Supplement to Analysis of a 10 percent Renewable Portfolio Standard

On June 10, 2003, Senator Pete Domenici, Chairman of the Senate Committee on Energy and Natural Resources, requested additional analysis of a Renewable Portfolio Standard (RPS), expected to be proposed as an amendment to energy legislation currently pending before the U.S. Senate.[1] This request asked the Energy Information Administration (EIA) to provide additional results from two previously released EIA analyses[2] of the proposed legislation, and to conduct further analyses with modified assumptions.

Specifically, Senator Domenici requested that EIA provide cumulative costs through 2030 for the May and June 2003 *Analysis of a 10-percent Renewable Portfolio Standard* and *Addendum* analyses, as well as a year-by-year accounting for credit and allowance expenditures. Senator Domenici also requested that EIA examine the same two scenarios from the May and June reports, respectively, a national RPS with a non-inflation adjusted 1.5 cent per kilowatt-hour price cap and a national RPS with an inflation-adjusted 1.5 cent per kilowatt-hour price cap, under the assumption that current State-level mandate programs for renewables (such as State-level RPS programs) fail to stimulate investment in renewable power. Senator Domenici also requested an analysis assuming that biomass co-firing, a significant contributor to satisfying the RPS requirements in the May and June analyses, would not be available or would be limited to low levels. Finally, Senator Domenici requested that EIA calculate compliance costs for the program if no new renewable resources could be supplied from the private market and all credits were purchased from the Secretary of Energy, as provided for in the proposed legislation. Senator Domenici also had additional questions about EIA assumptions for the analysis and their impact on the results.

A. More Detailed Data from The May 2003 Study and Its Addendum

EIA projects energy markets through 2025. Projected cumulative power industry costs through 2025 are $3.6 billion higher in the RPS Nominal Cap case (1.5 cent per kilowatt-hour credit price cap, not adjusted for inflation) than in the Reference case. For the RPS Real Cap case (1.5 cent per kilowatt-hour credit price cap, adjusted for inflation), this incremental cost over the Reference case is $4.9 billion in 2001 dollars. Both of these cumulative costs assume a real discount rate of 7 percent, the standard rate for analysis of future cost and benefit monetary values for Federal programs.[3] The request letter for the current analysis specified showing results without considering the time value of money[4].

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[1] Letter from Senator Domenici to EIA Administrator Guy Caruso dated June 10, 2003. See appendix A

[2] *Analysis of a 10-percent Renewable Portfolio Standard*, SR/OIAF/2003-01, May 2003 and *Addendum: Analysis of a 10-percent Renewable Portfolio Standard*, June 2003. See http://www.eia.doe.gov/oiaf/anal_renew.html

[3] *OMB Circular A-94: GUIDELINES AND DISCOUNT RATES FOR BENEFIT-COST ANALYSIS OF FEDERAL PROGRAMS.* http://www.whitehouse.gov/omb/circulars/a094/a094.pdf

[4] The time value of money refers to the premium people, corporations, governments, and societies place on having a given quantity of money now compared to having the same amount of money at some future point in time. This is evaluated through the use of discount rates. A high discount rate implies a large value in having money today compared to having money in the future, a zero discount rate implies indifference to having money today compared to having the same amount of money at any future time.

For comparison, the cumulative real value of U.S. electricity sales from 2003 through 2025 is projected in the Reference case to be $3.3 trillion ($6.6 trillion in 2001 dollars assuming no discount rate).

Compliance costs are measured as the difference between total industry costs with the RPS program compared to total industry costs without the RPS program (that is, the Reference case). Industry costs include all payments by the industry to recipients outside of that industry (such as fuel suppliers, technology vendors, or the government), but do not include payments from one member of the industry to a recipient within the industry (a “transfer” payment). An RPS allowance purchased from the government is an industry cost but not a resource cost from the perspective of the overall economy. An RPS credit purchased in the private market is a transfer payment within the industry, and is not included in the industry cost calculation.

Since the capital, operation, and maintenance costs needed to create the renewable generation is an industry cost, counting a private-market credit as an industry cost would be double-counting that cost. Specific industry costs items are: annual payments toward installed capacity, transmission, retrofits, and other capital additions; expenditures for fixed and variable operations and maintenance; fuel purchases; power purchased from non-utility generators; and purchases of RPS allowances from the government.

Table 1 compares the real, discounted power industry costs with both the undiscounted cost expressed in 2001 dollars as well as the undiscounted cost expressed in non-inflation adjusted (nominal) dollars.[5] The proposed RPS requires compliance through 2030, thus implying additional compliance costs not calculated for the period 2026 through 2030. Only an approximate estimate of these additional costs is possible. The approximation used here assumes that the average single-year compliance costs for 2020 through 2025 (the years in which the target share of renewables is the same as the 2026 through 2030) will continue to be incurred through 2030.

[5] In addition to accounting for the time value of money, comparison of monetary values in different years typically accounts for general inflation of the economy. When the effects of inflation are removed from each year’s monetary values, the value is indicated as “real”, as it represents the value in physical cash on hand today. If inflationary effects are not removed, the value is indicated as “nominal” and represents the monetary value of cash payments in the year of the transaction.

Table 1. Cumulative Power Industry Cost[1] through 2025 and 2030, RPS Nominal Case and RPS Real Case (billions)

Valuation	Case	2025	2030[2]
2001 Dollars, Discounted at 7%	RPS Nominal Cap	3.9	5.1
	RPS Real Cap	4.9	6.2
2001 Dollars, not Discounted	RPS Nominal Cap	11.7	18.0
	RPS Real Cap	14.4	21.5
Nominal Dollars, not Discounted	RPS Nominal Cap	18.2	30.7
	RPS Real Cap	22.3	36.3

1- Cost incurred by the power industry including fuel suppliers, equipment manufacturers, and Government RPS allowance costs. Does not include transfer payments within the industry, such as the purchase of RPS credits from private entities.

2- NEMS calculates values through 2025. 2026-30 based on average costs from 2020 through 2025, and would vary from actual resource costs that would be calculated within NEMS if the forecast horizon of the model were extended.

Source: EIA Office of Integrated Analysis and Forecasting. National Energy Modeling System (NEMS) runs mlbase.d050303a (Reference Case), ml_brpssm.d051203d (RPS Nominal case), and ml_brpssmr.d060403b (RPS Real case)

Table 2 shows the total, annual expenditures on RPS credits purchased from private markets and allowances purchased from the government, for both cases (Figure 1 in Appendix B contains the data in graphical format). Annual prices for RPS credits and allowances (credits purchased from the government) fluctuate significantly throughout the forecast period. This is partially a result of the step-wise increases in the RPS requirement over time. As may be expected, each time the renewable generation requirement is increased (every 4 years from 2008 through 2020), the credit price increases. However, in the years after each target adjustment, the credit price tends to decline as additional renewable generation becomes available, both to satisfy the current target and in anticipation of the next increase in the target. After 2020, compliance with the RPS becomes sufficiently costly that the price is set by the government sale of allowances. Note that in a few years prior to 2015 in the RPS Nominal Cap case or 2020 in the RPS Real Cap case, some government allowances are purchased to make-up for a single year shortfall in generation. However, these single-year shortfalls are largely a result of the uncertainty of actual generation requirements from year-to-year, and not the result of inadequate, cost-effective renewable resources. After 2015 in the RPS Nominal Cap case and 2020 in the RPS Real Cap case, the supply of new renewable generation available for less than 1.5 cents per kilowatt-hour is limited and the market begins to purchase Government allowances in each year.

Table 2. Credit and Allowance Cost for RPS Nominal Case and RPS Real Case (billions)

	RPS Nominal Case				RPS Real Case			
	Nominal, undiscounted		2001 dollars, undiscounted		Nominal, undiscounted		2001 dollars undiscounted	
Year	**Credit**	**Allowance**	**Credit**	**Allowance**	**Credit**	**Allowance**	**Credit**	**Allowance**
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.9	0.0	0.8	0.0	0.9	0.0	0.8	0.0
2009	0.9	0.0	0.8	0.0	0.9	0.0	0.8	0.0
2010	1.0	0.0	0.8	0.0	1.0	0.0	0.8	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	3.1	0.2	2.4	0.1	2.7	0.0	2.1	0.0
2013	3.3	0.2	2.5	0.1	2.5	0.0	2.0	0.0
2014	3.5	0.0	2.7	0.0	2.3	0.0	1.7	0.0
2015	3.1	0.0	2.3	0.0	4.5	0.0	3.3	0.0
2016	4.0	0.8	2.6	0.6	6.0	0.1	4.3	0.1
2017	4.2	0.6	2.7	0.4	5.6	0.0	3.9	0.0
2018	4.3	0.6	2.7	0.4	5.4	0.0	3.6	0.0
2019	4.5	0.5	2.8	0.3	6.6	0.0	4.4	0.0
2020	4.4	1.7	2.2	1.1	7.7	1.2	4.5	0.8
2021	4.5	1.8	2.1	1.1	8.0	1.2	4.5	0.7
2022	4.5	1.8	2.0	1.1	8.2	1.3	4.5	0.8
2023	4.5	1.9	1.8	1.1	8.4	1.5	4.3	0.9
2024	4.5	2.0	1.7	1.1	8.7	1.6	4.2	0.9
2025	4.5	2.1	1.5	1.2	8.9	1.9	4.1	1.0
2026	4.6	2.2	1.5	1.2	9.2	2.0	4.0	1.0
2027	4.5	2.3	1.2	1.2	9.4	2.1	3.9	1.1
2028	4.5	2.4	1.1	1.2	9.7	2.3	3.7	1.2
2029	4.4	2.5	0.9	1.2	9.9	2.5	3.6	1.2
2030	4.4	2.6	0.8	1.2	10.1	2.8	3.4	1.3
Total	81.9	25.8	40.0	14.6	136.7	20.5	72.4	11.1

Source: EIA Office of Integrated Analysis and Forecasting. NEMS runs ml_brpssm.d051203d (RPS Nominal case) and ml_brpssmr.d060403b (RPS Real case)

Also contributing to the year-to-year variability in credit prices is the effect of market expectations on capacity construction to meet the RPS target. Although the market precisely knows the RPS percentage requirement in any given year, the actual amount of annual sales is not known until the end of each year. Depending on the technology type, construction of new capacity takes anywhere from 2 to 4 years. An over-estimation of actual future sales will lead to over-building and tend to depress credit prices. Under-estimation of actual future sales will tend to increase credit prices.

B. New Model Runs and Analyses Using Different Assumptions

Based on the draft amendment language that EIA was originally asked to analyze, all scenarios analyzed in the May 2003 report (RPS Nominal Cap case) and the Addendum to the May report (RPS Real Cap case), explicitly assume that any time the private market cannot supply sufficient renewable generation to meet RPS requirements in a given year, the shortfall in credits will be purchased from the Federal government at the allowance cost of 1.5 cents per kilowatt-hour, in real or nominal dollars, depending on the case considered. In such a situation, the Federal government becomes the marginal supplier, and sets the market-clearing price for credits at 1.5 cents per kilowatt-hour.

Cases without State-mandated Renewables

Pursuant to the request to which this *Supplement* responds, EIA conducted a new analysis using the same assumptions as the May 2003 study *Analysis to a 10-percent Renewable Portfolio Standard* (examining an RPS without an inflation adjusted price cap) and the *Addendum* to that study (examining an RPS with an inflation-adjusted price cap), but assuming that all renewables projected to be built after 2003 in response to a state mandate or program would not be built.

The results of these cases are substantially similar to the RPS Nominal Cap and RPS Real Cap cases in the previous report. Comparing the RPS Nominal Cap case with the Nominal Cap Case without State mandates, renewable generation by 2025 is 5.6 percent of U.S. sales when State mandates are included, and 5.5 percent of U.S. sales when State mandates are not included. Looking at the comparison between the RPS Real Cap case and the Real Cap case without State mandates, by 2025 compliance without State-mandated builds is 6.6 percent of all U.S. sales, compared to 6.5 percent of U.S. sales when State-mandated builds are allowed. The exclusion of the State-mandated renewable builds, as specified in Senator Domenici's request, has two main effects that influence the level of realized renewable generation in opposing ways. First, eliminating State-mandated builds from the market does preclude some "learning-by-doing" effects in the early years of the national RPS program (when most state-mandated capacity is scheduled to come online). However, it also creates additional opportunity early in the forecast period for lower cost renewable projects to be built elsewhere in the country. This more efficient allocation of renewable generation results in a slightly higher level of renewable generation under the RPS with a real credit price cap when State-mandated builds are eliminated.

Table 3 summarizes the cumulative power industry cost, relative to the Reference case, for each of four cases: RPS Nominal Cap (from the May 2003 report); Nominal Cap, no State mandate; RPS Real Cap (from the June 2003 Addendum); and Real Cap, no State mandate.

Table 3. Cumulative Power Industry Cost[1] through 2025 and 2030, No State Mandate Cases (billions)

Valuation	Case	2025	2030[2]
2001 Dollars, Discounted at 7%	RPS Nominal Cap	3.9	5.1
	Nominal Cap, no state mandate	5.1	6.0
	RPS Real Cap	4.9	6.2
	Real Cap, no state mandate	6.3	7.6
2001 Dollars, not Discounted	RPS Nominal Cap	11.7	18.0
	Nominal Cap, no state mandate	13.5	18.4
	RPS Real Cap	14.4	21.5
	Real Cap, no state mandate	17.5	24.7
Nominal Dollars, not Discounted	RPS Nominal Cap	18.2	30.7
	Nominal Cap, no state mandate	20.0	29.7
	RPS Real Cap	22.3	36.3
	Real Cap, no state mandate	26.6	40.7

1- Cost incurred by the power industry including fuel suppliers, equipment manufacturers, and Government RPS allowance costs. Does not include transfer payments within the industry, such as the purchase of RPS credits from private entities.

2- NEMS calculates values through 2025. 2026-30 based on average costs from 2020 through 2025, and would vary from actual resource costs that would be calculated within NEMS if the forecast horizon of the model were extended.

Source: EIA Office of Integrated Analysis and Forecasting. National Energy Modeling System (NEMS) runs mlbase.d050303a (Reference Case), ml_brpssm.d051203d (RPS Nominal case), ml_brpssmr.d060403b (RPS Real case), ml_brpssmnnst.d060703a (Nominal No State Mandate case), and ml_brpssmrnst.d060603b (Real No State Mandate case)

Table 4 shows the year-by-year credit and allowance costs for the Nominal Cap without State Mandates case and the Real Cap without State Mandates case (Graphical results are shown in Figure 2 in Appendix B).

Table 4. Credit and Allowance Cost for Nominal No State Mandate Case and Real No State Mandate Case (billions)

	Nominal No State Mandate Case				Real No State Mandate Case			
	Nominal, undiscounted		2001 dollars, undiscounted		Nominal, undiscounted		2001 dollars, undiscounted	
Year	Credit	Allowance	Credit	Allowance	Credit	Allowance	Credit	Allowance
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	1.0	0.0	0.8	0.0	1.0	0.0	0.8	0.0
2009	1.0	0.0	0.9	0.0	1.0	0.0	0.9	0.0
2010	0.8	0.0	0.7	0.0	0.8	0.0	0.7	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	3.1	0.2	2.4	0.2	3.0	0.0	2.4	0.0
2013	3.3	0.2	2.5	0.1	2.7	0.0	2.1	0.0
2014	3.5	0.0	2.6	0.0	2.3	0.0	1.8	0.0
2015	3.1	0.0	2.3	0.0	4.5	0.0	3.3	0.0
2016	3.9	0.9	2.5	0.6	6.0	0.2	4.3	0.1
2017	4.0	0.8	2.5	0.6	6.0	0.0	4.2	0.0
2018	4.1	0.7	2.5	0.5	5.2	0.0	3.5	0.0
2019	4.3	0.5	2.7	0.3	6.5	0.0	4.3	0.0
2020	4.3	1.8	2.1	1.1	7.8	1.1	4.6	0.2
2021	4.3	1.9	2.0	1.2	8.1	1.2	4.6	0.2
2022	4.3	1.9	1.8	1.2	8.3	1.3	4.5	0.2
2023	4.3	2.0	1.7	1.2	8.5	1.3	4.4	0.2
2024	4.3	2.1	1.6	1.2	8.7	1.5	4.3	0.2
2025	4.3	2.2	1.4	1.2	9.0	1.7	4.2	0.2
2026	4.3	2.3	1.3	1.2	9.2	1.8	4.1	0.2
2027	4.3	2.4	1.1	1.2	9.5	2.0	4.0	0.2
2028	4.3	2.5	1.0	1.2	9.7	2.2	3.8	0.2
2029	4.3	2.5	0.8	1.3	9.9	2.4	3.7	0.2
2030	4.3	2.6	0.7	1.3	10.2	2.6	3.5	0.2
Total	79.5	27.6	38.0	15.7	137.9	19.2	73.9	2.3

Source: EIA Office of Integrated Analysis and Forecasting. NEMS runs ml_brpssmnnst.d060703a (Nominal No State Mandate case), and ml_brpssmrnst.d060603b (Real No State Mandate case)

Cases without Biomass Co-firing

Pursuant to the terms of the request to which this Supplement responds, EIA also conducted a new analysis assuming that biomass co-firing would not qualify for the RPS and thus receives no resulting subsidy from the program. Once again, two cases were examined, one using the same assumptions as the RPS Nominal Cap case, and the other with the same assumptions as the RPS Real Cap case.

As expected, this assumption eliminates the use of co-firing facilities as a compliance mechanism and reduces co-fired generation when compared to the case where co-firing is allowed. However, compliance achieved in the no co-firing cases is similar to that achieved in the respective cases with co-firing. With the Nominal Cap no Co-firing case, renewable generation in 2025 achieves 5.9 percent of U.S. sales, compared to 5.6 percent of sales when co-firing is allowed. For the Real Cap no Co-firing case, renewable generation in 2025 achieves 7 percent of U.S. sales compared to 6.5 percent of U.S. sales when co-firing is allowed.

When co-firing is not allowed, the lower cost biomass feedstock that was being burned in coal plants is, instead, burned in newer, more efficient dedicated biomass plants. Early investments in these dedicated biomass plants allow the capital cost to decline through "learning-by-doing" effects, resulting in additional renewables being economic relative to the 1.5 cent per kilowatt-hour cap.

Table 5 summarizes the cumulative power industry costs, relative to the Reference case, for four cases: RPS Nominal Cap (from the May 2003 report); Nominal Cap, no co-firing; RPS Real Cap (from the June 2003 Addendum); and Real Cap, no co-firing.

Table 5. Cumulative Power Industry Cost[1] through 2025 and 2030, No Co-firing Cases (billions)

Valuation	Case	2025	2030[2]
2001 Dollars, Discounted at 7%	RPS Nominal Cap	3.9	5.1
	Nominal Cap, no co-firing	5.8	7.0
	RPS Real Cap	4.9	6.2
	Real Cap, no co-firing	8.3	10.1
2001 Dollars, not Discounted	RPS Nominal Cap	11.7	18.0
	Nominal Cap, no co-firing	16.0	22.3
	RPS Real Cap	14.4	21.5
	Real Cap, no co-firing	23.2	33.0
Nominal Dollars, not Discounted	RPS Nominal Cap	18.2	30.7
	Nominal Cap, no co-firing	24.2	36.7
	RPS Real Cap	22.3	36.3
	Real Cap, no co-firing	35.4	54.7

1- Cost incurred by the power industry including fuel suppliers, equipment manufacturers, and Government RPS allowance costs. Does not include transfer payments within the industry, such as the purchase of RPS credits from private entities.

2- NEMS calculates values through 2025. 2026-30 based on average costs from 2020 through 2025, and would vary from actual resource costs that would be calculated within NEMS if the forecast horizon of the model were extended.

Source: EIA Office of Integrated Analysis and Forecasting. National Energy Modeling System (NEMS) runs mlbase.d050303a (Reference Case), ml_brpssm.d051203d (RPS Nominal case), ml_brpssmr.d060403b (RPS Real case), ml_brpssmnncfbw.d060703a (Nominal No Co-firing case), and ml_brpssmrncfbw.d060603a (Real No Co-firing case)

Table 6 shows the year-by-year credit and allowance costs for the Nominal Cap no co-firing case and the Real Cap no co-firing case (a graphical presentation of the data is in Appendix B).

Table 6. Credit and Allowance Cost for Nominal No Co-firing Case and Real No Co-firing Case (billions)

	Nominal No Co-firing Case				Real Case No Co-firing Case			
	Nominal, no discounting		2001 dollars, undiscounted		Nominal, no discounting		2001 dollars, undiscounted	
Year	Credit	Allowance	Credit	Allowance	Credit	Allowance	Credit	Allowance
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	1.9	0.3	1.6	0.2	2.1	0.3	1.8	0.3
2009	2.1	0.2	1.7	0.2	2.4	0.2	2.0	0.2
2010	2.3	0.1	1.9	0.0	2.7	0.0	2.2	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	2.8	0.7	2.1	0.6	3.5	0.7	2.7	0.6
2013	3.1	0.5	2.3	0.4	4.0	0.4	3.0	0.3
2014	3.5	0.2	2.6	0.2	4.6	0.1	3.5	0.1
2015	3.7	0.1	2.7	0.0	0.0	0.0	0.0	0.0
2016	4.0	1.0	2.6	0.7	6.1	0.5	4.2	0.4
2017	4.2	0.8	2.7	0.6	6.7	0.2	4.6	0.1
2018	4.5	0.6	2.8	0.4	6.9	0.0	4.6	0.0
2019	4.5	0.7	2.7	0.4	0.0	0.0	0.0	0.0
2020	4.5	1.8	2.2	1.2	8.0	1.6	4.6	1.0
2021	4.5	1.8	2.1	1.1	8.3	1.5	4.6	0.9
2022	4.6	1.9	2.0	1.2	8.6	1.7	4.6	1.0
2023	4.6	2.0	1.9	1.2	8.9	1.8	4.5	1.1
2024	4.6	2.1	1.8	1.2	9.3	2.0	4.4	1.1
2025	4.7	2.2	1.6	1.2	9.6	2.2	4.3	1.2
2026	4.7	2.2	1.5	1.2	9.9	2.3	4.3	1.3
2027	4.7	2.3	1.4	1.2	10.3	2.5	4.2	1.3
2028	4.7	2.4	1.2	1.2	10.6	2.7	4.0	1.4
2029	4.8	2.5	1.1	1.2	11.0	2.9	3.9	1.4
2030	4.8	2.5	0.9	1.2	11.4	3.2	3.8	1.5
Total	87.7	28.8	43.5	16.7	145.2	27.0	75.8	15.3

Source: EIA Office of Integrated Analysis and Forecasting. NEMS runs ml_brpssmnncfbw.d060703a (Nominal No Co-firing case), and ml_brpssmrncfbw.d060603a (Real No Co-firing case)

C. Separate "Simple" Analysis of RPS Credit Cost Assuming No New RPS Eligible Renewables

The request to which this *Supplement* responds asked EIA to calculate the value of RPS allowances purchased from the Government assuming that no new renewables could be built with the additional 1.5 cent per kilowatt-hour subsidy provided in the RPS program. Based on projected electricity sales in the Reference case, this would result in a total expenditure through 2030 of $26 billion (2001 dollars, discounted at 7%) with an allowance price remaining constant in nominal dollars or $37 billion (2001 dollars, discounted at 7%) with an allowance price adjusted for inflation. The total value of electricity sales over the 2004 to 2030 period calculated on a comparable basis is projected to be $3.4 trillion. The allowance costs referenced above represent 0.8 and 1.1 percent, respectively, of this value.

If all compliance were obtained through purchasing government allowances, Table 7 shows the estimated annual expenditure for allowances. This table is calculated based on electricity sales from the Reference case, and does not consider price feedback effects in electricity demand markets (that is, reductions in demand that would result in higher end-user prices).

Table 7. Cost if All Credits Purchased as Government Allowance (billions)

	Nominal RPS Cap		Real RPS Cap	
Year	Nominal Dollars	Real 2001 Dollars	Nominal Dollars	Real 2001 Dollars
2003	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0
2008	2.3	2.0	2.5	2.2
2009	2.4	2.0	2.6	2.2
2010	2.4	2.0	2.7	2.2
2011	2.4	2.0	2.8	2.3
2012	3.6	2.8	4.2	3.4
2013	3.6	2.8	4.4	3.4
2014	3.7	2.8	4.6	3.5
2015	3.7	2.8	4.8	3.5
2016	5.0	3.6	6.5	4.7
2017	5.0	3.5	6.8	4.7
2018	5.1	3.5	7.1	4.8
2019	5.2	3.4	7.4	4.9
2020	6.5	4.2	9.6	6.1
2021	6.6	4.1	10.0	6.2
2022	6.7	4.1	10.5	6.3
2023	6.8	4.0	11.0	6.4
2024	6.9	4.0	11.5	6.6
2025	7.1	3.9	12.0	6.7
2026	7.3	4.0	12.6	6.8
2027	7.4	4.0	13.2	6.9
2028	7.6	3.9	13.9	7.0
2029	7.7	3.9	14.6	7.2
2030	7.8	3.9	15.3	7.3
Total	122.8	77.1	190.8	115.4
Source: EIA Office of Integrated Analysis and Forecasting				

Allowance costs in Table 7 are based on shares of all renewable generation as a fraction of all U.S. sales. Keeping in mind that RPS-eligible renewables are already being added to the U.S. electricity supply system even without the additional economic incentive that would be provided by the RPS program analyzed in the May 2003 report, its *Addendum*, and the present *Supplement*, the calculations presented above are likely to exceed actual allowance costs, particularly in the early years of the program. The actual number of allowances purchased would be lower, as no purchases are required for renewable generation from capacity in-service prior to the enactment of the legislation.

D. Additional Requested Information

Wind is a naturally diffuse energy resource when compared to other common forms of electric generation (natural gas, coal, nuclear). Capturing wind energy and converting it to electricity requires significant dispersal of the necessary machinery (primarily the wind turbines themselves, but also supporting plant such as transformers). However, the dispersal of this machinery over a wide area does not necessarily mean that this machinery occupies a large physical space. EIA assumes that wind turbines can capture 6.5 megawatts of nameplate power for every square kilometer of windy land area (approximately 26 kilowatts per acre). A typical wind turbine constructed in the U.S. has nameplate capacity of around 1 megawatt. Such a 1-megawatt turbine would need to be sited on about 38 acres of suitable land. However, the turbine itself, including supporting structures, such as access roads and step-up transformers, would only physically occupy about 5 percent of this area (about 2 acres of the 38). The remaining 36 acres could continue to be put to a variety of other uses, particularly for agriculture and grazing. However, to avoid aerodynamic interference among turbines, no other turbines could be built within the 38-acre area (or more precisely, within 5 rotor diameters perpendicular to the dominant wind direction or within 10 rotor diameters in the dominant wind direction).[6]

Modern wind turbines are quite tall, as much as 400 feet from the base of the tower to the tip of the rotor disc (assuming an 80 meter diameter rotor with hub mounted on an 80 meter tower, a configuration consistent with a 1.5 megawatt turbine, the largest turbines commercially installed in the U.S. to date). Furthermore, to capture the best winds, they tend to be constructed on locally prominent terrain, such as hillcrests, ridges or mesas. Although varying greatly from site to site (or even from different directions at a single site), the visual impact of the turbines can extend for quite a distance away from the turbines. If terrain obstructs the view, a turbine might not be seen until one is within a half-mile of the tower. If the view is unobstructed, a turbine might be seen from five or more miles away. Because it is not possible to accurately generalize over the entire U.S. wind resource (or even within more localized resource areas), specific estimates of spatial extent of these impacts are not provided, however the impacts are included when estimating the economic supply of wind resources available.

[6] Actual spacing of turbines depends on a number of site-specific factors. Generally, the more the wind tends to blow from a single direction, the closer the turbines can be spaced perpendicular to that direction. Many current wind farms are constructed on narrow ridgelines with highly directional winds, and are spaced in linear strings with less than 3 rotor diameters between turbines. However, more intensive utilization of the wind resource will likely require more regular, rectangular arrays with greater spacing.

For the RPS Real Cap analysis, EIA projects that approximately 47 gigawatts of wind capacity would be constructed in the U.S. by 2025. This wind capacity would utilize the wind resources contained in 7,231 square kilometers (approximately 1.8 million acres) of land. Of this, however, only about 362 square kilometers (90 thousand acres) would actually be occupied by physical plant structure (including turbine foundations, access roads, and transformers). Depending on where these resources were developed, and how concentrated development was within particular resource areas, the area of land impacted by the visual imposition of the wind turbines could be substantially greater than 7,231 square kilometers. This compares with a total of 941 million acres of farmland in the U.S. in 2002 and an average annual loss of 2.7 million acres of farmland per year from 1993 to 2002.[7]

Currently, state and local zoning and permitting processes largely control the siting of wind power projects. Offshore projects located more than 3 miles from shore and projects located on Federal lands are subject to Federal permitting processes (EIA does not currently consider potential offshore wind resources). Anecdotal evidence suggests that some proposed wind power projects have not been able to receive permits, primarily based on issues of local concern (such as visual impacts). EIA currently assumes that several factors, such as local siting issues but also including access to adequate transmission and difficulty in physical access to some locations will severely limit the amount of economically exploitable wind resource.

The U.S. has a total of over 2,500 gigawatts of potentially available wind resource. Based on regional studies of economically available wind resources, EIA estimates that about 37 GW of this resource will be available with minimal additional cost to overcome local siting concerns, lack of adequate transmission, and other limitations to wind growth. An additional 220 GW of resource will be available if markets are willing to pay an additional 20 to 100 percent of base capital cost to mitigate siting concerns, upgrade existing or build new transmission, or use more expensive construction techniques to access more remote or rough sites. Almost 90 percent of the wind resource is only available if the markets are willing to pay an additional 200 percent of base capital cost (that is, at 3 times the base capital cost).

If less low-cost land is available than EIA currently accounts for, then the additional siting and construction costs will result in less purchase of wind power to satisfy the RPS. Our analysis indicates that with a 1.5 cent cap on RPS credit prices, little wind gets built for which an additional 20 percent capital expenditure is required. A reduction in low cost wind supply will likely result in reduced wind builds, although not necessarily in proportion to the reduction. For example, additional earlier market penetration of biomass, landfill gas, or geothermal technologies may induce sufficient "learning-by-doing" cost reductions to offset the higher costs that limited penetration of these technologies when co-firing is allowed.

[7] Table 9-2 *USDA-NASS Agricultural Statistics 2003*. http://www.usda.gov/nass/pubs/agr03/03_ch9.pdf

Appendix A.

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

June 10, 2003

The Honorable Guy Caruso
Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Caruso:

I would appreciate if EIA would review its RPS analysis of May 8, 2003 based on different assumptions. A description of the requested assumptions to be applied is attached. Please ensure that all responses use both a flat 1.5 cent/kWh credit cap and a 1.5 cent/kWh credit cap adjusted for inflation. To the extent possible, include total calculations as well as any tables, graphs, and yearly breakdowns in your review.

I ask that the requested assumptions be completed as soon as possible. I also request that my staff be briefed prior to any release of any information.

If you have any questions regarding this request, or need clarification, please contact Lisa Epifani at 202-224-4971 or lisa_epifani@energy.senate.gov. Thank you for your efforts and attention to this request.

Sincerely,

Pete V. Domenici
Chairman

1.

Assumptions for EIA RPS Analysis

Request for more detailed data from May 2003 study

1. What is the total cumulative cost in real and nominal dollars of the analysis all the way through 2030? In this and in all subsequent questions, "real" dollar values should only differ from nominal dollar values by the amount of price inflation, i.e., they should not be further adjusted by a real discount rate.

2. Please provide a table with year-by-year values (in both real and nominal dollars) for credits and for allowances.

Request assumptions for a separate model run and analysis

3. For every year when the supply of renewables is less that the required level of (demand for) renewables, assume that the market price for credits purchased from suppliers of renewable generation equals the allowance cost of 1.5 cent/kWh.

4. What is the end effect on the analysis if you dropped out all State renewable programs (eliminating stimulation of renewables tied to State programs as described at p. 7)?

5. Run the analysis with lower biomass co-firing (approximate one test as a zero growth and one at 10 billion kWh).

6. Provide a detailed definition of "net resource costs" and an itemization of what is included as well as any graphic representation of such costs.

7. What are the total cumulative costs in real and nominal dollars of these analyses all the way through 2030?

8. Please provide a table with year-by-year values (in both real and nominal dollars) for credits and for allowances for these analyses.

Request for separate "simple" analysis

9. What is the total cumulative cost in real and nominal dollars through 2030 if every necessary credit had to be purchased from the Secretary for 1.5 cent/kWh? That is, if no new renewables were built and all requirements under the RPS were met by buying allowances from the government at 1.5 cent/ kWh.

10. Please also provide a table with year-by-year values (in both real and nominal dollars) for allowances.

Additional questions

11. Given that wind is the largest growing renewable resource according to the analysis, how many acres of land will be needed to sustain that growth?

12. There are potentially amendments that will increase siting protocols for windmills in highly scenic areas. If siting becomes more onerous, what effect will this have? If the analysis' expected growth of wind resources was cut in half, what happens to allowance costs and consumer prices?

Appendix B

Figure 1a. Real Credit and Allowance Cost[1]

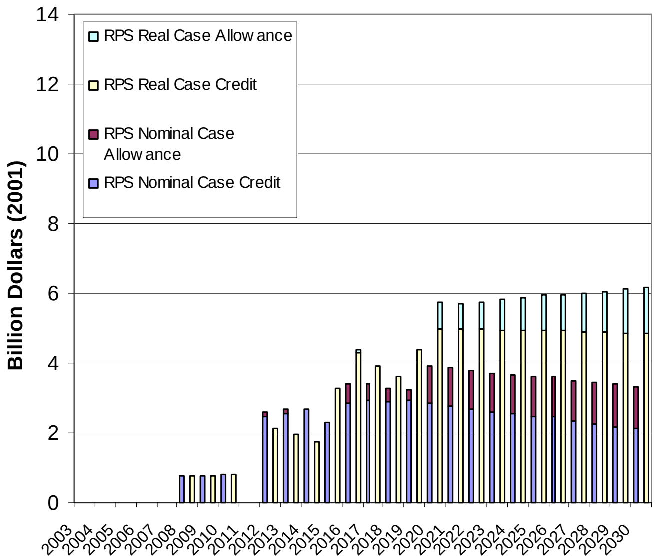
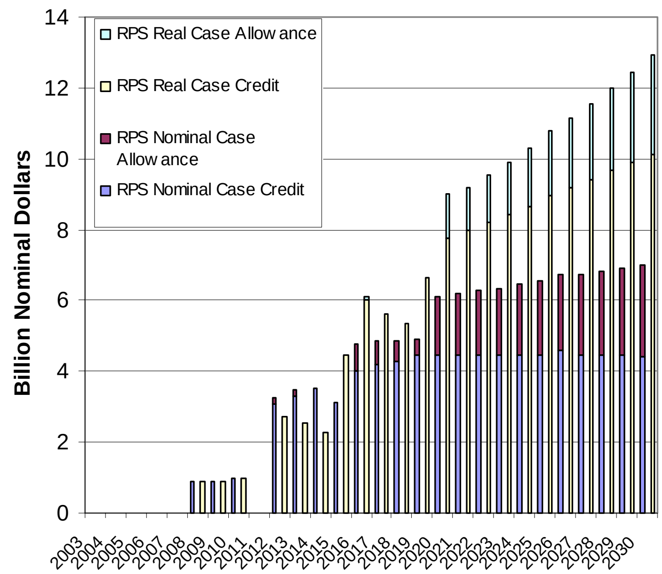


Figure 1b. Nominal Credit and Allowance Cost



1- For this report, credits are purchased from private markets and allowances are purchased from the government, the proposed legislation only uses the term "credit" to describe both types of purchases.
Source: EIA Office of Integrated Analysis and Forecasting. NEMS runs ml_brpssm.d051203d (RPS Nominal case) and ml_brpssmr.d060403b (RPS Real case)

Figure 2a. Real Credit and Allowance Cost[1]

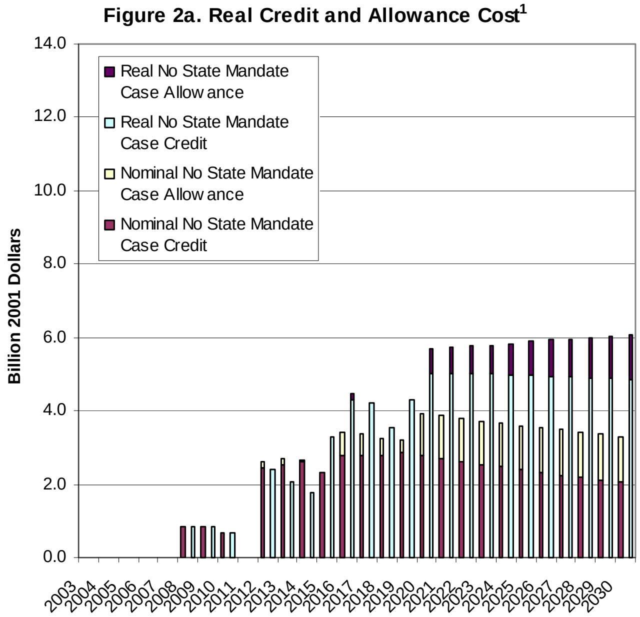
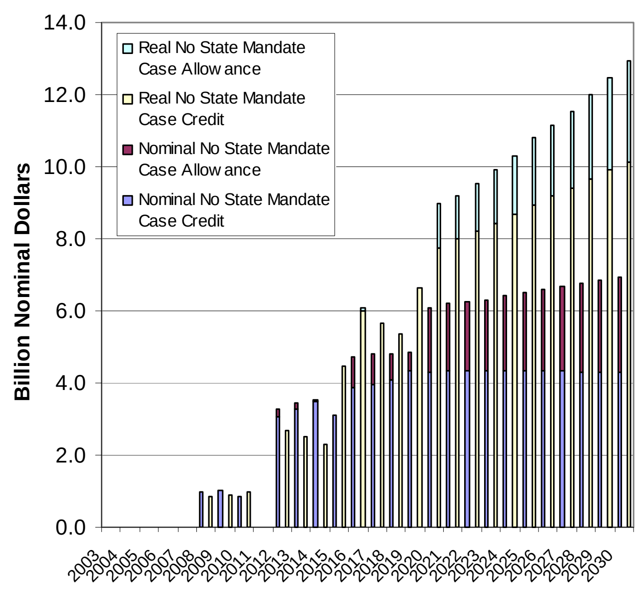
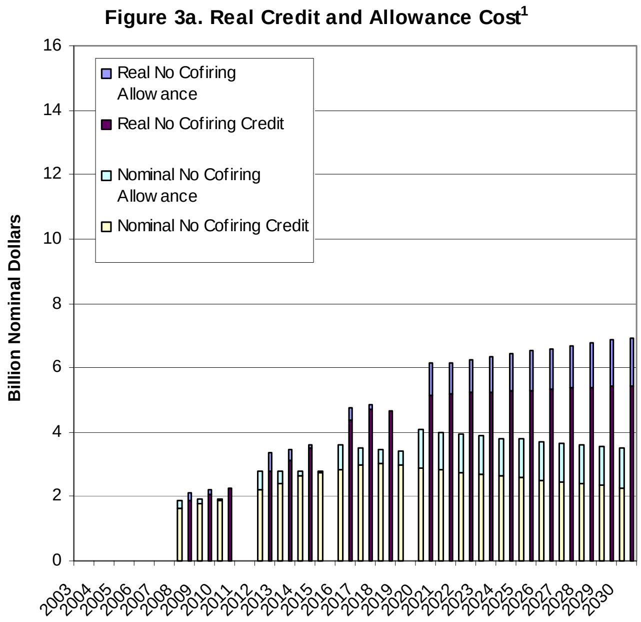
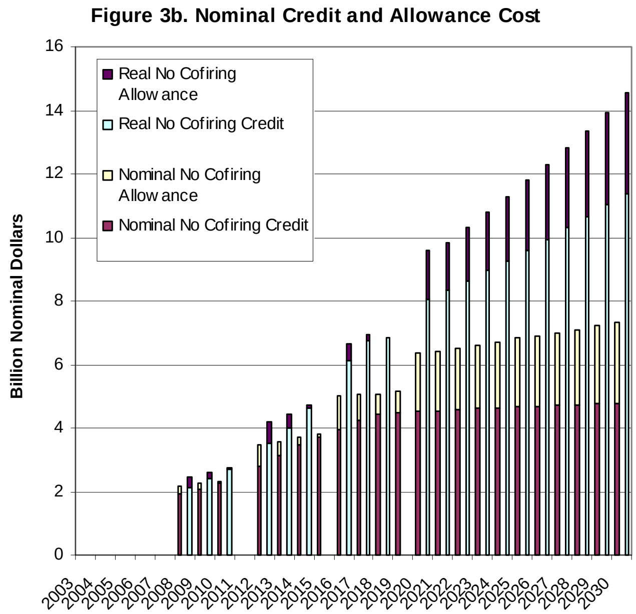


Figure 2b. Nominal Credit and Allowance Cost



1- For this report, credits are purchased from private markets and allowances are purchased from the government, the proposed legislation only uses the term "credit" to describe both types of purchases.
Source: EIA Office of Integrated Analysis and Forecasting. NEMS runs ml_brpssmnnst.d060703a (Nominal No State Mandate case), and ml_brpssmrnst.d060603b (Real No State Mandate case)





1- For this report, credits are purchased from private markets and allowances are purchased from the government, the proposed legislation only uses the term "credit" to describe both types of purchases.
Source: EIA Office of Integrated Analysis and Forecasting. NEMS runs ml_brpssmnncfbw.d060703a (Nominal No Co-firing case), and ml_brpssmrncfbw.d060603a (Real No Co-firing case)