3. Implementation of the Reference and Competitive Scenarios in POEMS

In order to measure the impacts of retail competition in the electricity sector, a baseline scenario of electricity markets absent competition must first be established. The Reference Scenario provides a reasonable expectation of the future evolution of the industry, assuming a continuation of utility regulation and cost-of-service pricing. This report analyses the Administration's proposed Comprehensive Electricity Competition Act (CECA) by comparing the Reference Scenario to a Competitive Scenario that assumes the implementation of retail competition as envisioned in the Administration's proposal.

Scenario Definitions and Baselines

Electricity market projections are intrinsically connected to the projected levels of national and regional economic activity, which determine the underlying demand for electricity services, and to projections of the costs of the fuels and technologies used to produce electricity. Both the Reference and Competitive scenarios developed in this report are based on the same underlying macroeconomic and energy sector projections, which are taken from the reference case presented by the Energy Information Administration (EIA) in the 1999 *Annual Energy Outlook* (*AEO*).[9] As noted by EIA, the *AEO* reference case is only one of a set of possible projections of the Nation's energy future, and it does not reflect a statement of what will happen. The same caveat applies to the electricity scenarios presented in this report: they would be altered by a change in the underlying economic and energy market projections on which they are based. Comparisons of differences between the Reference and Competitive scenarios are likely to be more meaningful than the absolute projections of prices and quantities in either scenario.

The July 1998 analysis of the Administration's electricity legislation submitted to the 105th Congress was based on an older EIA reference case, presented in the 1997 *AEO*. Table 6 summarizes the major differences between the 1997 and 1999 *AEO* reference cases for the years 2005 and 2010. The rate of economic growth is projected to be higher than in the 1997 report, primarily in the service rather than manufacturing sectors. Prices for natural gas delivered to electricity generators are also projected to be higher in the more recent projection, while delivered coal prices are projected to be lower. Finally, electricity demand is also higher in the more recent projection, primarily as a result of expected higher demand for office equipment use in the commercial sector.

The 1999 *AEO* includes updated information on the cost and performance of new technologies in the electricity generation sector. The most significant change is the increased rate of cost reduction for new technologies as a function of the level of cumulative capacity deployment. The database of existing and planned additions has been updated as well, to reflect knowledge of projects built or committed over the past 2 years. Both updates have been adopted in POEMS.

Electricity sector dispatch decisions and capacity additions can be influenced significantly by environmental regulations. In addition to the Clean Air Act requirements considered in the earlier analysis, the Reference and Competitive Scenarios in this report take account of the Ozone Transport Rule (NO_x SIP Call) promulgated in the fall of 1998. This rule imposes an absolute cap on NO_x emissions in 22 Eastern States during the summer ozone season (May through September), beginning in 2003.

[9]For more detail, see Energy Information Administration, *Assumptions to the Annual Energy Outlook 1999* (December 1998), web site www.eia.doe.gov/oiaf/aeo99/homepage.html.

Table 6. Comparison of 1997 and 1999 *Annual Energy Outlook* Projections

Projection	1997 *AEO*		1999 *AEO*	
	2005	2010	2005	2010
Population (Millions)	287.1	298.9	286.5	298.3
Gross Domestic Product (Billion 1992 Chain-Weighted Dollars)	8,390	9,185	8,769	9,896
Industrial Output (Index, 1987=1.000)	1.590	1.765	1.593	1.810
World Oil Price (1997 Dollars per Barrel)	20.46	21.18	19.25	21.30
Natural Gas Price to Electricity Generators (1997 Dollars per Million Btu)	2.37	2.41	2.94	3.08
Coal Price to Electricity Generators (1997 Dollars per Million Btu)	1.29	1.25	1.14	1.06
Electricity Demand (Billion Kilowatthours)	3,545	3,784	3,585	3,843

However, this report does not consider the effects of the April 1999 Regional Haze rule. The implications of that rule for the electricity sector depend on the exercise of discretion provided to the States and remain unclear at present.

The Reference Scenario assumes that wholesale competition is achieved through open transmission access under Order 888 of the Federal Energy Regulatory Commission, which was issued in 1996 pursuant to provisions of the Energy Policy Act of 1992. All new capacity is not included in the ratebase of utilities. In addition, transmission fees are "pancaked." In other words, if power is wheeled across two transmission systems, each will charge a separate fee for providing the transmission service.

The Competitive Scenario in this report represents the projected outcome under the Administration's proposal. This scenario is implemented in the POEMS model through a range of parameter settings that represent a vision of the fully competitive market for retail electricity that the Administration's proposed policies are designed to stimulate. Table 7 compares the settings of key parameters in the Reference and Competitive scenarios. Each parameter is discussed below in the context of the Act.

While both the Reference and Competitive Scenarios start from the same 1999 *AEO* baseline, the results reported in Chapter 2 and Appendix A of this report show differences in fuel prices, fuel demands in the electricity sector, and the level of electricity demand. These differences reflect the interaction of electricity prices, fuel demands in the electricity sector, and other sectors fuel prices resulting from the transition to competition and specific provisions of the CECA, notably, the renewable portfolio standard (RPS). The macroeconomic projections do not vary between scenarios, because feedback from the economic sector of POEMS was not included.[10]

Electricity Pricing and the Treatment of Stranded Costs

The market generation price in the Competitive Scenario is composed of the marginal generation cost, ancillary charges, an RPS premium (if applicable), a Public Benefits Fund charge, and stranded cost recovery charges. The marginal generation cost in each power control area (PCA) is established through a second price auction. The price in each period equals the marginal cost or bid price of the next least expensive option in the merit order above the last unit selected to operate. This next marginal unit could be native to the PCA or determined

[10] The macroeconomic module of the model uses a kernal regression approach to estimate the impact that changing energy prices would have on the economy. This requires the creation of a database of simulations made with the full DRI macroeconomic model which reflect the policies and projections being simulated in the integrated energy model. It is unclear whether the current databases maintained by EIA for NEMS are appropriate for this electricity restructuring analysis.

Table 7. Reference and Competitive Scenario Parameters

Category	POEMS Reference	POEMS Competitive
Electricity Markets	Competitive wholesale, cost-of-service regulated retail	Competitive wholesale, competitive retail
Market Power	None (regulated monopoly)	None (perfect competition)
Macroeconomic Scenario (GDP Growth)	1999 *AEO* reference case (2.4% per year, 2000 to 2010)	1999 *AEO* reference case (2.4% per year, 2000 to 2010)
Cost of Capital	10.8% weighted average	12.0% weighted average
Demand	1999 *AEO* demand modules	1999 *AEO* demand modules
Energy Efficiency	1999 *AEO* reference case	1999 *AEO* reference case, plus public benefit fund and “bundled efficiency” savings
Distributed Power (Combined Heat and Power)	1999 *AEO* Reference Case	Increase of 100 billion kilowatthours by 2010
Renewables	No special requirements	Renewable portfolio standard (non-hydro) of 7.5% in 2010, subject to a cap of 1.5 cents per kilowatthour on the premium paid for non-hydro renewables. Extension of renewables tax credit as in Administration FY2000 budget proposal. Green Power provides 0.3% of total demand.
Generation Pricing	Cost of service. New plants sell output under long-term contracts.	Marginal cost pricing, where variable costs equal fuel costs plus a percentage of O&M (percentage varies by technology).
Ancillary Services	Included in cost of service	Spinning reserves and ancillary charges associated with capacity to meet reserve requirements are included in prices.
Transmission		
Hurdle Rate	$3 per megawatthour	$1.5 per megawatthour
Organization	Pancaked	Postage stamp
Wheeling Fees	80% FERC Order 888	50% FERC Order 888
O&M and G&A Costs		
Generation		
O&M	Improvement through plant mix only	Improve 50-75% from current values to those of the top quartile of comparable plants.
G&A	1% per year decline	5% per year decline, 2000 to 2010
Transmission	No change	0.75% per year decline, 2000 to 2010
Distribution	No change	1.5% per year decline, 2000 to 2010
Heat rates	Improvement through plant mix only	Improve 50% from current values to those of the top quartile of comparable plants.
Availabilities	Coal/gas/oil steam at 85 percent. Nuclear varies by age of plant, as in 1999 *AEO*	Coal/gas/oil steam at 89 percent. Nuclear annual improvements increased by 0.5%, subject to 89-percent cap.
Reserve Margins	8% for all regions, except 4% for Florida	8% for all regions, except 4% for Florida
Stranded Cost Recovery		
Stranded Generating Assets	Not applicable	10-year recovery, 10% discount rate, 100% cost recovery
Surplus (Windfall) Generating Assets	Not applicable	30-year recovery, 10% discount rate, 100% payment to municipal and cooperative utility customers, 25% payment to IOU customers
Transitional Charges		
Regulatory Assets	Start year 1995, estimated current recovery periods, near 0 discount rate, 100% recovery	Same
Decommissioning Costs	Start year 1995, average 25-year recovery, 10% discount rate, 100% recovery	Same

through trade with other PCAs. The last unit could be native to the PCA or determined through trade with other PCAs. In accord with the standard economic model of competition, the market bid price for each unit is assumed to be its marginal cost—the sum of fuel costs and the variable portion of operating and maintenance (O&M) costs.

As outlined in Chapter 1, the capital investment in generating plants (both productive and abandoned) has been made by private investors (investor-owned utilities), various government entities (Federal, State, municipal) and member-owned systems (i.e., cooperatives), which have in many cases received subsidized direct loans or loan guarantees from government entities. The movement to a competitive generation market exposes some of these investments to potential under-recovery if their market value, based on the expected net cash flow they are projected to receive from the market, is less than their net book value (the investment outstanding). This is the well-known issue of stranded costs.

The competitive market will also provide a surplus (windfall benefit) for those plants whose market value exceeds their net book value. The recent record of sales of existing power plants, which have occurred in growing numbers due to both utility business strategy decisions and divestiture requirements imposed at the State level, suggests that the latter situation of "negative stranded costs" cannot be ignored. The overall projected stranded cost situation of an electric utility or other entity in the transition to competition is determined as the sum of the "strandings" of its individual plants.

With regard to electricity providers with positive stranded costs, the Administration's plan endorses the principle that utilities, regardless of ownership structure, should be able to recover prudently incurred, legitimate and verifiable retail stranded costs that cannot be reasonably mitigated. The Competitive Scenario therefore includes provision for recovery of stranded costs associated with productive generating assets over a 10-year period following the introduction of competition. Recovery of regulatory assets and decommissioning costs in the Competitive Scenario is assumed to be similar to that in the Reference Scenario, with the pace of recovery in these categories for both scenarios reflecting recent State-level practices.

For providers with negative stranded costs, the Competitive Scenario differentiates according to their ownership structure and specific provisions of the Administration's proposal. For federally-supplied power, the Administration plan does not change existing statutes under which service is provided to customers at cost-based prices. Therefore, the Competitive Scenario maintains cost-based pricing of Federal power, with no reflection of either positive or negative stranded costs in customer bills.

For generation assets owned by State and local power systems, the Competitive Scenario passes through the benefit of negative stranded costs to their customers, who are also the constituents of the government owners. In real-world power markets, the passthrough of negative stranded costs can be implemented by a decision to supply power for use of native customers at lower-than-market rates, or by selling power at market rates while "writing down" transmission and distribution costs.

For rural electric cooperatives (RECs) that serve rural member/owners, the treatment of negative stranded generation costs depends on their specific supply arrangements. Generation and transmission (G&T) cooperatives, which are owned by the RECs (and indirectly by the RECs' own customer/members) are the predominant source of supply to RECs. Many RECs have ownership positions in G&T cooperatives and/or access to Federal power at cost-based rates, either or both of which provide them with a physical hedge in the generation market. In the Competitive scenario as modeled by the Department using POEMS, the benefits of ownership, including any negative stranded costs, are passed through to the REC customer/owners in the form of lower generation prices.

Power from Federal projects and purchases from investor-owned utilities (IOUs) in the wholesale market provide the remainder of the power distributed by RECs. As noted above, Federal power will continue to be sold at cost-based prices, so that any negative stranded costs arising from a situation where cost-based prices are below market prices will be fully passed through to the RECs. Finally, where power is purchased from IOUs, the Competitive Scenario treats REC customers in the same manner as other customers, as outlined below.

For investor-owned electricity providers with negative stranded costs (market value of generation assets exceeding their book value) there is some uncertainly as to how the surplus of market over book value will be allocated between their owners (stockholders) and the customers on whose behalf the assets were built. The final disposition of negative stranded costs for IOUs ultimately will be resolved in the political process surrounding the transition to competition at the State level. For purposes of the Competitive Scenario, this analysis adopts the assumption that 75 percent of the negative stranded cost benefit accrues to the IOU stockholders, and 25 percent accrues to customers in the form of an accelerated writedown of transmission and distribution assets.

Methodology to Derive Prices at the State Level

POEMS is implemented at the power control area (PCA) level. PCA borders are not contiguous with State boundaries— some States have multiple control areas, and some control areas span multiple States. The mismatch in boundaries presents a challenge to the estimation of State-level prices.

Nonetheless, recognizing that estimates of State-level impacts may be of some interest to readers of this report, a methodology for deriving price projections from the PCA-level results was developed. Retail sales flowing from each PCA into each State were estimated by customer class (residential, commercial, industrial) using the 1995 form EIA-861 data. The State market shares were then used to calculate State-level weighted average retail prices for each customer class. In cases where PCAs span areas greater that a single State—such as the PJM (Pennsylvania-New Jersey-Maryland) Power Pool —the generation component of retail price was allocated to each State, and the T&D costs were added on the basis of the distribution of regional costs to each State.

Capacity Expansion and Plant Retirements

In both scenarios, new capacity is constructed to meet new load or replace more expensive existing generation. The same reserve margin targets were assumed in the two cases, in order to make them comparable in the quality of service delivered. In the Reference Scenario, it is assumed that all new construction will be purchased under long-term levelized contracts with electric utilities. In the Competitive Scenario, new generation plant owners will need to recover their investments in the competitive electricity market. They are assumed to receive the marginal bid price plus ancillary charges associated with the value of capacity.

Retirement of plants is economically driven. The economic retirement decision for generating plants is based on both short-term and long-term criteria. The short-term requirement is that plants cover their “going-forward” costs, which include all fixed and variable O&M costs as well as recovery of the annualized value of new capital additions. If a plant cannot cover those costs, it becomes a candidate for early retirement. The second consideration is the cost of building new generating capacity. In the capacity planning module, all existing units must pay their going-forward costs if the capacity is to be used over the full planning horizon. Thus, the planning module has the opportunity to “decide” to retire any or all of the existing units for economic reasons and instead build new capacity. If the planning module does decide to retire a unit and this same unit did not cover its variable costs in the last forecast year, it is retired. A plant must be uneconomical both in the short term and in the long term to be retired.

Cost of Capital

Under competition, electricity generators will not be guaranteed a fixed rate of return on their investments. As a result, plant owners will demand a greater expected return to compensate for the risk associated with their revenues. They will also need to finance their investments with less reliance on debt and more on equity. The weighted cost of capital is 10.8 percent in the Reference Scenario and 12 percent in the Competitive Scenario. These rates are 200 basis points lower than the assumptions used in the July 1998 analysis, reflecting an updated long-term outlook for inflation and interest rates.

Operating Costs: Generation, Transmission, and Distribution

As the electric power industry is transformed into a more competitive, market-based industry, the historical levels of costs are expected to be reduced by the pressures of competition. In the generation segment of the industry, costs per unit of output will decrease as the mix of capacity changes—i.e., more expensive generating units will be replaced by new, more efficient generating technology (typically natural gas fueled). In the Competitive Scenario, competitive pressures are expected to lower costs at existing generating facilities as well, as they begin to compete with other existing and new facilities. Overall nonfuel O&M expenses per kilowatthour generated are projected to be 17 percent lower in the Competitive Scenario than in the Reference Scenario in 2010. Competitive pressures also are assumed to spill over into the regulated segments of the industry. Transmission productivity improves by 0.75 percent per year, and distribution productivity improves by 1.5 percent per year through 2010 with the introduction of performance incentives.

Heat Rate Improvement

Historically, utilities were not rewarded for reducing their fuel costs. In fact, in many States, fuel costs were directly passed through to consumer bills. As long as a utility was acting "prudently," regulators would provide little pressure to reduce fuel costs. In part, this may explain why there is currently a very wide range of heat rates in power plants of the same type, size, and age. With intense competitive pressures, generator owners are likely to make cost-effective improvements and change their operations to improve the efficiencies of existing plants. Any improvements will either lead directly to increased profits or allow plants to continue operating that might otherwise be priced out of the market. Based on an analysis of existing heat rates, the Competitive Scenario assumes that existing plants will make significant strides toward achieving heat rates closer to those of the top 25 percent of comparable plants. The average improvement relative to the Reference Scenario is roughly 4 percent.

Capacity Availability Improvement

Competition will give generators an incentive to maximize the availability of their facilities, because they will only receive revenue when they are operating. In the Reference Scenario, fossil-fuel-fired steam units are assumed to have availabilities of 85 percent. In the Competitive Scenario, the same steam units are assumed to have 89 percent availabilities, which represent the 25th percentile for coal plants for the period 1992 to 1996.[11] In the July 1998 analysis, fossil and nuclear steam plants were assumed to be able to increase their availabilities to 90 percent.

Nuclear availabilities in this report vary by age of plant, as in EIA's 1999 *AEO*. Nuclear plants are assumed to improve in availability for several years, plateau at no higher than 85 percent, and then decline in later years of their operating lives. In the July 1998 analysis, nuclear availabilities were specified by region, following the EIA modeling approach in use at that time. For nuclear units, the availability improvement rate in the Competitive Scenario was increased by 0.5 percent per year, with the maximum availability increased to 89 percent.

Transmission System

FERC Order No. 888 required that ". . . seller(s) (and each of its affiliates) must not have, or must have mitigated, market power in generation and transmission and not control other barriers to entry."[12] For transmission-owning utilities, this

[11] Based on data from the NERC Generating Availability Data System (GADS).
[12] See page 63 of FERC Order No. 888.

meant that the utility must have on file with the FERC an open access tariff for the provision of comparable service. The Competitive Scenario assumes that all transmission owners will have an open access tariff over which retail and wholesale sales can occur. The Competitive Scenario, like the Reference Scenario, assumes that nonutility generators will provide all new generation capacity. The Competitive Scenario assumes that all consumers (residential, commercial, and industrial) will have equal access to the power exchanges.[13] (To assure that consumers of all types have the necessary information to make informed decisions, the Administration's proposal requires sellers to provide uniform information on price, terms, and conditions of service.

Transmission fees were computed using a formula similar to the *pro forma* tariff described in Order No. 888. In the Reference Scenario, the transmission fees were assumed to be pancaked.[14] In the Competitive Scenario, the assumption is that regional transmission groups (RTGs), tied together by an independent regional system operator (IRSO), would operate the transmission grid(s). The transmission fees in the Competitive Scenario were therefore assumed to be the same for moving power across the entire RTG region (i.e., a postage stamp rate). In the Reference Scenario, the wholesale transmission fee is assumed to be 20 percent less than the full cost of service. In the Competitive Scenario, the wholesale transmission fee is 50 percent less than the full cost of service, reflecting a combination of discounting and the reduction of pancaking.

In both the Reference and Competitive scenarios, 100 percent of the cost of service of the transmission system is initially allocated to native retail customers. Then the revenue collected through wholesale transactions is subtracted, and the remaining amount is charged to the retail customer explicitly for transmission. Wholesale transmission revenues may be larger or smaller in the Competitive Scenario than in the Reference scenario. On the one hand, transmission price discounting and competition itself stimulate increased use of the transmission system. On the other hand, the move from pancaked rates in the Reference Scenario to zonal rates in the Competitive Scenario can lead to reduced wholesale transmission revenues. The net effect varies by region. However, the total transmission cost remains unchanged between scenarios. Only the allocation between wholesale and retail components changes.

Renewable Portfolio Standard and Green Power

The RPS in the Administration's plan was included in the Competitive Scenario as a national standard with potential trading of credits. This means that renewable generation can be constructed wherever it is most cost-effective, rather than requiring it to be spread evenly across the Nation. The standard was expressed as a percentage of sales that must be met with renewables and was assumed to increase over the 2001 to 2010 period. In 2010, the RPS target in the Administration plan is 7.5 percent, but with a cost cap that limits the maximum premium for renewables to $15 per megawatthour (1.5 cents per kilowatthour) over the market price for electricity. All non-hydroelectric renewable generation qualifies to meet the standard, including industrial cogeneration and 61 percent of generation from municipal solid waste combustion, which is the proportion that can be attributed to the biomass content of the input fuel. Because of the ability to trade credits, electricity from renewables will command the same price premium nationally, equivalent to the marginal cost of non-hydroelectric renewables or the $15 per megawatthour cap, whichever is less.

The RPS in the Competitive Scenario works in conjunction with the existing program of tax credits for certain types of renewable generation. The

[13]Residential and commercial consumers (and small industrial consumers) may use "aggregators" to achieve the economy of scale necessary to access the competitive market effectively.

[14]In the Reference Scenario, each PCA was considered a transmission entity. Electricity trade through a PCA resulted in the addition of a transmission tariff. In the Competitive Scenario, PCAs were grouped into RTGs, and one tariff was established for each region as a whole.

Administration's budget proposal for fiscal year 2000, submitted in February 1999, proposes extension of the existing tax credits for wind and biomass and provision of a new, smaller tax credit for biomass co-fired with other fuels, such as coal.

The Competitive Scenario assumes that consumers nationwide would also be willing to pay for some additional Green Power, part of which is generated from new non-hydroelectric renewables above the RPS requirement. The labeling provisions of the CECA will provide consumers with the information they need to choose their generation suppliers on the basis of price and the environmental factors important to them. Pilot programs in various States, as well as activity in California, support the view that a segment of consumers will value these qualities. Purchases of Green Power in the Competitive Scenario result in a net addition of non-hydroelectric renewable generation equivalent to 0.3 percent of retail sales in 2010. This level is somewhat lower than that used in the July 1998 analysis, reflecting the likely impact of a higher RPS in "crowding out" some voluntary purchases of Green Power.

Public Benefits Fund and Integrated Energy Services

The Administration's proposal calls for the creation of a public benefits fund of up to $3 billion annually, to be matched by States and used for energy efficiency programs, technology research projects, low-income assistance, and consumer education. In addition, with electricity suppliers competing to meet the needs of customers, they are likely to offer a full range of energy services in order to be competitive. Energy efficiency improvements are already being offered in some of the nascent retail competition areas. Together, these efficiency improvements are assumed to reduce electricity demand by roughly 150 billion kilowatthours in 2010 relative to the reference case projection.

The Competitive Scenario was developed in the context of a $2 billion increment to annual baseline energy efficiency expenditures over the 2000 to 2010 period. The effectiveness of expenditures in reducing load is based on the average efficiency improvement per real dollar expended on utility demand-side management programs in the mid-1990s, based on information reported by EIA. Some believe that a focus on market transformation programs would result in greater cost-effectiveness in the future than has been seen in past programs. Such improved cost-effectiveness or additional expenditures in energy efficiency would further reduce electricity demand.

Distributed Power

The revised Administration proposal includes a package of provisions designed to promote the adoption of efficient combined heat and power and distributed generation technologies. It proposes the development of nationally applicable interconnection standards, clarification of depreciation treatment to assure that distributed generation installations are not subject to unfavorable schedules for the depreciation of structural components, and State-level consideration of stranded cost recovery mechanisms that do not impede cost-effective and energy-efficient combined heat and power projects. It also promises continued efforts by the Environmental Protection Agency and the Department of Energy to explore and implement regulatory approaches that recognize the environmental benefits of combined heat and power technologies.

Based on a review of more detailed analyses by others, the Competitive Scenario projects an increase in commercial and industrial cogeneration of roughly 100 billion kilowatthours over Reference Scenario levels by 2010. Part of the increased generation is used to reduce purchases of electricity, and part is sold over the grid.