# Appendix F.5- Sensitivities

**Sensitivities – Year 2008 Analysis**

A limited number of sensitivities were performed around the 2008 base case. As shown in Table 5.1.1., high load, high wind and low gas sensitivities were part of the 2008 analysis. The results of these studies can be found in Appendix F.3 Base Case, Base Case Results section.

**Table 5.1. 1: Base Case Runs**

| | 2008 Load | 2008 Load with additional Wind | High Load (2013 Level) |
|---|---|---|---|
| $4.00 Gas | X | X | X |
| $5.00 Gas | X | X | X |

**Sensitivities – Year 2013 Analysis**

Several sensitivities were performed to better understand the economic drivers – and uncertainties – of the resource and transmission alternatives. The sensitivities centered on Alternative 3 because this alternative serves as a midpoint between transmission expansions designed solely to meet Rocky Mountain loads and more aggressive resource development and expansions for export purposes.

Table B.5.1, shows the risk analyses to the 2013 test year.

**Table F.5. 1: Sensitivities study for Alternative 3, Option 3**

| | Low & High Hydro | DSM | Add Mohave | $CO_2$ Adder ($5 & 15) |
|---|---|---|---|---|
| $4.50 Gas | | | | X |
| $6.50 Gas | X | X | X | X |

**Gas Prices Sensitivities**

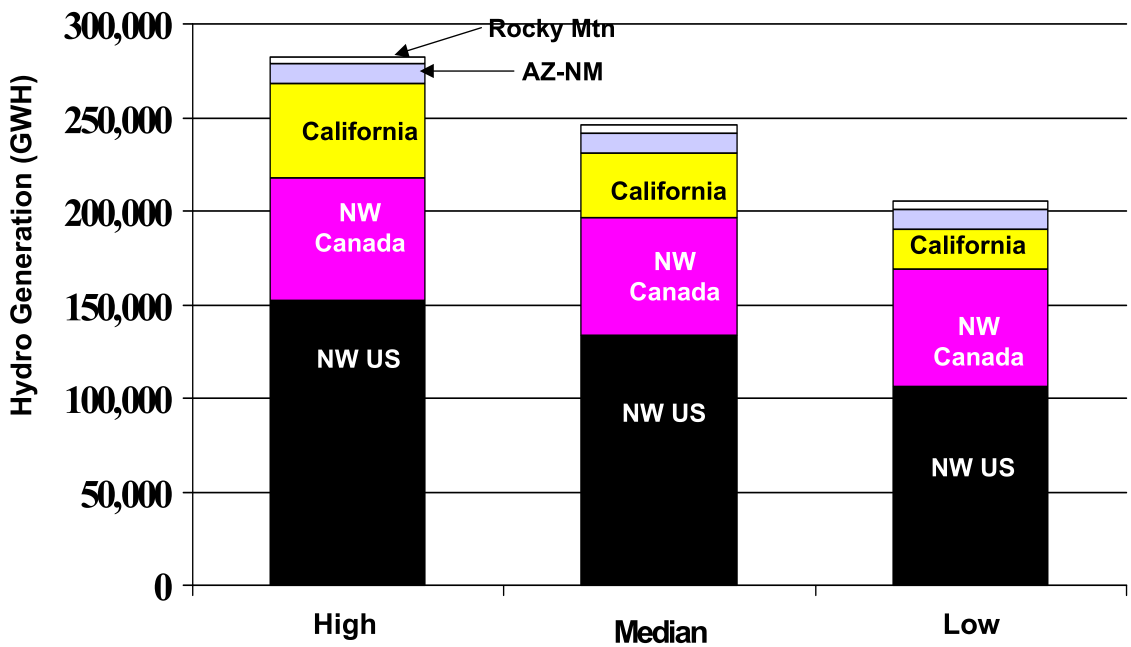
RAWG recommended using $6.50 gas in 2013 dollars ($5.20 gas in 2004 dollars), as the base line gas price assumption for 2013. For more information on the gas price forecast, see Appendix F.1, Gas Prices.

A $4.50 gas price sensitivity was run. The modeling showed that annual production costs are lower in all scenarios. Even in the low gas price sensitivity, the fuel prices for coal and wind resources are lower than the fuel prices for gas-fired resources. This causes coal-fired and wind resources to continue displacing gas-fired resources. A high gas price sensitivity of $8.50 was also performed for the All Gas Reference Case. This sensitivity resulted in higher production costs ($3.5 billion increase over the $6.50 gas price case). Such an increase is essentially due to the higher cost of gas fuel, not to re-dispatch of resources.

**Hydro Condition Sensitivities**

All 2013 alternatives and the 2008 base case used the median hydro conditions. A high and low hydro sensitivity was applied to Alternative 3- Option 3. Figure B.5.1 displays the hydro generation energy studied. Additional information on hydro conditions can be found in Appendix F.1.

**Figure F.5. 1: Annual hydro energy (GWh)**



## DSM

DSM was modeled as a reduction to load. Table B.5.2 displays by area the annual energy assumed in the 2013 study after an acceleration of DSM investment. The DSM sensitivities analysis held all assumptions other than load constant. In addition, two generation configurations were tested: 1) no generation additions, and 2) generation additions consistent with Alterative 2. Table F.5.3 displays the annual energy and summer & winter peak demand assumed in the DSM sensitivities.

**Table F.5. 2: Energy reductions and costs of accelerated DSM for the Rocky Mountain Region**

| Area | 2013 Baseline Energy (GWh) | 2013 Energy Savings (GWh) | Value of Savings in 2013 (Million $) | Energy Efficiency Investment (Million $) |
|---|---|---|---|---|
| Colorado- East | 59,158 | 4,733 | 313 | 987 |
| Colorado- West | 6,265 | 501 | 33 | 105 |
| Idaho- Goshen | 6,621 | 530 | 29 | 90 |
| Idaho- West | 16,552 | 1,324 | 72 | 226 |
| Montana- Broadview | 1,932 | 155 | 11 | 35 |
| Montana- West | 8,177 | 654 | 47 | 148 |
| Montana- East | 588 | 47 | 3 | 11 |
| Utah- Bonanza | 1,093 | 87 | 5 | 16 |
| Utah- North | 36,510 | 2,921 | 167 | 527 |
| Utah- South | 5,296 | 424 | 24 | 76 |
| Wyoming- Black hills | 6,316 | 505 | 25 | 78 |
| Wyoming- Laramie | 3,931 | 314 | 15 | 49 |
| Wyoming- Central | 2,223 | 178 | 9 | 28 |
| Wyoming- North | 3,625 | 290 | 14 | 45 |
| Wyoming- South | 3,868 | 309 | 15 | 48 |
| Other | 13 | 1 | 0 | 0 |
| **Total** | **162,168** | **12,973** | **783** | **2,468** |

**GWh: 162,168= 149,197 + 12,973**

**Table F.5. 3: Loads levels assumed in DSM case**

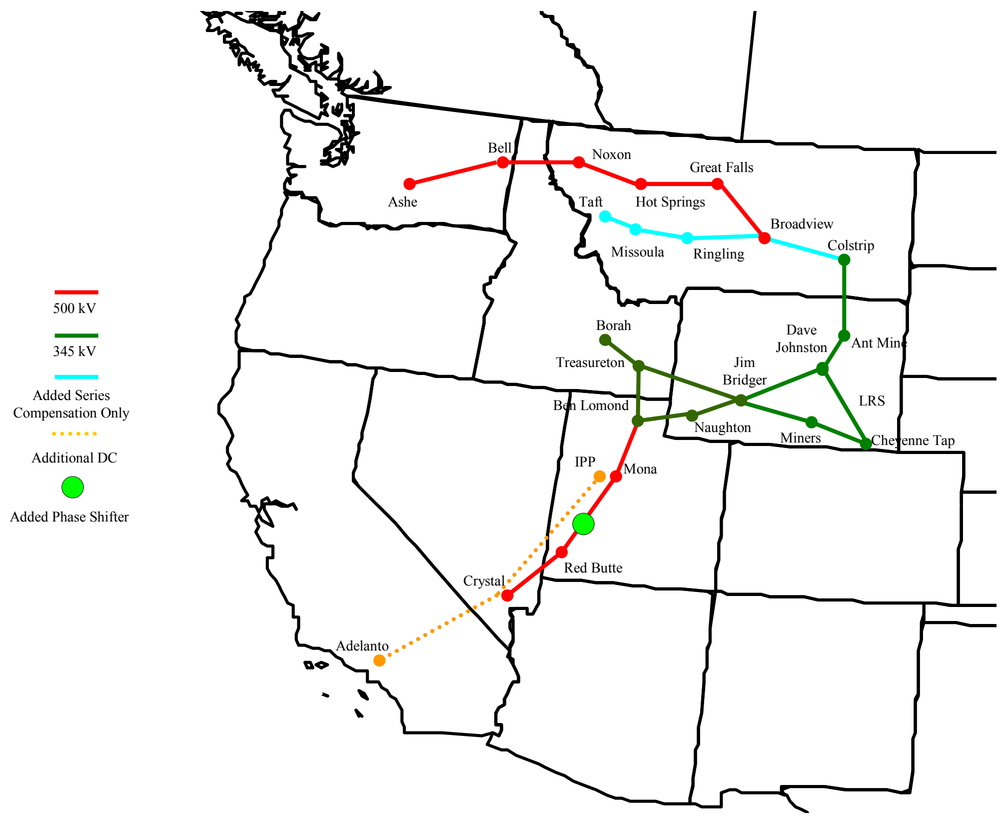
| Region | Annual Energy (MWh) | Summer Peak (MW) | Winter Peak (MW) | | Summer Peak Growth (MW) |
|---|---|---|---|---|---|
| Rocky Mountain | 149,196,529 | 23,803 | 21,823 | | 100 |
| Desert Southwest | 149,915,758 | 29,432 | 21,241 | | 883 |
| California | 323,394,364 | 58,965 | 45,070 | | 522 |
| Northwest | 185,403,864 | 25,610 | 31,003 | | 753 |
| Canada | 134,489,410 | 16,446 | 21,831 | | 132 |
| Mexico | 19,896,003 | 3,626 | 2,600 | | 1,130 |
| | | | | | |
| **Totals** | **962,295,928** | **157,882** | **143,568** | | **3,520** |

Two DSM options were conducted for 2013. Each option targeted a different objective but solved for the same load requirements (shown in Table B.5.2) and required the same level of DSM capital investment. Additional information concerning DSM is found in the *Expanded Energy Efficiency Scenario for the RMATS Study* discussion on the following page.

**Option 1:** Does not add generation or transmission to the Western Interconnect. It is assumed that all load growth between 2008 and 2013 would be served by DSM.

**Option 2:** Adds 3,900 MW of generation in the Rocky Mountain Area- the same generation assumed in Alternative 2. This generation is then exported to West Coast Markets as shown in Figure B.5.3.

**Figure F.5. 2: DSM Option 2 recommended transmission to be built**



**Expanded Energy Efficiency Scenario for the RMATS Study- Howard Geller, 2/12/04**

Southwest Energy Efficiency Project (SWEEP) has completed a major study examining the potential for and benefits from increasing the efficiency of electricity use in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming.[1] The study models two scenarios, a "business as usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and workplaces during 2003-2020.

Major regional benefits of pursuing the High Efficiency Scenario include:

- Reducing average electricity demand growth from 2.6 percent per year in the Base Scenario to 0.7 percent per year in the High Efficiency Scenario;
- Reducing total electricity consumption 18 percent (41,400 GWh/yr) by 2010 and 33 percent (99,000 GWh/yr) by 2020;
- Eliminating the need to construct thirty-four 500 megawatt power plants or their equivalent by 2020;
- Saving consumers and businesses $28 billion net between 2003-2020, or about $4,800 per current household in the region;
- Increasing regional employment by 58,400 jobs (about 0.45 percent) and regional personal income by $1.34 billion per year by 2020;
- Saving 25 billion gallons of water per year by 2010 and nearly 62 billion gallons per year by 2020; and
- Reducing carbon dioxide emissions, the main gas contributing to human-induced global warming, by 13 percent in 2010 and 26 percent in 2020, relative to the emissions of the Base Scenario.

These significant benefits can be achieved with a total investment of nearly $9 billion in efficiency measures during 2003-2020 (2000 $). The total economic benefit during this period is estimated to be about $37 billion, meaning the benefit-cost ratio is about 4.2. The efficiency measures on average would have a cost of $0.02 per kWh saved.

The High Efficiency Scenario is based on the accelerated adoption of cost-effective energy efficiency measures, including more efficient appliances and air conditioning systems, more efficient lamps and other lighting devices, more efficient design and construction of new homes and commercial buildings, efficiency improvements in motor systems, and greater efficiency in other devices and processes used by industry. These measures are all

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[1] *The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest.* Southwest Energy Efficiency Project. Boulder, CO. Nov. 2002. www.swenergy.org/nml/index.html

commercially available but underutilized today. Accelerated adoption of these measures cannot eliminate all the electricity demand growth anticipated by 2020 in the Base Scenario, but it can eliminate most of it.

The study acknowledges that the High Efficiency future will not happen on its own. While some utility, state, and local energy efficiency programs are advancing energy efficiency in the region, these programs are relatively limited in scope and budget. The study recommends new and expanded initiatives to achieve the High Efficiency future and its benefits, including:

- Adopting Systems Benefit Charges or Energy Efficiency Performance Standards to expand utility-based energy efficiency programs;
- Providing utilities with financial incentives to implement effective energy efficiency programs;
- Reforming utility rates to encourage greater energy efficiency;
- Upgrading to state-of-the-art building codes and promoting the construction of highly efficient new buildings that exceed these codes;
- Adopting minimum efficiency standards on products not yet covered by national standards;
- Providing sales tax waivers or income tax credits for innovative energy-efficient technologies;
- Expanding participation in industrial voluntary commitment programs;
- Adopting "best practices" in public sector energy management;
- Expanding energy efficiency training and technical assistance programs; and
- Incorporating energy efficiency initiatives in pollution control strategies.

Furthermore, the study indicates that expanding utility energy efficiency programs alone could result in 10-15% energy savings by 2020. Indeed, the most effective utility energy efficiency programs in the United States are providing electricity savings equivalent to about 1% of the utility's retail electricity sales each year, meaning 10% savings after a 10-year effort.[2]

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[2] For example, utility programs in Connecticut, Massachusetts, and Minnesota have achieved 1% (or close to 1%) electricity savings per year. See direct testimony of Jeff Schlegel on behalf of the Southwest Energy Efficiency Project, before the Arizona Corporation Commission in Docket No. E-01345A-0437, Feb. 3, 2004. www.swenergy.org/news/Schlegel_direct_testimony_Feb3.pdf

**RMATS Energy Efficiency Scenario**

The high efficiency scenario for the RMATS study assumes that utility (or state-based) energy efficiency programs ramp up during 2004 and 2005, and that these programs reduce electricity use by 1% per year and summer peak demand by 1.5% per year during 2006-2013. These programs occur in all states under consideration including CO, ID, MT, UT, and WY. A number of considerations underpin these assumptions. First, there is little or no electricity savings from utility or state-based energy efficiency programs in the baseline scenario. Second, after the phase-in period, the electricity savings are equivalent to the savings achieved by the best efficiency programs in the country, but are only about half the savings identified in SWEEP's *New Mother Lode* study. Third, the peak demand reduction is greater than the electricity savings in percentage terms because demand-side management (DSM) programs tend to emphasize measures that reduce peak electricity demand, such as reducing cooling load and improving the efficiency of cooling systems. These measures provide the most benefits to utilities. And with the emphasis on summer peak load reduction, it is assumed that the winter peak load reduction is the same as the overall electricity savings in percentage terms.

Assuming 0.33% energy savings in 2004, 0.67% energy savings in 2005, and 1% savings each year during 2006-2013 leads to total savings of 9% in 2013 (assuming no degradation in savings from measures installed in the early years). Since in reality there will be some loss of savings over time, it is more conservative to assume say 8% energy savings in 2013 as a result of this effort. The winter peak demand reduction is assumed to be 8% as well. But since the rate of peak demand reduction is assumed to be 1.5 times the rate of electricity savings in percentage terms, there would be a 12% summer peak demand reduction by 2013.

It is worth noting that more progressive utilities in the Southwest region have already established electricity savings and peak demand reduction goals along these lines. For example, the Ft. Collins, Colorado municipal utility has adopted a goal to reduce per capita electricity consumption 10% and per capita peak demand 15% by 2012. And Austin Energy, the municipal utility in Austin, Texas, plans to cut electricity use and peak demand 15% by 2020 through its energy efficiency and load management efforts.

Table B.1.4 presents the electricity savings and peak load reductions in the high efficiency scenario in 2013 by load area, for the primary load areas in the RMATS project. The electricity savings and summer peak load reductions eliminate a significant fraction (but by no means all) of the load growth projected during 2003-2013 in the baseline scenario, especially in key areas such as the CO East and UT North. For the region as a whole, the high efficiency scenario eliminates about 50% of the summer peak demand growth and 40% of the total electricity load growth during 2003-2013 in the baseline scenario.

Table B.1.2 presents the estimated investment in energy efficiency measures necessary to realize this level of electricity savings and peak load reduction by 2013. These estimates assume that electricity in the region costs $0.06/kWh on average (2004 dollars) and that efficiency measures have a three year simple payback period on average.[3] A three year payback is a fairly conservative assumption; many efficiency measures have a payback of under three years.[4] To achieve the projected energy savings in the high efficiency scenario, the estimated total investment in energy efficiency in the RMATS region during 2004-2013 is about $2.5 billion (2004 dollars). This figure includes both utility and participant costs, and includes a 5% surcharge on top of the cost of efficiency measures to account for efficiency program marketing, administration, etc.

There is potential to significantly increase energy efficiency in other western states as well as in the RMATS region. For Arizona and New Mexico, it is reasonable to assume the same electricity savings potential (8% electricity savings, 12% summer peak demand reduction by 2013) since these states have very weak energy efficiency programs at the present time. However, it is reasonable to assume half as much incremental savings potential in California, Oregon and Washington (an incremental 4% electricity savings and 6% peak demand by 2013) since relatively well-funded, substantial energy efficiency programs are underway in these states and savings from these programs is already factored into load forecasts. However, it is still possible to scale up efficiency programs and achieve greater energy savings in the coastal states, and in fact California is in the midst of establishing new, more aggressive energy savings and peak load reduction goals and scaling up DSM programs in order to meet these goals.[5]

[3] These estimates use average electricity prices in each state, assuming that electricity prices in 2004 are 10% greater than they were in 2001 (the last year for which state average price data are available). Electricity prices have increased in recent years due to rising natural gas prices and other factors.
[4] See Reference 1, for example.
[5] *Proposed Energy Savings Goals for Energy Efficiency Programs in California.* CEC staff report 100-03-021, California Energy Commission, Sacramento, CA, Oct. 27, 2003.

## Table F.5. 4: Loads assumed in DSM scenario

| Area | 2003 Summer Peak (MW) | 2003 Winter Peak (MW) | 2003 Energy (GWh) | Baseline Scenario 2013 Summer Peak (MW) | Baseline Scenario 2013 Winter Peak (MW) | Baseline Scenario 2013 Energy (GWh) | High Efficiency Scenario 2013 Summer Peak (MW) | High Efficiency Scenario 2013 Winter Peak (MW) | High Efficiency Scenario 2013 Energy (GWh) | High Eff. Scenario Savings 2013 Summer Peak (MW) | High Eff. Scenario Savings 2013 Winter Peak (MW) | High Eff. Scenario Savings 2013 Energy (GWh) | Savings in 2013 as a fraction of baseline growth 2003-2013 Summer Peak (MW) | Savings in 2013 as a fraction of baseline growth 2003-2013 Winter Peak (MW) | Savings in 2013 as a fraction of baseline growth 2003-2013 Energy (GWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Colorado- East | 7,724 | 7,329 | 46,256 | 10,205 | 8,559 | 59,158 | 8,980 | 7,874 | 54,425 | 1,225 | 685 | 4,733 | 0.49 | 0.56 | 0.37 |
| Colorado- West | 806 | 860 | 5,433 | 941 | 969 | 6,265 | 828 | 891 | 5,764 | 113 | 78 | 501 | 0.84 | 0.71 | 0.60 |
| Idaho- Goshen | 1,132 | 1,085 | 5,662 | 1,436 | 1,206 | 6,621 | 1,264 | 1,110 | 6,091 | 172 | 96 | 530 | 0.57 | 0.80 | 0.55 |
| Idaho- West | 2,701 | 2,170 | 13,621 | 3,388 | 2,562 | 16,552 | 2,981 | 2,357 | 15,228 | 407 | 205 | 1,324 | 0.59 | 0.52 | 0.45 |
| Montana- Broadview | 287 | 293 | 1,820 | 303 | 305 | 1,932 | 267 | 281 | 1,777 | 36 | 24 | 155 | 2.27 | 2.03 | 1.38 |
| Montana- West | 1,079 | 1,096 | 6,828 | 1,275 | 1,275 | 8,177 | 1,122 | 1,173 | 7,523 | 153 | 102 | 654 | 0.78 | 0.57 | 0.48 |
| Montana- East | 72 | 72 | 455 | 92 | 91 | 588 | 81 | 84 | 541 | 11 | 7 | 47 | 0.55 | 0.38 | 0.35 |
| Utah- Bonanza | 42 | 41 | 255 | 202 | 173 | 1,093 | 178 | 159 | 1,006 | 24 | 14 | 87 | 0.15 | 0.10 | 0.10 |
| Utah- North | 3,944 | 3,146 | 22,901 | 6,870 | 5,165 | 36,510 | 6,046 | 4,752 | 33,589 | 824 | 413 | 2,921 | 0.28 | 0.20 | 0.21 |
| Utah- South | 455 | 367 | 2,546 | 1,001 | 793 | 5,296 | 881 | 730 | 4,872 | 120 | 63 | 424 | 0.22 | 0.15 | 0.15 |
| Wyoming- Black hills | 774 | 743 | 5,097 | 936 | 939 | 6,316 | 824 | 864 | 5,811 | 112 | 75 | 505 | 0.69 | 0.38 | 0.41 |
| Wyoming- Laramie | 498 | 508 | 3,598 | 566 | 532 | 3,931 | 498 | 489 | 3,617 | 68 | 43 | 314 | 1.00 | 1.77 | 0.94 |
| Wyoming- Central | 292 | 285 | 2,005 | 316 | 312 | 2,223 | 278 | 287 | 2,045 | 38 | 25 | 178 | 1.58 | 0.92 | 0.82 |
| Wyoming- North | 400 | 453 | 3,276 | 451 | 496 | 3,625 | 397 | 456 | 3,335 | 54 | 40 | 290 | 1.06 | 0.92 | 0.83 |
| Wyoming- South | 348 | 332 | 2,549 | 514 | 504 | 3,868 | 452 | 464 | 3,559 | 62 | 40 | 309 | 0.37 | 0.23 | 0.23 |
| Other | 3 | 3 | 24 | 3 | 3 | 13 | 3 | 3 | 12 | 0 | 0 | 1 | NA | NA | NA |
| **Total** | **20,557** | **18,783** | **122,326** | **28,499** | **23,884** | **162,168** | **25,079** | **21,973** | **149,195** | **3,420** | **1,911** | **12,973** | **0.43** | **0.37** | **0.33** |

**Mohave In**

A sensitivity that included the Mohave coal plant was conducted using the Alternative 3-Option 3 case. Mohave is a 1,580 MW coal plant located near the border of Nevada and Arizona. It is scheduled to be retired at the end of 2005. This sensitivity was designed to test the impact on new Rocky Mountain area plants if rail coal plants closer to export load centers were added. The study found that by including Mohave, dispatch of Rocky Mountain plants changes marginally, while other areas, such as California and the Desert Southwest, benefited from Mojave through lower production costs.

**New Coal Unit at Midpoint, ID versus Jim Bridger, Wyoming**

During the development process for Alternatives 1 and 2, sensitivities were run comparing the location of a 575 MW coal plant at Midpoint versus at Bridger. Comparing the two sites, it was determined the production cost savings by locating the plant at Bridger nearly offsets the additional transmission construction costs required to deliver the energy to Midpoint. Consequently, other factors would need to come into play in deciding the ultimate location of this proposed coal resource.

**Sensitivity Production Cost Results**

As depicted in Figure B.5.6, gas prices and hydro conditions are by far the major drivers of production cost variability. Higher gas prices make coal and wind resources more economic in the West because their low fuel cost makes them cheaper to run than gas plants, even taking into account their long-range transmission costs. Conversely, low gas prices would remove much of this competitive advantage if low prices persist -- and would remove the economic justification for major transmission expansion.

Just as with wind generation, hydro generation uses a low or no cost fuel. Wind and coal generation are very economic in years when hydro supplies are poor. For most long-term planning purposes, average hydro conditions are generally used.

Table B.5.7 also provides an area-by-area view of the production costs. The $6.50 Gas Case is also referred to as Recommendation 2/Alternative 3- Option 3

## Table F.5. 5: Annual production costs for each area

| ID | Area Name | $6.50 Gas | Low Hydro | High Hydro | $4.50 Gas | DSM- Option 1 | DSM- Option 2 | Mohave in |
|---|---|---|---|---|---|---|---|---|
| 1 | New Mexico | 434 | 445 | 427 | 409 | 449 | 418 | 427 |
| 2 | Arizona | 3,714 | 3,880 | 3,517 | 3,097 | 3,890 | 3,683 | 3,515 |
| 3 | Nevada | 927 | 967 | 866 | 711 | 1,118 | 908 | 517 |
| 4 | WAPA- LC | 418 | 432 | 392 | 316 | 533 | 493 | 264 |
| 5 | Mexico | 866 | 874 | 852 | 650 | 660 | 651 | 858 |
| 6 | Imperial | 14 | 20 | 10 | 12 | 30 | 25 | 15 |
| 7 | San Diego | 654 | 821 | 537 | 462 | 674 | 601 | 635 |
| 8 | So. California | 1,318 | 1,644 | 1,161 | 1,004 | 1,859 | 1,516 | 1,698 |
| 9 | LADWP | 257 | 288 | 249 | 194 | 479 | 346 | 253 |
| 10 | IPP | 339 | 341 | 339 | 339 | 250 | 250 | 340 |
| 11 | PG AND E | 3,155 | 3,608 | 2,678 | 2,402 | 3,834 | 3,320 | 3,209 |
| 12 | Northwest | 1,908 | 2,379 | 1,550 | 1,504 | 1,855 | 1,619 | 1,941 |
| 13 | BC Hydro | 471 | 593 | 388 | 346 | 351 | 267 | 480 |
| 14 | Aquila | 29 | 32 | 25 | 20 | 0 | 0 | 29 |
| 15 | Alberta | 1,404 | 1,452 | 1,337 | 1,154 | 1,249 | 1,211 | 1,402 |
| 16 | Idaho- West | - | 0 | 0 | - | 3 | 0 | - |
| 18 | Montana- West | 69 | 80 | 61 | 50 | - | - | 71 |
| 19 | Sierra | 213 | 242 | 196 | 180 | 172 | 131 | 213 |
| 20 | Wyoming- Central | 112 | 112 | 111 | 109 | 49 | 76 | 112 |
| 22 | Bonanza | 63 | 65 | 62 | 63 | 69 | 67 | 64 |
| 23 | Utah- North | 142 | 158 | 130 | 127 | 216 | 183 | 136 |
| 24 | Utah- South | 422 | 433 | 407 | 372 | 386 | 471 | 420 |
| 25 | Colorado- East | 662 | 713 | 631 | 596 | 895 | 802 | 650 |
| 26 | Colorado- West | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 28 | Black Hills | 53 | 58 | 50 | 52 | 80 | 64 | 51 |
| 29 | Laramie River Station | 83 | 83 | 83 | 83 | 83 | 82 | 83 |
| 30 | Jim Bridger | 305 | 305 | 300 | 305 | 261 | 307 | 305 |
| 32 | Broadview | 48 | 48 | 48 | 48 | 17 | 36 | 48 |
| 33 | Colstrip- Crossover | 185 | 184 | 184 | 185 | 165 | 177 | 185 |
| | **Total** | **18,465** | **20,454** | **16,792** | **14,988** | **19,826** | **17,905** | **18,118** |

### Modeling $CO_2$ Adders

The risk of increased costs due to potential $CO_2$ mitigation measures is a key uncertainty associated with decisions to build new coal plants.

Two $CO_2$ cost adders were studied for each of the 2013 studies and sensitivities: $5 and $15 per ton of $CO_2$. The adders were applied to the incremental $CO_2$ tons produced from a case that does not build any new generation in the Rocky Mountain Area. $CO_2$ cost adders were not included in the dispatch simulation in ABB Market Simulator.

The $CO_2$ output from burning an MMBtu of coal was estimated at 205 pounds and 117 pounds for gas. To calculate the effect of the $CO_2$ adders, the incremental tons of $CO_2$ burned were multiplied by the adder cost for each case. The results of this analysis are shown in Table B.5.7.

In each case, with the exception of the DSM and High Hydro sensitivities, the amount of $CO_2$ tons increased. This is largely due to the increase in coal plant capacity and generation. The reason for the reduction in $CO_2$ costs for the DSM options is that lower load requirements reduce the dependency of fossil fuel resources, therefore reducing the adder amount. Higher hydro conditions also reduce the adder because the increase in hydro energy removes the need to burn fossil fuels. The greatest risk to increased emissions costs is low hydro conditions. In the low hydro case, the adder more than doubled from the median water year case. Fuel prices marginally change the amount of adder as shown between the $4.50 gas sensitivity and the Alternative 3- Option 3 results. This is because the gas price is not low enough to make a gas plant marginally more economic than a coal plant.

### Table F.5. 6: Incremental $CO_2$ adder cost (dollars in millions)

| *Study* | $5 | $15 |
|---|---|---|
| Alternative 1 | 28 | 85 |
| Alternative 2 | 33 | 100 |
| Alternative 3- Option 1 | 78 | 234 |
| Alternative 3- Option 2 | 80 | 240 |
| Alternative 3- Option 3 | 80 | 239 |
| Alternative 3- Option 4 | 80 | 239 |
| Alternative 4- Option 1 | 74 | 221 |
| Alternative 4- Option 2 | 73 | 220 |
| DSM- Option 1 | (75) | (226) |
| DSM- Option 2 | (62) | (185) |
| Low Hydro Senstivity | 176 | 528 |
| High Hydro Sensitivity | (7) | (20) |
| $4.50 Gas Sensitivity | 80 | 240 |
| Mohave in Senstivity | 121 | 362 |

## Modeling a Carbon Adder as Fuel Price Adder

### Table F.5. 7: Impact of $CO_2$ Adder on Dispatch of System (Assume no change in Generation Resources)

| Fuel Name | $CO_2$ Ton /mmbtu | No Adder (mmbtu) | $5/Ton Adder (mmbtu) | $15/Ton Adder (mmbtu) | $40/Ton Adder (mmbtu) |
|---|---|---|---|---|---|
| Biomass | 0 | 262 | 262 | 262 | 262 |
| Coal | 207 | 3,433,155,835 | 3,432,712,878 | 3,431,262,866 | 2,937,467,764 |
| Oil 2 | 150 | - | - | - | - |
| Oil 6 | 180 | 660 | - | - | - |
| Gas | 117 | 2,229,896,085 | 2,229,901,647 | 2,230,160,283 | 2,555,489,788 |
| Geothermal | 0 | 16,359 | 16,359 | 16,359 | 16,359 |
| Nuclear | 0 | 70,595 | 70,599 | 70,599 | 70,599 |
| Other | 0 | 5,840,721 | 5,847,240 | 5,852,684 | 5,913,582 |
| Total Tons of $CO_2$ | | 485,780,609 | 485,735,029 | 485,600,083 | 453,524,066 |
| Change From No Adder | | | (45,580) | (180,526) | (32,256,543) |
| Percent Change From No Adder | | | -0.009% | -0.037% | -6.640% |

### Table F.5. 8: Impact of $CO_2$ Adders on Fuel & Non-Fuel VOM

| Carbon Adder Sensitivity | Carbon Adder ($000) | Production Costs (Without Adder) | Production Costs with Adder ($000) | Change from Case with No Adder | Percent Change in Production Costs |
|---|---|---|---|---|---|
| No Carbon Adder | 0 | 18,465,093 | 18,465,093 | 0 | 0 |
| Carbon Adder @ $5/Ton | 2,428,675 | 18,464,720 | 20,893,395 | (373) | -0.002% |
| Carbon Adder @ $15/Ton | 7,284,001 | 18,465,991 | 25,749,992 | 898 | 0.005% |
| Carbon Adder @ $40/Ton | 18,140,963 | 19,576,163 | 37,717,126 | 1,111,071 | 6.017% |

The ABB Market Simulator model is designed to analyze the transmission system while minimizing production costs of a given electric system given the constraints (loads, resources, fuel costs, and transmission). The $CO_2$ output from burning an MMBtu of coal was estimated at 207 pounds while the number for natural gas was estimated at 117 pounds. A given a price per ton of $CO_2$ can be incorporated in the fuel costs and thus be reflected in the plant dispatch. These adders were calculated and attached to all fossil fuels and the dispatch impact was calculated.

Most proposed legislation allows a given level of emissions and only levies taxes on the emissions above that level. Thus, only a fraction of the emission is taxed, therefore avoiding some costs charge to customers.

The dispatch impact of a $CO_2$ adder on existing plants is much less than the impact on the choice of generation plant to build. This is similar to the economics of choosing between to drive a car or to ride a bus to work are different if you already own a car. This is because all fixed costs of owning the car drop out and you only have the incremental running costs of the car to compare with the cost of the bus ticket. The greatest ability to reduce $CO_2$ emissions occurs before the resource is built. As the ABB Market Simulator focuses on the use of the transmission system, it has limited abilities to analyze resource choices, unlike the models utilities use in IRP efforts.

**Figure F.5. 3: Energy Resource Selection by $CO_2$ Adder Level**

**(Draft for Illustration only)**

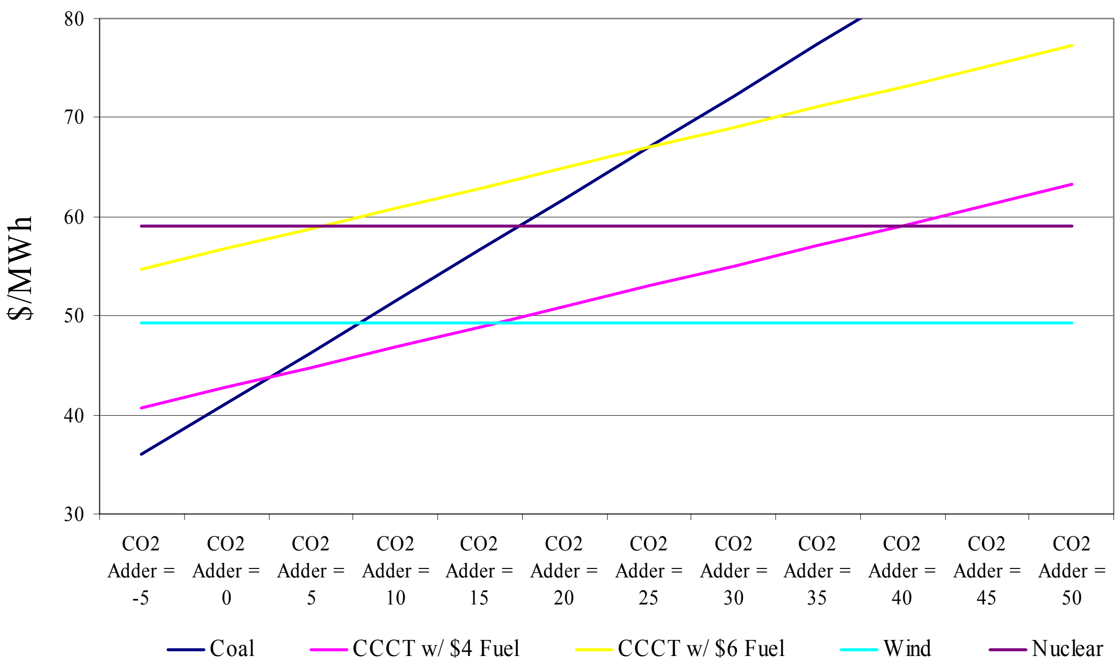

**Figure F.5. 4: $CO_2$ Adder vs Running Costs Coal Over CCCT up to $25-50/Ton Depending on Gas Price (Draft for Illustration Only)**