SR/OIAF/2004-01

Analysis of Five Selected Tax Provisions of the Conference Energy Bill of 2003

February 2004

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

Contacts

This report was prepared by the staff of the Office of Integrated Analysis and Forecasting, Energy Information Administration (EIA). General questions concerning the report can be directed to Mary J. Hutzler (mary.hutzler@eia.doe.gov, 202/586-2222), Director of the Office of Integrated Analysis and Forecasting and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor to the Office of Integrated Analysis and Forecasting.

Specific questions about the report can be directed to the following analysts:

Renewable Production Tax
Credit .... Chris Namovicz (cnamovicz@eia.doe.gov, 202/586-7120)
Advanced Nuclear Production
Tax Credit……………… Alan Beamon (jbeamon@eia.doe.gov, 202/586-2025)
Section 29 Tax Credits .....……Ted McCallister (tmccalli@eia.doe.gov, 202/586-4820)
Alan Beamon (jbeamon@eia.doe.gov, 202/586-2025)
Han-Lin Lee (han-lin.lee@eia.doe.gov, 202/586-4247)
Amortization of Geological and
Geophysical Expenditures…Dana VanWagener (dana.van-wagener@eia.doe.gov, 202/586-4725)
James Kendell (jkendell@eia.doe.gov, 202/586-9646)
Enhanced Oil Recovery Tax
Credit…........................……Philip Budzik (pbudzik@eia.doe.gov, 202/586-2847)
James Kendell (jkendell@eia.doe.gov, 202/586-9646)

Preface

On January 29, 2004, Senator John Sununu requested that the Energy Information Administration (EIA) provide an assessment of certain tax provisions of the Conference Energy Bill (CEB) of 2003 (also known as the Energy Policy Act of 2003). He requested that five specific tax provisions be assessed regarding incremental energy production, changes in petroleum imports, and tax revenue losses. The five provisions are as follows:

- Section 45 Credit for Electricity Produced from Certain Sources
- Credit for Electricity Produced from Advanced Nuclear Power Facilities
- Amortization of Geological and Geophysical Expenditures Over 2 Years
- Extension and Modification of Section 29 for Producing Fuel from Nonconventional Sources
- Enhanced Oil Recovery Tax Credits

This report responds to that request. Some of the tax provisions can be analyzed using the National Energy Modeling System (NEMS). In those cases, the impacts of the provisions are estimated by comparing the results of those provisions to the Reference Case of the *Annual Energy Outlook 2004* (*AEO2004*). Where the provisions are not amenable to modeling using NEMS, a qualitative analysis is provided.

The legislation that established EIA in 1977 vested the organization with an element of statutory independence. EIA does not take positions on policy questions. It is the responsibility of EIA to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of both public and private decisionmakers. This report should not be construed as representing the official position of the U.S. Department of Energy or the Administration.

The projections in the Reference Case used in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The Reference Case projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral starting point that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of scheduled regulatory changes, when defined, are reflected.

Table of Contents

Tables

Introduction

This report responds to request from Senator John Sununu that the Energy Information Administration (EIA) provide an analysis of certain tax provisions included in the Conference Energy Bill (CEB) agreed to by House and Senate conferees and subsequently passed by the House. The provisions covered by the request, as specified in Senator Sununu's letter of January 29, 2004, are:

- Extension and Expansion of Section 45 Credit for Electricity Produced from Certain Sources
- Credit for Electricity Produced from Advanced Nuclear Power Facilities
- Amortization of Geological and Geophysical Expenditures Over 2 Years
- Extension and Modification of Section 29 for Producing Fuel from Nonconventional Sources.
- Enhanced Oil Recovery Tax Credits

EIA was asked to provide analysis and numerical estimates, where possible, focusing on:

- The incremental energy produced or saved over the next 10 years and through 2025;
- The quantity of petroleum imports reduced or increased over the next 10 years and for the forecast;
- An estimate of the tax revenue losses that would result from each provision and a comparison with the estimates of the Joint Committee on Taxation (JCT), with an explanation of the differences, where possible.

Where a covered tax provision can be analyzed using EIA's National Energy Modeling System (NEMS)[1], its impacts are estimated by comparing a model run incorporating that provision to the Reference Case of the *Annual Energy Outlook 2004*[2] (*AEO2004*). Qualitative analysis is provided for provisions that cannot be modeled using NEMS.

This report evaluates each of the subject tax provisions individually. These policies, if applied together, could in theory interact to produce a combined effect that differs from the sum of their individual impacts. However, given the small magnitude of the individual impacts, interaction among policies considered herein is not likely to change the conclusions of this report.

Estimates of the tax revenue impacts computed by EIA may differ from those developed by the JCT[3] for several reasons. EIA estimates the amount of activity eligible for tax credits using a sophisticated energy model, and then calculates tax revenue impacts by applying the specified tax credits without taking account of their possible interactions with other parts of the tax code. JCT may have less capability to estimate the amount of activity eligible for a credit (for example,

---

[1] Energy Information Administration, The *National Energy Modeling System: An Overview 2003*, DOE/EIA-0581 (2003) (Washington, DC, March 2003), web site http://www.eia.doe.gov/oiaf/aeo/overview/index.html.
[2] Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0383(2004) (Washington, DC, January 2004), http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2004).pdf.
[3] http://www.house.gove/jct/x-101-03.pdf.

the JCT did not include biomass co-firing in the renewable PTC calculation) but greater expertise in accounting for tax interactions. Also, EIA's tax impact estimates extend out to 2025, the NEMS forecast horizon, while JCT's estimates stop at 2013. Some long-lived provisions (e.g., the advanced nuclear power provision) have substantial revenue impacts beyond 2013. Finally, while JCT provided revenue impact estimates for all provisions, EIA's revenue impact estimates are limited to those provisions it could model using NEMS.

The next section summarizes the major findings of this report. The five sections that follow it present the analysis of the five individual tax provisions that were reviewed by EIA.

Analysis Summary

Energy Production, Consumption, and Prices.

- With the exception of Section 29, the provisions considered in this report do not measurably increase domestic oil or gas production over the next 10 years or over the forecast through 2025.

- The Section 29 provisions increase total domestic natural gas production from unconventional resources, particularly for the period 2004 to 2009. Unconventional gas production remains higher than the Reference Case after 2009 because of the increased reserve additions in the early period when the tax credits are available. The increased unconventional production reduces natural gas imports and other conventional gas production.

- Total energy consumption is virtually unaffected by the modeled policies. The difference from the Reference Case is at most 0.2 percent in any year for any individual measure.

- Section 29 provisions, which change the timing and magnitude of gas investments, are estimated to reduce the average wellhead natural gas price by almost $0.15 per thousand cubic feet over the 2005 to 2010 period. However, natural gas wellhead prices later in the forecast are only slightly affected.

Petroleum Imports

- None of the provisions analyzed are expected to have a measurable impact on oil imports or domestic oil supplies. Since oil generates only a tiny portion of total electricity in the United States (about 2 percent), the electricity provisions do not impact the level of petroleum imports. The Section 29 provisions do not significantly affect petroleum markets, since coal-to-liquids and gas-to-liquids are not economic.

- EIA could not directly model the impacts resulting from the amortization of geological and geophysical (G&G) expenditures over 2 years. However, based on the JCT estimates of tax revenue losses, the apparent financial benefit to the industry is less than 1 percent of annual cash flow variations that are likely to occur from price fluctuations. A change of this magnitude would not result in any significant change in oil production or imports.

- Based on JCT estimates of revenue losses for application of enhanced oil recovery (EOR) tax credits against the alternative minimum tax for 2004 and 2005, the proposed tax change for EOR would increase industry cash flow by less than one-quarter of one percent. While this proposed tax change could improve some individual company balance sheets, on an industry level, the impact on domestic oil production and petroleum imports would be negligible if the JCT estimates are valid.

Tax Revenue Losses.

- The EIA estimate of the tax revenue impact of the renewable PTC extension and expansion differ significantly from the JCT estimate. For the period 2004 to 2013, the EIA estimate of the tax revenue loss is $6.7 billion, compared to the JCT estimate of $3 billion. The primary source of the difference for the 2004 through 2013 period is the exclusion of co-firing at existing facilities using "open loop" biomass from the JCT estimate. EIA's estimate including tax revenue losses that occur after 2013 is $7.1 billion.

- For the nuclear PTC, EIA and JCT estimates of tax revenue losses for the 2004 to 2013 period are very close -- $170 million for EIA and $167 million for JCT. However, given the long period required to bring new nuclear capacity into production, nearly all of the tax revenue losses associated with this provision occur after the 2013 end date of the JCT analysis. EIA's estimate of tax revenue losses for this provision over its entire period of application is $5.7 billion.

Caveats of the Study

The projections in the Reference Case and the analysis cases developed for this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The Reference Case projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral starting point that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes.

Section 45 Credit for Electricity Produced from Certain Sources

Section 1302 of the CEB would extend eligibility for the inflation-adjusted, 1.8-cent-per-kilowatthour PTC for wind and "closed-loop" biomass facilities under Section 45 of Title 26 U.S. Code for plants coming online from January 1, 2004, to December 31, 2006, for an additional 10-year period. It also expands the program to include renewable electricity generated from geothermal, solar, "open-loop" biomass, municipal solid waste, and landfill gas resources.[4] This provision would allow some of the newly eligible technologies to claim only two-thirds of the value of the PTC for wind and closed-loop biomass (that is, 1.2 cents), and limits each of these program additions to a 5-year payment period. Since the provision specifies no earliest in-service date for plants utilizing open-loop biomass fuel, existing plants that co-fire with biomass fuel can claim the credit.

Table 1 presents the impacts of the renewable PTC, without considering the impacts of the other CEB provisions on the electricity markets served by renewable resources. The renewable PTC extension and expansion supports significant growth in generation from wind and biomass co-firing, which is more than double the generation in the Reference Case in 2010. Some of the additional wind generation is due to the accelerated construction of units that would have occurred later in the Reference Case. By 2025, the level of wind generation with the PTC extension is 50 percent above the Reference Case. Other provisions of the CEB, such as the nuclear PTC, could claim a share of the electric power market that, in the case shown in Table 1, is served by wind power. Also, other provisions in the CEB could reduce the price of natural gas, a key fuel for electric power generation, thus eroding the competitiveness of wind generation.

Table 1 shows that significant increases in biomass co-firing at existing coal facilities occur when existing plants are allowed to claim the PTC for burning "open-loop" biomass. Some coal facilities are able to quickly modify operations, while others may take a couple of years to make the capital investments (about $200 per kilowatt) necessary to take advantage of this provision. At the peak PTC-eligibility year of 2008, 84 billion kilowatthours of biomass generation from co-fired facilities are projected, compared to only 9 billion kilowatthours in the same year for the Reference Case. However, once the 5-year PTC payment period has ended, the effective fuel cost of the biomass returns to pre-PTC levels, and it is no longer economic to utilize the incremental amount of biomass fuel. At this point, co-firing operations are greatly reduced, although they remain somewhat higher than in the Reference Case throughout the projection period as some facilities have already invested in the capital costs to take advantage of the PTC. Because of the near-term nature of the co-firing PTC, the level of biomass consumption for co-firing is similar after 2011.

[4] The term ``closed-loop biomass" refers to any organic material from a plant which is planted exclusively for purposes of being used at a qualified facility to produce electricity. This supply is also sometimes referred to as "energy crops". "Open-loop biomass" generally refers to a variety of waste and by-product sources of organic material including agricultural wastes, forestry and mill waste, urban wood waste, and landscape trimmings.

Table 1. Non-hydro Renewable Generation, *AEO2004* versus Renewable PTC Case

	2003	2008		2010		2015		2025	
Renewable Generation (billion kilowatthours)		AEO 2004	PTC Case	AEO 2004	PTC Case	AEO 2004	PTC Case	AEO 2004	PTC Case
Geothermal	13.82	19.14	19.14	23.25	23.32	32.31	32.83	46.66	46.82
Municipal Solid Waste / Landfill Gas	25.58	27.81	28.77	28.11	28.88	28.18	28.94	28.50	29.05
Wood and Other Biomass	15.74	21.64	97.59	23.53	62.12	25.07	30.44	29.16	29.61
Dedicated Plants	10.75	12.56	13.98	13.26	14.01	14.03	13.56	22.90	19.46
Cofiring	4.99	9.07	83.60	10.26	48.11	11.05	16.88	6.25	10.15
Solar Thermal	0.52	0.82	0.82	0.84	0.84	0.97	0.97	1.11	1.11
Solar Photovoltaic	0.08	0.28	0.28	0.36	0.36	0.57	0.57	1.02	1.02
Wind	17.38	22.46	32.37	24.07	52.53	32.95	57.54	53.16	80.16
Renewable Capacity (gigawatts)									
Geothermal	2.90	3.51	3.51	4.01	4.02	5.11	5.17	6.84	6.86
Municipal Solid Waste / Landfill Gas	3.61	3.89	4.01	3.92	4.01	3.92	4.02	3.95	4.02
Wood and Other Biomass	1.85	2.09	2.09	2.20	2.17	2.32	2.25	3.74	3.23
Solar Thermal	0.33	0.43	0.43	0.43	0.43	0.47	0.47	0.52	0.52
Solar Photovoltaic	0.04	0.12	0.12	0.15	0.15	0.24	0.24	0.41	0.41
Wind	6.5	7.6	10.40	8.01	15.94	10.48	17.27	15.99	23.29
Natural Gas Wellhead Prices (dollars per thousand cubic feet)	4.90	3.64	3.63	3.40	3.41	4.19	4.17	4.41	4.41
Natural Gas Use in the Power Sector (Quadrillion Btu)	5.1	6.5	6.4	6.8	6.6	7.8	7.7	8.6	8.6
Sources: National Energy Modeling System date codes aeo2004.d101703e, nrgptc.d012604a.									

Other renewables, such as geothermal and landfill gas, are expected to see relatively small increases in generation due to the extension and expansion of the renewable PTC. There are a limited number of economical geothermal facilities, and it takes several years to develop them. The relatively short 3-year extension of the renewable PTC limits the amount of geothermal that can take advantage of the credit. Most large landfill facilities, which produce high levels of methane where generation options might be attractive, have already been developed. The impact on net petroleum imports is negligible because petroleum is not a widely used fuel in electric power generation.

The loss of revenue to the U.S. Treasury resulting from the extension and expansion of the PTC is concentrated in the first 6 years of the program. This reflects the large tax credit claimed for biomass co-firing during this period. There is an additional 5-year period of significant loss of revenue, as the wind industry continues to claim the credit for 10 years beyond the last PTC-eligible installation in 2006. After 2016, the annual cost to the Treasury becomes zero.

Table 2 shows the cost to the Treasury and the incremental impact on renewable capacity and generation compared to the Reference Case. The total cumulative lost tax revenue for the program is $6.7 billion through 2013 and slightly over $7 billion through 2025. The total cumulative lost tax revenue for the program in real discounted dollars is $4 billion (real 2002 dollars, using a 7-percent discount rate), after all tax credits have been claimed.

EIA estimates of the tax revenue impact of the renewable PTC extension and expansion contained in the CEB differ significantly from the scoring of the renewable PTC provision released by the JCT. Through 2013, EIA estimates a tax revenue loss of $6.7 billion, while the JCT estimates $3.0 billion. The primary source of the difference between the two estimates appears to be the inclusion of biomass co-firing in the EIA estimate and the exclusion of biomass co-firing in the JCT estimate.

Table 2. Renewable Production Tax Credit Impacts, Renewable PTC Case versus *AEO2004* Reference Case

Year	Incremental Capacity (gigawatts)	Incremental Generation (billion kilowatthours)	Nominal Tax Revenue Impacts (million dollars)
2004	0.0	2.5	86
2005	0.0	22.9	407
2006	3.1	68.0	1120
2007	3.0	85.7	1143
2008	3.0	86.8	1169
2009	4.8	86.3	1137
2010	8.0	67.9	754
2011	8.0	38.8	274
2012	7.8	32.5	282
2013	7.4	30.7	290
2014	7.1	32.0	258
2015	6.9	31.2	217
2016	6.7	30.5	0
2017	6.4	29.2	0
2018	6.9	30.8	0
2019	8.2	33.1	0
2020	8.6	34.6	0
2021	7.9	31.3	0
2022	7.8	30.4	0
2023	7.6	30.8	0
2024	7.0	28.4	0
2025	6.9	28.2	0
Sum through 2013			6,660
Sum through 2025			7,136
Source: National Energy Modeling System Runs: aeo2004.d101703e, nrgptc.d012604a.			

Credit for Electricity Produced from Advanced Nuclear Power Facilities

Section 1310 of the CEB adds Section 45L to U.S. Code Title 26, Section 45, which provides a 1.8-cent-per-kilowatthour tax credit (unadjusted for inflation) for production from advanced nuclear facilities for the first 8 years of their operation. To receive the credit, new facilities must be built before January 1, 2021. The total amount of the credit is limited to $125 million annually per 1,000 megawatts of new capacity, and the total amount of new capacity that can receive the credit is 6,000 megawatts.

EIA projects that this credit would stimulate the development of 6,000 megawatts of new nuclear capacity. The increased use of nuclear will lead to lower use of natural gas. For example, in 2020, natural gas wellhead prices and natural gas use in the power sector are projected to be 3 percent lower in the nuclear PTC case. Because of the long lead times associated with permitting, licensing, and constructing a new nuclear plant in the United States, the first new plant is not expected until 2013. While the development of 6,000 megawatts of new nuclear capacity will lead to cost reductions for future plants, the cost reductions are not expected to be large enough to make additional plants economical. As a result, once the credit capacity limit has been exhausted, no further new nuclear plants are projected.

Table 3 provides the nuclear capacity and tax revenue impacts of the nuclear PTC. As each new nuclear plant is brought online, its output is assumed to ramp up to full production over a 3-year period. As a result, the $125 million annual credit limit per 1,000 megawatts of capacity is not reached in the first 2 years of each plant's operation and the total tax revenue loss falls slightly

Table 3. Nuclear Production Tax Credit Impacts

	Nuclear Capacity (1,000 megawatts)			Nominal Tax Revenue Impacts (million dollars)
	AEO2004	Nuclear PTC	Increment	
2013	101	103	2	170
2014	102	106	4	397
2015	102	108	6	647
2016	102	108	6	727
2017	103	109	6	750
2018	103	109	6	750
2019	103	109	6	750
2020	103	109	6	750
2021	103	109	6	500
2022	103	109	6	250
2023	103	109	6	0
2024	103	109	6	0
2025	103	109	6	0
Sum through 2013				170
Sum through 2025				5,692

Source: National Energy Modeling System Runs: aeo2004.d101703e, nrgncred.d012604a.

below $6 billion. Because of the long lead times associated with bringing on new nuclear plants, the tax revenue impacts through 2013 are relatively low, totaling $170 million in nominal terms, $133 million in 2002 dollars, and $72 million discounted to 2004 using a 7-percent real discount rate. The $170 nominal figure through 2013 is very similar to the $167 million estimate from the JCT. However, through 2025, these values are much larger, $5,692 million, $3,849 million, and $1,565 million, respectively. The impact on oil imports of these new plants is negligible.

Extension and Modification of Section 29 for Producing Fuel from Nonconventional Sources

Section 1345 of the CEB would extend and modify Section 29 of the Internal Revenue Code, established under the Windfall Profit Tax of 1980, under which tax credits were provided for producing fuel from nonconventional sources. Fuels that were eligible to receive the credit included: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and steam from agricultural products. For facilities producing gas from biomass or synthetic fuel from coal, the credit is available for production through 2007 from facilities placed in service before July 1, 1998. For all other sources to which Section 29 applied, the credit was available for production through 2002 for those facilities placed in service from 1980 to 1992.

In general, Section 1345 allows a credit of $3 (indexed for inflation with 2002 as the base year) per barrel (or Btu equivalent) for production from nonconventional sources for 4 years of production prior to 2010 for new wells placed in service through 2006. Fuels eligible to receive the new credit include: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, and tight formations; landfill gas; fuels from agricultural and animal waste; refined coal; coal-mine gas; and coke and coke gas. Production from existing oil and gas wells drilled from 1980 through 1992, previously eligible through 2002, is also eligible for the credit through 2006. For smaller landfills there is a credit of $3 for facilities placed in service after June 30, 1998, and before January 1, 2007, while the credit is reduced to $2 for larger landfills already required to add gas collection facilities. Refined coal facilities placed in service before January 1, 2008, are also eligible for 5 years of tax credit. The credit in Section 1345 is limited to an average daily production of 200,000 cubic feet of gas (or oil equivalent) per well or facility. The credit is fully effective when the price of crude oil is $35 per barrel or less and phases out gradually as the price rises to $41 per barrel.

Nonconventional Gas

For gas from tight formations (tight sands), Devonian shale (gas shales), and gas from coal seams (coalbed methane), EIA allowed a credit of 53 cents per thousand cubic feet ($3 per barrel Btu equivalent) for 4 years of gas production prior to 2010 for new wells placed in service through 2006. The credit was represented as an increment to the wellhead price in the first 4 years of a projected price path utilized to determine the decision whether or not to drill a well.

The primary benefit of Section 1345 lies in the increased development of nonconventional natural gas deposits (tight sands, gas shales, and coalbed methane) as a source of U.S. natural gas supply. In the Section 29 Case, the increased profitability of nonconventional fuels under Section 1345 is projected to result in significant drilling increases, higher reserve levels, and, ultimately, increased production (Table 4). During the period for which wells are eligible for the credit from 2004 to 2006, 20 percent more nonconventional gas wells are projected to be drilled in the Section 29 Case than in the Reference Case. Total nonconventional reserve additions over this period are projected to be 13 percent higher in the Section 29 Case than in the Reference Case. With the higher reserve base, cumulative nonconventional production is projected to be about 3 percent greater in the Section 29 Case from 2004 to 2009, the period during which the

Table 4. Nonconventional and Total Lower 48 Natural Gas Projections: Section 29 Case and *AEO2004* Reference Case

Projections	2004	2005	2006	2007	2008	2009	2015	2025
Wells Drilled								
Nonconventional Natural Gas								
Section 29 Case	11716	12082	10654	8193	7919	7175	7746	5989
Reference Case	10274	9710	8770	8303	8328	7481	7665	5959
Total Lower 48 Natural Gas								
Section 29 Case	22337	22699	21475	19329	19532	18896	20868	20233
Reference Case	20896	20394	19759	19620	20006	19211	20767	20161
Reserve Additions (billion cubic feet)								
Nonconventional Natural Gas								
Section 29 Case	11542	12259	11509	9793	9743	9101	9047	7931
Reference Case	10752	10434	9984	9873	9874	9133	8928	7808
Total Lower 48 Natural Gas								
Section 29 Case	24693	24470	23458	20334	21662	21672	20899	19322
Reference Case	23898	22719	22133	20609	21961	21871	20759	19155
Production (billion cubic feet)								
Nonconventional Natural Gas								
Section 29 Case	6117	6284	6751	7125	7350	7491	8790	9293
Reference Case	6116	6181	6452	6714	7059	7242	8671	9165
Total Lower 48 Natural Gas								
Section 29 Case	18976	19089	19358	19750	19793	19777	21076	21459
Reference Case	18974	19025	19098	19377	19629	19660	20983	21286
Lower 48 Average Wellhead Price (2002 dollars)								
Section 29 Case	3.88	3.49	3.33	3.38	3.57	3.43	4.20	4.45
Reference Case	3.88	3.54	3.48	3.53	3.64	3.47	4.19	4.40

Sources: National Energy Modeling System runs: aeo2004.d101703e and nrgsec29.d012704a.

credit could be claimed (for 4 consecutive years) on production from an eligible well. Also of significance, the increased profitability of nonconventional gas activities (due to the tax credit) allows this production to come forth at a price that averages 8 cents lower during the period. With these lower prices, though, total Lower 48 production does not increase by the same amount (in absolute terms) as nonconventional production, since some of the more marginal conventional activities are no longer profitable. Section 1345 is projected to have a negligible effect upon net petroleum imports.

The cost of Section 1345 is the tax revenue not received by the Federal government as a result of the provision. EIA was not able to estimate tax revenue losses because NEMS does not track the production of wells drilled in a given year (a process called vintaging). Using the JCT's estimates of the lost tax revenue from Section 1345, the projections of lost revenue are compared to projections of incremental natural gas production under the provision for the major nonconventional fuels (tight sands, gas shales, and coalbed methane) in Table 5.

Table 5. Revenue and Production Impacts of Section 1345, Section 29 Case versus *AEO2004* Reference Case

Projections	2004	2005	2006	2007	2008	2009	2010	2015	2025
Joint Committee on Taxation Estimated Tax Revenue Losses (million 2002 dollars)[a]	-98[a]	-291	-565	-779	-720	-326	-68	NA	NA
Incremental Nonconventional Natural Gas Production (billion cubic feet)	1	103	298	412	290	249	229	119	128
Percent Change in Production	0.0	1.7	4.6	6.1	4.1	3.4	3.1	1.4	1.4

[a]The Joint Committee on Taxation's assessment of the tax implications of Section 1345 was done in the latter part of 2003, with full implementation of the CEB assumed at the beginning of 2004. As a result, their study allowed for some increase in production in 2004. The EIA projections assume that the CEB will take effect at some later point in 2004. Although drilling and reserve additions are projected to increase in 2004 as a result of the bill, no significant change in production is expected to occur until the following year.
Sources: National Energy Modeling System runs: aeo2004.d101703e and nrgsec29.d012704a.

The effects of Section 1345 on production from other fuels qualifying under the provision were not quantitatively analyzed within NEMS. In most instances, it was determined that the provision would have little or no effect or that any significant effect it might have could not be quantitatively analyzed. These fuels include gas production from previously eligible oil and gas wells (drilled prior to January 1, 1993), oil produced from shale and tar sands, gas from geopressurized brine, landfill gas, fuels from agricultural and animal wastes, refined coal, coal mine gas, and petroleum coke and coke gas.

Petroleum Coke and Coke Gas

In 2002, EIA data indicated that there were 56 U.S. refineries producing coke, all were built in the timeframes specified in Section 1345.[5] The amount of tax credit allowed for coke producers (at $3 per barrel oil equivalent and subject to the daily limit) would be $2,172,000 per year (2002 dollars) for 2004 through 2009.[6]

There are currently three coke gasification facilities in operation, with two more planned in a few years.[7] The three existing coke gasification facilities could jointly claim $116,000 per year for 2004 through 2009.[8] Assuming the two planned facilities are to be placed in service by January 1, 2007, these two facilities could jointly claim an additional $78,000 per year for 2007 through 2009.

Given the short-term nature of the tax credit (2004 through 2006 for refinery capacity changes) and the size of the tax credit, the projections for coke and coke gas production under the CEB assumptions remained unchanged compared to the Reference Case. Consequently, the impact of this provision on oil or gas supply or oil imports is negligible.

Landfill Gas

Both large landfills subject to the landfill rule and small landfills that add collection facilities between June 30, 1998, and January 1, 2007, are eligible for a Section 29 tax credit. The credit only applies to new facilities, not existing facilities. The small landfills get $3 per barrel oil equivalent (in 2002 dollars) while the large landfills get a reduced credit, $2 per barrel oil equivalent, for the first 4 years of their operation. The last year of credits is 2009, so a facility brought on in the middle or latter part of 2006 would not get the full four years. The credit is also limited to only 200,000 cubic feet per day of production. Since a barrel of oil contains about 5.8 million Btu, these credits are worth approximately $0.52 (2002 dollars) per million Btu of gas for the small landfills and $0.34 (2002 dollars) per million Btu of gas for large landfills.

However, these same landfills are also eligible under Section 45 to receive the production tax credit for electricity generation from renewable fuels. Under this section, landfills brought on after the passage of the bill and prior to the January 1, 2007, are eligible. The credit is worth 1.2 cents per kilowatthour (two-thirds of the 1.8 cents available to some other renewables) for the first 5 years of the facility's operation (half the period available for some other renewable facilities). To put this credit on a comparable basis with the Section 29 credit, a heatrate of 10,000 Btus per kilowatthour is assumed. With this assumption, the Section 45 credit translates to $1.20 per million Btu of gas. Also, Section 45 provides 5 years rather than the 4 years of the

[5] Energy Information Administration, *Petroleum Supply Annual, Vol.1*, DOE/EIA-0340 (1992, 1998, and 2002) (Washington, DC).
[6] Coke production increases through January 1, 2007, are assumed to be through advancement in catalyst technologies. The few new cokers added in the past decade were largely offset by the number of closures or coker conversion to other uses at refineries.
[7] The existing coke gasifiers include: Motiva Enterprises – Deleware City, DE; Frontier Oil – El Dorado, KS; and Farmland Industries – Coffeyville, KS. Two coke gasifiers are planned for TECO/Citgo – Lake Charles, LA and Shell – Deer Park, TX. Two refineries using heavy oil as feedstock to produce syngas do not qualify for the tax credit under Section 1345.
[8] Mr. Chris Overend of Joint Committee on Taxation clarified that coke and coke gas under Paragraph (7) would also be subjected to Paragraph (8) provisions, thus the same daily limit on the tax credit allowed as other qualified fuels.

Section 29 credit. Since Section 45 is more economically attractive, runs for a longer period, and the quantity is not limited, landfill operators are expected to take advantage of it rather than Section 29. The tax credits to landfills are not expected to have a significant impact on natural gas supplies or oil imports.

Coal-Mine Gas

Coal-mine methane is methane trapped in coal beds which is currently uneconomic to produce, flared for reasons of safety prior to opening new mines, and not included in the recoverable resources in NEMS. Under Section 29 provisions, new coal-mine methane produced by drilling shallow wells between 2004 and 2006 would qualify for a tax credit equivalent to $0.52 per thousand cubic feet for a maximum of 4 years, ending in 2009. Economically recoverable coalbed methane is currently accounted for in NEMS and is produced when economic.

Based on marginal abatement costs for coal-related methane emissions provided by the Environmental Protection Agency (EPA) and used in a recent EIA study,[9] at most 0.1 trillion cubic feet might be economic to produce annually for a maximum of 4 years under Section 29 incentives. However, such an increase is unlikely. The tax credit would only be available for a maximum of 4 years, and methane from coal mines has a slow production rate compared to conventional onshore natural gas wells. New infrastructure would have to be constructed in many cases, rendering some projects uneconomic, and the areas where coal mining expansion is planned may not coincide with the more economic of the coal-mine resources. In this case, the incremental natural gas production from coal-mine methane is expected to be very small.[10]

Refined Coal

The current Section 29 tax credit is available for coal-based synthetic fuels produced through December 31, 2007, provided the qualified facility was placed in service by June 30, 1998. To qualify for the Section 29 tax credit, the coal-based synthetic fuel must undergo a significant chemical change, which is generally defined as a measurable and reproducible change in the chemical bonding of the starting components. While there are multiple technologies that have been developed for producing coal-based synthetic fuel, most technologies comply with the required chemical change by applying a liquid binding agent such as diesel fuel emulsions, pine tars, or latex to the blend of coal feedstock, which is then mixed and further processed through industrial equipment. In most cases, the production of coal-based synthetic fuel uses a combination of one or more coal feedstocks, which may include run-of-mine coal, coal fines, low-grade coal and/or other types of "waste" coal.

---

[9] Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003*, SR/OIAF 2003-02, (Washington, DC, June 2003). See also http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf. Note that the negative portions of the EPA marginal abatement cost curves for coal-mine methane in the analysis of S.139 were adjusted so that negative marginal costs were changed to $1/ton. Since a negative marginal cost implies that a portion of the resource is economic to extract, the negative marginal cost portions were assumed to be already accounted for in the NEMS coalbed methane resource base and not used for this calculation to avoid double counting.

[10] The most significant obstacle to taking advantage of the methane from coal opportunity is the shortness of the period for cost recovery. Since methane production from coal mines is much slower than gas produced from convention gas wells, recovery of the necessary infrastructure costs is likely to be a major impediment for some locations. Finally, the extent to which the more economic coal-mined methane resources will coincide with the new coal mines planned in the allowable period is unknown.

In 2003, the U.S. Internal Revenue Service (IRS) conducted a review of the processes being used to produce solid synthetic fuels derived from coal, issuing an announcement of their findings on November 13, 2003. The IRS decision reflects the general belief that, although the processes do not produce the required level of chemical change, it would be unfair to change the rules regarding the production of solid synthetic fuels in the middle of the game. IRS Rev. Proc. 2001-34 specifies modifications to the allowable particle size of the coal feedstock and modifies the guidelines related to the processing procedures used to obtain a significant chemical change.

In 2002, EIA data indicated that there were 44 coal synfuel plants operating in the United States reporting receipts of 83.1 million short tons of coal. This represented 7.6 percent of U.S. coal production for the year. Of these 44 plants, 36 were located in Appalachia, 7 in the Eastern Interior supply region, and 1 in the West. Since the tax credits are based on the energy content of the finished product, measured in Btus, Section 29 qualified coal synfuels using Appalachian coals as a feedstock are worth considerably more than synfuels using lower-Btu western lignite and sub-bituminous coals as a feedstock. The current Section 29 provides for a production tax credit of approximately $3.00 per barrel of oil equivalent in 1979 dollars, which after adjustment for inflation, equals $6.35 per barrel of oil equivalent in 2002 dollars. Assuming that there are 5.8 million Btu per barrel of oil,[11] the tax credit for a qualifying solid synthetic fuel derived from a bituminous coal feedstock from Appalachia had a value of approximately $25 per short ton in 2002. Using this value, the total coal synfuel credit in 2002 for the 83.1 million tons reported to EIA is approximately $2 billion.

The tax credit provisions set forth in Section 1345 extend the tax credit for coal and waste coal to new faculties coming on-line after the enactment of the legislation and prior to January 1, 2008. Qualified new facilities will be eligible to receive a Section 29 tax credit for the first 5 years of operation. Relative to the current Section 29 guidelines, the new guidelines for qualifying coal synfuel facilities are substantially more restrictive. Covered facilities under the newly proposed guidelines require: 1) a 20-percent reduction in the emissions of nitrogen oxides and either sulfur dioxide or mercury compared to the emissions released when burning the original feedstock coal or comparable coal; 2) the refined coal product must be at least 50 percent higher in economic value than the feedstock; and 3) the facility cannot be any advanced clean coal technology unit.[12] In addition, the new guidelines reset the production tax credit to $3.00 per barrel of oil equivalent in 2002 dollars, with annual adjustments for inflation to commence in 2003. This last change reduces the value of the credit by more than half from its 2002 level.

Coal-to-liquids (CTL) conversion is not generally competitive with petroleum-based fuels unless the world oil price is greater than $30 per barrel. If world oil prices fail to reach that level, the effects of Section 1345 with a relatively small daily limit allowed for the tax credit[13] would be insignificant to help overcome the economic barrier for the commercialization of CTL.

EIA is not able to provide a specific estimate of the impacts of the extended tax credits for coal synfuels derived from coal or waste coal. However, with a reduction in the credit value of more

[11] The IRS defines each barrel of oil equivalent as having 5.8 million Btu.
[12] As defined in Section 48A(e), this provision excludes integrated gasification combined cycle because it is specifically defined as an advanced clean coal technology in Section 48A(e).
[13] Per Paragraph (8) of Section 1345, the amount of qualified unconventional fuels for the Section 29 tax credit is limited by an average barrel-of-oil equivalent of 200,000 cubic feet of natural gas per day (or 35.4 barrels-of-oil per day).

than 50 percent and a tightening of the qualification requirements, use of the credit is expected to be substantially below the $2 billion estimated for 2002.

Amortization of All Geological and Geophysical Expenditures Over 2 Years

Section 1344 of the CEB would change the amortization of geological and geophysical (G&G) expenditures incurred in connection with the exploration and development of domestic oil and gas resources. Currently, unsuccessful G&G costs are deductible when the project is abandoned and successful G&G costs are amortized. The CEB proposal allows a 2-year amortization of G&G costs for both successful and unsuccessful projects.

The change in tax provision would result in lower tax liability and thus increased cash flow from operations. This increase in cash flow could be directed toward drilling activity as well as investing and financial activities, e.g., mergers and acquisitions, reductions in long-term debt, purchase of treasury stock, etc.

The JCT estimates that the G&G tax provision would result in a $190-to-$450-million annual decline in tax revenues (or an increase in industry cash flow) for the total industry for years 2005 through 2013. Relative to U.S. oil and gas production revenue, oil and gas producer revenue from the G&G tax provision is expected to be tiny. Even in 1998, when U.S. oil prices sank to $10.87 a barrel, U.S. oil and gas revenue was more than 150 times the highest JCT estimate of the tax revenue loss from the G&G tax provision. The tax provision is expected to have a negligible impact on oil and gas production because the annual cash flow from U.S. oil and gas production for major companies reporting to the EIA Financial Reporting System (FRS),[14] which comprise just a part of the industry, has been in the $17-to-$49-billion range over the 6 years from 1997 to 2002 (Table 6). If the JCT analysis is correct, year-to-year cash flow fluctuations (driven by oil and gas prices) can be at least 35 times larger than the tax value of the provision and, consequently, the provision is unlikely to appreciably sway drilling decisions. Also note that the increase in cash flow as provided by the JCT represents less than a 3-percent increase in FRS companies' cash flow from U.S. oil and gas production, assuming that the JCT analysis is correct. Since the FRS companies produce slightly less than half of U.S. oil and gas, the overall impact of the proposed tax change on the industry cash flow would be even less. The proposed tax change may improve individual company balance sheets, but on an industry level the impact on oil and gas production would be very small.

[14] These are major energy producers who are required to file form EIA-28 (Financial Reporting System). FRS companies account for almost half of total U.S. oil and gas production.

Table 6. Cash Flow for Major Oil and Gas Companies, 1997-2002

	1997	1998	1999	2000	2001	2002
U.S. Domestic First Purchase Oil Price (dollars per barrel)	17.23	10.87	15.56	26.72	21.84	22.51
Lower 48 Natural Gas Wellhead Price (dollars per thousand cubic feet)	2.32	1.96	2.19	3.69	4.02	2.95
U.S. Oil and Gas Production Revenue (billion dollars)	98.0	70.6	87.3	149.9	143.3	122.3
Pretax Cash Flow[a] from U.S. Oil and Gas Production (billion dollars)	29.8	17.0	22.8	47.5	48.6	39.9

[a] Defined as the sum of operating income, depreciation, depletion, and amortization, and dry hole expense.
Source: Prices and Revenue: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2004/01), (Washington, DC, January 2004); Cash Flow: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The Application of Enhanced Oil Recovery Tax Credits Against the Alternative Minimum Tax for 2004 and 2005

Section 1347 of the CEB would permit oil producers to apply their EOR tax credits against the Alternative Minimum Tax (AMT). Under current law, if an oil producer pays the AMT, then they would be constrained from applying some or all of their EOR tax credits to their tax bill. The CEB proposal would permit oil producers to reduce their AMT payment equal to the size of their outstanding EOR tax credits. This provision would remain in effect only for 2004 and 2005. This provision would primarily increase near-term cash flow for those petroleum companies which are subject to the AMT and which have unused EOR tax credits.

EIA cannot determine the budget impacts of this provision because company-specific tax information is required regarding whether a company is paying the AMT level and the amount of that company's unused EOR tax credits, which is not available to EIA. Any analysis of this provision would be further complicated by the fact that a company's future tax situation largely depends upon prevailing oil and gas prices. During periods when oil and gas prices are high, producers are less likely to be subject to the AMT. Because unused tax credits can be carried forward, an analysis calculating future budget impacts would have to anticipate when the EOR tax credits would otherwise be employed in the future. So this provision primarily changes the timing of when a company's EOR tax credits are applied to that company's tax bill.

Generally, the small petroleum producers, which have smaller gross margins than the large diversified companies, are more likely to be subject to paying the AMT. Because EIA currently projects oil prices to remain above $25 per barrel for 2004 and 2005,[15] the number of oil producers subject to the AMT which also have undeclared EOR tax credits is expected to be small.

[15] Energy Information Administration, *Short-Term Energy Outlook*, January 2004, http://www.eia.doe.gov/emeu/steo/pub/pdf/jan04.pdf, Table 4.

JCT estimates that the proposed tax provision would result in an average annual decline in tax revenues of $80 million during 2004 through 2006. If the JCT analysis is correct and if this decline in tax revenues translated directly into an increase in company cash flow, then it would have a negligible impact on total industry cash flow, and in turn, on oil and gas production. The annual cash flow from U.S. oil and gas production operations for FRS companies has been in the $17-to-$49-billion range over the last 5 years.[16] The proposed tax change would increase industry cash flow by less than one-half of one percent, assuming that the JCT analysis is correct. The proposed tax change may improve some individual company balance sheets, but on an industry level, the impact on oil production and imports would be negligible.

[16] Energy Information Administration, *Performance Profiles of Major Energy Producers*, DOE/EIA-0206, (Washington, DC), various annual editions, Table 4.

Appendix A

Request Letter from Senator Sununu

JOHN E. SUNUNU
NEW HAMPSHIRE

DEPUTY WHIP

BANKING, HOUSING, AND URBAN AFFAIRS

COMMERCE, SCIENCE, AND TRANSPORTATION

FOREIGN RELATIONS

GOVERNMENTAL AFFAIRS

JOINT ECONOMIC COMMITTEE

UNITED STATES SENATE

60 PLEASANT STREET
BERLIN, NH 03570
(603) 752-6074

50 TREMONT SQUARE
CLAREMONT, NH 03743
(603) 542-4872

1589 ELM STREET, SUITE 3
MANCHESTER, NH 03101
(603) 647-7500

ONE NEW HAMPSHIRE AVENUE, SUITE 120
PORTSMOUTH, NH 03801
(603) 430-9560

111 RUSSELL SENATE OFFICE BUILDING
WASHINGTON, DC 20510
(202) 224-2841

January 29, 2004

Mr. Guy F. Caruso
Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Ave. SW
Washington, DC 20585

Dear Mr. Caruso:

I would like to better understand the economic and productivity impacts of certain provisions in the conference report of the Energy Policy Act of 2003.

Specifically, Title XIII, ENERGY TAX INCENTIVES contains provisions that subsidize various forms of energy production and conservation. For each provision identified in the attachment to this letter, I would appreciate the following:

1. EIA's estimate of how much incremental energy (resulting from the subsidy compared to the annual energy outlook [AEO] 2004 reference case) is either produced or saved for each of the next ten years after enactment (assume '04). The analysis should include a projection to the year 2025.

2. EIA's estimate of how much petroleum imports are reduced or increased for each of the next ten years. The analysis should also include a projection to 2025.

3. EIA's estimate of the tax revenue losses that would result from each provision identified in the Attachment. Where EIA's estimate differs significantly from the Estimates of the Joint Tax Committee please provide an explanation of the differences.

I would appreciate receiving your estimates by February 9, 2004. Please do not hesitate to call my office if you have questions regarding this request.

With best regards,

John E. Sununu
United States Senator

ATTACHMENT-----Title XIII--- ENERGY TAX INCENTIVES[1]

Conservation Provisions

2. Section 45 credit for electricity produced from certain sources.

10. Credit for electricity produced from advanced nuclear power facilities.

Production Provisions

4. Amortize all geological and geophysical expenditures over 2 years.

5. Extension and modification of section 29 for producing fuel from non-conventional source.

B.2.b. Enhanced oil recovery credit for 2004 and 2005.

[1] Note that the number and description for each of the above provisions is from "Estimated Budget Effects of the Conference Agreement for the Energy Tax Policy Act of 2003" dated 11-18-03 published by the Joint Committee on Taxation.