.2)	(10.4)	(18.6)
SPS	IOU	(5.0)	49.5	44.5
Westar Energy	IOU	(17.0)	0.2	(16.9)
Midwest Energy	Coop	(7.9)	3.9	(3.9)
Western Farmers	Coop	1.3	(52.5)	(51.2)
SWPA	Fed	1.2	(20.9)	(19.7)
GRDA	State	(4.8)	(6.0)	(10.8)
Springfield, MO	Muni	(2.5)	6.1	3.5
Total		(86.3)	15.8	(70.5)

4.2.8.2 By State

An allocation by state was carried out for the six IOUs listed in Table 4-2. This was calculated by allocating between wholesale and retail customers using load shares and further dividing the retail customer results by state using load shares.[32] The retail customer results were further divided by state. Table 4-3 gives aggregate retail customer benefits (costs) by state for these six IOUs. Table 1-2 in Appendix 4-1 gives benefits by company by state. To the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

[32] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma, and Southwestern Electric Power Company prior to allocation to individual states.

Table 4-3 Stand-Alone Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

	Benefits excl. Wheeling	Total Benefits
Arkansas	(3.0)	(5.0)
Louisiana	(2.6)	(3.0)
Kansas	(22.2)	3.6
Missouri	(13.7)	2.7
New Mexico	(0.7)	5.9
Oklahoma	(16.2)	(25.9)
Texas	(5.5)	16.4

4.2.8.3 Other Results

Using the methodology described above, the benefit for other typical members that pay an SPP assessment (Arkansas Electric Cooperative Corporation; The Board of Public Utilities, Kansas City, Kansas; Oklahoma Municipal Power Authority; City of Independence, Missouri) is also computed and included in Table 1 in Appendix 4-1. The additional cost of moving to stand-alone status for these four typical members is $4.7 million. The additional cost incurred by SPP merchants when SPP transmission owners under the SPP tariff move to stand-alone status is $8.6 million.

Table 1 in Appendix 4-1 also lists the benefits to other load-serving utilities that are members of SPP but are not transmission owners under the SPP tariff. Considering only trade benefits and wheeling impacts, these utilities incur additional costs of $9.3 million when SPP transmission owners under the SPP tariff move to stand-alone status.

Finally, the rest of the Eastern Interconnect,[33] again considering only trade benefits and wheeling impacts, incurs additional costs of $30.5 million when SPP transmission owners under the SPP tariff move to stand-alone status. As shown in Appendix 4-1, Table 1, the total trade benefits and wheeling impacts across all companies is an additional cost of $53.8 million. As discussed above, this is exactly equal to the increase in production costs across the modeled footprint from the Base to the Stand-Alone case.

4.3 EIS Market Case Results and Discussion

4.3.1 Trade Benefits

Implementation of the EIS Market leads to a more efficient dispatch and thereby yields system-wide production cost savings in comparison to the Base case. Production costs savings for the entire Eastern Interconnect are $1,173 million over the study period. Production cost savings for the

[33] In the CBA the "Eastern Interconnect" includes the majority of the Eastern Interconnect, but excludes—for example—the Northeast markets.

transmission owners under the SPP Tariff are $2,569 million, while, in contrast, SPP merchants have a production cost increase of $2,670 million. As discussed above, these production cost impacts are shared among individual companies through trading. Using the methodology outlined above, the trade benefits for the transmission owners under the SPP Tariff in the EIS Market case are $614 million. Thus, transmission owners under the SPP tariff obtain 52% ($614/$1173) of the total trade benefits.

Tables 3, 4 and 5 in Appendix 4-2 give annual trading benefit results, production cost changes, and generation changes by company over the study period.

4.3.2 Transmission Wheeling Charges

No changes to wheeling rates from the Base case are assumed to take place in the EIS case. However, implementation of the EIS Market does change generation levels and tie-line flows. As noted above, the native load in each control area is assumed to pay the wheeling charges associated with the import of power. The wheeling charges decrease by $24 million over the study period for the transmission owners under the SPP Tariff. Since these are payments, this is a positive benefit to the EIS case. Table 6 in Appendix 4-2 gives annual wheeling charge increases by company over the study period.

4.3.3 Transmission Wheeling Revenues

Similarly, implementation of the EIS market changes also affects wheeling revenues. The wheeling revenues are paid to the exporting control area's transmission provider, and then allocated to the native load in that control area. That is, wheeling revenues are used to reduce the transmission revenue requirement for native load. The wheeling revenues for the transmission owners under the SPP Tariff decrease by $54 million. Since these are revenues, this is a negative benefit to the EIS case. Table 7 in Appendix 4-2 gives annual wheeling revenue increases by company over the study period. Since wheeling rates are unchanged between the Base and EIS market cases, the individual company wheeling impacts for the EIS market case are less affected by loop flow issues than those in the Stand-Alone case. With no change in wheeling rates and no intra-SPP wheeling rates, the loop flows will not significantly impact the change in wheeling impacts between the Base and EIS market cases if the loop flows into and out of SPP are similar in both cases.

4.3.4 SPP EIS Implementation and Operation Costs

SPP will incur considerable expenditures in implementing and operating the EIS market. These expenditures, in turn, will be assessed to the EIS market participants. An evaluation of the SPP budget was performed to project the costs that would be assessed to individual EIS market participants. For the transmission owners under the SPP tariff, the total cost that will be passed through by SPP is $104 million over the study period. Since this is an additional cost, this is a negative benefit to the EIS case. Table 8 in Appendix 4-2 gives the annual costs that would be assessed to EIS market participants.

4.3.5 Participant EIS Implementation and Operation Costs

EIS market participants will incur significant expenditures to participate in the EIS market over and above SPP's assessments for its own expenditures. In response to a request by CRA, EIS market participants provided a detailed annual estimate of the additional labor, O&M, and capital costs they would incur over the study period to participate in the EIS market. Appendix 4-4 gives details on these cost estimates. These costs were converted to annual revenue requirements and are summarized in Table 9 in Appendix 4-2. The total cost to transmission owners under the SPP tariff over the study period is $107 million. Since this is an additional cost, this is a negative benefit to the EIS case.

4.3.6 Total Benefits (Costs)

4.3.6.1 For Transmission Owners under the SPP Tariff

Table 4-4 shows the results by category in aggregate for the transmission owners under the SPP tariff. The aggregate benefit is $373.1 million over the study period.

Table 4-4 EIS Market Case Benefits (Costs) by Category for Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Trade Benefits	614.3
Transmission Wheeling Charges	24.4
Transmission Wheeling Revenues	(53.2)
SPP EIS Implementation Costs	(104.8)
Participant EIS Implementation Costs	(107.6)
Total	373.1

For each individual transmission owner under the SPP tariff, the total impact of moving to an EIS market is shown in Table 4-5. Table 1 in Appendix 4-2 gives results by company by category. While the aggregate benefit is positive, some companies show net additional costs. For those companies, the additional cost is driven by a relatively limited change in generation dispatch under an EIS market, which limits the accrual of trade benefits under the allocation method used in this study.

Table 4-5 EIS Market Case Benefits (Costs) for Individual Transmission Owners under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	47.9
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	27.4
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

4.3.6.2 By State

An allocation by state was performed for the six investor-owned utilities listed in Table 4-5 above. As noted above, this was calculated by allocating between wholesale and retail customers using load shares and further dividing the retail customer results by state using load shares.[34] Table 4-6 shows aggregate retail customer benefits (costs) by state for these six investor-owned utilities. Table 2 in Appendix 4-2 gives benefits by individual investor-owned utility by state. Again, to the extent that agreements are in place that share costs between IOU operating companies, these considerations were not taken into account in this study.

Table 4-6 EIS Market Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff

(in millions of 2006 present value dollars; positive numbers are benefits)

Arkansas	8.5
Louisiana	(3.8)
Kansas	26.4
Missouri	41.7
New Mexico	9.2
Oklahoma	141.1
Texas	26.6

4.3.6.3 Other Results

Using the methodology described above, the benefit for other typical members that pay an SPP assessment (Arkansas Electric Cooperative Corporation; The Board of Public Utilities, Kansas City, Kansas; Oklahoma Municipal Power Authority; City of Independence, Missouri) is also computed and included in Table 1 in Appendix 4-2. The collective benefit for these four typical members is $45.2 million without consideration of individual implementation costs, and this figure represents almost all of the remaining regulated generation for SPP members paying an SPP assessment.

The benefits to SPP merchants when the transmission owners under the SPP tariff form an EIS market are $123.9 million. The generation of the merchant plants is substantially greater in the EIS market case, and, as discussed above, merchants are attributed 50 percent of the trade benefits that accrue from their participation in the EIS market, with native load receiving the other 50 percent through contractual arrangements.

Table 1 of Appendix 4-2 gives the benefits to other load-serving utilities that are members of SPP but are not transmission owners under the SPP tariff and do not pay an annual assessment to SPP. These entities are not part of the EIS as currently formulated, but will nonetheless be affected by the institution of the EIS. Only trade benefits and wheeling impacts were evaluated for these utilities, which have a collective benefit of $28.6 million.

[34] Trade benefits for AEP were allocated to the AEP operating companies, Public Service Company of Oklahoma, and Southwestern Electric Power Company prior to allocation to individual states.

The balance of the Eastern Interconnect has a collective benefit of $382.6 million, again considering only trade benefits and wheeling impacts. Table 1 in Appendix 4-2 indicates that the total impact of trade benefits and wheeling impacts across all companies is $1,173 million. As discussed above, this is exactly equal to the decrease in production costs across the modeled footprint from the Base case to the EIS case.

5 Qualitative analysis of Energy Imbalance Market Impacts

This section explores impacts of SPP's implementing an Energy Imbalance Service (EIS) other than those impacts captured elsewhere in this report. (Section 3 addresses the potential energy market impacts that were determined quantitatively; Section 4 addresses expected SPP and market participant costs as part of the allocation.)

This assessment was made by comparing the existing imbalance energy provisions contained in SPP's Open Access Transmission Tariff with the filed tariff provisions and draft protocols describing the Imbalance Energy (IE) market. The following reference documents were relied upon:

Existing Settlement Provisions:

- Open Access Transmission Tariff (OATT) for Service Offered by the Southwest Power Pool, November 1, 2000
- Revised, SPP Board Approved, OATT Section 3 and Schedule 4-A
- Transmission Owner Tariff provisions for Imbalance Energy Settlement, as summarized by SPP staff, November 2004

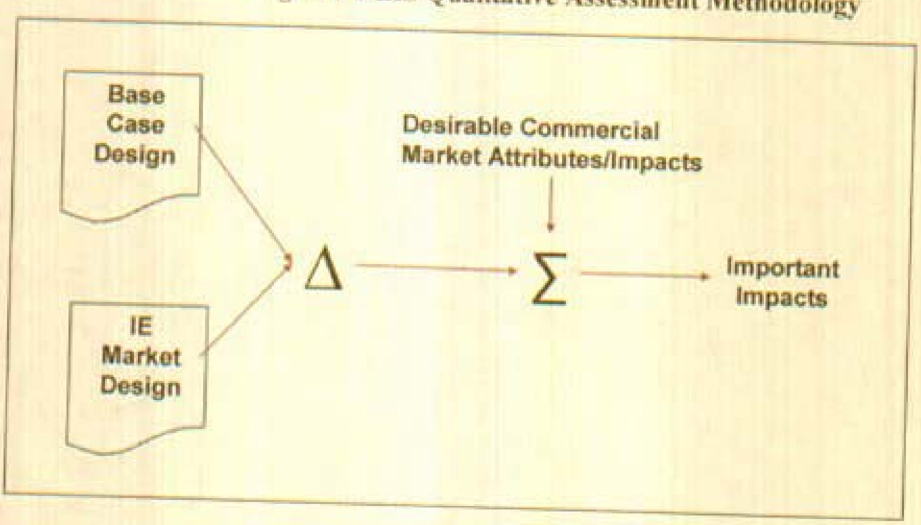
Future-State (EIS) Market Provisions:

- SPP Market Protocols (Draft) v2, January 6, 2005
- RTO Proposal of Southwest Power Pool, Inc., Volume I, October 25, 2003
- Market Working Group Meeting materials - various

5.1 Methodology

Figure 5-1 shows the general approach to assessing qualitative impacts associated with the EIS.

Figure 5-1 EIS Qualitative Assessment Methodology



Generally the existing and proposed EIS market designs were compared to identify significant design changes and underlying drivers of those changes. After a preliminary consideration of the potential impacts of the Significant Design Changes on SPP and the market participants, CRA grouped the potential impacts into nine categories of *Commercial Impacts*, which are listed and briefly described in Table 5-1.

The subsections that follow present the significant design changes and underlying drivers, followed by the Commercial impacts.

Table 5-1 Commercial Impacts

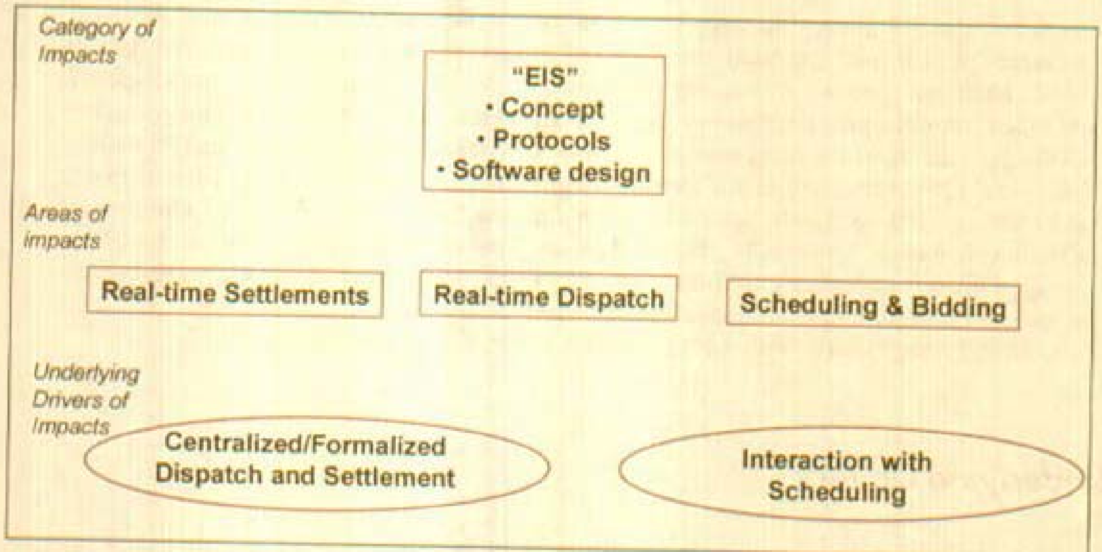
Commercial Impact	Illustrative Description
1. [Facilitate Development of] **Competitive Markets**	Does the Significant Design Change facilitate or hinder competition or market penetration (the ability of new retailers to compete for load)—for example, through complexity, volatility or cost shifting?
2. [Minimize] **Discriminatory Environment**	Does the Significant Design Change reduce perceived or actual barriers that unduly discriminate against small/large players, non-incumbents, etc.?
3. [Increase] **Efficiency of Production**	Does the Significant Design Change encourage the efficient use (dispatch, commitment) of existing facilities and/or promote economic efficiency in the consumption of electricity? (This considers microeconomic principles and also incorporates maximization of social welfare—the sum of consumer and producer surplus.)[35]
4. [Promote] **Efficient Resource Expansion**	Does the Significant Design Change provide proper incentives for resource investment (including Distributed Generation and Demand-Side Management)? This includes the need for site-specific pricing and resource siting signals, and changes in risk and/or uncertainty associated with nodal pricing.
5. [Promote] **Efficient Grid Expansion**	Does the Significant Design Change encourage or discourage investment in the grid by various entities? At the right locations? With the proper trade-offs between wires and resources/Demand Side Management?
6. [Neutralize] **Opportunities to Exercise Market Power**	Does the Significant Design Change increase or decrease the need for mechanisms to mitigate potential abuse of market power?
7. [Enhance] **Grid Reliability**	Does the Significant Design Change recognize the physical realities of the grid, reduce burdens on grid operators, and reduce the potential for (uneconomic) loss of load?
8. [Facilitate] **Ability to Conduct Business**	Does the Significant Design Change make it easier for entities to participate in the SPP market?
9. [Minimize] **Costs and Administrative Burdens**	Does the Significant Design Change reduce or increase costs (that are not already accounted for in the IIA) and burdens on market participants and on SPP?

[35] Note that this metric, as described, reflects Social Welfare generally. However, various impacts tend to affect producer surplus or consumer surplus. Given that which of these may be impacted may be relevant to various stakeholders (and it is not the consultant's role to judge the merits of how the social welfare is experienced), the discussions within the text identify, where possible, how the efficiency gains are expected to be experienced (for example, when Load Serving Entities are better off).

5.2 Market Rule Changes

While the EIS primarily relates to the settlement of imbalance energy, instituting a formal locational balancing energy has additional impacts. These impacts can be viewed on several levels, as shown in Figure 5-2.

Figure 5-2 EIS Changes - Various Views



There are several areas of impacts, and these have some common underlying drivers. The impact areas considered can be summarized as follows:

Real-time market: Impacts of Settlement using Locational Imbalance Pricing (LIP)

The most direct and obvious impacts related to instituting a formal Imbalance Energy market with locational pricing are associated with the changed settlement rules and processes; they include the impacts on loads and on generators of the change in pricing and settlement processes. For example, with the EIS:

- SPP manages, in a centralized way, settlements for inadvertent energy that were previously conducted bilaterally with each Control Area Operator (CAO).
- CAOs settle imbalance energy for load formally with SPP rather than simply load following or settling with neighboring control areas.
- Pricing between supply sources may be different than pricing of load.
- New metering reporting and management requirements are created.

While the fundamental impacts of the pricing changes are addressed in the MAPS modeling aspect of this study, and the infrastructure costs are addressed specifically, the movement to a formal EIS creates other non-monetized impacts.

Real-time: SPP Real-time Resource Deployment

In addition to the financial implications of LIP energy settlement, the EIS design includes the centralized optimization and dispatch of balancing energy sources. This creates the need for specific infrastructure from SPP, and likely for members, and it may substantially change the operational management of generator units in real-time. Each CAO no longer optimizes and deploys resources to balance its own system; instead, generation operators submit bid curves to SPP, which optimizes the balancing energy resources using a Security-Constrained Economic Dispatch (SCED) algorithm and (for units providing balancing energy) determines which units generate to what levels in real-time—providing formal dispatch notices.

Forward Market Impacts: Schedules and Bid Impacts

Given that the EIS creates the need for formal communication of system conditions and of individual participants' expected behavior and input data, the implementation of the EIS creates additional forward scheduling requirements. To operate an EIS, SPP needs specific and timely resource plan information. SPP will use a baseline of forward load and generation schedules as an allocation basis over which to allocate the financial results of the EIS market. Thus, the EIS creates different forward market requirements and may have different settlement impacts related to activities in the forward market. Application of uninstructed deviation charges or penalties to scheduled-to-real time difference and the use of the EIS to manage Firm schedules are examples of these types of impact. In some cases, these impacts are more significant during the period when there will be a locational market-based real-time congestion management system, but no forward congestion management system.[36]

5.3 Underlying Drivers

There appear to be two underlying drivers for the areas of impact just described, and these are essentially operational in nature:

1. Centralized/formal control of real-time balancing

   This driver relates to both operational control and pricing control and seems to be the strongest.

2. Relationship of real-time EIS coupled with scheduling

   The ultimate impacts are considered in the sense of these two underlying drivers.

5.4 Impacts of Underlying Drivers

This discussion presents those commercial impacts resulting from the fundamental drivers.

[36] For example, the issue of overscheduling or under-scheduling counterflow likely falls into this category in the sense that if SPP had a comparably-based congestion management system in the Day Ahead there would be more naturally balancing incentives for scheduling.

Facilitation of Competitive Markets

The long-run impacts of implementing a formal nodal EIS are expected to include improved transparency and improved price signals, and experience in other markets suggests that these will be the predominant impacts. Complexity produces adverse impacts during a transition period—for example, when parties are affected by locational balancing EIS prices yet do not have the operating history of what these prices and respective points' price spreads might be. Such impacts are expected to be alleviated with operating stability and history. That is, the market will eventually establish a pricing history that will provide market participants data reflecting expected pricing risks.

Applying explicit imbalance energy prices creates risks associated with not following schedules. The relative impact depends on the details of what is in place today regarding imbalance energy settlement with the CAOs. Whether the implementation of any test for schedule feasibility[37] when used in isolation without a formal day-ahead or hour-ahead congestion management market, will enhance or impede the competitiveness of the market depends on the effectiveness of the particular mechanisms implemented. Similarly, to the extent that the new centralized LMP algorithms or SCADA systems do not work correctly, there will be adverse impacts on the market until those issues are resolved.[38]

Market monitoring provisions offer the potential for more competitive markets, provided that they are not overly burdensome and that they do not create undue regulatory risk.

Minimize Potential Discriminatory Behavior

The movement to an explicit EIS should increase transparency, which would reduce the potential for discriminatory behavior and improve the competitiveness of markets generally.

Efficiency of Production

The production efficiency impacts of the EIS are measured by the MAPS modeling. To the extent that the EIS is cleared as efficiently as the model assumes, the numerical modeling results are expected to reflect the EIS benefits. To the extent that bilateral schedules do not directly reflect the efficient dispatch, and to the extent that the EIS is not used to manage congestion for the bilateral schedules, the predicted benefits may not be realized.

The movement with the EIS to the centralized management of inadvertent energy will likely have added production efficiencies that are not captured in the quantitative results of the MAPS modeling.[39]

[37] Note that some of the market design documents have contemplated the possibility that a "feasibility" test for schedules may be necessary to implement a workable real-time EIS. How "feasibility" will be determined, however has not yet been specified.

[38] That SPP intends to have policies related to the quality control and improvement of the EIS algorithms and SCADA systems is seen as a positive indication that any adverse software impacts will be minimized.

[39] The MAPS modeling assumes in all cases that inadvertent energy management is perfectly efficient at the seams of SPP, other than the financial effect of the boundary wheeling rates.

Resource Expansion

Location-specific and transparent pricing at nodes should provide improved price signals for siting. In other markets that CRA has observed, however, institutional barriers have emerged that prevented the market from responding appropriately to such price signals. These barriers include exogenous factors (e.g., NIMBY) that continue to have strong influences, and other market structures—such as capacity market implementation—that may dampen the price signals that are needed to overcome other factors. While specific nodal price signals should be beneficial, realizing their full benefit may take time while such other market structures are modified.

Grid Expansion

The implementation of the EIS is not likely to significantly improve grid planning or expansion. This is because long-term transmission investments must be justified primarily on the basis of anticipated future demand and long-term projections of future costs, rather than on specific historical uses and congestion costs. Most planners already use nodal information to determine the most appropriate transmission upgrades, so that the EIS nodal pricing for balancing energy seems to provide no direct advantage or disadvantage in the area of grid expansion.

Market Power

This study did not include an assessment of the propensity for any participant to exercise market power. One might expect that the EIS would reduce the ability to exercise vertical market power, given that SPP will be operating the EIS market. Participants may fear, however, that the ability to exercise horizontal market power might be greater, or perhaps more specifically that the consequence of the exercise of horizontal market power might be higher given that marginal pricing—as opposed to average pricing or returning "in-kind" energy for example—may have large pricing impacts in the EIS. While these factors are at play, it is not possible to determine whether the resulting impact, combined with the impacts of a market monitoring plan, would be positive or negative overall.

Grid Reliability

The grid is operated reliably today and it will be operated reliably under an EIS. This issue therefore addresses whether there are any factors that provide marginal additional levels of reliability. Here again balancing factors are likely at play. The movement to an SPP centralized real-time dispatch and balancing should afford more visibility and a broader perspective than does individual control area operations. This is a plus. At the same time, however, movement away from CAO balancing creates the possibility that specific knowledge of local grid issues will be lost over time. This loss of expertise is a disadvantage of the EIS in the sense of margins of reliability. Further, the EIS may result in exercise of the generation system in manners not previously experienced[40] and the centralized dispatch of resources may result in more rapid movements that require more regulation control. To the extent that this effect is strong, the reliability margin may be somewhat reduced.

It is not clear that either of these offsetting effects is significantly stronger than the other.

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[40] For example, with the fluid participation of independent generator resources in the EIS, the dispatch of the system will change; in addition, CAOs' regulation units will no longer be operated in conjunction with the CAO-controlled deployment of balancing energy resources.

Ability to Conduct Business and Administrative Burdens

This study quantitatively captures the costs to participate in the EIS. Both costs to SPP and costs to market participants are estimated. However, it is possible that these costs—especially those born by market participants—are not captured consistently across all market participants. Costs that may be outside the quantified values may include, for example, costs of increased scheduling needs, utilities' costs of hedging new EIS risks, and the costs of regulation unit owners associated with the price risk of regulation energy (the energy provided by the regulating units in real-time in response to frequency-control signals) relative to EIS energy. Similarly, parties that have in the past settled real-time imbalances with one more control areas will be relieved of the administrative costs of performing those settlements. It is not clear whether such costs were included in the quantifications of EIS costs.

5.5 EIS Qualitative Analysis Summary

Overall, it is expected that implementation of the EIS will create additional transparency and efficiency benefits. However the EIS will also increase administrative burdens, though it is likely that a significant fraction of these additional burdens will be transitional, meaning that they will return more or less to today's level once the EIS has been in place for some time (roughly 1 to 3 years). Further, it is likely that the administrative and infrastructure costs borne by participants for the EIS will be "lumpy," in the sense that allowing for the EIS requires significant infrastructure much of which will be useable also for the full day-ahead market and congestion management process if, and when, it is implemented.

6 Qualitative Analysis of Market Power Impacts

The SPP Regional State Committee has asked CRA to address market power issues that might arise in the context of the implementation of the EIS market, in particular. The question is whether the EIS market would provide an increased opportunity to exercise market power on the part of one or more owners of generation resources in the area. In this context, it is useful to recall that market power is the ability and incentive to increase market prices by a significant amount for an extended period. In particular, a generation owner must have both the ability and the incentive to exercise market power in order to be considered as possessing market power at all, regardless of whether it actually exercises that market power.

6.1 Market Monitoring

Market monitoring and mitigation is an essential function for RTOs and is required by FERC Order 2000. As part of the institution of an EIS market, SPP will implement a market monitoring process that includes the appointment of an independent contractor to oversee the safe and reliable operation of SPP's transmission system.

The principal functions of SPP's market monitoring process are the following: reporting on compliance and market power issues relating to transmission services, including compliance and market power issues involving congestion management and ancillary services; evaluation and recommendations respecting any required OATT revisions, standards or criteria; ensuring that market monitoring is performed in an independent manner; developing procedures to inform government agencies and others with respect to market activities; monitoring market behavior and market participants to determine whether any activity is constraining transmission or excluding competitors; and ensuring the non-discriminatory provision of transmission service by SPP.

SPP has proposed a Market Monitoring Plan intended to provide for the monitoring of SPP's market and for the mitigation of the potential exercise of horizontal and vertical market power by market participants. The plan will be implemented and maintained by two Market Monitors: a Market Monitoring Unit (MMU) internal to SPP, and an Independent Market Monitor (IMM).

The MMU has primary responsibility for implementing the Plan, with the advice and oversight of the IMM, by (a) continuously monitoring SPP's markets and services provided under SPP's OATT, (b) implementing approved market mitigation measures, (c) taking the lead in investigations and in compliance and corrective actions, and (d) collecting and retaining relevant data and information.

The IMM has several responsibilities. Among these, the IMM: (a) develops, reviews, and recommends updates to the monitoring and mitigation procedures and supports SPP in obtaining FERC approval for such procedures, (b) suggests revisions to the SPP market design and procedures, (c) advises the MMU and monitors its activities, (d) advises the SPP Board, and (e) periodically reports on SPP's market and services.[41]

Together, the SPP MMU and the IMM will monitor SPP's markets and services by analyzing market data and information such as the following: resource and ancillary service plans, schedules and offer curves submitted for generating units; commitment and dispatch of generating units; locational

[41] SPP Market Monitoring Plan, OATT Attachment, Draft 11/8/04

imbalance prices; control area data (e.g., net scheduled interchange, actual net interchange, and forecasts of operating reserves and peak demand); transmission services and rights (e.g., ATC, AFC, tariff administration, operation and maintenance of the transmission system, markets for transmission rights, and reservation and scheduling of transmission service); transmission congestion; and settlement data.[42]

Market participants or government agencies may submit confidential complaints or requests for investigation to the MMU or the IMM. The MMU and/or the IMM may engage in discussions to resolve issues informally, may issue demand letters requesting market participants to discontinue actions as necessary to achieve mitigation and/or compliance, and may implement any FERC-approved mitigation measure. A process is also in place for the MMU or the IMM to recommend changes in market design or procedures as needed to ensure just and reasonable prices. The IMM will publish annual state-of-the-market reports and quarterly reports on instances of market power, if any. The IMM will also provide an annual review of the activities of the MMU.[43]

SPP estimates that market monitoring will cost about $1 million per year, or about $0.005 per megawatt-hour of net annual energy for the SPP region.

6.2 Generation Market Power

CRA has not conducted a formal, quantitative review of the potential impact of the SPP Energy Imbalance Market on the likelihood that market power might be exercised in the generation market within SPP. Such an assessment would be hypothetical and difficult to quantify given the uncertainty concerning future economic conditions and future market behavior of participants.

In CRA's view, the implementation of the Energy Imbalance Market, by itself, is unlikely to increase significantly the likelihood of actual exercises of market power in the SPP generation market. This is because most power delivered within SPP will be subject to the continuation of cost-based retail rates. In addition, it is our understanding that much of the wholesale market is covered by long-term contracts for which a short-term increase in the spot price for power would be immaterial. In these circumstances, generation owners in SPP would have little, if any, incentive to withhold generation from the SPP Energy Imbalance Market for the purpose of increasing the market-clearing price in that market. This is because the output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price. Without the incentive to exercise market power, which would be lacking under cost-based regulation and long-term contracts, the issue of market power is likely to be a minor consideration under the SPP market conditions.

Nonetheless, it is important that the SPP Market Monitoring Unit and the SPP Independent Market Monitor review the performance of the SPP Energy Imbalance Market and report their findings to FERC as needed. The market monitoring function is an important deterrent to the exercise of whatever residual market power exists in the market.

Given the underlying economic fundamentals of regulation and long-term contracting in the SPP area, and SPP's plans for active and ongoing monitoring of the market, CRA believes that the potential for the exercise of market power in the SPP Energy Imbalance Market is not likely to be significant and

[42] Ibid.
[43] Ibid.

should not be considered a significant risk in the implementation of that market. We have not reviewed the costs versus the reduced-risks/benefits of the market monitoring function itself given that this function is required under current FERC guidelines in any case.

7 Aquila Sensitivity Cases

7.1 Aquila Sensitivity Cases—Methodology

The Aquila Sensitivity cases measured the wholesale energy modeling impact of Aquila being a part of SPP rather than of the MISO RTO during the simulation year 2006. In the balance of the study's wholesale energy modeling, Aquila was assumed to be part of MISO. The Base and EIS cases were simulated.

Aquila consists of two control areas, which in the study are designated as Missouri Public Service (MIPU) and WestPlains Energy (WEPL). To simulate the configuration of SPP with Aquila as a member, the following changes were made to the cases:

- **Wheeling rates.** Wheeling rates between Aquila and other SPP areas were eliminated, while wheeling rates were instituted between Aquila areas and MISO.
- **Reserves.** Because of the formula used to calculate reserve requirements in SPP (largest contingency plus one-half the next largest contingency) the total reserve requirements for SPP do not change between the two cases. With Aquila as a member, however, this requirement is spread over a greater load base, so the reserve requirement for each individual member company is reduced. Because MISO reserves are met on a system-wide basis as a percent of load, the total reserve requirement in MISO is also reduced if Aquila becomes part of SPP. (Though the average load share of reserves in MISO would remain the same.)
- **Commitment.** In the Aquila sensitivity case, units in WEPL and MIPU are committed against load in SPP.

Wholesale energy results were generated for the Aquila case for both the Base and EIS cases. No specific analysis of cost or benefit allocation (such as the allocations described in Section 4) was performed for the Aquila cases.

7.2 Aquila Sensitivity Cases—Results

This section presents the results of the Aquila sensitivity runs. Results are presented such that readers can both compare the impacts for either case (Base or EIS) of Aquila being part of MISO or of SPP, and also see the extent to which the benefits of the EIS case are sensitive to Aquila being in MISO or SPP.

Table 7-1 shows results for the combined SPP and Aquila footprint[44] for four fundamental physical and financial metrics:

- Generation
- Average per MWh generation cost
- Total generation cost, normalized to the generation levels of the Aquila in MISO, Base case
- Average regional spot price of energy

[44] For a consistent comparison, the results are shown inclusive of Aquila regardless of whether Aquila is in SPP or MISO.

Table 7-1 SPP and Aquila Regional Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation in SPP + Aquila (GWh)	204,865	206,637	(1,772)	207,406	209,422	(2,016)	2,541	2,785	(244)
Average Generation Cost ($/MWh)	$ 19.07	$ 19.12	$ (0.05)	$ 18.68	$ 18.74	$ (0.06)	$ (0.39)	$ (0.38)	$ (0.01)
Normalized Generation Costs ($million)	$ 3,907	3,917	$ (10)	$ 3,827	3,839	$ (12)	$ (80)	$ (78)	$ (2)
Per MWh Spot Energy Cost	$ 40.59	$ 40.75	$ (0.16)	$ 38.10	$ 38.35	$ (0.26)	$ (2.49)	$ (2.40)	$ (0.09)

The simulations indicate that the region generates more if Aquila is located with SPP than it does if it is located within MISO under both the Base and EIS cases. Regional generation costs are simulated to be $10 million to $12 million lower if Aquila is in MISO, roughly 0.25% of the region's total generation cost. Spot marginal energy costs are expected to be $0.16/MWh less expensive with Aquila in MISO under the Base case and $0.26/MWh less expensive under the EIS case.

The column entitled EIS-Base, Difference (MISO-SPP) indicates, as shown by the relatively small values for each metric, the benefits of the EIS market for the region as measured in the modeling is not particularly sensitive to whether Aquila is in MISO or SPP.

Table 7-2 shows the impact similar to Table 7-1 on the Aquila companies only.

Table 7-2 Aquila Companies' Results

	Base Case			EIS Case			EIS - Base		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
Generation Aquila (GWh)	6347	6295	52	6280	6307	(27)	(67)	12	(79)
Average Generation Cost Aquila ($/MWh)	$ 21.07	$ 20.80	$ 0.27	$ 20.79	$ 20.71	$ 0.08	$ (0.28)	$ (0.09)	$ (0.19)
Normalized Generation Costs Aquila ($million)	$ 133.72	$131.99	$ 1.73	$ 131.94	$131.43	$ 0.50	$ (1.79)	$ (0.56)	$ (1.22)

Table 7-2 indicates several characteristics of the Aquila impacts as given by the modeling:

- Aquila companies generate more if in MISO under the Base case, but more if in SPP if SPP has an Energy Imbalance market. (In both cases the change in Aquila generation is less than 1%).
- Based on generating costs, Aquila shows benefits of being a member of SPP, and those benefits are higher under the Base case than under the EIS case (1.3% and 0.3%, respectively)

Also notable from the information shown in Tables 7-1 and 7-2 is that while the SPP region's generating costs would be lower with Aquila in MISO ($10 million in the Base case), Aquila's generating costs would be lower with Aquila in SPP ($1.7 million in the Base case).

Table 7-3 shows the impact on NOx and SOx emissions. As with the generation costs, the impacts to the Aquila emissions behave opposite to that of the SPP region to whether Aquila is in SPP or MISO, and in this sense the impacts on emissions between Aquila and SPP are somewhat offsetting. In either case the impact to SPP or to Aquila is approximately a 1% change in emissions.

Both Aquila companies show benefits from being in SPP. Under both the Base and EIS cases, the generator net revenues for MIPU are higher if Aquila is in SPP ($2 million for the Base case, $2.7 million for the EIS case), but the load energy costs are lower if MIPU is in SPP ($2.6 million for the Base case, $2.2 million for the EIS case).

For WEPL, the magnitude of the increase in generation net revenues when WEPL is part of SPP is lower than it is for MIPU ($0.8 million for the Base case, $1.4 million for the EIS case). The impact to load is comparable, a saving if part of SPP of $2.4 million in the Base case, $2 million in the EIS case. Note that the energy cost impact for WEPL is a savings of approximately $1/MWh if Aquila is in SPP. This relatively significant savings is due to the fact that WEPL is entirely within the SPP footprint (as opposed to MIPU, which borders to some extent MISO).

Table 7-3 Emission Impacts of Aquila Cases

	Base Case NOx Emissions (Tons)			EIS Case NOx Emissions (Tons)			EIS - Base NOx Emissions (Tons)		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
SPP	283,538	286,624	(3,086)	276,929	279,640	(2,711)	(6,608)	(6,984)	376
Aquila Companies	18,477	18,297	180	18,243	18,296	(52)	(233)	(1)	(232)
Total SPP+ Aquila	302,014	304,920	(2,906)	295,173	297,935	(2,763)	(6,842)	(6,985)	143

	Base Case SOx Emissions (Tons)			EIS Case SOx Emissions (Tons)			EIS - Base SOx Emissions (Tons)		
	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)	Aquila in MISO	Aquila in SPP	Difference (MISO-SPP)
SPP	449,349	454,883	(5,535)	449,010	453,982	(4,971)	(338)	(902)	563
Aquila Companies	22,173	22,102	71	22,049	22,144	(95)	(124)	43	(166)
Total SPP+ Aquila	471,521	476,985	(5,464)	471,059	476,126	(5,067)	(462)	(859)	397

CHARLES RIVER ASSOCIATES

Appendices 1-1, 1-2, 2-1, 3-1, 3-2, and 3-3

CRA CHARLES RIVER ASSOCIATES

Appendix 1-1: Roster of SPP Regional State Committee (RSC)

RSC President:	Denise Bode Chairman, Oklahoma Corporation Commission
RSC Vice-President:	Sandra Hochstetter Chairman, Arkansas Public Service Commission
RSC Secretary:	Julie Parsley Commissioner, Public Utility Commission of Texas
RSC Member:	Steve Gaw Commissioner, Missouri Public Service Commission
RSC Member:	Brian Moline Chairman, Kansas Corporation Commission.

Appendix 1-2: Roster of SPP RSC Cost Benefit Task Force

Members:

Sam Loudenslager, Arkansas Public Service Commission * *Chairman*
James Watkins, Missouri Public Service Commission
John Cita, Kansas Corporation Commission
Ken Zimmerman/Joyce Davidson, Oklahoma Corporation Commission
Jess Totten, Public Utility Commission of Texas

Richard Spring, Kansas City Power & Light **Vice-Chairman*
Michael Desselle, American Electric Power
Darrell Gilliam, Southwestern Power Administration
Shah Hossain, Westar Energy
Robin Kittle, Xcel Energy
Mel Perkins, Oklahoma Gas and Electric

Jeffrey Price, Southwest Power Pool * *Secretary*

Associate Members:

Ryan Kind, Missouri Office of Public Counsel
Les Dillahunty, Southwest Power Pool

Others Actively Participating:

Burton Crawford, Kansas City Power & Light
Terri Gallup, American Electric Power
Bernard Liu, Xcel Energy
Alan Myers, Aquila
Rick Running, Southwest Power Pool
Mike Sheriff, Oklahoma Gas and Electric
Bary Warren, Empire District Electric Company

Appendix 2-1 Cost-Benefit Studies in Electric Industry Restructuring

Starting in the 1970s and continuing through the 1990s, a number of studies attempted to evaluate, by simulation and other means, the various benefits expected to arise from increased competition and the restructuring of the U.S. electric utility industry.[1]

On December 17, 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000 mandating that utilities join an RTO with certain minimum characteristics. FERC next proposed the creation of a set of RTOs, and in 2001 it commissioned a cost-benefit analysis of RTOs and their markets.[2] This was the first of a wave of specific studies on the benefits and costs of RTOs.[3] This section briefly surveys six of these studies[4] (references for these studies are listed in Appendix 2-2.

1. The ICF FERC Study
2. The CAEM PJM Study
3. The PJM Northeast RTO Study
4. The TCA RTO West Study
5. The CRA SEARUC Study
6. The CAEM PJM Study
7. The TCA ERCOT Study

These studies, summarized in Table 2-1, differ in a number of important respects, addressing different policy questions and comparing market restructuring at various stages of integration. Central to the comparison of these studies is the question being addressed. The ICF FERC study addresses the national policy question "Should we encourage RTO development?" The CRA RTO West and CRA SEARUC studies address the forward-looking benefits of initial new RTO formation. The PJM Northeast RTO Study addresses the integration of existing operational Independent System Operators (ISOs) and RTOs. The CAEM PJM Study is a historical retrospective study, and the TCA ERCOT Study examined a nodal market structure.

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[1] See the recent summary by Michaels (September 2004).
[2] ICF FERC Study.
[3] The CRA SEARUC Study, p. 97, has an appendix providing a detailed comparison of six different RTO studies.
[4] In addition to these, two additional studies are under way: one focusing on impacts of stages of RTO Implementation in the WestConnect region, and the measurement of benefits of SPP RTO as well as the measurement of potential benefits of implementing an Energy Imbalance market in that region.

This SPP CBA is similar to those past studies in one respect, namely in its consideration of movement from an RTO structure (the Base case) to the Stand-Alone case: the PJM NE RTO, TCA RTO West, and CRA SEARUC studies assessed the impacts of movement to an RTO.

The analysis of the implementation of the Energy Imbalance market in this CBA is unique in that it isolates impacts of the increased access to the transmission system by non-network resources in addition to measuring the impact of improved management of congested lines under a centralized market.

Table 1 Comparison of Select Industry Cost-Benefit Studies

	ICF FERC Study	PJM NE RTO Study	TCA RTO West Study	CRA SEARUC Study	CAEM PJM Study	TCA ERCOT Study
Market Focus	Nationwide	Integration of NE RTOs	RTO West (and impacts on rest of WSCC)	Formation of multiple sub-region RTOs	Historical examination of PJM benefits	ERCOT energy market
Key Issue Addressed	Economic benefits of FERC RTO Policy change	Economic benefits of ISO and RTO integration	Economic benefits of RTO formation	Economic benefits of RTO formation and coordination	Benefits of PJM RTO in historical context	Impacts of movement to a nodal market design
Benefits	Improvements in transmission system operations, inter-regional trade, congestion management, reliability and coordination; improved performance of energy markets, including greater incentives for efficient generator performance; and enhanced potential for demand response.	Improvements in production cost	Improvements in dispatch with reduction in transmission rate "pancaking"	Improvements in production cost, reflecting implications of transmission funding/ tariff alternatives	Benefits in wholesale, retail, capacity, and demand response markets, based on assumptions that restructuring dominated the price changes in the period and thus illustrate the benefits	Improvements in the ability to manage congestion given resource-specific bidding and scheduling, congestion pricing and generation siting
Costs	RTO formation cost	Cost of RTO/ISO integration	RTO formation costs	RTO formation costs	—	Infrastructure costs
Net Benefit Treatment	No separation of producer surplus gains/losses from consumer surplus impact	Total production cost less formation/integration cost	Gains/losses in producer and consumer surpluses	Native load benefits	Change in consumer surplus; rejects consideration of producer surplus impact	Gains/losses in producer and consumer surpluses less cost impacts
Sub-regional impacts	—	Included	Included	Included	PJM and adjacent states	Included

	ICF FERC Study	PJM NE RTO Study	CRA TCA RTO West Study	CRA SEARUC Study	CAEM PJM Study	TCA ERCOT Study
Long-run benefits	Estimates of improved generator efficiency and demand response	—	—	—	—	Generator Siting
Time Horizon	Forecast 2002–2021	Two years forecast, 2005 and 2010	Single-year forecast, 2004	Forecast 2004–2013	Historical analysis 1997–2002	2004-2014
Primary methodol-ogy	Nationwide LP simulation of power system, fuel markets, and environmental limitations	MAPS generation and transmission modeling	MAPS generation and transmission modeling	MAPS generation and transmission modeling	Ad hoc historical analysis	MAPS generation and transmission modeling, Rate impact allocation sharing trade benefits
Treatment of constraints reduced by shift in policy	Mostly technological change	—	Specific treatment of institutional changes and impact on dispatch	Specific treatment of institutional changes and transmission tariff development	—	Specific treatment of institutional changes and impact on dispatch
Key Conclusion s	Substantial but uncertain benefits from RTO development	Combination of 3 NE RTOs has no net benefit	Modest benefits in core RTO region	Benefits uncertain, negative in some sub-regions	—	Energy benefits seem to exceed cost impacts
Release date	February 2002	January 2002	March 2002	November 2002	Sept/Oct 2003	November 2004

Appendix 2-2: References for Other Cost Benefit Studies

Robert Michaels, "Vertical Integration and the Restructuring of the U.S. Electricity Industry", (Sept. 2004). http://ssrn.com/abstract=595565

Dr. Ronald J. Sutherland, "Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region," Version 1.1 (October 2003) Center for the Advancement of Energy Markets, http://www.caem.org [The CAEM PJM Study]

Mathew J. Morey, Laurence D. Kirsch, Steven Braithwait, B. Kelly Eakin, "Erecting Sandcastles From Numbers: The CAEM Study of Restructuring Electricity Markets or a Critique of 'Estimating The Benefits Of Restructuring Electricity Markets: An Application To The PJM Region,'" (December 3, 2003) Prepared for National Rural Electric Cooperative Association. Prepared by Laurits R. Christensen Associates, Inc., Madison, WI.

Charles River Associates, "The Benefits and Costs Of Regional Transmission Organizations and Standard Market Design in the Southeast," (November 6, 2002). Prepared for The Southeastern Association of Regulatory Utility Commissioners. [CRA SEARUC Study]

Steve Henderson, "RTO Cost Benefit Analysis" (May 2003). Presentation to Harvard Electricity Policy Group, Charles River Associates.

ICF Consulting, "Economic Assessment of RTO Policy," (February 26, 2002). Prepared for the Federal Energy Regulatory Commission. [ICF FERC Study]

Tabors Caramanis & Associates, "RTO West Benefit/Cost Study," (March 11, 2002). Final Report Presented to RTO West Filing Utilities. http://www.rtowest.com/Stage2BenCstMain.htm [TCA RTO West Study]

PJM, "PJM Cost/Benefit Analysis for Northeast RTO," (January 2002) [PJM NERTO Study]

Tabors Caramanis & Associates and KEMA Consulting, "Electric Reliability Council of Texas Market Restructuring Cost-Benefit Analysis," (November 30, 2004). http://www.ercot.com/TNT/default.cfm?func=documents&intGroupId=83&b= [TCA ERCOT Study]

Appendix 3-1: SPP MAPS Inputs

This appendix summarizes MAPS inputs and data sources for the SPP Cost Benefit study. Data sources include specific data from CBTF participants and from SPP and a database compiled from public sources by Charles River Associates (CRA) and Tabors Caramanis & Associates (TCA, now part of CRA). Public-domain data sources include FERC Forms 1, 714, and 715, Form EIA-411, the NERC ES&D and GADS databases, data from the US EPA, various trade press announcements, and planning data from NERC regions, control areas, and ISOs. In addition, CRA purchased transmission contingency constraint data for use outside of the SPP system from General Electric based on GE's in-depth PSS/E transmission system studies. CRA performed extensive in-house analysis to ensure data integrity and validity and to ensure consistency of the system representation with market developments.

Data Item **Page**

1. Load Inputs

Description. MAPS requires an hourly load shape and a forecast of annual peak load and total energy for each load-serving entity or zone. SPP provided CRA with EIA-411 load forecast data for each company within the study region for the study years 2005 through 2013. For 2014, CRA applied linear extrapolation to estimate the peak load and annual energy by company.

MAPS uses a historical hourly load shape for each load area to distribute energy over the course of each forecast year. SPP also provided historical hourly loads for each load area for the base year 2003. However, 2003 load shapes were not readily available for regions outside of SPP, and CRA believed that the use of inconsistent historical load shapes for different regions would lead to unrealistic patterns of interregional power flows. It was thus decided, in consultation with the CBTF, that CRA would apply 2002 load shapes (available from public sources) for all areas in SPP and outside to ensure inter-regional load consistency. MAPS uses hourly load shapes, combined with forecasts for peak load and annual energy for each company, to develop a detailed load forecast by company for each forecast year.

Data Sources. SPP provided EIA-411 data for peak load and annual energy by company, as well as hourly load shapes from FERC 714 filings by company.

2. Thermal Unit Characteristics

Description. MAPS models the operational characteristics of generation units in detail to predict hourly dispatch and prices. The following characteristics are modeled:

- Unit type (*e.g.*, steam cycle, combined-cycle, simple cycle, cogeneration)
- Heat rate values and curve (based on unit technology)
- Summer and winter capacity
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick-start and spinning reserves capabilities
- Startup costs
- Emission rates

CRA's generation database reflects unit-specific data for each generating unit based on a variety of sources. For this study, each member company updated and/or validated CRA's list of units and unit characteristics for their own generating assets.

If unit-specific operational data were not available for a particular unit, representative values based on unit type, fuel, and size were used,**Error! Reference source not found.** and Table 2 documents these generic assumptions.[5] As was the case throughout the MAPS analysis, all prices are in real 2003 dollars.

Data Sources. The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, primary and secondary fuel type, and capacity data for existing units. For units within SPP, SPP member

[5] Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include full load heat rates and emissions data.

companies supplemented and/or updated these data as necessary. Heat rate data were drawn from prior ES&D databases where available. For newer plants, heat rates were based on industry averages for the technology of each unit. The NERC Generation Availability Data System (GADS) database published in October 2003 (data through 2001) was the source for forced and planned outage rates, based on plant type, size, and age.

Fixed and variable operation and maintenance costs are estimates based on plant type, size, and age. These estimates are supplemented by FERC Form 1 submissions where available. The fixed operations and maintenance cost (FOM) values include an estimate of $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

Table 1. Characteristics for Generic Thermal Units

Unit Type & Size	FOM ($/kW-yr)	VOM ($/MWh)	Minimum Downtime (hrs)	Minimum Uptime (hrs)	Heat Rate Shape
Combined Cycle	18.00	2.00	6	6	2 blocks, each 50%@FLHR
Combustion Turbine <100 MW	7.00	7.00	1	1	One block
Combustion Turbine >100 MW	7.00	3.50	1	1	One block
Steam Turbine [coal] <100 MW	38.00	2.00	6	8	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <200 MW	35.00	2.00	8	8	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] >200 MW	35.00	1.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [gas] <100 MW	38.00	8.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <200 MW	35.00	6.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] >200 MW	16.00	4.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	38.00	8.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <200 MW	35.00	6.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] >200 MW	16.00	4.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%

CRA models recently constructed CCGT units at a heat rate of 7100 Btu/kWh. For future CCGT units, CRA generically assumes a lower heat rate of 6900 Btu/kWh. CRA recognizes that such a heat rate for CCGT may not be achievable if the unit operates in a cycling mode with minimum up and down time limited to 6 hours as shown in Table 1. Thus, it is possible that the efficiency of future CCGT generating units might be overstated. However, this will make nearly no impact on the results of this study, because as explained below, no newly constructed CCGT units were modeled within the SPP region.

Table 2. Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start Capability (% of Capacity)	Spinning Reserves (% of Capacity)	Forced Outage Rate (% of Year)	Planned Outage Rate (% of Year)	Total Unavailability (% of Year)	Startup (MMBtu /MW)
Combined Cycle	0.00	30.00	1.50	6.82	8.32	5.00
Combustion Turbine <100 MW	100.00	90.00	4.34	5.21	9.55	0.00
Combustion Turbine >100 MW	100.00	50.00	2.53	7.50	10.03	0.00
Steam Turbine [coal] <100 MW	0.00	10.00	2.96	9.48	12.44	
Steam Turbine [coal] <200 MW	0.00	10.00	3.46	8.66	12.12	20.00
Steam Turbine [coal] >200 MW	0.00	10.00	4.51	9.79	14.30	
Steam Turbine [gas] <100 MW	0.00	10.00	3.09	7.27	10.36	
Steam Turbine [gas] <200 MW	0.00	10.00	3.69	10.50	14.19	10.00
Steam Turbine [gas] >200 MW	0.00	10.00	3.38	12.46	15.84	
Steam Turbine [oil] <100 MW	0.00	10.00	2.14	7.91	10.05	
Steam Turbine [oil] <200 MW	0.00	10.00	4.64	10.95	15.59	
Steam Turbine [oil] >200 MW	0.00	10.00	4.01	12.04	16.05	10.00

3. Nuclear Units

Description. CRA assumes that all nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates for each nuclear unit are drawn from the Energy Central database of unit outages. These plants do not contribute to quick-start or spinning reserves. Refueling and maintenance outages for each nuclear plant are also simulated. Outages posted on the NRC website or announced in the trade press for the near future are included. For later years, refueling outages for each plant are projected based on its refueling cycle, typical outage length, and last known outage dates. Since these facilities are treated as must-run units, CRA does not specifically model their cost structure.

Data Sources. Nuclear unit data were obtained from NRC publications, trade press announcements, and the Energy Central database.

4. Hydro Units

Description. MAPS has special provisions for modeling hydro units. For conventional or pondage units, CRA specifies a pattern of water flow, i.e., a minimum and maximum generating capability and the total energy for each plant. CRA assumes that hydro plants can provide spinning reserves of up to 50% of plant capacity. CRA assumes that the maximum capacity for each hydro unit is flat throughout the year, that the minimum capacity is zero (i.e., that there are no stream-flow or other constraints that force a plant to generate), and that the monthly capacity factor is 17%.

For hydro units in the SPP region, CRA developed hydropower schedules based on consultation with and/or data provided by hydro plant owners.

Data Sources. The list of hydro units and their maximum generating capacities is taken from the NERC ES&D database for 2003.

5. Wind Resources

Description. Individual wind resources were modeled either as zero-cost dispatchable energy resources with high (70%) outage rates or as hourly modifiers based on historical production data.

6. Capacity Additions and Retirements

Description. New entry is based on existing projects in development and on projects with signed interconnection agreements. These units are listed in Table 3. For study years 2010 and 2014, CRA had proposed to also add capacity based on economic and/or reliability criteria. However, due to a surplus of capacity in SPP no capacity balance units were required in the region during the study period.

Economic new capacity was added outside of the SPP region to balance regional markets in future years. New capacity was assumed to be based on combined-cycle gas turbines (CCGT) or simple-cycle gas turbines (SCGT), depending on market requirements and the relative economics of these options.

Discussions with the CBTF indicated that no units would be retired in SPP during the study period beyond those listed in Table 4, for which retirements have already been announced.

Table 3 New entry in SPP

Unit Name	State	Area	Type	Installation	Capacity (MW)	Heat Rate
Iatan 2	MO	KACP	STc	1/1/2010	800	9000

Table 4 Retirements in SPP

Unit Name	State	Type	Retirement	Capacity (MW)	Heat Rate
Teche 1	LA	STc	1/1/2008	23	13672
Teche 2	LA	STg	1/1/2008	48	12125
Teche 3	LA	Stgo	1/1/2008	359	10554
Rodemacher	LA	Stgo	1/1/2011	440	10316

Table 5 shows the resulting capacity balance for SPP.

Table 5 SPP Capacity Balance (MW)

Category	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Internal Demand	38,715	39,176	39,976	40,802	41,513	42,083	42,775	43,405	44,016	44,751
Interruptible Demand	1,010	1,014	1,021	1,026	1,030	1,033	1,039	1,044	1,052	1,056
Net Internal Demand	37,705	38,162	38,955	39,776	40,483	41,050	41,736	42,361	42,964	43,695
Required Reserve Margin (%)	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Load + Reserve	42,833	43,352	44,253	45,186	45,989	46,633	47,412	48,122	48,807	49,637
Purchases	2,331	2,377	2,176	2,034	2,044	2,042	2,051	1,947	1,947	1,947
Sales	1,045	982	724	729	734	610	557	511	511	511
New Entry	30	-	-	-	800	-	-	-	-	-
Retirement	-	-	430	-	-	440	-	-	-	-
Installed Capacity	52,059	52,089	52,089	51,659	51,659	52,459	52,019	52,019	52,019	52,019
Balance	10,512	10,132	9,288	7,778	6,980	7,258	6,101	5,333	4,648	3,818

7. Fuel Price Forecasts

Description. MAPS requires monthly fuel prices for each generating unit in the model footprint. The fundamental assumption concerning participant behavior in competitive energy markets is that generators will bid their marginal cost into the energy market, including the marginal cost of fuel, variable operations and maintenance (O&M) and the costs associated with marginal emission of pollutants. The marginal cost of fuel is defined as either the opportunity cost of fuel purchased or the spot price of fuel at a location representative of the plant. If the fuel is purchased on a long term contract, it assumed that the opportunity cost of the fuel is the same as the price of fuel on the locational spot market. CRA uses forecasts of spot prices at regional hubs, and refines these prices on the basis of historical differentials between price points and their associated hubs. For fuel oil and coal, CRA uses estimates of the delivered price of fuel to generators on a regional basis.

Dual-fuel generators are simulated as follows:

- Natural Gas Primary. Units that primarily burn natural gas may burn fuel oil in at most one month of the year. Because natural gas prices are typically highest in January, the model allows the unit to switch to fuel oil for January if the oil price at that location is lower than the natural gas price.

- Fuel Oil Primary. Units that primarily burn oil may switch to natural gas whenever it is economically justified. CRA assumes that natural gas shortages prevent this from happening in the winter heating period, defined as November though March. A heat rate degradation of 3% is modeled when the unit switches to natural gas. Thus, the fuel type is switched to natural gas during April through October, whenever the price of natural gas plus 3% is less than the price of fuel oil.

Coal prices are drawn from a database provided by Resource Data International (RDI), which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States.

Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Specific oil and gas price forecasts used in this study are provided in Appendix 3-2.

8. Transmission System Representation

Description. The MAPS analysis is based on load-flow cases that include the entire eastern interconnect transmission system—transformers, lines, phase shifters, and buses—based on SPP's Market Development Working Group (MDWG) load flow cases for 2005 (used in the year-2006 analysis) and 2010 (used in the 2010 and 2014 analyses.) Potentially binding lines, interfaces, and contingency constraints are monitored. Within the SPP system, constraints and flow limits were represented as provided by SPP. Outside of SPP, constraints were drawn from the CRA database, which is derived and maintained from public data sources. Flow limits were based either on the thermal ratings of lines as provided in the load flow case (normal limit for interfaces, emergency limits for line-loss contingencies) or on regional reliability studies.

Data Sources. Load flow cases from the MDWG process were provided by SPP. SPP flowgate constraints were applied for the SPP Region. Outside of SPP, an updated set of potentially binding contingencies was prepared under contract to CRA by General Electric, based on GE's exhaustive contingency analysis, and was updated and validated by CRA.

9. Environmental Regulations

Description. For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the marginal production cost and the unit energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NO_x or SO_2 abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation. MAPS allocates the cost of the SO_2 trading permits to energy throughout the year. NO_x emissions permit prices are based on market trading data published by Cantor Fitzgerald.

Emission quantities are do not account for any projected future environmental controls required under the current Clean Air Interstate Rules, Clean Air Mercury Regulations, nor were any additional environmental controls included for pending regulation and/or legislation.

Data Sources. The EPA's Clean Air Markets database (2002) provides plant heat input, NO_x and SO_2 emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. NO_x permit prices are obtained from a Cantor Fitzgerald on-line resource.

10. External Region Supply

Description. The modeling footprint includes SPP, SERC, FRCC, MISO, Western PJM (Allegheny, Duquesne, AEP, ComEd), Ontario, and those portions of ECAR and MAPP that are not in MISO nor in PJM West. CRA did not explicitly model regions external to this footprint, such as ERCOT, the WECC, and the northeast power pools such as Eastern MAAC, NYISO, and ISO NE. Economic transactions with these outlying pools were generally represented as price-sensitive supply and demand curves to reflect historical patterns. The power flows between SPP and the WECC were represented as an hourly flow schedule, as to agreed with the CBTF following its review of interregional flows from the first set of model runs. The switchable units within SPP's footprint (Kiowa and Gateway, switchable to ERCOT) were not considered to be SPP capacity for purposes of the wholesale market study. The Oklaunion unit was reflected as a jointly owned unit.

11. Dispatchable Demand (Interruptible Load)

Description. The presence of demand response is important to the energy and installed capacity markets. The value of energy to interruptible load caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. For this study, the size of interruptible load is determined as a percentage of total load in SPP, based on Interruptible Demand and Direct Control Load Management as reported in the EIA-411 data provided by SPP. The dispatchable demand for each load area is modeled as a generator with a dispatch price of $600/MWh for the first block (50% of the area's dispatchable demand) and $800/MWh for the second block. These proxy units rarely run in the model, because the high prices they require indicate a supply shortfall and prompt new entry. Thus they play an insignificant role in the energy market, but they play an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

Data Sources. Data were drawn from the EIA-411 report data, as provided by SPP.

12. Market Model Assumptions

- *Marginal Cost Bidding*. All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

- *Operating Reserves Requirement (spinning and standby)*. Operating reserves are based on requirements instituted by SPP and are based on the sum of the largest single contingency and one-half of the second largest contingency in the system. This requirement is distributed through the system on a load-share basis to form individual company reserve requirements. The spinning reserves market affects the energy prices because when capacity is reserved for spin it is not available for electricity production to serve load. Energy prices are higher when reserves markets are modeled. Outside of SPP, reserve requirements were implemented on a pool-wide basis according to pool-specific operating requirements.

- *Transmission Losses*. Transmission losses are modeled at average rates.

Wheeling rates. Within SPP, no wheeling rates between control areas are assumed for the Base and EIS cases. Wheeling rates between control areas for the Stand-Alone case are based on company-specific firm transmission rates as detailed in the individual transmission tariffs. Wheeling rates do apply between Cleco and other SPP companies as well as between SPP and SERC, SPP and MISO, and between MISO and SERC. Region-to-region wheeling rates are detailed in Table 6; company-specific wheel-out rates for SPP companies (Stand-Alone case) are shown in Table 7.

Table 6 Wheeling rate overview

			TO				
	Region	Scenario	SPP	MISO	SERC	Aquila	Cleco
FROM	SPP	IE & BC	-	Tariff	Tariff	Tariff	Tariff
		SA	Tariff	Tariff	Tariff	Tariff	Tariff
	MISO	IE & BC	\$2	-	\$2	-	NA
		SA	\$2	-	\$2	-	NA
	SERC	IE & BC	\$2	\$2	-	\$2	-
		SA	\$2	\$2	-	\$2	-
	Aquila	IE & BC	Tariff	-	Tariff	-	NA
		SA	Tariff	-	Tariff	-	NA
	Cleco	IE & BC	\$4	NA	\$4	NA	-
		SA	\$4	NA	\$4	NA	-

Table 7 Wheel-out rates for SPP and Aquila companies

Company	Commitment	Dispatch
Public Service Company of Oklahoma and Southwestern Electric Power Company	\$2	\$2
City Utilities of Springfield, Missouri	\$2	\$3
Empire	\$2	\$2
Grand River Dam Authority	\$3	\$7
Kansas City Power and Light Company	\$2	\$2
Mid-West Energy	\$4	\$6
Oklahoma Gas & Electric Company	\$2	\$2
Southwestern Power Administration	\$1	\$2
Southwestern Public Service	\$2	\$3
Western Resources, Inc	\$2	\$2
Western Farmers Electric Cooperative	\$3	\$3
Aquila Companies		
Missouri Public Service	\$1	\$1
West Plaines	\$2	\$3

Appendix 3-2: Fuel Price Assumptions

MEMORANDUM

TO: SPP CBTF

FROM: Alex Rudkevich, Charles River Associates

SUBJECT: Fuel Price Forecast

DATE: August 30, 2004

The purpose of this memo is to document the Base Case scenario for the electricity generation fuels price forecast. The forecast includes prices for natural gas, distillate (#2), residual (#6) fuel oil and coal. Note that all prices are in real 2003 dollars. Also all figures are detailed in the Excel workbook accompanying this memo along with the underlying numerical data.

Coal Price Forecast

Long-term forecast of coal prices by power plant has been provided by CRA which purchased this forecast from Platt's RDI. CRA will rely on this forecast in its entirety.

Fuel Oil and Natural Gas Price Forecast

CRA develops an in-house forecast of natural gas and fuel oil prices discussed in the balance of this memorandum.

Geographical Markets

The regionalization of fuel markets follows natural gas trading points rather than markets for fuel oil. The forecast covers the following areas in the US and Canada.

Table 1 Forecast Regions

Midwestern Regions	**South Atlantic South**	**IA/MO/NE**	**Appalachia**	**South Atlantic East**	**Midcon**	**Canada**
Illinois	Alabama	Iowa	Kentucky	Georgia	Kansas	East Ontario
Indiana	Arkansas	Missouri	Ohio	North Carolina	Oklahoma	West Ontario
Michigan	Louisiana	Nebraska	Pennsylvania	South Carolina		
Minnesota	Mississippi		West Virginia	Virginia		
Wisconsin	Tennessee			South Maryland		
				Delaware		
Florida	**Texas non-ERCOT**			DC		
Florida	East TX non ERCOT					
	North TX non ERCOT					

Forecasts Drivers

The principal drivers of CRA fuel forecasts are projected prices for crude oil (Light Sweet Crude) and for natural gas at Henry Hub and selected regional hubs traded forward on NYMEX. All other forecasts are derived from these driving projections using forecast and/or historical basis differentials as explained later in this memo.

Generally CRA develops the base case forecast of crude oil prices as a composition of NYMEX futures prices in the short term and EIA's forecast in the long-term as published in EIA's *Annual Energy Outlook 2004*.

Similarly, CRA develops the forecast for the spot price of natural gas at Henry Hub as a composition of futures prices in the near-term and a long-term forecast from EIA's *Annual Energy Outlook 2004*.[6] In addition, CRA relies on forward basis differentials for the following natural gas hubs traded on NYMEX Clearport (NYMEX hubs):

- ANR OK
- Chicago
- Columbia Gulf Onshore
- Dominion
- MichCon
- NGPL Midcon
- NGPL TexOk
- NGPL Louisiana

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[6] *AEO-2004* does not forecast Henry Hub prices but instead predicts prices at the wellhead. A historical multiplication factor of 1.129 is used to derive the Henry Hub price forecast.

- Permian
- Northern Natural Demarcation
- Panhandle
- TCO (Columbia Gas)
- TETCO East LA
- TETCO Zone M3
- Transco Zone 3
- Transco Zone 6
- Ventura

Basis differentials to these hubs from the Henry Hub are traded for a relatively short period, typically between 12 and 24 months. For those periods, CRA derives summer and winter basis differentials to those hubs using NYMEX data. Beyond those periods, CRA scales these basis differentials in proportion to the Henry Hub price forecast. Forecast prices at each hub are derived as a sum of the Henry Hub price forecast and a hub-specific basis differential.

Natural Gas Pricing Points

For the purpose of modeling electricity markets, CRA recognizes multiple pricing points within each region. All pricing points are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with NYMEX hubs, hence the forecast for these pricing points are given by the forecast for NYMEX hubs described above. CRA derives forecasts for pricing points that do not coincide with NYMEX hub using regression models calibrated with historical data. Table 2 below lists all relevant pricing points and maps points to NYMEX hubs used as drivers for those points in the CRA regression model.

Table 2 Pricing Points

Natural Gas Regions	Pricing Points	NYMEX Hubs used for regression
E. Ontario	Niagara	MichCon Transco Z6
Midwest	Chicago	Chicago
	MichCon	MichCon
S. Atlantic South	Henry Hub	Henry Hub
IA/MO/NE	Ventura	Ventura
W. Ontario	Dawn	Dominion MichCon
Appalachia	Columbia Gas (TCO)	Columbia Gas (TCO)
	Dominion	Dominion
	CNGL	Dominion
Midcon	NGPL Midcon	NGPL Midcon
S. Atlantic East	FGTMB	Tetco East LA
	KochM	Transco Z3
	Tetco M-1	Tetco East LA
	TRS85	Tetco East LA
	Transco Z6 (Non-NY)	Transco Z6 Columbia Gas (TCO)
	TETCO M-3	TETCO M-3
Texas Non-ERCOT East	Carthage	Henry Hub
Texas Non-ERCOT North	NGPL Midcon	NGPL Midcon
	NGPL Permian	Permian
Florida	Florida Gas Transm	Henry Hub

Basis Forecasts

As stated earlier, the key underlying forecasts are projected prices for crude oil (WTI) and for natural gas (Henry Hub). All other forecasts are derived from these two basic forecasts using projected and/or historical basis differentials.

Figure 1 below presents the CRA proposed base case forecast of crude oil prices in comparison with:

- historical prices,
- NYMEX futures prices for the light sweet crude oil (as of August 26, 2004), and
- a long term forecast for crude oil prices from EIA's *Annual Energy Outlook-2004*.

As one can see, CRA's proposed forecast is a composition of futures prices in the short term (2005-2009) and EIA's forecast in the long-run (2013-2020). Years 2010 through 2012 are interpolated.

Similarly, Figure 2 presents the CRA proposed forecast for the spot price of natural gas at Henry Hub. The forecast is shown in comparison with average NYMEX futures prices (as of August 26, 2004[7]) and a long-term forecast per EIA's Annual Energy Outlook-2004.[8] CRA's proposed forecast is a composition of futures prices in the near-term (2005-2009), and EIA's long-term forecast in the long-run (2012-2020). Years 2010 and 2011 are interpolated.

Generation Fuel Prices

Generation fuel prices are derived from the basis forecasts. Figures 3 through 8 present comparisons of monthly generation fuel prices for the Midwestern region, South Atlantic South, South Atlantic East, Appalachia, Midcon and IA/MO/NE for the period 2005-2015. Figure 9 provides a comparison of regional natural gas prices. The methodologies associated with these forecasts are explained below.

Fuel Oil Prices – Methodology

To derive fuel oil prices for electric generation, an in-house linear regression model, which links crude oil prices with #6 and #2 fuel oil in the Northeastern US (New York Harbor), was used. For petroleum prices in other regions, state-specific basis differentials using EIA Form 423 data for 1997-2000 and historical spot prices for #2 and #6 fuel oil at New York Harbor were used. CRA assumes a modest seasonal pattern for #2 fuel oil prices, the same in all regions. Prices for #6 fuel oil are assumed flat. Table 3 shows the fuel oil basis differentials.

7 The NYMEX Clearport futures data available for the NYMEX hubs are usually one day old while the NYMEX futures data are available in real time.

8 *AEO-2003* does not forecast Henry Hub prices, instead it predicts prices at the wellhead. To come up with the Henry Hub price forecast a historical multiplication factor of 1.14 is applied.

Table 3 Basis Differentials from NY Harbor to the Burner-tip by State

State	FO2 Basis ($/MMBtu)	FO6 Basis ($/MMBtu)
IL	0.62	0.53
IN	0.52	
MI	0.39	0.38
MN	0.82	
WI	0.56	
AL	-0.10	
AR	0.42	
LA	0.37	0.05
MS	0.18	-0.31
TN	0.28	
FL	0.49	0.01
IA	0.39	
MO	0.38	-0.35
NE	0.69	
OH	0.38	
GA	0.48	0.18
SC	0.47	
NC	0.26	
DE	0.34	0.11
DC	0.38	
VA	0.33	-0.07
MD	0.23	0.10
PA	0.31	0.11
KY	0.85	
WV	0.77	
OK	0.21	
KS	0.54	-0.29
TX	0.37	0.81

Natural Gas Prices – Methodology

1. The burner-tip price for natural gas is a sum of two components – regional price and local delivery price.

2. Local delivery price is differentiated by state based on the American Gas Association's statistics. This price is applied **to existing plants only** (see Table 4 below for details).

3. For new gas-fired plants, the local component is set at $0.07/MMbtu to reflect pipeline lateral charges. (This is CRA's "best-guess" estimate.)

4. Forecast regional gas prices are derived from the NYMEX Hubs forecast using CRA in-house regression models calibrated on historical regional prices vs. prices at Henry Hub. The modeling structure by region is outline in Table 2.

5. Seasonal patterns are developed in the following manner:

   For Henry Hub, CRA uses seasonal pattern revealed in futures prices. Revealed pattern for 2009 is assumed for all years from 2010 onward.

Regional seasonal patterns appear automatically by applying the regression model to the monthly Henry Hub forecast.

Table 4. LDC Charges Applied for Older Gas-fired Plants by State

State	LDC Charge ($/MMBtu)
IL	0.09
IN	0.36
MI	0.59
MN	0.12
WI	0.49
AL	0.37
AR	0.23
LA	0.09
MS	0.19
TN	0.37
FL	0.23
GA	0.32
SC	0.96
NC	0.47
VA	0.52
MD	0
DE	0
DC	0
IA	0.31
MO	0.01
NE	0.13
OH	0.53
PA	0.11
KY	0.69
WV	0.26
OK	0.24
KS	0.31
TX	0.03