Documentation of the Electricity Market Module (EMM)
Appendix: Model Developers Report

Prepared by:
Nuclear and Electricity Analysis Branch
Energy Supply and Conversion Division
Office of Integrated Analysis and Forecasting
Energy Information Administration

1. Introduction

1.1 Purpose of the Report

The Office of Integrated Analysis and Forecasting (OIAF) is required to provide complete model documentation to meet the EIA Model Acceptance Standards. The Model Documentation for the Electricity Market Module (EMM) provides a complete description of the EMM methodology, structure, and relation to other modules in the National Energy Modeling System (NEMS). This Model Developers Report (MDR) serves as an appendix to the methodology documentation. The MDR provides an assessment of the sensitivity of the EMM results to changes in input data or parameters.

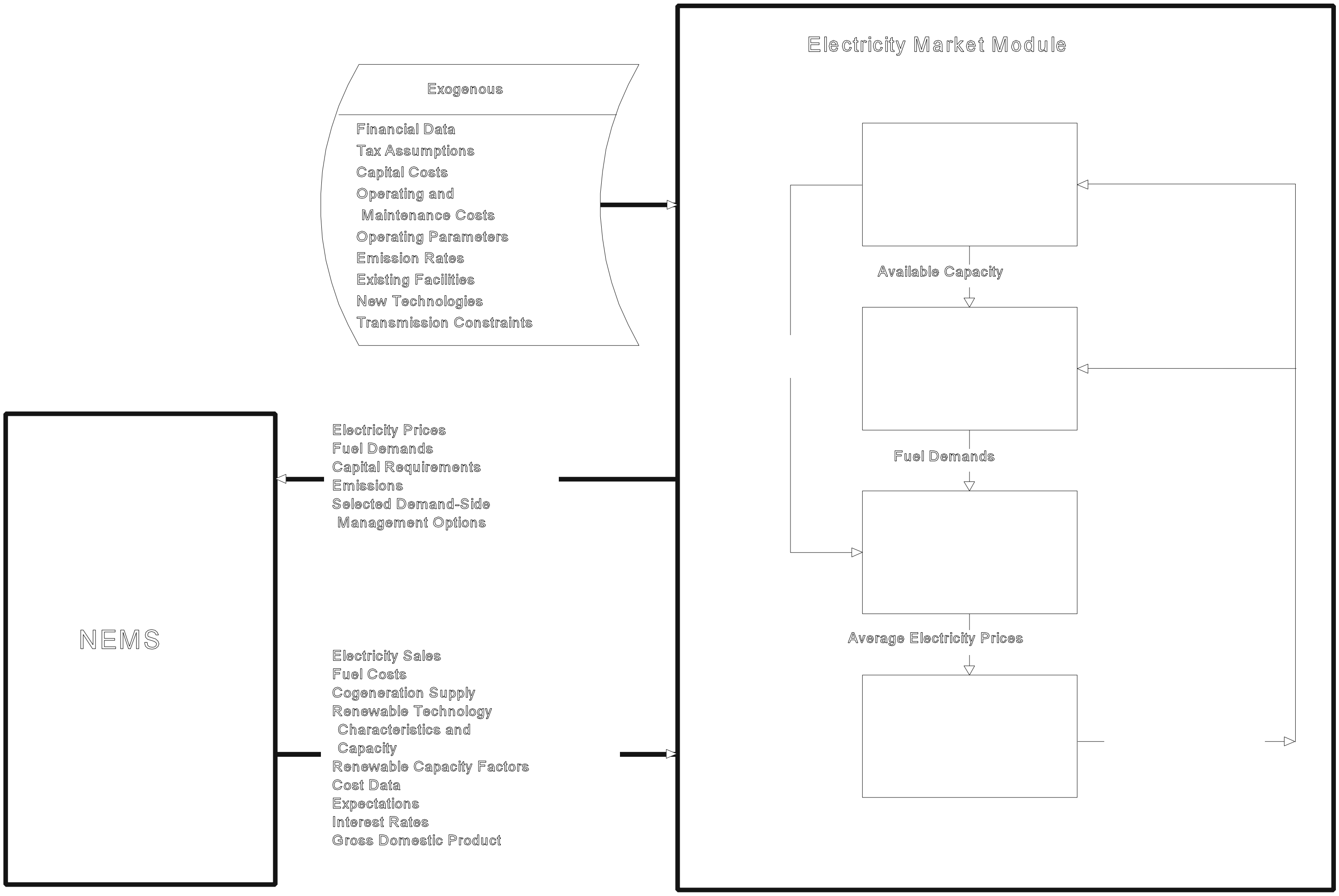
1.2 Model Summary

NEMS is a computer modeling system that produces a general equilibrium solution for energy supply and demand in the U.S. energy market. NEMS is structured as a modular system, which consists of four supply modules (oil and gas supply, natural gas transmission and distribution, coal, and renewable fuels), two conversion modules (electricity and petroleum refineries), four demand modules (residential, commercial, transportation, and industrial), two modules to simulate world energy/domestic energy interaction (macroeconomic and international energy), and one module to provide the mechanism that achieves a general market equilibrium among all the modules (the integrating module). This report focuses on the EMM run in a standalone rather than the integrated version.

The EMM is the electricity supply component of NEMS. The supply of electricity is a conversion activity, since electricity is produced from other energy sources (e.g., fossil, nuclear, and renewable). The EMM represents the generation, transmission, and pricing of electricity. The EMM consists of four main submodules: Electricity Capacity Planning (ECP), Electricity Fuel Dispatching (EFD), Electricity Finance and Pricing (EFP), and Load and Demand-Side Management (LDSM). The ECP submodule evaluates changes in the mix of generating capacity that are necessary to meet future demands for electricity and comply with environmental regulations. The EFD submodule represents dispatching (i.e., operating) decisions and determines how to allocate available capacity to meet the current demand for electricity. Using investment expenditures from the ECP and operating costs for the EFD, the EFP submodule calculates the price of electricity, accounting for State-level regulations involving the allocation of costs. The LDSM submodule translates annual demands for electricity into distributions that describe hourly, seasonal, and time-of-day variations. These distributions are used by the EFD and the ECP to determine the quantity and types of generating capacity that are required to ensure reliable and economical supplies of electricity. The EMM also represents nonutility suppliers and interregional and international transmission and trade. These activities are included in the EFD and the ECP.

This report focuses on the responsiveness of selected output variables of the EMM, given changes to key input variables. The analytical approach in the MDR includes a one-at-a-time sensitivity analysis. First, a reference case based on the Annual Energy Outlook 1995 (AEO95) is established for the analysis. Selected input data to the EMM are varied from the reference case, and the impact of these variations on key EMM outputs is examined. The EMM MDR is based on standalone rather than integrated NEMS runs. Figure 1, on the following page, shows the interaction between the EMM and the other NEMS modules. In the standalone version, all data and feedback that are input from modules outside the EMM are read from the restart file of the reference case. The implication of running the standalone version is that the feedback from other modules is not incorporated into the decisions made by the EMM. For example, except for Test 1, where the electricity demand is varied (see page 6), the annual demand is read from the restart file of the reference case so that the demand in future years is not impacted by decisions made by the EMM for the current year. However, the scenario analysis performed with the standalone EMM meets the principal intent of the MDR: to assess the performance characteristics of the EMM. The test results from the standalone version of the EMM indicate the sensitivity of the output when all input parameters from exogenous modules are held constant.

Figure 1. Electricity Market Module Structure



1.3 Properties of the EMM

- Solution Methodology

The ECP submodule of the EMM employs a linear programming (LP) formulation; the other three submodules are process models.

The solution methodology to the ECP submodule uses a variant of the simplex algorithm. Convergence of the ECP is assured, provided the feasible domain is non-empty and bounded. The LP algorithm is finite (must terminate) because there are a finite number of vertices to examine on the convex polyhedron defined by the constraints and bounds. Consequently, for a non-empty constraint set, convergence within the ECP is never an issue nor is it relevant, since the algorithm within the ECP used to solve the model is finite.

In practice, the ECP typically produces unique solutions. However, it is possible for a specific set of assumptions to produce a non-unique solution. For any LP, one of the following statements is true when the feasible space is bounded:

(a) there is no solution when the feasible region is empty;

(b) there is exactly one solution if the hyperplane defining the linear objective function intersects the polyhedra at a corner point of optimality;

(c) there are an infinite number of solutions if the hyperplane defining the objective function is coincident with a line segment on the polyhedron at optimality.

The model requires no estimate of the current-year solution to compute the solution to the EMM, since the current-year solution depends only on the values of the solution in the previous year plus the current economic conditions and other inputs from the rest of NEMS.

LP models can exhibit "knife-edge" solution tendencies; that is, small changes in a cost or efficiency assumption can change the mix and levels of the decision variables. When the dual solutions are explicitly used in NEMS, discontinuities may occur in them with small changes to the primal[1]. Such discontinuities are far more likely when the LP formulation is simplistic and does not capture the complexities of the market being modeled. Recognizing that potential pitfall, the ECP represents

---

[1] Every linear programming problem has associated with it another linear programming problem known as the dual. The term primal is used to refer to the original linear programming problem. For a thorough discussion of duality theory see Chapter 6 of Hillier and Lieberman's book, *Introduction to Operations Research*, 1986, Holden Day, Stanford, CA.

sufficient complexity of the market to avoid most occurrences of discontinuities.

In addition, the LP model in the EMM has been augmented by a market-sharing algorithm, which adjusts the planning decisions determined by the LP. Each decision variable that is not selected by the LP model is characterized by a "reduced cost," which describes the cost reduction that would be required for a given option to be most economical. The market-sharing algorithm then reallocates the decisions from the LP model among those options that are "competitive."[2] This algorithm eliminates the "all-or-nothing" decisions that lead to large changes in the results due to small changes in cost or performance characteristics.

The solution methodology of the EFP, EFD, and LDSM submodules of the EMM is a direct, one-pass computation of linear and non-linear systems to develop the load curves, electricity rates, generation costs, and avoided costs parameters. Consequently, convergence of these submodules within the EMM is not a relevant issue, since these processes are not iterative.

- Theoretical Considerations

Because of the nature of the LP solution algorithm in the ECP submodule and because all of the functions in all the other submodules of the EMM are linear, continuous, and differentiable in the domain of applicability of the model (that is, when "reasonable and consistent inputs" are provided in the model), the model always produces a solution. Uniqueness cannot be assured, however. Non-uniqueness is not usually problematic for this model. However, non-uniqueness or near non-uniqueness of any model can slow convergence of the entire NEMS system. Convergence of an individual LP model is not an issue (provided the feasible region is non-empty and bounded). Some of the inputs to the model may be correlated, and if inconsistent pairs of such inputs or negative prices are chosen, then the model may produce silly results. This behavior, however, is consistent with the well-known reality in computer models, "garbage in-garbage out." When the model is run in a standalone fashion, the user must be certain that the inputs are consistent and reliable.

In the EMM, a decision that is not chosen by the LP model is considered competitive if its reduced cost is within 20 percent of its actual cost. The market-sharing algorithm will be described in the forthcoming documentation of the Electricity Capacity Planning Submodule for the AEO95.

2. Methodology

2.1 Variations of the Input Variables

The following key input variables were chosen to test the sensitivity of the EMM. For each variable the variation from the reference case is given as well as the reasoning behind the choice. Figure 2 at the end of this section summarizes the percentage change from the reference case for the six input variables chosen.

- Test 1: Electricity Demand

Test 1 measures the sensitivity of the model to sustained changes in electricity demand. The average annual growth rate for electricity demand was decreased by 0.5 percentage points in the "Low" case and increased by 0.5 percentage points in the "High" case. In the AEO95 reference case, the demand for electricity grew at an average annual rate of 1.1 percent per year. The variation chosen for Test 1 exceeds the range observed in the AEO95, as the minimum growth rate was 0.8 percent per year in the Low Economic Growth case and the maximum rate was 1.4 percent per year in the High Economic Growth case.

- Test 2: Fuel Prices

Generation costs have four components: fuel prices, technology capital costs, variable operations and maintenance (O&M) costs, and fixed O&M costs. The first two are the most important. Test 2 changes the delivered fuel prices for coal and natural gas simultaneously and leaves all other generation costs the same as in the reference case. Because fuel prices make up only one component of the total generation costs, the impact is much more dramatic for natural gas than for coal. This is because fuel prices make up approximately two-thirds of the generation costs for gas-fired plants and approximately one-third of the generation costs for coal steam plants. Therefore, varying the fuel costs of both fuels by 10 percent will vary the generation costs of gas-fired plants by 6.6 percent and vary the generation costs of coal steam plants by 3.3 percent.

Test 2 examines changes in the average generation costs of coal-fired and gas-fired plants as a result of adjustments to their respective fuel costs. In the "Low" case, the delivered fuel prices for coal and natural gas are decreased simultaneously by 10 percent beginning in the year 2000. In the "High" case, the corresponding prices are increased simultaneously by 10 percent beginning in 2000. Between 1995 and 2000, the adjustments are phased in linearly (i.e., 2 percent different in 1996, 4 percent in 1997, etc.) to prevent a large deviation (i.e., cliff/valley) in prices during the initial years of the period. The fuel prices of coal and natural gas were chosen because these two fuels compete for the majority of the baseload generation on a national scale. Other fuels, such as oil, are considered marginal fuels and are used primarily to meet peak load demands.

- Test 3: Technology Capital Costs

This test examines the sensitivity of planning decisions and fuel choice decisions to variations in the average generation costs that result from adjustments to capital costs. The costs of building new coal-fired steam and combined-cycle units are adjusted simultaneously. In the "Low" case, the costs for new coal-fired steam and combined-cycle capacity are decreased by 10 percent. In the "High" case, these costs are increased by 10 percent.

- Test 4: Interest Coverage Ratio

Tests 4, 5, and 6 all look at the sensitivity of the model to variations in the financial structure for utilities. The interest coverage ratio is defined as the earnings before interest and taxes divided by the interest expenses. In the model structure, the interest coverage ratio has been modified to include purchase power payments as debt, and a minimum target ratio is specified. The minimum interest coverage ratio is used to limit the amount of capacity that utilities can purchase from nonutilities. In the reference case the ratio is assumed to be 2.15. In the "Low" case a ratio of 1.8 is used, and in the "High" case a ratio of 2.5 is used. A lower allowable interest coverage ratio lets a utility acquire more debt in relation to profits for a fixed interest rate. Likewise a higher interest coverage ratio should limit the acquisition of more debt. The purpose of this test is to examine the variations in utility versus nonutility planning as a result of a higher or lower interest coverage ratio.

- Test 5: Cost of Equity

Tests 5 and 6 both vary the discount rate used for planning decisions, which is the after-tax, weighted-average cost of capital (i.e., the average cost of equity and debt financing). In order to examine the impact of changes to the cost of capital used to finance new investments, the cost of equity is revised. The cost of equity is decreased by 1.0 percentage point in the "Low" case and is increased by 1.0 percentage point in the "High" case. Because the cost of equity varies by region, the percentage change from the reference case reported in Figure 2 is the weighted average for all the regions. The weights are calculated using the total assets of each region.

- Test 6: Capital Structure

In the EMM, it is assumed that the current capital structure, which is approximately 50 percent debt and 50 percent equity, is maintained throughout the forecast horizon. This test examines the model's sensitivity to changes in the capital structure by the variation in the debt/equity shares. In the "Low" case the equity share is reduced by 10 percentage points, which corresponds to an increase of 10 percentage points in the debt share. In the "High" case, the equity share is increased by 10 percentage points, which corresponds to a decrease in the debt share by 10 percentage points. This test also results in changes to the average cost of capital and the discount rate for planning decisions, although the costs of debt and equity financing are not modified from the reference case.

Figure 2. Summary of Input Changes for the EMM MDR

Test	Input Variable	Percentage Change from the Reference Case	
		Low	High
1	Electricity Demand	-0.50	0.50
2	Fuel Prices	-10.00	10.00
3	Technology Capital Costs	-10.00	10.00
4	Interest Coverage Ratio	-16.28	16.28
5	Cost of Equity	-23.47	23.47
6	Capital Structure	-10.00	10.00

2.2 Output Variables of Interest

- Generation by Fuel Type
- Fuel Consumption by Fuel Type
- Cumulative Unplanned Additions by Ownership Type
- Electricity Prices

When adding capacity the model seeks the least cost solution. As described in Test 4, a minimum interest coverage ratio is used as a constraint to limit the amount of capacity a utility can purchase from a nonutility. The model determines the split between utility and nonutility ownership of new additions, depending upon the tightness of this constraint for each region. Tests 1-3 do not alter the interest coverage ratio, and therefore the more important output variables are total unplanned additions and the changes in technology choices for new additions. Test 4 varies the interest coverage ratio in order to test the sensitivity of this constraint on ownership type. Tests 5-6 change the costs of financing new plants, which indirectly affect the interest coverage ratio. Therefore, for tests 4-6, the change in ownership type is more important than the technology choice. For completeness we have chosen to report cumulative unplanned additions by technology choice separately for utilities and nonutilities as well as the total for all six tests.

The chosen variables were selected as those that generally are of primary interest to the largest segment of the analysis community.

3. Test Results

The results from each test are accompanied by a series of tables and graphs, which are located in the Appendix of this report. The tables show the variation in each of the output variables as a result of each test. The graphs provide a useful basis for comparing the impact on a selected output variable as it is effected by each test change in turn.

There are 6 sets of tables, one for each input variable test. Each table contains the selected output variables for the years 2000 and 2010. The results are arranged in a set of three displays, designated A, B, and C. The A table shows the levels for each output variable. The B table shows the percentage change between the test result and the reference case. The percentages are relative to the specific output variable, so that comparisons among different output variables should be made by considering both tables A and B. For example, a 3-percent variation from the reference case for coal generation is larger in terms of billion kilowatthours than is a 30- percent variation from the reference case for oil generation. This is because coal generation is roughly 20 times larger than oil generation. Lastly, the C table presents the ratio of percentage change in each output variable to the percentage change in the input variable as an indication of the relative sensitivity of the model. The sign of the number in the C table indicates the direction of the variation. A positive sign means that the output variable shifted in the same direction as the input variable. A negative sign indicates that the output variable shifted in the opposite direction from the input variable.

There are 11 sets of graphs, one for each selected output variable. The graphs show the sensitivity of a selected output variable to each of the different tests. The percentage difference between the test results and the reference case for each output variable is graphed as a function of time. Graph sets 1 through 7, and 11 have two graphs in each set. Graphs sets 8, 9, and 10 have four graphs. Each graph in the set shows the results from three tests on a selected output variable. This disaggregated presentation is intended to avoid obscuring the results, which would be likely if the results from all six tests were displayed in a single graph.

3.1 Input Variable Test Results

- Test 1: Electricity Demand (Tables 1A,1B,1C)

Table 1C shows that changes in electricity demand lead to proportional changes in total generation and consumption. Unplanned additions were highly sensitive to changes in the electricity demand. For total unplanned additions the ratio of percentage change in unplanned additions to percentage change in electricity demand was 11:1 in the high case and 10:1 in the low case. This high sensitivity is due to the way the EMM forecasts future demand. The steady change implemented by the test for the years 1996-2010 is expected to continue beyond 2010. Therefore the model is planning for the future. The variation in electricity prices did not include fuel price impacts because these tests were standalone runs with the supply modules turned off. It is expected that in the fully integrated model variations in electricity demand would have a greater impact on electricity prices.

- Test 2: Fuel prices (Tables 2A,2B,2C)

As expected, Test 2 had the greatest impact on the fuel mix and caused only minor variations in total generation, total consumption, and total unplanned additions. Oil consumption and generation was more sensitive to Test 2 than any other fuel type because oil is the marginal fuel used to satisfy baseload capacity after coal and natural gas. In the High case, oil displaced natural gas. In the Low case, natural gas displaced all other fuel types. The choice of technologies for unplanned additions was also sensitive to variations in fuel prices. In the AEO95, capital costs for coal steam plants varied from $1,213 to $1,345 per kilowatt, compared with $486 per kilowatt for a combined-cycle plant. When natural gas prices are low, the model chooses to build gas-fired plants instead of coal steam plants, because the fuel price of natural gas is low enough that when combined with the savings in capital costs, the long-run average generation costs for a gas-fired plant are lower than the long-run average generation costs for a coal steam plant. When natural gas and coal prices are high, then coal steam plants are built instead of gas-fired plants, because the high capital cost of a coal plant is more economical, in terms of long-run average costs, than the sustained high fuel price for natural gas. Table 2B shows that in 2010 total unplanned coal additions were 51 percent below the reference case for the Low case, while combined-cycle additions increased by 53 percent. The opposite happened in the High case; coal additions increased by 37 percent and combined-cycle additions decreased by 34 percent. The shift in the High case was to a smaller magnitude, because only the fuel costs of natural gas and coal were raised, allowing oil to become more competitive. Electricity prices have a direct correlation with fuel prices, varying by 2 percent with a 10-percent change in fuel prices (Table 2B). The impact was relatively minor since fuel prices are only one component of the electricity prices, and the feedback from the supply and demand modules was turned off in the standalone runs.

- Test 3: Technology Capital Costs (Tables 3A,3B,3C)

Variations in the technology capital costs had a small impact on generation and consumption. Table 3B shows that the total generation and consumption varied by at most 1 percent for both cases. Renewables showed a modest 2-percent increase in generation, which replaced some coal generation. This competition between the two capital-intensive fuels, renewables and coal, parallels the competition between oil and gas in Test 2. The total number of additions was insensitive to variations in capital costs. However, in the High case utilities chose to build combined-cycle and renewable plants in place of coal steam plants. Table 3A shows that changes for nonutilities were more moderate in terms of gigawatts of unplanned capacity. However, the large percentages reported in Table 3B are due to the differences in magnitude for utilities and nonutilities. A 17-percent change in unplanned utility coal steam additions is larger in total gigawatts than a 37-percent change in nonutility coal additions.

- Test 4: Interest Coverage Ratio (Tables 4A,4B,4C)

When utilities have a lower interest coverage ratio, the limit on the amount of debt they can assume is increased; therefore, utilities can acquire more capacity from nonutilities. As expected, when the interest coverage ratio was decreased by 16 percent, total nonutility additions increased by 17 percent in 2010 and total utility additions decreased by 24 percent. This was a reversal of what occurred when the interest coverage ratio was increased by 16 percent. In that scenario, utility additions increased by 22 percent in the year 2010 and nonutility additions decreased by 19 percent.

- Test 5: Cost of Equity (Tables 5A,5B,5C)

Tests 5 and 6 both vary the discount rate used for planning decisions. A lower cost of equity favors utility additions. Table 5B shows that for both the High and Low cases the total gigawatts of unplanned capacity varied by 1 percent. However, there were much larger variations in the ownership types. This is because of the current capital structure, where nonutilities have a capital structure of 20 percent equity and 80 percent debt whereas utilities have an equal 50/50 split between debt and equity. Therefore, raising the cost of equity highly favors nonutility additions. To a lesser extent, because the discount rate is the weighted average cost of debt and equity, lowering the cost of equity will favor utility additions.

- Test 6: Capital Structure (Tables 6A,6B,6C)

A change in the capital structure has an effect similar to that seen in Test 5. In the Low case the capital structure is 40 percent equity and 60 percent debt. This reduces the cost of equity and favors utility additions. The model was less sensitive to changes in capital structure than it was to changes in cost of equity, because changing the cost of equity by 1 percent varied the discount rate by 0.5 percent from the reference case, while changing the capital structure varied the discount rate by 0.3 percent. This is demonstrated visually by comparing the shapes of Test 5 and Test 6 on Graph 9B. The shapes are nearly identical, but the magnitudes are different. As expected, Test 6 had a greater impact on the ownership of new additions than on the technology choice for new additions. Table 6A shows that both cases showed a slight increase in the total number of unplanned additions: 3 percent and 2 percent in 2010, for the Low and High cases, respectively. However, the split between utility and nonutility ownership for a particular case followed the expected pattern: in the Low case, total utility ownership increased from the reference case while total nonutility ownership decreased from the reference case, whereas the opposite occurred in the High case.

3.2 Output Variable Test Results

- Sensitivity of Generation

Graphs:
1. Coal Generation (Graphs 1A,1B)
2. Natural Gas Generation (Graphs 2A,2B)
3. Oil Generation (Graphs 3A,3B)
4. Renewable Generation (Graphs 4A,4B)

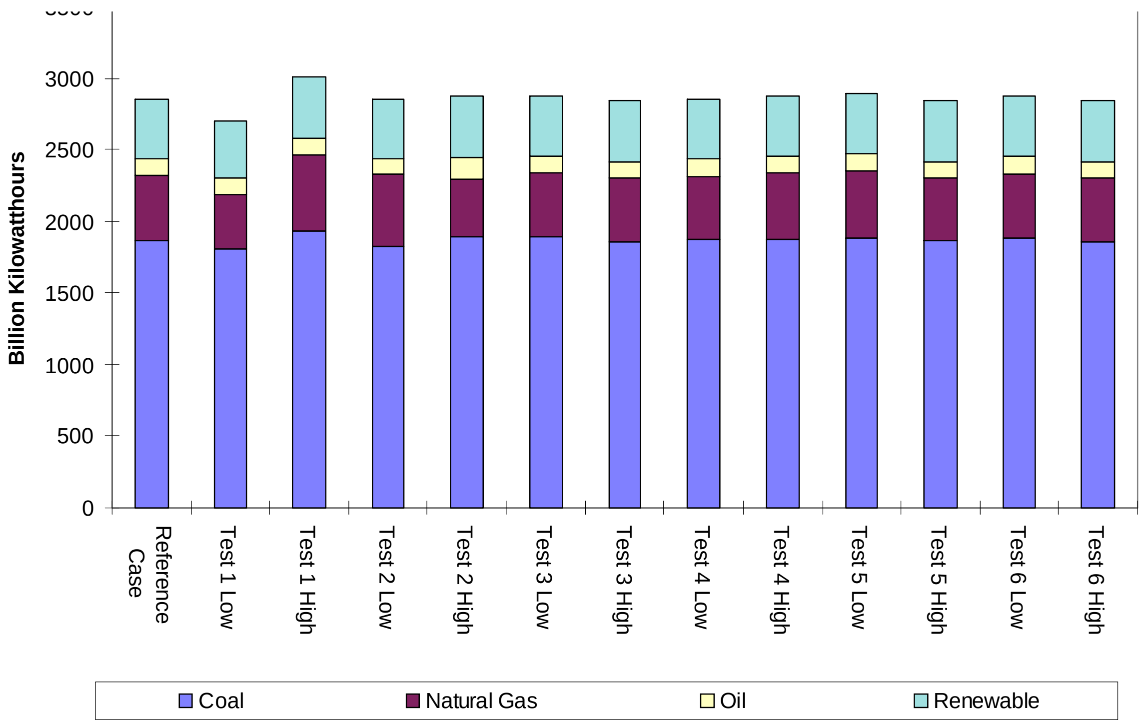
In the EMM, the total generation is directly proportional to electricity demand. Therefore, except for Test 1, which varied the electricity demand, the change in total generation was small for all other tests. Figure 3 demonstrates how stable total generation remains for all tests that do not affect the demand. The height of the bar represents the total generation in the year 2010 for the High and Low cases of all six tests as well as the reference case. This was expected in the standalone run because demand is determined outside the EMM. A more interesting measure is the variation in the fuel mix. Oil generation is the most sensitive of all fuel types, varying by as much as 40 percent from the reference case. However, Figure 3 shows that it is difficult to compare the relative percentages between different fuel types. In the graphs at the end of this report, graph set 3 shows that oil generation varied by as much as 33 percent in the year 2010, whereas graph set 1 shows that coal generation never varied by more than 4 percent. Comparing the height of changes in coal and oil generation in Figure 3 shows that a 30-percent change in oil generation is about the same in terms of billion kilowatthours as a 3-percent change in coal generation. However, the sensitivity of oil is significant since oil is the marginal fuel and is used after coal and natural gas to fill baseload capacity.

- Sensitivity of Consumption

Graphs:
5. Coal Consumption (Graphs 5A,5B)
6. Natural Gas Consumption (Graphs 6A,6B)
7. Oil Consumption (Graphs 7A,7B)

Changes in consumption mirrored the changes in generation for all tests and fuel types. This is expected and indicates that the model is using all of its generation to meet demand.

Figure 3: Generation by Fuel Type for the Year 2010



- Sensitivity of Unplanned Capacity Additions

Graphs:
8. Unplanned Utility Additions (Graphs 8A,8B,8C,8D)
9. Unplanned Nonutility Additions (Graphs 9A,9B,9C,9D)
10. Total Unplanned Additions (Graphs 10A,10B,10C,10D)

Graph sets 8, 9, and 10 each contain four graphs. Graph A indicates the changes in total unplanned addition by ownership type for tests 1, 2, and 3. Graph B is for tests 4, 5, and 6. As expected, the total combined number of additions (Graphs 10A, 10B) show little variation from the base case for all tests except Test 1. This is because the number of unplanned additions is linked to the electricity demand. The major variations occurred in the ownership of new additions. Graph sets 8 and 9 show the tradeoff between total utility and nonutility additions. Additional graphs C for tests 1, 2, and 3 and D for tests 5, 6, and 7 are added to each graph set to show how the fuel mix changes for each addition, where combustion turbine and combined cycle are combined to represent gas-fired additions. Graphs C and D give the additions in total gigawatts for each fuel type. These graphs show how sensitive each fuel type is to the different tests. A comment is needed on the sharp decrease in utility additions that Graph 8A shows for the last three years of the High case in Test 1. Even though the relative percentage fell for total utility additions, the actual gigawatts built increased for the years 2007 through 2010, as can be seen for the year 2010 in Graph 8C.

- Sensitivity of Electricity Prices

Graphs:
11. Electricity Prices (Graphs 11A,11B)

The price of electricity never varies by more than 3 percent from the reference case. Graphs 11A and 11B also show that for each of the tests the slope of the graph is nearly zero, indicating that the price of electricity increased or decreased at the same rate as the reference case.

Conclusions

The results of the MDR analysis of the EMM generally conform to expectations regarding the direction and relative magnitude of changes. This demonstrates the stability of the model and the methodology. Findings of the analysis include:

- Generation costs appear to be more important than the capital structure in determining model results. The model was much more sensitive to Tests 1-3, which changed the actual generation costs, than it was to Tests 4-6, which varied the financial structure for new investments. However, because the magnitudes of the variations differed in each of the tests, an exact comparison cannot be made between Tests 1-3 and 4-6.

- Electricity prices showed little variation, for two main reasons: (1) the model was run in a standalone rather than integrated version, and (2) the electricity price is regulated and the model reflects this regulatory structure, which protects against large increases and decreases.

- Generation and consumption varied in the same direction and magnitude for all input variations.

- The capital structure for nonutilities, which heavily weights debt instead of equity, encourages utilities to use nonutilities to add capacity. The model currently uses the after-tax, weighted-average cost of capital for planning decisions because it reflects the current regulatory structure. These decisions may have to be reconsidered in a competitive environment.

- Electricity demand drives the decisions concerning the quantities of generation by fuel type, fuel consumption, and capacity additions. However, it is the EMM that determines the fuel mix that fulfills the required demand levels.

The EMM is "well behaved" in that the levels of and changes in results are reasonable. The EMM MDR will be a valuable tool in analyzing integrated runs since it gives the magnitude and direction of output shifts caused by input variations. In this way the effects of other modules can be better gauged.

Charts and Graphs

Pages A-1 through A-32 contains the charts and graphs as listed in Section 3 of this report.

Table 1A. **Sensitivity Analysis: Variation in Electricity Demand**

Output Variable	2000 Low Case	2000 Reference Case	2000 High Case	2010 Low Case	2010 Reference Case	2010 High Case
Generation by Fuel Type[1]						
(billion kilowatthours)						
Coal	1679.05	1699.18	1717.88	1811.48	1868.18	1928.29
Natural Gas	298.32	333.38	362.69	376.27	447.87	530.68
Oil	73.42	81.87	90.12	110.13	116.98	120.78
Renewable	366.26	366.22	367.76	401.40	420.04	428.29
Total	2417.06	2480.65	2538.47	2699.27	2853.08	3008.03
Fuel Consumption[1]						
(trillion Btu)						
Coal	17.16	17.39	17.59	18.54	19.12	19.70
Natural Gas	3.02	3.37	3.69	3.88	4.54	5.37
Oil	0.86	0.95	1.05	1.27	1.35	1.40
Total	21.04	21.71	22.33	23.68	25.00	26.47
Cumulative Unplanned Additions[2]						
(gigawatts)						
Utilities						
Coal Steam	0.00	0.00	0.00	5.23	8.03	13.41
Combined Cycle	1.43	1.41	1.94	2.84	5.65	9.67
Combustion Turbines	0.71	0.79	1.00	2.46	7.69	14.38
Renewable	0.15	0.15	0.21	2.04	3.18	3.96
Total	2.28	2.34	3.15	12.57	24.54	41.42
Nonutilities[3]						
Coal Steam	0.00	0.00	0.00	0.93	4.28	7.31
Combined Cycle	1.48	1.99	2.00	3.01	6.76	10.30
Combustion Turbines	0.60	1.07	1.84	6.43	11.90	18.44
Renewable	2.50	2.50	2.66	7.29	10.61	13.42
Total	4.57	5.56	6.50	17.65	33.55	49.47
Total						
Coal Steam	0.00	0.00	0.00	6.16	12.32	20.72
Combined Cycle	2.91	3.39	3.93	5.85	12.40	19.97
Combustion Turbines	1.30	1.85	2.84	8.89	19.59	32.82
Renewable	2.64	2.65	2.88	9.33	13.79	17.39
Total	6.85	7.89	9.65	30.23	58.10	90.89
Electricity Price						
(1992 cents per kilowatthours)	6.75	6.76	6.77	6.97	7.10	7.28

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 1B. **Sensitivity Analysis: Variation in Electricity Demand Percentage Changes from Reference Case**

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	-1	1	-3	3
Natural Gas	-11	9	-16	18
Oil	-10	10	-6	3
Renewable	0	0	-4	2
Total	-3	2	-5	5
Fuel Consumption[1]				
Coal	-1	1	-3	3
Natural Gas	-11	9	-15	18
Oil	-10	10	-6	4
Total	-3	3	-5	6
Cumulative Unplanned Addition				
Utilities				
Coal Steam	0	0	-35	67
Combined Cycle	2	38	-50	71
Combustion Turbines	-10	27	-68	87
Renewable	-1	46	-36	25
Total	-2	35	-49	69
Nonutilities[3]				
Coal Steam	0	0	-78	71
Combined Cycle	-26	1	-56	52
Combustion Turbines	-44	73	-46	55
Renewable	0	6	-31	26
Total	-18	17	-47	47
Total				
Coal Steam	0	0	-50	68
Combined Cycle	-14	16	-53	61
Combustion Turbines	-30	53	-55	68
Renewable	0	8	-32	26
Total	-13	22	-48	56
Electricity Price				
	0	0	-2	2

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 1C. **Sensitivity Analysis: Ratio of Percentage Change in Relative to Percentage Change in Electricity Demanc**

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0.2	0.2	0.6	0.6
Natural Gas	2.1	1.8	3.2	3.7
Oil	2.1	2.0	1.2	0.6
Renewable	0.0	0.1	0.9	0.4
Total	0.5	0.5	1.1	1.1
Fuel Consumption[1]				
Coal	0.3	0.2	0.6	0.6
Natural Gas	2.1	1.9	2.9	3.7
Oil	1.9	2.0	1.2	0.7
Total	0.6	0.6	1.1	1.2
Cumulative Unplanned Additions[2]				
Utilities				
Coal Steam	0.0	0.0	7.0	13.4
Combined Cycle	-0.4	7.5	9.9	14.3
Combustion Turbines	2.0	5.4	13.6	17.4
Renewable	0.1	9.2	7.2	5.0
Total	0.5	6.9	9.8	13.8
Nonutilities[3]				
Coal Steam	0.0	0.0	15.6	14.1
Combined Cycle	5.1	0.1	11.1	10.5
Combustion Turbines	8.8	14.6	9.2	11.0
Renewable	0.1	1.3	6.3	5.3
Total	3.5	3.4	9.5	9.5
Total				
Coal Steam	0.0	0.0	10.0	13.6
Combined Cycle	2.8	3.2	10.6	12.2
Combustion Turbines	5.9	10.7	10.9	13.5
Renewable	0.1	1.7	6.5	5.2
Total	2.6	4.4	9.6	11.3
Electricity Price	0.0	0.0	0.4	0.5

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 2A. **Sensitivity Analysis: Variation in Fuel Prices[4]**

Output Variable	2000			2010		
	Low Case	Reference Case	High Case	Low Case	Reference Case	High Case
Generation by Fuel Type[1]						
(billion kilowatthours)						
Coal	1696.42	1699.18	1698.43	1828.16	1868.18	1896.53
Natural Gas	341.33	333.38	313.98	502.43	447.87	392.32
Oil	76.95	81.87	102.06	108.56	116.98	154.54
Renewable	365.97	366.22	366.22	410.10	420.04	426.76
Total	2480.68	2480.65	2480.68	2849.24	2853.08	2870.15
Fuel Consumption[1]						
(trillion Btu)						
Coal	17.35	17.39	17.37	18.74	19.12	19.39
Natural Gas	3.47	3.37	3.17	5.00	4.54	3.99
Oil	0.90	0.95	1.16	1.26	1.35	1.75
Total	21.72	21.71	21.70	25.00	25.00	25.13
Cumulative Unplanned Additions[2]						
(gigawatts)						
Utilities						
Coal Steam	0.00	0.00	0.00	3.86	8.03	10.91
Combined Cycle	1.43	1.41	2.11	7.25	5.65	4.40
Combustion Turbines	0.82	0.79	0.74	7.26	7.69	9.38
Renewable	0.12	0.15	0.16	2.44	3.18	3.96
Total	2.37	2.34	3.01	20.80	24.54	28.64
Nonutilities[3]						
Coal Steam	0.00	0.00	0.00	2.14	4.28	5.97
Combined Cycle	1.91	1.99	1.45	11.77	6.76	3.73
Combustion Turbines	1.11	1.07	0.95	12.75	11.90	12.30
Renewable	2.46	2.50	2.49	8.91	10.61	11.38
Total	5.47	5.56	4.89	35.57	33.55	33.39
Total						
Coal Steam	0.00	0.00	0.00	6.00	12.32	16.88
Combined Cycle	3.34	3.39	3.55	19.02	12.40	8.13
Combustion Turbines	1.93	1.85	1.69	20.01	19.59	21.67
Renewable	2.57	2.65	2.65	11.34	13.79	15.34
Total	7.84	7.89	7.89	56.37	58.10	62.03
Electricity Price						
(1992 cents per kilowatthours)						
[4]Only natural gas and coal prices wer	6.64	6.76	6.88	6.96	7.10	7.27

[1]Includes utilities and nonutilities, excluding cogenerators.

[2]Cumulative additions after December 31, 1990.

[3]Excludes cogenerators

Table 2B. **Sensitivity Analysis: Variation in Fuel Prices[4]**
Percentage Changes from Reference Case

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0	0	-2	2
Natural Gas	2	-6	12	-12
Oil	-6	25	-7	32
Renewable	0	0	-2	2
Total	0	0	0	1
Fuel Consumption[1]				
Coal	0	0	-2	1
Natural Gas	3	-6	10	-12
Oil	-6	22	-7	29
Total	0	0	0	0
Cumulative Unplanned Addition:				
Utilities				
Coal Steam	0	0	-52	36
Combined Cycle	2	50	28	-22
Combustion Turbines	5	-5	-6	22
Renewable	-21	8	-23	25
Total	1	29	-15	17
Nonutilities[3]				
Coal Steam	0	0	-50	39
Combined Cycle	-4	-27	74	-45
Combustion Turbines	4	-11	7	3
Renewable	-2	0	-16	7
Total	-2	-12	6	0
Total				
Coal Steam	0	0	-51	37
Combined Cycle	-1	5	53	-34
Combustion Turbines	4	-9	2	11
Renewable	-3	0	-18	11
Total	-1	0	-3	7
Electricity Price	-2	2	-2	2

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators
[4]Only natural gas and coal prices were varied

Table 2C. **Sensitivity Analysis: Variation in Fuel Prices[4] Relative to Percentage Change in Fuel Prices**

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0.0	0.0	0.2	0.2
Natural Gas	-0.2	-0.6	-1.2	-1.2
Oil	0.6	2.5	0.7	3.2
Renewable	0.0	0.0	0.2	0.2
Total	0.0	0.0	0.0	0.1
Fuel Consumption[1]				
Coal	0.0	0.0	0.2	0.1
Natural Gas	-0.3	-0.6	-1.0	-1.2
Oil	0.6	2.2	0.7	2.9
Total	0.0	0.0	0.0	0.0
Cumulative Unplanned Additions[2]				
Utilities				
Coal Steam	0.0	0.0	5.2	3.6
Combined Cycle	-0.2	5.0	-2.8	-2.2
Combustion Turbines	-0.5	-0.5	0.6	2.2
Renewable	2.1	0.8	2.3	2.5
Total	-0.1	2.9	1.5	1.7
Nonutilities[3]				
Coal Steam	0.0	0.0	5.0	3.9
Combined Cycle	0.4	-2.7	-7.4	-4.5
Combustion Turbines	-0.4	-1.1	-0.7	0.3
Renewable	0.2	0.0	1.6	0.7
Total	0.2	-1.2	-0.6	0.0
Total				
Coal Steam	0.0	0.0	5.1	3.7
Combined Cycle	0.1	0.5	-5.3	-3.4
Combustion Turbines	-0.4	-0.9	-0.2	1.1
Renewable	0.3	0.0	1.8	1.1
Total	0.1	0.0	0.3	0.7
Electricity Price				
	0.2	0.2	0.2	0.2

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators
[4]Only natural gas and coal prices were varied

Table 3A. **Sensitivity Analysis: Variation in Technology Capital Costs**

Output Variable	2000 Low Case	2000 Reference Case	2000 High Case	2010 Low Case	2010 Reference Case	2010 High Case
Generation by Fuel Type[1]						
(billion kilowatthours)						
Coal	1699.29	1699.18	1699.29	1888.89	1868.18	1850.40
Natural Gas	333.18	333.38	333.16	450.63	447.87	447.33
Oil	82.08	81.87	82.09	117.58	116.98	116.17
Renewable	366.15	366.22	366.15	414.61	420.04	430.16
Total	2480.69	2480.65	2480.69	2871.71	2853.08	2844.07
Fuel Consumption[1]						
(trillion Btu)						
Coal	17.39	17.39	17.39	19.31	19.12	18.95
Natural Gas	3.37	3.37	3.37	4.54	4.54	4.54
Oil	0.95	0.95	0.95	1.36	1.35	1.34
Total	21.71	21.71	21.72	25.21	25.00	24.83
Cumulative Unplanned Additions[2]						
(gigawatts)						
Utilities						
Coal Steam	0.00	0.00	0.00	10.68	8.03	6.67
Combined Cycle	1.36	1.41	2.18	5.72	5.65	6.77
Combustion Turbines	0.74	0.79	0.84	6.99	7.69	7.66
Renewable	0.14	0.15	0.14	2.55	3.18	3.85
Total	2.23	2.34	3.16	25.95	24.54	24.95
Nonutilities[3]						
Coal Steam	0.00	0.00	0.00	5.54	4.28	2.68
Combined Cycle	2.09	1.99	1.16	7.98	6.76	5.37
Combustion Turbines	1.08	1.07	1.08	9.99	11.90	13.65
Renewable	2.49	2.50	2.49	9.53	10.61	12.53
Total	5.66	5.56	4.73	33.04	33.55	34.24
Total						
Coal Steam	0.00	0.00	0.00	16.22	12.32	9.35
Combined Cycle	3.45	3.39	3.35	13.70	12.40	12.14
Combustion Turbines	1.82	1.85	1.92	16.98	19.59	21.32
Renewable	2.63	2.65	2.63	12.08	13.79	16.38
Total	7.89	7.89	7.90	58.99	58.10	59.19
Electricity Price						
(1992 cents per kilowatthours)	6.76	6.76	6.76	7.08	7.10	7.12

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 3B. Sensitivity Analysis: Variation in Technology Capital Costs Percentage Changes from Reference Case

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0	0	1	-1
Natural Gas	0	0	1	0
Oil	0	0	1	-1
Renewable	0	0	-1	2
Total	0	0	1	0
Fuel Consumption[1]				
Coal	0	0	1	-1
Natural Gas	0	0	0	0
Oil	0	0	0	-1
Total	0	0	1	-1
Cumulative Unplanned Addition				
Utilities				
Coal Steam	0	0	33	-17
Combined Cycle	-4	55	1	20
Combustion Turbines	-6	7	-9	0
Renewable	-7	-7	-20	21
Total	-5	35	6	2
Nonutilities[3]				
Coal Steam	0	0	29	-37
Combined Cycle	5	-41	18	-21
Combustion Turbines	1	1	-16	15
Renewable	-1	-1	-10	18
Total	2	-15	-2	2
Total				
Coal Steam	0	0	32	-24
Combined Cycle	2	-1	10	-2
Combustion Turbines	-2	4	-13	9
Renewable	-1	-1	-12	19
Total	0	0	2	2
Electricity Price	0	0	0	0

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 3C. **Sensitivity Analysis: Ratio of Percentage Change in (**
Relative to Percentage Change in Technology Capita

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0.0	0.0	-0.1	-0.1
Natural Gas	0.0	0.0	-0.1	0.0
Oil	0.0	0.0	-0.1	-0.1
Renewable	0.0	0.0	0.1	0.2
Total	0.0	0.0	-0.1	0.0
Fuel Consumption[1]				
Coal	0.0	0.0	-0.1	-0.1
Natural Gas	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	-0.1
Total	0.0	0.0	-0.1	-0.1
Cumulative Unplanned Additions[2]				
Utilities				
Coal Steam	0.0	0.0	-3.3	-1.7
Combined Cycle	0.4	5.5	-0.1	2.0
Combustion Turbines	0.6	0.7	0.9	0.0
Renewable	0.7	-0.7	2.0	2.1
Total	0.5	3.5	-0.6	0.2
Nonutilities[3]				
Coal Steam	0.0	0.0	-2.9	-3.7
Combined Cycle	-0.5	-4.1	-1.8	-2.1
Combustion Turbines	-0.1	0.1	1.6	1.5
Renewable	0.1	-0.1	1.0	1.8
Total	-0.2	-1.5	0.2	0.2
Total				
Coal Steam	0.0	0.0	-3.2	-2.4
Combined Cycle	-0.2	-0.1	-1.0	-0.2
Combustion Turbines	0.2	0.4	1.3	0.9
Renewable	0.1	-0.1	1.2	1.9
Total	0.0	0.0	-0.2	0.2
Electricity Price				
	0.0	0.0	0.0	0.0

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 4A. Sensitivity Analysis: Variation in Interest Coverage Ratio

Output Variable	2000 Low Case	2000 Reference Case	2000 High Case	2010 Low Case	2010 Reference Case	2010 High Case
Generation by Fuel Type[1] (billion kilowatthours)						
Coal	1699.62	1699.18	1699.20	1870.39	1868.18	1869.02
Natural Gas	332.21	333.38	333.33	445.46	447.87	471.38
Oil	81.95	81.87	82.16	115.44	116.98	117.71
Renewable	366.93	366.22	365.99	422.01	420.04	415.59
Total	2480.71	2480.65	2480.67	2853.30	2853.08	2873.71
Fuel Consumption[1] (trillion Btu)						
Coal	17.39	17.39	17.39	19.13	19.12	19.13
Natural Gas	3.36	3.37	3.38	4.52	4.54	4.78
Oil	0.95	0.95	0.96	1.34	1.35	1.36
Total	21.70	21.71	21.72	24.99	25.00	25.27
Cumulative Unplanned Additions[2] (gigawatts)						
Utilities						
Coal Steam	0.00	0.00	0.00	5.44	8.03	9.74
Combined Cycle	1.62	1.41	1.74	4.52	5.65	7.06
Combustion Turbines	0.90	0.79	1.07	6.03	7.69	8.60
Renewable	0.13	0.15	0.14	2.77	3.18	4.59
Total	2.65	2.34	2.96	18.76	24.54	29.98
Nonutilities[3]						
Coal Steam	0.00	0.00	0.00	7.31	4.28	2.52
Combined Cycle	2.00	1.99	1.52	7.33	6.76	5.47
Combustion Turbines	0.64	1.07	0.93	13.20	11.90	11.53
Renewable	2.72	2.50	2.44	11.53	10.61	7.79
Total	5.36	5.56	4.90	39.37	33.55	27.31
Total						
Coal Steam	0.00	0.00	0.00	12.75	12.32	12.26
Combined Cycle	3.62	3.39	3.27	11.85	12.40	12.52
Combustion Turbines	1.54	1.85	2.00	19.23	19.59	20.13
Renewable	2.85	2.65	2.59	14.31	13.79	12.38
Total	8.01	7.89	7.86	58.14	58.10	57.29
Electricity Price (1992 cents per kilowatthours)	6.76	6.76	6.76	7.10	7.10	7.13

[1]Includes utilities and nonutilities, excluding cogenerators.

[2]Cumulative additions after December 31, 1990.

[3]Excludes cogenerators

Table 4B. **Sensitivity Analysis: Variation in Interest Coverage Ratio Percentage Changes from Reference Case**

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0	0	0	0
Natural Gas	0	0	-1	5
Oil	0	0	-1	1
Renewable	0	0	0	-1
Total	0	0	0	1
Fuel Consumption[1]				
Coal	0	0	0	0
Natural Gas	0	0	0	5
Oil	0	0	-1	1
Total	0	0	0	1
Cumulative Unplanned Addition:				
Utilities				
Coal Steam	0	0	-32	21
Combined Cycle	15	24	-20	25
Combustion Turbines	14	37	-22	12
Renewable	-12	-2	-13	44
Total	13	27	-24	22
Nonutilities[3]				
Coal Steam	0	0	71	-41
Combined Cycle	1	-23	8	-19
Combustion Turbines	-40	-13	11	-3
Renewable	9	-2	9	-27
Total	-3	-12	17	-19
Total				
Coal Steam	0	0	4	0
Combined Cycle	7	-4	-4	1
Combustion Turbines	-17	8	-2	3
Renewable	7	-2	4	-10
Total	1	0	0	-1
Electricity Price				
	0	0	0	0

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 4C. **Sensitivity Analysis: Ratio of Percentage Change in Output Va**
Relative to Percentage Change in Interest Coverage Rati

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.3
Oil	0.0	0.0	0.1	0.0
Renewable	0.0	0.0	0.0	-0.1
Total	0.0	0.0	0.0	0.0
Fuel Consumption[1]				
Coal	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.3
Oil	0.0	0.0	0.1	0.0
Total	0.0	0.0	0.0	0.1
Cumulative Unplanned Additions[2]				
Utilities				
Coal Steam	0.0	0.0	2.0	1.3
Combined Cycle	-0.9	1.5	1.2	1.5
Combustion Turbines	-0.9	2.2	1.3	0.7
Renewable	0.8	-0.1	0.8	2.7
Total	-0.8	1.6	1.4	1.4
Nonutilities[3]				
Coal Steam	0.0	0.0	-4.3	-2.5
Combined Cycle	-0.1	-1.4	-0.5	-1.2
Combustion Turbines	2.4	-0.8	-0.7	-0.2
Renewable	-0.5	-0.2	-0.5	-1.6
Total	0.2	-0.7	-1.1	-1.1
Total				
Coal Steam	0.0	0.0	-0.2	0.0
Combined Cycle	-0.4	-0.2	0.3	0.1
Combustion Turbines	1.0	0.5	0.1	0.2
Renewable	-0.5	-0.1	-0.2	-0.6
Total	-0.1	0.0	0.0	-0.1
Electricity Price				
	0.0	0.0	0.0	0.0

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 5A. **Sensitivity Analysis: Variation in Cost of Equity**

Output Variable	2000 Low Case	2000 Reference Case	2000 High Case	2010 Low Case	2010 Reference Case	2010 High Case
Generation by Fuel Type[1]						
(billion kilowatthours)						
Coal	1698.63	1699.18	1699.36	1881.95	1868.18	1862.00
Natural Gas	333.80	333.38	332.89	471.08	447.87	440.43
Oil	82.23	81.87	81.99	121.32	116.98	116.20
Renewable	366.01	366.22	366.45	415.18	420.04	424.94
Total	2480.68	2480.65	2480.70	2889.53	2853.08	2843.58
Fuel Consumption[1]						
(trillion Btu)						
Coal	17.38	17.39	17.39	19.25	19.12	19.05
Natural Gas	3.38	3.37	3.37	4.79	4.54	4.46
Oil	0.96	0.95	0.95	1.40	1.35	1.34
Total	21.71	21.71	21.71	25.44	25.00	24.86
Cumulative Unplanned Additions[2]						
(gigawatts)						
Utilities						
Coal Steam	0.00	0.00	0.00	12.42	8.03	3.43
Combined Cycle	2.03	1.41	1.53	7.57	5.65	4.23
Combustion Turbines	1.02	0.79	0.76	10.19	7.69	4.45
Renewable	0.16	0.15	0.14	5.67	3.18	3.08
Total	3.22	2.34	2.43	35.86	24.54	15.19
Nonutilities[3]						
Coal Steam	0.00	0.00	0.00	1.91	4.28	8.02
Combined Cycle	1.26	1.99	1.89	4.32	6.76	7.98
Combustion Turbines	0.93	1.07	1.05	9.26	11.90	14.99
Renewable	2.44	2.50	2.57	6.63	10.61	12.43
Total	4.63	5.56	5.51	22.12	33.55	43.42
Total						
Coal Steam	0.00	0.00	0.00	14.33	12.32	11.45
Combined Cycle	3.29	3.39	3.42	11.89	12.40	12.20
Combustion Turbines	1.96	1.85	1.81	19.45	19.59	19.44
Renewable	2.60	2.65	2.71	12.30	13.79	15.51
Total	7.85	7.89	7.95	57.97	58.10	58.60
Electricity Price						
(1992 cents per kilowatthours)	6.69	6.76	6.81	7.05	7.10	7.17

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 5B. Sensitivity Analysis: Variation in Cost of Equity Percentage Changes from Reference Case

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0	0	1	0
Natural Gas	0	0	5	-2
Oil	0	0	4	-1
Renewable	0	0	-1	1
Total	0	0	1	0
Fuel Consumption[1]				
Coal	0	0	1	0
Natural Gas	0	0	6	-2
Oil	0	0	3	-1
Total	0	0	2	-1
Cumulative Unplanned Additions				
Utilities				
Coal Steam	0	0	55	-57
Combined Cycle	44	9	34	-25
Combustion Turbines	30	-3	33	-42
Renewable	11	-3	79	-3
Total	38	4	46	-38
Nonutilities[3]				
Coal Steam	0	0	-55	87
Combined Cycle	-37	-5	-36	18
Combustion Turbines	-12	-1	-22	26
Renewable	-3	3	-38	17
Total	-17	-1	-34	29
Total				
Coal Steam	0	0	16	-7
Combined Cycle	-3	1	-4	-2
Combustion Turbines	6	-2	-1	-1
Renewable	-2	2	-11	12
Total	-1	1	0	1
Electricity Price	-1	1	-1	1

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 5C. **Sensitivity Analysis: Ratio of Percentage Change in (Relative to Percentage Change in Cost of Equity**

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	-0.2	-0.1
Oil	0.0	0.0	-0.2	0.0
Renewable	0.0	0.0	0.0	0.0
Total	0.0	0.0	-0.1	0.0
Fuel Consumption[1]				
Coal	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	-0.2	-0.1
Oil	0.0	0.0	-0.1	0.0
Total	0.0	0.0	-0.1	0.0
Cumulative Unplanned Additions[2]				
Utilities				
Coal Steam	0.0	0.0	-2.3	-2.4
Combined Cycle	-1.9	0.4	-1.4	-1.1
Combustion Turbines	-1.3	-0.1	-1.4	-1.8
Renewable	-0.5	-0.1	-3.3	-0.1
Total	-1.6	0.2	-1.9	-1.6
Nonutilities[3]				
Coal Steam	0.0	0.0	2.3	3.7
Combined Cycle	1.5	-0.2	1.5	0.8
Combustion Turbines	0.5	-0.1	0.9	1.1
Renewable	0.1	0.1	1.6	0.7
Total	0.7	0.0	1.4	1.2
Total				
Coal Steam	0.0	0.0	-0.7	-0.3
Combined Cycle	0.1	0.0	0.2	-0.1
Combustion Turbines	-0.2	-0.1	0.0	0.0
Renewable	0.1	0.1	0.5	0.5
Total	0.0	0.0	0.0	0.0
Electricity Price	0.0	0.0	0.0	0.0

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 6A. **Sensitivity Analysis: Variation in Capital Structure**

Output Variable	2000 Low Case	2000 Reference Case	2000 High Case	2010 Low Case	2010 Reference Case	2010 High Case
Generation by Fuel Type[1] (billion kilowatthours)						
Coal	1698.75	1699.18	1698.76	1881.45	1868.18	1854.65
Natural Gas	333.62	333.38	333.32	451.77	447.87	448.00
Oil	82.15	81.87	82.46	117.32	116.98	116.81
Renewable	366.18	366.22	366.15	419.76	420.04	424.71
Total	2480.70	2480.65	2480.69	2870.31	2853.08	2844.16
Fuel Consumption[1] (trillion Btu)						
Coal	17.38	17.39	17.38	19.24	19.12	19.00
Natural Gas	3.37	3.37	3.37	4.58	4.54	4.53
Oil	0.96	0.95	0.96	1.35	1.35	1.35
Total	21.71	21.71	21.71	25.18	25.00	24.88
Cumulative Unplanned Additions[2] (gigawatts)						
Utilities						
Coal Steam	0.00	0.00	0.00	10.08	8.03	5.04
Combined Cycle	1.68	1.41	1.84	5.70	5.65	5.55
Combustion Turbines	0.80	0.79	0.77	8.58	7.69	6.45
Renewable	0.17	0.15	0.13	3.85	3.18	2.93
Total	2.66	2.34	2.74	28.21	24.54	19.97
Nonutilities[3]						
Coal Steam	0.00	0.00	0.00	4.45	4.28	4.98
Combined Cycle	1.79	1.99	1.63	6.08	6.76	7.46
Combustion Turbines	0.96	1.07	1.02	11.14	11.90	14.17
Renewable	2.47	2.50	2.50	9.68	10.61	12.45
Total	5.22	5.56	5.15	31.35	33.55	39.06
Total						
Coal Steam	0.00	0.00	0.00	14.52	12.32	10.02
Combined Cycle	3.47	3.39	3.48	11.78	12.40	13.01
Combustion Turbines	1.76	1.85	1.79	19.72	19.59	20.62
Renewable	2.65	2.65	2.63	13.53	13.79	15.39
Total	7.88	7.89	7.89	59.56	58.10	59.03
Electricity Price (1992 cents per kilowatthours)	6.70	6.76	6.82	7.04	7.10	7.17

[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

Table 6B. **Sensitivity Analysis: Variation in Capital Structure Percentage Changes from Reference Case**

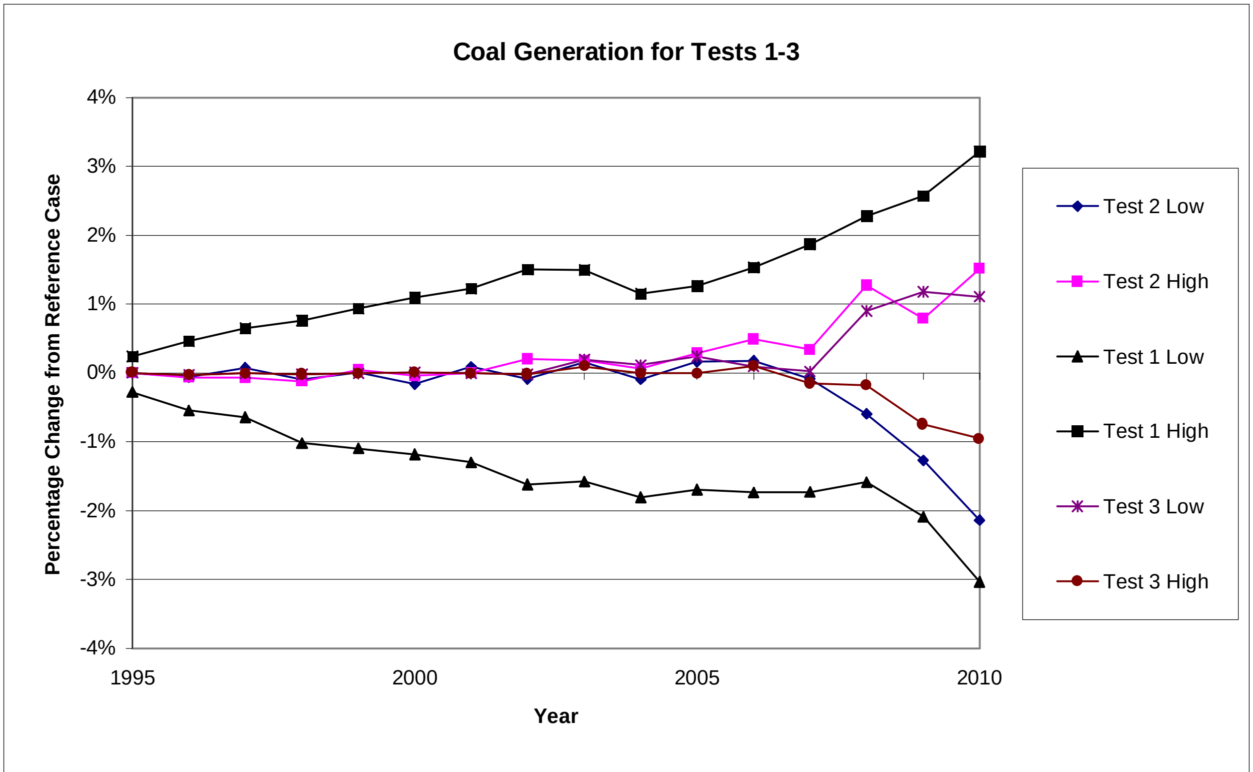
Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0	0	1	-1
Natural Gas	0	0	1	0
Oil	0	1	0	0
Renewable	0	0	0	1
Total	0	0	1	0
Fuel Consumption[1]				
Coal	0	0	1	-1
Natural Gas	0	0	1	0
Oil	0	1	0	0
Total	0	0	1	-1
Cumulative Unplanned Addition				
Utilities				
Coal Steam	0	0	25	-37
Combined Cycle	20	31	1	-2
Combustion Turbines	2	-2	12	-16
Renewable	19	-13	21	-8
Total	14	17	15	-19
Nonutilities[3]				
Coal Steam	0	0	4	16
Combined Cycle	-10	-18	-10	10
Combustion Turbines	-10	-4	-6	19
Renewable	-1	0	-9	17
Total	-6	-7	-7	16
Total				
Coal Steam	0	0	18	-19
Combined Cycle	2	3	-5	5
Combustion Turbines	-5	-3	1	5
Renewable	0	-1	-2	12
Total	0	0	3	2
Electricity Price	-1	1	-1	1

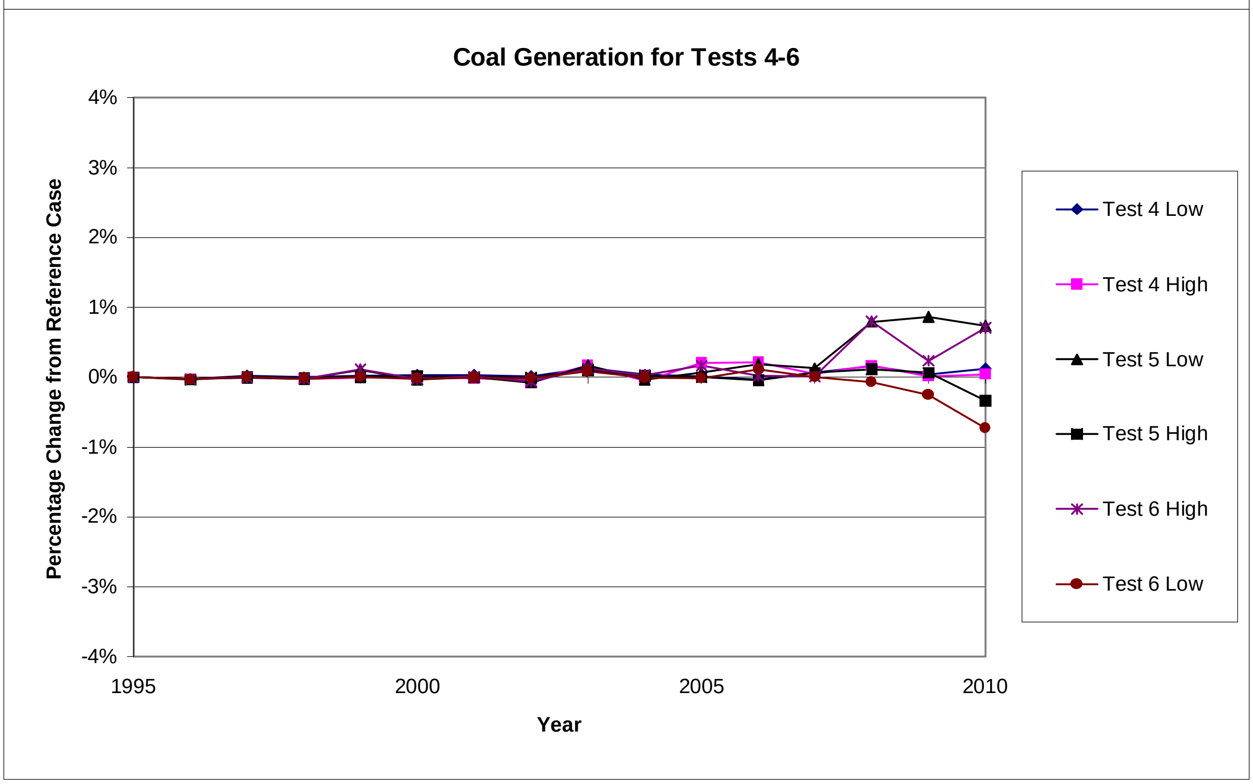
[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators

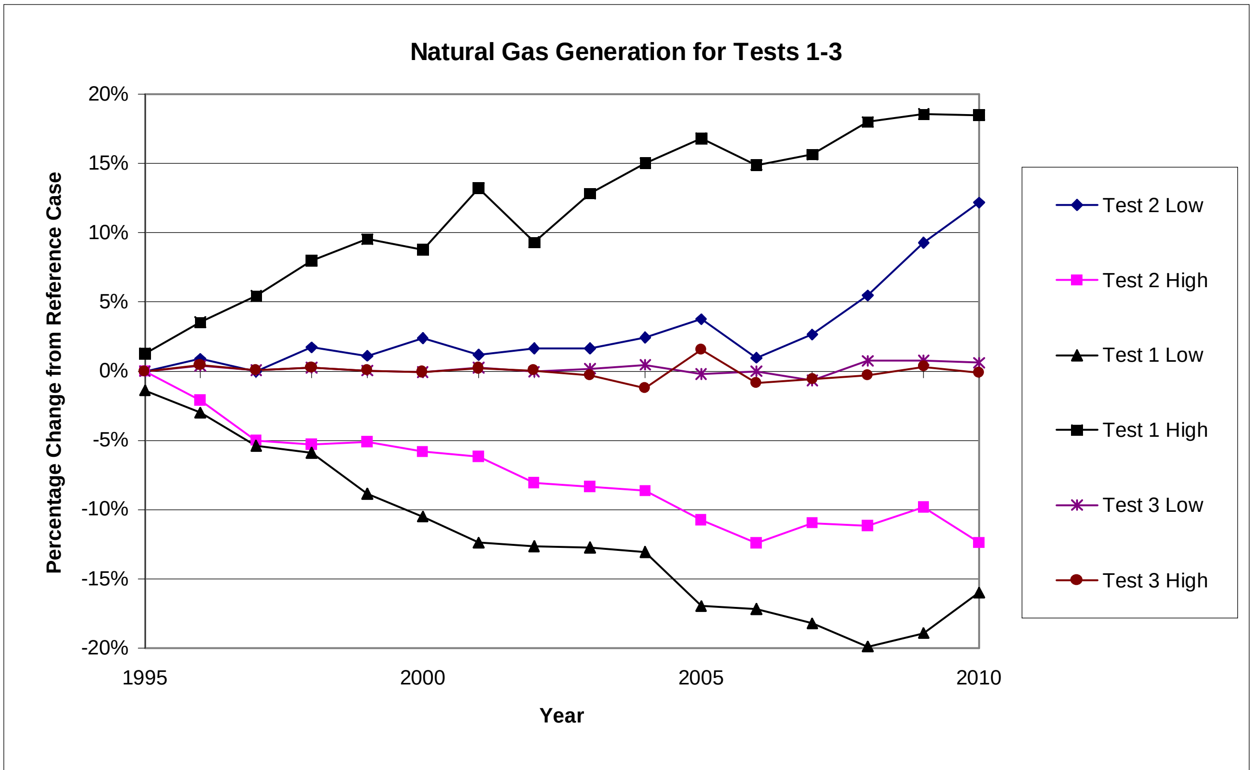
Table 6C. **Sensitivity Analysis: Ratio of Percentage Change in Output Var Relative to Percentage Change in Capital Structure**

Output Variable	2000 Low Case	2000 High Case	2010 Low Case	2010 High Case
Generation by Fuel Type[1]				
Coal	0.0	0.0	-0.1	-0.1
Natural Gas	0.0	0.0	-0.1	0.0
Oil	0.0	0.1	0.0	0.0
Renewable	0.0	0.0	0.0	0.1
Total	0.0	0.0	-0.1	0.0
Fuel Consumption[1]				
Coal	0.0	0.0	-0.1	-0.1
Natural Gas	0.0	0.0	-0.1	0.0
Oil	0.0	0.1	0.0	0.0
Total	0.0	0.0	-0.1	-0.1
Cumulative Unplanned Additions[2]				
Utilities				
Coal Steam	0.0	0.0	-2.5	-3.7
Combined Cycle	-2.0	3.1	-0.1	-0.2
Combustion Turbines	-0.2	-0.2	-1.2	-1.6
Renewable	-1.9	-1.3	-2.1	-0.8
Total	-1.4	1.7	-1.5	-1.9
Nonutilities[3]				
Coal Steam	0.0	0.0	-0.4	1.6
Combined Cycle	1.0	-1.8	1.0	1.0
Combustion Turbines	1.0	-0.4	0.6	1.9
Renewable	0.1	0.0	0.9	1.7
Total	0.6	-0.7	0.7	1.6
Total				
Coal Steam	0.0	0.0	-1.8	-1.9
Combined Cycle	-0.2	0.3	0.5	0.5
Combustion Turbines	0.5	-0.3	-0.1	0.5
Renewable	0.0	-0.1	0.2	1.2
Total	0.0	0.0	-0.3	0.2
Electricity Price	0.1	0.1	0.1	0.1

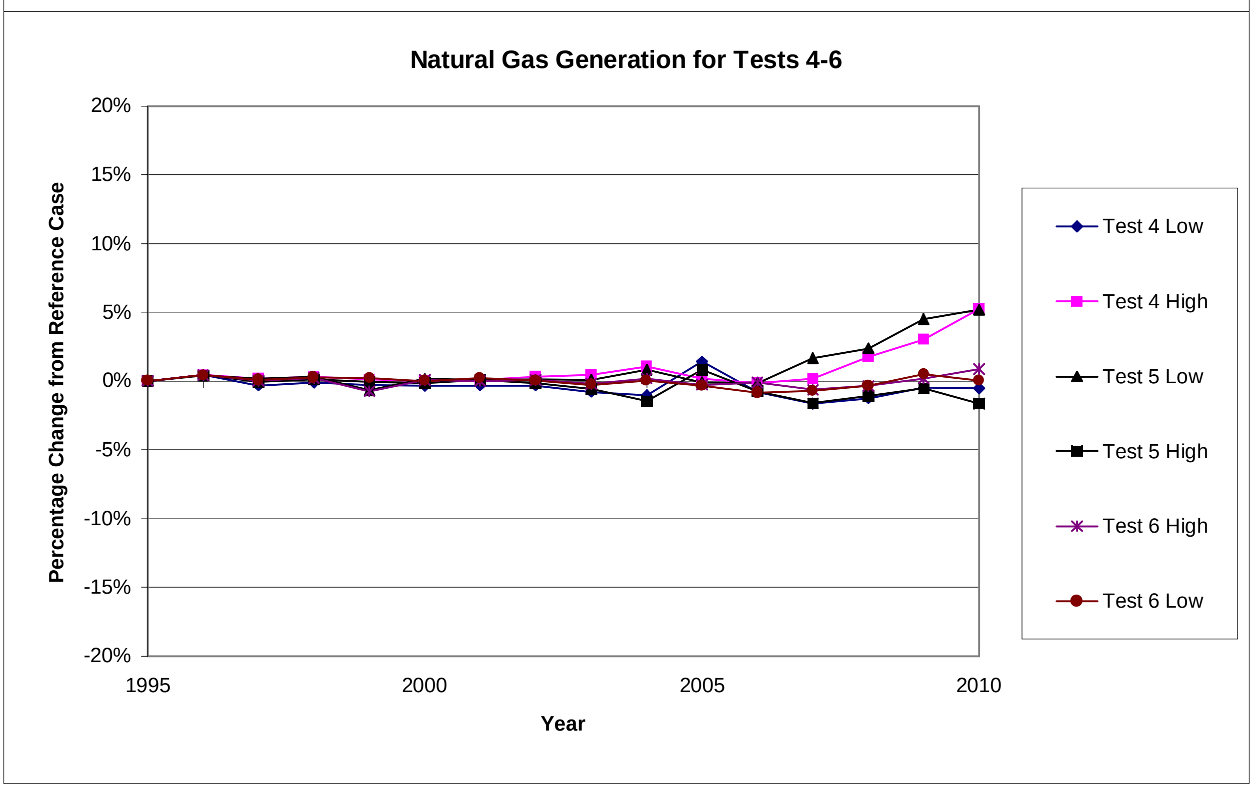
[1]Includes utilities and nonutilities, excluding cogenerators.
[2]Cumulative additions after December 31, 1990.
[3]Excludes cogenerators


Coal Generation for Tests 1-3
Percentage Change from Reference Case
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

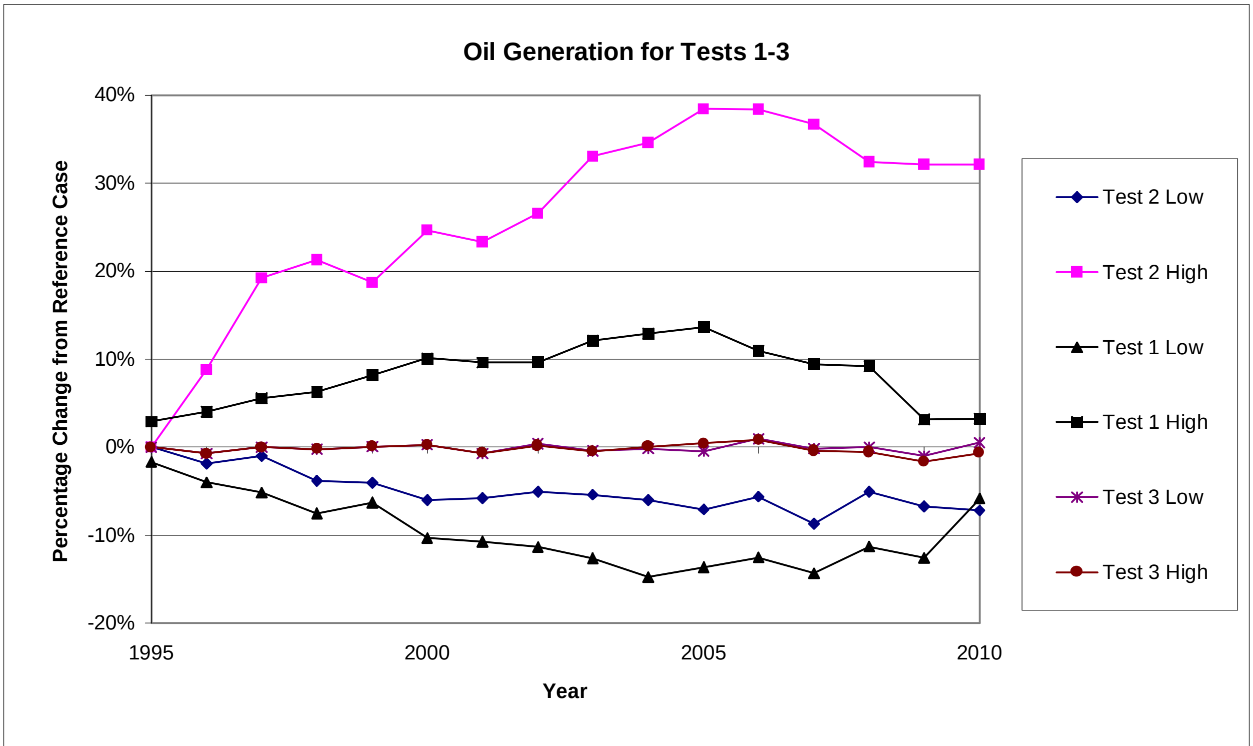

Coal Generation for Tests 4-6
Percentage Change from Reference Case
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 High
Test 6 Low

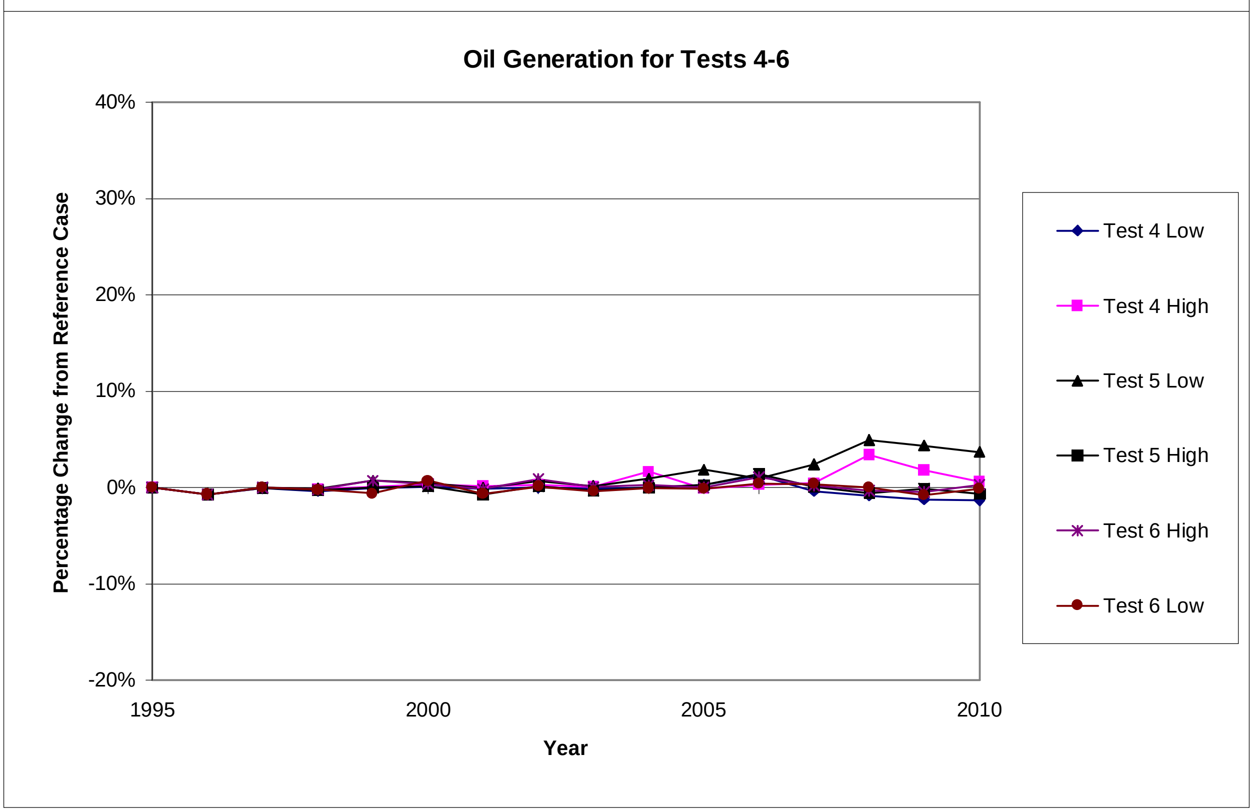


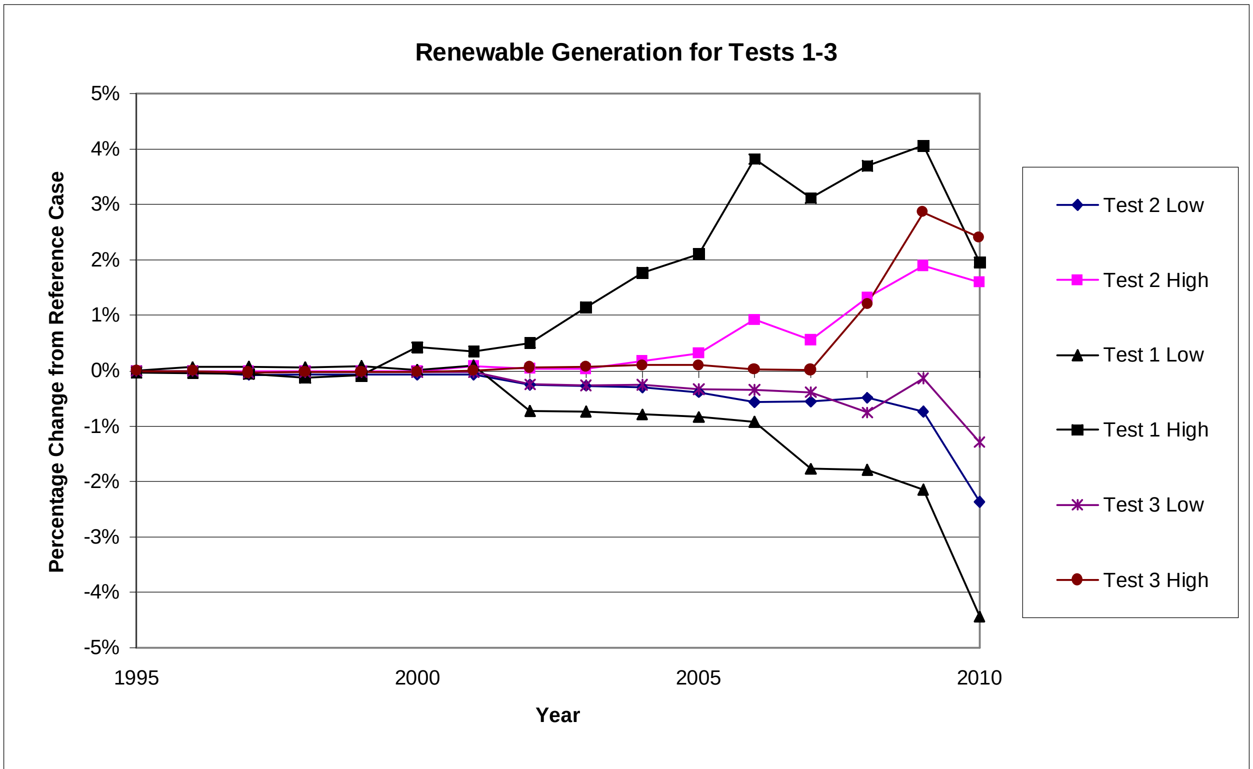
Natural Gas Generation for Tests 1-3
Percentage Change from Reference Case
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High



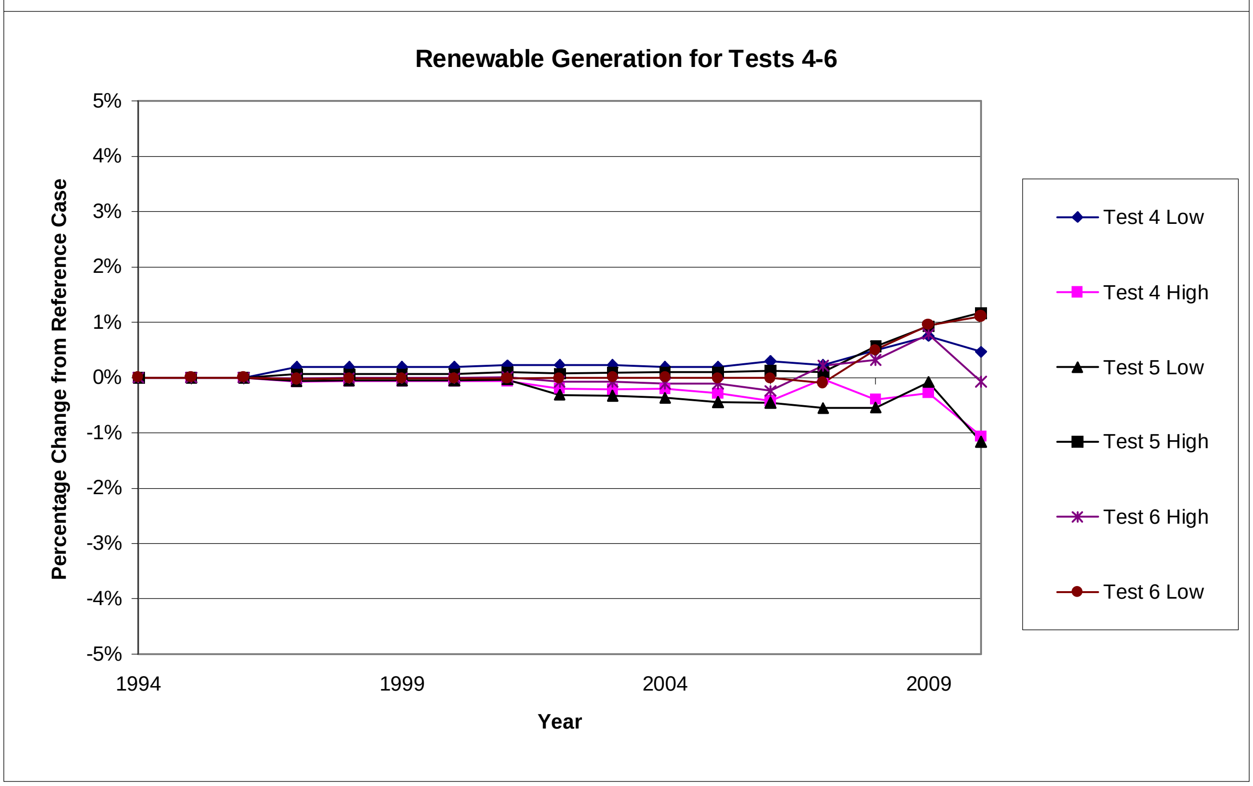
Natural Gas Generation for Tests 4-6
Percentage Change from Reference Case
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 High
Test 6 Low


Oil Generation for Tests 1-3
Percentage Change from Reference Case
40%
30%
20%
10%
0%
-10%
-20%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

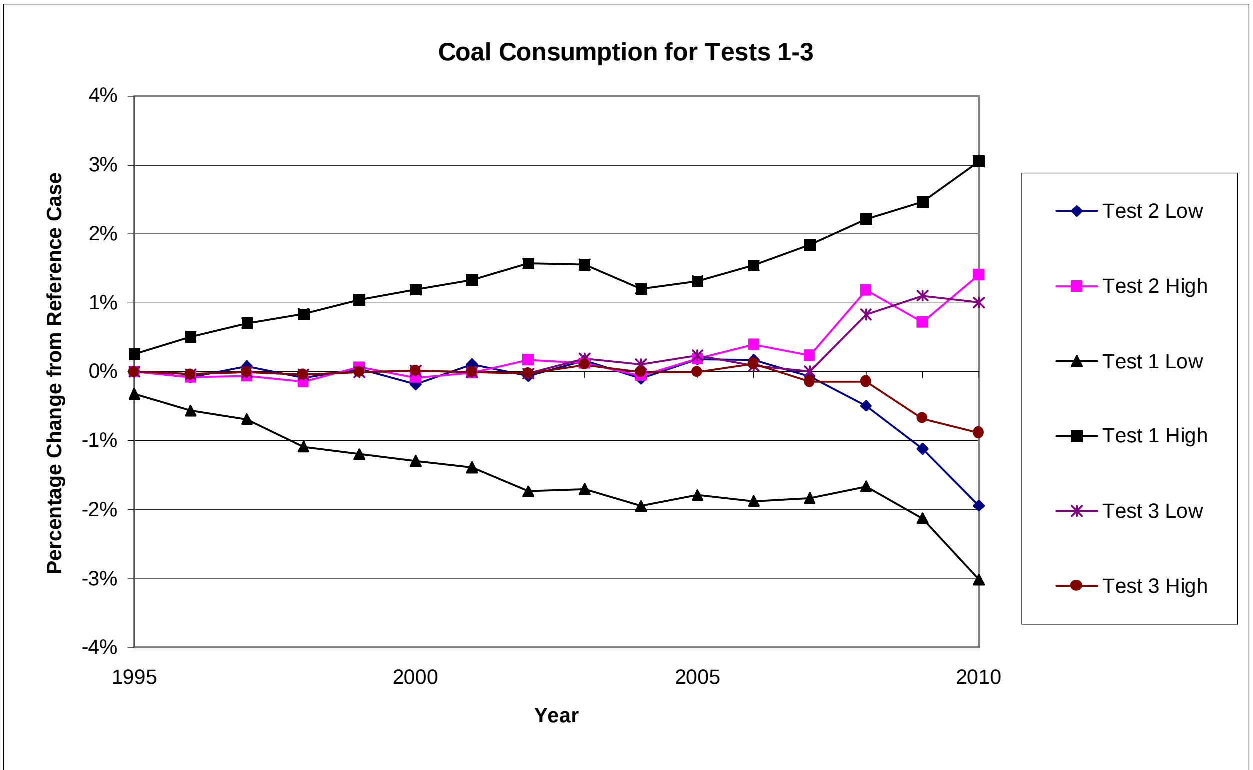

Oil Generation for Tests 4-6
Percentage Change from Reference Case
40%
30%
20%
10%
0%
-10%
-20%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 High
Test 6 Low

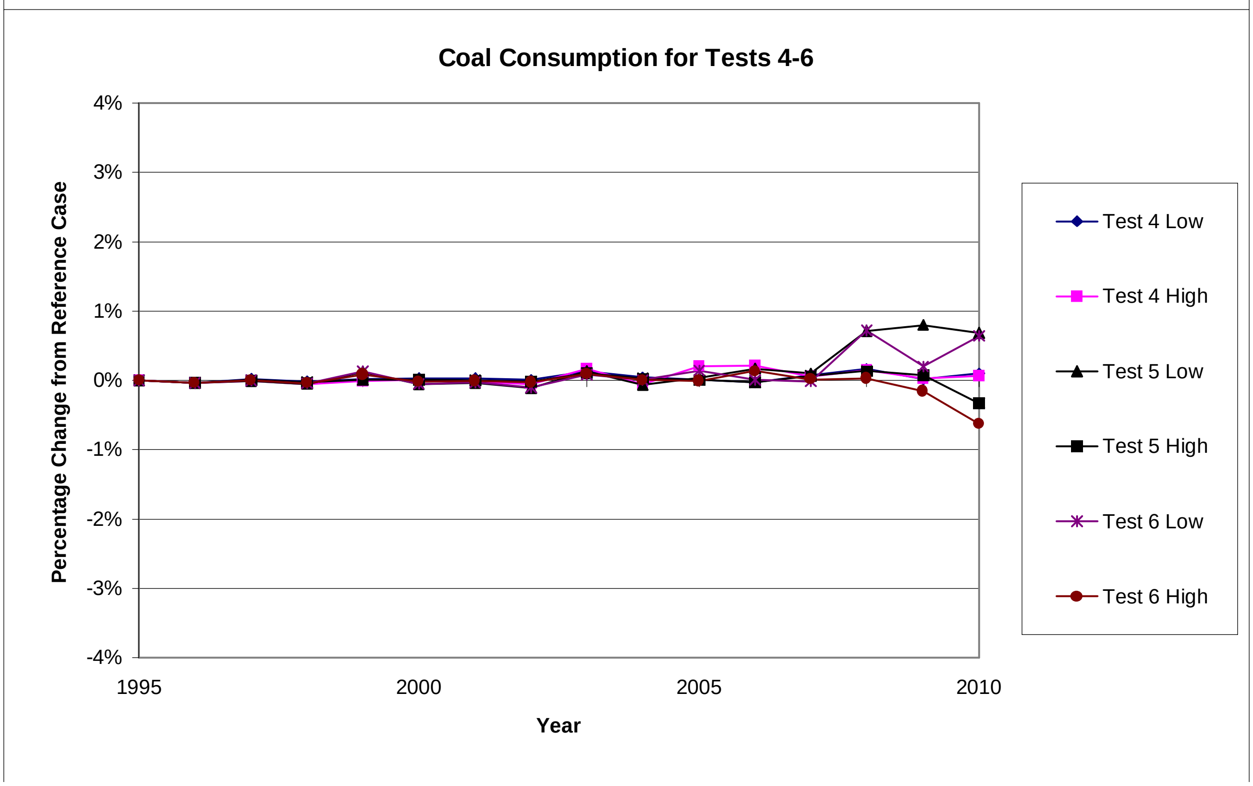


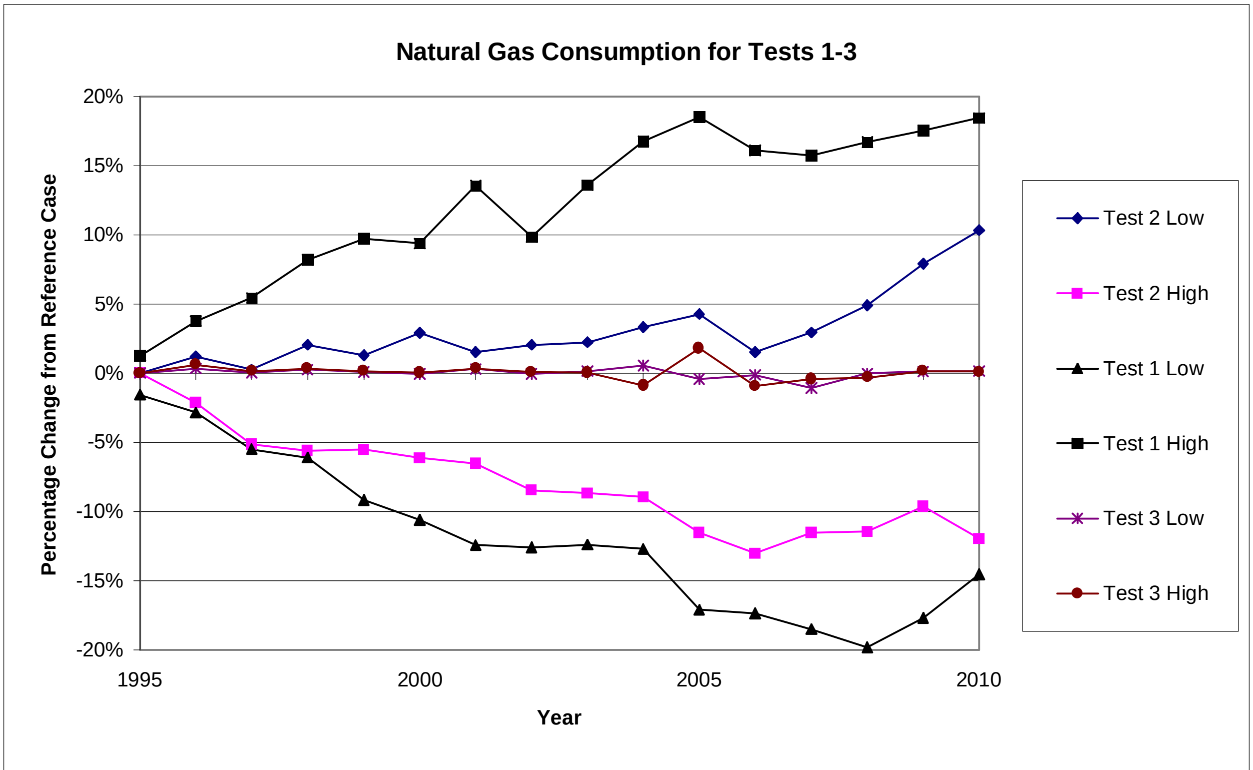
Renewable Generation for Tests 1-3
Percentage Change from Reference Case
5%
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
-5%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High



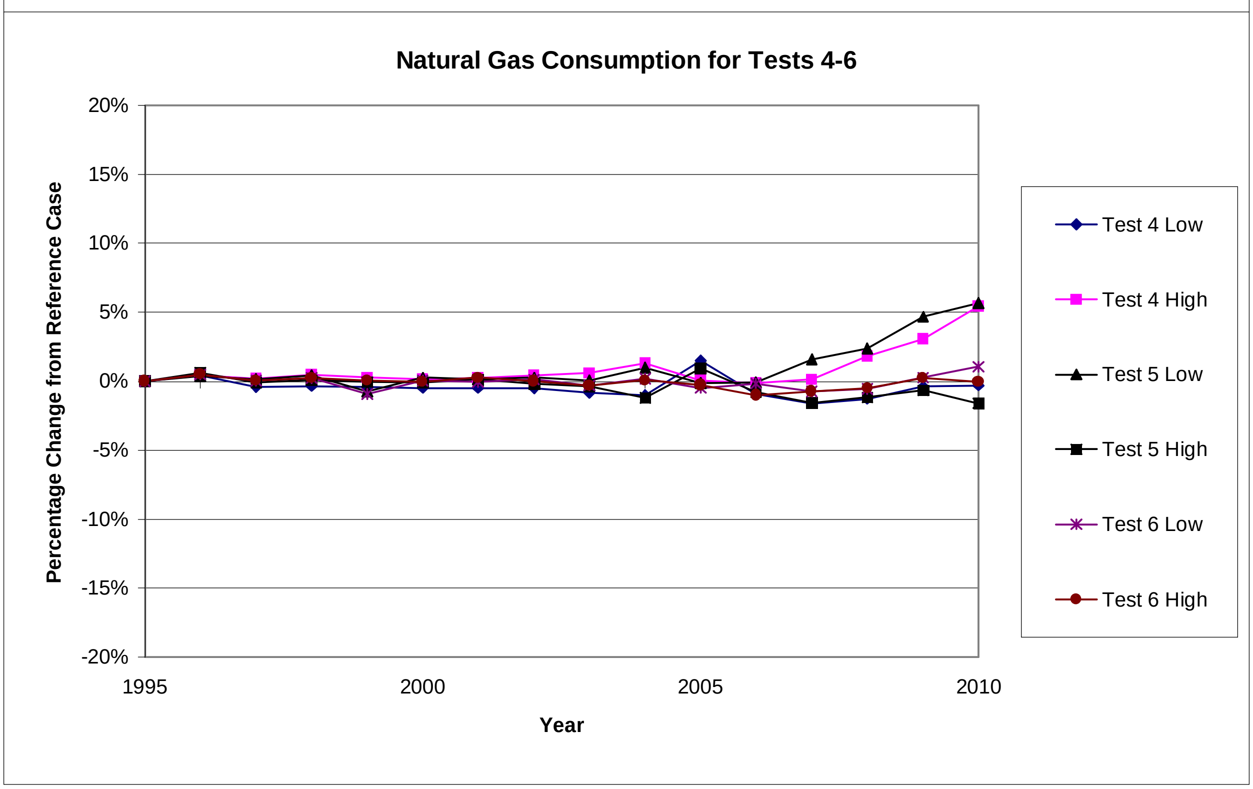
Renewable Generation for Tests 4-6
Percentage Change from Reference Case
5%
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
-5%
1994
1999
2004
2009
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 High
Test 6 Low


Coal Consumption for Tests 1-3
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
Percentage Change from Reference Case
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

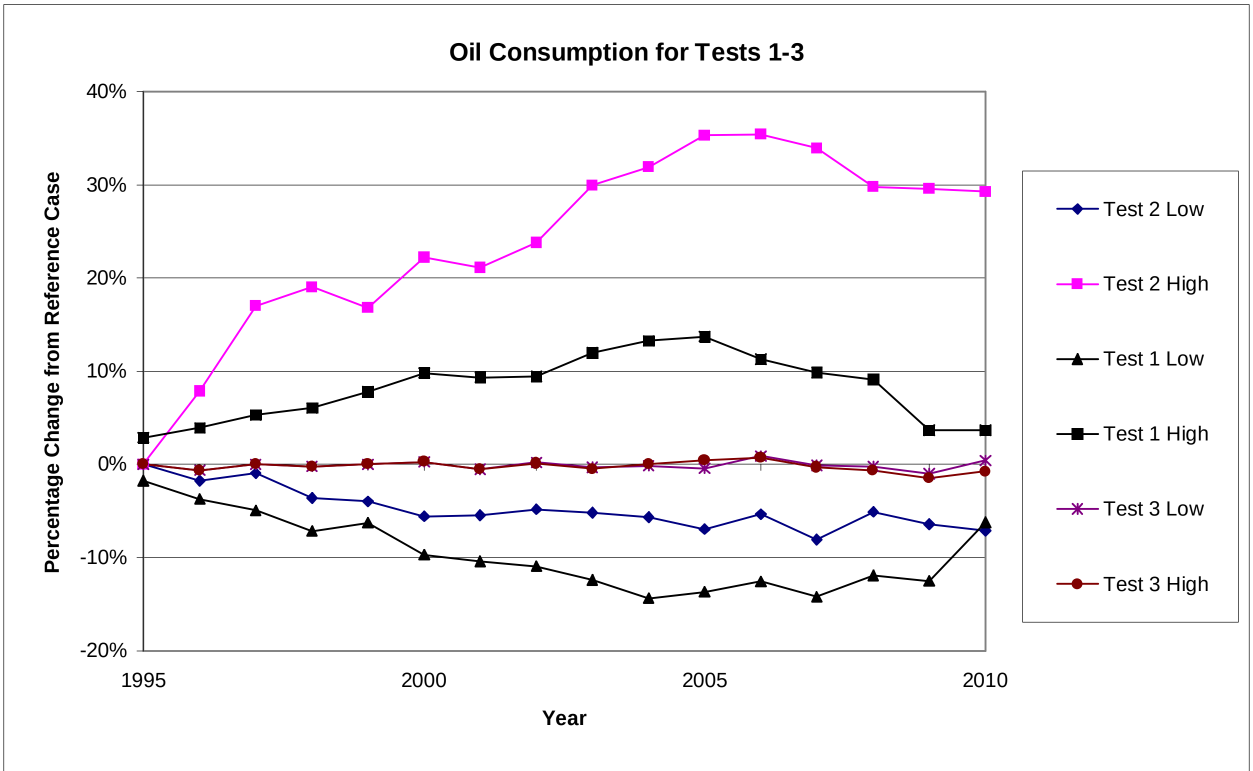

Coal Consumption for Tests 4-6
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
Percentage Change from Reference Case
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High

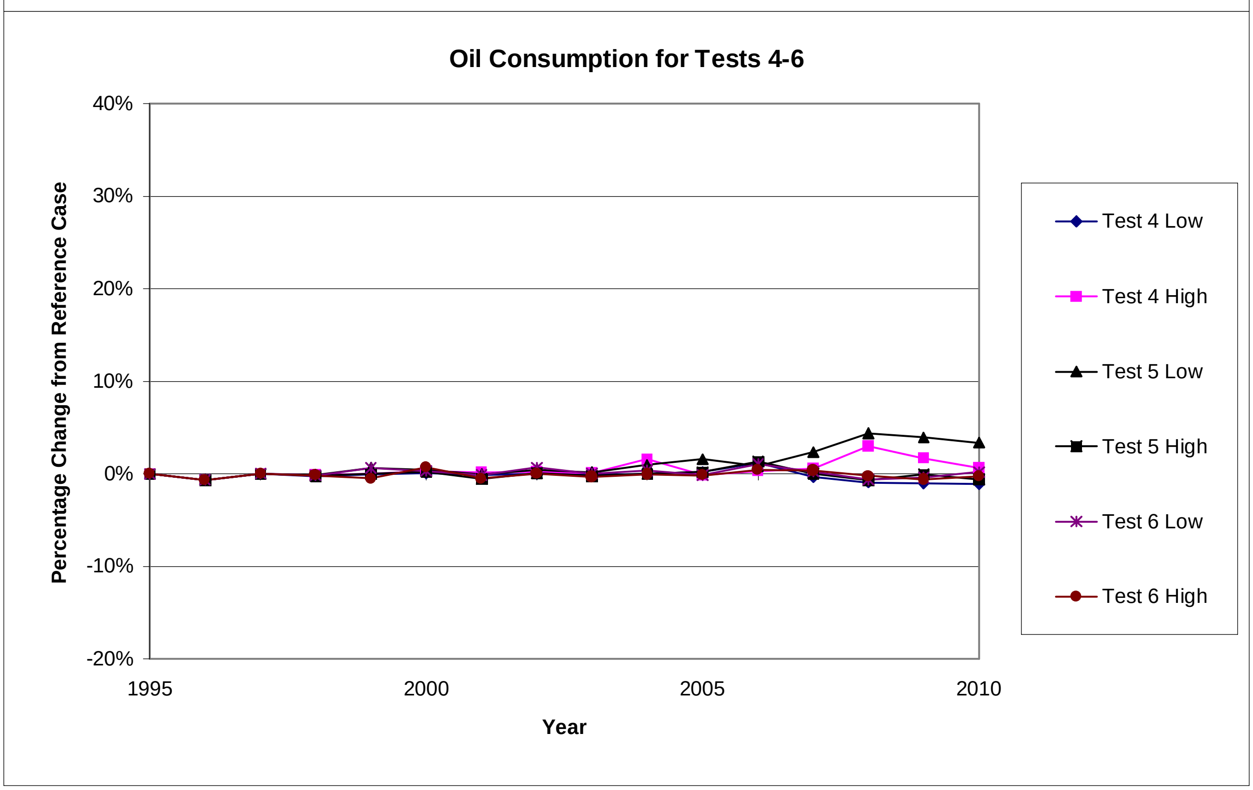


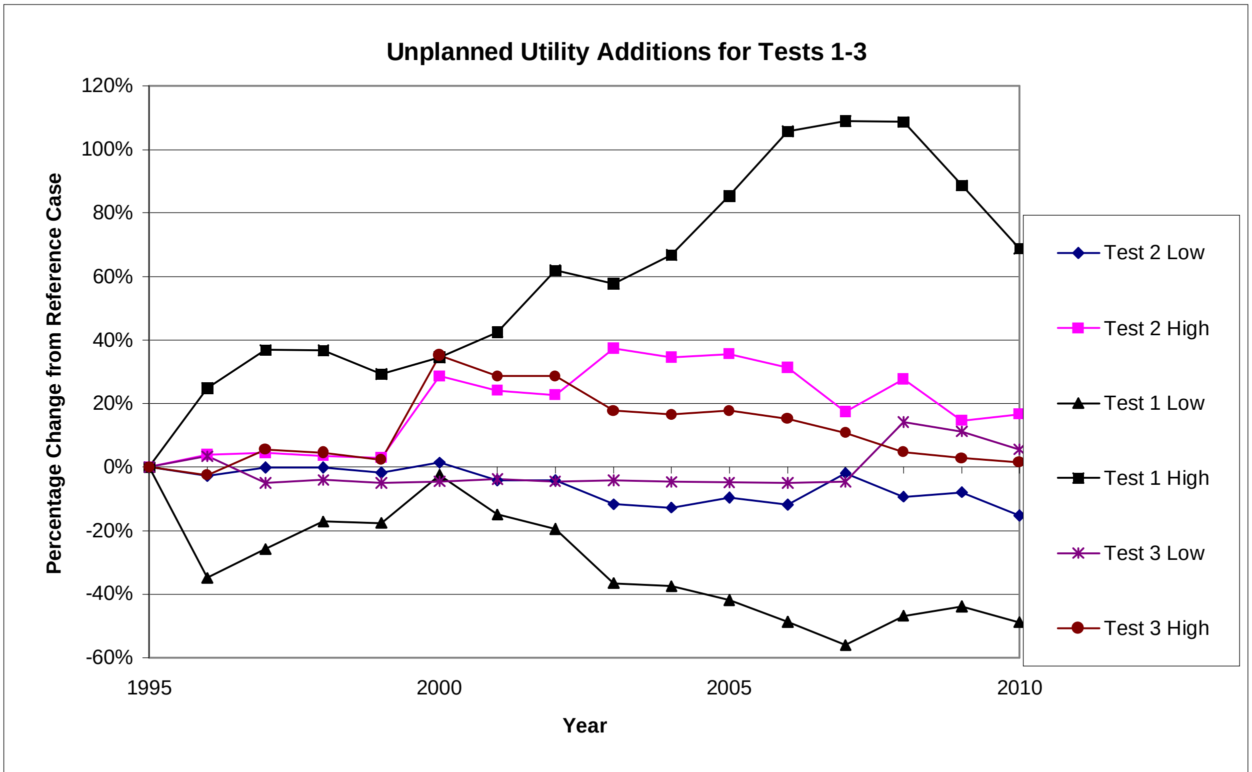
Natural Gas Consumption for Tests 1-3
Percentage Change from Reference Case
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

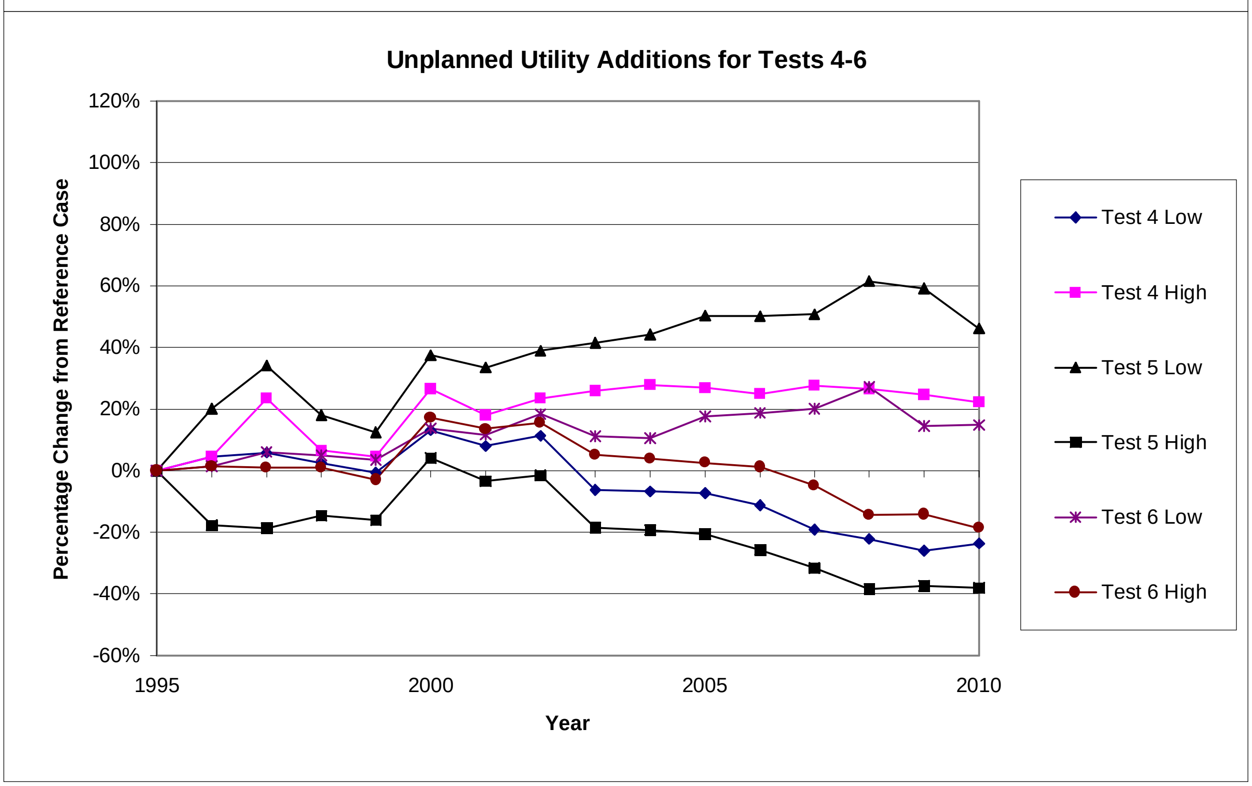


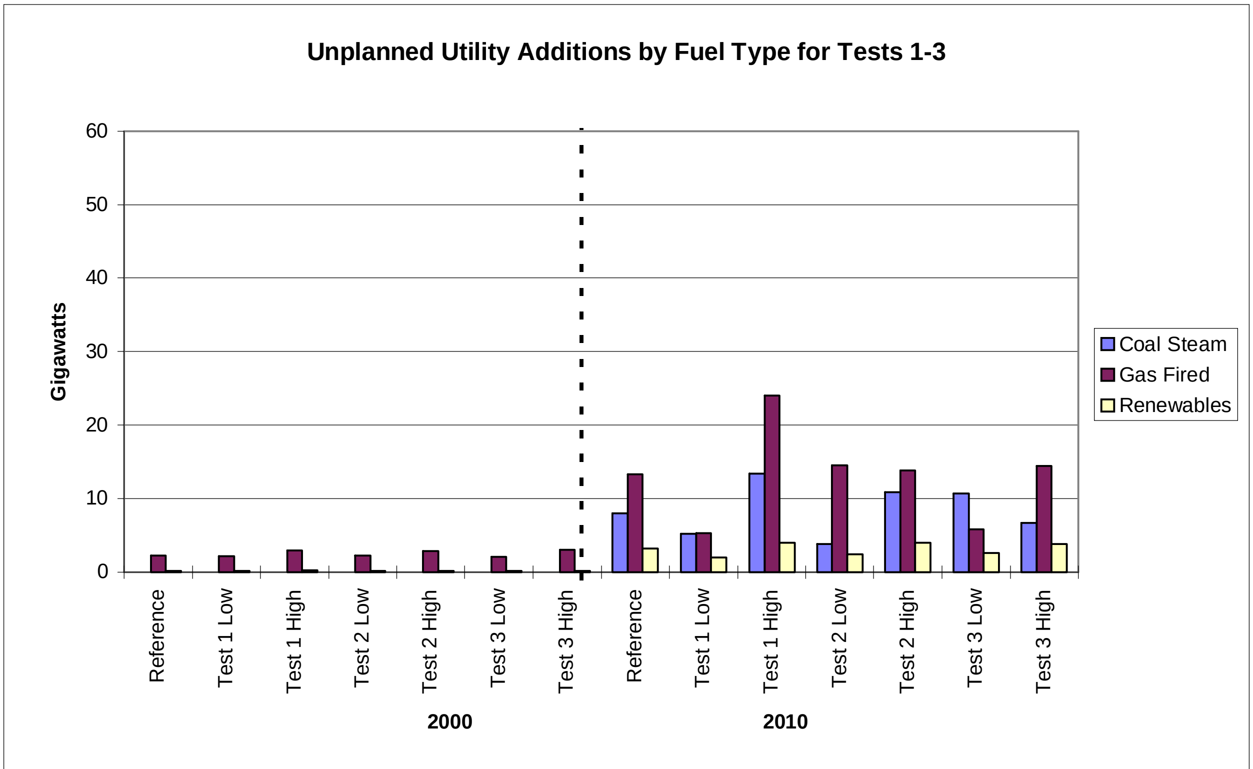
Natural Gas Consumption for Tests 4-6
Percentage Change from Reference Case
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High

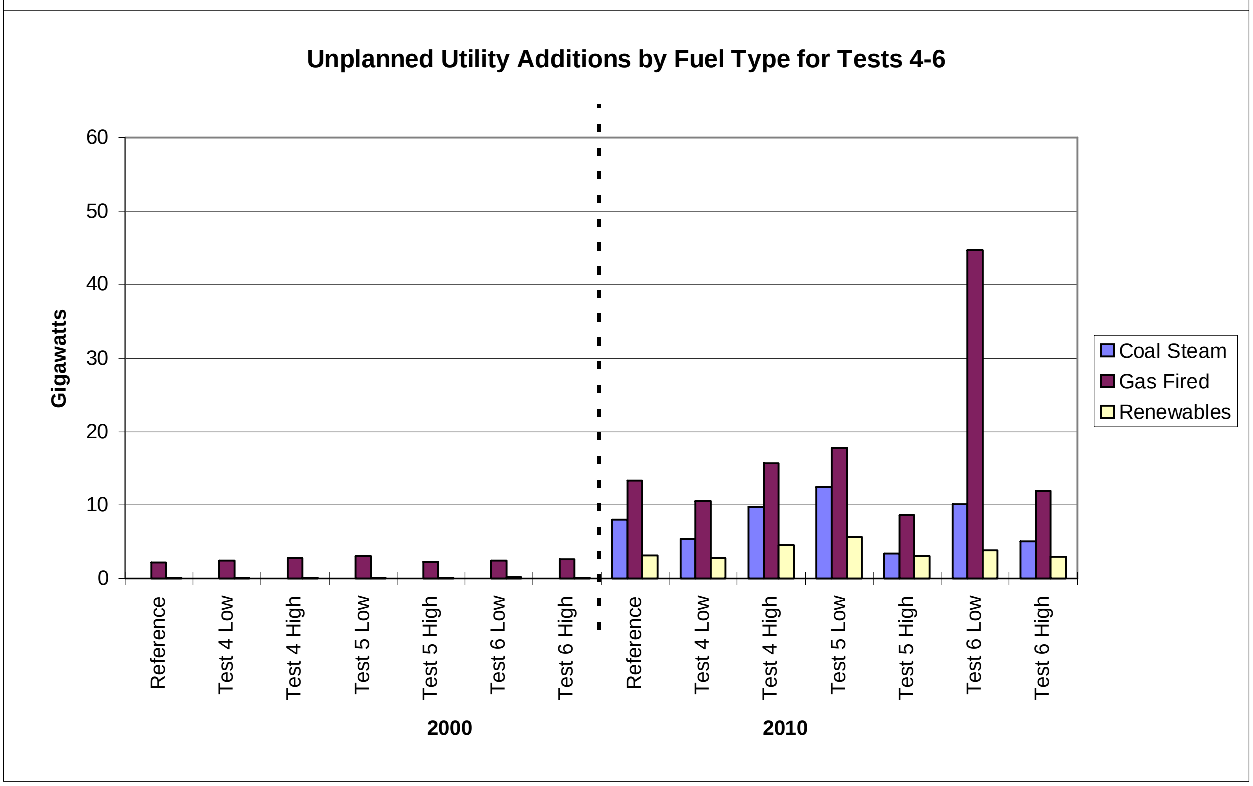

Oil Consumption for Tests 1-3
40%
30%
20%
10%
0%
-10%
-20%
Percentage Change from Reference Case
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

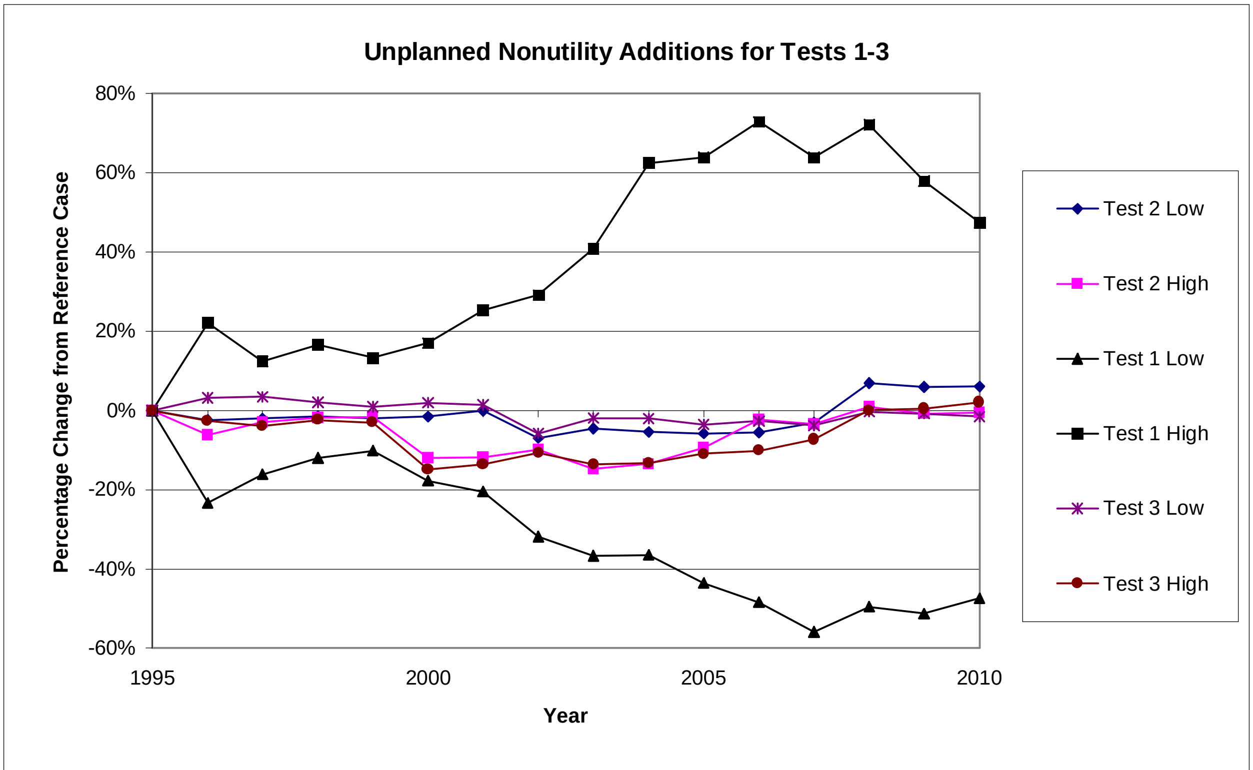

Oil Consumption for Tests 4-6
40%
30%
20%
10%
0%
-10%
-20%
Percentage Change from Reference Case
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High


Unplanned Utility Additions for Tests 1-3
Percentage Change from Reference Case
120%
100%
80%
60%
40%
20%
0%
-20%
-40%
-60%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

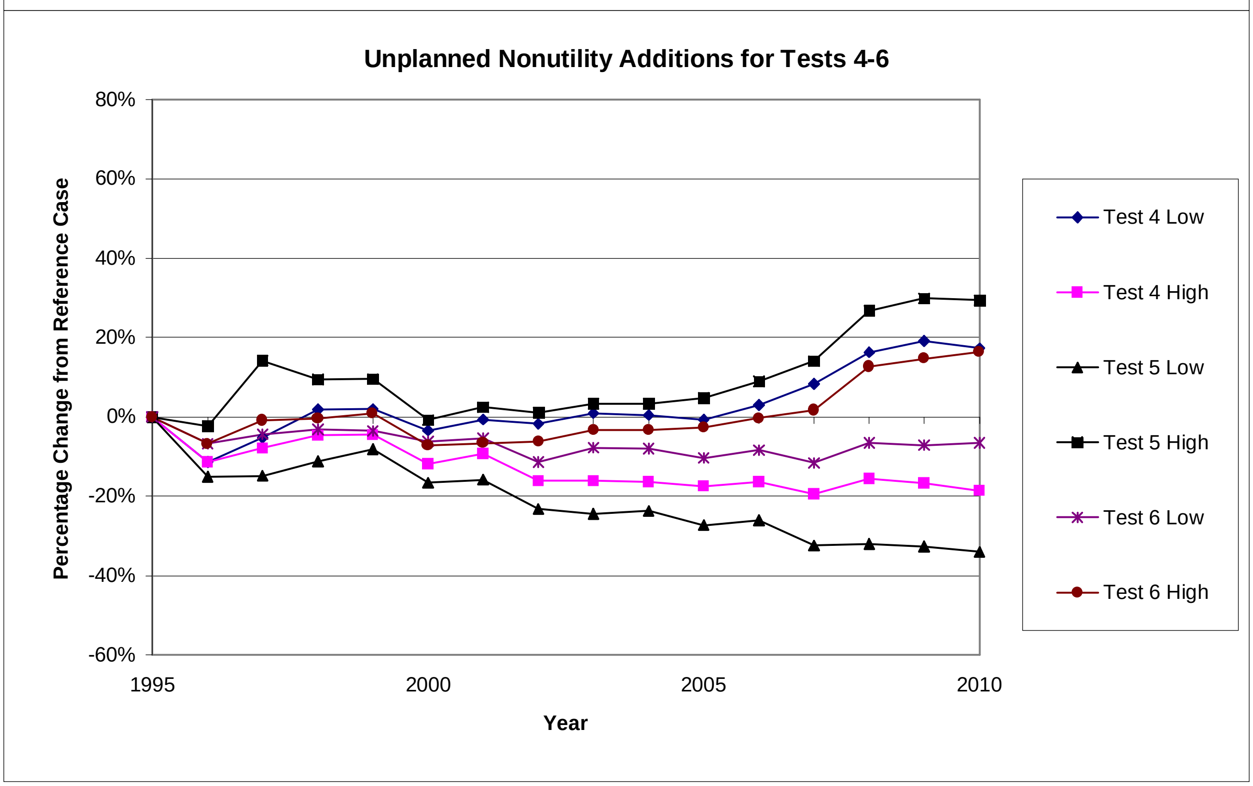

Unplanned Utility Additions for Tests 4-6
Percentage Change from Reference Case
120%
100%
80%
60%
40%
20%
0%
-20%
-40%
-60%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High


Unplanned Utility Additions by Fuel Type for Tests 1-3
Gigawatts
60
50
40
30
20
10
0
Reference
Test 1 Low
Test 1 High
Test 2 Low
Test 2 High
Test 3 Low
Test 3 High
Reference
Test 1 Low
Test 1 High
Test 2 Low
Test 2 High
Test 3 Low
Test 3 High
2000
2010
Coal Steam
Gas Fired
Renewables

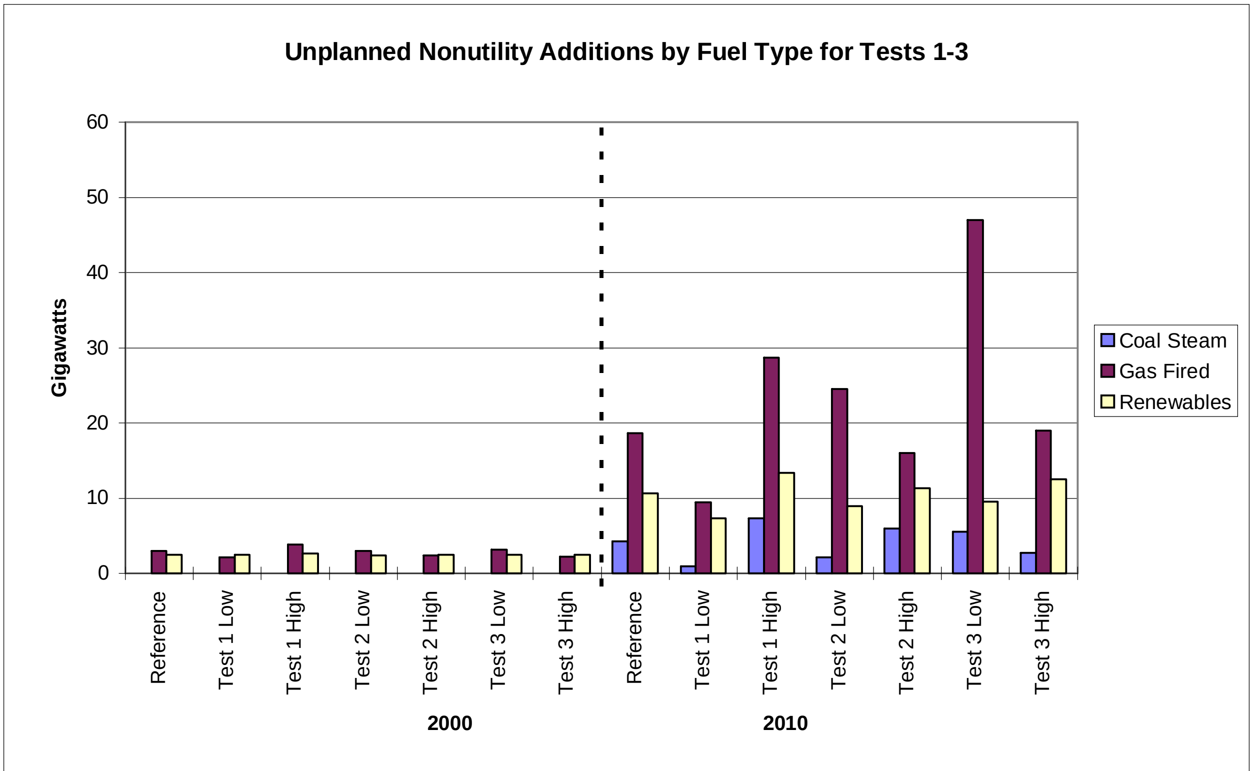

Unplanned Utility Additions by Fuel Type for Tests 4-6
Gigawatts
60
50
40
30
20
10
0
Reference
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High
Reference
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High
2000
2010
Coal Steam
Gas Fired
Renewables

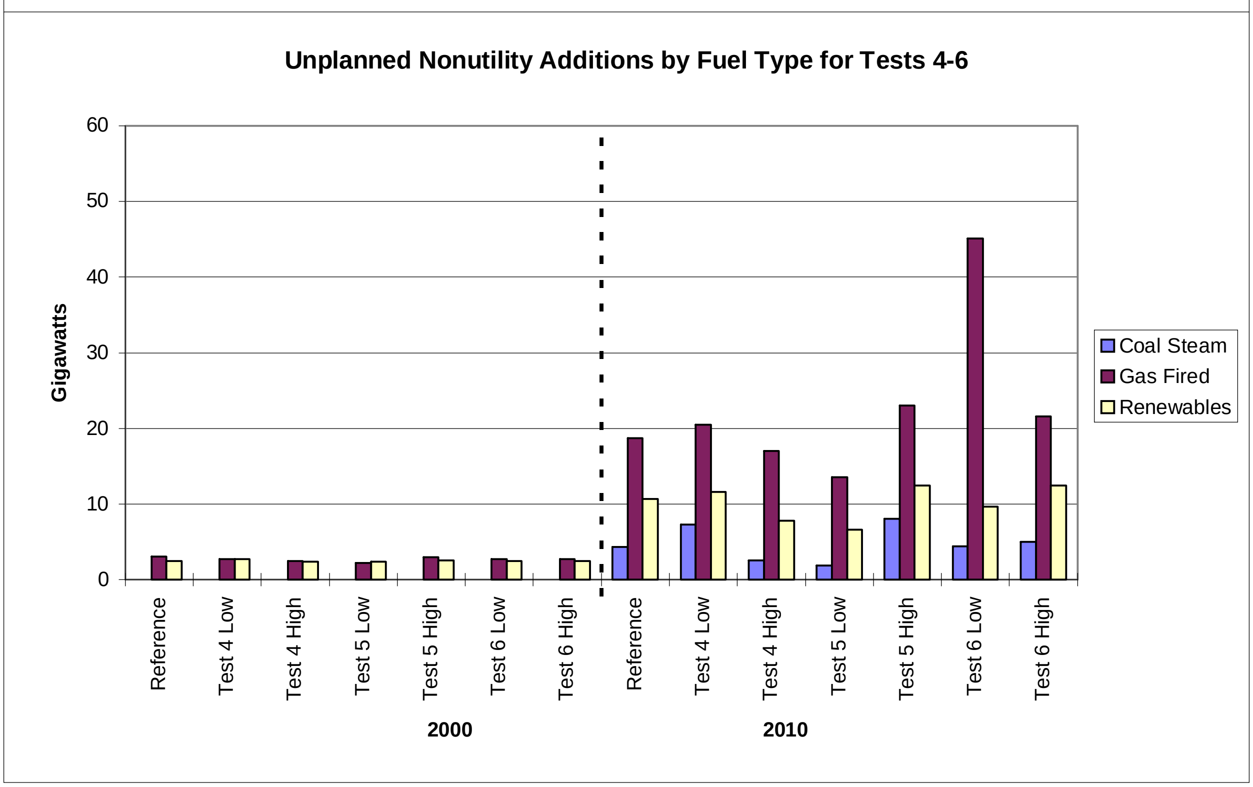


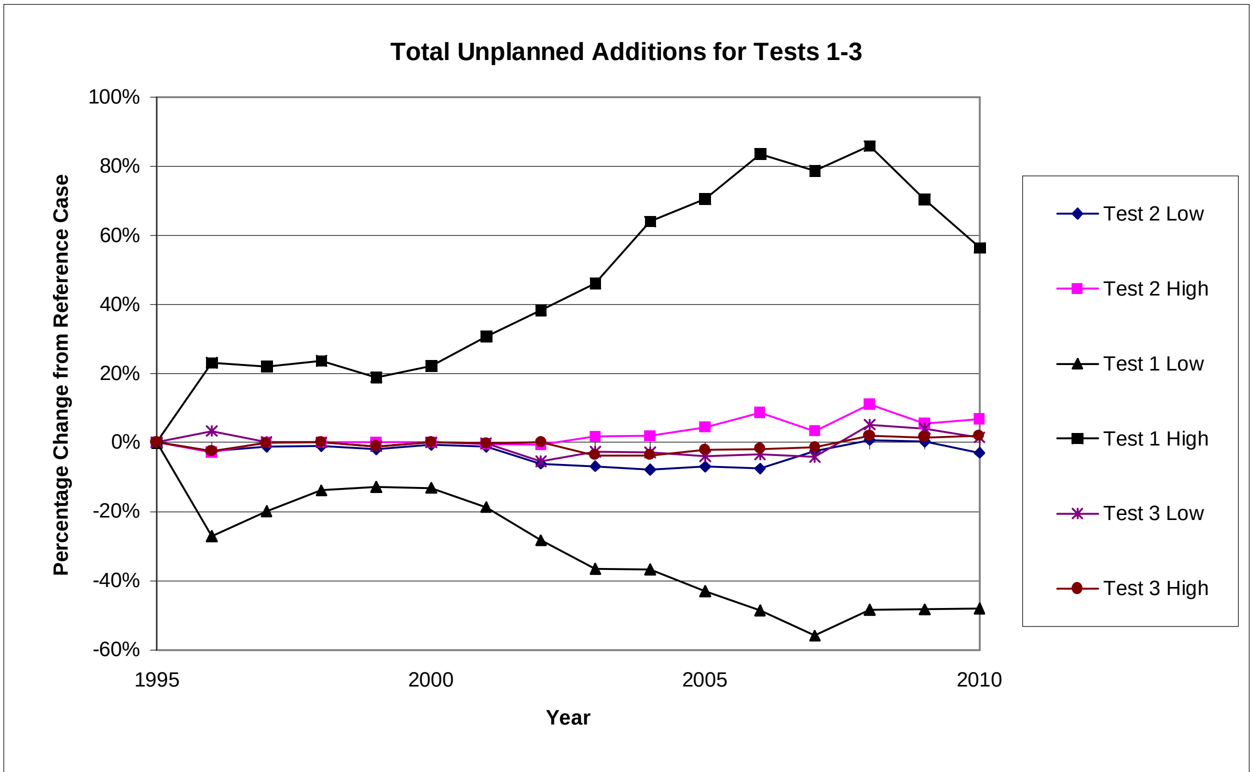
Unplanned Nonutility Additions for Tests 1-3
80%
60%
40%
20%
0%
-20%
-40%
-60%
Percentage Change from Reference Case
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High



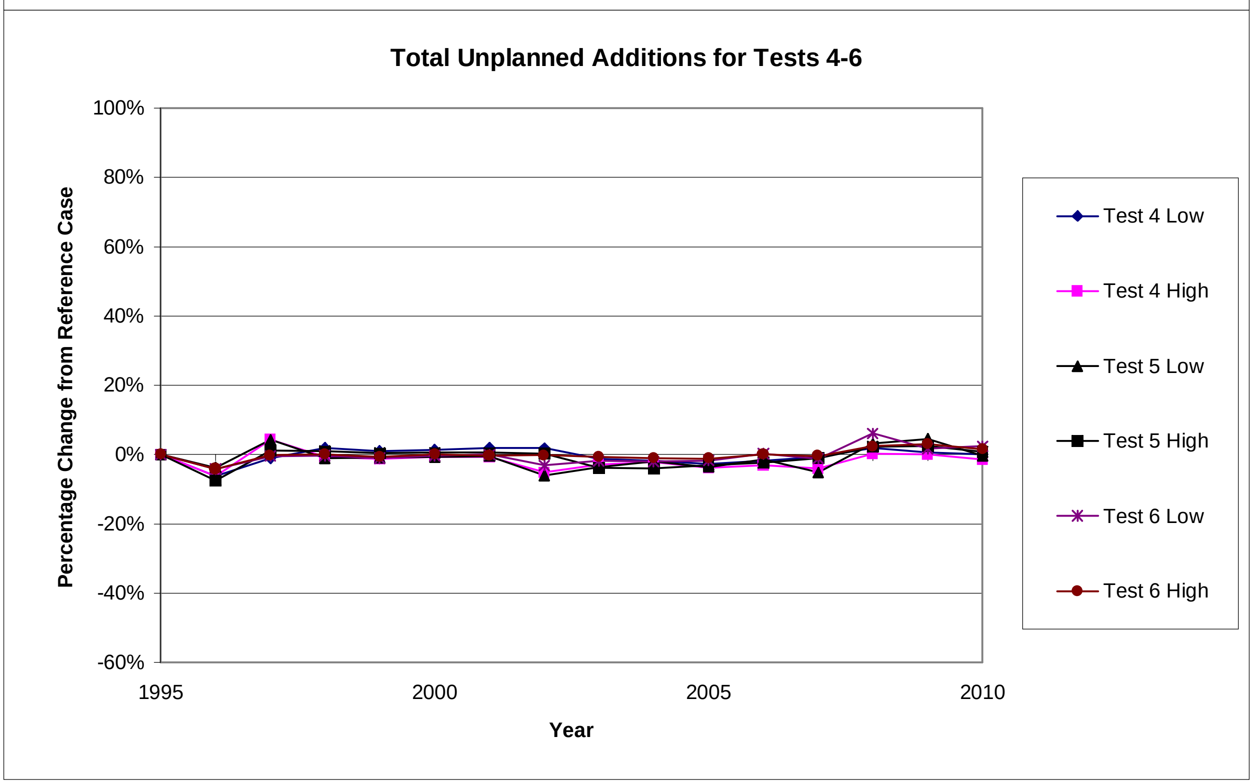
Unplanned Nonutility Additions for Tests 4-6
80%
60%
40%
20%
0%
-20%
-40%
-60%
Percentage Change from Reference Case
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High


Unplanned Nonutility Additions by Fuel Type for Tests 1-3
Gigawatts
60
50
40
30
20
10
0
Reference
Test 1 Low
Test 1 High
Test 2 Low
Test 2 High
Test 3 Low
Test 3 High
Reference
Test 1 Low
Test 1 High
Test 2 Low
Test 2 High
Test 3 Low
Test 3 High
2000
2010
Coal Steam
Gas Fired
Renewables

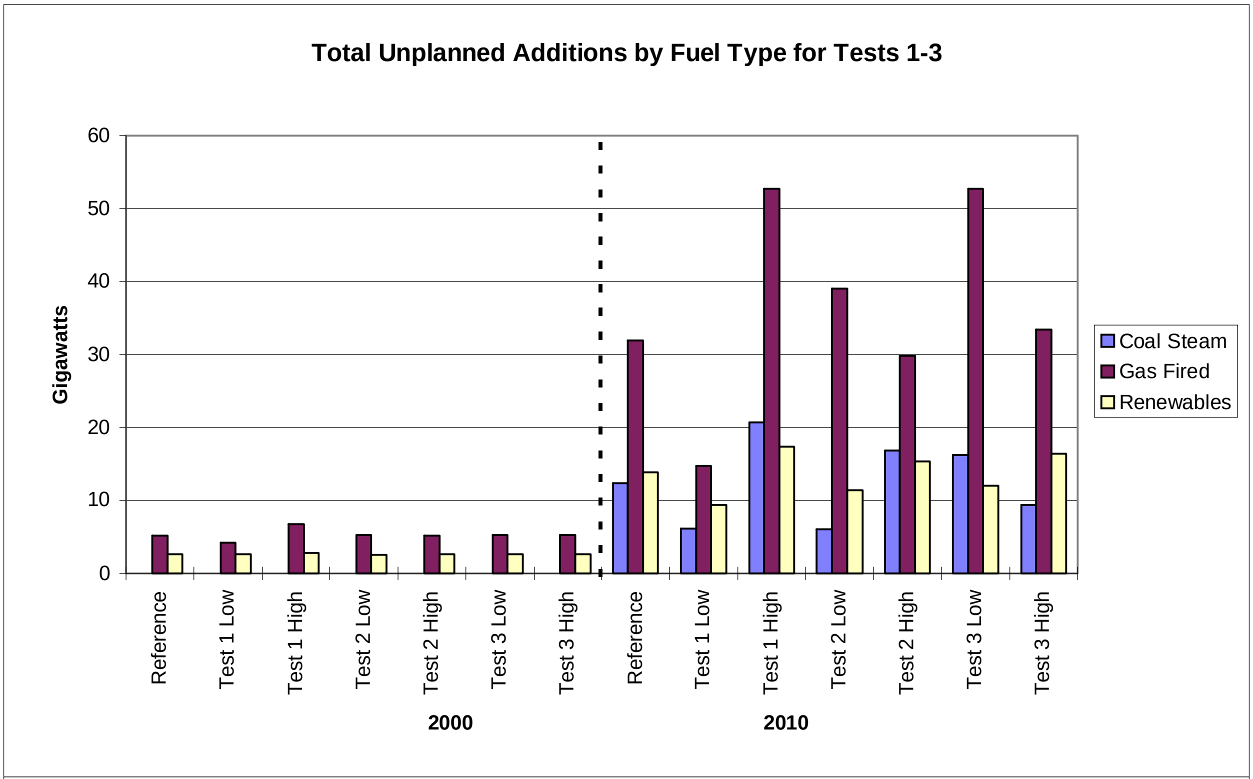

Unplanned Nonutility Additions by Fuel Type for Tests 4-6
Gigawatts
60
50
40
30
20
10
0
Reference
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High
Reference
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High
2000
2010
Coal Steam
Gas Fired
Renewables

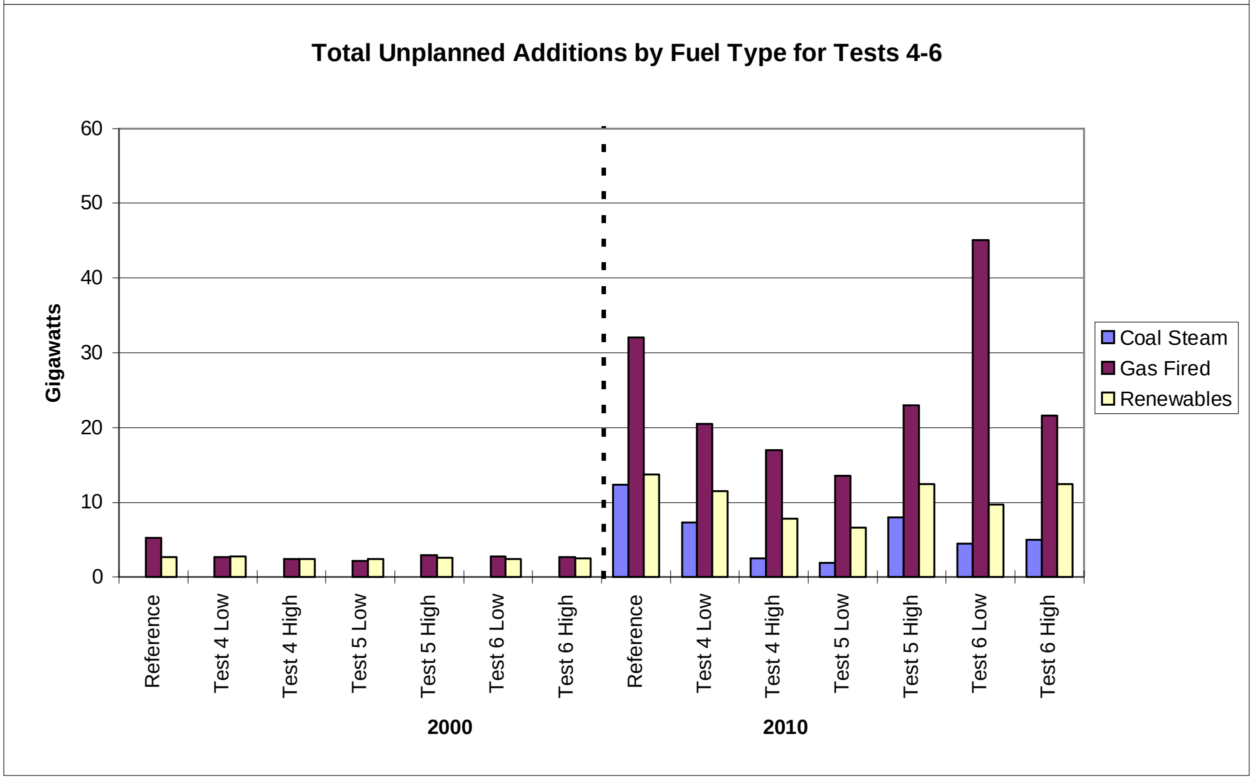


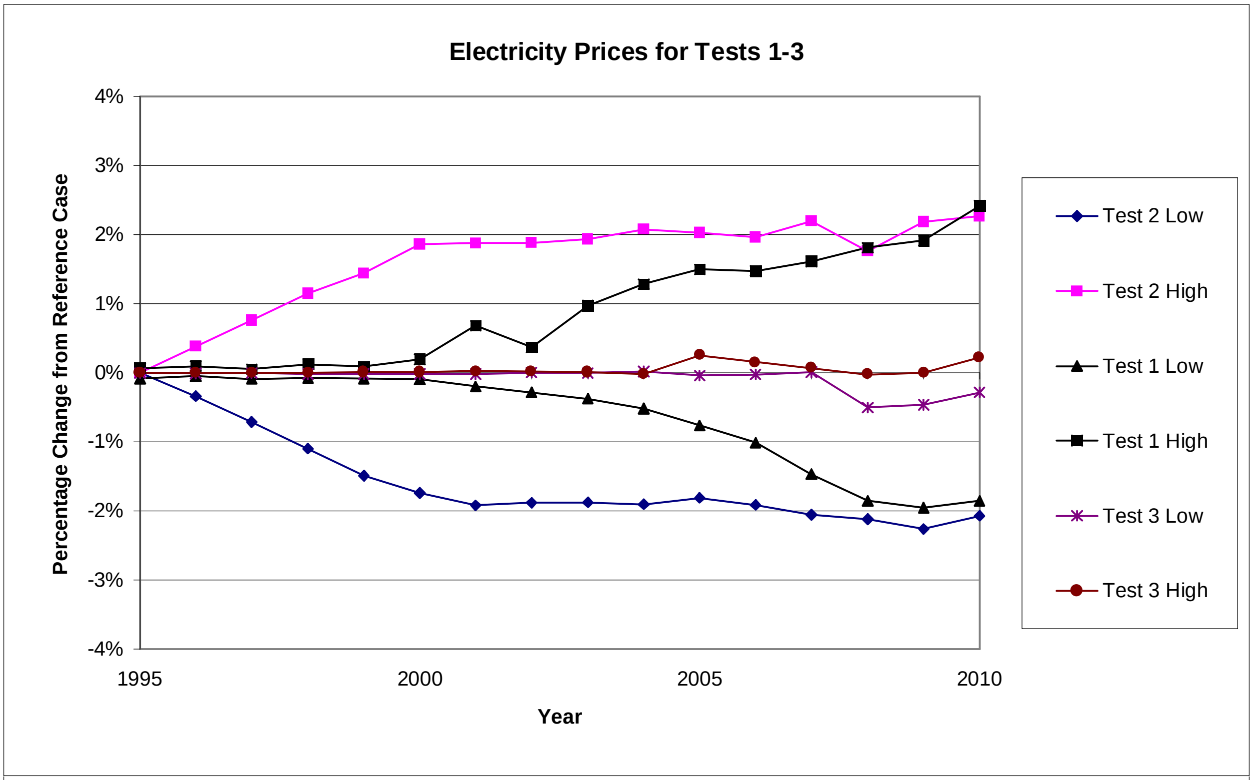
Total Unplanned Additions for Tests 1-3
Percentage Change from Reference Case
100%
80%
60%
40%
20%
0%
-20%
-40%
-60%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High

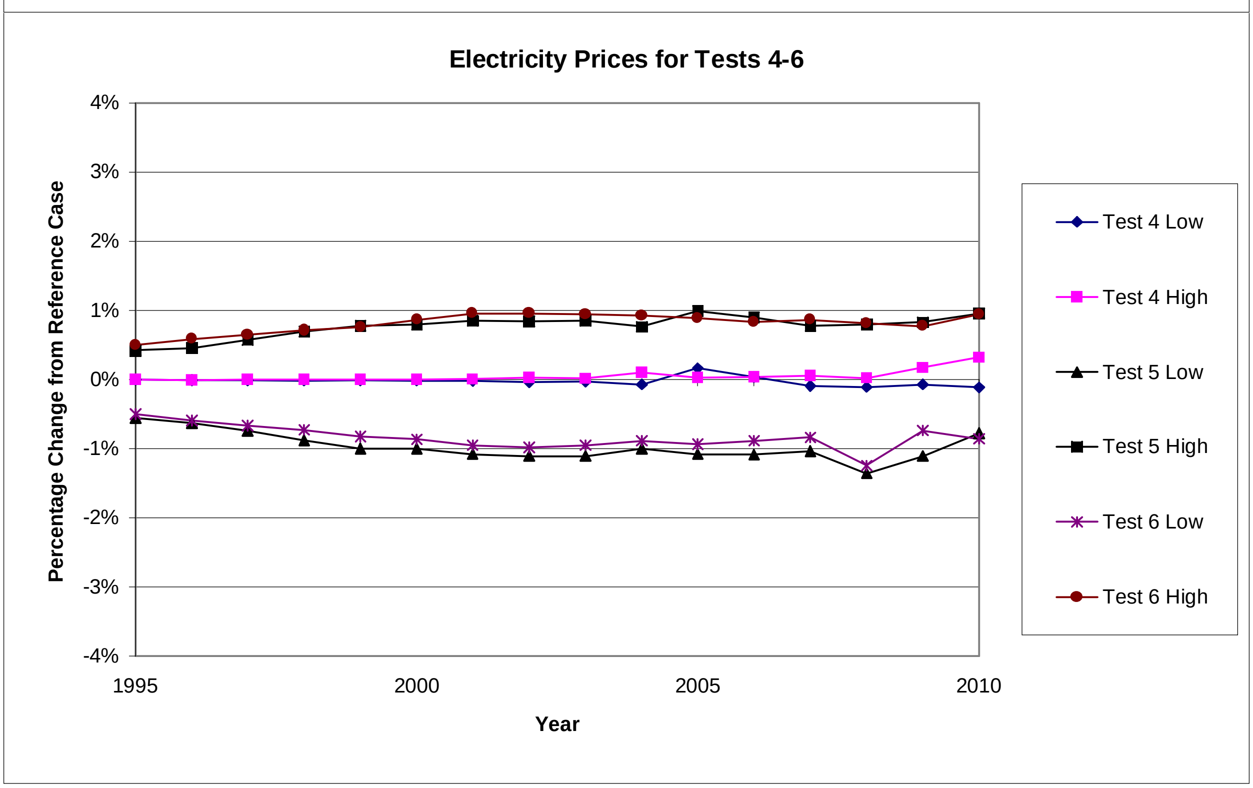


Total Unplanned Additions for Tests 4-6
Percentage Change from Reference Case
100%
80%
60%
40%
20%
0%
-20%
-40%
-60%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High


Total Unplanned Additions by Fuel Type for Tests 1-3
Gigawatts
0
10
20
30
40
50
60
Reference
Test 1 Low
Test 1 High
Test 2 Low
Test 2 High
Test 3 Low
Test 3 High
2000
2010
Coal Steam
Gas Fired
Renewables


Total Unplanned Additions by Fuel Type for Tests 4-6
Gigawatts
0
10
20
30
40
50
60
Reference
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High
2000
2010
Coal Steam
Gas Fired
Renewables


Electricity Prices for Tests 1-3
Percentage Change from Reference Case
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
1995
2000
2005
2010
Year
Test 2 Low
Test 2 High
Test 1 Low
Test 1 High
Test 3 Low
Test 3 High


Electricity Prices for Tests 4-6
Percentage Change from Reference Case
4%
3%
2%
1%
0%
-1%
-2%
-3%
-4%
1995
2000
2005
2010
Year
Test 4 Low
Test 4 High
Test 5 Low
Test 5 High
Test 6 Low
Test 6 High