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Federal Financial Interventions and Subsidies in Energy Markets 2007

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Energy Information Administration
Office of Coal, Nuclear, Electric, and Alternate Fuels
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Preface and Contacts

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This report responds to a request from Senator Lamar Alexander of Tennessee that the EIA update its 1999 to 2000 work on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration and Congressional action since the previous report was written, and to provide an estimate of the size of each current subsidy. Subsidies to be included are those through which a government or public body provides a financial benefit with a Federal budget impact. Senator Alexander's letter of May 17, 2007, provided as Appendix H, asked EIA to focus particularly on subsidies directed to electricity production, including an estimate of electricity subsidies on a per unit basis.

This report was prepared by an EIA-wide project team including staff from EIA's Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), the Office of Integrated Analysis and Forecasting (OIAF), and the Office of Energy Markets and End Use (EMEU). General questions about the report may be directed to the primary point of contact, Robert Schnapp, Director, Electric Power Division (CNEAF), at 202-586-5114, or via e-mail at rschnapp@eia.doe.gov. Questions about specifics within the report may be directed to the following analysts:

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Within its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review this report and provide comment. The reviewers provided comments on a draft version of the report, after an earlier meeting with EIA to discuss the methodology and preliminary results. All comments from the reviewers either have been incorporated or were considered for incorporation. As is always the case when peer reviews are undertaken, not all the reviewers are in agreement with all the methodology, inputs, and conclusions of the final report. The contents of this report are solely the responsibility of EIA. The assistance of the following reviewers in preparing the report is gratefully acknowledged:

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Executive Summary

Background

In May 2007, Senator Lamar Alexander asked the Energy Information Administration (EIA) to develop an analysis of Federal energy subsidies focusing on subsidies to electricity production. Senator Alexander also specified that the analysis should be limited to subsidies provided by the Federal government, those that are energy-specific, and those that provide a financial benefit with an identifiable budget impact. Federal energy subsidies and interventions discussed in the body of this report take four principal forms:

- **Direct Expenditures**. These are Federal programs that directly affect the energy industry and for which the Federal government provides funds that ultimately result in a direct payment to producers or consumers of energy.

- **Tax Expenditures**. Tax expenditures are provisions in the Federal tax code that reduce the tax liability of firms or individuals who take specified actions that affect energy production, consumption, or conservation in ways deemed to be in the public interest.

- **Research and Development (R&D)**. Federal R&D spending focuses on a variety of goals, such as increasing U.S. energy supplies, or improving the efficiency of various energy production, transformation, and end-use technologies. R&D expenditures do not directly affect current energy production and prices, but, if successful, they could affect future production and prices.

- **Electricity programs serving targeted categories of electricity consumers in several regions of the country**. Through the Tennessee Valley Authority (TVA) and the Power Marketing Administrations (PMAs), which include the Bonneville Power Administration (BPA) and three smaller PMAs, the Federal government brings to market large amounts of electricity, stipulating that "preference in the sale of such power and energy shall be given to public bodies and cooperatives." The Federal government also indirectly supports portions of the electricity industry through loans and loan guarantees made by the U.S. Department of Agriculture's Rural Utilities Service (RUS).

With the exception of the Federal electricity programs, this report measures subsidies and support on the basis of the cost of the programs to the Federal budget provided in budget documents. Support associated with Federal electricity programs is measured by comparing the actual cost of funds made available to these entities to EIA estimates of the cost of funds that they might otherwise have incurred in the absence of Federal support.

Summary of Findings

Total Federal energy-specific subsidies and support to all forms of energy are estimated at $16.6 billion for fiscal year (FY) 2007 (Table ES1). Total energy subsidies have more than doubled in real terms (2007 dollars), increasing from an estimated $8.2 billion in FY 1999. Tax expenditures have more than tripled since 1999, rising from $3.2 billion that year to more than $10.4 billion in 2007.

The increase in energy subsidies and support since 1999 is distributed widely across all energy groups (Table ES1). Changes in the distribution of subsidies by fuel type between

1999 and 2007 reflect a redirection of priorities. For example, subsidies for renewables increased from 17 percent of total subsidies and support in 1999 to 29 percent in 2007. Natural gas and petroleum related subsidies declined as a share of total subsidies primarily as a result of the expiration of the Alternative Fuels Production Tax Credit for the production of unconventional natural gas in 1999, whereas refined coal was the principal beneficiary of this tax expenditure in 2007. Coal-related subsidies, excluding refined coal, experienced a modest decline from 7 percent in 1999 to 6 percent in 2007.

Table ES1. Energy Subsidies and Support by Type and Fuel, FY2007 and FY1999 (million 2007dollars)

Beneficiary	Direct Expenditures	Tax Expenditures	Research & Development	Federal Electricity Support	Total
2007 Subsidies					
Coal	-	290	574	69	932
Refined Coal[1]	-	2,370	-	-	2,370
Natural Gas and Petroleum Liquids	-	2,090	39	20	2,149
Nuclear	-	199	922	146	1,267
Renewables	5	3,970	727	173	4,875
Electricity (Not fuel specific)	-	735	140	360	1,235
End Use	2,290	120	418	-	2,828
Conservation	256	670	-	-	926
Total	2,550	10,444	2,819	767	16,581
1999 Subsidies					
Coal	-	79	489	-	567
Natural Gas and Petroleum Liquids[2]	-	1,878	198	-	2,077
Nuclear	-	-	740	-	740
Renewables	5	1,000	412	-	1,417
Electricity (Not fuel specific)	-	139	175	-	314
End Use	1,545	103	487	-	2,135
Conservation	191	-	-	-	191
Federal Electricity Programs	-	-	-	753	753
Total	1,741	3,199	2,500	753	8,194

Total may not equal sum of components due to independent rounding.

[1]Tax expenditures attributable to the Alternative Fuels Production Tax Credit.

[2] In 1999, the Alternative Fuels Production Credit was realized mostly from the production of coalbed methane; valued at $1.2 billion, that subsidy is reported in Natural Gas and Petroleum Liquids.

Recent Federal legislation, including the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) and the Energy Independence and Security Act of 2007 (EISA 2007) (Public Law 110-140) suggest that certain energy-related tax expenditures are likely to increase.

Some of the most significant subsidy provisions in EPACT2005 concern nuclear power. Given that no new nuclear power plants are expected to produce electricity before the middle of the next decade, this report provides no estimates for the value of these provisions. EPACT2005 also included mandates for the use of renewable motor fuels that were significantly expanded in EISA 2007. EISA 2007 mandates are not considered in this report given its focus on historical and current tax expenditures. The EISA renewable fuel mandates could become binding in the near future.

Notwithstanding the doubling of Federal energy-related subsidies and support between 1999 and 2007, and a significant increase in most energy prices over that period, U.S. energy production is virtually unchanged since 1999 (Table ES2). Basic economic principles suggest that higher real energy prices together with the significant incentives provided to various production segments of the energy sector would tend to raise domestic energy production. A variety of factors unrelated to prices or subsidy programs such as State and Federal statutory limitations imposed on onshore and offshore oil and natural gas exploration in environmentally sensitive areas, uncertainty regarding future environmental policies possibly restricting future emissions of greenhouse gases, and declines in future production from previously developed domestic oil and natural gas resources may have impeded growth in energy production despite modest growth in consumption.

In response to Senator Alexander's specific request, this report focuses on subsidies that provide benefits to the electric power industry in one of three ways, specifically that:

Table ES2. Total Energy Subsidies and Support, Selected Indicators,1999 and 2007

Item	1999	2007	Percent Change 1999 to 2007	Average Annual Growth (Percent)
Energy Subsidies and Support (million 2007 dollars)	8,194	16,581	102.4	9.2
Energy Expenditures (billion 2007 dollars)	674	1,269	88.1	8.2
Energy Consumption (quadrillion Btu)	97	101	4.6	0.6
Energy Production (quadrillion Btu)	72	72	0.1	*

NOTE: * Value is less than one-tenth of one percent.

Sources: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Tables 1.1, 1.2, 1.3, 1.5, and D1; *Short-Term Energy Outlook* (Washington DC, January 8, 2008 release), http://www.eia.doe.gov/emeu/steo/pub/contents.html; *Annual Energy Outlook 2008 (Early Release*), http://www.eia.doe.gov/oiaf/aeo/index.html, and this report.

- affect a fuel used as input for the generation of electricity;
- are directed to technological components of the industry, such as generation, transmission, or distribution;
- are directed to, or are applied by, a business enterprise whose primary purpose is the generation, transmission, and/or distribution of electricity.

Table ES3 summarizes the split between electricity production subsidies, support to Federal utility programs, and other energy subsidies deemed to be unrelated to electricity production.

Table ES3. Allocation of Electricity Production and Other Energy Subsidies (million 2007 dollars)

Subsidy and Support Category	FY 2007 Electricity Production Subsidies and Support	FY 2007 Other Energy Subsidies and Support	FY 2007 Total Energy Subsidies and Support
Fuel Specific[1]	5,105	2,330	7,435
Transmission and Distribution [2]	1,235	-	1,235
Federal Utilities and RUS Borrowers Capacity[3]	407	-	407
Energy Subsidies Unrelated to Electricity Production[4]	-	7,504	7,504
Total	6,747	9,834	16,581

NOTES: Totals may not equal sum of components due to independent rounding.

[1]Includes fuel-related tax expenditures, R&D, and direct expenditures applicable entirely to a specific type of electric generation, or primary fuel production-related subsidies allocated to either electricity or other sectors based on each sector's proportionate consumption of the applicable fuel. Excludes fuels that have no role in electricity production such as ethanol and other biofuels.

[2] Includes transmission and distribution-related tax expenditures, R&D, and $360 million of estimated financial support attributable to Federal utilities' and RUS borrowers' debt associated with transmission and distribution assets.

[3]Reflects the estimated portion of Federal utilities' and RUS borrowers' interest support attributable to long-term debt associated with capacity and certain TVA and BPA regulatory assets. This support is then assigned by fuel-type.

[4]Includes tax and direct expenditures for end-use activities and transportation-related alternative fuels. Among these subsidies are conservation programs, residential and commercial energy efficiency programs, and ethanol and biofuels tax credits.

Sources: See Table 26, Table 27 and Table 30.

Findings Regarding Electricity Production-Related Subsidies

Subsidies and support related to electricity production are estimated at $6.7 billion (Table ES3), or about 41 percent of total energy subsidies. A significant portion of electricity subsidies and support ($1.2 billion, or 18 percent of total electricity subsidies and support) is directed to electric plant or infrastructure, such as transmission. Another $407 million consists of capital cost support associated with electric generation assets of Federal utilities and RUS loans. The beneficiaries of this support are electricity consumers who purchase power produced by the Federal utilities and RUS borrowers. The estimated interest subsidy associated with these assets is allocated by fuel type. The remaining $5.1 billion of electricity subsidies are either directed at specific types of electricity production, based on fuel type or investment, or expenses associated with upstream production and transportation of fuels used in electricity production—all of which either affect the cost of the input fuel or reduce the cost of generating equipment used to produce electricity.

Tax expenditures comprise about two-thirds of the total subsidies and support related to electricity production (Table ES4). The alternative fuel production tax credit,[1] which is largely directed to producers of coal-based synthetic fuels, also referred to as refined coal, accounted for about one-half of total tax expenditures related to electricity production in FY 2007.

Nuclear programs, renewable programs, and non-fuel-specific electricity production subsidies and support each ranged from $1 billion to $1.3 billion.

Natural gas and petroleum liquids receive a lower level of support from electricity production-related subsidies and support than other fuel groups. Overall, electricity production-related subsidies are spread broadly across the various fuel groups, probably more so than in the past.[2]

Table ES4. Fiscal Year 2007 Electricity Production Subsidies and Support (million 2007 dollars)

Fuel End Use	Direct Expenditures	Tax Expenditures	Research & Development	Federal Electricity Support	Total
Coal	-	264	522	68	854
Refined Coal	-	2,156	-	-	2,156
Natural Gas and Petroleum	-	203	4	20	227
Nuclear	-	199	922	146	1,267
Renewables	3	724	108	173	1,008
Transmission and Distribution	-	735	140	360	1,235
Total	3	4,281	1,696	767	6,747

NOTES: Estimates of Federal electricity program support are based on the most recent audited annual reports for Federally-owned utilities which conform to Federal fiscal year convention. The Rural Utilities Service estimate is based on calendar year 2005 data.

Totals may not equal sum of components due to independent rounding.

Sources: See Table 34.

Electricity production subsidies and support per unit of production (dollars per megawatthour) vary widely by fuel. Coal-based synfuels (refined coal) that are eligible for the alternative fuels tax credit, solar power, and wind power receive, by far, the highest subsidies per unit of generation, ranging from more than $23 to nearly $30 per megawatthour of generation (Table ES5). Subsidies and support for these generation sources are substantial in relationship to the price or cost of electricity at the wholesale or end-user level. The average U.S. electricity price was about $53 per megawatthour at the wholesale level in 2006 and about $92 per megawatthour to end users in all sectors in FY 2007.[3]

[1] The alternative fuel production tax credit was initially established in the Windfall Profit Tax Act of 1980 (Public Law 96-223). The provision was codified in Section 29 of the Internal Revenue Code. It was subsequently modified by Section 710 of the American Jobs Creation Act of 2004 (Public Law 108-357) to include synthetic coal, which was redefined as refined coal and recodified in Section 45 of the Internal Revenue Code. The expiration date to qualify for the credit was extended in EPACT2005.
[2] EIA did not analyze electricity production subsidies in particular in its 2000 report. However, a line item comparison of various energy subsidies indicates that newer subsidy programs have been directed toward fuel groups and activities, such as renewables, conservation, and transmission that previously received less attention.
[3] Energy Information Administration Form EIA-861 "Annual Electric Power Industry Report," 2006; and Energy Information Administration, *Electric Power Monthly December 2007,* DOE/EIA 0026(0712) (Washington, DC, December 2007), Table 5.6.B.

Table ES5. Subsidies and Support to Electricity Production: Alternative Measures

Fuel/End Use	FY 2007 Net Generation (billion kilowatthours)	Alternative Measures of Subsidy and Support	
		FY 2007 Subsidy and Support (million 2007 dollars)	Subsidy and Support per Unit of Production (dollars/megawatthour)
Coal	1,946	854	0.44
Refined Coal	72	2,156	29.81
Natural Gas and Petroleum Liquids	919	227	0.25
Nuclear	794	1,267	1.59
Biomass (and biofuels)	40	36	0.89
Geothermal	15	14	0.92
Hydroelectric	258	174	0.67
Solar	1	14	24.34
Wind	31	724	23.37
Landfill Gas	6	8	1.37
Municipal Solid Waste	9	1	0.13
Unallocated Renewables	NM	37	NM
Renewables (subtotal)	360	1,008	2.80
Transmission and Distribution	NM	1,235	NM
Total	4,091	6,747	1.65

NOTES: Unallocated renewables include projects funded under Clean Renewable Energy Bonds and the Renewable Energy Production Incentive.

NM=Not meaningful. Totals may not equal sum of components due to independent rounding.

Sources: See Table 35

The differences between rankings of subsidies and support based on absolute amounts and amounts per megawatthour are driven by substantial differences in the amount of electricity generation across fuels. Capital-intensive, baseload generating technologies, such as coal-fired steam generators and nuclear generators, together produce about 70 percent of total net generation,[4] which tends to reduce their subsidies and support per unit of production compared to the other fuel groups (Table ES5). For the same reason, electricity subsidies for solar and wind show a relatively large subsidy per unit of production, as these groups account for less than 1 percent of total net generation in the country. It is important to recognize that the subsidies-per-megawatthour calculations are a snapshot taken at a particular point in time. Some electricity sources, such as nuclear, coal, oil, and natural gas, have received varying levels of subsidies and support in the past which may have aided them in reaching their current role in electricity production.[5] The impacts of prior subsidies, some of which may no longer be in effect, are not measured in the current analysis.

A per-unit measure of electricity production subsidies and support may provide a better indicator of its market impact than an absolute measure. For example, even though coal receives more subsidies in absolute terms than wind power, the use of wind is likely to be more dependent on the availability of subsidies than the use of coal.

[4] In fiscal year 2007, nuclear and coal accounted for 68 percent of total net generation.
[5] See Energy Information Administration, Federal *Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy,* SR/OIAF/99-03 (Washington, DC, September 1999); Energy Information Administration*, Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets,* SR/EMEU/92-02 (Washington, DC, November 1992).

Other factors can also play an important role in determining the market impact of a particular production subsidy. For example, generation using refined coal whose production is made possible by its eligibility for the Alternative Fuel Production Tax Credit would probably be replaced entirely by conventional coal generation if the tax credit were unavailable. In contrast, generation resulting from the growth in wind power capacity that is supported by renewable production tax credits would likely be replaced with generation from a broad mix of generation sources if that credit were unavailable.

Findings Regarding Energy Subsidies Not Related to Electricity Production

Based on the subsidy categories used in this report, 59 percent of energy-related subsidies are associated with end-use applications or with fuel consumed outside the electric power sector. These subsidies totaled $9.8 billion in FY 2007 (Table ES6).

About one-third of energy subsidies unrelated to electricity production are related to the promotion of alternative fuels, particularly ethanol and biodiesel, both of which are eligible to receive a blender's credit under the Volumetric Ethanol Excise Tax Credit (VEETC). Blenders receive a $0.51 per gallon credit for each gallon of ethanol that is blended with gasoline for use as a motor fuel.[6] The benefit provided by the credit is equivalent to that provided by the reduced excise tax rate for gasohol in effect prior to the enactment of VEETC in late 2004. Internal Revenue Service regulations require that blenders apply for VEETC refunds to offset gasoline excise tax payments, but they may submit a claim for payment or take a credit against other taxes if their VEETC credits exceed their gasoline excise tax liability. Based on its implementation rules, the Treasury reports VEETC as a reduction in excise tax revenues for FY 2007. For purposes of this report, it is classified as a tax expenditure.

Non-fuel specific subsidies totaling $3.6 billion focus on energy efficiency, conservation, and energy-related financial assistance to residential, commercial, and industrial end users. Conservation and energy efficiency subsidies can affect electricity consumption in the long run by reducing the need for investment in additional generating capacity, with a resultant decline in fuel use. While these subsidies can affect electricity markets, they do not provide a direct or indirect subsidy to electricity production and are therefore classified separately from the electricity production-related subsidies estimated for purposes of this report.

[6] The credits for mixtures other than ethanol are $0.60 per gallon for alcohol fuel mixtures (other than ethanol), $0.50 per gallon of biodiesel, and $1.00 per gallon for agri-biodiesel.

Table ES6. Energy Subsidies Not Related to Electricity Production: Alternative Measures

Category	Fuel Consumption (quadrillion Btu)	Alternative Measures of Subsidy and Support: FY 2007 Subsidy and Support (million 2007 dollars	Alternative Measures of Subsidy and Support: Subsidy per million Btu (2007 dollars)
Coal	1.93	78	0.04
Refined Coal	0.16	214	1.35
Natural Gas and Petroleum Liquids	55.78	1,921	0.03
Ethanol/Biofuels	0.57	3,249	5.72
Geothermal	0.04	1	0.02
Solar	0.07	184	2.82
Other Renewables	2.50	360	0.14
Hydrogen	*	230	NM
Total Fuel Specific[1]	60.95	6,237	0.10
Total Non-Fuel Specific	NM	3,597	NM
Total End-Use and Non-Electric Energy	NM	9,834	NM

NOTES: Non-electric power refined coal consumption is based on the sum of monthly deliveries, in short tons, reported in the EIA publications cited below for FY 2007. Delivered refined coal to non-electric customers is converted to equivalent Btu consumption based on EIA's estimate of the average Btu content for refined coal deliveries to generators reported to EIA. Other renewables includes hydroelectric, wood, biomass losses and co-products, and hydroelectric power as reported in the sources noted below.

[1]Subsidy shown differs from that shown in Table ES3 due to inclusion of fuels that have no role in electricity production, such as ethanol and other biofuels.

*Less than 500 trillion Btu.

NM = Not meaningful

Totals may not equal sum of components due to independent rounding.

Sources: See Table 36.

1. Introduction

Background and Purpose

In May 2007, Senator Lamar Alexander asked the Energy Information Administration (EIA) to develop an analysis of Federal energy-specific subsidies that provide a financial benefit with an identifiable budget impact. His request letter of May 12, 2007, provided as Appendix H, asked EIA to focus particularly on subsidies directed to electricity production, including an estimate of electricity subsidies on a per unit basis.

In 2000, EIA enumerated and summarized energy subsidies and support generally; this report focuses on electricity production, specifically those subsidy and support programs that affect the production of primary fuels used to generate electricity (coal, natural gas, petroleum, and nuclear fuel), and the development of generating technologies including renewable generating technologies, and the development and maintenance of the electricity infrastructure.

Scope of the Report and Measurement of Subsidies and Support

Federal energy subsidies discussed in the body of this report take four principal forms:

- Direct Expenditures. These are Federal programs that provide direct financial benefits to targeted producers and consumers of energy to promote investment in critical infrastructure, develop and diversify domestic energy supplies, foster efficient end-use consumption, and reduce energy costs incurred by economically-disadvantaged consumers.

- Tax Expenditures. Tax expenditures are provisions in the Federal tax code that reduce the tax liability of firms or individuals who engage in specific economic activities that affect energy production, consumption, or conservation in ways deemed to be in the public interest.

- Research and Development (R&D). Federal R&D spending focuses on a variety of goals, from increasing U.S. energy supplies, to improving the efficiency of various energy production, transformation,[7] and end-use technologies. R&D expenditures do not directly affect current energy production, prices, and environmental quality, but, if successful, they could affect future energy production, prices, and environmental quality.

- Federal programs that indirectly support electricity production. Through the Tennessee Valley Authority (TVA) and the Power Marketing Administrations (PMAs), which include the Bonneville Power Administration (BPA) and three smaller PMAs, the Federal government brings to market large amounts of electricity, stipulating that "preference in the sale of such power and energy shall be given to public bodies and cooperatives."[8] The Federal government also provides direct financial support and credit enhancement for construction and generation, transmission, and distribution facilities by entities eligible to participate under the U.S. Department of Agriculture's Rural Utilities Service (RUS) loan programs.

[7] Energy transformation consists of network infrastructure and delivery systems. Electricity is the primary transformation sector analyzed in this report. The electricity sector consists of generation, transmission, and distribution.
[8] Flood Control Act of December 2, 1944 (58 Stat. 890; 16 U.S.C. 825s). Surplus Federal utility power is sold to investor-owned utilities.

In measuring the cost to the Federal government of the subsidies (and financial support provided TVA and PMA customers and RUS borrowers) this report uses the measure of budget cost or revenue losses to the greatest extent possible; in some cases, budget outlays—the actual expenditures by Federal agencies—are cited. For many R&D programs, however, the available outlay data are less disaggregated than the appropriations data. Hence, using the appropriations data provides a more detailed understanding of Federal R&D efforts by type of energy supported. There are also several programs for which the Federal budget itself is not a meaningful measure of the concept of budget costs. Tax expenditures are not line items in the budget. The Treasury Department estimates the cost of tax expenditures as revenue foregone as a result of a provision in the tax code that reduces or defers tax liability and, therefore, tax receipts. The Treasury Department's estimated revenue losses associated with energy-related tax expenditures are used in this study.[9] EIA measures support provided by Federal electricity programs through a cost-of-capital analysis.

Using the Federal budget has the advantage of ease of measurement; however, budget values may understate both the economic costs and the market impacts of specific programs, especially where small subsidies are applied to large existing markets.[10] On the other hand, some large subsidies are applied to small markets and have a substantial impact on certain forms of energy production and consumption. Some subsidies offer relatively large payments to producers using certain energy technologies that otherwise would be uneconomical at present. In these cases, the immediate effects on markets may be small, but the impact on specific technologies may be significant now and in the future.

Definition of Subsidy and Types of Subsidies and Support Addressed

There is no universally-accepted definition of subsidy. For the purposes of this report, a subsidy is defined as a transfer of economic resources by the Federal government to the buyer or seller of a good or service that has the effect of reducing the price paid, increasing the price received, or reducing the cost of production of the good or service with incentives that reduce the producers' taxable income. A subsidy is conditioned on a particular economic outcome. The net effect of such a subsidy is to alter the production or consumption of a commodity over what it would otherwise have been.[11] In some instances subsidies may also result in a transfer of wealth because they change the behavior of the recipient of the subsidy.[12] Subsidies are measured in terms of monetary value. They exist when government intervention either lowers energy prices for consumers or supports producers when their production costs prohibit sales at market prices. There are a number of Federal interventions in energy markets that fall outside the framework of this report, an important one being government regulation. The cost of spillovers, such as the effects that certain forms of energy production and consumption have on the environment and public health, is another.

This report quantifies direct and indirect energy subsidies and support to Federal electricity programs. Direct subsidies include (a) payments from the government directly to producers or consumers and (b) tax expenditures. Tax expenditures are provisions in the tax code that reduce the Federal tax liability of qualifying firms or individuals who have undertaken particular

[9] Previously, the Treasury Department estimated revenue impacts using an additional method, outlay equivalents. EIA used outlay equivalents to measure budget impacts in its previous reports.

[10] This is true particularly in the context of comparing the aggregate and the relative share of subsidies for a long-standing energy supply chain (e.g., coal) versus a nascent energy supply chain (e.g., bioenergy).

[11] See C. Shoup, *Public Finance* (Chicago, IL: Aldine Publishing Company, 1969), p. 145.

[12] Direct assistance provided by the Low Income Heating Assistance Program (LIHEAP) could be viewed as falling into this category, since the primary purpose of the program is to assist the economically disadvantaged in meeting high energy bills. Thus, this element of the LIHEAP program is not for the purpose of inducing a change in behavior, e.g., conservation or investment in energy efficiency.

actions. Energy-related examples include tax credits for certain kinds of activity (e.g., producing refined coal) or favorable treatment of capital recovery (e.g., excess of percentage over cost depletion for independent oil producers).

Indirect energy subsidies consist of other forms of Federal financial commitment that affect the cost of consumption or production of some form of energy. Indirect subsidies include the provision of energy or energy services at subsidized prices through several means: loans or loan guarantees; insurance services; R&D activities and expenditures; and the unreimbursed provision by the Federal government of environmental, safety, or regulatory services. The market risk and opportunity cost of capital borne by the Federal government through the Federal electricity programs is estimated as the difference between the incurred cost of capital relative to a range of risk adjusted market interest rates.

The budgetary cost of government-funded R&D is relatively easy to measure. Determining the extent to which government R&D is a subsidy to energy is more problematic. Although R&D funding often consists of direct payments to producers or consumers, the payments are not tied to the actual production or consumption of energy in the present, and thus do not fall within the definition of direct energy subsidies. Federal funding for energy R&D may, in some instances, act as a subsidy to the extent that it serves as a substitute for private R&D expenditures that would have been made in the absence of government outlays. This is why much Federal government-funded R&D is directed at the early stages of technological advances which are undertaken long before any resulting innovative good makes its way into the marketplace.

In addition to quantified energy subsidies and support for Federal electricity programs, this report discusses other indirect subsidies in Appendix A (Fact Sheets), which include descriptions of programs such as loan guarantees, insurance programs, and certain trust funds. When the Federal government assumes actual or potential liabilities of private-sector entities or government entities that compete with private sector entities, it transfers risk to the government. For instance, the default risk associated with loan guarantees represents a potential cost to the government if the borrower defaults and the government must honor the guarantee.[13] In the case of trust funds and insurance programs the funds needed to cover the liability may be collected through a levy on the industry. If the expected present value of the cost of the liability assumed by the government exceeds the present value of the levy on the industry, it is considered to be an indirect subsidy.

This report provides a snapshot of Federal subsidies and support for Federal electricity programs in domestic energy markets. To be included in this report, a subsidy or support must derive from a Federal program, be specific to energy markets, and provide a financial benefit to its recipients.

Certain programs considered as subsidies by others are not included. Because this report focuses exclusively on subsidies and support for Federal electricity programs that involve direct intervention in markets for primary energy sources and electricity, Federal regulatory activities are excluded from the analysis.[14] State and local government programs are excluded by

[13] Under the Federal Credit Reform Act of 1990 (Public Law 101-508), the budgetary cost of Federal loan and loan guarantee programs are measured in terms of the present value of debt service payments based upon the government's cost of capital, the default risk associated with the borrower or class of borrowers, and loan recovery rate. This measure also includes the Treasury's exposure to duration risk, i.e., the subsidy is recalculated annually to adjust for changes to Treasury Constant Maturities applicable to the cohort of loans.

[14] For example, the Price-Anderson Act, which provides liability limits for nuclear plant operators, is excluded from this analysis (See Appendix A). Other examples include the import tariff on ethanol, and the statutory mandate for blending alternative fuels with gasoline.

definition. Subsidies which arise from broad provisions in the Federal tax code are not considered to be "energy specific." Therefore, for example, economic impacts from accelerated depreciation and tax exempt status for municipal entities are not analyzed. Since trust funds are funded by user fees, they are not included in the analysis.[15] Tax-free bonds used by municipal electric utilities are excluded because non-energy companies such as municipal water and sewer facilities can also use them. Similarly, accelerated depreciation used by investor-owned utilities is also excluded because of its use by non-energy companies. However, tax exempt bonds that are targeted to specific types of energy entities, which are available to multiple-ownership classes, are included in the study.[16]

Public interest in energy subsidies arises in part from concerns that the subsidies may affect competition between energy and non-energy investments or between different forms of energy. Concerns also arise when subsidies lead to higher prices or taxes, either direct or indirect. Because all government programs have costs and benefits, there has been a tendency for the term "subsidy" to lose specificity and acquire derogatory connotations. This study does not ascribe normative values (negative or positive) to subsidies. The report does not attempt to weigh the benefits of each subsidy, nor does it revisit the original considerations—correcting perceived market problems or achieving social objectives—which are the domain of policymakers. It should be noted that in the U.S. economy a wide array of industries and individuals benefit from various subsidies, not just energy producers and consumers. This study identifies and attempts to quantify certain energy subsidies for fiscal year (FY) 2007. For FY 2007, this report used the value of energy-specific subsidies and R&D expenditures from actual budget data and estimates of tax expenditures prepared by the Treasury Department and the congressional Joint Committee on Taxation (JCT).[17] Once the subject of these energy subsidies in FY 2007 is identified and quantified, the study concludes with an examination of fuel-specific impacts of these subsidies on electricity production.

Valuing Energy Subsidies and Support: Theoretical Issues

EIA considered several theoretical issues in developing an analytical approach that would provide information responsive to the request for this report. Those theoretical issues included:

- The Incidence Theory, which recognizes that the statutory beneficiaries of a subsidy or support may not necessarily be the economic beneficiary. The division of benefits between statutory and economic beneficiaries is dependent on economic behavior that requires an analytical assessment generally beyond the scope of this report.

- Marginal versus inframarginal benefits of subsidies and supports addresses the extent to which a subsidy induces the marginal behavior intended by the particular subsidy or simply transfers wealth to an entity already behaving in the “desired” manner. EIA

[15] For example, nuclear decommissioning trust funds for which the plant owner is responsible for funding from revenue collected from wholesale and retail customers are excluded.
[16] In this report two tax expenditures take the form of bond issuances, both of which are specifically directed towards energy entities, i.e., the exclusion of interest income on certain energy facility bonds from taxable income and the tax credit to holders of Clean Renewable Energy Bonds.
[17] The use of JCT estimates was limited to certain tax expenditures directed at the electric utility industry in EPACT2005 that were not itemized by the Treasury Department in FY 2007 budget documents. The JCT prepares annually a 5-year projection of tax expenditures. Other than for the exception noted, EIA relied on the Treasury Department estimates and determined that a comparison of Treasury Department and JCT tax expenditure estimates would not be appropriate because, according the JCT, they are not “necessarily comparable .” The methods and assumptions used by the Treasury Department differ from those used by the JCT. For example, the JCT uses an economic forecast by the Congressional Budget Office, whereas the Treasury Department relies on the Administration’s economic forecast. See, “Estimates of Federal Tax Expenditures for Fiscal Years 2007-2011,” Staff of the Joint Committee on Taxation, (Washington, DC, September 24, 2007), pp. 21-22.

recognizes that benefits may be divided in this fashion. However, an analysis of marginal and inframarginal effects was beyond the scope of this analysis.

- The study examines the market risk and opportunity costs to the Federal government incurred through its participation in Federal electricity programs. While these programs may not be reflected in the Federal budget as direct expenditure line-items, market risk and opportunity costs, while difficult to quantify, are real.

The Incidence Theory

A rigorous economic and financial analysis of energy-related subsidies that directly impact electricity production requires an empirical examination of the underlying behavior of market participants in the product markets to which a subsidy is directed to determine who ultimately receives the benefit.[18] In other words, the statutory beneficiary of a tax or direct subsidy may not be the economic beneficiary, depending on economic behavior of market participants. The literature on public finance and taxation refers to this as the Theory of Incidence.[19]

Subsidies for which fuel producers or transporters (e.g., natural gas pipelines) are the statutory beneficiaries may pass forward, i.e., transfer, in whole or part to electricity generators based on a variety of economic circumstances. EIA recognizes that a pass forward of economic incidence may occur with many subsidies described in this report. The number and variety of subsidies provided to segments of the energy industry that are upstream of electricity production makes it impractical to perform a quantitative estimate of tax incidence on a subsidy-specific basis which distinguishes between statutory and economic incidence for subsidies. Accordingly, for purposes of this report, EIA adopted an allocation method based on fuel consumption by the electric industry to allocate the value of these subsidies to electric generation by fuel-type as described in Chapter 5. This method was adopted in recognition of the potential presence of economic incidence, but should not be construed as being an estimate of actual economic incidence.

Marginal Versus Inframarginal Effects of Subsidies and Support

A second economic consideration associated with subsidies is the extent to which the subsidy leads to the desired marginal behavior such as increased production of a preferred fuel or renewable resource, or a subsidy that results simply in a transfer of resources or wealth, often described as an inframarginal effect. For example, ethanol producers and fuel blenders benefit from three Federal interventions: (1) a tariff imposed on ethanol imports, (2) a mandate that requires the blending of renewable fuels with gasoline, and (3) the Volumetric Ethanol Excise Tax Credit (VEETC). While the latter is a tax subsidy estimated by the Treasury Department

[18] Methods include partial equilibrium analyses, static general-equilibrium analyses, dynamic equilibrium analyses and empirical analyses using micro-data sets to investigate the impacts of an individual subsidy on behavior. These alternative methods are described in the context of examining where the ultimate burden of a tax falls, as opposed to a tax subsidy in the article "Incidence of Taxes" written by George Zidrow that appears in the Urban Institute *Encyclopedia of Taxation and Tax Policy,* http://www.urban.org/UploadedPDF/1000534.pdf.

[19] A cogent example of the difference between statutory and economic incidence, and the quantitative analysis (regression analysis) required to thoroughly investigate this issue appears in a recently published paper that examined the hybrid vehicle tax credit included in the Energy Policy Act of 2005. The author used data on the sales of the Toyota Prius to assess whether consumers (the statutory beneficiary) of the tax credit realized the benefit, or whether it was transferred to Toyota as a result of its economic behavior in response to the tax credit. Specifically, the author sought to quantitatively determine whether Toyota raised prices to clear the market and capture the majority of the benefit of the tax credit that statutorily was directed to consumers. Based on the results of the analysis, the author concluded, that Toyota did not raise prices, despite capacity constraints out of a concern that raising current prices would dampen future demand. See, Sallee, James M. "The Incidence of Tax Credits for Hybrid Vehicles," University of Michigan, January 22, 2008, http://www-personal.umich.edu/~jsallee/Homepage/Home.html. The Incidence Theory suggests that normally when a product market is supply or capacity constrained, a supplier receiving a tax credit is likely to retain the benefit of the tax credit. If the product market is not constrained and market entrance is relatively easy for new suppliers seeking to capture the tax credit, i.e., statutory incidence, the price of the product will be bid down by competition. This economic behavior results in the transfer of the benefit to consumers, i.e., economic incidence.

and discussed in Chapter 2, the first two interventions are not assumed to be subsidies in this report. Interactions between these three interventions in ethanol markets, or other energy products and services for which multiple subsidies may be available under Federal law, are not analyzed in this report, and the extent to which the current level of ethanol production would have occurred in the absence of VEETC because of the tariff on ethanol imports and the renewable fuels mandate is not addressed. To the extent the current levels of production could have been achieved without VEETC, it would result in a wealth transfer to the beneficiaries of the excise tax credit. EIA considered the examination of the marginal and inframarginal effects of energy-related subsidies to be outside the scope of this report.

Measurement of Financial Support to Federal Utilities' Customers and Rural Utilities Service Borrowers

A final consideration relates to the inclusion of Federal financial support to Federally-owned utilities and direct loans and loan guarantees provided by the Rural Utilities Service (RUS) to eligible borrowers for investment in generation, transmission and distribution facilities. RUS borrowers are primarily generation and transmission cooperatives (G&T) and distribution cooperatives. The Federal utilities included in this report include the Tennessee Valley Authority (TVA), a wholly-owned government corporation, and the Federal Power Marketing Administrations (PMA), which include the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southwestern Power Administration (SWPA) and the Southeastern Power Administration (SEPA). For convenience, WAPA, SWPA and SEPA are collectively referred to as the small PMAs.

As discussed in more detail in Chapter 4, the PMAs market electricity from hydroelectric facilities owned by the Army Corps of Engineers and the Bureau of Reclamation. These facilities were financed by the Federal government. The small PMAs finance capital improvements with internally generated funds and limited, but ongoing borrowing from the Treasury. BPA continues to maintain a revolving fund with the Treasury for financing certain capital activities. However, the bulk of its outstanding debt was restructured pursuant to the Bonneville Administration Refinancing Section of the Omnibus Reconciliation Act of 1996,[20] which required that it pay a higher ongoing rate of interest. The economic effect of the restructuring reduced BPA's outstanding principal, but increased its interest expense such that the present value of debt service payments, plus a required $100 million upfront payment equals its original outstanding obligations. TVA has refinanced its Federal debt with bonds sold to private investors, and meets its incremental capital requirements through the issuance of bonds to private investors. It is important to note that while Federal utilities have had access to low-cost Federal financing; it is pursuant to a statutory framework that requires them to operate on a cost-basis, such that any Federally-provided financial benefit is reflected in the cost of power charged to their customers.[21]

The statutory provisions under which Federal utilities operate provide them with independent authority to establish electric rates on a cost basis, including the repayment of debt. Therefore, it can be argued that the benefit of low-cost capital that flows through to their customers is not a

[20] 16 U.S.C. 838(l).

[21] From their inception and over time, Congress has defined the duties of TVA and the PMA's, particularly BPA, to include non-electric related functions ranging from supporting agriculture, industrial development, and environmental stewardship. These activities have resulted in Federal investment in non-electric facilities and the incurrence of ongoing operating expense. Some of these costs are joint and common that may or may not be recovered through electric rates. For example, BPA operates Federally-financed irrigation projects for which it is not fully compensated by irrigation customers. However, it is required to make payments to the Treasury for the original construction costs only if in doing so it does no require an increase in electric rates. These payments are made from accumulated net revenues. According to BPA's 2007 Annual Report, these payments could total $689 million over time. The analysis in Chapter 4 has not excluded the portion of financial support associated with joint and common costs.

subsidy in the absence of a default. The contrary argument is that notwithstanding the statutory framework under which the Federal utilities operate, their customers are receiving financial support because there is neither explicit recognition of the market risk that is borne by the Federal government in the event of a default, nor of the opportunity cost to the Federal government's stakeholders, i.e., taxpayers which include the customers of the Federal utilities. The value of this financial support is a cost to the Federal government which is not quantified and assigned to the Federal utilities in the budget. To the extent it is a significant and measurable cost, it is reflected in the interest rate set in the market for Treasury securities and in the annual interest expense on Federal debt included in the budget.

In order to estimate the value of the financial support provided to the customers of the Federal utilities, EIA has adopted a cost-of-capital approach that estimates the value based on the difference between the interest expense that Federal utilities actually paid in 2006 versus what they would have paid by applying a range of contemporaneous interest rates to their outstanding debt. The interest rates range from the risk-free Treasury rate to the full range of interest rates for investment grade investor-owned utility (IOU) bonds. In order to express the value of Federal financial incentives provided directly and indirectly to electricity production on a unit of production basis, EIA compared Federal utilities' weighted average cost-of-capital to the market interest rate associated with an A-rated IOU bond.

The analysis is a snapshot that compares the current interest expense based on the average cost of outstanding debt to a hypothetical interest expense that applies a contemporaneous market interest rate to the outstanding debt. In effect, this implies the debt is being refinanced. A more accurate measure would have been to estimate the value based on the sum of the difference between the face amount of each original loan or bond and present value of each loan or bond issue at the market rate of interest at the time the obligation was incurred. The data required to perform this analysis were not available to EIA.

Opinions vary with respect to the extent to which there is a significant risk premium between the risk-free Treasury rate and the market rate of interest that Federal utilities would be required to pay in the absence of their ownership status and the statutory framework under which they operate. This is true with respect to TVA and BPA, both of which have received ratings ranging from AA- to AAA from the nationally recognized credit rating agencies. As discussed in Chapter 4, the nationally recognized credit rating agencies have issued credit rating reports that offer different perspectives on this issue. For example, Fitch Ratings stated in a January 2008 issue rating for TVA Global Power Bonds that:

> "TVA's outstanding debt is not a full faith and credit, or limited obligation of the U.S. Government. However, Fitch believes that U.S. authorities would use extraordinary efforts to support their operations and senior debt obligations in the unlikely event that TVA encountered financial difficulties. This analysis takes into account TVA's ownership by the U.S. government, the sizeable role that TVA plays in the Tennessee Valley and broader economies, and the level of its obligations that are held by domestic and other foreign based investors (similar to that of government sponsored entities (GSE))."[22]

[22] "Fitch Rates Tennessee Valley Auth's $500MM Global Power Bonds 2008 Series A 'AAA'," BusinessWire, January 18, 2008, http://www.businesswire.com/portal/site/google/index.jsp?ndmViewId=news_view&newsId=20080118005746&newsLang=en, Accessed February 23, 2008.

In order to develop a point estimate of the value of the support provided to the customers of the Federal utilities, EIA performed a financial ratio analysis that compared TVA and the PMAs to comparably structured governmentally-owned wholesale power suppliers. The financial ratios measure an entity's ability to meet its debt and fixed obligations, i.e., liquidity and cash flow. This approach was adopted in order to neutralize any actual or perceived credit enhancement that financial markets attribute to Federal ownership and/or the ability to borrow at the Federal government's cost of funds or at interest rates comparable to GSE interest rates. This resulted in the adoption of a market interest rate associated with an A rating. Limiting the derivation of the market interest rate to consideration of only financial ratios allowed for uniformity in EIA's analysis and eliminated the effects of actual or perceived credit enhancement attributed to Federal support provided in accordance with Federal statutes applicable to the Federal utilities. Therefore, the rating used to develop a point estimate of the value of Federal support should not be construed as an alternative to actual credit ratings issued by the nationally recognized credit rating agencies. The rating agencies consider a multitude of factors in addition to financial performance in developing credit ratings that were not considered by EIA.

Impacts of Subsidies and Support in Electricity Markets

The process of transforming a primary fuel to electricity is not uniform. Electric generators acquire input fuels in a variety of markets[23] using delivery systems that differ by fuel type (e.g., coal transported by rail or barge; natural gas by pipeline; or oil by pipeline or tanker trucks). Once at the electric plant, different technologies convert the fuels with different rates of efficiency.[24] Certain primary fuels used in electricity production are consumed broadly, while others have no practical application other than electricity production. Most electricity is produced for retail sale, but some electricity is produced at regulated prices to maintain system reliability. These factors make it difficult to state with certainty the exact impacts of the subsidies that are the subject of this report on production by each specific fuel type.

A simplified approach is adopted in this analysis to assess the impacts arising from subsidies to primary fuels used in electricity generation. All primary fuel subsidies are assumed to impact electricity production in proportion to the amount of primary fuel consumed by electricity producers, unless it is clear that the entire subsidy should be directly assigned to a specific fuel type. Most coal is consumed for electricity generation, but only an estimated 29 percent of natural gas consumption and estimated 1 to 2 percent of petroleum consumption are used to generate electricity. All nuclear fuel is consumed by the electric power industry. Power sector consumption of renewable fuels varies greatly by type of fuel.[25]

Many subsidies are directed to aspects of the electricity industry which occur after the electricity is produced, such as conservation programs, programs directed to energy efficiency (end-use R&D), or direct grant programs such as the Low Income Home Energy Assistance Program (LIHEAP), which provides States with funds to help defray the heating and cooling bills for lower-income households. Since these programs do not affect electricity production directly, they are classified as non-electricity subsidies.

Four electricity subsidies are associated with transmission: a tax expenditure program which enables transmission companies to defer income realized from the sale of transmission property; an accelerated investment recovery period; a 5-year net operating loss carryforward for transmission investment; and an R&D program directed toward improving transmission

[23] Long-term contracts, spot markets, tolling agreements, and options.
[24] Identical technologies may also differ in their relative efficiency due to the quality of fuel (i.e., coal), ambient atmosphere conditions, and quality of equipment and facility maintenance.
[25] Wind energy is consumed wholly in the power sector, but solar energy is consumed almost entirely in the residential sector.

infrastructure reliability and performance. Since electricity consumption and production occur with rough simultaneity, and since transmission directly enables ultimate consumption, transmission activities are included as non-fuel specific electricity production subsidies. Similarly, support to Federal electricity programs are generally realized as benefits to ultimate consumers of Federal power. Federal electricity programs involve all three segments of the electricity industry (generation, transmission, and distribution), and it is not always feasible or informative to allocate all aspects of these subsidies to fuel specific groups. Therefore, some of the support associated with Federally-owned and RUS-financed transmission and electric plant are analyzed as non-fuel specific support.

Although electricity prices are affected by Federal intervention in energy markets, the impact of this intervention is not always clear. A consumer surplus arises when Federal utilities price power at below market prices. This creates additional demand, a point evidenced by the high concentration of aluminum smelters receiving electricity from Federally-owned utilities in the Pacific Northwest. On the other hand, government intervention in global fuel markets probably has little impact on electricity prices or on demand. This is particularly true of petroleum, and, to a lesser extent, coal. Today, Canadian and American natural gas markets are relatively integrated and current liquefied natural gas developments portend a future global natural gas market.

It is unclear as to how much the value of a particular subsidy will benefit producers or consumers.[26] In most States, ultimate consumers of electricity face cost-of-service tariffs, so that most electricity is sold at average cost rather than marginal cost. Because so little electricity is sold at market-based rates to retail consumers, it is not clear what effect a subsidy to primary fuel has on consumer behavior. In those regions of the country where competitive centralized wholesale markets and competitive retail markets co-exist (e.g., California, New England, and Texas), the effects of subsidies may be more pronounced than in other areas. In regions of the country where retail markets remain regulated or are returning to rate regulation, producers may attempt to engage in rent-seeking by trying to capture the producer surplus related to a particular subsidy. This is more likely to occur if the retail supplier purchases wholesale power from an independent power producer at a market-based wholesale rate, as opposed to building a plant and placing the asset in the rate base itself. In the latter case, State regulators are likely to set retail rates that transfer potential producer surplus to ultimate consumers.

However, some electricity subsidies and support could affect long-term decision making in the selection of generation technologies. They could also affect retail consumption decisions to the extent customers receive inefficient price signals. For instance, the production tax credit,[27] which provides producers with a credit per unit of electricity production, is often recognized as having given rise to much of the recent additions to wind generation capacity. Still, given wind generation's small share of the overall electricity market, it is doubtful that this added capacity has had much of an impact upon overall electricity prices.

[26] TVA and the PMAs are required to operate on a cost-basis. Similarly, electric cooperatives must operate on the basis of cost as that term is defined by the Internal Revenue Service in order to preserve their cooperative status. Accordingly, there is greater certainty that the benefits of Federal support to electricity programs are passed through to customers. However, an increase or decrease in one expense, such as interest expense, may be offset by a change in other expenses. Therefore, a rate change may not be necessary if borrowing costs go up or down.

[27] The new technology credit is a tax expenditure discussed in Chapter 2.

Organization of Report

In addition to this introductory chapter, this report contains four chapters. Chapter 2 reports on energy-related tax expenditures and direct expenditures. Chapter 3 discusses subsidies which are listed in the Federal budget as R&D expenditures. Chapter 4 evaluates support associated with Federal electricity programs. Chapter 5 analyzes electricity subsidies and their association with specific fuel groups in electricity production.

The report also includes several appendixes. Appendix A contains Fact Sheets that summarize Federal energy-related programs and tax expenditures, not all of which are discussed in the body of the report. Appendix B provides alternative estimates of energy subsidies to Federal utilities. Appendix C provides an historical perspective on tax expenditures. Appendix D provides a description of credit ratings criteria and interpretation of credit ratings; Appendix E describes the RUS Electric Program, including direct and hardship loans and loan guarantee programs. Appendix F contains a list of energy-related statutes and Federal regulations referred to in this report. Appendix G contains a bibliography; and Appendix H contains the request letter from Senator Alexander.

2. Tax Expenditures and Direct Expenditures

Overview

This chapter focuses on Federal tax expenditures and Federal direct expenditures that subsidize activities of energy producers and consumers. For FY 2007, energy-related tax expenditures are estimated at $10.4 billion (Table 1). This represents sizable growth in real terms from the estimated $3.2 billion (2007 dollars) in energy-related tax expenditures conferred in 1999. [28] Another means by which the Federal government can intervene in energy markets is through Federal direct expenditures. The direct expenditures covered in this chapter that impact energy markets are the Low Income Home Energy Assistance Program (LIHEAP), the Building Technology and Assistance Program, and the Renewable Energy Production Incentive. Direct expenditures for FY 2007 are estimated at $2.6 billion versus $1.7 billion in 1999 (2007 dollars).

Tax Expenditures

Since the beginning of the last century, the United States has used the Internal Revenue Code (the Code, or IRC) as a tool for implementing energy policy.[29] Energy tax expenditures are broadly defined as provisions in the Code that provide beneficial tax treatment to taxpayers who produce, consume, or economize on energy in ways that are judged to be in the public interest.[30] Tax expenditures are not treated in budgetary terms as spending even though they have a similar impact on the budget. That is, the revenue foregone that is attributable to tax expenditures can be equated to direct appropriations included in the budget to achieve the same result.

The Federal budget lists tax expenditures, pursuant to the Congressional Budget Act of 1974 (Public Law 93-344), which defines them as "revenue losses attributable to provisions of Federal tax laws, which allow a special exclusion, exemption, or deduction from gross income or provide a special credit, preferential rate of tax, or deferral liability."[31] The concept of what constitutes a tax expenditure is widely understood. However, the determination of what exactly is a preferential provision is subject to interpretation. In preparing this section on energy-related tax expenditures, the EIA relied on the definitions of tax expenditures incorporated in the Federal budget and the associated tax expenditures estimated by the Treasury Department that are itemized in Section 19 of Budget of the United States Government, Fiscal Year 2008, Analytical Perspectives. To a lesser extent, this table includes data estimates by the congressional Joint Committee on Taxation (JCT).

Tax Expenditures Caveats

Each year the Treasury Department estimates tax expenditures for the upcoming fiscal year budget. The Treasury Department also publishes a forecast of tax expenditures, usually for about 5 years going forward. It is important to recognize that tax expenditure data are estimates

[28] Current and prior year's tax expenditures are expressed in 2007 dollars (2007 dollars) for comparative purposes.

[29] The option to expense intangible drilling costs (and dry hole costs) of oil and natural gas wells was originally established in 1916, based in Treasury regulation number 45, article 223, which stated such costs be treated as an ordinary operating expense. See, General Accounting Office, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work*, GAO/RCED-00-301R, (Washington, DC, September 2000) , p. 8.

[30] The House of Representatives defines tax expenditures as: "loosely, a tax exemption or advantage, sometimes called an incentive or loophole; technically, a loss of governmental tax revenue attributable to some provision of Federal tax laws that allows special exclusion, exemption, or deduction from gross income or that provides a special credit, preferential tax rate, or deferral of tax liability. The tax exemption or advantage is usually intended to assist a certain group or to encourage a certain activity, such as the purchase of homes. In their impact on the Federal budget, tax expenditures are, in effect, subsidies provided through the tax system. Instead of making direct payments to beneficiaries, the government permits certain taxpayers to pay lower taxes than they otherwise would have to pay." See: http://www.rules.house.gov/archives/glossary_fbp.htm. Accessed March 12, 2008.

[31] Office of Management and Budget, *Budget of the U.S. Government Analytical Perspectives , Fiscal Year 2008*, p.285.

and forecasts. Furthermore, prior year tax expenditure estimates may be substantially revised. However, a particular year's revision will not necessarily affect all past estimates. Additionally, the methodology used to estimate tax expenditures is subject to periodic modification. These changes are not always applied to revisions of all historical tax expenditure data.

This report uses expenditure estimates for FY 2007, projections for the period 2008 through 2012, and historical data dating back to 1967 (see Appendix C). Although all of these estimates were produced by the Treasury Department and the JCT, some secondary sources of data were used to compile some of the historical data. Due to the limitations just cited, the historical tax expenditure data used in this report are less precise than more current data. However, historical data are useful in illustrating the magnitude of various tax programs affecting energy production and consumption over time. The value of particular tax expenditure programs can be compared to other energy-related tax expenditure programs and relative to where these expenditures stood historically.

For the most part tax expenditures are linked to either energy production, consumption, or investment. In many cases, the level of energy production or investment determines the potential value of the tax expenditure for qualified taxpayers. However, the value of the tax expenditure received by eligible taxpayers may not equal the potential value of the expenditure based upon production or investment. One factor mitigating the eligible party receiving the full value of the tax expenditure is the alternative minimum tax, from which most tax expenditures are not exempt. The alternative minimum tax becomes effective when deductions become too large relative to income. Another mitigating factor is that the expenditure, in many cases, may not be received in the year in which the investment or production took place, but may be "carried back or forward" a number of years.[32]

Tax expenditures arise from special exclusions, exemptions, deductions, credits, and deferrals in Federal tax laws.

Tax Credit. A tax credit is an amount deducted directly from income tax liability.

Tax Deduction. A tax deduction is deducted from total income to arrive at taxable income.

Tax Deferral. A tax deferral allows for payment of a tax in a later year. The Office of Management and Budget (OMB) reports the cash value of deferrals as expenditures OMB notes that "although such estimates are useful as a measure of cash flow into the government, they do not accurately reflect the true economic cost of the provisions. For example, for a provision where activity levels have changed, so that incoming tax receipts from past deferral are greater than deferred receipts from new activity, the cash-basis tax expenditure estimate can be negative, despite the fact that in present value terms current deferrals have a real cost to Government."[33]

Preferential Tax Rate. A preferential tax rate treats certain forms of taxable income more favorably than other income.

Tax Exclusion. A tax exclusion excludes a portion of income from taxation.

[32] In many cases, tax deductions may be transferred to a year other than the current year because they exceed certain limits. These deductions may be carried back to earlier years or carried forward to later years until the eligibility period is valid or the deduction is used up.
[33] Office of Management and Budget, *Analytical Perspectives of the United States Budget, Fiscal Year 2008* (Washington, DC, 2007).

Sizable changes in the dollar value of particular expenditures over time can generally be viewed as an indication of the relative importance of these programs (Table 1). The historical data also reveal when particular energy programs were implemented and terminated. Although there are gaps in the data for some years, generalized trends in tax expenditures are still apparent. Readers of this report are cautioned that some of the tax expenditure data presented in this report will be revised in the future and that some of the historical data presented here have not been fully revised. Further, most of the tax expenditure data highlighted in this report reflect estimates for FY 2007, which are based upon incomplete Treasury tax receipts. In all likelihood, these estimates will be revised in subsequent years. This report sums annual tax expenditures across various programs. These summations should be treated with care as the Treasury Department cautions that there are interactions among tax expenditure provisions, which can result in some double counting.

Oil and natural gas royalty payments are an important source of Federal government revenue. To the extent that the Federal government is forgoing revenues by not “optimizing” royalty payments, the Federal government may be providing a subsidy similar to a tax expenditure. About 35 percent of U.S. oil and natural gas production is produced on Federally-owned or Native American lands.[34] To the extent that these payments treat resources extracted from Federal lands used in the production of energy differently from resources used for other purposes, a subsidy may be present. Further, to the extent that certain royalty payments from some resources used in the production of energy are treated differently from other resources used in the production of energy might also constitute a subsidy. However, royalty rates are based upon a number of factors. One critical factor involves the costs of extracting minerals from areas that are difficult to access, such as oil and natural gas lying in deepwater offshore sections of the Gulf of Mexico. In recent years, favorable royalty payments provided to offshore Outer Continental Shelf (OCS) oil and natural gas production have been targets of criticism because royalty payments have not kept pace with sharply higher oil and natural gas prices. However, designing “optimal” royalty payments should, in theory, be based upon a number of factors such as maximizing revenue and oil and natural gas production over the years during which production takes place. This makes estimating the value of “favorable” oil and gas leases dependent on forecasting future oil and gas prices and production. Moreover, the existence of “favorable” royalty payments —again, in theory— should be offset by higher bids for leases. Favorable royalty payments, to the extent that they exist, were not considered within the scope of this analysis. A Government Accountability Office study released in May 2007 reported that an increase in royalty rates by the Federal government on oil and natural gas production from 12.5 percent to 16.67 percent on future leases sold in the deepwater regions of the Gulf of Mexico will, according to the Minerals and Management Service, increase overall Federal revenues by $4.5 billion over the next twenty years, but will also cause reductions in some fees and in oil and gas production. Offsetting revenue losses were reported at $820 million.[35]

[34] Government Accountability Office, *Royalty Revenues: Total Revenues Have Not Increased at the same Pace as Rising Oil and Natural Gas Prices due to Decreasing Production Sold*, GAO-060786R, (Washington, DC, June, 2006).
[35] Government Accountability Office, *Oil and Gas Royalties,: A Comparison of the Share of Revenues Received from Oil and Gas Production by the Federal Government and Other Resource Owners*, GAO-07-676R (Washington, DC, May 2007).

Table 1. Estimates of Tax Expenditures by Fiscal Year (million 2007 dollars)

	Historical Data				Forecasted Data		
Tax Expenditures	**1999**	**2005**	**2006**	**2007**	**2008**	**2009**	**2012**
Capital Gains Treatment of Royalties in Coal	79	95	164	170	174	177	143
Expensing of Exploration and Development Costs	(97)	410	695	860	859	739	340
Exception from Passive Loss Limitation for Working Interests in Oil and Natural Gas Properties	36	42	31	30	31	31	33
Enhanced Oil Recovery	273	316	-	-	-	-	-
Expensing of Tertiary Injectants	-	-	-	-	-	-	-
Alternative Fuel Production Credit	1,242	2,441	3,046	2,370	797	10	-
New Technology Credit	61	253	521	690	981	1,166	1,263
Alcohol Fuel Credit	18	42	51	50	61	72.8	-
Alternative Fuel and Fuel Mixture Credit	-	158	-	-	-	-	-
Excess of Percentage over Cost Depletion	321	621	777	790	807	822	813
Temporary 50-Percent Expensing for Equipment Used in the Refining of Liquid Fuels	-	-	10	30	123	250	(55)
Amortization of All Geological and Geophysical Expenditures Over 2 Years	-	-	10	60	92	73	11
Natural Gas Distribution Pipelines Treated as 15-Year Property	-	-	20	50	92	125	132
Exclusion of Interest on Bonds for Certain Energy Facilities	139	84	41	40	51	52	55
Exclusion for Utility-Sponsored Conservation Measures	103	84	112	110	112	115	121
Credit, Deduction for Clean Fuel Vehicles	103	74	112	260	153	135	(70)
Credit for Holding Clean Renewable Energy Bonds	-	-	20	60	82	104	110
Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants	-	-	82	90	133	52	(11)
Credit for Production from Advanced Nuclear Power Facilities	-	-	-	-	-	-	-
Deferral of Gain from Disposition of Transmission Property to Implement FERC Restructuring Policy	-	516	634	530	235	(104)	(593)
Credit for Investment in Clean Coal Facilities	-	-	-	30	51	83	275
Pass Through Low-Sulfur Diesel Expensing to Cooperative Owners	-	42	-	-	-	-	-
Credit for Energy-Efficiency Improvements to Existing Homes	-	-	235	380	153	-	-
Credit for Energy-Efficient Appliances	-	-	123	80	-	-	-
Credit for Construction of New Energy-Efficient Homes	-	-	10	20	31	21	-
30-Percent Credit for Residential Purchases/Installations of Solar and Fuel Cells	-	-	10	10	10.2	-	-
Deduction for Certain Energy-Efficient Commercial Building Property	-	-	82	190	174	94	(11)
Partial Expensing for Advanced Mine Safety Equipment	-	-	-	10	20	-	-
Expensing of Capital Costs with Respect to Complying with EPA Sulfur Regulations	-	11	10	10	31	52	-
Biodiesel and Small Agri-Biodiesel Producer Tax Credits	-	32	92	180	204	31	11
Exclusion of Special Benefits for Disabled Coal Miners	-	-	51	50	41	42	44
Electric Transmission Property Treated as 15-Year Property	-	-	3	18	-	-	-
5-Year Net Operating Loss Carryover for Electric Transmission Equipment	-	-	74	43	-	-	-
Treatment of Income of Certain Electric Cooperatives	-	-	-	14	-	-	-
84-Month Amortization of Certain Pollution Control Facilities	-	2	10	30	-	-	-
Nuclear Decommissioning	-	-	123	199	-	-	-
Excise Taxes (Alcohol Fuels Exemption/Volumetric Ethanol Excise Tax Credit)	921	1,578	2,627	2,990	3,536	4,454	-
Total (Tax Expenditures)	3,199	6,798	9,775	10,444	9,035	8,596	2,613

NOTE: Total may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget, *Analytical Perspectives*, *Budget of the United States Government, Fiscal Years 2001 and 2008*, Tables 5-1 and 19-1, respectively. Joint Committee on Taxation, "Description of the Technical Explanation of the Conference Agreement of H.R. 6, Title XIII, The Energy Tax Incentives Act of 2005," JCX-60-50 and JCX-59-05, July 28, 2005.

Historical tax expenditure data used in this report are taken from a number of government sources. For the FY 2007, the Treasury Department is the primary provider of estimates for tax expenditures, supplemented by data provided by the JCT. For earlier years, this report uses U.S. Treasury tax expenditure estimates appearing in the OMB publication *Analytical Perspectives of the U.S. Budget* for tax expenditures starting in 1995. A Congressional Budget Office publication, *Tax Expenditures: Current Issues and Five-Year Budget Projections for Fiscal Years 1982-1986*, was relied upon for data for the years 1967 through1981, and values appearing in the EIA service report *Federal Energy Subsidies* for the years 1987 through 1992.[36]

Background and Definitions

Energy-related tax expenditures take many different forms. One example is the immediate expensing of intangible drilling costs (IDCs). IDCs are geological and geophysical expenditures made by oil and natural gas companies incurred in connection with oil and natural gas exploration and development.[37] The intention behind this tax expenditure is that by accelerating the expensing of IDC, taxable income is lowered which increases internally generated funds which can be used for investment. This investment, in turn, stimulates additional production. This chapter presents a detailed discussion of some of the more significant energy-related tax expenditures in effect during FY 2007. Tax expenditures of smaller monetary value are discussed briefly. This latter group of tax expenditures is discussed at greater length in the Fact Sheets appearing in Appendix A.

Tax expenditures account for a large and rapidly growing proportion of the U.S. budget. In a 2005 study on tax expenditures, the Government Accountability Office (GAO) reported that the sum of tax expenditures exceeded discretionary spending for most years in the prior decade.[38] The GAO also noted that, since 1974, the number of tax expenditures more than doubled and the sum of tax expenditure revenue loss estimates tripled in real terms to nearly $791 billion (2007 dollars) by 2004. In 2004, tax expenditures equaled about 7.5 percent of gross domestic product.[39]

Tax Expenditures' Role in the Economy

At $10.4 billion, energy-related tax expenditures are relatively small compared with other tax expenditures and overall Federal spending in FY 2007. For instance, the exclusion of employer contributions for medical insurance premiums and medical care for income tax purposes totaled $144 billion in FY 2007. Second in size to the employer medical care deduction, the home mortgage interest rate deduction was valued at $82 billion in FY 2007. Overall Federal on-budget spending in FY 2007 was expected to total over $3 trillion, making energy tax expenditures equal to roughly 0.3 percent of total government expenditures. Energy expenditures, i.e., money spent by consumers to purchase energy, totaled $1.3 trillion in FY 2007, making energy-related tax expenditures equal to roughly 1 percent of total energy expenditures for that year.[40]

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[36] Energy Information Administration Service Report, Federal *Energy Subsidies: Direct and Indirect Interventions in Energy Markets,* SR/EMEU/02-02 (Washington, DC, 1992). The values appearing in this report were obtained from United States budget documents. The original source data were not available for this report.

[37] These expenditures include some administrative costs, survey and seismic costs, drilling costs, equipment transportation costs, and road construction costs.

[38] Pursuant to the GAO Human Capital Reform Act of 2004 (Public Law 108-271), the General Accounting Office was renamed the Government Accountability Office. Citations to reports issued prior to the name change shall be attributed to the General Accounting Office. The acronym GAO is used interchangeably in this report.

[39] Government Accountability Office, Government Performance and Accountability, *Tax Expenditures Represent a Substantial Federal Commitment and Need to be Examined,* GAO-05-690, (Washington, DC, September 2005).

[40] Energy Information Administration, *Short Term Energy Outlook* (Washington DC, January 8, 2008, release), http://www.eia.doe.gov/emeu/steo/pub/contents.html.

Tax Expenditures in Energy

Both the value and the composition of energy-related tax expenditures have changed significantly since EIA's prior analyses of Federal subsidy and support programs specific to energy. Between 1992 and 2007, tax expenditures have grown from $2.8 billion to $10.4 billion, while there was relatively little change between the values reported in the 1992 and 1999-2000 reports. In 1992, the two biggest tax expenditures were excess of percentage over cost depletion ($1.0 billion) and the alternative fuel production credit ($618 million). In FY 2007, the largest tax expenditure was the Volumetric Ethanol Excise Tax Credit[41] (VEETC), at $3.0 billion, followed by the alternative fuel production credit ($2.4 billion), and the expensing of oil and natural gas exploration and development costs ($0.9 billion). VEETC's predecessor, the excise fuel tax exemption, though technically not a tax expenditure, had a value of $747 million in 1992, which at the time was second only to the excess of percentage over cost depletion, whose value equaled $1.0 billion. The excess of percentage over cost depletion[42] was the fourth largest in FY 2007 at $0.8 billion. The number of tax expenditures has increased since the first EIA subsidy analysis was performed. There were 10 tax expenditures identified in the 1992 EIA study, 12 in the 1999 and 2000 EIA reports, and 37 in the current study. In the past, some tax expenditures have come and gone. A number of the EPACT2005 tax provisions included sunset dates. Unless they are extended (as many tax expenditures' sunset dates have been in the past), the value of tax expenditures is expected to decline to $2.6 billion by 2012.

The remainder of this chapter is organized as follows. First, an analysis of energy tax expenditures by fuel type is presented. This analysis includes a description of tax expenditures affecting both electricity and non-electricity, although energy–related sectors. After that, some of the highest-value tax expenditures are discussed, two of which affect the electricity sector (the new technology credit and the alternative fuel production sector). This is followed by a discussion of VEETC, a tax expenditure affecting transportation, which in FY 2007 is the largest energy-related tax expenditure. A discussion of Federal direct expenditures affecting electricity production and consumption follows.

Coal-Related Tax Expenditures

Coal production was estimated to be the largest recipient of electricity-related tax expenditures in FY 2007. Over 90 percent of coal is consumed by the electricity sector. Coal-related tax expenditures have an estimated value of $2.7 billion in FY 2007. The alternative fuel production tax credit for refined coal was the largest tax expenditure related to coal use. The estimated value of this tax expenditure in FY 2007 is $2.4 billion (Table 2).

[41] OMB does not define VEETC as a tax expenditure. OMB presents this reduction in tax receipts as a footnote to the Tax Expenditure Table appearing in OMB, *Analytical Perspectives of the United States Budget 2008*. Table 19-1. Table 19-1 reports a $50 million tax expenditure for fuel alcohol tax credits and $2.99 billion in foregone excise tax revenue due to VEETC. See EIA's *Monthly Energy Review*, DOE/EIA-0035(200712) (Washington, DC, December 2007), Table 10.3 for fuel ethanol production data.

[42] Under cost depletion, outlays are deducted over the productive life of the property based on the fraction of the resources extracted. Under percentage depletion, taxpayers can deduct a percentage of gross income from mineral production at rates of 22 percent for uranium; 15 percent for oil, natural gas, and shale oil; and 10 percent for coal. The deduction is limited to 50 percent of net income from the property, except for oil and gas where the deduction can be 100 percent of net property income. Production from geothermal deposits is eligible for percentage depletion at 65 percent of net income. Source: Office of Management and Budget, *Analytical Perspectives of the United States Budget*, *Fiscal Year 2008* (Washington, DC, 2007).

Table 2. Coal-Related Tax Expenditures (million 2007 dollars)

Tax Expenditure	Type	FY 1999	FY 2007
Exclusion of Special Benefits for Disabled Coal Miners	Exemption	-	50
Partial Expensing for Advanced Mine Safety Equipment	Expense Deduction	-	10
Credit for Investment in Clean Coal Facilities	Credit	-	30
Capital Gains Treatment of Royalties in Coal	Preferential Tax Rate	79	170
84-Month Amortization of Pollution Control Equipment	Expense Deduction	-	30
Subtotal Coal Tax Expenditures		**79**	**290**
Alternative Fuel Production Credit (Refined Coal)	Credit	-	2,370
Total Coal and Refined Coal Tax Expenditures		**79**	**2,660**

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget, *Analytical Perspectives, 2001 & 2008*, Tables 5-1 & 19-1.

The Alternative Fuel Production Credit was initiated with the passage of the Windfall Profit Tax of 1980 (Public Law 96-223). It was originally codified in the Code as Section 44(d), but it was later recodified as Section 29. The alternative fuel credit is production-based. At $2.4 billion, it is estimated to be the second largest energy-related tax expenditure in FY 2007. The credit was designed to encourage the production of domestic energy from certain unconventional sources to reduce the Nation's dependence on energy imports. Barring its extension, which has occurred a number of times in the past, the value of this credit is expected to decline to about $10 million in 2009 and then disappear. In EIA's 1999-2000 subsidy reports, the primary beneficiaries of this tax expenditure were coalbed methane producers. However, coalbed methane's eligibility for the credit expired December 31, 2002. Refined coal is now the largest beneficiary of this tax expenditure. Refined coal was defined in Section 710 of the American Jobs Creation Act of 2004 (AJCA) (Public Law 108-357). Prior to defining refined coal in the AJCA, the Section 29 credit was applied to synthetic fuels, one of which used coal as a fuel stock.[43]

Other smaller tax credits affecting the coal sector include:

The Credit for Investment in Clean Coal Facilities was added to the Code with EPACT2005, Section 1307. This credit has an estimated value of $30 million in FY 2007. A 20-percent credit is applied to coal gasification a project using integrated gasification combined-cycle (IGCC) technology and a 15-percent credit is applied to other advanced coal technologies. The credit is

[43] As a result of the AJCA, Section 29 was moved into Section 45(k), which defines refined coal as:

> a liquid, gaseous, or solid synthetic fuel produced from coal (including lignite) or high carbon fly ash, including such fuel used as a feedstock, (ii) is sold by the taxpayer with the reasonable expectation that it will be used for purpose of producing steam, (iii) is certified by the taxpayer as resulting (when used in the production of steam) in a qualified emission reduction, and, (iv) is produced in such a manner as to result in an increase of at least 50 percent in the market value of the refined coal (excluding any increase caused by materials combined or added during the production process), as compared to the value of the feedstock coal.

Refined coal must meet certain emission reductions. Qualified emission reduction means a reduction of at least 20 percent of the emissions of nitrogen oxide and either sulfur dioxide or mercury released when burning the refined coal (excluding any dilution caused by materials combined or added during the production process), as compared to the emissions released when burning the feedstock coal or comparable coal predominantly available in the marketplace as of January 1, 2003. Prior to the AJCA, under Section 29, coal was deemed eligible for the credit if the refining process produced a "significant chemical change."

capped at $1.3 billion of which $800 million is allocated towards electricity-related IGCC projects and $500 million towards other advanced coal technologies. An additional $350 million is applied to coal gasification technologies for industrial use.

The Capital Gains Treatment of Royalties on Coal Credit was established with the 1951 Revenue Act (Public Law 82-183, Section 177 (j) and Section 117 (k)). The estimated value of this credit in FY 2007 was $170 million. Owners of coal mining rights who lease their property usually receive royalties on mined coal. If the owners are individuals, these royalties can be taxed at a lower individual capital gains tax rate rather than at the higher individual top tax rate.

The Exclusion of Special Benefits for Disabled Coal Miners in the Department of Labor, Health and Human Services, and Education and Related Agencies Appropriation Act, 1986, (Public Law 99-178) allows for the payment of medical-related travel expenses. This expenditure involves payments to disabled miners out of the Black Lung Trust Fund. These benefits are excluded from taxable income. This provision is categorized by the Treasury Department as an Income Security tax expenditure. The value of this expenditure is estimated at $50 million in FY 2007.

The Expansion of Amortization for Certain Atmospheric Pollution Control Facilities in Connection with Plants Placed in Service After 1976 was added with EPACT2005, Section 1309. This provision modifies Section 169 of the Code, which permitted a 60-month amortization of qualifying pollution control facilities used in connection with plants placed in service before January 1, 1976. The modification extends the amortization period to 84 months and eliminates the applicability of the provision to plants placed in service prior to the end of 1975. The revised amortization period is now applicable to qualifying pollution control facilities placed in service after April 11, 2005. The JCT estimated the value of this expenditure to be $30 million for FY 2007.

The Partial Expensing of Mine Safety Equipment Section 404 of the Tax Relief and Welfare Act of 2006 (Public Law 109-432) allows qualified mine safety equipment to be expensed rather than capitalized. Its value for FY 2007 is estimated at $10 million.

Electricity Transformation-Related Tax Expenditures

Overall, it is estimated that the electric power industry tax expenditures in FY 2007 have a value of $735 million (Table 3). For purposes of this report, electricity-related tax expenditures include those applicable to all segments of electricity production and delivery (i.e., generation, transmission, and distribution of electricity), but not of the fuel used to produce electricity. Seven tax expenditures were directed at electricity transformation during FY 2007. One tax expenditure, the exclusion of interest on bonds for certain energy facilities, traces its origins back to 1968. The six remaining tax expenditures were enacted in the AJCA and EPACT2005, which amended the Code to provide utilities with incentives to (1) make infrastructure investments in transmission and pollution control facilities and (2) engage in transactions that will increase the amount of transmission facilities subject to non-discriminatory open access transmission. The Code was also modified to eliminate impediments to the transfer of ownership of nuclear plants arising from the tax treatment of qualified and nonqualified nuclear decommissioning trust funds. Because these particular revisions to the Code were not itemized by OMB, EIA relied on the estimates of the value of these tax expenditures prepared by the JCT.[44] One tax expenditure, the credit for the production from advanced nuclear power

[44] Joint Committee on Taxation, "Description of the Technical Explanation of the Conference Agreement of H.R. 6, Title XIII, The Energy Tax Incentives Act of 2005," JCX-60-50 and JCX-59-05, July 28, 2005.

facilities, had no value in 2007, as this credit does not go into effect until qualifying new nuclear power plants produce electricity.

The Deferral of Gain from Disposition of Transmission Property to Implement Federal Energy Regulatory Commission (FERC) Restructuring Policy is the largest tax credit directly affecting the provision of electricity, as opposed to an electricity-related fuel. This tax expenditure was provided for in Section 1305 of EPACT2005. The value of this deferral in FY 2007 is estimated at $530 million. Tax deferrals are frontloaded benefits, which are offset in later years when the deferral reverses. The Treasury Department projects a $1.4 billion cumulative deferral between 2006 and 2008. The deferral begins to reverse in 2009, as reflected by projected net revenue loss of $104 million in 2009.[45]

The Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants (EPACT2005, Section 1336) has an expected value of $90 million in FY 2007. EPACT2005 provides a 30-percent energy tax credit for the purchase of qualified fuel cells with a maximum of $500 for each 0.5 kilowatt of capacity. For qualified microturbine property, the nameplate capacity must be less than 2000 kilowatts and the electricity-only efficiency must exceed 26 percent of International Standard Organization Conditions. For qualified fuel cells, in order to qualify for the credit, the plant must have an electricity-only efficiency of 30 percent or more and capacity of at least 0.5 kilowatts of power generation.

The Exclusion of Interest on Bonds for Certain Energy Facilities was established by the Revenue Expenditure and Control Act of 1968 (Public Law 90-364), which exempts from Federal income tax interest on private activity bonds issued by State or local governments to finance certain energy facilities. Private activity bonds may be used to finance a variety of infrastructure projects such as airports, port facilities, and public housing, as well as facilities for the local provision of electricity and natural gas. The IRS determines the maximum amount that each State may issue annually through a solicitation process. The States determine which eligible projects may issue bonds from their respective allocations. The Treasury has estimated that the value of this expenditure is $40 million in FY 2007.

The Credit for the Production of Advanced Nuclear Generation was established under EPACT2005 (Section 1306) and has no value in FY 2007 due to the fact that no nuclear power plants are currently under construction. Over the Treasury Department's 2007 through 2012 tax expenditure forecast horizon, the value of this credit remains at zero as no eligible nuclear power plants are expected to come on line during that time frame. The credit is worth 1.8 cents per kilowatthour of electricity produced during the first 8 years of operation from plants having a NRC approved design. The legislation limits the capacity for this production tax credit (PTC) to 6,000 megawatts. The Secretary of Energy is responsible for the allocation of this credit by capacity. The provision has an additional limitation of $125 million per thousand megawatts of capacity per taxable year.

The Transmission Property Treated as 15-Year Property set forth in Section 1308 of EPACT2005 modifies Section 168 of the Code by shortening the recovery period from 20 to 15 years for eligible assets used in the transmission of electricity following sale of the property or related land improvements. Specifically, this applies to Section 1245 property, i.e., personal property and real property, subject to depreciation or amortization, used in the transmission of electricity that is energized at 69 kilovolts or more. The provision applies to transmission

[45] A negative value for tax expenditures indicates that the Treasury actually gains more revenue than it would have in the absence of the tax expenditure.

facilities placed in service by the taxpayer after April 11, 2005, but excludes any transmission facilities for which the taxpayer or related party had entered into a binding construction contract for or initiated self-construction on or before April 11, 2005. For FY 2007, the estimated value of accelerating the recovery period by 5 years is $18 million.

Table 3. Electricity Transformation-Related Tax Expenditures (million 2007 dollars)

Tax Expenditure	Type	FY 1999	FY 2007
Deferral of Gain from Dispositions of Transmission Property to Implement FERC Restructuring Policy	Deferral	-	530
Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants	Credit	-	90
Credit for Production from Advanced Nuclear Power Facilities	Credit	-	-
Exclusion of Interest on Bonds for Certain Energy Facilities	Exemption	139	40
Transmission Property Treated as 15-Year Property	Expense Deduction	-	18
5-Year Net Operating Loss Carryover for Transmission Investment	Enhanced Tax Attribute	-	43
Treatment of Certain Electric Cooperative Income	Exemption	-	14
Total		139	735

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget*, Analytical Perspectives of the United States Budget Fiscal Year 2001 and 2008*, Tables 5-1 and 19-1, respectively. Joint Committee on Taxation, "Description of the Technical Explanation of the Conference Agreement of H.R. 6, Title XIII, The Energy Tax Incentives Act of 2005," JCX-60-50 and JCX-59-05, July 28, 2005.

The Five-Year Net Operating Loss Carryover for Electric Transmission Equipment (EPACT2005, Section 1311) allows taxpayers the option to carry back a net operating loss (NOL) for each of the 5 years prior to the tax year in which the loss was incurred.[46] The 5-year carryover applies to losses included in 2003, 2004, and 2005. Regardless of the taxable year in which an eligible NOL arose, refund claims resulting from the extended carryover period can be made during any taxable year ending after December 31, 2005, and before January 1, 2009. The refund claimed during any one taxable year may not exceed the amount of the electric utility company's investment in electric transmission property and pollution control facilities. The amount of an NOL that may be carried back may not exceed 20 percent of the value of investment made in qualified transmission and pollution control facilities in the preceding year. The estimated value of this tax benefit for FY 2007 is $43 million.

The Treatment of Income of Certain Electric Cooperatives (EPACT2005, Section 1304) was enacted in the AJCA, Section 319. It contained a sunset provision, which would have applied in all years after December 31, 2006. Section 1304 of EPACT2005 eliminated the sunset provision. The provision applies to tax-exempt electric cooperatives that are organized under Section 501(c) (12) of the Code. Among the requirements to qualify for tax-exempt status is the 85-percent test. The 85-percent test provides that in order to qualify for tax-exempt status

[46] Carryback refers to the practice of using an NOL from taxable income for a prior tax period. Carryforward refers to using an NOL in a future taxable period. Normally, a taxpayer is permitted a 2-year carryback and a 20-year carryforward for NOLs to reduce taxable income during the carryback and carryforward period. NOLs must be applied on a first-in-first-out basis. NOLs expire if they are not used within the applicable periods.

a cooperative may receive no more than 15 percent of its income from business conducted with non-members (i.e., at least 85 percent of income must come from conducting business with members). It is a "bright-line" test. FERC Policy requires Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to be independent of market participants. Consistent with the requirement, the cost of, and the charges for, use of facilities placed under the operational control of an RTO/ISO are administered under the RTO/ISO's FERC-approved tariff. Therefore, if an exempt cooperative were to join an RTO/ISO, transmission-related income received from members would be reclassified as non-member income received from the RTO/ISO for purposes of computing the 85-percent test, potentially resulting in the loss of tax-exempt status. Similarly, any income from transmission and ancillary services a cooperative might provide voluntarily to a non-member would be classified as non-member income. The amendment to Section 501(c)(12) also excludes non-member income a cooperative may receive from providing transmission service under a nondiscriminatory open access tariff for purposes of calculating the 85-percent test. The provision also allows cooperatives to exclude nuclear decommissioning trust income, which is classified as non-member income for purposes of computing the 85-percent test. The JCT estimated the value of this tax expenditure at $14 million for FY 2007.

The Modification to Special Rules for Nuclear Decommissioning Costs (EPACT2005 Section 1310). Section 1310 changes the IRS rules for qualified nuclear decommissioning trust funds by repealing the cost of service requirement for contributions to a qualified decommissioning trust fund created under IRC Section 468A. This change permits full present value funding of a qualified nuclear decommissioning fund and the transfer of pre-1984 decommissioning funds held in nonqualified trusts. The provision also requires that nuclear plant owners obtain a new schedule of ruling amounts from the IRS upon renewal of a plant's operating license by the NRC. In FY 2007, the estimated value of this tax expenditure is $199 million. Modification of section 468A of the Code was done to eliminate an impediment to nuclear plant sales arising from the structural change in the electric utility industry. While the discussion of this tax expenditure is included with other electricity-related tax expenditures, it is not reported in Table 3. It is included as a subsidy to nuclear fuel in Table 1 and in the estimate of subsidies by fuel type in Chapter 5.

Renewable-Related Tax Expenditures

Renewable-related tax expenditures in FY 2007 are estimated at $4.0 billion (Table 4). There were two tax expenditures directed at renewable-related electricity production and three non-electricity related tax expenditures directed at transportation.

Table 4. Renewable-Related Tax Expenditures (million 2007 dollars)

Tax Expenditure	Type	FY 1999	FY 2007
Excise Taxes/VEETC (ethanol fuel)	Credit	921	2,990
New Technology Credit	Credit	61	690
Biodiesel and Small Agri-Biodiesel Producer Tax Credit	Credit	-	180
Credit for Holding Clean Renewable Energy Bonds	Credit	-	60
Alcohol Fuel Credit	Credit	18	50
Total		1,000	3,970

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget, *Analytical Perspectives of the United States Budget, Fiscal Years 2001 and 2008*, Tables 5-1 and 19-1, respectively.

The Volumetric Ethanol Excise Tax Credit (VEETC) was implemented with the American Jobs Creation Act of 2004 (Public Law 108-357, Title 3, Sections 301-302). It is estimated to be the largest energy-related tax credit in FY 2007. Its predecessor, the alcohol fuel excise tax exemption, was estimated to be the largest tax-related benefit in the 1999-2000 EIA subsidy reports. VEETC is directed at the production of transportation-related fuels. The alcohol fuels excise tax exemption first appeared in Section 221 of the Energy Tax Act of 1978 (Public Law 95-618). This exemption was replaced in 2004 with VEETC by Section 301 of the AJCA. The AJCA extended the benefit through 2010. VEETC provides ethanol blenders/retailers with 51 cents per pure gallon of ethanol or $.0051 per percentage point of ethanol blended in motor gasoline. The value of VEETC is estimated at $3.0 billion in FY 2007. By 2010, the value of this credit is expected to exceed $5 billion.

The New Technology Credit is the next largest energy-related tax credit. The new technology credit is also known as the production tax credit (PTC).[47] The new technology credit is estimated to be $690 million in FY 2007. By 2008, the new technology credit is expected to be both the second largest energy-related tax expenditure and the second largest renewable energy tax expenditure. Wind power is estimated to be the primary beneficiary of the credit in FY 2007. Other eligible energy sources include: closed and open-loop biomass facilities, geothermal, solar, municipal solid waste, landfill gas resources, certain hydroelectric facilities, and coal produced on Indian (Native American) lands. Initially, tax benefits for renewable generation were established in the Energy Tax Act of 1978 (Public Law 95-618) via a 10-percent investment tax credit for solar, wind, geothermal, and ocean thermal technologies.

The Biodiesel and Small Agri-Biodiesel Producer Tax Credit has an expected value of $180 million in FY 2007. Section 313 of the AJCA created a $1-per-gallon credit for the sale of agri-biodiesel fuel. The credit applies to "virgin" agricultural feedstock such as soybeans or cottonseed. A 50-cent credit is provided to biodiesel produced from recycled grease. The credit was due to expire at the end of 2006. Section 1344 of EPACT2005 extended the credit though the end of 2008. This is primarily a transportation-related tax expenditure.

The Alcohol Fuel Credit is directed at the transportation sector. The alcohol fuel credit originated in the Crude Oil and Windfall Profit Tax of 1980 (Public Law 96-223). The credit has an estimated value of $50 million in FY 2007.

The Credit for Holding Clean Renewable Energy Bonds was established in Section 1303 of EPACT2005. It provides for the issuance of Clean Renewable Energy Bonds (CREBs) through December 31, 2007. Taxpayers holding CREBs are entitled to a tax credit in lieu of interest payments from the bond issuer. Prior to passage of EPACT2005, only investor-owned utilities (IOUs) qualified to receive tax incentives for producing electricity from renewable energy resources. EPACT2005 placed an $800 million cap on the issuance of CREBs. CREBS allows non-IOU electricity providers to issue interest free bonds to finance qualified energy projects. The value of this tax credit is estimated at $60 million in FY 2007. Section 202 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432) increased the allocation of CREBs to $1.2 billion and extended the deadline to December 31, 2008.[48]

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47 The new technology credit is a term defined by the Treasury Department. It appears in Office of Management and Budget, *Analytical Perspectives of the United States Budget Fiscal, Year 2008*, Table 19-1.

[48] The U.S. House of Representatives Ways and Means Committee: http://waysandmeans.house.gov/media/pdf/taxdocs/hr6408taxdetailedsummary.pdf, accessed October 16, 2007.

Natural Gas and Petroleum-Related Tax Expenditures

Of the 10 natural gas and petroleum-related tax expenditures identified, five are allocated to electricity production, one was not in effect in FY 2007, and three are primarily transportation-related in FY 2007. The alternative fuel production credit applied to natural gas in FY1999 (coalbed methane), but is now directed to refined coal, which for FY 20007 appears in Table 2. The total value of these tax expenditures is estimated at $1.8 billion in FY 2007 (Table 5).

Table 5. Natural Gas and Petroleum-Related Tax Expenditures (million 2007 dollars)

Tax Expenditure	Type	FY 1999	FY 2007
Expensing of Exploration and Development Costs	Deferral	(97)	860
Excess of Percentage over Cost Depletion	Deferral	321	790
Amortization All Geological and Geophysical Expenditures over 2 Years	Deferral	-	60
Natural Gas Distribution Pipelines Treated as 15-Year Property	Deferral	-	50
Exception from Passive Loss Limitation for Working Interests in Oil and Natural Gas Properties	Deferral	36	30
Temporary 50-Percent Expensing for Equipment Used in the Refining of Liquid Fuels	Deferral	-	30
Expensing of Capital Costs with Respect to Complying with EPA Sulfur Regulations	Deferral	-	10
Enhanced Oil Recovery	Credit	273	-
Alternative Fuel Production Credit	Credit	1,242	-
Credit and Deduction for Clean Fuel Vehicles	Credit	103	260
Total		1,878	2,090

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget, *Analytical Perspective of the United States Budget, Fiscal Years 2001 and 2008*, Table 5 and 19-1.

The Expensing of Exploration and Development Costs Deferral originated in 1916. Federal tax law allows energy producers, principally oil and natural gas producers, to expense exploration and development (E&D) expenditures rather than capitalize and depreciate them over time. The most important of these expenditures consist of intangible drilling costs associated with oil and natural gas investments. In FY 2007, this tax expenditure is estimated at $860 million.

The Excess of Percentage over Cost Depletion Deferral dates back to World War I. Depletion on a discovery basis became an accepted practice between 1918 and 1926. Percentage depletion for oil and natural gas properties became law with the passage of the 1926 Revenue Act. Under cost depletion, the annual deduction is equal to the non-recovered cost of acquisition and development of the resource times the proportion of the resource removed during that year. Under percentage depletion, taxpayers deduct a percentage of gross income from resource production. In FY 2007, the value of this tax expenditure is estimated at $790 million.

The Tax Credit and Deduction for Clean-Fuel, Alternative Fuel, and Electric Vehicles was initiated with Section 1913 of the Energy Policy Act of 1992 (EPACT1992, Public Law 108-486). EPACT 1992 provided an electric vehicle (EV) tax credit for up to 10 percent of the vehicle cost (capped at $4,000) for purchases of qualified EVs and hybrid-electric vehicles (HEVs). Section 1913 also provided a tax deduction of $2,000 for alternative fueled vehicles (AFVs) up to $2,000 for light-duty vehicles (LDVs), and $5,000 to $50,000 for medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs). Section 1341 of EPACT2005 provides tax credits for fuel cell vehicles of $8,000 to $40,000, and advanced lean-burn technology vehicles (limited to LDVs) and hybrid motor vehicles of up to $3,400. The value of the tax credit is estimated at $260 million in FY 2007.

The Amortization of all Geological and Geophysical Expenditures Over 2 Years provides that geological and geophysical (G&G) expenditures for domestic exploration of oil and natural gas be amortized over 2 years. This tax expenditure was enacted in EPACT2005, Section 1329. This tax expenditure is estimated to be $60 million in FY 2007. Section 503 of the Tax Increase Prevention and Reconciliation Act of 2005 (Public Law 109-222) scaled back this benefit by lengthening the amortization period for integrated petroleum companies to 5 years.

The Natural Gas Distribution Pipelines Treated as 15-Year Property Deferral was established by EPACT2005 (Section 1308) and is estimated to have a value of $50 million in FY 2007. Section 1308 accelerates the recovery period for natural gas distribution lines from 20 years to 15 years.

The Exception from Passive Loss Limitation for Working Interest in Oil and Natural Gas Properties Deferral was established with the Tax Reform Act of 1986 (Public Law 99-519). The value of this tax credit in FY 2007 is estimated at $30 million. The exception allows owners of working interests to offset their losses from passive activities against active income. Under normal rules, passive losses that remain after being netted against passive income can only be carried forward to apply against passive income in future years. The exception from passive loss limitation provisions on oil and natural gas properties applies principally to partnerships and individuals rather than corporations.

The Temporary 50-Percent Expensing of Equipment Used in the Refining of Liquid Fuels Deferral was established by Section 1323 of EPACT2005. It is estimated to be $30 million in FY 2007. It is a transportation fuel subsidy.

The Expensing of Capital Costs with Respect to Complying with Environmental Protection Agency Sulfur Regulations Deferral was provided for in Section 1324 of EPACT2005. It allows small refiners to deduct 75 percent of qualified capital costs related to complying with EPA sulfur regulations. The estimated value of this tax expenditure is $10 million in FY 2007. Section 1324 is a transportation fuel subsidy.

The Enhanced Oil Recovery Credit enables taxpayers to claim a general business credit for enhanced oil recovery (EOR) investment. The credit was provided by Section 11511 of the Omnibus Budget Reconciliation Act of 1990 (Public Law 101-508). The EOR credit applies to 15 percent of the cost of one or more tertiary recovery methods. EOR involves the extraction of the oil from a petroleum reservoir greater than that which can be economically recovered by conventional primary and secondary methods. The credit also applies to the construction of a natural gas treatment plant in Alaska to process Alaskan natural gas for pipeline transportation. The credit phases out when the inflation-adjusted price of oil exceeds $28 per barrel (in 1991 dollars) or $39 per barrel (in 2007 dollars) in the preceding year. Due to the average price of oil in 2007 being above the cap, the value of this credit was zero in FY 2007.

The Alternative Fuel Production Credit was established with the Windfall Profits Tax of 1980 (Public Law 96-223). The credit did not impact natural gas or petroleum-related expenditures in 2007, as the credit went mostly to producers of coalbed methane and natural gas from unconventional sources, whose eligibility expired at the end of 2002. The credit did, however, have an effect on refined coal production in 2007 (see Table 2).

The Credit for the Deduction of Clean Fuel Vehicles was established with the Clean Air Act Amendments of 1990 (CAAA90) (Public Law 101-549) and the Energy Policy Act of 1992 (EPACT1992) (Public Law 102-486), which mandated that vehicle fleets owned by fuel providers and State governments, as well as certain vehicle fleets operating in air quality nonattainment areas, gradually acquire and use low-emission vehicles in increasing percentages through the year 2010. The value of the credit was ascribed by EIA to transportation in 2007.

Energy Efficiency and Conservation-Related Tax Expenditures

EPACT2005 contained a number of provisions that are designed to promote energy conservation. One conservation-related tax expenditure dates back to EPACT1992. The provisions are primarily directed at individuals (residential) and commercial taxpayers in the form of tax expense deductions, tax credits or exclusion of certain receipts from gross income. Conservation-related tax expenditures are estimated at $790 million in FY 2007 (Table 6).

Table 6. Conservation, Efficiency, and End-Use Tax Expenditures (million 2007 dollars)

Tax Expenditure	Type	FY 1999	FY 2007
Credit for Energy-Efficiency Improvements of Existing Homes	Credit	-	380
Allowance of Deduction for Certain Energy-Efficient Commercial Building Property	Deduction	-	190
Exclusion for Utility-Sponsored Conservation Measures	Exclusion	103	110
Credit for Energy-Efficient Appliances	Credit	-	80
Credit for Construction of New Energy-Efficient Homes	Credit	-	20
Pass Through Low-Sulfur Diesel to Cooperative Owners	Credit	-	-
30-Percent Credit for Residential Purchases/Installations of Solar and Fuel Cells	Credit	-	10
Total		103	790

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget*, Analytical Perspectives of the United States Budget Fiscal Years 2001 and 2008*, Tables 5-1 and 19-1, respectively; and, Joint Committee on Taxation, "Description of the Technical Explanation of the Conference Agreement of H.R.6, Title XIII, The Energy Tax Incentives Act of 2005," JCX-60-05 and JCX 59-05, July 22, 2005.

The Credit for Energy-Efficiency of Existing Homes (EPACT2005, Section 1333) has an estimated value of $380 million in FY 2007. This credit applies to windows, furnaces, boilers, fans, and building envelope components, such as exterior doors and any metal roof that has appropriated pigmented coatings. The credit is available to houses constructed before December 31, 2007.

The Credit for Efficient Appliances (EPACT2005, Section 1334) has an estimated value of $80 million in FY 2007. Appliance manufacturers receive a tax credit for manufacturing energy-efficient dishwashers, clothes washers, and refrigerators. The credits apply to appliances manufactured between December 31, 2005, and January 1, 2008. The tax credit is limited to 2 percent of the gross revenue for the 3 taxable years prior to the taxable year in which the credit occurs.

The Allowance of Deduction for Certain Energy-Efficient Commercial Building Property was established with EPACT2005 (Section 1331). Taxpayers are permitted to take a deduction of $1.80 per square foot on new construction built after December 31, 2005, and before December 31, 2007, if annual energy and power costs of interior lighting systems, heating, cooling, ventilation, and hot water systems are 50 percent or more below the standards set by the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE). The value of this credit is estimated at $190 million for FY 2007. Section 201 of The Tax Relief and Health Care Act of 2006 extended the credit to December 31, 2008.

The Credit for Construction of New Energy-Efficient Homes was established by Section 1332 of EPACT2005. It provides home builders a tax credit of $2,000 for the construction of a new energy-efficient home. To qualify, the home must achieve energy savings of 50 percent over a comparable unit constructed in conformance with the International Energy Conservation code. The value of this credit is estimated at $20 million for FY 2007. Initially, the credit was available to houses constructed before December 31, 2007. The eligibility window was extended to December 31, 2008, in the Tax Relief and Health Care Act of 2006.

The Exclusion for Utility-Sponsored Conservation Measures was established by Section 136 of EPACT1992. Section 136 amended the Code to provide tax benefits to individual consumers for participating in utility-sponsored energy conservation programs. Payments individual consumers receive from utilities for investing in energy conversation measures may be excluded from gross income for purposes of calculating taxable income. For example, utilities engaged in demand-side management activities often pay rebates to consumers who purchase more efficient heating or cooling equipment in order to reduce the consumption of natural gas and electricity. The value of this credit is estimated at $110 million for FY 2007.

The 30-Percent Credit for Residential Purchases/Installations of Solar and Fuel Cells has an estimated value of $10 million in FY 2007. Section 1335 of EPACT2005 established a 30-percent personal tax credit, not to exceed $2,000, for the purchase of solar electric and solar water heating property. A 30-percent tax credit up to $500 per 0.5 kilowatt (kW) of capacity is also available for fuel cells. The fuel cell provision of EPACT2005 was due to expire at the end of 2007. It was extended through the end of calendar year 2008 by Section 206 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432).

Alcohol and Biofuels Tax Provisions

At $3.2 billion in 2007, Federal government support of alcohol fuels is estimated to be the largest energy-related tax expenditure for 2007. In 2006, ethanol accounted for 6 percent of U.S. energy consumption. Currently, the United States is the world's largest producer of ethanol in the world, having surpassed Brazil in 2005. (Unlike corn-based U.S. ethanol production, sugarcane is the primary feedstock for Brazilian ethanol production.) Support for alcohol fuels originated in the Energy Tax Act of 1978. Subsequently, at least seventeen pieces of legislation have been directed at this fuel (Table 7). Currently, there are three ethanol-related tax expenditures.[49]

[49] The Federal government also promotes ethanol production through mandatory blending of ethanol with gasoline. EPACT2005 included a Renewable Fuels Standard that required that 4 billion gallons of renewable fuel be blended with gasoline in 2006, increasing to 7.5 billion gallons in 2012. The Energy Independence and Security Act of 2007 increased the volumes of renewable fuels to be blended with gasoline to 9 billion gallons in 2008, increasing to 36 billion gallons in 2022. Ethanol production is also supported by a 54-cent-per-gallon tariff on imported ethanol, exclusive of ethanol produced by countries participating in the Caribbean Basin Initiative. The tariff is slated to be lifted on December 31, 2008.

The Volumetric Ethanol Excise Tax Credit (VEETC) was established by the Energy Tax Act of 1978, which allowed for a 4-cent-per-gallon exemption from excise taxes for motor fuels that contained a minimum of 10-percent biomass-derived alcohol. Subsequent legislation both raised and lowered this exemption. In 2004, this exemption was replaced by AJCA Section 301. The AJCA replaced the excise tax exemption with VEETC and extended the benefit through 2010. The VEETC is available to ethanol blenders and is equal to an amount of 51 cents per gallon of ethanol blended with gasoline based upon the volume of ethanol, not on the blend rate. The value of this expenditure in FY 2007 is estimated at $3 billion.

The Biodiesel and Small Agri-Biodiesel Producer Tax Credit was included in the AJCA. It provides a $1-per-gallon credit for the sale of agri-biodiesel fuel. Section 313 of the Act applies the credit to "virgin" agricultural feedstock such as soybeans or cottonseed. A 50-cent credit was provided to biodiesel produced from recycled grease. Initially, the credit was due to expire at the end of 2006. EPACT2005 extended the credit though 2008. The value of this tax expenditure is estimated at $180 million for FY 2007.

The Alcohol Fuel Credit is the third tax expenditure for ethanol production. This tax expenditure originated in the Crude Oil Windfall Profit Tax Act of 1980 (Public Law 96-223), which introduced an alcohol fuel blenders' tax credit. This credit was made available to blenders and to users or retail sellers of straight alcohol fuels. The credit was initially 40 cents per gallon for alcohol that was at least 190 proof and 45 cents per gallon for alcohol that was between 150 and 190-proof. The credit was available through December 31, 1992. The Deficit Reduction Act of 1984 (Public Law 98-369) increased the credit from 40 cents to 60 cents per gallon of blend for 190-proof alcohol. The Transportation Efficiency Act of the 21st Century of 1998 (Public Law 105-178) extended the credit through 2007 and reduced its value to 51 cents per gallon. This tax credit was not used to any significant degree until 2007. In FY 2007, it amounts to about $50 million. Blenders generally use the excise tax exemption rather than the tax credit, because the excise tax exemption provides them with an immediate cash flow. When used, this credit is offset by the VTEEC described above.

Table 7. Laws Promoting Ethanol as a Transportation Fuel

Public Law	Name	Provisions
95-618	Energy Tax Act of 1978	Exempted 10-percent ethanol/gasoline blends from the 4-cents-per-gallon Federal gasoline excise tax. Provided 10-percent of the energy investment tax credit for biomass-ethanol conversion equipment.
96-126	Interior & Related Agencies Appropriation Act of 1980	Provided grants for the economic feasibility of commercial-scale alcohol fuel production and cooperative agreements.
96-223	Crude Oil Windfall Tax Act of 1980	Extended ethanol excise tax exemption through 1992. Established 40-cents-per-gallon tax credit for ethanol fuel use.
96-294	Energy Security Act of 1980	Authorized loan guarantees for ethanol production facilities.
99-499	Omnibus Reconciliation Tax Act of 1980	Placed a 54-cent-per-gallon tariff on imported ethanol.
96-304	Supplemental Appropriation & Rescission Act of 1980	Provided additional grants for feasibility studies and cooperative agreements.
97-424	Surface Transportation Assistance Act of 1982	Raised excise tax exemption for 10-percent ethanol blends to 5-cents-per-gallon.
98-369	The Deficit Reduction Act of 1984	Raised the excise tax exemption for 10-percent ethanol/gasoline blends to 6-cents-per-gallon and the ethanol tax credit to 60-cents-per-gallon.
100-494	Alternative Motor Fuels Act of 1988	Enacted Corporate Average Fuel Economy credits for alternative fuel vehicles.
100-647	Technical and Miscellaneous Revenue Act of 1988	Liberalized the excise tax rule.
101-508	Omnibus Budget Reconciliation Act of 1990	Reduced ethanol excise exemption to 5.4 cents per gallon; reduced ethanol tax credit to 54 cents per gallon. Extended ethanol fuel tax incentives thru 2000. Established small ethanol producers' tax credit of 10 cents per gallon.
101-549	Clean Air Act Amendments of 1990	Mandated winter use of oxygenated fuels in 39 nonattainment areas carbon monoxide (where EPA emissions standards for carbon dioxide had not been met); required year-round use of oxygenates in 9 severe ozone nonattainment areas in 1995.
102-486	Energy Policy Act of 1992	Modified excise tax exemption to accommodate blends of less than 10-percent ethanol resulting from more sophisticated blending strategies for pollution control. Tax exemption was set at 4.2-cents-per-gallon for mixtures containing 7.7-percent ethanol and 3.1-cents-per-gallon for mixtures containing 5.5 percent ethanol.
105-178	Transportation Equity Act for the 21st Century of 1998	Extended ethanol tax incentives thru 2007. Reduced value of the exemption to 5.1-cents-per-gallon and the tax credit to 51 cents per gallon.
108-357	The American Jobs Creation Act of 2004	Extended ethanol subsidies through 2010 and introduced VEETC.
109-58	Energy Policy Act of 2005	See Appendix C.
110-140	Energy Independence and Security Act of 2007	Expands existing biofuels programs including increasing the volume of alternative fuels blended with gasoline. Requires 36 billion gallons be blended by 2022.
Source: Library of Congress, http://thomas.loc.gov/		

Section 29: The Alternative Fuel Production Credit

The Alternative Fuel Production Credit (IRC Section 29) was established by the Windfall Profit Tax of 1980 (Public Law 96-223) and became operational in the same year. The credit applied to qualified fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. Production from qualifying wells could receive the credit for volumes produced through December 31, 2002. Thus, producers operating qualifying wells or facilities were eligible for credits over a period of not less than 10 years or more than 22 years. The initial qualified fuels were:

- oil produced from shale and tar sands;
- natural 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.

The principal changes that have occurred since 1980 include extending the qualifying in-service date for wells and other alternative fuel production facilities and the types of fuel that are eligible for the credit. The initial January 1, 1980, and December 31, 1992, qualification period has been extended several times by subsequent legislation. In 1989, legislation allowed a 1-year extension of the time limits. The Omnibus Budget Reconciliation Act of 1990 (Public Law 101-508) provided an additional 2-year extension. The 1990 Act also eased the qualifying requirements for natural gas produced from tight sands after 1990. The qualification has at times been sharply constrained by Executive Branch rulings and judicial decisions. However, EPACT1992 extended the placed-in-service deadline for synfuel facilities. For synfuel facilities placed in service after December 31, 1992, and before July 1, 1998, the credit can continue to be claimed for qualifying synfuel sold through December 31, 2007. Due to favorable private letter rulings (PLR) issued by the IRS in the late 1990s, an increasing number of coal synfuel facilities claiming the credit came into existence. By the beginning of 2007, 59 qualifying coal synfuel plants were producing about 140 million tons of coal synfuel per year. All of these plants meet the placed-in-service window of December 31, 1992, to July 1, 1998 and, therefore, are eligible for the credit through 2007. Because the credit expires for all of these facilities at the end of 2007, it is anticipated that most, if not all, of the 59 plants operating in 2007 will have shut down at the end of 2007.

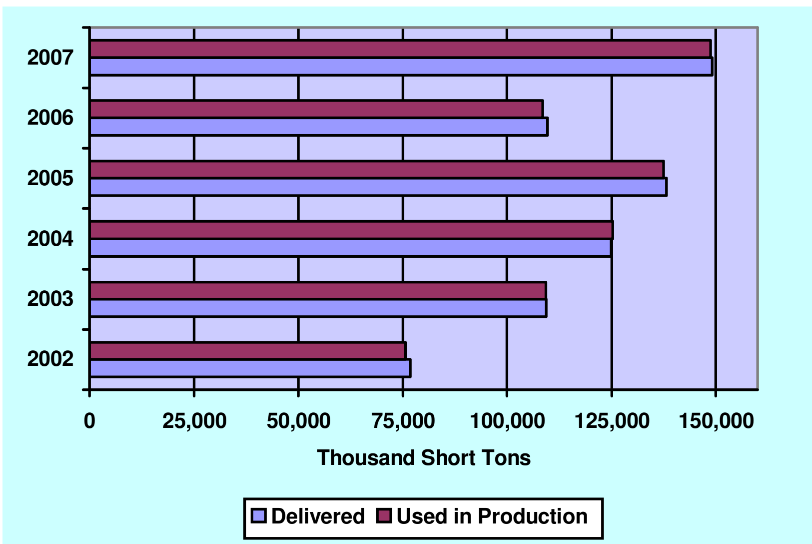
The tax credit for nonconventional fuels is $3.00 (1979 dollars) per barrel of oil equivalent produced.[50] The credit is fully effective when the price of crude oil is less than $55.06 (2006

[50] All prices as well as the credit are specified in 1979 dollars, but for actual use they are indexed for inflation relative to that base. Conversion factors are used to convert the various fuels into their crude oil equivalent for purposes of calculating the credit. The formula for calculating the credit for 2006 is as follows: ($3.00*2.3429)*[($59.68-($23.50*2.2349))/($6.0*2.2349))] = $2.31. Where:

- the benchmark oil price is $59.68, the first purchase price of crude in 2006;
- the Section 29 credit is $3 per barrel oil equivalent (1979 dollars);
- the inflation adjustment factor for 2006 is 2.3429;
- the upper factor cap is $6, which is adjusted for inflation, and
- the inflation factor for 2006 is 2.3429.
- the $2.31 is subtracted from the unadjusted tax credit of $7.03 per barrel of oil equivalent to produce. the adjusted tax credit for 2006 is $4.72.

dollars) per barrel and phases out gradually as the price rises to $69.12 in 2006 dollars[51]. The credit is reduced if the taxpayer receives certain other energy subsidies such as government grants and tax-exempt financing. Per IRS instructions, the credit is calculated in current dollars using the Commerce Department gross national product (GNP) implicit price deflator for the calendar year. In 2006, the maximum credit was $3 times 2.3429 or $7.03 per barrel of oil equivalent. For typical bituminous coal with 24 million Btu, the maximum credit for a ton of coal synfuel was the quotient of 24 million Btu and 5.8 million Btu times $7.03 or $29.08. The IRS defines a barrel of oil equivalent to mean an energy content of 5.8 million British thermal unit (Btu). The credit varies as actual coal Btu content varies relative to the 5.8 million Btu value. The credit in 2006 is reduced when the price of oil (average wellhead price for all domestic crude oil) exceeds $55.06 per barrel.

Figure 1. Coal Delivered and Used in Refined Coal Production, Fiscal Year 2002 to 2007



Sources: Energy Information Administration, *Quarterly Coal Report July-September 2007, DOE-EIA-0121 (2007/3Q) (Washington, DC, 2007) and prior editions starting with 2002 fourth quarter report.*

For 2006, the Department of Energy (DOE) published an average wellhead price for all domestic crude oil of $59.68 per barrel, which reduced the 2006 credit to $19.53 per ton (assuming 24 million Btu per ton). In the middle of 2006, some coal synfuel plant operators incorrectly anticipated that rising oil prices would wipe out the entire credit, and they reacted by shutting down some operations, leading to a decline in synfuel plant output (Figure 1).

The credit expired for coalbed methane at the end of 2002. Credits for synthetic coal, landfill gas, and coke and coke oven gas were still in effect in 2007, but the synthetic coal credit for the 59 qualifying synfuel plants expired at the end of 2007. Most synthetic coal projects are owned by institutional investors such as insurance companies, banks, utilities, and large corporations with substantial net revenues against which the tax credits can be taken. Between 2002 and 2007, synthetic coal production nearly doubled (Figure 1). Production fell between 2005 and 2006 when high oil prices caused some plant operators into shutting down their facilities for part of the year.

Source: U.S. Internal Revenue Service, Notice 2007-38; 2007-18 I.R.B. 1103 (2007), Nonconventional Source Fuel Credit, Section 45K Inflation Adjustment Factor and Section 45K Reference Price (Washington, DC, April 30, 2007). EIA first published data on synthetic coal production in 2001.

[51] The value of the credit is provided in this report in 2007 dollars based upon an estimate of the 2007 GNP implicit price deflator. At the time of this estimate, applicable IRS oil price band data were unavailable.

The American Jobs Creation Act of 2004 (AJCA, Section 710, Public Law 108-357) introduced additional criteria for facilities producing synthetic (also referred to as "refined coal").[52] Under AJCA, qualifying facilities must meet two tests applicable to environmental performance and economic value: (1) a qualifying facility must achieve 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; and, (2) the refined coal product must be at least 50 percent higher in economic value than the feedstock. Under AJCA, new facilities placed in service after October 22, 2004, and prior to January 1, 2009 qualify for the tax credit if they meet the tests outlined in the previous paragraph. Qualified refined coal facilities are eligible to receive a tax credit for the first 10 years of operation. Compared to Section 29 guidelines, which expired at the end of 2007, the AJCA guidelines for qualifying facilities are more restrictive. Thus far, no facilities are receiving the refined coal credit.

Section 1322 of EPACT2005 moved Section 29 to Section 45 as a new section 45K. Section 45K allows old Section 29 credits to be combined with other general business credits. As an alternative fuel product credit, it may be carried forward 20 years and carried back one year. Section 1321 of EPACT2005 expanded the credit to coke and coke gas produced in certain facilities placed in service before January 1, 2010. The credit for coke or coke gas is $3.00 per barrel of oil equivalent, indexed for inflation using 2004 as the base year with a credit-available production limit of an average barrel-of-oil equivalent of 4,000 barrels per day. Section 211 of the Tax Relief and Heath Care Act of 2006 removed the phase-out provision for coke and coke gas.

New Technology Credit

The new technology credit promotes electricity production from renewable resources. The new technology credit is also referred to as the section 45 credit because it is codified in Section 45 of the Code. Renewable generating sources include conventional hydropower, wind, geothermal, biomass,[53] and solar thermal and photovoltaic energy. The primary energy sources for renewable generation tend to be intermittent (e.g., dependent on weather conditions). Renewable energy, excluding conventional hydropower, is a fairly new contributor to U.S. electricity supply. The electric power sector accounted for about 56 percent of renewable energy consumption in 2006.[54] Because of the intermittent nature of many forms of renewable generation, the per-unit production cost tends to be higher than conventional forms of generation that operate at higher capacities. This is exacerbated by the higher capital costs associated with emerging renewable generation technologies.[55] This differential has decreased over time. Renewable generating capacity has grown considerably over the last 4 decades (Table 8). Non-hydro renewables accounted for 3 percent of electricity production in 2006. EIA's *Annual Energy Outlook 2008 (Revised Early Release)* projects nonhydroelectric renewables to account for 7 percent of electricity production by 2030.[56]

Renewable technologies, however, are acknowledged to have favorable environmental attributes (or fewer negative externalities) relative to conventional technologies; these include

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[52] Although the terms "synthetic" and "refined" have been defined somewhat differently in various legislative provision, they are used interchangeably in this report.
[53] Biomass includes wood/wood waste, biogenic municipal solid waste (MSW), landfill gas (LFG), agricultural byproducts/crops, sludge waste, and other biomass solids, liquids, and gases.
[54] Energy Information Administration, Annual Energy Review 2006, DOE/EIA-0384(2006) (Washington, DC, June 2007), p. 281.
[55] Capital costs include the cost of field development, plant construction, and plant equipment.
[56] Energy Information Administration, *Annual Energy Outlook 2008 (Revised Early Release)*, DOE/EIA-0383 (2008) (Washington, DC, March 2008), Table 8 and Table 16, http://www.eia.doe.gov/oiaf/aeo/index.html.

low or zero emissions and a replenishable energy supply.[57] Over the years, incentives and mandates for renewable energy have been used to advance different energy policies, such as ensuring energy security or promoting environmentally benign energy sources.[58]

Table 8. U.S. Renewable Fuels Electricity Generating Capacity (Gigawatts)

Fuel	1970	1980	1990	2000	2006	2007
Conventional Hydroelectric	64	82	74	79	78	78
Other Renewables (subtotal)	NA	NA	13	16	24	27
Wood	NA	*	6	6	6	6
Waste	NA	NA	3	4	4	4
Geothermal	*	1	3	3	2	2
Solar/PV	NA	NA	*	*	*	*
Wind	NA	NA	2	2	11	15
Total	64	83	87	95	102	105

NOTE: Total may not equal sum of components due to independent rounding.

The capacity values for 2007 are an EIA estimate based on renewable capacity additions reported for calendar year 2007 on the EIA, Form 860-M, “Monthly Update to the Annual Electric Generator Report.”

NA=Not Available.

* Indicates less than .5 gigawatts of capacity.

Source: Energy Information Administration *Annual Energy Review, 2006,* DOE/EIA-0384 (Washington, DC, June 2007) Table 8.11a; Energy Information Administration, *Electric Power Monthly*, Historical Excel Tables, February 2008, http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html

Tax incentives directed toward nonconventional electric generation originated with the Energy Tax Act of 1978 (Public Law 95-618), which established a business energy tax credit of 10 percent of investment in technologies such as solar, wind, geothermal, and ocean thermal. This was in addition to an existing standard 10-percent investment tax credit available to related technologies. The Tax Reform Act of 1986 (Public Law 99-514) eliminated the standard 10-percent investment tax credit and extended the energy tax credit to 1988, but it reduced that credit from 15 percent to 10 percent and eliminated wind as a candidate for any credits.
The business tax credit was extended on a year-to-year basis until passage of EPACT1992. The term "new technology credit" was first introduced as part of EPACT1992 when it became a production tax credit. It was defined as a 1.5-cents-per-kilowatthour payment (adjusted annually

[57] Attempts to measure the value of such benefits and add them to the market price by regulatory fiat (known as "full-cost pricing") have been proposed but not implemented in the United States. Recently, some States have instituted Renewable Energy Certificate/Credit programs that monetize these environmental attributes.
[58] Energy Information Administration, Renewable Energy 2000: Issues and Trends, "Incentives, Mandates, and Government Programs for Promoting Renewable Energy," DOE/EIA-0628(2000) (February 2001, Washington, DC), pp. 1-17.

for inflation), available for 10 years to private investors, as well as to investor-owned electric utilities. The credit applied to electricity produced from wind and closed-loop (dedicated crops) biomass facilities placed in service between 1994 and June 30, 1999. Section 242 of EPACT2005 expanded the tax credit to include incremental hydroelectric generation for a 10-year period at 1.8 cents per kilowatthour. EPACT2005 also extended the in-service date to qualify for the credit by 2 years for closed-loop biomass, geothermal, landfill gas, irrigation-produced power, landfill gas municipal solid waste, open-loop biomass, and wind facilities. For qualifying open-loop biomass, geothermal, solar, and small irrigation power facilities, the credit period was expanded from 5 to 10 years.

Estimation of the Production Tax Credit

In order to estimate the energy effects of the production tax credit and allocate those impacts to renewable fuel groups, qualified capacity at the generating unit level was identified through the end of FY 2007.[A] The portion of qualified capacity at each plant was assumed to produce electricity in proportion to its share of total plant capacity. Capacity eligible to claim the credit was determined for all years through FY 2007 and grouped by renewable technology. Renewable capacity placed in service in 2007 was identified from the latest available monthly information compiled from EIA survey data[B] and FY 2007 net generation was reported to EIA.[C] Applying the credit by technology type yields an estimate of the maximum credit which might be claimed by qualifying technology type. The credit shares for each technology type were applied to the Treasury Department's FY 2007 $690-million estimated value for this tax expenditure to obtain an estimate for each technology (Table 9). With approximately 10 gigawatts of new capacity built or expected over the 3-year period ending in 2007, wind technology dominates the allocation of the credit, claiming about 97 percent of the total credit. Compared to wind, other major sources eligible for the credit saw relatively little incremental capacity additions during their eligibility window. Based on the reported wind generation for FY 2007, wind generators were eligible to claim at least an estimated $526 million in tax credits, significantly less than the estimated $666-million tax expenditure estimated by the Treasury Department, i.e., the value of credit used to reduce tax liability. One plausible explanation for the difference is that during the initial years of operation wind generators may be accumulating credits while incurring tax losses. This may occur because wind energy property has a 5-year life for tax depreciation purposes. Wind generators that have been in operation for more than 5 years, having fully depreciated their property for tax purposes, may now be realizing taxable income to which they are applying prior-period tax credits that they are permitted to carry forward.

For purposes of this report, the subsidy estimates are based on the Treasury Department's aggregate New Technology Credit estimated expenditures. EIA adopted the methodology described above to allocate the Treasury Department's aggregate estimate of the New Technology Credit to specific technologies because of the lack of publicly-available financial data and tax-related data from which fuel-specific estimates could be derived.

[A]. Energy Information Administration, "Annual Electric Generator Report," Form EIA-860 (2006).
[B]. Energy Information Administration, "Monthly Update to the Annual Electric Generator Report," Form EIA-860M (September 2007).
[C]. Energy Information Administration, "Power Plant Report," Form EIA-906, and "Combined Heat and Power Plant Report," Form EIA-920.

Table 9. Fuel Allocation for New Technology Credit Fiscal Year 2007 Estimated Expenditure

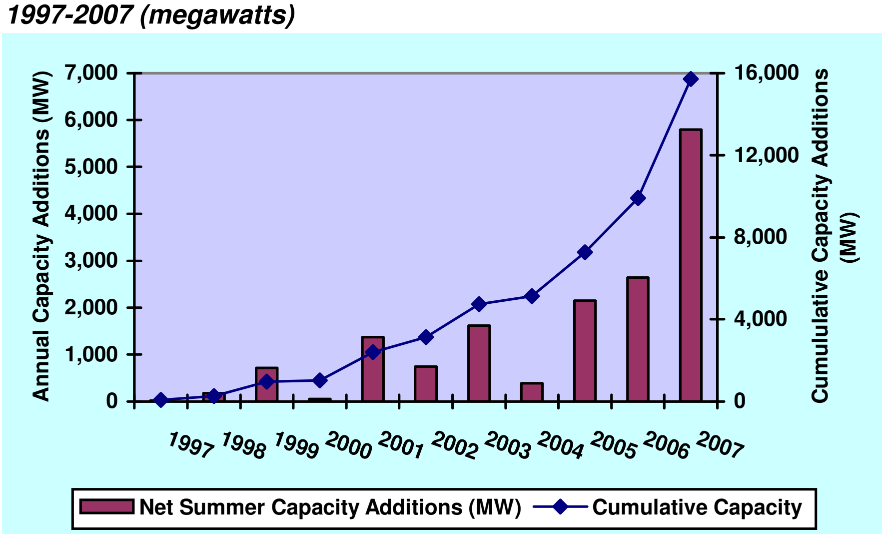
Renewable Technology	Estimated Qualified Capacity (Megawatts)	Estimated Eligible Generation (FY07 Megawatthours)	Average Capacity Factor (percent)	Value of Credit (cents per kilowatthour)	EIA Estimate Based on FY07 Generation (Thousand dollars)	Treasury's Estimated Credit Allowed (Thousand dollars)
Biomass (open loop)	188	351,139	21.3	0.95	3,336	4,223
Geothermal	68	346,945	58.7	1.90	6,592	8,345
Hydroelectric	44	85,318	22.3	0.95	811	1,026
Landfill Gas	193	705,341	41.7	0.95	6,701	8,482
Municipal Solid Waste	37	89,988	27.9	0.95	855	1,082
Solar	87	31,143	4.1	1.90	592	749
Wind	15,312	27,694,360	20.6	1.90	526,193	666,093
Total or Weighted Average	15,928	29,304,234	21.0	1.86	545,078	690,000

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget*, Analytical Perspectives of the United States Budget, Fiscal Year 2008,* Table 19-1. Energy Information Administration, "Power Plant Report," Form EIA-906, and "Combined Heat and Power Plant Report," Form EIA-920.

The historical growth of wind generation, which correlates with the periods in which the PTC has been available to wind power producers, supports the method EIA used to allocate the estimated $690-million New Technology Tax credit to the various forms of renewable generation. Wind power has grown rapidly, especially since 1998 (Figure 2).

Figure 2. Annual and Cumulative Wind Power Capacity Additions, 1997-2007 (megawatts)



In part, this has been due to declining production costs, which has made wind more competitive as fuel costs have increased for conventional fossil-fired generation. In 2006, wind capacity increased at record levels both in terms of capacity additions and its share of total electricity production.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (2006); Form EIA-860, "Monthly Update to Annual Electric Generator Report," January-December, 2007; Form EIA-906, "Power Plant Report," and Form EIA-920 "Combined Heat and Power Plant Report," January-December, 2007.

The PTC for wind has expired and has been reinstated several times since it first went into effect in June of 1994 (Table 10). It has been estimated that the PTC reduces wind costs by roughly one-third. On the basis of megawatthours generated by fuel type, wind power was the second largest beneficiary of electricity-related subsidies after solar. Most of the subsidy allocated to wind is attributable to the $666-million estimate of PTC tax expenditures.

Table 10. History of the New Technology (Production Tax) Credit and Related Development Activity

Legislation	Date Enacted	PTC Eligibility Window	Effective Duration (with lapses)	Wind Capacity Built in PTC Window (Megawatts)
Section 1914, Energy Policy Act of 1992 (P.L. 102-486)	10/24/92	1994-June 1999	80 Months	894
Section 507, Ticket to Work and Work Incentives Act of 1999 (P.L 106-170)	12/19/99	July 1999-2001	24 Months	1,764
Section 603, Job Creation and Workers Assistance Act of 2002, (P.L. 107-147)	03/09/02	2002-2003	22 Months	2,078
Section 313, The Working Families Tax Relief Act of 2004, (P.L. 108-311)	10/04/04	2004-2005	15 Months	2,796
Section 1301, Energy Policy Act of 2005 (P.L. 109-58)	08/08/05	2006-2007	24 Months	5,454
Section 201, Tax Relief and Health Care Act of 2006 (P.L. 109-432)	12/20/06	2008	12 Months	3,000[E]

Source: "Wind Power and the Production Tax Credit: An Overview of Research Results," Prepared Testimony of Dr. Ryan Wiser, Lawrence Berkeley National Laboratory, before the Senate Finance Hearing on Clean Energy: From the Margins to the Mainstream, March 29, 2007, p. 5.

E=Estimate

Unreported Tax Expenditures

The Congressional Budget Act of 1974 (Public Law 93-344) mandates reporting of tax expenditures. The Budget of the U.S. Government defines tax expenditures as "revenue losses due to preferential provisions of the Federal tax laws, such as special exclusions, exemptions, deductions, credits, deferrals, or tax rates." Although the concept of what constitutes a tax expenditure is clear, the determination of what exactly is a preferential provision is subject to interpretation. In preparing this chapter on energy-related tax expenditures, the EIA relied primarily on the definitions of tax expenditures presented in OMB documents. EIA relied on estimates of the value of certain tax expenditures contained in EPACT2005, which were prepared by the JCT. These provisions were described in the discussion on electricity-related tax expenditures. The JCT estimated the total value of these tax expenditures for FY 2007 to be $304 million.

The Treasury Department does not provide estimates of de minimis tax expenditures, i.e., $5 million or less. Therefore, the impact of these tax expenditures is not reported in either OMB budget documents or this report.

This report does not quantitatively address energy legislation that has recently been passed and for which the budgetary impact has not yet been assessed by the OMB for FY 2007 or for future years. A case in point is Section 1306 of EPACT2005 which provides a production tax credit for eligible nuclear power sales. This credit does not have a value before 2012 because no eligible plant is expected to be producing electricity before that time.

Direct Expenditures

There has been renewed growth in direct expenditures in recent years, as a result of higher levels of spending to assist low income consumers with rising energy costs (Table 11).

Table 11. Direct Expenditures in Energy (million 2007 dollars)

Direct Expenditure	FY 1999	FY 2007
Renewable Energy Production Incentive	5	5
Low Income Home Energy Assistance Program	1,545	2,188
DOE Conservation (Weatherization and State Energy)	191	256
Rural Business Service Programs and RUS High Energy Cost Grant Program	-	101
Total	1,741	2,550

Sources: Department of Energy Budgetary Documents and Department of Health and Human Service Budget Documents.

This is reflected in the increase in funding for LIHEAP. LIHEAP expenditures have increased from $1.5 billion in FY 1999 to $2.2 billion in FY 2007. Funding for DOE conservation programs has increased by 34 percent over the same period.

Renewable Energy Production Incentive

The Renewable Energy Production Incentive (REPI) is part of an integrated strategy to promote the generation of electricity from renewable energy sources and to advance renewable energy technologies. This program was authorized under Section 1212 of EPACT1992. It provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. DOE is responsible for managing REPI. EPACT1992 designated eligible electricity production facilities that started operations between October 1, 1993, and September 30, 2003, that are owned by State and local government entities (such as municipal utilities and Tribal governments) and not-for-profit electric cooperatives. The REPI provides not-for-profit entities with a financial incentive to invest in renewable generation technologies much like the incentive provided to for-profit entities eligible for Section 45 PTCs. Initially, qualifying facilities were eligible for annual incentive payments of 1.5 cents per kilowatthour (1993 dollars and indexed for inflation) for the first 10-year period of their operation. The availability of incentive payments is subject to the annual appropriations process. Criteria for qualifying facilities and the application procedures were contained in the rulemaking for this program.[59] Qualifying facilities were to use solar, wind, geothermal (with certain restrictions as contained in the rulemaking), or closed-loop biomass (except for municipal solid waste combustion) generation technologies. In FY 2007, the value of REPI was estimated to be $4.9 million.

Low Income Home Energy Assistance Program

In FY 2007, the Federal government’s Low Income Home Energy Assistance Program (LIHEAP) funding totaled $2.2 billion. LIHEAP was established in 1981 as a block grant

[59] 10 C.F.R. 451 (2007) – Renewable Energy Production Incentives.

program. The Federal government gives States, the District of Columbia, U.S. territories, and Indian tribal organizations annual grants to provide home energy assistance to low-income households primarily to subsidize heating and cooling costs. LIHEAP is administered by the U.S. Department of Health and Human Services (HHS), but program implementation is generally managed by the grantees. LIHEAP assistance does not reduce eligibility or benefits under other aid programs.

LIHEAP establishes a standard of 60 percent of a State's median income to become eligible. LIHEAP grantees have some flexibility as the program allows "maximum policy discretion to grantees." For a four-person family in FY 2007, 60 percent of the mean national income is $66,111.[60] Federal law defines income eligibility as the greater of 60 percent of the State's median income or 150 percent of the HHS poverty income guidelines.[61,]

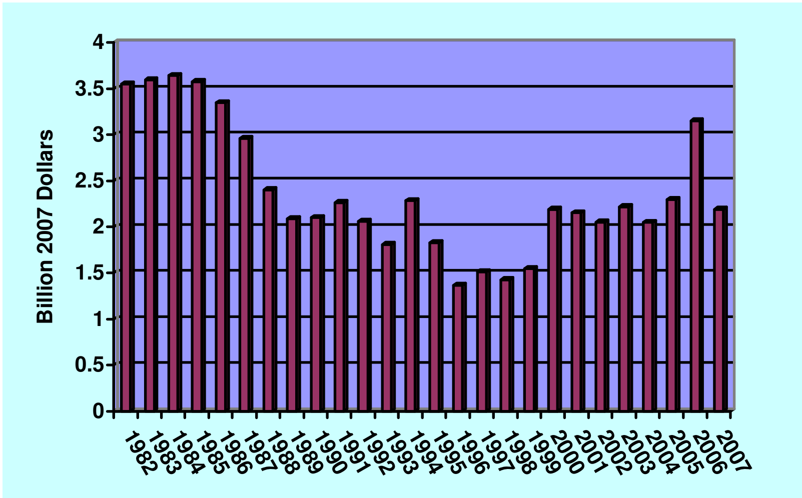
Federal rules also require outreach activities, coordination with DOE's Weatherization Assistance Program, and annual audits. Grantees decide the mix and dollar range of benefits, choose how benefits are provided, and select the agency or agencies responsible for administering the program. In addition to funds used for heating and/or cooling assistance, funds must be set aside by grantees for energy crisis intervention. Fifteen percent of grantees' allotments (up to 25 percent with a waiver) may be used for low-cost residential weatherization or other energy-related home repair.

Payments may be made directly to eligible households or to retail energy suppliers. Assistance may be in the form of cash, vouchers, or payments by the entity administering the program to retail energy suppliers such as utility companies or fuel dealers. In practice, the majority of the funds are paid directly to energy providers. LIHEAP funds are only used by a fraction of eligible participants. In 2004, between 5 and 6 million households were recipients of heating, cooling, and weatherization assistance out of an eligible population of 35.4 million households under the Federal LIHEAP income maximum standard and 24.1 million households under the States' LIHEAP maximum standard.[62]

In the early years of the program, LIHEAP funding averaged around $3.5 billion. Since 1998, annual funding for LIHEAP has ranged from $1.4 billion to $2.4 billion (Figure 3), with the exception of FY 2006 when funding exceeded $3 billion. In 2006, Congress appropriated an additional $1 billion in emergency LIHEAP expenditures due to the spike in energy prices. A portion of the funding was also directed at Gulf Coast States most affected by the Hurricane Katrina.

[60] In 2007, a family with annual income of under $20,000 is considered to fall beneath the Federal Government's poverty level.
[61] Department of Health and Human Services: Low Income Home Energy Assistance Program, LIHEAP Disaster Relief, http://www.acf.hhs.gov/programs/liheap/guidance/special_topics/disaster_relief.html, last updated: January 31, 2006.
[62] Leon Lithow, Lead Program Analyst, Division of Energy Assistance, Low Income Home Energy Assistance Program, November 20, 2007.

Figure 3. LIHEAP Funding, Fiscal Years 1982-2007



Source: Department of Health and Human Services, Low Income Home Energy Assistance Program, http://www.acf.hhs.gov/programs/liheap/funding/approp.html.

The program sought to help lower-income families maintain their standard of living. The aging of the population and increased independence of handicapped persons means that these groups will account for a growing share of LIHEAP payments. In 2002, according to HHS, "of the 4.1 million households receiving heating assistance, approximately 1.4 million households had at least one member 60 years or older; approximately 1 million of these households had at least one child 5 years or under. Some of these households contained both an elderly person and a young child. Although available, State data on households with disabled members are not comparable as each State can use its own definition of 'disabled.'"[63]

Building Technology Assistance Program

Federal appropriations for the DOE conservation program increased from $191 million in FY 1999 to $256 million in FY 2007. DOE provides conservation assistance in a number of areas, primarily through the Building Technology Assistance Program. It complements DOE's R&D efforts and accelerates the deployment of new technologies and the adoption of advanced building practices through technical and financial assistance, outreach, and selective demonstration projects. According to the Office of Energy Efficiency and Renewable Energy, "The Building Technology Assistance Program works to improve the energy efficiency of the nation's buildings through innovative new technologies and better building practices." The Building Technology Assistance Program supports two grant programs: the Weatherization Assistance Program, which provides support for the weatherization of low-income homes, and the State Energy Program, which provides grants to promote innovative State energy efficiency and renewable energy activities.

The Weatherization Assistance Program engages State and local partners to increase the efficiency of homes occupied by low-income citizens who can least afford rising energy bills. The State Energy Program provides grants to State and local governments to create a network for energy efficiency.

[63] Department of Health and Human Services, http://www.acf.hhs.gov/programs/opre/acf_perfplan/ann_per/apr2005/apr_sg3_73.html.

3. Federal Energy Research and Development

The Federal government's role in financing large-scale civilian research and development (R&D) dates back to the late 1940s. The principal landmarks were President Eisenhower's decision to commercialize nuclear energy articulated in his 1953 "Atoms for Peace" speech and the public concern raised by the launch of the Soviet Sputnik satellite in 1957. Since 1949, the largest R&D outlays have been for defense and, to a lesser extent, space and health programs.[64] In the 1980s, total Federal R&D spending rose by more than 100 percent. The growth was primarily associated with defense-related R&D. In the late 1980s, spending on health research also increased in relative importance. During the 1990s, the growth in R&D expenditures was less than in the past. After 2000, R&D outlays have grown rapidly, particularly for defense and health care. According to the Office of Management and Budget (OMB), the FY 2007 appropriations for energy-related R&D (basic and applied research) amounted to about 5 percent of all Federally-funded R&D. Total Federal R&D for fiscal year (FY) 2007 exceeded $125 billion, 60 percent of which was defense-related.

The scale and focus of energy-related R&D expenditures have changed over time (Table 12). In the late 1970s, funding was influenced strongly by the decade's two oil crises. As oil prices abated through much of the 1980s, Federal R&D funding levels fell considerably. Funding levels fell from $6.5 billion in 1978 to $1.2 billion in 1987. Funding levels have picked up since, averaging $1.9 billion to $2.5 billion over the last decade. Since the last EIA subsidy report was released in the year 2000, energy-related R&D expenditures for biofuels, advanced nuclear, and advanced coal technologies have substantially increased. Like the growth in tax expenditures, EPACT2005 has had a significant impact on energy-related R&D expenditures. Due in part to EPACT2005, funding for hydrogen-related R&D grew from zero to $230 million between 1999 and 2007. Title VIII of EPACT2005 authorizes $3.3 billion in hydrogen-and-fuel-cell-related R&D for the period 2006 through 2010. Title IX of EPACT2005 authorized R&D funding for energy efficiency, distributed generation, nuclear energy, and renewable energy. For example, EPACT2005 authorized funding for nuclear-related R&D totaling $2.4 billion over the years 2007 through 2009. Due in part to widespread power outages in the eastern United States during the summer of 2003, EPACT2005 contained provisions directed at improving transmission and distribution system reliability.

Since 1978, funding for energy-related R&D has totaled $75 billion, of which $30 billion has been devoted to nuclear, $20 billion to coal, $13 billion to renewable energy, $4 billion to other fossil fuels, and $8 billion to end-use technologies.

Defining Federal Research and Development

For purposes of this report Federal energy-related R&D is divided into three categories: basic research, research that seeks to develop new energy technologies, and research that enhances existing technologies.

[64] See http:/www.whitehouse.gov/omb/budget/fy2008/pdf/hist.pdf.

Table 12. Summary of U.S. DOE R&D Expenditures, 1978 to 2007 (million 2007 dollars)

Fiscal Year	Renewable Energy	Coal	Other Fossil	Nuclear	End Use	Clean Coal Technology	Total
1978	1,046	1,709	275	2,938	561	0	6,529
1979	1,302	1,685	322	2,614	541	0	6,464
1980	1,367	1,657	203	2,373	413	0	6,011
1981	1,196	1,464	184	2,018	377	0	5,239
1982	588	975	97	1,954	155	0	3,769
1983	454	497	68	1,313	99	0	2,432
1984	346	500	80	1,110	106	0	2,142
1985	328	523	71	702	81	0	1,705
1986	270	504	63	586	61	0	1,484
1987	224	430	55	450	55	0	1,213
1988	253	502	63	422	55	309	1,603
1989	159	383	75	492	64	284	1,457
1990	155	435	78	494	47	796	2,004
1991	223	439	105	463	60	543	1,833
1992	277	513	95	500	54	563	2,002
1993	282	331	122	419	61	0	1,216
1994	355	231	222	441	64	291	1,604
1995	416	224	238	471	61	47	1,456
1996	314	335	208	289	45	185	1,377
1997	289	258	202	980	42	(3)	1,768
1998	300	182	192	1,218	398	(124)	2,166
1999	344	174	218	900	438	(49)	2,024
2000	326	172	244	742	595	(173)	1,905
2001	468	400	150	643	634	120	2,415
2002	317	486	144	570	632	48	2,197
2003	319	482	123	570	603	(52)	2,045
2004	298	535	105	754	498	(106)	2,083
2005	376	511	81	1,124	502	(168)	2,424
2006	356	530	64	1,062	470	(20)	2,462
2007	444	470	0	946	414	0	2,273
Total	13,392	17,537	4,147	29,558	8,186	2,491	75,302

Source: U.S. Department of Energy, Budget Authority History Table by Organization.

Research to Develop New Technologies. R&D expenditures in this category attempt to discover new scientific knowledge for which there is potential for commercial application. Although reaching the point of technology transfer to the private sector for commercialization is the objective this type of R&D, the probability of success is uncertain.

Research to Improve Existing Technologies. These expenditures use scientific knowledge to design and test new processes that may have substantial technical and cost uncertainties. The immediate beneficiaries are generally well defined, i.e., current producers and consumers of particular fuels, or operators and customers of the technology being improved.

Energy Research and Development as a Subsidy

It is easier to measure energy R&D spending than to characterize it as a subsidy. R&D spending is intended to create useful knowledge and develop technologies that have potential commercial benefits to society. Thus, all Federal R&D spending could, in a general way, be considered a subsidy to knowledge and technology. However, the extent to which specific R&D programs actually affect energy markets is more difficult to ascertain.

The results of R&D are inherently uncertain. Many programs are intended to advance knowledge across a range of energy and non-energy applications, rather than in the context of a particular fuel or form of consumption. Furthermore, the knowledge obtained may not be of value, in the sense that the research may only reveal technical or economic dead ends to be avoided in the future.[65] Thus, only a portion of Federal energy R&D is likely to achieve results in the form of changes in energy production costs or consumption that can be attributed to a specific R&D program. Moreover, to the extent that R&D yields commercial technologies, they are likely to be measurable only years after the funded research effort is initiated.

Federal R&D is intended to support research that the private sector will not undertake. It is not supposed to substitute for private sector R&D. However, the creation of a Federally-funded R&D program could, under some circumstances, displace private-sector R&D. In that case, the Federal program would not produce new knowledge that could not be developed by the private sector, but would simply reduce private R&D costs. It is impossible to know with certainty what R&D private-sector firms would have performed in the hypothetical absence of a Federal program. In general, the less "basic" the R&D program and the more focused on near-term commercialization, the greater the risk that the program will be a substitute for private-sector R&D. As R&D projects approach commercial viability, the justification for government participation lessens.[66]

Federal government energy-related R&D spending often represents a first stage of Federal intervention in energy markets. The rationale for government intervention in technology development lessens as products approach commercialization, because private investors at later stages of product development face fewer barriers towards successful commercialization. Other forms of Federal interventions in energy markets may complement the preliminary work done at the R&D stage.

For example, in promoting planned construction of advanced nuclear power, recent Federal intervention has involved new programs and changes to programs already in place. While this chapter describes Federal interventions supporting nuclear-related R&D, other chapters and the appendix to this report describe nuclear-related Federal energy interventions as they relate to tax expenditures, such as EPACT 2005's nuclear production tax credit, or loan guarantees, construction insurance, enhanced accident insurance, and regulatory changes. The combination of these programs suggests that the nuclear industry, in order to expand, faces several difficult hurdles, technological advancement being only one. For instance, preapproved technologies may reduce some of the regulatory risk associated with the

[65] Several studies suggest that the return on overall Federal R&D investment is much lower than the return on private-sector R&D, implying relatively high failure rates. See, Terlecyyj, N., "Effects of R&D on the Productivity Growth of Industries: An Exploratory Study (Washington, DC: National Planning Association, 1974), and Griliches, Z., "Returns to R&D in the Private Sector," in Kendrick, J. and Vaccara, B. (eds.), "New Developments in Productivity Measurement and Analysis," NBER Studies in Income and Wealth No. 44 (Chicago, IL: University of Chicago Press, 1980), pp. 419-454. This result need not be surprising, as the Federal Government's research portfolio may be much riskier than the private sector's.

[66] One recent study, "Energy Research at DOE: Was It Worth It? Energy and Fossil Energy Research 1978 to 2000," concluded that: "DOE's R&D programs in fossil energy and energy efficiency have yielded significant benefits (economic, environmental, and national security-related), important technological options for potential applications in a different (but possible) economic, political and/or environmental setting, and important additions to the stock of engineering and scientific knowledge in a number of fields." The committee also found that DOE has not employed a consistent methodology for estimating and evaluating the benefits from its R&D programs in these and presumably other areas." National Research Council Committee on the Benefits of DOE R&D on Energy Efficiency and Fossil Energy, Washington, DC: National Academy Press (2001), p. 5.

construction of new nuclear power plants. Potential investors in new nuclear power units may also need assurances that sufficient economies of scale will be undertaken so as to make new builds financially viable and that any construction delays will not result in financial losses and abandoned projects. However, most Federal government programs directed at reviving nuclear power have sunset provisions which are intended to become effective as advanced nuclear power becomes a commercially viable investment.

Therefore, tax expenditures directed toward developers, manufacturers, and end-use consumers of emerging technologies may act as a substitute for Federal R&D programs, allowing manufacturers (and others) to gather useful information and introduce modifications to improve performance and reliability, and lower costs. In the end, there are no means to determine conclusively whether or not particular Federal energy R&D projects are substitutes or complements for private-sector activities. Moreover, because research is risky, with the prospects of failure an inherent part of the process, the effectiveness of Federal R&D cannot easily be assessed. This report makes no judgments on either of these issues. Rather, it surveys the current composition of Federal R&D spending and provides an historical perspective on changes in the composition of Federal energy R&D efforts in response to changes in national priorities. Because Federal energy R&D programs may sponsor both fuel-consuming capital equipment, particularly power generation technologies, and fuel production technologies, e.g., biofuels, Federal R&D may produce conflicting benefits. Such projects may be more properly viewed as a subsidy to capital equipment manufacturers, rather than to fuel producers or consumers. Because generation technologies aided by Federal R&D may become more energy efficient, they will only benefit producers if they help to expand the market for their fuel. Thus, if one seeks to understand the effects, rather than the intent, of R&D spending, the success of the programs must be evaluated with the understanding that considerable time and resources may be expended as a new technology moves from the R&D stage through demonstration to commercialization. Only then can the full consequences of any new technologies be ascertained.

Finally, much of what is defined as energy R&D in the Federal government's budget accounts is not directly expended on energy research or development. Rather, a portion of the funds are expended on environmental restoration and waste management associated with the byproducts of energy-related research facilities, e.g., nuclear waste disposal.

Energy Research and Development Trends

Currently, about 57 percent ($3.8 billion) of total Federal energy R&D is allocated to basic research. DOE's largest basic research outlay is the General Science Program, funded at $1.9 billion in FY 2007. This program supports research and operates facilities to provide the foundation for new and improved energy technologies. This program also provides funding for understanding environmental impact of these technologies. Basic Research also includes the Fusion Energy Sciences Program which is funded at $319 million in FY 2007. It is the National research effort to advance plasma science, fusion science, and technology needed for a fusion energy source in the future. Basic research is difficult to characterize as an energy subsidy because it cannot be allocated between energy and non-energy benefits or among forms of energy. Therefore, these programs, including Fusion Energy Sciences, are not included as subsidies in this analysis.

The balance of this chapter focuses on applied energy R&D. Federal energy R&D that is unrelated to basic research, or Applied R&D, accounts for $2.8 billion (Table 13). This includes energy programs in the FY 2007 DOE Operating Plan, as well as energy programs in other Federal agencies.

Table 13. Federal Energy R&D by Type and Function (million 2007 dollars)

R&D Program Category	FY 1999 Appropriation	FY 2007 Operating Plan
Basic R&D		
General Science	1,968	1,942
General Energy Science	996	1,292
Environment, Safety, and Health	57	28
Other Allocated	60	250
Fusion Energy Sciences	270	319
Basic R&D Sub Total	3,352	3,831
Applied R&D		
Coal	489	574
Natural Gas and Petroleum Liquids	198	39
Nuclear Power	740	922
Renewable and Other Electric Technologies	587	867
End Use	487	418
Applied R&D Sub Total	2,500	2,819
Total	5,853	6,650

NOTE: Total may not equal sum of components due to independent rounding.

Sources: U.S. Department of Energy FY 2007 Operating Plan by Appropriation; Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy*, SR/OIAF/99-03 (Washington, DC, September 1999); *Federal Financial Interventions and Subsidies in Energy Markets 1999: Energy Transformation and End Use*, SR/OIAF/2000-02, (Washington, DC, May 2000).

Applied R&D focuses on turning knowledge and concepts into useful products. Applied energy R&D expenditures are about $2.8 billion in FY 2007. The largest programs are the renewable technologies ($905 million)[67] and nuclear power ($922 million). Funding for coal is $574 million. Natural gas and petroleum liquids are funded at about $39 million for geologic assessments and expenses incurred in connection with the phase-out of existing programs.

The largest funding category for renewables technologies is for biofuels and biomass ($246 million) followed by hydrogen technologies (Table 14). The hydrogen technologies program, which did not exist when EIA prepared its report in 1999, is funded at $230 million in FY 2007.[68] Solar programs are funded at $187 million. These renewable programs, unlike others, such as wind, are not yet considered commercially viable because of cost and performance issues. Technologies receiving smaller funding levels include wind ($58 million) and geothermal ($6 million). There are no R&D funds allocated to hydropower for FY 2007. Geothermal R&D funding was $35 million in FY 1999, compared to $6 million in FY 2007. The Electricity Delivery and Energy Reliability programs have increased from $54 million in FY 1999 to $140 million in FY 2007. The Nuclear Power program includes new nuclear plants ($319 million), Waste/Fuel and Safety ($350 million), and Program Direction and Termination Costs ($253 million). These programs are discussed in more detail in the balance of this chapter.

[67] Technical system reliability R&D totaling $137 million is included in this portion of Applied R&D. It is classified as "Electricity" in the Executive Summary and Chapter 5.
[68] Although hydrogen R&D programs are not renewables, they are included here because they are administered by the DOE Office of Energy Efficiency and Renewable Energy.

Table 14. Renewables and Other R&D Expenditures (million 2007 dollars)

R&D Program	FY 1999 Appropriation	FY 2007 Operating Plan
Wind	42	58
Solar	120	187
Hydrogen Technology	-	230
Biofuels and Biomass	116	246
Geothermal	35	6
Hydroelectric	4	-
Other Allocated	95	-
Total Renewables	412	727
Electricity Deliverability and Energy Reliability	54	140
Total	466	867

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: U.S. Department of Energy FY 2007 Operating Plan by Appropriation, U S Department of Agriculture, *FY 2007 Budget Summary and Annual Performance Plan*, pp. 32 and 78; Defense Logistics Agency, The Defense Logistics Agency Hydrogen and Fuel Cell Program, September 12, 2007, leo.plonsky@dla.mil; http://www.rita.dot.gov/agencies_and_offices/research/hydrogen_portal/. Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy*, SR/OIAF/99-03 (Washington, DC, September 1999); *Federal Financial Interventions and Subsidies in Energy Markets 1999: Energy Transformation and End Use*, SR/OIAF/2000-02, (Washington, DC, May 2000),

Federal Energy R&D Subsidies to Renewable and Other Technologies

Renewable R&D

The Office of Energy Efficiency and Renewable Energy (EERE) conducts research, development, and deployment activities in partnership with industry to advance a diverse supply of reliable and affordable, efficient and clean power technologies.[69] The FY 2007 budget emphasizes research on alternatives that are intended to reduce the Nation's dependence on foreign oil and accelerate development of clean electricity supply options.

The Hydrogen Technology program, created by EPACT2005, focuses on hydrogen production, delivery, storage, and fuel cell technologies. This program supports the Bush Administration's 5-year, $1.2-billion Hydrogen Fuel Initiative intended to reverse America's growing dependence on foreign oil by accelerating the development of hydrogen fuel cell vehicles and infrastructure technologies. The program is intended to enable a commercialization decision by industry on fuel cell vehicles and hydrogen infrastructure by 2015. A positive commercialization decision in 2015 could lead to the introduction of hydrogen fuel cell vehicles in the market by 2020. The responsibility for implementing the Hydrogen Fuel Initiative rests with a number of organizations. Basic hydrogen research is managed by the Office of Science. The Office of Fossil Energy oversees coal-based hydrogen production research. Nuclear-based hydrogen production research resides with the Office of Nuclear Energy, Science and Technology. The Department of Transportation manages activities related to hydrogen safety. The fuel cell program is under the direction of the Defense Logistics Agency of the Department of Defense.

[69] The text in this section is extracted from the Department of Energy FY 2007 Congressional Budget Request Budget Highlights DOE/CF-009.

The Biomass and Biorefinery Systems R&D program includes a new Departmental Initiative that is funded at $234.2 million and a program at the United States Department of Agriculture (USDA) funded at $12 million in FY 2007. The DOE Biofuels Initiative is intended to accelerate research, development, and deployment of industrial-scale biorefinery operations. The program focuses on three areas: (1) Platforms R&D, to reduce the cost of outputs and byproducts from biochemical and thermochemical processes; (2) Utilization of Platform Outputs, to develop technologies and processes that co-produce liquid and gaseous fuels, chemicals and materials, and/or heat and power, and integrate those technologies and processes into biorefinery configurations; and, (3) Feedstock Infrastructure, to develop cost-effective biomass harvesting, storage and delivery systems, and to develop energy crops suitable for diverse regions and climates.

There is also funding for Biomass Research and Development within the USDA Natural Resources Conservation Service that is coordinated with the DOE Biofuels Initiative.[70] The funding level for FY 2007 is $12 million. The total funding for the DOE and USDA programs is $246.2 million in FY 2007. Biofuels and bioenergy research performed by USDA, including the Agricultural Research Service, are included in Renewable R&D expenditures. Biofuels and bioenergy R&D within the USDA Research, Education and Extension Mission Area excluding the $12 million are reported in Table 14. This additional funding totaled $29 million in FY 2007 (see Table 17).

The Solar Energy program is funded at $186.9 million in FY 2007. It focuses on R&D to enable cost-effective development of solar power that will reduce the demand for natural gas during peaking hours and promote a cleaner environment. Through DOE's new Solar America Initiative (SAI), the Solar Program is intended to help accelerate the competitiveness of solar electricity from photovoltaic (PV) systems. Under the SAI, industry-led teams will compete to deliver future PV systems that are less expensive, more efficient, and highly reliable. By focusing on PV technology manufacturing issues while advancing systems integration, SAI intends to promote deployment of 5 to10 gigawatts (GW) of new grid-connected solar electricity generating capacity by 2015. The Solar Energy programs also focus on lowering the cost of solar power through larger-scale centralized generation.

The Wind Energy program is funded at $57.8 million in FY 2007. This program develops and promotes the use of advanced technologies to harness kinetic wind energy. The program is developing low wind speed utility scale technology through leveraged partnerships with industry to substantially increase the economically viable wind resource base across the country. The program explores innovative applications that will open new markets for wind technology, including offshore development.

Since 1974, the Geothermal Technology program has worked in partnership with U.S. industry to establish geothermal energy as an economically-competitive contributor to the U.S. energy supply. DOE planned to conclude the Geothermal Technology program in FY 2007 and transfer program R&D results to industry and State and local governments. The program is funded at $5.9 million in FY 2007. However, the program was funded in DOE's FY 2008 budget at $20 million, with an additional request for $30 million in FY 2009. In 2006, the Massachusetts Institute of Technology (MIT) issued a DOE-sponsored study in which MIT researchers concluded that enhanced geothermal systems could provide 100 gigawatts (GW) or more of

[70] U.S. Department of Agriculture, Fiscal Year 2007 Budget Summary and Annual Performance Plan, p. 78.

cost-competitive geothermal generating capacity over the next 50 years with a reasonable amount of R&D investment.[71]

Electricity Delivery and Energy Reliability R&D

The Office of Electricity Delivery and Energy Reliability (OE) leads the national effort to modernize and expand the U.S. electricity delivery system to ensure a reliable and robust electricity supply. In addition to its policy and regulatory functions, OE is engaged in a variety of R&D initiatives related to transmission and distribution reliability, technology, and system control. FY 2007 funding totals $140 million for the following programs (Table 14).

The High Temperature Superconductivity R&D program is intended to pursue improvements in the efficiency and reliability of the Nation's electric delivery system. The goal of this research is to develop by 2016 operational wire and power prototypes that are physically smaller than current infrastructure and deliver energy with half of the losses of conventional equipment with the same power rating.

The Visualization and Controls R&D program is intended to develop communication and control systems that support adaptive, intelligent grid operations, which integrate distributed energy devices. These advances will improve electric delivery system reliability and maximize efficiency by increasing the use of transmission and distribution assets.

The Energy Storage and Power Electronics R&D program pursues advancements that reduce the adverse effects of electricity disturbances.

The Distributed Energy R&D program aims to develop a diverse array of cost-competitive, integrated distributed-generation and thermal energy technologies. It also supports the use of these technologies in residential, business, and industrial applications to improve electricity reliability and reduced negative environmental impacts. The FY 2007 program consists of three activities: Research and Development Permitting, Siting and Analysis, and Infrastructure Security and Energy Restoration.

The Permitting, Siting and Analysis subprogram supports Federal initiatives authorized in EPACT2005, including a national analysis of electric transmission congestion, the designation of national interest electric transmission corridors, and the designation of multi-purpose energy corridors on Federal lands.

Direct Thermal to Electric Conversion program is conducted by the Defense Advanced Research Projects Agency (DARPA). The program focuses on research to significantly reduce the gap between practically-achievable thermal to electric conversion efficiencies and theoretically-achievable thermodynamic efficiencies. The program is funded at $2.5 million in FY 2007. Table 14 includes the aggregate of funding for Electricity Deliverability and Energy Reliability among OE's R&D programs. FY 2007 funding is nearly three times the FY 1999 funding level.

Federal Energy R&D Subsidies to Nuclear Energy

DOE's Office of Nuclear Energy, Science and Technology (NE) mission is to develop new nuclear energy generation technologies to meet energy and climate goals; develop advanced, proliferation-resistant nuclear fuel technologies that maximize energy from nuclear fuel; and

[71] Massachusetts Institute of Technology, prepared under Idaho National Laboratory Subcontract No. 6300019 for the U.S. Department of Energy, Assistant Secretary for Energy Efficiency and Renewable Energy, Office of Geothermal Technologies, ISBN: 0-615-13438-6, 2006.

maintain and enhance the national nuclear infrastructure. DOE's nuclear energy R&D program collaborates with international research communities in planning and conducting applied research to further the course of nuclear technology advancement.

Through the Advanced Fuel Cycle Initiative, DOE seeks to develop advanced, proliferation resistant nuclear fuel technologies that maximize the energy produced from nuclear fuel while minimizing resulting wastes. Associated with this program, the Global Nuclear Energy Partnership (GNEP) aims to further provide for the expansion of nuclear power plants in the United States and around the world, in addition to promoting nuclear nonproliferation goals and helping resolve nuclear waste disposal issues.

NE is funded in two accounts within the Energy and Water Development Appropriations: Energy Supply and Conservation and Other Defense Activities. All funding for R&D and landlord activities for the Idaho National Laboratory (INL) is included in the Energy Supply and Conservation account. Funding for Safeguards and Security is within the Other Defense Activities account. DOE received an appropriation of $922 million for civilian nuclear R&D in FY 2007 (Table 15). Nearly 40 percent of the appropriation ($350 million) is allocated to the cleanup of contaminated nuclear energy and research sites.[72]

Table 15. Nuclear Power R&D Expenditures (million 2007 dollars)

R&D Program	FY 1999 Appropriation	FY 2007 Operating Plan
New Nuclear Plants (Nuclear Energy Research Initiative)	36	319
Waste/Fuel/Safety (Environmental Management)	530	350
Other Allocated (Termination Costs and Program Direction)	173	253
Total	740	922

NOTE: Totals may not equal sum of components due to independent rounding. Space and defense infrastructure and medical isotopes infrastructure programs are not included in this table.

Source: U.S. Department of Energy FY 2007 Operating Plan by Appropriation.

Improving Existing Power Plants and Enhancing Nuclear Power

DOE created the Nuclear Energy Research Initiative (NERI) to address and help overcome the technical and scientific obstacles to the future use of nuclear energy in the United States. NERI is also expected to help preserve the nuclear science and engineering infrastructure within the Nation's universities, laboratories, and industry to advance the state of nuclear energy technology and to maintain a competitive position worldwide.

The FY 2007 allocation of $319 million supports innovative applications of nuclear technology to develop new nuclear generation technologies and advanced energy products. It is also supporting the development of advanced proliferation-resistant nuclear fuel technologies that maximize energy output, and maintain and enhance national nuclear capabilities (Table 15). The Advanced Fuel Cycle Initiative (AFCI), which is integral to the Generation IV Nuclear Energy Systems effort, aims to develop a better, more efficient and proliferation-resistant nuclear fuel cycle. This R&D program is focusing on methods to reduce the volume and long-term toxicity of high-level waste from spent nuclear fuel, reduce the long-term proliferation threat posed by civilian inventories of plutonium in spent fuel, and provide for proliferation-

[72] U.S. Department of Energy Fiscal Year 2007 Operating Plan by Appropriation.

resistant technologies to recover the energy content in spent nuclear fuel. The focus of this initiative will be Global GNEP, which consists of 16 member nations which promote the expansion of peaceful applications of nuclear power.[73]

GNEP is intended to accelerate the work being done under the AFCI program. Advanced recycling technologies can extract highly radioactive elements of commercial spent nuclear fuel and use that material as fuel in fast spectrum reactors to generate additional electricity. The extracted material, which includes all transuranic elements (e.g., plutonium, neptunium, americium and curium), would be consumed by fast breeder reactors to significantly reduce the quantity of material requiring disposal in a repository. The plutonium would remain bound with other highly radioactive isotopes, thereby improving its proliferation resistance and reducing security concerns. With the transuranic materials separated and used for fuel, the volume of waste that would require disposal in a repository whose size would be reduced by 80 percent.

The Nuclear Power 2010 program operating plan is funded at $80.3 million in FY 2007 for purposes of obtaining three early site permits by the NRC. In addition, the program will complete the industry cost-shared project initiated in FY 2003 to develop generic guidance for the Construction and Operating License (COL) application preparation, to resolve generic COL regulatory issues, and to continue the implementation phase of the two New Nuclear Plant Licensing Demonstration Projects awarded in FY 2005.

The goal of the Generation IV Nuclear Energy Systems Initiative (Gen IV) is to address the fundamental R&D issues necessary to establish the viability of next-generation nuclear energy system concepts. The 2007 budget provides $35.6 million for the Gen IV initiative to expand R&D that could help achieve the desired goals of sustainability, economic feasibility, and proliferation resistance. The Nuclear Hydrogen Initiative (NHI), with funding of $19.3 million, intends to conduct R&D on enabling technologies, and develop technologies that will apply heat from Generation IV nuclear energy systems to produce hydrogen through electrolysis. The budget level for nuclear R&D in FY 2007 is 25 percent greater than it was in FY 1999. A substantial part of the increase is for the Nuclear Energy Research Initiative which increased by $283 million compared with FY 1999.

Environmental Management

A substantial portion of Federally-funded nuclear R&D is used for managing and addressing the environmental legacy resulting from past nuclear energy and research activities. Thousands of contaminated areas and buildings exist throughout the United States. The goal of the program is to decommission. Upon completing the clean up of these facilities, DOE's presence and associated costs will be limited to long-term surveillance and maintenance.

Other Allocated Expenditures

Other allocated expenditures amount to $253 million in FY 2007 (Table 15). The largest portion of this amount is for Idaho facilities management and safeguards and security ($190 million). The Idaho Facilities Management program provides site-wide infrastructure needed to support R&D while the Safeguards and Security Program protects DOE interests. The remaining $62.6 million is allocated to nuclear energy program direction, which provides Federal staffing resources and associated funding required to execute DOE's nuclear energy program.

[73] GNEP member countries include the United States, Australia, Bulgaria, China, France, Ghana, Hungary, Japan, Jordan, Kazakhstan, Lithuania, Poland, Romania, Russia, Slovenia, and the Ukraine.

Federal Energy R&D Subsidies to Coal

The Fossil Energy Research and Development program started in the late 1980s. The program goal is to ensure that economic benefits of moderately-priced coal-fired generation are compatible with public expectations for environmental quality with the intent of achieving energy security derived from reliance on abundant domestic coal-resources. The program pursues these goals by: (1) managing and performing energy-related research that reduces market barriers to the reliable, efficient, and environmentally sound use of fossil fuels for power generation and conversion to other fuels such as hydrogen; (2) partnering with industry and others to advance the commercialization of clean and efficient fossil energy technologies; and, (3) supporting the development of information and policy options that benefit the public by ensuring access to adequate supplies of affordable and clean energy.[74]

EPACT2005 Section 962 directs DOE to conduct a coal and power systems research, development and demonstration program to facilitate the production and generation of coal-based power. Cost and performance goals are to be established to insure the continued competitiveness for electricity generation, transportation fuel, and chemical feed stocks. Section 963 establishes a program for carbon capture technologies to be used in conjunction with combustion based systems with the intent of reducing future greenhouse gas emissions. Table 16 compares FY 1999 and FY 2007 expenditures for DOE's Office of Fossil Energy coal R&D program.

Table 16. Coal R&D Expenditures (million 2007 dollars)

R&D Program	FY 1999 Appropriation	FY 2007 Operating Plan
Clean Coal Power Initiative	106	61
Advanced Clean Fuels	19	-
Future Gen Advanced Clean Fuels	-	54
Fuel and Power Systems	24	311
Clean Coal Technology Adjustment	222	-
Other Allocated	118	148
Total	489	574

NOTES: Totals may not equal sum of components due to independent rounding.
The Clean Power Initiative was previously referred to as Advanced Clean Efficient Power Systems. Advance Clean Fuel funding now falls under Fuel and Power Systems. Source: U.S. Department of Energy FY 2007 Operating Plan by Appropriation.

The program focuses on near-zero atmospheric emissions coal-based electricity and hydrogen production. The President's Coal Research Initiative is aimed at meeting these objectives. The programs included in this initiative are the Clean Coal Power Initiative (CCPI), FutureGen, and Fuel and Power Systems. The total FY 2007 appropriation for the R&D program is $574 million.

The CCPI is a cooperative, cost-sharing program between the Federal government and industry intended to demonstrate emerging technologies in coal-based power generation. The objective of CCPI is to collaborate with the Nation's power generators, equipment manufacturers, and coal producers to help identify the most critical barriers to using coal in the power sector. Technologies will be selected with the goal of accelerating development and commercial deployment of coal technologies that will economically meet environmental standards.

[74] The Department of Energy Fiscal Year 2007 Congressional Budget Request Budget Highlights, DOE/CF-009.

FutureGen aimed to establish the capability and feasibility of co-producing electricity and hydrogen from coal with near-zero atmospheric emissions. Carbon sequestration is an integral component of the project.[75] FutureGen is intended to employ a public/private partnership aiming to demonstrate technology with the goal of developing near-zero atmospheric emission plants that are fuel-flexible and capable of multi-product output with electrical efficiencies of over 60 percent. The cost of the electricity produced is to amount to no more than a 10-percent increase over comparable plants, without carbon sequestration, that use coal, biomass, or petroleum coke. The project is intended to retain the strategic value of coal.

The Fuel and Power Systems program provides funding for research in connection with FutureGen. The Fuel and Power System program focuses on how to reduce coal power plant emissions, especially mercury, and significantly improve efficiency in terms of carbon emissions per unit of electricity produced, leading to a viable near-zero atmospheric emissions coal energy system.

The Innovations for Existing Plants (IEP) program focuses on the near-to-mid-term task of retrofitting existing power plants to improve overall power plant efficiency and develop advanced cost-effective environmental control technologies. It focuses on reducing mercury emission and other coal technologies, including those developed in the FutureGen project that can be deployed when retrofitting existing power plants.

The Integrated Gasification Combined Cycle (IGCC) program continues the development of technologies for gas stream purification to meet quality requirements for use with fuel cells and conversion processes. The program also focuses on impurity tolerant hydrogen separation technology, enhanced process efficiency, and reductions in costs, including energy required to produce oxygen for gasification.

The Advanced Turbines program focuses on creating the technology base for turbines that will permit the design of near-zero atmospheric emission IGCC plants and a class of FutureGen plants with carbon capture and sequestration. The Advanced Turbine program research focuses on developing technology for high-efficiency hydrogen and syngas turbines for advanced gasification systems to be incorporated in FutureGen plants.

The Carbon Sequestration program is developing a portfolio of technologies with potential to reduce greenhouse gas emissions. The program focuses on developing capture and separation technologies that may dramatically lower the costs and energy requirements for reducing carbon dioxide emissions from fossil-based (especially coal) power plants. The program goal is to research and develop a portfolio of safe and cost-effective greenhouse gas capture, storage, and mitigation technologies by 2012.

The mission of the Advanced Clean Fuels program is to conduct the research necessary to promote the transition to a hydrogen economy. Research will target cost reduction and increased efficiency of hydrogen production from coal feedstocks.

[75] The prospects of the FutureGen grew uncertain when, in January 2008, the U.S. Department of Energy announced that it intended to restructure FutureGen. The DOE's new FutureGen vision called for "Federal-funding to demonstrate cutting edge CCS (Carbon Capture and Storage) at multiple commercial-scale integrated gasification combined-cycle (IGCC) demonstration plants…Under this new approach multiple plants would produce at least 3000 megawatts of electricity and jointly these projects will capture and safely sequester at least double the amount of carbon dioxide annually compared to the concept announced in 2003." Source: DOE, Fact Sheet, "DOE to Demonstrate Cutting-Edge Carbon Capture and Sequestration Technology at Multiple FutureGen Clean Coal Projects." The DOE cited higher than expected costs for the restructuring. The DOE also stated that the program would be revamped so that DOE would only fund the carbon sequestration element of the program. The restructuring cast strong doubts over whether the prototype plant, selected in December 2007 for Mattoon, Illinois, would continue.

Advanced Research projects seek a greater understanding of the physical, chemical, biological, and thermodynamic barriers that limit the use of coal and other fossil fuels. The program funds two types of activities. The first includes applied research programs to develop the technology base needed for the development of super clean, high efficiency coal-based power and coal-based fuel systems. The second is a set of crosscutting studies and assessment activities in environmental, technical and economic analyses, coal technology export, and integrated program support.

The objectives of the Fuel Cells program are to provide for the development of low-cost, scalable fuel flexible fuel cell systems that can operate in central, coal based power systems in distributed or dispensed generation applications.

The Other Allocated funding includes several other expenditures, the largest of which is program direction funded at $125.6 million in FY 2007. Other expenditures include plant and capital equipment, fossil energy environmental restoration, and special recruitment programs. The total funding for this category in FY 2007 is $148 million (Table 16).

The overall funding for coal R&D in FY 2007 has increased by $85.1 million compared with FY 1999. The largest increase is in Fuel and Power Systems which has increased by $287 million. About one-third of the increase in this program is R&D for carbon sequestration.[76]

Federal Energy R&D Subsidies to Natural Gas and Petroleum Liquids

The United States relies on fossil fuels for approximately 85 percent of the energy it consumes. EIA's *Annual Energy Outlook 2008 (Revised Early Release)* forecast projects that reliance on fossil fuels will modestly decline to 82 percent by 2030.[77] To address this situation, the Natural Gas and Petroleum Liquids program promotes the development of environmentally-sensitive and economically-efficient fossil fuel energy systems for the benefit of current and future energy users. R&D funding for oil and natural gas is $39 million in FY 2007 (Table 13).

The United States Geological Survey (USGS) is funded at $20.1 million in FY 2007 to conduct research to enhance exploration, development, and production of oil, natural gas, coal, and other resources such as geothermal. EPACT2005 calls for a focus on all energy sources with an emphasis on assessment of geothermal resources and alternative energy sources such as gas hydrates and oil shale. Section 351 of EPACT2005 directed USGS to create the Preservation of Geological and Geophysical Data Program to rescue, curate, and preserve materials and data related to energy and minerals. Section 351 also directs USGS to assess the oil and gas underlying Federal lands in the United States.

DOE's FY 2007 oil research efforts are funded at $3.5 million for management costs associated with the closeout of the program. The program addressed new technologies that improve exploration, drilling, reservoir characterization, and extraction. Similarly, the Natural Gas Program received $15.4 million in FY 2007 for the closeout of the program. It focused on natural gas research and fuel cells.

Federal Subsidies to End Use Energy R&D

The End Use Energy program develops technologies, techniques, and tools for making residential and commercial buildings more energy efficient, productive, and affordable. The

[76] Although there is no legislation mandating reductions in carbon dioxide emissions, the carbon sequestration program is included because it meets the definition of a subsidy used in this analysis.
[77] Energy Information Administration, *Annual Energy Outlook 2008 (Revised Early Release)*, DOE/EIA-0383 (2008) (Washington, DC, March 2008), Year-by-Year Reference Case Table 1, http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

portfolio of activities includes: (1) efforts to improve the energy efficiency of building components and equipment; (2) advancement of solid state lighting technologies for general illumination; (3) integration of advanced light systems using whole-building-system-design techniques; (4) development of energy efficient building codes and equipment standards; and (5) integration of clean renewable energy systems into building design and operation.

The Building Technologies Program works in partnership with States, industry, and, particularly, manufacturers, to improve the energy efficiency of buildings. Through new technologies and systems-engineered building practices, the design, construction, and operation of approximately 15 million new buildings projected to be constructed by 2015 is expected to be improved. Funding for this program was $103 million in FY 2007 (Table 17).

Table 17. Federal Funding for End-Use R&D (million 2007 dollars)

R&D Program	FY 1999 Appropriation	FY 2007 Operating Plan
Building Technology, State and Community Programs	117	103
Industrial Sector	201	66
(Less Advanced Turbine Systems)	(121)	-
Industrial Sector Net	80	66
Vehicle Technologies	245	221
Research, Education and Extension Service (USDA)	-	29
Other Allocated (Policy and Management)	46	-
Total	487	418

NOTE: Totals may not equal sum of components due to independent rounding.

Source: U.S. Department of Energy FY 2007 Operating Plan by Appropriation.

The program advances the R&D of energy-efficient building technologies and practices for both new and existing residential and commercial buildings. It works with State and local regulatory groups and others to improve building codes, appliance and equipment standards, and guidelines for efficient energy use and promotes market transformation by educating homeowners, builders, and developers about the returns they can achieve by adopting energy-efficient technologies and practices.

The Industrial Technologies program focuses on reducing the energy intensity of the U.S. industrial sector through a coordinated program of R&D, validation, and dissemination of energy-efficiency technologies and best practices. During FY 2007, activities with specific industries (forest products, glass, metal casting, aluminum, mining, chemicals, and supporting industries) and crosscutting activities (materials and Industrial Assessment Centers) were aimed at focusing on the successful completion of existing projects with the highest potential energy efficiency gains and environmental benefits. New projects were selected that were unlikely to be undertaken without Federal support, and that significantly were expected to reduce energy intensity, consistent with DOE's R&D Investment Criteria.[78] Funding for this program was $66 million in FY 2007.

The Vehicle Technologies program supports the FreedomCAR and Fuel Partnership and the 21st Century Truck Partnership, to enable light- and heavy-duty highway transportation to become more fuel efficient. Technology research includes advanced lightweight materials,

[78] Pursuant to President Bush's Management Agenda, the three primary criteria applicable to all R&D programs are relevance, quality, and performance. See Memorandum for the Heads of Executive Departments and Agencies, Executive Office of the President Office of Management and Budgets, M-05-18, July 8, 2005.

advanced batteries, improved power electronics, electric motors, and advanced combustion engines and fuels. These technologies are intended to contribute to reducing oil consumption. In FY 2007, the program is increasing research on technologies needed for cost-effective plug-in hybrid vehicles. At $221 million, the Vehicle Technologies program accounted for more than half of end-use R&D funding in FY 2007.

4. Federal Electricity Programs

Introduction

The Federal government provides Federal utilities and electric utilities (primarily cooperatives), participating in the RUS electric program, access to capital at reduced interest rates resulting from Federal government support. The Federally-owned utilities include the Tennessee Valley Authority (TVA) and the four Power Marketing Administrations (PMAs), the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA).[79] Even though Federal ownership is not a factor, lending subsidies provided through the RUS loan programs are included due to the advantages that these programs provide to eligible borrowers.

Federal Power Programs

Federal utilities are a conduit for and not the ultimate beneficiaries of low-cost capital. The customers for whom they have a statutory obligation to serve are the primary beneficiaries of low-cost Federal power, the price of which includes capital cost recovery. They are generally cooperatives and government-owned utilities (State and local) that resell the power to their customers at cost. These benefits derive from the Federal utilities' ability to borrow directly from the Treasury, sell bonds to the public in the case of TVA, or assume payment of debt obligations of third parties in the case of BPA, at interest rates that reflect investors' perception that such obligations are guaranteed by the Federal government. Even though TVA and BPA bond issuances state that no Federal government guarantees exist, the Nationally Recognized Statistical Rating Organizations, i.e., credit rating agencies recognized by the Securities and Exchange Commission, indicate that perceived implicit Federal government support and the ability to borrow from the Treasury enhances their creditworthiness. However, due to the less than unconditional nature of this support, this report refers to Federal utilities' advantaged access to capital as "support" rather than "subsidy."

In the early years of Federal power, its proponents asserted that publicly-supported electricity was essential in order to electrify large parts of rural America. Critics at the time argued that Federal power was a subsidy provided by urban taxpayers to rural areas.[80] For example, investor-owned utilities (IOU) mounted a legal challenge to the creation of the TVA out of competitive concerns.[81] Moreover, the original and primary purpose of TVA, BPA, and the smaller PMAs, as utilities, was to market the surplus output of hydroelectric facilities that was incidental to flood control, navigation, and irrigation operations. In the early years of their operations, however, the provision and marketing of electricity has evolved as a core function of TVA, BPA and the smaller PMAs.

Federal utilities do not directly service residential or commercial customers. They make wholesale sales to municipals and cooperatives and some direct sales to large industrial customers. In 2006, TVA, for instance, sold 87 percent of its power to municipalities and

[79] The United States Department of Interior, Bureau of Indian Affairs owns or has interests in irrigations projects primarily engaged in irrigation that also provide electric service on Indian Reservations. See NEOS Corporation," Draft Final Report: Tribal Authority Case Studies: The Conversion of on-Reservation Electric Utilities to Tribal Ownership and Operation," prepared for the Western Area Power Administration, Contract No. DE-AC65-91WA07849, January 1996. Any subsidies that may exist with respect to these government-owned projects are excluded from the analysis because their primary purpose is agricultural irrigation, not electricity production.

[80] Shapiro, D. "Public Power Policy: The Controversial Origins," in Generating Failure (New York, NY: University Press of America, 1989).

[81] In Ashwander v. Tennessee Valley Authority, 297 U.S. 288 (1936) minority shareholders of the Alabama Power Company claimed that TVA lacked the authority to sell its energy and that the creation of the TVA was unconstitutional. The Supreme Court upheld the constitutionality of TVA's (i.e., the Federal Government's) right to dispose of electricity and property (in this case, the sale of surplus electricity by TVA and the purchase of transmission lines from Alabama Power Company).

cooperatives, 12 percent directly to industrial customers, and 1 percent to Federal agencies.[82] In 2006, about one-half of BPA's sales for power and transmission services were to public utility districts, city light departments, and cooperatives, another 15 percent was sold to IOUs, and roughly one-quarter was sold to aluminum companies and other large industrial concerns. WAPA sold nearly half of its power to municipalities and cooperatives, 18 percent to State agencies, 6 percent to IOUs, 12 percent to public utility districts, 4 percent to Federal agencies, and the remaining 1 percent to other customers.[83] In 2006, cooperatives accounted for 57 percent of SWPA's power sales, municipals, 25 percent. Two percent was sold to Federal agencies.[84]

The Federal role in providing electric power is at least a century old and was very prominent in the early years of the Nation's electrification. Federal interventions in electricity markets started with the Reclamation Act of 1902 (Public Law 57-161). In large measure, these interventions were related to electricity produced at hydropower generation facilities as a byproduct of Federally-supported irrigation projects for reclamation of arid lands. At the time, hydroelectric power was the Nation's dominant source of electricity. The Reclamation Act was amended in 1906 to permit the lease of surplus power to towns and the revenue credited to repay irrigation costs.[85] The Federal role in marketing electricity from Federally-owned facilities grew rapidly during the 1930s. The recipients of preference power were largely municipals and cooperatives. Some of the largest hydroelectric power plants were placed in service during this era including the Hoover Dam in 1936, the Bonneville Dam in 1938, and the Grand Coulee Dam in 1941. Between 1933 and 1941, Federal power accounted for half of the Nation's new generating capacity.[86] These projects facilitated electrification and regional economic development. Federal utilities rely more heavily on hydroelectric power than other electricity producers which in general makes their power relatively inexpensive. Although Federal power is widely sold throughout the contiguous United States, with the exception of most of the Midwest and Northwest, Federal power sales are concentrated in particular geographic areas. The States located in the Pacific Northwest[87] and the Tennessee River Valley are the largest recipients of Federal power.[88] This chapter primarily focuses on the Federal utilities, which consist of the four PMAs and TVA.

Federal electric utilities are primarily transmitters and wholesale marketers of electricity generated by Federally-owned generating facilities. As required by law, they are not-for-profit and are obligated to offer power to statutorily defined preference customers first. Federally-owned utilities are by Federal statute obligated to recover costs and enjoined by law from pricing power to make a profit. Preference customers include municipal utilities, cooperatives, Indian tribes, State utilities, and irrigation districts. They may also include State governments and Federal agencies. After meeting commitments for electricity to preference customers, the Federal utilities can and do sell surplus electricity to IOUs in wholesale markets or directly to industry.

[82] Tennessee Valley Authority, SEC 10-K, 2005, p. 8.
[83] Western Area Power Administration, Statistical Appendix to the 2004 Annual Report.
[84] Southwestern Power Administration, Annual Report 2004-2006, p. 14.
[85] Town Sites and Power Development Act of 1906 (34 Stat.116), codified as 43 USC 522 provided surplus electricity produced at hydro projects constructed for irrigation purposes be sold to preference customers.
[86] Ibid, p. 6.
[87] The genesis of Federal power in the Northwest relates in part to the regional strength of the public power movement in the early days of electrification. The public power movement during the 1930s was very strong in the State of Washington. In 1936, 15 districts voted to establish public utility districts.
[88] Most of this hydroelectric power was constructed long ago. Currently, prospects for the expansion of hydroelectric power are limited. Particularly in the case of TVA, future expansion of electric generation is likely to be thermal resources.

The PMAs' electricity generation facilities are owned and operated by the U.S. Department of the Interior's Bureau of Reclamation, the U.S. Army Corps of Engineers, and the International Boundary and Water Commission.[89] Most of the electricity produced by these facilities is marketed by the four PMAs. The yearly financial and operational results for the power purpose activity of the Corp of Engineers, the Bureau of Reclamation, and the International Boundary and Water Commission are reported in each of the four PMAs' annual reports as consolidated operations. For an example, the SEPA balance sheet, income, and cash flow statements consolidate SEPA's financial data with the Corp of Engineers. TVA, the largest producer of Federal power, owns, operates, and markets its own electricity.

Rural cooperative electric utilities are member-owned, i.e., a cooperative's members and customers are one and the same. They are established in rural areas to provide electricity to those members. Cooperatives are organized under State law. They are governed in accordance with the principles of cooperative operation, which includes: (1) operation on the basis of cost; (2) members are entitled to receive a return of, but not a return on, capital they contributed to the organization; and (3) governance based on one-member-one vote. The organization is governed by a board of directors elected by the membership. Electric cooperatives also may qualify as tax-exempt organizations under Section 501(c)(12) of the Internal Revenue Code (IRC or Code). There are a number of requirements in the Code and Internal Revenue Service (IRS) pronouncements required to qualify for tax-exempt status. The most significant requirement is that cooperatives receive at least 85 percent of their income from business conducted with members. Cooperatives that meet RUS eligibility requirements have access to low-cost Federal government loans and loan guarantees. Cooperatives account for roughly 10 percent of electricity sales to ultimate consumers.

This chapter examines support provided by the Federal government to certain electric power customers. This support differs significantly from the subsidies provided to other energy sectors described in this report. First, the Federal support outlined in the following discussion does not include any direct expenditures provided to Federal utilities by the Federal government, as is the case for other Federal programs (such as the Low Income Home Energy Assistance Program expenditures discussed under direct expenditures in Chapter 2). The market value of the interest subsidies provided to TVA, the PMAs, and RUS borrowers is not measured by the Treasury Department, and it is not reported in Federal budget documents. The measures of support described in this chapter are values estimated by the EIA.

Areas Excluded from the Analysis

This report examines the support that the Federal government provides to electricity that is unique to electricity producers. Hence, some means of support provided to electricity is excluded because it is not exclusively applied to electricity or it is not Federal in nature. These include:

The ability of publicly-owned utilities to issue tax-exempt debt is not considered in this analysis because this benefit is available to government-owned enterprises outside of the electric utility industry. Additionally, government entities, including State and municipal utilities may issue tax-exempt debt for the benefit of third parties to finance eligible utility plant and equipment (e.g., pollution control equipment).

[89] Federal utilities provide consolidated financial and operational data for their own operations, as well as for the operations of related Bureau of Reclamation and U.S. Army Corps of Engineers power facilities.

The tax-exempt status of electric cooperatives and publicly-owned utilities pursuant to Federal tax law and State tax law and corporate law permitting utilities to organize as cooperatives or governmentally-owned enterprises is not included in this analysis. These benefits exist under Federal and State law for other enterprises operated on a cooperative basis and governmentally-owned enterprises. They are not unique to the electric utility industry.

Federal Policies Affecting Power Costs and Pricing

The prices charged by Federal utilities and RUS borrowers are generally lower than those charged by IOUs.[90] Prices are generally lower because Federal utilities and cooperatives have a distinct legal status and access to low-cost capital. These long-established Federal programs include:

Access to Low-Cost Credit. As a result of a number of Federal government programs (some of which date back to the inception of Federal power), in some instances, Federal utilities and RUS borrowers have been able to borrow funds at interest rates below prevailing Treasury rates.[91] In some instances, Federal utilities have been able to borrow at rates linked to Treasury rates for debt of comparable maturity or at rates available to government agencies. In other instances, Federal utilities borrow at private-sector interest rates, but their creditworthiness is enhanced by an implicit Federal guarantee that they will not default on their debt obligations. All of these interest rate advantages constitute Federal government support for the Federal utilities.

Access to Low-Cost Generation. Federal utilities are required to sell their electricity preferentially to certain users. By law, PMA electricity is sold "at the lowest possible rates consistent with sound business principles,"[92] which today is less than what the price of power would be under competitive market conditions. The "lowest possible rates" require Federal utilities to price electricity so as not to earn a profit. Essentially, Federal utilities pass lower prices on to statutorily defined preference customers in lieu of profits.[93] Charging prices below market constitutes price support to particular groups of customers, i.e., preference customers.

The RUS Electric Program. Rural electric cooperatives, under a program dating from 1935, are eligible for low-interest long-term loans from the Federal government, which were made at a 2-percent interest rate until 1973. Direct loans made between 1973 and 1993 were made at a 5-percent interest rate, with up to a 35-year term to maturity.[94] At the same, the RUS loan guarantee program was initiated. Under this program, eligible RUS power supply borrowers may obtain loan guarantees to finance generation and transmission projects. Loans made by the Federal Financing Bank (FFB) are made at the Treasury's cost of money plus one-eight of a

[90] The exception being the Tennessee Valley Authority, which EIA estimates to have had higher wholesale prices than neighboring utilities in 2006.
[91] In general, the extent to which Federal utility average cost of funds is less than the U.S. Treasury's own cost of raising capital is due to the more favorable treatment of past Federal treatment of debt.
[92] The Flood Control Act of 1944 (58 Stat. 887, 890); Department of Energy Delegation Order No. 00-37.00, which is applicable to the three smaller PMAs was issued in December of 2001. Delegation Order 00-37.00 directs the Federal Energy Regulatory Commission ascertain whether PMA rates are" (a) whether the rates are the lowest possible to customers consistent with sound business principles, (b) whether the revenue levels generated by the rates are sufficient to recover the costs of producing and transmitting electric energy including the repayment, within the period of cost recovery permitted by law, of the capital investment allocated to power and costs assigned by Acts of Congress to power for repayment; and (c) the assumptions and projections used in developing the rate components that are subject to Commission review.
[93] The PMAs' rates fluctuate on the basis of hydrological conditions. In lower water years, they often must purchase higher priced wholesale power to meet their contractual obligations.
[94] Rural Utilities Service: http://www.usda.gov/rus/electric/loans/loan_types041118.pdf.

point.[95] In 1993, the Municipal Rate Loan program replaced 5-percent interest rate loans. Interest rates for these loans are based on an index of interest rates for municipal bonds. Debt remains on the balance sheets of RUS borrowers at interest rates that applied at the time funds were advanced, including 2-percent and 5-percent loans.[96] At the end of 2005, RUS borrowers had roughly $30 billion (2007 dollars) in Federal loans and guarantees.[97]

Measuring the Support

For purposes of this report, EIA measured Federal support to TVA, the PMAs, and RUS borrowers in term of the their reduced borrowing costs relative to current market interest rates stemming from their ability to benefit from (1) borrowing from the Treasury, (2) accessing low cost Federal loans and loan guarantees, and (3) the financial markets' perception of an implied Federal guarantee of non-Federal obligations of TVA and BPA. This measure consists of a snapshot of the difference between the interest expense paid by TVA, the PMAs, and RUS borrowers at their embedded cost of debt relative to what they would have paid at a range of interest rates. These interest rates include the Treasury's cost of money and interest rates that reflect the variations in credit quality within the general category of investment grade debt (i.e., AAA to BBB-) for IOU bonds rated by nationally-recognized rating agencies.[98]

Two other methods for measuring the effect of Federal support to these enterprises include a comparison of the prices charged for electricity under Federal programs and an estimate of relevant "market" prices. That is, the quantifiable benefit received by preference customers is defined as the difference between the cost-based rates charged for Federal power versus the rates that would be estimated to prevail in competitive wholesale markets. The third method addresses the question: if Federal utilities were allowed to achieve a competitive rate of return (similar to IOUs), how much higher would their revenues (and associated electricity prices) be? Of the three, the chosen measure of support is the most direct, because interest rate subsidies directly reduce the utilities' borrowings costs. This method is discussed in this chapter. The other two methods appear in Appendix B "Alternative Methods of Estimating Federal Electricity Subsidies and Interventions."

[95] These loans have up to a 35-year term to maturity. The interest rate is based on the Treasury Department's cost of money at the comparable term to maturity. The interest rate is established when loan funds are advanced.
[96] 1987 regulations permitted RUS borrowers to "buyout" their debt at a discount. Thus, the amount of 2-percent and 5-percent funds has significantly diminished.
[97] Rural Utilities Service, *2005 Statistical Report Rural Electric Borrowers*, I.P. 201-1, Tables 3 and 5.
[98] An alternative measure of Federal support would employ a comparison of a weighted average of the various maturities of all Federal debt at the time of issuance against Treasury and IOU debt being issued contemporaneously to the Federal debt with the same maturities. There are several shortcomings with this alternative measure. First there is a lack of relevant interest data. The source of constant-maturity U.S. Treasury interest rates used in this report is the Federal Reserve Bank's Federal Statistical Release H-15 (FRB: H-15). In 2001, due to expectations of future budgetary surpluses, the United States Treasury announced that it would suspend issuance of its 30-year bond, the long-bond. Hence, FRB: H-15 lacks historical data on constant-maturity 30-year Treasuries for the years 2003 through 2005, making a comparison for those years subject to estimating 30-year Treasury surrogates. A second issue also concerns data availability. While the Federal utilities reported debt issuances that go back 50 years or more, corresponding data are unavailable for U.S. Treasuries and IOUs. For instance, FRB: H-15 reports long-bond Treasury rates going back no earlier than 1977. Another issue concerns standardized maturities. While the Treasury issues bonds with standardized maturities of 10, 20, and 30 years, Federal utilities issue debt with various maturities. For instance, a Federal utility issuing debt having a maturity of 15 years would have no U.S. Treasury counterpart with the same maturity. Moreover, Federal utilities issue debt with maturities ranging well in excess of 30 years. For instance, for 2007, the TVA reported that 15 percent of its total debt had a maturity ranging from 31 to 50 years. Furthermore, a portion of BPA's ENW debt has variable interest rates (See: *Energy Northwest 2007 Annual Report*, p. 54. Any attempt to estimate interest rates based upon "hypothetical" comparative Treasuries involves extrapolations for debt with maturity dates greater than 30 years, which would have to surmount a number of issues, such as how to deal with periodic yield curve inversions. Finally, bond-by-bond comparison would overlook an advantage available to the PMAs in that they are allowed by the Department of Energy to pay off their high cost debt prior to maturity. While IOUs may issue callable debt, which also may be retired prior to maturity, this debt would be priced at rates higher than those associated with debt, which could not be retired prior to maturity.

Interest Rate Support

An important element of Federal aid to Federal utilities and RUS borrowers is access to low-cost credit. Low-cost credit means more than raising capital advantageously. It also means a potential shift of capital from bond issuers and commercial borrowers with market-based risk profiles to entities whose risk is being underwritten by the Federal government. For instance, the three smaller PMAs are currently carrying debt at interest rates that result in their average cost of embedded debt being less than the Treasury's current cost of money. In the case of RUS borrowers, some past interest paid on insured loans was fixed by statute. Thus, at various points in time they were able to borrow at rates below the Treasury's cost of money.[99,100] Some Federal utilities receive appropriations, to be repaid as if they were borrowings at, or near, Treasury rates or U.S. Government agency rates. Even when Federal utilities borrow by issuing bonds, they receive higher credit ratings than would be attained if it were not for the widely-held view by the financial community that this debt carries an implicit Federal guarantee. That is, notwithstanding that both TVA and BPA state that debt issued to the public is not supported by a government guarantee, financial markets believe the government would intervene to prevent a default. The magnitude of the resulting support can be computed by comparing the actual interest paid with interest that would be paid at various market interest rates. When Federal utilities are able to raise funds in capital markets at interest rates lower than those at which they could borrow were it not for their Federal government status, a measure of support is conferred.

Although some Federal utilities borrow at various interest rates under various legal authorities, on balance they pay lower rates than privately-owned utilities. In the case of their private sector borrowings, the credit markets view Federal utility debt as having an implicit Treasury guarantee, although no guarantee in fact exists.[101] In its issuer rating of TVA bonds sold in 2003, Standard and Poor's assigned the debt an AAA rating. In doing so, Standard and Poor's noted that: "Status (TVA's) as government agency affords implicit support, monopoly service territory, legal authority to set rates without regulatory oversight, low-variable-cost generating units leading to competitive rates…" [102] According to Standard and Poor's, only six U.S. non-bank companies carry an AAA bond rating.[103]

[99] In general, loans made below the Treasury cost of funds, pursuant to statutory interest rates are of an older vintage and many have been paid down. In the case of the RUS lending, loans made prior to 1973 were made at a rate of 2-percent. Between 1973 and 1993 direct loans were made at a 5-percent statutory interest rate. After 1993, the RUS interest rate structure was tied to rates on municipal bonds.
[100] In debt financing the timing of debt issuance and maturities can have an impact upon embedded interest costs. For instance, under unusual assumptions, it is theoretically possible for an advantaged borrower, with access to debt financing at interest rates lower than those available to an unadvantaged borrower at any particular point in time, to have higher embedded interest costs. In such a case, there would be a significant difference in the vintage of each entity's debt portfolio This might occur if, say, the advantaged borrower consistently issued debt during high interest periods, while the unadvantaged borrower consistently issued debt during periods when interest rates were low. Practically, this possibility is very remote, as utilities (both Federal and non-Federal) issue debt during most years, with both entities trying to avail themselves of credit in periods when interest rates are relatively low. Moreover, both have the ability to restructure their outstanding debt to adapt to changes in interest rate environments, such as by refinancing or by paying down high cost debt early.
[101] In its offering statements, TVA discloses in bold print that its bonds: " Will not be obligations of, nor will payment of the principal thereof or the interest thereon be guaranteed by, the United States of America." Source: www.tva.gov/finance/opportun/pdf. Accessed February 26, 2008. TVA also states that: "TVA bonds are backed solely by the net power proceeds of the TVA power system and are neither obligations of nor guaranteed by the U.S. Government." Source: Tennessee Valley Authority, http://www.tva.gov/finance/opportun/. n a Fitch Ratings, *Public Power New Issues for Energy Northwest*, BPA notes that: "BPA's obligations are not general obligations of the United States government and are not secured by the full faith and credit of the United States." Source: www.bpa.gov/corporate/finance/debt_management/reports_articles_docs/Fitch_03_02_06.pdf, Sourced: February 25, 2008.
[102] Standard and Poor's, http://www2.standardandpoors.com/portal/site/sp/en/us/page.search/search/0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0.htmlH. Accessed October 15, 2007.
[103] The Economist, "AAAsking for Trouble," July 12, 2007.

As a result, even publicly-issued debt of the Federal utilities is priced at rates below those paid by all but the IOUs with ratings at the higher side of the range of the investment grade category. TVA- and BPA-backed debt have outstanding debt rated between AA- and AAA.
A long-standing issue in financial markets has been the degree to which the Federal government would prevent a default by government corporations such as the TVA or the Federal Deposit Insurance Corporation (FDIC);[104] and government-sponsored entities (GSE) such as the Federal National Mortgage Association (FNMA) and financial institutions within the Farm Credit System (FCS). The debt of these entities carries no explicit guarantee by the Treasury. In fact, TVA explicitly states that its debt is not a legal obligation of the Federal government.[105,106] However, financial markets perceive otherwise, believing that the Federal government would not allow TVA to default on its obligations. Although the financial community's assumptions are subject to debate, there is evidence suggesting that their view is correct.

According to a study completed by the Federal Reserve Bank of Richmond, Virginia, twice during the 1980s, the Treasury Department provided support to two GSEs—the FNMA and the FCS—during times of financial difficulty. The Federal Reserve Bank study noted that in both cases the Treasury Department acted to mitigate the increased yield spread between GSE and Treasury securities from increasing the Treasury's borrowing costs. In both cases, the Treasury made the "implicit guarantee explicit by providing Federal government loans to the GSEs. Once the loans were made, the interest spread of the GSE securities and comparable Treasury securities narrowed."[107]

When rating TVA's debt, the nationally-recognized credit agencies assume that the government will provide support if needed. According to Moody's Credit Service: "Although TVA's debt is not an obligation of the U.S. Government, the company's status as an agency and the fact that the Government is TVA's only shareholder, indicates strong 'implied support' [that] would afford assistance in times of difficulty . . . . This implied support provides important bondholder protection." Similarly, according to Standard and Poor's: "The [AAA] rating reflects the U.S. Government's implicit support of TVA and Standard and Poor's view that, without a binding legal obligation, the Federal government will support principal and interest payments on certain debt issued by entities created by Congress. The rating does not reflect TVA's underlying business or financial conditions." Standard financial texts also describe Federal agency debt as carrying a "de facto backing from the Federal government." [108] Fitch Ratings notes that its AAA rating "reflects TVA's status as a wholly-owned corporation of the U.S. government and Fitch's assessment of the likelihood and degree of government support for TVA and similarly rated institutions. The rating also takes into account "TVA's strong historical operating and financial performance, its solid competitive position (compared to the other highly rated public power utilities in the "'AA'" category) and its integral role in developing and supporting the regional economy…TVA's outstanding debt is not a full faith and credit, or limited obligation of the U.S. government. However, Fitch believes that U.S. authorities would use extraordinary efforts to

[104] OMB characterizes Federal insurance programs as an alternative to direct spending. See, *Analytical Perspectives of the Budget of the United States, Fiscal Year 2008*, p. 67.
[105] General Accounting Office, *Tennessee Valley Authority: Financial Problems Raise Questions About Long-Term Viability*, GAO/AIMD/RCED-95-134 (Washington, DC, August 1995), p. 29.
[106] For example, TVA clearly states that its securities receive no credit enhancement from the Federal government on page 41 of its 2006 SEC 10K. "Although TVA is a corporate agency and instrumentality of the United States government, TVA securities are not backed by the full faith and credit of the United States. Principal and interest on TVA securities are payable solely from TVA's net power proceeds."
[107] T.Q. Cook and R.K. Laroche, eds.," Instruments of the Money Market," (Richmond, VA: Federal Reserve Bank, 1993).
[108] M. Stigum, "The Money Markets: Myth, Reality, and Practice," (Homewood, IL: Dow Jones-Irwin, 1978), p. 161.

support their operations and senior debt obligations in the unlikely event that the TVA encountered financial difficulties."[109]

In addition, TVA's former chairman has acknowledged the implicit guarantee arising from potential pressure on the Treasury to prevent any agency default. According to a quote appearing in the March 5, 1997, *Wall Street Journal*, then TVA chairman Craven Crowell stated: "If Congress does anything that devalues us, you always have the potential for the Treasury having to get involved."[110] Were the Federal government to allow a default by an agency or GSE, the ability of all Federal agencies and GSEs to borrow money at favorable rates could be affected. The failure of the Federal government to remedy a default could cause financial markets to downgrade the value of all government corporations, government agency and GSE debt, an action that could significantly affect their borrowing costs and their ability to carry out their government mandates. In all likelihood this potential hazard weighs heavily on the Federal government to prevent even one default. TVA may have an even closer relationship with the Federal government than do the GSEs, which may increase whatever implicit support its debt derives. For instance, unlike the GSEs, the Treasury Department treats TVA debt as gross Federal debt. TVA's borrowings accounted for 98 percent of $26 billion in Federal government agency debt outstanding as of the end of 2006.[111] GSEs had, however, $1.3 trillion in debt (2005 dollars) outstanding at the end of 2005, which makes them a considerable component of total U.S. credit markets.[112] Total Treasury obligations, for instance, equaled $7.9 trillion in 2005.[113,114] In this report, "implicit support" is included in the estimates of total support provided by the Federal government to TVA and the PMAs, because the ratings and yields on their debt instruments would be different in the absence of Federal government support.

There are alternative viewpoints on the issue of implicit interest support. These viewpoints question whether the Federal government support truly exists in the absence of a binding legal obligation to intervene to preclude a TVA default. According to these views, market expectations that the Federal government would act to prevent default are a perception and not necessarily a reality. Although the market views a TVA debt default as "highly unlikely," there is no absolute guarantee that the market is infallible. On the other hand, the Federal government ownership of TVA and the overall statutory framework in which it operates appears to be sufficient to justify the highest of investment grade credit ratings and attendant lower borrowing costs than lesser quality bonds.

According to a Congressional Budget Office report on GSEs and their implicit Federal subsidy: "Agency or GSE status substantially enhances the debt rating of these enterprises…The subsidy conveyed is the avoided cost of meeting the standards of credit worthiness. In concept, the subsidy has a cost to government equal to the insurance premiums that would be charged by a group of highly-rated insurers to guarantee the timely payment of interest and principal on GSE debt in the absence of government sponsorship…The implicit guarantee of GSE debt has never required a cash outlay by the Federal government. The subsidy that never leads to a cash payment may appear not to be 'real'–that is, not costly. The implicit guarantee of GSE

[109] "Fitch Rates Tennessee Valley Auth's $500 Global Power Bonds 2008 Series A "AAA," *Reuters*, http://www.reuters.com/article/pressRelease/idUS241174+18-Jan-2008+BW20080118, accessed March 10, 2008
[110] J. Ball, "TVA Plan Seen by Critics as Unfair Grab for Power," *Wall Street Journal* (March 5, 1997), p. 1.
[111] Office of Management and Budget, *Analytical Perspectives of the United States Budget 2008,* (Washington, DC, 2007), p. 229.
[112] Office of Management and Budget, *Analytical Perspectives of the United States Budget 2007*, (Washington, DC, 2006), p. 223.
[113] Office of Management and Budget, *Analytical Perspectives of the United States Budget 2007*, (Washington, DC, 2006), p. 86.
[114] The term "agency debt" is defined more narrowly in the budget than customarily in the securities market, where it includes not only the debt of the Federal agencies but also the debt of government sponsored agencies. See, Office of Management and Budget, *Analytical Perspectives of the United States Budget, Fiscal Year 2006*, p. 222.

debt is costly in terms of alternatives that must be necessarily, if unconsciously, given up by the economy."[115]

Larger corporations or financial institutions may also benefit from an implicit guarantee against failure. There have been periodic episodes of Federal intervention to prevent their demise, giving rise to the “too-big-to-fail” argument. For instance, during the late 1970s, the Federal government intervened to assist the Chrysler Corporation, and in 1984 the Federal government intervened to help Continental Illinois Bank. In the late 1980s and early 1990s, Federal intervention was used to assist the Nation’s Savings and Loan industry, costing the Federal government in excess of $100 billion. In all cases, concerns that the failure of these entities would have widespread economic repercussions motivated government action.

Unlike TVA, the PMAs are not government corporations; they are line agencies within DOE. They submit annual budgets to Congress. Like the TVA, however, one PMA – the Bonneville Power Administration (BPA) -- does benefit from the implicit support which results from its government status. Bonneville Power Administration has nuclear-related obligations. BPA has a contractual obligation to pay the debt service on bonds issued by Energy Northwest, the successor to the Washington Public Power Supply System. Payments are based on cash flow generated from a net billing arrangement between BPA and utilities in the Pacific Northwest.[116] In Moody’s High Profile New Issue April 2004 issue, Moody’s states: "Contributing to the Aaa rating on the Energy Northwest (ENW) bonds are the evident implicit support by the Federal government for Energy Northwest bonds through BPA and BPA’s established record of full cost recovery from its business operation and rates."[117] Both Standard and Poor’s and Fitch Ratings assign AA- issue ratings to BPA’s ENW debt. Standard and Poor’s notes that BPA’s rating is based upon the fact that BPA is the obligor for ENW debt and that this debt is “senior to the more than $7 billion in Treasury obligations at Bonneville.[118] Fitch noted in its 2006 AA-issue rating that BPA’s “Payments to the U.S. Treasury are subordinate to ENW bonds, providing added security to these instruments.”[119]

The three smaller PMAs’ (SEPA, SWPA, and WAPA) average embedded cost of outstanding debt is below the current cost of borrowing by the U.S. Treasury. In part, this is because DOE allows them to repay higher cost debt early whenever possible, a privilege not held by the Treasury Department.[120] Moreover, before 1983, the three smaller PMAs were allowed to finance capital projects at rates lower than the Treasury's cost of money, which also lowers the average embedded cost of combined debt currently carried on the PMAs’ books.[121]

[115] Congressional Budget Office, *Government-Sponsored Enterprises and Their Implicit Government Subsidy: The Case of Sallie Mae*, (Washington, DC, December 1985), pp. 29-30.

[116] Rating agencies rate both bond issuers and bond issuances. In the case of bond issuers, it is the creditworthiness of the issuer that is being rated. In the case of bond issuances, it is the creditworthiness of an obligor with respect to a specific financial obligation that is being rated. In this latter category, rating agencies would consider such matters as whether the bond were insured, or other forms of credit enhancement. While Moody’s provides Energy Northwest Bonds with an Aaa rating based upon the issuer, Fitch and Standard and Poor’s provide Energy Northwest bonds with an AA- rating based upon the issuance.

[117] Moody’s Investors Service, High Profile New Issue, April 2004.

[118] Standard and Poor’s, Ratings Direct, Summary: Bonneville Pwr Admin, or: Utility, Wholesale Electric, March 16, 2006.

[119] Fitch Ratings, Public Power New Issue, Energy Northwest (Bonneville Power Administration, March 21, 2006. Fitch also noted that “Positive support for the rating is BPA’s position as a leading provider of electricity and transmission in the Pacific Northwest and its highly competitive wholesale power rates derived from its hydro-based system.”

[120] General Accounting Office, *Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities*, GAO/AIMD-96-145 (Washington, DC, September 1996), p. 7.

[121] General Accounting Office, Federal Power: *Options for Selected Power Marketing Administrations’ Role in a Changing Electricity Industry*, GAO/RCED-98-43 (Washington, DC, March 1998), p. 7.

In addition to being able to pay off their high-cost debt first, the PMAs also have discretion in deciding how to make the annual payments for their appropriated debt to the Treasury.[122] These borrowings do not have to be amortized on a straight-line basis, but can occur anytime over the maturity of the debt instrument, which can be as long as 50 years for electric generating assets. These are appropriations for capital projects only and not appropriations for operations, which generally need to be repaid in the current operating year.[123] Typically, unless the bonds of IOUs, publicly-owned utilities, and a few cooperatives, are callable, interest is paid on a current basis, and principal is paid based on the terms of each specific bond issue.[124]

The analysis in this report uses both public-sector and private-sector interest rates as benchmarks against which to measure the value of interest rate support. The public-sector benchmark is the Treasury's constant yield to maturity for 30-year obligations. For the private-sector rates, the benchmarks used are the interest rates paid by utilities using various Moody's utility bond ratings ranging from Aaa down to Baa. These ratings indicate two different measures of support. When debt carried on the balance sheets of Federal utilities has lower average borrowing costs than the U.S. Treasury itself, the underlying advantage can be viewed as support provided directly to the borrower by the U.S. Treasury or by the public at large. The second measure of support assumes that Federal utilities are advantaged to the extent that the associated average interest costs of their outstanding borrowing costs are at rates less than they would be if they were private entities or otherwise unable to issue tax-exempt debt. This measure of support compares the borrowing costs of the Federal utilities with the cost of funds realized by risk-adjusted groups of IOUs that raise debt in the market place. The comparable IOU rating may or may not be appropriate, depending on the presumed creditworthiness a Federal utility would command were it to lose the borrowing benefits derived from Federal ownership or its implicit financial backing from the U.S. Treasury.

The measure used to estimate the Federal interest rate support for Federally-owned utilities is highly dependent on the risk differential reflected by the spread between the interest rates for the various categories of investment grade bonds described above. In 2006, interest rates were generally lower than in 1998 (Table 18).[125] However, in measuring interest support for a single year, what matters is the interest rate spread, which reflects the risk premium. Table 18 illustrates that the level of estimated support varies directly with the benchmark interest rate chosen. The spread between these rates could remain relatively stable or could change over time. In 2006, the average yield on 30-year Treasury bonds was 4.91 percent while the average yield on Aaa-rated utility bonds was 5.59 percent, producing a spread of 68 basis points; in contrast, the spread between the 5.58 percent 30-year Treasury and the 6.77 percent investor-owned Aaa rate in 1998 equaled 119 basis points.

[122] Of the 4 PMAs, Bonneville is an exception. Since 1974, Bonneville has not received appropriations from the Congress but instead relies on a revolving fund with the Treasury.
[123] A GAO study concluded that the PMAs pay off their high interest debt first and defer repayment of lower interest rate debt. See: General Accounting Office, *Power Marketing Administrations, Their Ratesetting Practices Compared with Those of Nonfederal Utilities*, GAO/AIMD-00-114, March 2000, pp. 27-30.
[124] In the Southeastern Power Administrations 2004 Annual Report, it states: "Annual net revenues available for repayment are generally applied first against investments in projects bearing the highest interest rates. To the extent that funds are not available for payment of such operating expenses and interest, such amounts become payable from the subsequent year's revenue prior to any repayment of the Federal investment." Source: Southeastern Power Administration, *2004 Annual Report*, p, 40.
[125] Changes over time in the spread between interest rates of Federal utilities and the benchmark rates they are being measured against do not reflect intended changes in Federal support for these electricity programs. Rather, they reflect supply and demand conditions in credit markets prevailing in 1998 and in 2006.

Table 18. Interest Rates used to Estimate Federal Utilities and RUS Interest Subsidies, 1998 and 2006 (percent)

Comparison Debt	1998	2006
30-Year Treasury	5.58	4.91
Investor-Owned Aaa	6.77	5.59
Investor-Owned Aa	6.91	5.84
Investor-Owned A	7.04	6.07
Investor-Owned Baa	7.26	6.32

Sources: The Investor-Owned Aa, A, and Baa Utility rates: Global Insight; Original Source: Moody's Investor Services. The Aaa Investor-Owned rate was obtained from the Federal Reserve Bank's Statistical Release H-15 (FRB: H-15) with the following note: Moody's Aaa rates through December 6, 2006, are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only. The Municipals were provided by Global Insight. The U.S. Treasury 30-year rate was also obtained from FRB: H-15. Treasury rates reflect constant maturities.

The estimated interest support will be higher when the IOU Aa rate is compared to the Treasury rate and higher still when the comparison is graduated downward to the IOU Baa rate. For the year 2006, the difference in yield between a 30-year Treasury and a Baa IOU rated bond was 141 basis points. The difference in yield between an Aaa utility rating and Baa utility was 73 basis points versus 49 basis points in 1998. The level of support therefore rises and falls depending on three developments: (1) changes in the yield spread between different debt instruments (e.g., Treasuries and utilities); (2) changes in the level of outstanding debt; and, (3) the Federal utilities and RUS borrowers embedded cost of debt versus the Treasury's and utilities' current cost of money.

Selection of a Market Interest Rate

The statutory provisions under which Federal utilities operate provide them with independent authority to establish electric rates on a cost basis, including the repayment of debt. Similar considerations apply to RUS borrowers. Cooperatives set their rates on the basis of cost to meet the requirements of IRC Section 501(c)(12). The board of directors is responsible for setting rates, subject to regulatory approval in some States. Therefore, it can be argued that the benefit of low-cost capital that flows through to Federal utilities' customers is not a Federal support in the absence of a default. With respect to RUS borrowers, the Federal Credit Reform Act requires that the interest subsidy associated with RUS loans be included in the budget. The methodology used to calculate the subsidy incorporates a default rate and recovery rate. Therefore, one can argue that there is no additional support over and above the subsidy reflected in the budget.

The contrary argument is that notwithstanding the statutory framework under which the Federal utilities operate, their customers are receiving financial support because there is neither explicit recognition of the market risk that is borne by the Federal government in the event of a default nor of the opportunity cost to the Federal government's stakeholders, i.e., taxpayers and the customers, in the capital cost associated with the electricity sold by Federal utilities. The value of this financial support is a cost to the Federal government which is not quantified and assigned to the Federal utilities in the budget. To the extent it is a significant and measurable cost, it is reflected in the interest rate set in the market for Treasury securities and in the annual interest expense on Federal debt included in the budget, compared with the interest rate that would otherwise be obtained.

In order to estimate the value of the financial support provided to the customers of the Federal utilities, EIA has adopted a cost-of-capital approach that estimates the value based on the difference between the interest expense that Federal utilities actually paid in 2006 versus what they would have paid under a range of contemporaneous interest rates to their outstanding debt. The interest rates range from the risk-free Treasury rate to the highest interest rate for IOU bonds. For purposes of estimating the value of Federal financial incentives provided directly and indirectly to electricity production be expressed on a unit of production basis, EIA used the interest rate associated with an A-rated IOU bond to compare with Federal utilities' weighted average cost-of-capital.

The analysis is a snapshot that compares the current interest expense based on the average cost of outstanding debt to a hypothetical interest expense that applies a contemporaneous market interest rate to the outstanding debt. In effect this implies the debt is being refinanced. A more accurate measure would have been to estimate the value based on the sum of the difference between face amount of each original loan or bond and present value of each loan or bond issue at the market rate of interest at the time the obligation was incurred. The data required to perform this alternative analysis would be extremely complex, and in any event, were not available to EIA.

Opinions vary with regard to the extent to which there is a significant risk premium between the risk-free Treasury rate and the market rate of interest that Federal utilities would be required to pay in the absence of their ownership status and the statutory framework under which they operate. This is true with respect to TVA and BPA, both of which have received AAA and AA ratings, as well as imputing a market interest rate to the smaller PMAs. In order to develop a point estimate of the value of the support provided to the customers of the Federal utilities, EIA performed a financial ratio analysis that compared TVA and the PMAs to comparably structured governmentally-owned wholesale power suppliers. The financial ratios measure an entity's ability to meet its debt and other fixed obligations, such as lease payments. This approach was adopted in order to neutralize any actual or perceived credit enhancement that financial markets attribute to Federal ownership and/or the ability to borrow at the Federal government's cost of funds or at interest rates comparable to GSE interest rates. This resulted in the adoption of a market interest rate associated with an A credit rating. Limiting the derivation of the market interest rate to consideration of only liquidity-related financial ratios allowed for uniformity in EIA's analysis and eliminated the effects of actual or perceived credit enhancement attributed to Federal support provided in accordance with Federal statutes applicable to the Federal utilities. Therefore, the rating used to develop a point estimate of the value of Federal support should not in any way be construed as an alternative to actual credit ratings issued by the nationally-recognized credit rating agencies. The rating agencies' consider a multitude of factors in addition to financial performance in developing credit ratings that were not considered by EIA.

The interest support associated with the benchmark A rated IOU bond is used only for purpose of estimating the generation portion of the support by fuel type. The benchmark A rating was selected for purposes of calculating the support based on a comparison of financial metrics for the Federal utilities and RUS borrowers to data compiled by Fitch Ratings for comparable wholesale public power entities (i.e., rated generation and transmission cooperatives (G&T), and public power agencies) and retail public power systems that purchase their power supply requirements. The financial metrics are standard measures used by the financial community to assess creditworthiness. Fitch Ratings defines the debt service coverage ratio (DSC) as the ratio of funds available to meet debt service payments (FADS) to annual debt service payments, i.e., principal and debt service. Numerically, it illustrates how much free cash flow is available to meet debt service payments and other fixed obligations after taking into account operating expenses. A 1.0 DSC indicates that a business has FADS exactly equal to annual debt service payments. A DSC of less than 1.0 indicates the enterprise is not generating sufficient cash flow to meet its debt service payments and other fixed obligations treated as debt for purposes of assessing creditworthiness. It should be noted that government-owned utilities such as Federal utilities and G&T cooperatives financed by RUS borrowers, by virtue of their ownership structure, rely primarily on long-term debt to finance capital investments, unlike investor-owned utilities that finance capital investment through a combination of debt and equity. The Federal utilities and G&Ts' rates are set with the intention of insuring that sufficient free cash flow is available after operating expenses to cover annual debt service payments and to accrue equity.[126] Accordingly, their DSC ratios are typically lower than that of IOUs.

Days of cash on hand provides a gauge of the amount of cash immediately available to respond to unforeseen events such as the purchase of replacement power due to an unscheduled outage of a power plant, or increases in other operating expenses. Days of liquidity adds other sources of cash such as commercial paper and credit lines. High levels of unrestricted cash and liquidity on hand provide a measure of the enterprises ability to meet contingencies from cash generated by operations and short-term borrowing, and still be able to meet debt service and other fixed obligations. Variable rate exposure (VRE) quantifies the net amount of outstanding debt and the VRE-to-capitalization measures the portion of total capitalization that is subject to interest rate risk. The higher the ratio, the greater the exposure to an increase in interest rates and interest expense. If all other factors remain constant, i.e., revenue, operating expenses and depreciation expense (which is a source of cash) financial risk increases. This is because free cash flow will decline.

The ratio of total debt to funds available for debt service (Debt/FADS) measures the factor by which total debt exceeds cash and short-term credit instruments. In effect it measures how much cash is available to meet total debt and fixed obligations in the event of default and an acceleration of the payment of such obligations. A low Debt/FADS ratio indicates the enterprise has adequate cash and liquidity and lower financial risk relative to comparable businesses with higher ratios.

Fitch Ratings Definitions of Selected Financial Terms

- **Debt Service Coverage (DSC)**: Funds Available for Debt Service Divided by Total Annual Debt Service.
- **Funds Available for Debt Service (FADS):** The sum of operating income, depreciation and amortization, and interest income.
- **Total Annual Debt Service:** Sum of scheduled long-term principal and annual short- and long-term debt interest payments.
- **Total Debt (Debt):** Sum of long-term debt (including capital leases) plus commercial paper, notes payable, current maturity of long-term debt (including capital leases). No adjustment is made for unamortized discounts or premiums.
- **Debt- to-FADS:** The ratio of total debt to funds available for debt service.
- **Unrestricted Cash:** Cash that is available for immediate liquidity needs, with flexible (e.g., board or management policy) or no limitations on use.
- **Days of Cash on Hand:**
  Numerator = Unrestricted cash and investments.
  Denominator = Operating expenses less depreciation.
  Multiplied by 365.
- **Days Liquidity on Hand:**
  Numerator = Unrestricted cash + available lines of credit + commercial paper capacity.
  Denominator = Operating expenses less depreciation.
  Multiplied by 365.
- **Capitalization:** The sum of total debt and total equity.
- **Variable Rate Exposure (VRE):** The sum of variable rate debt, outstanding commercial paper and fixed-to-variable-rate swaps less variable-to- fixed-rate swaps.
- **Variable Rate Exposure-to-Capitalization**: Ratio of VRE to Capitalization

Source: Fitch Ratings, *U.S. Public Power Peer Study,* June 2007, pp.27-28.

[126] The PMAs' audited financial statements refer to equity as Accumulated Net Revenue. For example, in 2006, BPA reported $1.9 million in Accumulated Net Revenue. Fitch Ratings refers to the same value as equity in its March 16,2007 issue rating for Energy Northwest 2007 A-D refunding and revenue bonds which BPA is obligated to pay.

Fitch Ratings classifies its bond ratings according to the primary activity of the rated entity. Entities such as joint municipal action agencies, public power authorities, G&Ts, TVA and BPA are classified as wholesale systems. Fitch Ratings provides financial statistics that measure the ability of wholesale systems to meet their fixed obligations based on certain measures of liquidity. The definitions of formulas and financial inputs to the formulas developed by Fitch Ratings that are used in EIA's analysis are provided (see text box: Fitch Ratings Definitions of Selected Financial Terms).

The comparison of TVA's financial metrics to all wholesale suppliers rated by Fitch Ratings shows that with the exception of its DSC and debt as a percentage of funds on hand, TVA's remaining metrics are consistent with median values for wholesale systems in the A to BBB range (Table 19). An A rating appears to be a reasonable benchmark comparison for TVA when its high debt service coverage ratio and days' liquidity on hand are balanced against the remaining metrics that in some instances fall below the median value for the lowest investment grade rating (BBB).

The comparison of BPA's financial metrics to all wholesale suppliers rated by Fitch Ratings shows that with the exception of the DSC and equity as a percentage of total capitalization,

Table 19. Median Financial Ratios: Investment Grade Rated Wholesale Public Power Suppliers

	Debt Service Coverage	Equity as Percent of Total Capital	Debt/FADS Ratio	Days Cash On Hand	Days Liquidity on Hand	VRE as Percent of Capitalization
BPA (FY ending 2006)	1.26	13	8.0	204	235	NA
TVA	1.95	10	8.2	32	183	9.0
Median Value for All Rated Wholesale Suppliers						
AA (All Wholesale Systems	1.70	27	7.0	98	200	3.0
A (All Wholesale Systems)	1.29	17	8.6	74	126	5.0
BBB (All Wholesale Systems)	1.18	5	9.8	92	143	4.0
Median Value for All Rated G&Ts						
AA (G&Ts)	1.42	30	6.1	135	199	5.0
A (G&Ts)	1.10	18	8.2	29	139	1.5
BBB (G&Ts)	1.15	11	9.0	52	155	8.0

NOTE: A borrower's desired liquidity on hand can in turn be affected by its credit status in that having a higher credit rating might allow the borrower more ready access to borrowing short-term funds.

NA: No ratio provided by Fitch Ratings.

Sources: Fitch Ratings, *U.S. Public Power Peer Group Study, June 2007*, p. 18; Fitch Ratings, *Public Power New Issue, Energy Northwest (Bonneville Power Administration)*, March 16, 2007, www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/

BPA's financial metrics are consistent with the median values of wholesale systems within the A to AA range (Table 19). The DSC at 1.26 is slightly below that of the median value for A rated wholesale systems (1.29).[127] However, BPA's days of cash on hand and days of liquidity exceed the median values for AA-rated wholesale systems. This tends to mitigate against the low DSC. Based on this analysis, EIA has also adopted an A rating for purposes of benchmarking BPA's Federal interest rate support in this report.

With respect to the smaller PMAs, EIA also selected the benchmark A rating based on a review of their audited financial statements. SEPA reported its DSC ratio has ranged from 0.38 to 1.30 between 2001 and 2005. It has exceeded 1.0 for the 3-year period ending in 2005. During this period, SEPA's DSC was within a range consistent with that of the median DSC for wholesale systems rated with BBB to A ratings by Fitch Ratings.[128] SWPA and WAPA reported operating losses in 2005. However, they were able to meet their obligations to the Treasury and appear to have adequate cash reserves. Accordingly, an A rating was assumed for purposes of estimating the market value of their respective interest support levels.

The ratings data suggest an A rating is appropriate for the RUS loans for generation and transmission facilities made to G&Ts. Fitch Rating's financial data include 39 public power authorities and G&Ts. Among these 39 entities are 14 G&Ts. Of these 14 G&Ts, 10 received Secured Debt ratings ranging from A- to A+. Three received AA Secured Debt ratings 129 and 1 received a BBB+ ratings.[130] Their total RUS debt was $8.5 billion, which was equivalent to 55 percent of RUS loans to G&T at the end of 2005.[131]

The benchmark interest rate for an A-rated IOU bond is also used to estimate the support associated with the distribution cooperative segment of the RUS loan portfolio. This is based on the use of the National Rural Utilities Cooperative Finance Corporation's (CFC) credit ratings as a proxy for the creditworthiness of RUS distribution borrowers. CFC provides interim construction, permanent financing, and loan guarantees to G&Ts. It also provides supplemental loans to RUS distribution cooperatives and total financing to former RUS distribution borrowers. For its fiscal year ending May 31, 2006, CFC reported $12.9 billion of distribution loans and $3.7 billion of power supply loans and loan guarantees. Collectively, these loans and loan guarantees accounted for 86 percent of its total portfolio.[132] CFC's Senior Secured and Senior Unsecured debt received A1 and A2 ratings, respectively, from Moody's and A ratings from Standard & Poor's and Fitch. Given that CFC's secured debt is secured by its loan portfolio, and given the breadth of its electric cooperative loan portfolio, it is reasonable to use CFC's A rating as a proxy for RUS distribution debt.[133]

Since the financial accounts of the four PMAs, TVA, and RUS borrowers differ considerably, and due to reasons cited below, a single Federal interest rate support estimate was used in this

[127] Fitch Ratings reports that BPA's 2006 DSC was 4.93 for non-Federal Project debt issued by Energy Northwest. The terms under which BPA has assumed the payment obligation for this debt provides that debt service payments to the Federal government are subordinated to Energy Northwest, i.e., Energy Northwest bondholders have payment priority over the Federal government. The 1.26 DSC includes BPA's Federal and non-Federal obligations.
[128] Southeastern Power Administration, Annual Report 2005, p. 26.
[129] Georgia Transmission Corporation, an RUS financed transmission cooperative received an AA rating by Fitch.
[130] Three of the G&Ts rated by Fitch, Old Dominion Electric Cooperative (A rated Senior Debt), Great River Energy (A- rated Senior Debt), and Golden Spread Electric Cooperative (A- rated Senior Debt), are no longer RUS borrowers.
[131] The credit rating agencies' criteria for wholesale systems include an examination of the financial strength and service territories of the members of a G&T. Basin Electric Power Cooperative and Associated Electric Cooperative members include 14 G&Ts, of which 12 are RUS borrowers. Collectively, the outstanding RUS debt of these 12 G&Ts, excluding Tri-State Generation and Transmission Association which is included in the $8.5 billion of rated G&T debt, in 2005 was $296 million. Associated and Basin are rated AA and AA- , respectively, by Fitch Ratings.
[132] National Rural Utilities Cooperative Finance Corporation, 2007 SEC 10-K, p. 33.
[133] For Moody's rating see, www.nrucfc.org/investors/pdfs/cfc_credit_opinion.pdf. For Standard and Poor's rating see www.nrucfc.org/investors/pdfs/cfc_sp_analysis.pdf. For Fitch's rating see, www.nrucfc.org/investors/pdfs/fitch_02-23-07.pdf, accessed December 10, 2007.

analysis. A more complicated method would be to measure the interest paid by Federally-supported power entities against the interest paid on similar debt (i.e., same maturity) issued by the Treasury or by IOUs at the same time the debt was issued. However, several difficulties arise with the latter methodology. In essence the yield curve for the Federal utilities is fundamentally different from the yield curve for the IOUs. One problem is that the debt maturities cannot always be matched. For instance, TVA has issued debt with maturities as long as 50 years, for which there are no similar Treasury or IOU debt instruments. Another difficulty is that some bonds are callable, which means it may not be held to maturity. There is an interest rate differential between callable and non-callable debt. Callable debt, all other factors being equal, has a higher interest rate. Another problem is the lack of available data. Although some of the debt on the books of the PMAs dates back to the 1940s, there is little in the way of comparable IOU and Treasury interest rate data available. For instance, the U.S. Treasury did not start to issue 30-year debt until 1978 and in the years 2003, 2004 and 2005, no 30-year Treasury bonds were in circulation. Finally, the PMAs also have two other advantages over IOUs that tend to make an IOU/PMA bond-to-bond comparison problematic. First, the PMAs have the right to pay off high-interest debt first and, second, the PMAs can defer payments of debt during revenue shortfalls up to the point of the maturity of the loan. These deferrals can be as long as 50 years.[134]

In making comparisons between the interest costs faced by the Federal utilities and the IOUs, two other complications arise. The first began in FY 2000, when TVA initiated lease/lease back arrangements.[135] In lease/lease back arrangements, the TVA "leases" TVA generation assets to investors for a one-time cash payment used to retire debt.[136] In turn, the TVA leases back the plants and makes periodic lease payments.[137] The second complication relates to TVA's prepayment plan. In 2003, the TVA initiated a pre-payment plan, which allowed TVA customers to pay for their power in advance in return for discounted, wholesale rates. Again, TVA used the transactions proceeds to retire long-term debt. Due to both of these transactions, the TVA significantly reduced its long-term debt. Both of these obligations are recorded as liabilities on TVA's balance sheet. TVA does not define these liabilities as debt. However, due to their strong resemblance to debt, this report defines them as such. Both lease/lease back arrangements and prepayments are discussed later in the TVA section of this chapter.

TVA's debt in 2006 received an Aaa bond rating. The imputed interest expense in TVA lease payments and the prepayment discount were not treated as interest expense in TVA's financial documents. Therefore, TVA's interest costs were estimated by applying an Aaa interest expense to TVA's long-term debt which includes both the values of its lease payment obligation and the unamortized balance of the prepayment which is TVA's power supply obligation to those who prepaid. The Aaa interest rate expense was then compared to what the TVA would pay in interest with a lower bond rating.

[134] General Accounting Office, Power Marketing Administrations*, Their Ratesetting Practices Compared with those of Nonfederal Utilities*, GAO/AIMD-00-114, (Washington, DC, March 2000), p.14.
[135] In general, lease/leaseback arrangements appeared in the 1980s. These leases often involved the transfer of tax benefits to third parties when the utility cannot use them (i.e., publicly-owned utilities do not benefit from accelerated depreciation). Source: Public Utilities Report Guide, Chapter 5 Financial Issues for Utilities 1999, p. 5-28, Public Utilities Reports Inc., Vienna, Virginia.
[136] TVA's lease/leaseback arrangements also include a secondary lease with structured payments over time.
[137] One of the benefits of this arrangement is the transfer of the tax benefit of depreciation to the equity investors participating in the lease lease/back transaction that is not available to TVA. Under this type of transaction, the parties typically share in the benefit of the tax benefit being transferred. In this case, TVA realizes a portion of the benefit in lease payments that are passed on to its customers. The equity investors realize the benefits of the deductibility of deprecation as an operating expense and the deferral associated with the timing difference between book and tax depreciation. The value of the portion of the transaction transferred to the counterparty may be viewed as a form of Federal government support, although insufficient information prevents estimating its value in this report.

For the PMAs, the debt values and interest expenses were obtained from their 2006 annual reports. Having actual data on both PMAs' long-term debt and interest on long-term debt allows for a comparison of what that interest might be if PMA's borrowed at IOU rates. The three smaller PMAs have embedded cost of debt below the current 30-year Treasury rate. Although currently all new debt issued by the three smaller PMAs is at or near prevailing Treasury rates, much of their old debt bears interest well below that of similar Treasury debt with comparable maturities at today's rate. Furthermore, unlike TVA, the three smaller PMAs have an advantage unavailable to the Treasury itself in that DOE allows the retirement of high-interest debt first. Therefore, borrowing costs for the 3 smaller PMAs were also measured against borrowing costs at the Treasury rate along with the interest rates for investment grade IOU bonds rated Aaa, Aa, A, and Baa. However, the comparison with an A rating is used as the benchmark.

Tennessee Valley Authority

The TVA was established in 1933 under the Tennessee Valley Act (Public Law 73-17). Its original purpose was to promote economic development in the Tennessee Valley, to improve navigation, and to aid in flood control. TVA is far and away the largest of the Federal utilities, having an asset base greater than that of the four PMAs combined. TVA is operated as an independent government-owned corporation. Its nine-member board of directors is solely responsible for setting rates and for policymaking.[138] The board is appointed by the President of the United States. Unlike the other Federal utilities, TVA's hydropower accounts for a relatively small share of its total generation. In 2006, generation from fossil fuels accounted for 64 percent of TVA's total generation, while nuclear generation accounted for 29 percent, and hydroelectric generation accounted for 6 percent.[139] TVA's service territory covers 8.7 million people located in nearly all of Tennessee and parts of Alabama, Kentucky, North Carolina, Mississippi, Georgia, and Virginia. Tennessee accounted for 64 percent of TVA's electricity sales in 2006. Its wholesale customers include 108 utilities and 20 electric cooperatives. TVA received 87 percent of its revenue from cooperatives in 2006. Memphis Light Gas and Water Division and Nashville Electric Services are the largest utility customers of TVA. The United States Enrichment Corporation is the largest direct service industrial customer.[140]

Prior to the TVA Act of 1959, TVA was financed through Federal appropriations. The 1959 TVA Act authorized the TVA to raise capital on its own—to be "self-financing," allowing TVA considerably more latitude in making its investment decisions. Congress initially imposed a $750 million debt cap on TVA. This debt cap was later raised to $1.75 billion in 1966, $5 billion in 1970, $15 billion in 1975, and $30 billion in 1979. In 2006, long-term debt stood at $26 billion.[141] Since 2000, TVA has not relied on Federal appropriations to fund its non-power operations, such as multipurpose activities and recreational programs, when other sources of revenues, such as user's fees, were insufficient to fund those programs. Funding for these programs has been derived from user fees, other revenues, and electricity sales.

A number of explicit and implicit benefits are received by TVA due to its status. For example, TVA receives implicit interest rate support via a favorable debt rating since it is owned by the

[138] Unlike the PMA administrators who receive their appointments through the Department of Energy, the TVA's commissioners receive their appointments from the President. The Consolidated Appropriations Act of 2005 restructured the board to include nine part time commissions from the previous three full time commissioners. The commissioners are appointed for 5-year terms as compared to the 9-year term appointments under the previous regime. A Chief Executive Officer is to be chosen by the nine-member board. The board is responsible for establishing the broad goals, objectives, and policies of the Corporation and approving an annual budget. Source: Public Law 108-447.

[139] Tennessee Valley Authority, SEC 10-K, 2006, pp. 6, 14, 11, 18.

[140] Tennessee Valley Authority, SEC 10-K, 2006, pp. 9 and 11.

[141] General Accounting Office, Tennessee Valley Authority: *Bond Ratings Based on Ties to the Federal Government and Other Nonfinancial Factors*, GAO-01-540 (Washington, DC, April 2001), p. 3.

Federal government. In general, TVA borrows at rates comparable to those of Federal government agencies. In addition, TVA's customers are required to provide up to 10-years notice before they are allowed to switch their service to another utility. This provides for stability in TVA's revenue from electricity generation. It is also exempt from antitrust laws, an exemption IOUs and the other Federal utilities do not enjoy. EPAct1992 provided an exemption for TVA from amendments to the Federal Power Act that enhanced the Federal Energy Regulatory Commission's (FERC) authority to order utilities to provide transmission service. This exemption is referred to as the "anti-cherry picking" advantage.[142,143] The anti-cherry picking provision although regulatory (and not included as a Federal support in this report) reinforces the financial community's perception that TVA bonds are virtually a risk-free investment.[144] However, the TVA Act of 1959 places strict limits on how much power the TVA can sell outside of its jurisdiction. The TVA Act of 1959 established a "fence" based upon the geographic area of the distributors served by the TVA in 1957.

TVA rates are not regulated by the FERC, nor are its rates subject to State regulation. TVA's Board has complete discretion in setting rates. Over the last decade, TVA's rates have been generally higher than those of surrounding utilities. Until recently, TVA was exempt from the reporting requirements required of publicly-held companies. However, in February 2003, the TVA Board adopted the TVA Corporate Accountability and Disclosure Plan which required TVA to develop corporate practices that reflect the reforms of the Sarbanes-Oxley Act of 2002 (Public Law 107-204), including certification of financial statements and related disclosures by the TVA Board of Directors and the Chief Financial Officer.[145]

Based on these factors, EIA adjusted TVA's outstanding debt to reflect two obligations, which pursuant to Generally Accepted Accounting Practices (GAAP), are not reflected as long-term debt on its balance sheet, but as other liabilities. These liabilities included TVA's (1) obligations pursuant to two lease/lease back transactions associated with 24 generating plants and other system electric system facilities and (2) future obligations to supply power to its largest customer, Memphis Light, Gas, and Water Division (MLGW). MLGW issued tax-exempt debt, the proceeds of which were used to prepay future power supply costs at a discount.[146]

In 2006, the TVA carried over $1.1 billion (2007 dollars) in lease/lease back liabilities on its balance sheet and energy prepayment obligations totaling $1.2 billion (2007 dollars). These obligations have an effect on TVA's cash flow and therefore its ability to meet debt service obligations. The Office of Management and Budget (OMB) treats TVA's lease/lease back arrangements as debt and has advised that this should be included in the TVA's $30 billion debt ceiling.[147] In the FY 2008 budget, the OMB determined "that each of these methods (lease/lease back obligations and prepayment financing methods) is a means of financing the

[142] General Accounting Office, *Tennessee Valley Authority, Debt Reduction Efforts and Potential Stranded Costs*, GAO-01-327, (Washington, DC, February 2001), p. 6.

[143] General Accounting Office, *Tennessee Valley Authority, Assessment of 10-year Business Plan*, GAO/T-AIMD-99-295, (Washington, DC, September 1999), p. 2.

[144] In July 2005, a bill was introduced (S.1499) that would effectively remove any area within Kentucky from coverage by the anti-cherrypicking provision. This bill would require the FERC to mandate that the TVA wheel power from a supplier other than TVA for use inside that portion of TVA's service area that is within Kentucky.

[145] Tennessee Valley Authority: http://www.tva.gov/foia/readroom/policy/prinprac/bun24.htm, accessed October 11, 2007.

[146] In 2003 TVA initiated a pre-payment plan, which allowed TVA customers to pay for their power in advance but in return receive discounted rates, again resulting in a reduction in long-term debt. In 2004, TVA and MLGW, entered into an energy prepayment agreement under which MLGW prepaid TVA $1.5 billion for the future costs of electricity to be delivered by TVA to MLGW over a period of 180 months. TVA reported the prepayment as unearned revenue, and booked future energy sales obligations to MLGW as a long-term liability on its balance sheet. In 2006, TVA reported $1.2 billion (2007 dollars) liability in energy prepayment obligations.

[147] Office of Management and Budget: http://www.whitehouse.gov/omb/budget/fy2004/pma/tvapower.pdf and http://www.whitehouse.gov/omb/budget/fy2004/agencies.html; accessed October 11, 2007.

acquisition of assets owned and used by the Federal government, or refinancing debt previously incurred to finance such assets. They are equivalent in concept to other forms of borrowing from the public, although at different terms and conditions."[148] The GAO also concluded that "while the lease/lease back arrangements are not considered debt for purposes of financial reporting and debt cap compliances, they have substantially the same economic impact on TVA's financial condition and future competitiveness as traditional debt financing…Thus while the lease/lease back arrangements are not treated as debt for financial reporting purposes, they are in essence debt because they have substantially the same economic impact on TVA as traditional debt financing."[149] GAO also noted that GAAP does not require that the lease/lease back arrangements be classified as debt.

For its part, TVA has expressed concerns that applying the $30-billion debt ceiling to lease/lease back arrangements may result in a capital shortfall: "If Congress decides to broaden the type of financial instruments that are covered by the debt ceiling or to lower the debt ceiling, TVA might not be able to raise enough capital to, among other things, service its then-existing financial obligations, properly operate and maintain its power assets, and provide for reinvestment in its power program."[150] TVA records lease/lease back transactions and power prepayment obligations—along with more traditional forms of debt—as Total Financial Obligations (TFOs). In the President's 2007 budget, the TVA indicated that it intended to reduce its TFOs by $7.8 billion by 2016.[151]

In 2006, TVA had outstanding long-and short-term debt of $26 billion (Table 20), which compares to the $33 billion in debt it reported in 1998 (2007 dollars). One method of calculating the value underlying TVA's high credit rating would be to compare TVA's total interest costs against what TVA would pay if it had a lower credit rating. To determine the different levels of borrowing costs under various credit ratings, an estimate of the spread between different interest rates was calculated. The spread between TVA's borrowing costs and alternative borrowing costs presents a measure of the value of TVA's interest rate support. This report uses TVA's Aaa bond rating as a comparison to other interest rates for purposes of measuring Federal support. In other words, if TVA borrowed money at the Aa rate rather than the Aaa rate, its borrowing costs in 2006 would increase 25 basis points, or result in $65 million (2007 dollars) in additional interest expense. This is one measure of Federal support. An A bond rating would raise TVA's 2006 borrowing costs by $124 million (2007 dollars), and the Baa rating by $189 million (2007 dollars). In 1998, an Aa rating would have raised TVA's borrowing costs by $46 million (2007 dollars), an A rating by $88 million (2007 dollars), and a Baa rating by $160 million (2007 dollars). Although the basis point spread between the 30-year Treasury and corresponding utility rates narrowed between 1998 and 2006, the spread between the Aaa utility bonds and all other investment-grade rated utility bonds increased, thereby increasing the estimated support going to the TVA despite lower interest costs and lower debt outstanding. For purposes of a point estimate for this report, the comparison with an A rating yield support of $124 million is used.

[148] Office of Management and Budget, *Analytical Perspectives of the United States Budget, Fiscal Year 2008*, (Washington, 2007), p. 229.

[149] General Accounting Office, *Information on Lease-Leaseback and Other Financing Arrangements*, GAO-03-784, (Washington, DC, June 2003).

[150] Tennessee Valley Authority, SEC 10-K, 2006, p. 42.

[151] Tennessee Valley Authority, http://www.tva.gov/news/reduction_tfo.htm, accessed October 11, 2007.

Table 20. Estimate of Federal Electricity Interest Rate Support to TVA, 1998 and 2006 (million 2007 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
1998					
1. Benchmark Interest Rate (%)	5.58	6.77	6.91	7.04	7.26
2. Outstanding Debt ($)	32,678	32,678	32,678	32,678	32,678
3. Average Cost of Outstanding Debt (%)	6.77	6.77	6.77	6.77	6.77
4. Actual Interest Expense ($)	2,212	2,212	2,212	2,212	2,212
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	1,823	2,212	2,258	2,301	2,372
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	(389)	0	46	88	160
2006					
1. Benchmark Interest Rate (%)	4.91	5.59	5.84	6.07	6.32
2. Outstanding Debt ($)	25,848	25,848	25,848	25,848	25,848
3. Average Cost of Outstanding Debt (%)	5.59	5.59	5.59	5.59	5.59
4. Actual Interest Expense ($)	1,445	1,445	1,445	1,445	1,445
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	1,269	1,445	1,510	1,569	1,634
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	(176)	0	65	124	189

NOTES: The table above presents the historic value of TVA's debt in 2007 dollars for purposes of illustrating how the support values for 1998 and 2006 were calculated. The nominal value of debt reported on TVA's balance sheet was at $26,582 million in 1998.

A negative value for estimated interest support indicates that the weighted average cost of outstanding debt exceeds the benchmark interest rate.

Sources: Tennessee Valley Authority Annual Report 1998 and SEC 10-K, 2006, Moody's Utility Manual, Federal Reserve Bank Form H-15, and Table 18.

The Power Marketing Administrations

The Bonneville Project Act of 1937 (Public Law 75-329) resulted in the creation of the Bonneville Power Administration. The Act required BPA to market hydropower produced from the Columbia River and to promote regional economic development. BPA is the largest of the Federal PMAs and the second largest Federal utility in terms of assets after TVA. The second largest PMA, the Western Area Power Administration (WAPA), was created in 1977 with the Department of Energy Organization Act of 1977 (Public Law 95-91). WAPA was charged with marketing hydropower facilities in the western United States including the power from the Hoover Dam, which was built in 1935. Both the Southwestern Power Administration and the

Southeastern Power Administration owe their existence to the Flood Control Act of 1944 (Public Law 78-534) although the Southeastern Power Administration was not actually created until 1950. The Flood Control Act required: "Electric power and energy generated at reservoir projects under the control of the Department of the Army and in the opinion of the Secretary of the Army not required in the operation of such projects shall be delivered to the Secretary of the Interior, who shall transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rate to consumers consistent with sound business principles…Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years. Preference in the sale of such power and energy shall be given to public bodies and cooperatives. The PMAs operate within the Department of Energy and the Secretary of Energy selects the PMA administrators."

The PMAs sell about 5 percent of the Nation's electricity, virtually all of it wholesale. BPA's service territory covers Washington, Oregon, and small pieces of western Montana and western Wyoming. WAPA covers California, Nevada, Utah, Arizona, New Mexico, Utah, most of Montana, most of Wyoming, west Texas, North and South Dakota, Nebraska, western and southern Kansas, and the western edges of Minnesota and Iowa. The SWPA serves the rest of Kansas, Missouri, and Oklahoma, the rest of Texas, Arkansas, and Louisiana. The SEPA serves Illinois, West Virginia, Kentucky, Tennessee, Mississippi, Alabama, Georgia, and the Florida panhandle, North and South Carolina, and Virginia.

BPA's Borrowing Costs

BPA receives no direct payment from the Treasury. Rather, the support it receives is implicit, involving the interest it pays on its debt. As with all other Federal utilities, BPA is a not-for-profit enterprise and prices its power to recover its operating and capital costs. Although in large measure BPA's lower prices are the result of its access to low-cost generation from Federal hydropower facilities, below-market borrowing costs also contribute. The size of BPA's estimated Federal interest rate support is a function of the interest rate chosen to reflect the appropriate "market" interest rate, as discussed below. For purposes of a point estimate for this report, a comparison with A-rated debt is used (Table 20).

Appropriated Debt. BPA appropriated debt refers to the unpaid portion of pre-1992 appropriations by Congress to fund the construction and replacement of U.S. Army Corps of Engineer's generation facilities.[152] Since passage of the EPACT1992, BPA has been required to fund these operations directly. BPA's appropriated debt was restructured in 1996. Under the BPA Appropriations Refinancing Act of 1996[153] (The Refinancing Act), BPA reduced its principal obligation of the debt by $2.5 billion based on the present values of its debt service payment. It was then required to pay interest on the restated principal balance based on prevailing Treasury rates as of October 1996.[154] The $2.5 billion reflects the difference between BPA's original principal balance and restated principal. It appears on BPA's financial statements as a

[152] This includes some funding for fish and wildlife recovery.
[153] 16 U.S.C. 838l.
[154] The Act also required the BPA to pay the Treasury an additional $100 million, prorated over the course of the appropriations. This value was incorporated by BPA into its interest payment on appropriated debt and was captured in the interest support estimated in this chapter. In 2006, BPA's appropriated debt stood at $6.4 billion. This includes a capitalization adjustment of $2.1 billion, which was included under appropriated debt prior to 1997. In 1997, the principal on BPA's appropriated debt was reduced by $2.6 billion while interest on the debt was raised to 7.1 percent from 3.5 percent. BPA realized a $100-million dollar transaction cost as a result of this principal and interest adjustment.

Capitalization Adjustment. Because BPA sets its own rates, it is able to record the Capitalization Adjustment on its balance sheet as a regulatory liability and to amortize through its income statement under Financial Accounting Standards Board Announcement No. 71 (FAS No. 71). In the absence of meeting the requirements of FAS No. 71, BPA would be required to write off the Capitalization Adjustment. In other words, the Refinancing Act obligated BPA to pay a higher interest rate on a lower amount of debt. After the refinancing, the total cash flow to the Treasury, including a $100 million up-front cash payment, yields the same present value as BPA's pre-refinancing obligation.

In 2006, BPA's appropriated debt plus the Capitalization Adjustment equaled $6.4 billion (2007 dollars) versus $8.4 billion in 1998 (2007 dollars). The nominal value of BPA's appropriated debt was $6.9 billion in 1998. BPA's estimated interest rate on its average embedded cost of funds was 4.3 percent in 2006.

Long-Term Debt. BPA's long-term debt primarily funds its transmission system. In 1974, the Congress, as a part of the Columbia River Transmission Act (Public Law 93-454), allowed BPA an amount limited to a nominal $4.5 billion in direct borrowing authority from the Treasury with $3.2 billion earmarked to fund the utility's transmission and other investment capital program and $1.3 billion for conservation and renewable energy investments. The appropriations are to be repaid to the Treasury by BPA. This long-term debt is actually a combination of medium- and long-term maturities. The debt is held by the Treasury at interest rates set by the Treasury, which approximate the interest rates paid by government agencies. The rates are adjusted to reflect the cost of specific features of BPA's bonds. In 2006, BPA's long-term debt equaled approximately $1.9 billion versus $2.8 billion in 1998 (2007 dollars). The nominal value of BPA's debt equaled $2.4 billion in 1998.

Non-Federal Projects Debt. Non-Federal projects debt stems from BPA's assumption of the payment obligation on the debt of three Washington State Public Power Supply System (WPPSS) nuclear projects and several smaller generation and conservation investments. In 2000, BPA's one commercially-operating reactor, WNP-2 was renamed the Columbia Generating Station. During the 1980s, WPPSS defaulted on nuclear units 4 and 5.[155] WPPSS is now known as Energy Northwest. [156] Energy Northwest is responsible for the financing of Nuclear Projects 1, 2, and 3.[157] As a result of its net billing arrangements, BPA passes on the cost of its non-Federal project debt to its customers. Net billing agreements are contractual arrangements under which the BPA bills participants in its inoperable Trojan nuclear plant[158,159] and the Columbia Generating Station. Each participant assigns its share of output to the BPA and in return BPA credits the participant's wholesale bill up to the monetary value of the participant's share of the generation output.[160] Thus, non-Federal project debt is not actually issued by BPA, but rather it is issued by Energy Northwest with BPA as the obligor pursuant to a net billing power supply arrangement.[161]

[155] Myers, Elaine and David, Lessons from WPPSS, "In Context," Volume No. 7, p. 28 August 1984. See, http://www.context.org/ICLIB/IC07/Myers.htm
[156] Unit 4 is located at Richland, Washington while unit 5 is located at Satsop, Washington.
[157] The only operating unit among these is Project 2, the Columbia Generating Station.
[158] The Trojan project is among Bonneville's terminated nuclear plants along with Energy Northwest Nuclear Projects 1 and 3.
[159] BPA charges preference customers' entitlement shares of output from the abandoned Trojan project. BPA became responsible for Trojan's debt service and decommissioning costs.
[160] Bonneville Power Administration: http://www.bpa.gov/Power/PSR/pbl_billing_procedures.pdf, accessed October 11, 2007.
[161] Standard and Poor's notes that "Debt service on the $7.17 billion of outstanding ENW debt as of March 1, 2007 is legally an operating expense of Bonneville." Source: Standard and Poor's Public Finance: http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/SP_2_17_04.pdf, accessed October 11, 2007.

In 2006, approximately $4.0 billion of BPA's $6.6 billion (2007 dollars) in non-Federal project debt was devoted to cancelled nuclear power plants. Although the Federal government does not explicitly guarantee BPA's non-Federal debt, the financial community treats the debt as though it was guaranteed. BPA is line agency within DOE, and for its latest debt financing in 2007, Standard and Poor's and Fitch Ratings assigned newly issued Energy Northwest revenue and refinancing bonds an AA- rating.[162] Moody's rated the bonds as Aaa.[163] According to Moody's: "The Aaa rating is rooted in the strength of the legal arrangements between Energy Northwest and the Federal entity that provides the underlying security for the bonds, Bonneville Power Administration…Credit strength is derived from BPA's status as a line agency of the U.S. Department of Energy and the strong relationship with the U.S. Government that allows for direct borrowing authority with the U.S. Treasury and the legal ability to defer annual Treasury repayment when necessary to meet commitments under the net billing agreements."[164,165] In Moody's High Profile New Issue, dated April 2004, the credit rating agency states: "Contributing to the Aaa rating on the Energy Northwest bonds are the evident implicit support by the Federal government for Energy Northwest bonds through BPA and BPA's established record of full cost recovery from its business operation and rates."[166] In providing its AA- rating to Energy Northwest debt, Fitch notes that payments of debt to the U.S. Treasury is subordinate to payment on Energy Northwest debt. Fitch also notes that the positive support for the rating is BPA's position as a leading provider of electricity and transmission in the Pacific Northwest and its highly competitive wholesale power rates.

In the estimate of BPA's Federal interest rate support presented below, the interest cost of BPA's non-Federal power debt is compared to the cost of similar debt issued by IOUs. This methodology is not without controversy. On the one hand, although much of BPA's Energy Northwest debt is exempt from Federal taxation, BPA is obligated to pay the debt service on Energy Northwest bonds and this debt appears on the balance sheet of a Federally-owned utility.[167] As obligor of this debt, whatever tax-free status this debt enjoys due to it "municipal" status, is deemed not relevant to the calculation of interest support provided through implicit Federal ownership and backing. However, an alternative view might be to compare the cost of this debt to the cost of debt on tax-free municipal bonds.

BPA's Federal Interest Support

The difference between BPA's current total cost of funds compared to what it would have spent had it borrowed at the U.S. Treasury rate and various IOU rates varies by the alternative interest rate selected (Table 21). Borrowing at the Treasury 30-year bond rating would have cost BPA an additional $19 million, in 2006. Borrowing at a public utility rating of Aaa would have cost BPA an additional $120 million (2007 dollars); an Aa rating would have cost BPA an additional $157 million (2007 dollars); an A rate would have cost BPA an additional $191 million (2007 dollars) over its 2006 interest charges; and, a Baa rating an additional $228 million (2007

[162] Standard and Poor's Public Finance, Bonneville Power Administration: http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/2007/S%20&%20P%20Report.pdf. Accessed October 15, 2007.
[163] S&P and Fitch have provide issue ratings that are applicable to the specific bonds. Moody's has provided an issuer rating corporate rating that applies to the enterprise and not specific bond issues.
[164] Bonneville Power Authority, Ratings Update: Energy Northwest, WA, March 19, 2004, http://www.bpa.gov/corporate/Finance/Debt_Management/reports_articles/docs/Moodys_3_19_04.pdf, accessed October 11, 2007.
[165] Net billing agreements are an arrangement under which the more than 100 Northwest utilities purchased all of the project capability of Nuclear Project No. 1, Columbia and Energy Northwest's 70 percent ownership of Nuclear Project No. 3. These utilities resold their electricity to BPA and in return BPA is required to finance the annual costs of these projects. Source: Energy Northwest, http://www.energy-northwest.com/annualbudgetdownloads/Final%202008%20Glossary.pdf, accessed October 11, 2007.
[166] Moody's Investors Service, *High Profile New Issue*, April 2004.
[167] Certain Energy Northwest bond issues are also enhanced with bond insurance.

dollars). These values represent an increase from 1998 when, for instance, borrowing at an A rating would have raised BPA's borrowing costs by $138 million over the Treasury rate. A large portion of the reduction in borrowing costs can be attributed to the $4.7-billion reduction in debt between 1998 and 2006. For purposes of a point estimate for this report, the comparison with the A rating is used.

Table 21. Estimate of Federal Electricity Interest Rate Support to BPA, 1998 and 2006 (million 2007 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
1998					
1. Benchmark Interest Rate (%)	5.58	6.77	6.91	7.04	7.26
2. Outstanding Debt ($)	19,610	19,610	19,610	19,610	19,610
3. Average Cost of Outstanding Debt (%)	6.34	6.34	6.34	6.34	6.34
4. Actual Interest Expense ($)	1,243	1,243	1,243	1,243	1,243
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	1,094	1,328	1,355	1,381	1,424
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	(149)	85	112	138	181
2006					
1. Benchmark Interest Rate (%)	4.91	5.59	5.84	6.07	6.32
2. Outstanding Debt ($)	14,810	14,810	14,810	14,810	14,810
3. Average Cost of Outstanding Debt (%)	4.78	4.78	4.78	4.78	4.78
4. Actual Interest Expense ($)	708	708	708	708	708
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	727	828	865	899	936
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	19	120	157	191	228

NOTES: BPA's debt values are exclusive of BPA's current liabilities. BPA's current liabilities consist of payments to the Treasury to fund Federal post retirement programs and irrigation assistance programs. The table above presents the historic value of BPA's debt in 2007 dollars for purposes of illustrating how the support values for 1998 and 2006 were calculated. The nominal value of the debt reported on BPA's balance sheet was at $15,951 million in 1998.

A negative value for interest rate support indicates that the weighted average cost of outstanding debt exceeds the benchmark interest rate.

Sources: Bonneville Power Administration 1998 and 2006 Annual Reports and Table 18.

The Smaller Power Marketing Administrations

The three smaller PMAs are the SEPA, the SWPA, and the WAPA. Each is headed by an administrator appointed by the Secretary of Energy. More so than either BPA or TVA, the three smaller PMAs benefit from low-cost hydropower dams that were built as long as 60 years ago. The PMAs receive appropriations from the Treasury for most of their operations and maintenance expenses, as well as for capital expenditures. The former is expected to be paid off in the year it is received; the latter can be paid back with interest over the service life of the investment, for a period not to exceed 50 years. In the 2007 budget, the OMB proposed that the borrowing costs of the three PMAs be raised to those of a "government corporation."[168] This would raise the rate charged by the Treasury to the PMAs closer to the rate the BPA pays on its long-term debt. In a 2008 budget document, the Bush Administration proposed an initiative to charge the three smaller PMAs interest rates on new capital investments, occurring after September 30, 2006, at levels similar to those charged to governmental corporations.[169] In 2006, the PMAs' embedded cost of debt was more than 100 basis points below the Treasury's own borrowing costs.

Before 1983, the interest rate on the three smaller PMAs' debt was set below prevailing Treasury rates. In 1983, DOE required the PMAs to pay a rate equal to the average Treasury yield during the previous fiscal year for new projects. According to an OMB study on PMA debt repayment, the Treasury has made a practice of borrowing money for the PMAs at 6 to12 percent and accepting repayments on that debt at 2 to 4 percent.[170] The PMAs are required to retire their high-cost debt first whenever possible, an advantage unavailable to the Treasury itself.[171] This is another reason that the PMAs can realize an effective borrowing rate lower than the Treasury.[172]

PMA Borrowing Costs

The three PMAs' current interest expense was compared to what they would have paid had they borrowed at long-term Treasury rates or A, Aa, Aaa, or Baa IOU rates. The Federal interest rate support is estimated as the difference between a hypothetical interest payment based on Treasury and market interest rates and the actual interest expense reported by each PMA. Depending on the comparative interest rate benchmarks, the three smaller PMAs received Federal support ranging from $69 million (2007 dollars) if their debt were priced at the Treasury rate to $164 million (2007 dollars) at the Baa rate in 2006 (Table 22). This compares with no estimated support at the Treasury rate[173] in 1998 (2007 dollars) and $92 million at the Baa rate. Based upon an A utility rate, the PMA interest support rose from $77 million to $148 million. This latter value is used as the point estimate for purposes of this report.

[168] Department of Energy, Budget 2007, www.cfo.doe.gov/budget/07budget/Content/Highlights/Highlights.pdf. Accessed March 5, 2008.
[169] http://www.whitehouse.gov/omb/budget/fy2008/pdf/budget/energy.pdf
[170] Office of Management and Budget, "Fact Sheet on Reform of Federal Power Marketing Administration Debt Repayment Practices," (Washington, DC, 1990).
[171] IOUs have the ability to issue callable bonds which allows them the same advantage. However, when a bond is called, typically the issuer of the bond pays the bondholder a premium above the par value of the bond.
[172] General Accounting Office, Federal Power: *Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry*, GAO/RCED-98-43, (Washington, DC, March 1998), p. 7.
[173] When the PMA have average embedded borrowing costs below that of the U.S. Treasury, estimated Federal interest rate support is nonexistent.

Table 22. Estimate of Federal Electricity Interest Rate Support to the Three Smaller PMAs, 1998 and 2006 (million 2007 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
1998					
1. Benchmark Interest Rate (%)	5.58	6.77	6.91	7.04	7.26
2. Outstanding Debt ($)	7,060	7,060	7,060	7,060	7,060
3. Average Cost of Outstanding Debt (%)	5.96	5.96	5.96	5.96	5.96
4. Actual Interest Expense ($)	420	420	420	420	420
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	393	478,	488	497	513
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	(27)	57	67	77	92
2006					
1. Benchmark Interest Rate (%)	4.91	5.59	5.84	6.07	6.32
2. Outstanding Debt ($)	6,742	6,742	6,742	6,742	6,742
3. Average Cost of Outstanding Debt (%)	3.88	3.88	3.88	3.88	3.88
4. Actual Interest Expense ($)	262	262	262	262	262
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	331	377	394	409	426
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	69	115	132	148	164

NOTES: 2006 data for WAPA were obtained from their 2006 Annual Report. 2006 data for SEPA were extrapolated based on 2005 data appearing in SEPA's 2005 Annual Report. SWPA produced a single 2004-2006 Annual Report with a 2006 income statement but with a balance sheet lacking U.S. Army Corp of Engineer data. SWPA's outstanding debt was extrapolated from 2003 data reported in its 2003 Annual Report.

The table above presents the historic value of 3 smaller PMAs debt in 2007 dollars for purposes of illustrating how the support values for 1998 and 2006 were calculated. The collective value of the debt reported on the 3 smaller PMA's balance sheets has not changed due to inflation. The nominal value of their debt stood at $5,743 million in 1998.

A negative value for interest rate support indicates that the weighted average cost of outstanding debt exceeds the benchmark interest rate.

Sources: Southeastern Power Administration, Annual Reports, 1998 and 2004-2006, Western Area Power Administration, Annual Reports, 1998 and 2006.

Rural Utilities Service Electric Loans, Guarantees, and Grants

RUS is an agency within USDA. In 2005, the RUS served nearly 12 million customers and provided 7 percent of the Nation's electricity (Table 23). RUS is the successor to the Rural Electrification Administration (REA). It was established under the Federal Crop Insurance

Reform and Department of Agriculture Reorganization Act of 1994 (Public Law 103-354) as one of the Federal program agencies authorized to provide financial and technical assistance under the USDA Rural Development Mission Area. REA was created by Executive Order in May 1935. The functions and authority of the REA administrator were initially codified with the passage of the Rural Electrification Act of 1936 (the REAct).[174] The REAct, as amended, authorizes the RUS to provide direct loans and loan guarantees to electric utilities serving customers in rural areas.[175] RUS loans and loan guarantees may be used to finance the construction of electric distribution, transmission, and generation facilities, including system improvements and replacement required to furnish and improve electric service in rural areas. Borrowers may also submit applications to finance demand side management, energy conservation programs, and on-grid and off-grid renewable energy systems. Entities eligible to apply for loan and loan guarantees include corporations, States, territories, and subdivisions and agencies such as municipalities, people's utility districts, and cooperative, nonprofit, limited-dividend, or mutual associations that provide retail electric service needs to rural areas or supply the power needs of distribution borrowers in rural areas. Section 3 of the REAct[176] provides that a preference be given to government-owned utilities (e.g., State, municipal and public power districts) and cooperatives.

To qualify for loans and loan guarantees, borrowers must demonstrate financial feasibility, i.e., that all loans will be repaid in accordance with their terms, and provide adequate security pursuant to the RUS mortgage and loan contract. In addition, the borrower must demonstrate that it serves customers in rural areas in accordance with Section 13 of the RE Act.[177] Borrowers that meet this test are referred to as REAct beneficiaries.

The original mission of RUS was to facilitate electrification of rural America. Suburban growth into cooperatives' service areas heretofore deemed rural has raised questions concerning the extent to which current recipients of RUS are receiving loans and loan guarantees, a portion of which benefits customers in non-rural areas. The results of a USDA analysis of borrower and community characteristics for $3.3 billion in financing approved in 2005 were in connection with power supply, transmission, and distribution loans in 1,682 of 2,500 non-metropolitan counties that included 332 counties classified as persistent poverty counties. The distribution loans supported investment in facilities to serve approximately 2 million consumers of which 92.5 percent were classified as rural by the Census Bureau.[178]

The FY 2008 budget proposed two programmatic reforms. First, in recognition of the deregulation of wholesale electric markets, RUS will focus on providing financial assistance for transmission and distribution facilities. It will continue to provide funding for upgrading existing generation, but G&Ts should be expected to consider commercial capital markets for funding new generation. Second, the budget proposed that RUS promulgate rules requiring electric and telecommunications borrowers to recertify their rural status commencing with their first loan request submitted in or after 2008 and the first loan requested after each decennial Census.[179]

[174] 7. U.S.C. 901, et seq.
[175] In addition to the Electric Loan Program, RUS administers loan programs for infrastructure investment in rural telecommunications systems (i.e., telephony, broadband, distance learning, telemedicine) and water and wastewater systems.
[176] 7 U.S.C. 903.
[177] 7 U.S.C. 913.
[178] Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2008—Appendix*, Department of Agriculture, p. 146. See, http://www.whitehouse.gov/omb/budget/fy2008/appendix.html.
[179] Ibid. In the FY 2008 budget, the Congress approved a provision precluding RUS from incurring administrative expenses, drafting regulations, or implementing rules that require recertification of rural status. See, House Report 110-497, Division A-Agriculture Rural Development, Food and Drug Administration and Related Agencies Appropriation Act of 2008, Title VII, Section 726.

The total population of RUS borrowers has declined as distribution borrowers and G&Ts have paid off their RUS loans. Since 1986, 224 distribution cooperatives prepaid their loans at a discount as provided in RUS regulations. The number of power supply borrowers has declined over the past 15 years as financially-distressed borrowers were liquidated or exited the program as part of debt settlement or bankruptcy reorganization plans. The number of consumers served by the RUS borrowers in 2005 accounted for 6.6 percent of total electricity sales (Table 23).

Table 23. Key Statistics for the Rural Utilities Service Electricity Program, 1998 and 2005

Statistic	1998		2005	
	RUS Borrowers	RUS Borrowers as Percent of National Total	RUS Borrowers	RUS Borrowers as Percent of National Total
Retail Consumers Served	10,858,441	8.7	11,548,604	8.2
End-Use Sales (thousand megawatthours)				
Residential	125,210	11.1	144,944	10.7
Commercial/Industrial	84,269	4.1	100,568	4.4
Other	8,166	7.9	7,523	NA
Total Sales	217,645	6.7	253,035	6.6

NOTE: Other sales include street lighting sales, sales to public authorities, railroads and railways, and interdepartmental sales.

EIA no longer collects data for the “Other” sector.

Sources: Rural Utilities Service, *1998 Statistical Report Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), pp. 10 and 14, and *2005 Statistical Report Rural Electric Borrowers*, IP 201-1 (Washington, DC, December 2006), pp 10. Energy Information Administration, *Electric Power Annual 1998*, Volume 2, DOE/EIA-0348(89/2) (Washington, DC, December 1999) and *Electric Power Annual 2005*, Table ES1: http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfilees1.pdf

The RUS Electric Program provides financial assistance to eligible borrowers by making direct loans and providing loan guarantees for loans made by the Federal Financing Bank (FFB) to distribution and power supply borrowers. Additionally, the Farm Security and Rural Investment Act of 2002 (2002 Farm Bill) amended the REAct by adding Section 313A,[180] which authorizes RUS to guarantee bonds and notes to eligible cooperatives and non-profit lenders.[181] RUS also administers a grant program to mitigate high energy costs for those entities that meet the eligibility criteria. The five electric loan programs and grant program administered by RUS are described below.

Hardship Loans

Hardship loans are available to electric distribution borrowers that have experienced an unavoidable natural disaster. They are also available to electric distribution borrowers that meet a rate disparity and consumer income test that compares the borrower’s retail rates and its

[180] 7 U.S.C. 940c-1; Guarantees for bonds and notes issued for electrification and telephone purposes.
[181] Public Law 107-171.

customers' per capita or household income to statewide values.[182] The hardship loans may be used for distribution, subtransmission, and headquarters facilities. The loan carries a fixed 5-percent interest rate for a term equal to the lesser of the useful life of the facilities, or 35 years.[183]

Municipal Rate Loans

These loans are available to finance distribution, subtransmission, and headquarters facilities. Distribution and power supply borrowers may participate in this program. Power supply borrowers participation is limited to subtransmission and headquarters facilities. The interest rate is established quarterly by RUS based on a municipal bond market index for loans of comparable maturity. The interest rate is determined when loan funds are advanced. The term of the loan is equal to the lesser of the useful life of the facilities being financed, or 35 years. The borrower must obtain supplemental financing from another lender for typically 30 percent of the loan amount. Traditionally, cooperatives have relied upon CoBank and the CFC to meet the supplemental lending requirement.[184]

Treasury Direct Loans

Treasury Direct loans are available to distribution cooperatives to construct distribution, subtransmission, headquarters facilities and renewable generating facilities. Power supply borrowers may participate in this program to finance renewable generating facilities. Interest rates are set daily by the Treasury Department based on its current cost of money over a yield curve with maturities ranging from 3 months to 30 years. The interest rate is set on the date of each advance of approved loan funds to the borrower. The term of a Treasury Direct loan is set at the lesser of the useful life of the facilities being financed, or 35 years. There is no supplement financing requirement associated with this program.

FFB Guaranteed Loans

RUS guarantees of FFB loans are available to distribution and power supply borrowers to finance distribution, transmission, generation, and headquarters facilities. The interest rate for FFB loans is established daily by the Treasury Department based on its current cost of money plus one-eighth of 1 percent. The interest rate is set on the date of each advance of approved loan funds to the borrower.[185] The term of an FFB loan may not exceed the lesser of the useful life of the facilities, or 35 years.[186] The wholesale power contract between power supply

[182] Residential and average system rates must not be less than 120 percent of the average for all utilities in the State and either per capita income or household income must be less than State average per capita income or the State median household income. (See, 7 CFR 1714.8).

[183] The interest rate for hardship loans was increased from 2 percent to 5 percent in the Rural Electric Loan Restructuring Act of 1993 (Public Law 103-129).

[184] The Municipal Rate loan program was created with the enactment of Rural Electric Loan Restructuring Act of 1993.

[185] Under the FFB Note, borrowers may opt for a long-term maturity date (e.g., 35 years), but select interim maturity dates to obtain the benefit of lower interest rates associated the Treasury Department's lower cost of money for securities with shorter maturities. At the interim maturity date, the note reprices based on the applicable rate for the next interim maturity date selected by the borrower. Alternatively, the borrower has the option of paying off the loan. See, RUS Bulletin 1710b-1 Guide to Federal Financing Bank Loans Guaranteed by RUS at http://www.usda.gov/rus/regs/bulls/1710b-1, accessed October 11, 2007.

[186] The Agricultural, Rural Development, Food and Drug Administration and Related Agencies and Appropriation Act of 2006 (Public Law 109-97) amended the RE Act by adding Section 316, which provides for the term extension of FFB loans guaranteed by RUS for power plants and transmission facilities. The primary purpose of this amendment was to permit power supply cooperatives to extend the term of loans on nuclear power plants to be coterminous with NRC license extension. In the absence of a term extension, the prospective reduction in depreciation expense based on the license extension can create an adverse mismatch between cash flow and principal payments on existing loans with a maturity date coterminous with the termination of the existing NRC operating license. Under Section 316, borrowers are permitted to apply for term extensions for nuclear, fossil and transmission facilities. Extensions are permitted subject to the borrower demonstrating financial feasibility, sufficient collateral to support the loan extension, and, where applicable, regulatory orders (i.e., NRC orders extending operating licenses). Borrowers are required to pay a modification fee based on the requirements of Section 502 of the Federal Credit Reform Act of 1990 (Public Law 101-58), as amended (2 U.S.C. 661a).

borrowers and their distribution members is pledged as security for FFB guaranteed loans. Accordingly, the loan may not exceed the terms of the contract.

Guarantees for Bonds and Notes Issued for Electrification and Telephone Purposes

Under this program, RUS guarantees bonds and notes issued by cooperatives and not-for-profit lenders to the FFB. Eligible cooperatives and not-for-profit borrowers participating in the program are required to pay a 30-basis point annual fee for the guarantee. It is applied to the unpaid principal. Up to one-third of the 30-basis point guarantee fee may be used to pay for the guarantee. This amount may be adjusted by Congress or at the mutual consent of RUS and the borrower to ensure sufficient funds are available to pay for the guarantee. The remaining portion of the guarantee is deposited in the Rural Economic Development Subaccount, which funds the Rural Economic Development Loan and Grant Fund (REDLG).[187]

Under this program, eligible applicants identify existing secured loans not previously pledged as collateral to secure bonds purchased by FFB. The bonds may have a maximum maturity of 20 years. If the guaranteed lender's credit rating, irrespective of the RUS guarantee, on senior secured debt falls below A, it must provide the secured loans identified as collateral to RUS. The guaranteed lender, RUS and FFB must execute various security agreements including a guarantee agreement and bond purchase agreements for an amount not to exceed the maximum funding authorized by Congress. The guaranteed lender must submit documentation for advances under the bond document at which time the interest rate and term are determined. Presently, the CFC is the only non-profit lender participating in the program. Congress has authorized RUS to guarantee $2 billion for which CFC has executed Bond Purchase Agreements with RUS and FFB.

The proceeds from any advances made to CFC may not be used to directly or indirectly fund generation projects. The guaranteed bond proceeds may be used for electrification and telephony purposes or to refinance debt previously issued by the guaranteed lender. The funds may not be used to reduce interest rates on new or outstanding loans other than supplemental loans issued under the Municipal Rate program.[188] CFC executed a Series A Bond Purchase Agreement with FFB and RUS with a loan commitment amount not to exceed $1 billion on June 14, 2005. A Serial B Bond Purchase Agreement was executed on April 28, 2006 with a loan commitment amount not to exceed $1.5 billion.[189] In addition to providing a source of funding for the Rural Development REDLG program, this loan program provides CFC with another source of liquidity to reduce its borrowing cost, which in turn reduces cooperatives' cost of borrowing from CFC. According to CFC's 2007 SEC Form 10-K, as of May 31, 2007, it has pledged $2.8 billion of loans to the trust for $2 billion in notes payable to RUS. There is not sufficient data available to determine the benefit that CFC borrowers receive in lower borrowing costs from this program.[190]

[187] The REDLG program provides funding to rural projects through local utility organizations. The program is administered by the Rural Business-Cooperative Service (RBS), which is in the USDA Rural Development Mission Area. Under the loan program, USDA provides zero interest loans to local utilities which they, in turn, pass through to local businesses (ultimate recipients) for projects that will create and retain employment in rural areas. The ultimate recipients repay the lending utility directly. The utility is responsible for repayment to RBS. The grant program provides funds to local utility organizations to establish revolving loan funds. Loans are made from the revolving loan fund to projects that will create or retain rural jobs. When the revolving loan fund is terminated, the grant is repaid to RBS.

[188] For a complete description of the application process, eligibility criteria, collateral and creditworthiness requirements see RUS Regulation Guarantees for Bonds and Notes for Electrification or Telephone Purposes, 7 C.F.R. 1720 (2004).

189 The Bond Purchase Agreements and related documents are available on the Securities Exchange Commission website (EDGAR) as exhibits to CFC's SEC 10-K.

[190] Based on the assumed default rate and recovery rate, and the 30 basis point payment over the Treasury's borrowing cost to pay for the guarantee, OMB estimated that the FY 2007 subsidy for this program was a negative $5 million. Accordingly, no budget

Assistance to High Energy Cost Communities

The High Energy Cost Grant Program provides financial assistance to communities with home energy costs in excess of 275 percent of the National average.[191] The program provides grants for the improvement of energy generation, transmission, and distribution facilities serving eligible rural communities. Eligible applicants include legally-organized for-profit or non-profit organizations, sole proprietorships, State or local government, or any agency or instrumentality of a State or local government, including a municipal utility or public power authority, Indian tribes, a tribally-owned entity, an Alaska Native Corporation, or other area authorized by law to participate in RUS programs or under the RE Act. Eligibility may be established using average annual household expenditures for individual fuels or for total energy, or average per unit cost for home energy.

Grants under this program may be used for the acquisition, construction, installation, repair, replacement, or improvement of energy generation, transmission, or distribution facilities in communities with extremely high energy costs. On-grid and off-grid renewable energy projects, energy efficiency, and energy conservation projects are eligible.[192]

Cost of Loan Support Provided to RUS Electricity Borrowers

The RUS programs reduce the cost of borrowing to its borrowers relative to the contemporaneous cost of long-term secured debt in private capital markets. Enumerating the savings that flow to RUS borrowers requires assessing the administrative costs of running the RUS programs, the costs RUS incurs by loaning money to its borrowers at interest rates below the Treasury's cost of money, the costs RUS incurs when it covers defaults on loans it has guaranteed, and measuring the benefit RUS borrowers receive from being able to borrow money below competitive market interest rates. If the RUS did not exist, many of these costs would be borne by the borrowers in the form of higher fees and interest rates.

The benefit of the interest rate subsidy received by RUS borrowers is a function of the spread between the cost of borrowing from RUS relative to cost of long-term debt available in commercial capital markets. The latter reflects a risk premium associated with a borrower's credit worthiness. Absent the interest rates and remaining term to maturity for all direct loans and loan guarantees that RUS holds in its portfolio, it is difficult to obtain a present value estimate of the benefit received by RUS borrowers over the life of the existing loan portfolio. Therefore, the interest rate subsidy estimate contained in this report provides a 1-year snapshot of the subsidy by comparing the embedded cost of RUS loans and loan guarantees to the Treasury rate and a range of electric utility investment grade bonds for 2006. The difference in interest rates approximates the benefit consumers served by RUS electric borrowers received in 2006.[193]

The measurement of financial support provided to RUS borrowers has market risk and opportunity cost implications for the Federal government.[194] The difference between the

authority is required. See, Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2008-Appendix,* Department of Agriculture, p. 146.

191 The 275 percent criteria are measured on the basis of either annual expenditures per household or in unit cost of designated energy sources including electricity, liquefied petroleum gas, natural gas, fuel oil and total household energy consumption (dollars per year or dollars per Btu). The benchmark values are derived from Energy Information Administration data.

192 On May 25, 2005, RUS provided $19.5 million in high energy cost grants. On August 17, 2007, it issued a Federal Register Notice of Availability of Funding for $21.9 million.

193 Data for 2006 were extrapolated based upon RUS 2005 data and the gross domestic product (GDP) implicit price deflator.

194 In a 2004 study the Congressional Budget Office (CBO) examined the impact of using the risk-free Treasury rate versus a risk-adjusted commercial rate to measure the cost of Federal credit programs. CBO concluded that "for all programs, ignoring the cost

Federal utilities and RUS is that as a Federal credit agency RUS is required to calculate the subsidy associated with its loan and loan guarantee programs. This calculation is required by the Federal Credit Reform Act of 1990 (FCRA) (Public Law 101-158) and is included in the budget. FCRA requires that Federal agencies are required to calculate the lifetime costs for direct loans and loan guarantees for a budget year based on the expected cash flows for loan disbursements, fees, and repayment, taking into account default risk and recovery rates. The difference between present value of the cash outflows (disbursements) and cash inflows represents the subsidy. This value constitutes the budget authority for an authorized level of loans and loan guarantees for that fiscal year. The cash flows are discounted using the interest rate for marketable Treasury securities of comparable maturity. If a loan or loan guarantee is truly risk-free, then the subsidy value is equal to the market value. However, if the loan or loan guarantee is not a risk-free loan, the use of the Treasury rate as the discount rate understates the market risk of the loan. This may be the case with the RUS electric loan program, specifically with the loan guarantee program. Under the loan guarantee program, borrowers pay interest at the Treasury's cost of money at the time funds are advanced, plus 12.5 basis points, i.e., one-eight of 1 percent.[195] Thus, under the methodology required to calculate the subsidy under FCRA, interest paid on FFB guaranteed loans is always computed at a rate that exceeds the discount rate used to determine the value of the subsidy. Therefore, unless the assumed default rate is very high (a reflection of a lack of creditworthiness) and the recovery rate is extremely low, the FCRA calculation can result in a negative subsidy.

The actual FY 2007 subsidy estimate for the RUS electric program consisted of the $3 million for the Hardship Loan program and a ($36) million for the Federal Financing Bank (FFB) loan guarantee program. Therefore, excluding program administration costs, the loan program generated net income of $33 million because of the negative subsidy associated with the loan guarantee program.[196] EIA used the same cost of capital method applied to the Federal utilities to estimate support provided to RUS borrowers. A range of subsidy values was estimated for RUS loans to G&Ts and distribution cooperatives, as well as a point estimate that reflects a market rate of interest for an A-rated IOU. The A rating was based on an analysis of the financial ratios for all rated G&Ts.

As a surrogate measure, the weighted average interest rate, i.e., embedded cost of debt, of RUS borrowers is compared with the 2006 average 30-year Treasury Constant Maturity, and the 2006 Aaa, Aa, A, and Baa IOUs. The range is provided, because it is unclear what rate US

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of risk understates the federal cost of credit assistance, potentially biasing the allocation of budgetary resources." See, *Estimating the Value of Subsidies for Federal Loans and Loan Guarantees,* Congress of the United States, Congressional Budget Office, (Washington, DC, August 2004), p. 4.

[195] In a 1982 report, the Congressional Budget Office stated that a borrower with an FFB guaranteed loan would have to pay 50 basis points to issue securities in the market. See, Congressional Budget Office, *The Federal Financing Bank and the Budgetary Treatment of Federal Credit Activities,* (Washington, DC, January 1982) p. x.

[196] Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2009-Appendix, Department of Agriculture*, http://www.whitehouse.gov/omb/budget/fy2009/pdf/appendix/agr.pdf, p.162. Accessed February 28, 2008. The estimated subsidy for FY2008 is zero for Hardship Loans. The FY2009 budget estimates no lending authority for either the Municipal Loan or Treasury Loan programs for either FY2008 or FY2009. Accordingly there are zero subsidy values associated with these programs. The negative subsidies for FY 2008 and FY 2009 for the FFB loan guarantee program are estimated to be ($45) million and ($91) million. Therefore, based on the scoring method prescribed by the FCRA, the estimated budget impact for the RUS electric program, excluding administrative costs is zero for both FY2008 and FY2009. Because of the estimated negative subsidy calculated for the FFB loan guarantee program, the program "makes money."

electricity borrowers would face in private markets without RUS guarantees.[197] The average interest rate paid on the outstanding debt of RUS electricity borrowers in 2006 is actually slightly above the average 30-year Treasury rate for a bond issued in 2006 (Table 24).

Table 24. Interest Support to RUS Borrowers, 1998 and 2006 (million 2007 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
1998					
1. Benchmark Interest Rate (%)	5.58	6.77	6.91	7.04	7.26
2. Outstanding Debt ($)	39,547	39,547	39,547	39,547	39,547
3. Average Cost of Outstanding Debt (%)	5.90	5.90	5.90	5.90	5.90
4. Actual Interest Expense ($)	2,333	2,333	2,333	2,333	2,333
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	2,207	2,677	2,733	2,784	2,871
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	(127)	344	399	451	538
2006					
1. Benchmark Interest Rate (%)	4.91	5.59	5.84	6.07	6.32
2. Outstanding Debt ($)	30,134	30,134	30,134	30,134	30,134
3. Average Cost of Outstanding Debt (%)	5.06	5.06	5.06	5.06	5.06
4. Actual Interest Expense ($)	1,524	1,524	1,524	1,524	1,524
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	1,480	1,684	1,760	1,829	1,904
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	(45)	160	235	305	380

NOTES: The table above presents the historic value of RUS debt in 2007 dollars only for purposes of illustrating how the support values for 1998 and 2006 were calculated. The value of the debt on the RUS borrower's balance sheets has not changed due to inflation. The nominal value of this debt was at reported by RUS at $32,170 million in 1998.

A negative value for interest rate support indicates that the weighted average cost of outstanding debt exceeds the benchmark interest rate. In FY2007, the RUS hardship loan program was scored for budget purposes by the Office of Management and Budget (OMB) at $3 million. The Federal Financing Bank loan guarantee program was scored at negative $36 million. The budgetary cost is estimated using OMB's Credit Subsidy Calculator. See OMB, *Circular A-11, Part 5, Federal Credit*, www.whitehouse.gov/omb/circulars/a11/current_year/a11_toc.html.

Sources: Rural Utilities Service, *1998 Statistical Report Rural Electric Borrowers*, IP 201-1 (Washington, DC, August 1999), pp. 10 and 14, and *2005 Statistical Report Rural Electric Borrowers*, IP 201-1 (Washington, DC, December 2006). Table 18.

[197] Fifteen G&Ts have senior debt rated by Fitch Ratings. All 15 are rated investment grade. With the exception of one, which is rated BBB+, all are rated above A-. (See, Fitch Ratings, *Electric Cooperatives-An Industry Outlook and Primer*, June 14, 2007). For 11 of these G&Ts, outstanding debt accounted for 52.9 percent of the $21.0 billion of outstanding debt for all RUS power supply borrowers. Two of the rated cooperatives had no RUS debt in 2005 (Old Dominion Electric Cooperative and Chugach Electric Association). A third G&T, Great River Energy, completed a $1.3 billion through a bond issue on July 2, 2007 and retired all of its $1.1 billion in RUS guaranteed debt. The transaction was supported with bond insurance provided by MBIA. See, www.greatriverenergy.com/press/news/071007_capital_market.html, accessed October 11, 2007.

The estimated support value, using weighted borrowing rates, ranges from $160 million (based upon the IOU Aaa rate) to an estimated $380 million (based upon a Baa rate).

Several analyses have concluded that the RUS faces a significant risk of large loan defaults. For example, in 1997 GAO found that $618 million of the outstanding electricity loan portfolio was owed by borrowers who were delinquent in their payments and that $7.4 billion of the outstanding debt was owed by borrowers who were in financial distress. At that time the outstanding RUS electricity debt totaled $32.3 billion, of which approximately 25 percent was at risk of not being fully repaid. In a subsequent GAO report found that the RUS wrote off more than $3.2 billion in loans made to three borrowers.[198] Much of the problem debt was associated with loan guarantees for borrowers' investments in high-cost nuclear plants in the early 1980s. For example, the *Wall Street Journal* reported that more than $1.5 billion in debt was written down for two borrowers in 1996. In 2006, the RUS reported $818,000 in a loan write-down due to the default of Vermont Electric Generation and Transmission Cooperative. [199]

Summary

The total value of support provided Federal utilities and RUS borrowers is estimated as $767 million (Table 25) at the A benchmark rate although the estimate varies using different benchmark interest rates. Federal utilities and participants in RUS electricity lending programs borrow at rates typically below those available to non-publicly-owned power producers. The ratio of embedded cost of debt (interest expenses) to their outstanding debt for Federal utilities and RUS borrowers indicates that these entities have borrowed at rates ranging from below the Treasury's own costs of funds to as high as a highly-rated utility with a bond rating, i.e., the Aaa bond rating. For a discussion on bond ratings, see Appendix D.

Table 25 compares the cost of borrowing by Federal utilities and U.S. electricity loan participants to the Treasury borrowing costs and the borrowing costs of investor owned utilities with bond ratings ranging from Aaa to Baa for the years 1998 and 2006. The comparisons to the Treasury and Aaa rates in the table include only that portion of the debt that was below the respective interest rates. For example, only about $22 billion of the total outstanding debt of $78 billion has an average embedded cost below the benchmark Treasury rate. The corresponding debt below the Aaa rate was $52 billion. For debt that has an average embedded cost above these rates, the implicit support is assumed to be zero. Table 25 indicates that of those borrowers that had debt with an embedded cost below the Treasury's cost of funds, the value of those preferential interest rates was $89 million in 2006 (2007 dollars). The $89 million value for the year 2006 is the difference between what the interest costs would be on those particular loans that have an average embedded cost below the Treasury's associated costs of funds and those realized by current borrowers from the Treasury. For each successively lower-graded utility bond rating in the table, the methodology increases the value of the support as the average cost of debt falls below the comparison utility bond rate.

For instance, for electricity loans priced at rates above the Treasury's cost of funds (as measured by the Treasury's 30-year bond), but below the utility Aaa rate, the value of the support rises to an estimated $395 million for 2006. For loans priced below an Aa rate (all of them), support would equal an estimated $589 million; below an A rate, an estimated $767

[198] Government Accountability Office, Rural Utilities Service: *Opportunities to Better Target Assistance to Rural Areas and Avoid Unnecessary Financial Risk*, GAO-04-647 (Washington, DC, June 2004), p. 8.
[199] Conversation with Chris Tuttle of the Rural Utilities Service, July 30, 2007.

million (which serves as the point estimate measure); and, below a Baa rate, an estimated $961 million.

Table 25. Interest Support to Federal Utilities and RUS Borrowers 1998 and 2006 (million 2007 dollars)

	Treasury Rate	Aaa IOU Rate	Aa IOU Rate	A IOU Rate	Baa IOU Rate
1998					
1. Benchmark Interest Rate (%)	NA	6.77	6.91	7.04	7.26
2. Outstanding Debt ($)	0	66,217	98,895	98,895	98,895
3. Average Cost of Outstanding Debt (%)	NA	6.04	6.28	6.28	6.28
4. Actual Interest Expense ($)	NA	3,997	6,209	6,209	6,209
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	NA	4,483	6,834	6,962	7,180
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	NA	486	624	753	971
2006					
1. Benchmark Interest Rate (%)	4.91	5.59	5.84	6.07	6.32
2. Outstanding Debt ($)	21,552	51,686	77,534	77,534	77,534
3. Average Cost of Outstanding Debt (%)	4.50	4.83	5.08	5.08	5.08
4. Actual Interest Expense ($)	970	2,494	3,939	3,939	3,939
5. Interest Expense Computed at Benchmark Rate ($) [(1) x (2)]	1,058	2,889	4,528	4,706	4,900
6. Estimated Interest Support at Benchmark Interest Rate ($) [(5)-(4)]	89	395	589	767	961

NOTE: NA indicates that some of the cost of outstanding debt exceeds the benchmark interest rate. There is no support when benchmark rates are less than the weighted cost of capital.

5. Subsidies Per Unit of Production

The previous chapters of this report described energy-related subsidies that the Federal government provides through tax expenditures, direct expenditures, research and development (R&D), and financial assistance in the form of grants, direct loans and loan guarantees for energy producing industries, intermediate product market participants, and end-users. In considering electricity production, the electric power industry generally involves all of these segments. It includes producers in terms of the production of electric power. It includes intermediate product market participants with respect to the factor inputs to electricity production, e.g., capital, labor and fuel. Finally, it includes retail customers, who are beneficiaries of a variety of tax expenditures and direct subsidies that are intended to foster conservation and energy efficiency and reduce the cost of electricity to qualified low income consumers.

The previous chapters of this report also quantified energy-related tax expenditures, R&D, and other subsidies, many of which have a direct or indirect impact on electricity production. However, some of those tax expenditures, R&D outlays, and other subsidies have no connection to electricity production. Others, such as exploration and production tax credits for fuel producers, have an indirect impact on electricity production in that they provide financial incentives to fuel producers to invest in new technologies and explore for fuel resources, which at current market prices may only be marginally economic. If these incentives are successful in terms of bringing significant supplies to market in the long run, it helps to ensure energy security and potentially lowers equilibrium prices as supply increases. This may affect utility and nonutility generators' selection of particular forms of generation. For purposes of this analysis, while fuel producers are the direct beneficiary of production tax credits, electricity producers indirectly benefit from supply increases and diversity of fuels. Therefore, a portion of direct subsidies to these entities is allocated as a subsidy to electricity production in proportion to the amount of the fuel consumed in electricity production to which a particular subsidy applies. The subsidies are presented in total dollars and per megawatthour (MWh) of generation by fuel type based on EIA generation data for the 12-month period ending September 30, 2007 (FY2007 MWh).[200]

This chapter describes the methodology used to estimate electricity production subsidies by fuel type. The methodology consists of defining the electricity production to which the subsidies apply, identifying the subsidies for which there is a direct or indirect benefit to electricity production by fuel type, and allocating the estimated dollar value of each subsidy to each fuel type. The dollar per unit--MWh--of subsidies by fuel type is calculated as the aggregate subsidy in dollars for each fuel divided by the corresponding FY2007 generation (MWh). Subsidies provided to the electric utility industry that are unrelated to generation, such as transmission-related tax expenditures are expressed in dollars per MWh based on total electricity production. This is based on the assumption that the incentives these benefits provide to transmission owners to expand or upgrade their systems benefit all forms of generation in proportion to their use of the transmission system. Therefore, the dollar per MWh value for total nonfuel-related electricity subsidies is based on total electricity production.

[200] Energy Information Administration, Form EIA-906, "Power Plant Report" and Form EIA-920, "Combined Heat and Power Plant Report," October 2006 through September 2007.

Definition of Electricity Production

For purposes of this analysis, electricity production encompasses the principal classes of electric plant required to produce and deliver electricity to the end-user. This includes all assets associated with the three functional areas of electricity supply: generating plants, transmission lines and distribution facilities. Electricity production is defined as: electricity produced via generating plants owned by traditional utilities (investor-and publicly-owned-utilities, generation/transmission cooperatives, and Federally-owned utilities) and nonutility generators. Fuel is an operating cost that is associated with electricity production.

Non-utility generators include independent power producers (IPPs), affiliated power producers, Qualifying Facilities (QFs) and combined heat and power (CHP) plants whose primary purpose is to sell electricity or electricity and heat to the public. Nonutility generators are included because these entities are direct or indirect beneficiaries of numerous subsidies identified in this report.

Electricity Production Subsidies

A number of energy-related R&D direct expenditures and tax expenditures programs described in the previous chapters are not included in the subsidies assigned to electricity production. These include direct expenditures, tax expenditures, and R&D associated with development of alternative transportation fuels and end-user related activities such as energy efficiency and conservation. Of the $16.6 billion in energy-related subsidies identified by EIA, $6.7 billion are classified as direct or indirect subsidies and directed to electricity production (Table 26).

Indirect subsidies consist of fuel-specific R&D for use in electric generation. Indirect subsidies also include tax incentives and direct expenditures provided to entities engaged in the production of fuel used to produce electricity. These benefits are allocated to electricity production based on fuel allocation factors discussed below. Direct subsidies to electricity producers that provide incentives to investment in generation technology of a specific fuel type are assigned to electricity production in their entirety and are included in the $5.1 billion of subsidies allocated to electricity production by fuel type.

The methodology used to allocate the interest rate support by fuel type is described below. The interest rate support for the Federal utilities and Rural Utilities Service (RUS) borrowers is estimated to be $767 million. Of this amount, $407 million is allocated to power sector generation by fuel type. The remaining $360 million, which is the interest subsidy associated with Federally-subsidized transmission and distribution facilities, is included in non-production related electricity subsidies. The interest rate support for the Tennessee Valley Authority (TVA), the Federal Power Marketing Administrations (PMAs) and RUS borrowers is the estimated subsidy calculated at the benchmark interest rate for A-rated IOU bonds described in Chapter 4. Subsidies provided to the electric power industry that are not directly allocated to electricity production by fuel type are estimated at $1.2 billion. The majority of these subsidies are transmission-related tax incentives that modify provisions of the Internal Revenue Code (Code or IRC) to promote investment in transmission infrastructure and increase transmission owners' participation in open access transmission. In some instances, as was described in Chapter 2, certain provisions of the Code acted as impediments for transmission owners to engage in activities and transactions that would expand the amount of transmission capacity operating under non-discriminatory open-access tariff or under the control of regional transmission organizations and independent system operators (RTOs/ISOs).

Table 26. Allocation of Electricity Production and Other Energy Subsidies (million 2007 dollars)

Subsidy and Support Category	FY 2007 Electricity Production Subsidies and Support	FY 2007 Other Energy Subsidies and Support	FY 2007 Total Energy Subsidies and Support
Fuel Specific[1]	5,105	2,330	7,435
Transmission and Distribution[2]	1,235	-	1,235
Federal Utilities and RUS Borrowers Capacity[3]	407	-	407
Energy Subsidies Unrelated to Electricity Production[4]	-	7,504	7,504
Total	6,747	9,834	16,581

NOTES: Totals may not equal sum of components due to independent rounding.

[1]Includes fuel-related tax expenditures, R&D, and direct expenditures applicable entirely to a specific type of electric generation, or primary fuel production-related subsidies allocated to either electricity or other sectors based on each sector's proportionate consumption of the applicable fuel. Excludes fuels that have no role in electricity production, such as ethanol and other biofuels.

[2] Includes transmission and distribution-related tax expenditures, R&D, and the financial support attributable to Federal utilities' and RUS borrowers' debt associated with transmission and distribution assets with an estimated value of $360 million (See Table 34).

[3]Reflects the estimated portion of Federal utilities' and RUS borrowers' interest support attributable to long-term debt associated with capacity plant and certain TVA and BPA regulatory assets. This support is then assigned by fuel-type.

[4]Includes tax and direct expenditures for end-use activities and transportation-related alternative fuels. Among these subsidies are conservation programs, residential and commercial energy efficiency programs, and ethanol and biofuels tax credits.

Sources: Office of Management and Budget*, Budget of the United States Government, Fiscal Year 2008-Appendix*. Office of Management and Budget, *Analytical Perspectives Budget of the United States Government, Fiscal Year 2008, Federal Receipts and Collections*, http://www.whitehouse.gov/omb/budget/fy2008/. Joint Committee on Taxation, "Estimated Budget Effects Of The Conference Agreement For Title XIII of H.R. 6, The Energy Tax Incentives Act Of 2005," JCX59-05, July 27, 2005. (Washington, DC, November 2007).
Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," 2006; Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report," October 2006 through September 2007.

To the extent these incentives provide benefits to all users of transmission facilities placed under the operational control of RTOs/ISO, all forms of generation benefit. Accordingly, these tax expenditures are included in non-production-related electricity subsidies. Subsidies unrelated to electricity production, totaling $7.5 billion, are not included in the estimate of direct and indirect subsidies for electricity production, as are $2.3 billion in fuel-related subsidies that are allocated to consumers, i.e., residential, commercial, industrial and transportation, based their direct receipt and consumption of the applicable fuel.

Allocation of Subsidies

This portion of the chapter describes the method used to allocate the four categories of subsidies described above. The following four sections provide a description of the methodology and the specific subsidies that comprise the $16.6 billion of total energy-related subsidies and support, and the $6.7 billion assigned to electricity production.

Subsidies Unrelated to Electricity Production

Energy-related subsidies totaling $9.8 billion have not been allocated to electricity production. These subsidies are divided into two categories. The first category consists of subsidies totaling $7.5 billion (Table 27). The second category consists of the portion of fuel-specific subsidies that are allocated to end-use sectors, i.e., residential, commercial, industrial and transportation, other than the electric power sector based on their relative consumption of the fuels to which the subsidies applied. These fuel-specific subsidies totaled $2.3 billion FY 2007.

The $7.5 billion in subsidies unrelated to electricity production are either related to the promotion of alternative transportation fuels, i.e., bioenergy/biofuels or funding for programs that focus on energy efficiency and conservation by residential, commercial, and industrial end users of electricity and other conventional energy sources. Conservation, energy efficiency, and other end-use subsidies reduce consumption thereby slowing the demand for capacity additions. While these subsidies may be related to electricity (and other forms of energy consumption, such as natural gas), they do not provide a direct or indirect subsidy to electricity production. Therefore, they are not included for purposes of allocating electricity-related subsidies. A second category of subsidies considered end use for purposes of this analysis are grants, loans, and loan guarantees made by the Rural Business-Cooperative Service (RBS) under various programs including the Renewable Energy and Energy Efficiency Program that was created under Section 9006 of the Farm Security and Rural Investment Act of 2002 (Public Law 107-171). These subsidies include grants and loan guarantees for feasibility studies for renewable electric power facilities, e.g., wind, solar, and biomass, or financial assistance for the construction of such facilities. The recipients are farmers, ranchers, and small business that are planning or actually constructing electric production facilities for use at their commercial establishments, farms, or ranches. The electricity produced from facilities that may be constructed under these programs is for off-grid use. It is primarily for purposes of improving the efficiency of and reducing energy costs for an individual commercial enterprise. Thus, they do not fall within the definition of electric production used in this report.

Energy assistance programs for low-income consumers are also excluded from electricity production subsidies. These include LIHEAP and the RUS Assistance to High Energy Cost Rural Community grant program. The LIHEAP program, at $2.2 billion, was the second-largest energy subsidy not allocated to electricity production.[201] Arguably, LIHEAP provides an indirect subsidy to retail electricity suppliers by providing financial assistance to low-income consumers to defray heating and cooling costs through block grants provided to the States. Thus, the indirect benefit to retail electricity suppliers is the reduction of accounts receivable or delinquent accounts.

[201] The tax credit for alcohol fuels, at $3.0 billion, was the largest energy-related subsidy not allocated to electricity production.

Table 27. Subsidies not Allocated to Electricity Production (million 2007 dollars)

Program	**2007 Subsidy**	**Recipient or End-Use Category**
Hydrogen R&D	230	Basic Research
Credit for Construction of New Energy-Efficient Homes	20	Residential
DOE Conservation (Weatherization and State Energy)	256	Residential
RUS High Energy Cost Community Grants	-17[1]	Econ. Dev.
RBS Small Minority Producer Grants	0.3	Small Businesses
RBS Value Added Grants	3	Small Businesses
30-Percent Credit for Residential Purchases/Installations of Solar and Fuel Cells	10	Residential
RBS Section 9006 Grants	13	Small Business
Temporary 50-Percent Expensing for Equipment Used in the Refining of Liquid Fuels	30	Refiners
RBS Loan Guarantees	42	Small Business
RBS Business and Industry Loan Guarantee	60	Small Business
DOE Industrial R&D	66	Applied Research
Credit for Energy Efficient Appliances	80	Manufactures
Building Technology, State and Community Programs	103	Commercial
Exclusion for Utility-Sponsored Conservation Measures	110	Residential
Allowance of Deduction for Certain Energy-Efficient Commercial Building Property	190	Commercial
Credit for Energy-Efficiency Improvements of Existing Homes	380	Residential
Low Income Home Energy Assistance Program	2,188	Residential
Expensing of Capital Costs with Respect to Complying with EPA Sulfur Regulations	10	Refiners
USDA Research, Education, and Extension Service (REES)-Bioenergy/Biofuels	29	Applied Research
Alcohol Fuel Credit	50	Alt. Fuels Industry
Biodiesel and Small Agri-Biodiesel Product Tax Credits	180	Alt. Fuels Industry
DOE Transportation R&D	221	Applied Research
Credit, Deduction for Clean Fuel Vehicles	260	Individuals/Fleets
Excise Taxes/VEETC (Alcohol Fuels Exemption)	2,990	Alt. Fuels Industry
Subtotal	7,540	
Fuel Specific Subsidies	2,330	End-use sectors other than Electric Power
Total	9,834	

NOTES: Total may not equal sum of components due to independent rounding.

[1]Reflects a rescission of allocated grant funds from the prior fiscal year.

Sources: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2008-Appendix*. Office of Management and Budget, *Analytical Perspectives Budget of the United States Government, Fiscal Year 2008, Federal Receipts and Collections*, http://www.whitehouse.gov/omb/budget/fy2008/. Joint Committee on Taxation, "Estimated Budget Effects Of The Conference Agreement For Title XIII of H.R. 6, The Energy Tax Incentives Act Of 2005," JCX59-05, July 27, 2005. Energy Information Administration, Electric Power Annual 2006, DOE/EIA-0348 (2006) (Washington, DC, November 2007). http://www.eia.doe.gov/fuelelectric.html. EIA analysis.

Energy assistance programs do not subsidize investment in generating capacity because many utilities would still be required to provide service under State regulations that preclude the termination of service during periods of extreme temperatures.[202] The RUS High Energy Cost Rural Community grant program provides assistance for rural utility infrastructure. However, the means tests for determining eligibility are such that communities and small utilities in Alaska are

[202] A State-by-State summary of seasonal termination protection policies is available on the LIHEAP Clearinghouse web site at http://liheap.ncat.org/Disconnect/SeasonalDisconnect.htm.

the principal beneficiaries. Many of these systems are electrically isolated within the State of Alaska.

The $2.3 billion in fuel-specific subsidies not allocated to electric production include an allocable portion of a variety of tax expenditures and direct expenditures including; expensing of exploration and development costs, excess of percentage over cost depletion, fuel-specific R&D, and changes in natural gas pipeline property life for tax depreciation purposes. All of the fuel-specific subsidies that were allocated on the basis of end-use consumption ratios are listed in Table 30. The derivation of the fuel allocation ratios and the division of fuel-specific subsidies to the electric power sector are described in the following section.

Subsidies Allocated by Fuel Type

There are a variety of tax expenditures and R&D expenditures that provide benefits to fuel producers, researchers, and industry. Tax expenditures are in the form of production or investment tax credits, tax deferrals, preferred tax rates, and expense deductions, e.g., expensing all or a portion of costs that are normally capitalized. Electricity producers are not necessarily the direct beneficiary of these expenditures. Fuel producers, as taxpayers, are the direct recipient of the benefit of production tax credits, investment tax credits, and preferential expensing of development and capital costs allowed for the production of particular fuels. The attribution and allocation of these subsidies to electric generation by fuel type is premised on the fact that government expenditures that promote such economic activities ultimately provide benefits to electricity producers that consume that particular fuel. For example, the expensing of natural gas and oil exploration and development costs reduces producers' current period taxable income, which provides an incentive to invest in capital equipment to explore and develop natural gas and oil resources situated in deep water or in remote and geologically complex onshore locations. By subsidizing the initial foray of exploration and development that harbor potential plentiful domestic supplies that are not commercially viable at current market prices, the industry is able to develop new technologies and methods that may hasten the commercial viability of bringing geologically remote energy supplies to market. In the long-run, the expectation is that these subsidies increase energy supplies. Thus, existing electricity generators will benefit from increased supply and lower prices.

A similar argument applies with respect to allocating R&D expenditures for advanced clean fuels and power production technology to current electric production. From an intertemporal perspective, current generating capacity may employ more efficient production and environmental technologies as a result of past R&D expenditures. While the electric power industry invests in R&D to increase the efficiency of the production and delivery of electricity, e.g., the research activities of the Electric Power Research Institute, government R&D expenditures are typically targeted at the investigation of new technologies for which either the risk or the long lead time incurred prior to realization of a return on investment make such expenditures financially prohibitive to the private sector. Based on this theory, current electricity producers are deemed to be indirect beneficiaries of R&D expenditures. Therefore, fuel-related R&D expenditures are allocated to generation by fuel type based on the proportion of each fuel consumed in electricity production relative to total consumption across all market segments.

Other subsidies are more clearly attributable to electricity production by fuel type, such as the production tax credit for electricity generated by newly-constructed nuclear plants and clean coal tax initiatives. Clean Renewable Energy Bonds and New Technology Tax Credits subsidize a variety of renewable fuels, e.g., biofuels, synthetic coal, wind, and biomass. Given the inherent uncertainty regarding technology and fuel choice of electricity producers that choose to take advantage of these subsidies, they are allocated based on the proportion of each fuel that was consumed in electricity production in 2006. In the absence of detailed information on individual renewable subsidies, a weighted average fuel ratio reflecting the amount of all renewable fuels consumed by electricity producers is used. With respect to the Section 29 and Section 45 production tax credits, the methodology used to allocate the value of these tax expenditures estimated by the Treasury Department is described in Chapter 2.

Derivation of Fuel Ratios

The ratios used to allocate subsidies by generation fuel type represent the portion of each primary fuel consumed for electricity production relative to the remaining sectors of the economy, such as industry and transportation (Table 28).

Table 28. Fuel Allocation Factors (percent)

Fuel	Fuel Consumed in Electricity Production as a Percentage of Total Fuel Consumption
Coal	91.0
Natural Gas and Petroleum Liquids	11.3
Nuclear	100.0
Renewables	56.4
Wind	100.0
Solar	7.0
Biomass and biofuels	12.9
Geothermal	89.5
Hydroelectric	98.9

NOTE: The ratio of power sector consumption for Natural Gas and Petroleum Liquids represents a weighted average across both fuel types.

Source: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007), Tables 1.3 and 2.1f.

Natural gas and petroleum liquids are represented by a single ratio. This ratio reflects the weighted average of natural gas and petroleum used in electricity production relative to total natural gas and petroleum consumption. The Treasury Department's published estimate of oil and natural gas production-related tax expenditures does not allocate the value of the tax expenditure between oil and natural gas. Because natural gas predominates compared to oil in electricity production, EIA used a weighted average of the respective amounts of each fuel consumed by electricity producers. Additionally, in 2006, 32.4 percent of natural gas-fired generation for which natural gas is the primary fuel reported petroleum as a secondary fuel.[203]

A composite fuel ratio and individual fuel ratios are developed for purposes of allocating subsidies to renewable electric generation. This is because some subsidies specifically target a particular technology while in other instances insufficient data were available to allocate a subsidy between the categories of renewables. For example, the allocation among renewable

[203] Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 2.8.

technologies for governmental entities and electric cooperatives that received volume cap allocations to issue Clean Renewable Energy Bonds (CREB) tax credit bonds pursuant to IRC Section 54(f) cannot be estimated with any reasonable precision because Internal Revenue Service (IRS) disclosure limitations preclude the release of taxpayer-specific information. In the case of CREBS, IRC section 54(d)(2) defines the term "qualified project" as any of the following qualified facilities: wind, closed-loop biomass, open-loop biomass, geothermal, solar energy, small irrigation power, landfill gas, trash combustion, refined coal production facility under IRC section 45(d)(8) and a qualified hydropower facility.[204]

Furthermore, based on the data available for the results of the IRS' most recent allocation of CREBs credits by fuel–type or technology, which uses a "smallest to largest method," i.e., projects for which the smallest amount of the dollar cap has been requested, up to the maximum volume cap, there are not sufficient data to allocate CREBs credits by individual renewable technology.[205] On December 27, 2005, the IRS issued a notice requesting applications for allocations of CREBS. On November 20, 2006, the IRS released the results of the volume cap allocation process. There were a total of 610 projects approved by renewable fuel type, which are summarized by fuel type in Table 29. While 71 percent of the approved projects were solar and 18 percent were wind, in the absence of detailed tax return information

Table 29. Fiscal Year 2006 CREB Authorized Allocation by Fuel Type

Renewable Fuel Type	Number of Projects
Hydroelectric	14
Landfill Gas	36
Open Loop Biomass	13
Refined Coal	1
Solar	434
Wind	112
Total	610

Source: Internal Revenue Service, Informational Release IR-2006, November 20, 2006.

for those projects that issued CREBs, it is not possible to determine which renewable technology received the largest benefit in total dollars.

Subsidies Allocated by Fuel Type

The total value of energy subsidies that is allocated to specific fuel types $7.4 billion (Table 30). EIA estimates that, of this $7.4 billion, $5.1 billion is allocable to electricity production based on the share of each fuel consumed by the electric power sector relative to the total consumption of each fuel. The remainder of those subsidies for which less than 100 percent is allocated to electricity is assumed to be utilized by other sectors of the economy that also consume the particular fuel.

EPACT2005 provides for a nuclear production tax credit of 1.8 cents per kilowatthour applicable to electricity produced by the first 6 gigawatts of new nuclear capacity constructed and placed in service by 2020. As there are no nuclear plants eligible for the credit in the year 2007, there is

[204] A qualifying hydroelectric project must certify that an incremental increase in capacity of an existing facility meets FERC efficiency requirements. Applicants must also certify that the proposed facility meets FERC licensing regulations. See IRC Sections 45(c)(8) and 45(d)(9).
[205] On December 27, 2005, the IRS issued a notice requesting applications for allocations of CREBS. On November 20, 2006, the IRS released the results of the volume cap allocation process. The Secretary of the Treasury authorized 610 State and local governmental entities, and electric cooperatives to issue CREBs.

no estimate of subsidy associated with nuclear production tax credit in this analysis. The Federal Credit Support Supplement to the FY 2008 budget shows no loan commitments for the EPACT Title XVII loan guarantee for program FY 2007.[206] The anticipated commercial operation date for new nuclear plants that would qualify for the credit is outside this forecast period.[207]

[206] Office of Management and Budget, *Federal Credit Supplement Fiscal Year 2008*, Table 2: Loan Guarantees: Subsidy Rates, Commitments and Average Loan Size," p.2.

[207] EIA's *AEO2007* reference case forecast assumes 9.0 gigawatts of nuclear capacity will be built by 2020 and will receive tax credits worth 1.2 cents per kWh, which is consistent with the allocation method prescribed by the IRS in the event the nameplate capacity of eligible nuclear capacity exceeds the 6-gigawatt limit. See Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383 (Washington DC, February 2007), p. 84. The IRS provided guidance concerning the allocation of the nuclear production tax credit in Internal Revenue Bulletin 2006-18, Notice 2006-40, "Credit for Production from Advanced Nuclear Facilities," Section 3, May 1, 2006.

Table 30. Fuel-Specific Energy Subsidies (million 2007 dollars)

Subsidy Program	2007 Subsidy	Electricity Production Share	Fuel
Refined Coal Alternative Fuel Production Credit	2,370	2,156	Refined Coal
Fuel and Power Systems (Advanced Research and Technology Development)	311	283	Coal
Capital Gains Treatment of Royalties in Coal	170	155	Coal
Clean Coal Power Initiative (R&D)	61	55	Coal
Future Gen Advanced Clean Fuels (R&D)	54	49	Coal
Exclusion of Special Benefits for Disabled Coal Miners	50	46	Coal
84-Month Amortization of Certain Pollution Control Facilities	30	27	Coal
Credit for Investment in Clean Coal Facilities	30	27	Coal
Partial Expensing for Advanced Mine Safety Equipment	10	9	Coal
Unallocated (Coal R&D Programs)	148	135	Coal
Expensing of Exploration and Development Costs	860	98	Nat. Gas and Oil
Excess of Percentage over Cost Depletion	790	90	Nat. Gas and Oil
Amortize All Geological and Geophysical Expenditures over 2 Years	60	7	Nat. Gas and Oil
Natural Gas Distribution Pipelines Treated as 15-Year Property	50	6	Nat. Gas and Oil
Exception from Passive Loss Limitation for Working Interests in Oil and Natural Gas Properties	30	3	Nat. Gas and Oil
U.S. Geological Survey Energy Research and Development	20	2	Nat. Gas and Oil
Natural Gas (R&D)	15	2	Nat. Gas and Oil
Oil (R&D)	4	*	Nat. Gas and Oil
New Nuclear Plants (R&D)	319	319	Nuclear
Waste/Fuel/Safety (R&D)	350	350	Nuclear
Nuclear Decommissioning (R&D)	199	199	Nuclear
Unallocated (Nuclear R&D)	253	253	Nuclear
New Technology Credit (Investment Energy Tax Credit, Production Tax Credit)	690	690	Wind
Biomass (and Biofuels) (R&D)	246	32	Biomass (and Biofuels)
Solar (R&D)	187	13	Solar
Credit for Holding Clean Renewable Energy Bonds	60	34	Renewables
Wind (R&D)	58	58	Wind
Geothermal (R&D)	6	5	Geothermal
Renewable Energy Production Incentive	5	3	Renewables
Total	7,435	5,105	

NOTES: Totals may not equal sum of components due to independent rounding.

* Value less than $0.5 million.

Sources: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2008-Appendix*, Office of Management and Budget, *Analytical Perspectives Budget of the United States Government, Fiscal Year 2008, Federal Receipts and Collections.* See, http://www.whitehouse.gov/omb/budget/fy2008/. Joint Committee on Taxation, "Estimated Budget Effects Of The Conference Agreement For Title XIII of H.R. 6, The Energy Tax Incentives Act Of 2005," JCX59-05, July 27, 2005. Energy Information Administration, Electric Power Annual 2006, DOE/EIA-0348 (2006) (Washington, DC, November 2007). Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" October 2006-September 2007.

Interest Rate Support to Federal Utilities and RUS Borrowers

The implied Federal support to TVA, the PMAs, and RUS borrowers is measured in terms of the differential between the embedded cost of debt of each entity, i.e., the quotient of current interest expense and current long-term debt, and a series of current interest rates for debt of comparable maturity. These rates include the Treasury's cost of money and investment grade rated IOU bonds ranging from Aaa to Baa. Theoretically, this method is akin to TVA, the PMAs, and all RUS borrowers refinancing their outstanding obligations at current interest rates, excluding transaction costs, while assuming all other risk factors, i.e., operational, financial, regulatory, environmental, competition, etc., that investors would consider in pricing the new debt issue are consistent with a given investment grade rating. For purposes of this report, the A bond rate is used for a point estimate.

Chapter 4 provides a detailed discussion of how a range of cost-of-capital support values was derived for each entity. The methodology considered their unique attributes and made adjustments to account for long-term obligations that for purposes of calculating the support should be treated as long-term debt. These obligations, such as TVA's lease/lease back and the unamortized prepayment received from customers that reduced their future power supply costs through prepayments, are obligations that the nationally-recognized rating agencies would consider in determining the adequacy of cash flow to cover fixed obligations (i.e., a modified debt service coverage ratio).

With respect to the Federal utilities, the support was allocated by fuel type on the basis of the reported net book cost for each type of generating capacity, as reported in their respective financial reports. The RUS interest support estimate, which reflects the support applicable to RUS generation-related insured loans and loan guarantees made to both distribution and power supply borrowers, was allocated on the basis of net summer capability. Based on an A-rated benchmark interest rate, support associated with the Federal utilities' generating capacity (and therefore allocated by fuel type) is estimated at $366 million (Table 31). Of the five, BPA realizes the highest interest rate support based on current interest rates at $146 million, followed by TVA at $119 million. WAPA ranks third at $41 million. Unlike the PMAs, TVA owns and operates a diversified portfolio of generation, which is dominated by its investment in nuclear and coal-fired capacity.

Table 31. Allocation of Federal Utilities' Interest Support by Fuel Type (million 2007 dollars)

Federal Utility	Interest Support by Fuel Type
TVA Hydroelectric	8
TVA Nuclear	63
TVA Fossil	43
TVA Combustion Turbine	5
TVA Total	119
BPA Hydroelectric	65
BPA Nuclear	81
BPA Total	145
WAPA Hydroelectric	41
SWPA Hydroelectric	36
SEPA Hydroelectric	24
Federal Utilities Support Allocated to Generation	364

NOTES: Total may not equal sum of components due to independent rounding.

TVA and PMA support is calculated from their annual audited financial statements, which conform to the Federal government's fiscal year.

Sources: Based on EIA analysis and financial data obtained from Global Insight; Original Source: Moody's Investor Services. Federal Reserve Bank's Form H-15. Tennessee Valley Authority SEC 10-K, 2006. Bonneville Power Administration 2006 Annual Report. Southeastern Power Administration 2005 Annual Report, Southwestern Power Administration 2004-2006 Annual Report and Western Area Power Administration 2006 Annual Report.

Based on an A bond rating, the estimate of the RUS generation-related interest rate support is $43 million of which $25 million is allocated to coal-fired capacity and $15 million to natural gas-fired and oil-fired capacity (Table 32). The support allocated to nuclear generation is $3 million, or 6 percent of the total generation-related subsidy. While RUS provided a substantial amount of loan guarantees for nuclear plants in the late 1970s and early 1980s, many of these assets were sold to investor-owned utilities in conjunction with bankruptcy reorganization plans and consensual debt-restructuring agreements.

Table 32. Allocation of RUS Interest Support by Fuel Type

Fuel Type	Summer Capability (MW)	Summer Capability (percent)	Support by Fuel Type (million 2007 dollars)
Coal	22,383	56	25
Natural Gas and Oil	13,474	35	15
Nuclear	2,238	6	3
Hydroelectric	804	2	*
Renewable	55	*	*
Total	38,954	100	43

NOTE: Totals may not equal sum of components due to independent rounding. RUS support values are calculated on calendar year balance sheet data.

*Less than 0.5 percent, or less than $500 million.

Sources: Based on EIA analysis and data obtained from Rural Utilities Service, *2005 Statistical Report of Rural Electric Borrowers*, Publication 201-1, and (December 2006). Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," 2006. EIA analysis.

Transmission, Distribution, and Other Subsidies and Support for Electricity Production

Approximately $1.2 billion in subsidies and support are directed to transmission, distribution, and general plant (Table 33). These subsidies and support include the interest support associated with the transmission and distribution assets owned by the Federal utilities and transmission and distribution loans made by the RUS. Also included in this category are transmission-related tax expenditures that were created to provide incentives for transmission owners to invest in transmission infrastructure and restructure ownership or operational control of transmission facilities consistent with Federal Energy Regulatory Commission policies. A third component consist of R&D expenditures. The tax credit for fuel cells and microturbines, was included in this category. They are forms of distributed or dispersed generation that be used as a substitute for transmission and distribution facilities. Therefore the subsidy was included in this category. Finally, the exclusion from gross income of interest on certain energy facilities was included in this category because of a lack of data to allocate this tax expenditure by fuel type.

Of the $1.2 billion of electricity subsidies not directly related to production, nearly one-half ($530 million) is associated with the favorable treatment of the gain realized from the sale of transmission assets to an independent transmission company (Table 33). The purpose of this tax expenditure was to reduce the immediate tax burden associated with the sale of transmission assets by deferring recognition of the gain over a 4-year period to be ratably recovered over 8 years. The extent to which the Treasury Department's estimate of this subsidy is realized depends on the number of qualified transactions that occur prior to the provision's expiration on December 31, 2008. Since the enactment of this provision in Section 909 of the AJCA, and the extension of the sunset to December 31, 2007, in Section 1305 of EPACT2005, only one such transaction has been approved by FERC and closed. Another transaction is pending approval by various State regulatory commissions and the FERC.

Both transactions involve the acquisition of investor-owned utility properties by operating subsidiaries of ITC Holdings.[208] The first transaction involved the ITC Holdings' subsidiary ITC Transmission Company's acquisition of Michigan Electric Transmission Company LLC and Trans-Elect NTD Path 15, LLC. The transaction was approved by the FERC on September 21, 2006. The second transaction, which was announced in early 2007, involved ITC Midwest's acquisition of the transmission facilities of Interstate Power & Light Company. FERC approval of the acquisition is pending, as are approvals by a number of Midwest State regulatory commissions. The second largest expenditure is the interest rate support applicable to the Federal utilities and RUS associated with transmission, distribution, and general plant.

Table 33. FY 2007 Electricity Transmission, Distribution, and Other Subsidies and Support (million 2007 dollars)

Program Subsidy and Support Categories	Subsidy and Support
RUS Other Electric Plant	262
SWPA Other Electric Plant	8
WAPA Other Electric Plant	40
BPA Other Electric Plant	46
TVA Other Electric Plant	5
Electricity Delivery and Reliability (Electricity Technologies)	137
Direct Thermal to Electric Conversion	3
Treatment of Income of Certain Electric Cooperatives	14
5-Year Net Operating Loss Carryover for Electric Transmission Equipment	43
Transmission Property Treated as 15-Year Property	18
Deferral of Gain from Dispositions of Transmission Property to Implement FERC Restructuring Policy	530
Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants	90
Exclusion of Interest on Bonds for Certain Energy Facilities	40
Total	1,235

NOTE: Total may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2008-Appendix*, Office of Management and Budget, *Analytical Perspectives Budget of the United States Government, Fiscal Year 2008*, *Federal Receipts and Collections*. See, http://www.whitehouse.gov/omb/budget/fy2008/. Joint Committee on Taxation, "Estimated Budget Effects Of The Conference Agreement on Title XIII of H.R. 6, The Energy Tax Incentives Act Of 2005," JCX59-05, July 27, 2005. Energy Information Administration, *Electric Power Annual 2006*, DOE/EIA-0348 (2006) (Washington, DC, November 2007). Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" October 2006-September 2007. Tennessee Valley Authority SEC 10-K, 2006. Bonneville Power Administration, 2006 Annual Report. Southeastern Power Administration, 2005 Annual Report, Southwestern Power Administration, 2004-2006 Annual Report and Western Area Power Administration, 2006 Annual Report.

Collectively, the interest support for non-generation-related assets owned or financed by these entities totals $361 million. This is followed by transmission and delivery R&D at $137 million. Because all types of generation benefit from non-discriminatory open access, increased reliability, and new technology, this support is allocated to electricity production in general rather than to a specific fuel or technology.

[208] In a September 2007 Press Release, ITC Holdings described itself as the "only publicly-traded company engaged exclusively in the transmission of electricity in the US Source: ITC Holdings, http://investor.itc-holdings.com/releasedetail.cfm?releaseid=264581.

Per-Unit Electricity Subsidies by Fuel Type

When grouped by type of subsidy, tax expenditures account for $4.3 billion of the estimated $6.7 billion in electric production subsidies (Table 34). R&D is the second largest category of subsidies at $1.7 billion. When allocated by fuel type fuel type, refined coal alternative fuel production tax credits account for one-half at $2.2 billion, followed by nuclear at $1.3 billion and non-fuel specific electricity subsidies at $1.2 billion. Renewable electricity production received an estimated $1.0 billion in subsidies, of which $724 million consists of tax expenditures.

Table 34. Fiscal Year 2007 Electricity Production Subsidies and Support (million 2007 dollars)

Fuel/Other	Direct Expenditures	Tax Expenditures	Research & Development	Federal Electricity Support	Total
Coal	-	264	522	68	854
Refined Coal	-	2,156	-	-	2,156
Natural Gas and Petroleum Liquids	-	203	4	20	227
Nuclear	-	199	922	146	1,267
Renewables	3	724	108	173	1,008
Transmission and Distribution	-	735	140	360	1,235
Total	3	4,281	1,696	767	6,747

NOTE: Totals may not equal sum of components due to independent rounding.

Sources: Office of Management and Budget, *Budget of the United States Government Fiscal Year 2008-Appendix*, Office of Management and Budget, *Analytical Perspectives Budget of the United States Government, Fiscal Year 2008, Federal Receipts and Collections*. See, http://www.whitehouse.gov/omb/budget/fy2008/. Joint Committee on Taxation, "Estimated Budget Effects Of The Conference Agreement For Title XIII Of H.R. 6, The Energy Tax Incentives Act Of 2005," JCX59-05, July 27, 2005. Energy Information Administration, *Electric Power Annual 2006*, DOE/EIA-0348(2006) (Washington, DC, November 2007). Energy Information Administration, Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" October 2006-September 2007. Tennessee Valley Authority SEC 10-K, 2006. Bonneville Power Administration 2006 Annual Report. Southeastern Power Administration 2005 Annual Report. Southwestern Power Administration 2004-2006 Annual Report and Western Area Power Administration 2006 Annual Report.

The per-unit subsidies are calculated as the subsidies allocated to each fuel type divided by the FY 2007 electricity generated by each fuel type (Table 35). Refined-coal-related generation receives the largest subsidy in absolute terms, at roughly $2 billion, as well as the highest per-unit value at $29.81 per megawatthour. Renewable electricity production, in aggregate, received subsidies totaling $1.0 billion, but the per-unit subsidy in aggregate is $2.80 per megawatthour. On a fuel-specific basis, solar and wind subsidies receive the second-and-third highest per unit subsidies. However, the total value of subsidies received by each of these technologies was roughly in proportion to their relative share of net generation. As, a result, their respective per-unit subsidies are nearly equal. In the case of solar, the per-unit subsidy estimate of $24.34 per megawatthour is a function of the relatively high allocation of subsidies received, $14 million, and its low share of total electricity production. Wind received $724 million in subsidies, valued at $23.37 per megawatthour.

Table 35. Subsidies and Support to Electricity Production: Alternative Measures

Fuel/End Use	FY 2007 Net Generation (billion kilowatthours)	Alternative Measures of Subsidy and Support: Subsidy and Support Value 2007 (million dollars)	Alternative Measures of Subsidy and Support: Subsidy and Support Per unit of Production (dollars/megawatthours)
Coal	1,946	854	0.44
Refined Coal	72	2,156	29.81
Natural Gas and Petroleum Liquids	919	227	0.25
Nuclear	794	1,267	1.59
Biomass (and Biofuels)	40	36	0.89
Geothermal	15	14	0.92
Hydroelectric	258	174	0.67
Solar[1]	1	14	24.34
Wind	31	724	23.37
Landfill Gas	6	8	1.37
Municipal Solid Waste	9	1	0.13
Unallocated Renewables	NM	37	NM
Renewables (subtotal)	360	1,008	2.80
Transmission and Distribution	NM	1,235	NM
Total	4,091	6,747	1.65

NOTES: Total may not equal sum of components due to independent rounding.

Unallocated renewables include projects funded under Clean Renewable Energy Bonds and the Renewable Energy Production Incentive.

NM = Not meaningful.

[1]Net generation rounded to the nearest whole number. The actual value is 583 million kilowatthours.

Sources: Energy Information Administration, Forms EIA-906, "Power Plant Report;" Form EIA-920, "Combined Heat and Power Plant Report;" October 2006-September 2007.

Of the $9.8 billion in energy subsidies not related to electricity (Table 36), about one-third of the total promotes fuels, particularly ethanol and biodiesel, which are eligible to receive a blender's credit under the Volumetric Ethanol Excise Tax Credit (VEETC). Blenders receive a $0.51 per gallon credit for each gallon of ethanol that is blended with gasoline for use as a motor fuel. In FY 2007, ethanol (and biofuels) consumption was just over half a quadrillion Btu, or about one half of one percent of all the energy consumed in the United States. On a consumption basis, ethanol is subsidized at a rate of $5.72 per million Btu, more than any other non-electric fuel.

About 60 percent of all fuel consumed in the United States is consumed by primary end-use sectors, i.e., residential, commercial, industrial and transportation. In FY 2007 subsidies for petroleum liquids and natural gas totaled $2.1 billion. Although natural gas-fired generation has increased 86 percent between 1997 and 2007, power sector consumption of natural gas has increased only slightly as a share of total energy consumption in the United States, growing from around 5 percent of the national total to just under 7 percent. So, of the $2.1 billion in total natural gas and petroleum liquids subsidies, $1.9 billion are allocated to the primary end-use sectors with the remainder to electricity production. With over 60 percent of total energy consumption in the U.S. associated with natural gas and petroleum, the two fuels receive relatively small subsidies on a consumption unit basis, only about three cents per million Btu. Similarly, hydrogen, which is used in fuel cells and in a limited number of transportation pilot programs received $230 million in subsidies in FY 2007. However, consumption is so small that the subsidy per million Btu is not meaningful for comparison purposes in Table 36.

Subsidies totaling another $3.6 billion do not directly affect fuel production or specific fuel consumption. These programs focus on energy efficiency, conservation, and energy-related financial assistance to residential, commercial, and industrial end-users. The largest of these programs, the Low Income Home Energy Assistance Program (LIHEAP), provided $2.2 billion in FY 2007 to subsidize heating and cooling costs. No program information is available to determine the portion of the expenditure directed to the affected fuels, which include distillate fuel, natural gas, coal, and electricity.

Table 36. Energy Subsidies Not Related to Electricity Production: Alternative Measures

Category	Fuel Consumption (quadrillion Btu)	Alternative Measures of Subsidy and Support: FY 2007 Subsidy and Support (million 2007 dollars	Alternative Measures of Subsidy and Support: Subsidy per million Btu (2007 dollars)
Coal	1.93	78	0.04
Refined Coal	0.16	214	1.35
Natural Gas and Petroleum Liquids	55.78	1,921	0.03
Ethanol/Biofuels	0.57	3,249	5.72
Geothermal	0.04	1	0.02
Solar	0.07	184	2.82
Other Renewables	2.50	360	0.14
Hydrogen	*	230	NM
Total Fuel Specific[1]	60.95	6,237	0.10
Total Non-Fuel Specific	NM	3,597	NM
Total End-Use and Non-Electric Energy	NM	9,834	NM

NOTES: Non-electric power industry refined coal consumption is based on the sum of monthly deliveries, in short tons, reported in the EIA publications cited below for FY 2007. Delivered refined coal to non-electric customers is converted to equivalent Btu consumption based on EIA's estimate of the average Btu content for refined coal deliveries to generators reported to EIA. Other renewables includes hydroelectric, wood, biomass losses and co-products, and hydroelectric power as reported in the sources noted below.

[1]Subsidy shown differs from that shown in Table 26 due to inclusion of fuels that have no role in electricity production, such as ethanol and other biofuels.

*Less than 500 trillion Btu.

NM = Not meaningful.

Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, *Monthly Energy Review December 2007,* DOE/EIA-0035 (2007/12) (Washington, DC, December 2007), Table 10.2a and 10.2b; Energy Information Administration, *Quarterly Coal Report,* DOE/EIA-0121 (2007/03Q) (Washington, DC, December 2007), Table 35; Energy Information Administration, *Quarterly Coal Report* , DOE/EIA-0121 (2006/04Q) (Washington, DC, March 2007), Table 38; Office of Management and Budget*, Budget of the United States Government, Fiscal Year 2008-Appendix*; Office of Management and Budget, *Analytical Perspectives Budget of the United States Government, Fiscal Year 2008, Federal Receipts and Collections*, http://www.whitehouse.gov/omb/budget/fy2008/; Joint Committee on Taxation, "Estimated Budget Effects Of The Conference Agreement For Title XIII of H.R. 6, The Energy Tax Incentives Act Of 2005," JCX59-05, July 27, 2005. (Washington, DC, November 2007); Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," 2006; Form EIA-906, "Power Plant Report;" and Form EIA-920, and "Combined Heat and Power Plant Report," October 2006 through September 2007.

Perspectives on Electricity Subsidy Estimates

The issue of what constitutes a Federal government benefit is not without controversy. The intention of this analysis is not to assess all the cost differences faced by Federal utilities, cooperatives, public power, and the IOUs. There are numerous tax benefits and tax expenditures associated with ownership class. Electricity cooperatives are organized as tax-exempt organizations under Federal tax law. Publicly-owned utilities are tax-exempt and have the ability to issue lower-cost tax-exempt debt. IOUs benefit from accelerated depreciation, which defers taxes and lowers their cost of capital by increasing cash flow. These benefits flowed from decisions by individuals and communities on how, and from whom, they wished to acquire electric service during the period in which the Nation was electrified. In essence, tax laws were expected to allow for different ownership classes of electric utility assets. Whether the basis for tax and other benefits attributable to class ownership are equal, or not, remains a debatable question to industry analysts.

These tax expenditures and direct expenditures provide incentives for market participants to engage in behavior, e.g., capital investment decisions that will achieve a desired benefit to society. This includes reducing dependence on imported oil, promotion of the use of environmentally preferred renewable resources, and encouraging participation in transmission organizations that facilitate reliability and enhance competition in wholesale electricity markets.

EIA was requested to provide an estimate of electricity subsidies with fuel-specific effects on a per-unit basis. In developing the analytical framework for this study, EIA adopted an inclusive approach that encompasses all energy-related R&D, direct expenditures, and tax expenditures to which there was a direct or indirect connection to current or future electricity production. This approach leaves a number of issues open to further discussion and analysis:

- EIA recognizes, particularly with respect to tax expenditures that the economic sector that the statutory beneficiary of a specific tax expenditure may or may not be the economic beneficiary. However, the calculations made in this report assume full pass through of current subsidies and support to fuel producers and transporters to electricity production. The Incidence Theory suggests that if a tax credit is applicable to a good or service that is supply inelastic, the statutory beneficiary can be expected to retain the benefit of a tax-expenditure. Possibly, a more accurate result could be obtained by conducting either a general equilibrium or partial equilibrium analysis, or a statistical-based micro-data analysis for individual tax expenditures.

- Including R&D expenditures raises intertemporal equity issues when applied to current electricity production by fuel type. Inclusion of these subsidies can be justified on the basis that past R&D expenditures are reflected in generation technologies in use today. Moreover, these expenditures are representative of the current direction of energy policy of diversification of energy supply, energy security, and environmental protection. Additionally, the report recognizes that at times there is a continuum associated with applied research and tax expenditures. In certain instances, R&D produces technology for which there is only nascent demand because of the initial cost or perceived market risk that limits access to financing. Thus, tax incentives or direct expenditures may be necessary to overcome this barrier. The production tax credits available for the first 6 gigawatts of advanced technology nuclear capacity is a good example of the linkage between R&D and tax expenditures.

- Inclusion of Federal electricity programs is not intended to highlight or discriminate against a particular segment of the industry. EIA recognizes the methodology used for estimating the support is based on available data, and is subject to some uncertainty. However, generally accepted economic theory and empirical observation lead to the conclusion that the structure of Federal utilities confers a benefit on their customers through the belief by capital markets that there is an implicit Federal guarantee of their debt. EIA quantified this support using a capital cost method that provides an estimated range of interest rate support by comparing the interest expense for each entity at its embedded cost of debt to a range of interest rates. By providing an estimate of interest rate support between the Treasury rate and the lowest investment grade bond rating, alternative estimates of support may be inferred. Based on a comparison of the Federal utilities with comparably-structured government-owned wholesale producers, it was determined that a benchmark A rated bond interest rate was the most appropriate for a point estimate for this report.

Appendix A
Fact Sheets

Tax Expenditures

1. 30-Percent Credit for Purchase of Residential Solar and Fuel Cells

Description

Section 1335 of the Energy Policy Act of 2005 (EPACT2005)(Public Law 109-58) established a 30-percent personal tax credit, not to exceed $2,000 for the purchase of solar electric and solar water heating property. A 30-percent tax credit up to $500 per 0.5 kilowatt (kW) of capacity is also available for fuel cells. The fuel cell provision of EPACT2005 was due to expire at the end of 2007, however, it was extended through the end of calendar year 2008 by Section 206 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432). The generator must have an efficiency rating of 30-percent and generate at least 0.5 kW of electricity. Installation expenditures, such as those for labor, are considered eligible for the credit. Solar water heating property must meet performance specifications certified by the Solar Rating Certificate Corporation.

Solar swimming pools are ineligible for the credit.

To be eligible for the credit, a system must be placed in service (activated) between January 1, 2006 and December 31, 2008.

Revenue Loss/Outlays

The lost revenue to the U.S. Treasury from this credit is $10 million (nominal) per year from Fiscal Year (FY) 2006 through FY 2008.[209] The "Revenue Loss" data in the tabulation were generated estimated by the Treasury Department (Table A1). The Revenue Loss is the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that royalties on coal are taxed at the regular rate. The actual case assumes that the royalties are taxed at the capital gains tax rate to the extent taxpayers so choose.

Table A1. Estimated Revenue Loss: Residential Solar and Fuel Cell Credit, 2006 to 2008 (million nominal dollars)

Fiscal Year	Revenue Loss-Individuals
2006	10
2007	10
2008	10

NOTE: All estimates have been rounded to the nearest $10 million. Provisions with estimates that rounded to zero in each year are not included in the table.

Source: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

Rationale

To reduce reliance on grid-connected electricity.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Residential distributed generation.

[209] *Analytical Perspectives, Budget of the United States Government, Fiscal Year 2008*, Table 19-1, "Estimates of Total Income Tax Expenditures," Office of Management and Budget; http://www.whitehouse.gov/omb/budget/fy2008/pdf/spec.pdf; accessed August 13, 2007.

2. 84-Month Amortization of Certain Pollution Facilities

Description

To effect reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions, Section 1309 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) modified Section 169 of the Internal Revenue Code (IRC), which permitted a 60-month amortization of qualifying pollution control facilities used in connection with plants placed in service before January 1, 1976. The modification extends the amortization period to 84 months and eliminates the applicability of the provision to plants placed in service prior to the end of 1975. The revised amortization period is now applicable to qualifying pollution control facilities placed in service as of April 11, 2005. The Joint Committee on Taxation estimated the value of this expenditure to be $30 million for 2007. Certified pollution control facilities include identifiable treatment facilities used to reduce, alter, dispose, store, or prevent the emission of pollutants.

Revenue Loss/Outlay

There is no expected revenue loss associated with this program for 2007.

Rationale

To reduce electricity-related emissions.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Generation.

3. Alcohol Fuel Credit

Description

The Energy Tax Act of 1978 (Public Law 95-618) established a subsidy for alcohol-based fuels. Federal financial incentives for renewable fuels in the transportation sector, strictly speaking, are limited to ethanol. Ethanol is produced from grain crops, with corn being the primary feedstock. The main use of ethanol is for gasohol (a blend of 90 percent unleaded gasoline and 10 percent ethanol, E-10) and for lower blends of ethanol to meet oxygenated gasoline requirements. Ethanol used in gasohol and other oxygenated gasoline blends meets the definition of a replacement fuel, but not of an alternative fuel. Two higher blends of ethanol, E-85 and E-95, are being used as alternative fuels in limited amounts. The value of the tax expenditure for renewable transportation fuels is $50 million in fiscal year 2007.

The alcohol fuel income tax credit and its associated excise tax credit (which is now the Volumetric Ethanol Excise Tax Credit or VEETC, see Fact Sheet 20) were initially implemented in the late 1970s and early 1980s. The income tax credit was initially 40 cents per gallon minus the amount of excise tax exemption, which was 4 cents per gallon. Some modifications to the original legislation have subsequently been made. The Omnibus Budget Reconciliation Act of 1990 (OBRA) (Public Law 101-508) reduced the income tax credit from 60 cents per gallon to 54 cents per gallon. The 1990 OBRA also introduced the small producer income tax credit of 10 cents per gallon. These provisions went into effect on January 1, 1993. The value of the $3.0 billion excise tax exemption on taxable motor gasoline mixed with ethanol is far greater than the $50 million ethanol tax expenditure cited above.

Revenue Loss/Outlays

The “Revenue Loss” data were estimated by the Treasury Department. The Revenue Loss is the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments (Table A2) is presented. The reference case assumes that no income tax credits are granted. The actual case assumes that the income tax credit exists and that the excise tax credit remains in effect.

Rationale

Reduced dependence on foreign sources of transportation fuels.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Ethanol production, and to a much smaller extent, petroleum production.

Table A2. Estimated Revenue Loss: Alcohol Fuel Credit, 1984 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
1984	([a])	([a])	([a])
1985	([a])	([a])	([a])
1986	([a])	([a])	([a])
1987	5	5	10
1988	5	5	10
1989	([a])	([a])	([a])
1990	([a])	([a])	([a])
1991	([a])	([a])	([a])
1992	([a])	([a])	([a])
1993	([a])	([a])	([a])
1994	10	5	15
1995	5	5	10
1996	5	5	10
1997	10	10	20
1998	5	10	15
1999	5	10	15
2000	10	10	20
2001	10	20	30
2002	10	20	30
2003	10	20	30
2004	10	20	30
2005	10	30	40
2006	10	40	50
2007	10	40	50
2008	10	50	60
2009	20	50	70
2010	20	50	70
2011	10	60	70
2012	0	0	0

NOTE: ([a]) indicates a value under $2.5 million

All estimates have been rounded to the nearest $5 from 1984 through 2001. Thereafter all estimates are rounded to the nearest $10 million. Provisions with estimates that rounded to zero in each year are not included in the table.

Sources: Office of Management and Budget, *Budget of the United States Government, Analytical Perspectives Fiscal Year 2008* (Washington, DC, 2007), Table 19-2, and earlier versions. Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy*, SR/OIAF/99-03, (Washington, DC, September, 1999).

4. Allowance for the Deduction of Certain Energy-Efficient Commercial Building Properties

Description

Section 1331, of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58), provides for a new formula-based tax deduction for energy-efficient commercial properties. The formula-based tax deduction was added to the Internal Revenue Code at Section 179D. under the new IRS Code, 179D. Section 1331 provides This tax provision allows for a tax deduction of $1.80 per square foot on new commercial property construction built after December 31, 2005, and before December 31, 2007, if annual energy and power costs of interior lighting systems, heating, cooling, ventilation, and hot water systems are 50 percent or more below American Society of Heating, Refrigerating (ASHRAE) Standard 90.1-2001. In the case of properties owned by Federal, State, or local governments, or political divisions thereof, the U.S. Treasury Department is responsible for issuing regulations to allocate the deduction to the primary designer of the property. Section 204 of the Tax Relief and Health Care Act of 2006 extended the credit to December 31, 2008.

For properties not fully meeting the 50 percent reduction, there is a provision for a deduction of $0.60 per square foot of property. Partial credit is allowed for qualified improvements to building envelope, hot water, heating, ventilation and air conditioning systems (HVAC), and lighting systems. These deductions apply to buildings placed in service between January 1, 2006, and December 31, 2007. Tax expenditures occasionally affect years outside the timeframe in which the law is in force. This may be due to reporting years not overlapping with fiscal years or it may be due to tax-loss carryforwards. When the availability of a tax deduction causes results in accelerated spending in the near-term, later-term revenue loses may result. The affect of this tax deduction is to reduced demand for electricity and natural gas by the commercial sector.

Revenue Loss/Outlays

Table A3. Estimated Revenue Loss: Energy-Efficient Buildings Deduction, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	Corporations	Total
2006	20	60	80
2007	50	140	190
2008	40	130	170
2009	20	70	90
2010	10	20	30
2011	0	(10)	(10)
2012	0	(10)	(10)

NOTE: All estimates have been rounded to the nearest $10 million. Provisions with estimates that rounded to zero in each year are not included in the table.

Source: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

Rationale

To improve the energy efficiency of commercial buildings.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity and natural gas.

5. Alternative Fuels Production Tax Credit

Description

The Alternative (or nonconventional) Fuels Credit was established with the Windfall Profits Tax of 1980 (Public Law 96-223). It was originally codified as Internal Revenue Code (IRC or Code) Section 44D, but it was later redesignated as Section 29 which is what it is most commonly referred to today. The Alternative Fuels Credit is a production-based tax credit that originally applied to qualified fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992, and sold through the year 2002. The qualified fuels were: (1) oil produced from shale and tar sands; (2) natural gas produced from geopressurized brine, Devonian shale, coal seams, tight formations, or biomass; (3) liquid, gaseous or solid synthetic fuels produced from coal liquefaction and pressurization; (4) fuel from qualified processed wood; and (5) steam from solid agricultural byproducts. The Alternative Fuel Production Credit is often referred as a Section 29 credit based upon its former IRS Code citation. A taxpayer is entitled to the credit under Section 29 in the taxable year in which the qualified fuel is sold. Section 29 cannot be used to offset the alternative minimum tax.

The principal additional changes that have occurred since the 1980 Act have been to extend the time limits by which wells or facilities must be placed in service and fuels sold in order to be eligible for the credit. In 1989, legislation allowed a 1-year extension of the time limits. The Omnibus Budget Reconciliation Act of 1990 (Public Law 101-508) provided an additional 2-year extension. The 1990 act also greatly eased the qualification for gas produced from tight sands after 1990. However, subsequently, the qualification had been sharply constrained by Executive Branch rulings and judicial decisions. The Energy Policy Act of 1992 (EPACT1992)(Public Law 102-486) expanded the credit for certain nonconventional fuels.

Synthetic coal is the largest recipient of the Section 29 tax credit. Under IRC Section 48 coal was qualified as a synthetic fuel as defined if it differs significantly in chemical composition from the alternative substance used to produce it. To qualify for this credit, a taxpayer must produce and sell qualified fuel from a production facility that was placed in service as of July 1, 1998, pursuant to a binding written contract in place as of January 1, 1997, and produced through December 31, 2007. The coal may be of any rank from lignite to anthracite although bituminous coals are most prominently used. In order to be classified as a synthetic fuel, coal must undergo a significant chemical change under the criteria of Internal Revenue Service Revenue Ruling 86-100. This measurement takes place in a lab where feedstock coal is compared to synthetic coal to confirm that the chemical makeup of the synthetic fuel is not predicted from the ingredients. The liquid binding agents used are often such items as diesel fuel emulsions, pine tars, or latex to the blend of coal feedstock. The tax credits are based on the Btu value of the synthesized coal. As a consequence, Section 29 qualified coal synfuels using Eastern bituminous coals as a feedstock is more valuable than synthetic coals using lower-Btu western lignite and sub-bituminous coals. Companies have been claiming the credits since as early as 1998.[210]

Section 710 of the American Jobs Creation Act of 2004 (Public Law 108-357) required that synthetic coal be sold by the taxpayer with the reasonable expectation that it will be used for purpose of producing steam. The American Jobs Creation Act also redefined synthetic coal to “refined coal.” Section 710 also introduced certain restrictions concerning what coal could qualify as “refined coal.” Qualified new facilities were to be eligible to receive a Section 45 tax credit, as discussed in the next paragraph, for the first 10 years of operation. Compared to Section 29 guidelines, which expire at the end of 2007, the revised guidelines for qualifying coal synfuel facilities are significantly more restrictive. Qualifying facilities under the new 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; and, 2) the refined coal product must be at least 50 percent higher in economic value than the feedstock.

[210] Energy Information Administration, Coal News and Markets, Week of August 10, 2003.

Section 1322 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) appended Section 29 to Section 45 as a new section 45K. Section 45K allows old Section 29 credits to be combined with other general business credits. This allows credits to be carried forward 20 years, with a 1-year look back. Section 1301 of EPACT2005 extended the Section 45 tax credit to Indian coal production. The credit is good for a 7-year period beginning in January 1, 2006. Section 1321 of EPACT2005 expanded the credit to apply to coke and coke gas produced in certain facilities placed in service before January 1, 2010. The credit amount for coke or coke gas is $3.00 per barrel of oil equivalent, indexed for inflation using 2004 as the base year with a credit-available production limit of an average barrel-of-oil equivalent of 4,000 -barrels -per -day. The tax credit provisions set forth in the EPACT2005 extended the tax credit for “refined coal” and waste coal to new facilities coming on-line after October 22, 2004, and prior to January 1, 2009.Section 211 of the Tax Relief and Heath Care Act of 2006 (Public Law 109-432) removed the phase-out provision for coke and coke gas.

The tax credit for these fuels is $3-per-barrel of oil-equivalent produced. (Conversion factors are used to convert the various fuels into their crude oil equivalent for purposes of calculating the credit.) The credit is fully effective when the price of crude oil is $23.50 per barrel or less and phases out gradually as the price of oil rises to $29.50 per barrel when the subsidy disappears. All prices as well as the credit are specified in 1979 dollars, but for actual use they are indexed for inflation relative to that base. For 2006, the IRS reported the credit oil price caps at $50.06 when the cap began and $69.12 when the cap was complete.[211] Domestic first purchase price, the price to which the cap is applied, averaged $59.68 per barrel in 2006, indicating that the credit was phased down somewhat. The credit is also reduced if certain other energy subsidies, such as government grants and tax-exempt financing, are used. The credit applies only to fuel produced at a facility placed in service before July 1, 1998, and sold before January 1, 2008.

Revenue Loss/Outlays

The lost revenue to the Treasury related to Section 29 started to grow significantly in the early 1990s. Revenue losses are expected to peak in 2007 before falling to zero by 2011.The “Revenue Loss” data in Table A4 were generated by the Treasury Department. The “Revenue Loss” is the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments) is presented. The reference case assumes that the alternative fuels receive no production credit. The actual case assumes that the credit is granted.

[211] Phone interview with Jamie Parks of the IRS, August 20, 2007.

Table A4. Estimated Revenue Loss: Alternative Fuel Production Tax Credit, 1987 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
1987	(a)	10	10
1988	(a)	10	10
1989	(a)	10	10
1990	(a)	10	10
1991	50	205	255
1992	90	360	450
1993	120	640	760
1994	140	760	900
1995	150	820	970
1996	150	850	1,000
1997	30	680	710
1998	45	815	860
1999	50	975	825
2000	40	930	970
2001	40	860	900
2002	60	1,500	1,560
2003	50	1,230	1,280
2004	40	1,000	1,040
2005	100	2,220	2,320
2006	120	2,860	2,980
2007	100	2,270	2,370
2008	30	750	780
2009	0	10	10
2010	0	10	10
2011	0	0	0
2012	0	0	0

NOTES: (a) $2.5 million or less.

All estimates have been rounded to the nearest $5 from 1984 through 2001. Thereafter all estimates are rounded to the nearest $10 million. Provisions with estimates that rounded to zero in each year are not included in the table.

Sources: 1987-1993: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992) and earlier editions. 1994-2004: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008*. (Washington, DC, 2007), Table 19-2.

Rationale

The alternative fuel tax credit is one of several measures adopted in the early 1980s to encourage the development of synthetic fuels produced by nonconventional means or sources. The credit is designed to encourage capital investment in alternative fuel production by protecting producers of those fuels against the effects of oil price reductions.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal bed methane and synthetic (refined) coal.

6. Biodiesel and Small Agri-Biodiesel

Description

Section 302 of The American Jobs Creation Act of 2004 (AJCA) (Public Law 108-357) amended the Internal Revenue Code (IRC or Code) of 1986 by adding a new Section 40A[212], which provides for a biodiesel mixture credit and a biodiesel credit.[213] The estimated value of this credit is $180 million for 2007. Initially, the credit was due to expire December 31, 2006. Section 1345 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) further amended Section 40A to include a tax credit for the production and sale of agri-biodiesel by small producers and extended the sunset provision through December 31, 2008.

For purposes of determining general business takes credits under Section 38 of the Code, Section 40A defines the biodiesel fuels credit to be the sum of (1) the biodiesel mixture credit, (2) the biodiesel credit, and (3) with respect to small agri-diesel producers, the small agri-diesel producer credit.

Eligible taxpayers receive a 50-cents-per-gallon biodiesel mixture credit for each gallon of biodiesel used to produce a qualified biodiesel mixture. The taxpayer may sell the biodiesel mixture as a fuel or it may be used as a fuel by the taxpayer producing the mixture. The sale or use by the taxpayer must be in trade or business in which the taxpayer is engaged, and the credit is applicable in the year of the sale or use of the biodiesel mixture. The biodiesel tax credit is 50-cents-per-gallon for each gallon that is not mixed with diesel. It is available to taxpayers during the taxable year that use biodiesel in a business or trade or is sold by the taxpayer as motor vehicle fuel.[214] The same conditions apply for the agri-biodiesel credit except that it is increased to $1.00.

The small agri-biodiesel producer credit is available to any eligible producer of agri-biodiesel. The producer of qualified agri-biodiesel is eligible for a 10-cent-per-gallon credit for any taxable year if the product is sold (1) to another person engaged in the manufacture of a biodiesel mixture, (2) for use by the purchaser as a fuel in a trade or business, or, (3) sold at retail as vehicle fuel. The credit is limited to production not to exceed 15 million gallons per year and the producer may not have annual agri-biodiesel production capacity in excess of 60 million gallons.[215]

The tax credit is intended to stimulate production of renewable transportation fuels. Increased demand for agricultural commodities used as feedstock for the manufacture of biodiesel may increase the demand and prices. As a result, heightened demand for eligible feedstock commodities for biodiesel may increase the cost of food products (e.g., soybean products and vegetable oils).

Revenue Loss/Outlays

For fiscal year (FY) 2007, the Treasury estimates a $180 million revenue loss as a result of this tax credit. It is projected to grow to $200 million in FY 2008. Between FY 2009 and FY 2012, the cumulative revenue loss is projected to be $70 million.[216] The "Revenue Loss" data in the estimated by the Treasury Department. The Revenue Loss is the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that tax credits are not available for biodiesel mixture,

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[212] 26 U.S.C. 40A (2006).

[213] A biodiesel mixture means a mixture of biodiesel and diesel fuel, without regard to the use of kerosene that is sold by the taxpayer as fuel to any person or used as a fuel by the taxpayer producing the mixture. A mixture contain at least 0.1 percent by volume of diesel fuel is considered a biodiesel mixture. Kerosene is not included in the volume for purposes of determining whether the mixture meets the minimum 0.1 percent diesel. Agri-biodiesel is defined as fuels derived solely from virgin oils including, but not limited to esters from corn, soybeans, cottonseeds, crambee, rapeseeds, safflowers, flaxseed, rice bran, mustard seeds and animal fat. See, 2005-35 I.R.B., Notice 2005-62 "Modification of Notice 2005-4; Biodiesel and Aviation-Grade Kerosene, pp. 446-447 (August 29, 2005).

[214] Taxpayers may not claim a credit for both the use and retail sale of biodiesel.

[215] EPACT2005, Section 1345 also modified Section 40A to provide for pass-through treatment of tax credits to S corporations and allocation of credits to patrons of sub-Chapter T cooperatives in proportion to their patronage with the organization.

[216] Office of Management and Budget, *Analytical Perspectives, Budget of the United States Government, Fiscal Year 2008*, "Federal Collections and Receipts," Table 19.1, p. 287. http://www.whitehouse.gov/omb/budget/fy2008/pdf/apers/receipts.pdf.

biodiesel or small agri-diesel. The actual case assumes that the credits are available to eligible taxpayers.

Rationale

The Section 40A tax credit provides financial incentives to producers and vehicular users of biodiesel mixtures, biodiesel, and agri-biodiesel.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

This subsidy affects the production and use of renewable transportation fuels.

7. Capital Gains Treatment of Royalties on Coal

Description

The capital gains treatment of royalties on coal was established by the 1951 Revenue Act (Public Law 82-183, Section 177 (j) and Section 117 (k)). Owners of coal mining rights who lease their property usually receive royalties on mined coal. If the owners are individuals, these royalties can be taxed at the lower individual capital gains tax rate of 15 percent rather than at the higher regular individual top tax rate of 35 percent. The capital gains tax rate dropped from 28 percent to 20 percent in 1997 and to 15 percent in 2003. This, and the gradual increase in coal prices starting in 2000, account for the higher estimated revenue loss beginning in 1997.

In order to claim capital gains treatment, the royalty owner must own the property for a minimum of 1 year and meet other simple requirements. Owners who elect the capital gains tax rate cannot also elect percentage depletion. The capital gains treatment of coal royalties, one of the oldest energy subsidies, is provided for by law and has been in effect since the early 1950s.

Revenue Loss/Outlays

For the year 2007, the value of this tax expenditure equals an estimated $170 million. The "Revenue Loss" is estimated by Treasury Department (Table A5) as difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that royalties on coal are taxed at the regular rate. The actual case assumes that the royalties are taxed at the capital gains tax rate to the extent taxpayers so choose.

Rationale

The capital gains treatment of coal royalties was adopted for three reasons: (1) to encourage additional production, (2) to place coal on the same tax footing as lumber, and (3) to provide a benefit to long-term lessors who might not benefit substantially from percentage depletion.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal production.

Table A5. Estimated Revenue Loss: Coal Royalties Capital Gains Treatment, 1987 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
1987	45	5	50
1988	(a)	(a)	(a)
1989	0	0	0
1990	0	0	0
1991	5	0	5
1992	10	0	10
1993	10	0	10
1994	10	0	10
1995	15	0	15
1996	15	0	15
1997	50	0	50
1998	60	0	60
1999	65	0	65
2000	70	0	70
2001	100	0	100
2002	100	0	100
2003	100	0	100
2004	70	0	70
2005	90	0	90
2006	160	0	160
2007	170	0	170
2008	170	0	170
2009	170	0	170
2010	190	0	190
2011	180	0	180
2012	130	0	130

NOTES: (a) $2.5 million or less.

All estimates have been rounded to the nearest $5 million from 1984 through 2001. Thereafter, all estimates are rounded to the nearest $10 million. Provisions with estimates that rounded to zero in each year are not included in the table.

Sources: 1987-1993: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992) and earlier editions. 1994-2004: Office of Management and Budget, *Budget of the United States, Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

8. Credit for Business Installation of Qualified Fuel Cells and Microturbine Power Plants

Description

Section 1336 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides for a 30-percent energy tax credit for the purchase of qualified fuel cells with a maximum of $500 for each 0.5 kilowatt of capacity. EPACT2005, Section 1336 amends Internal Revenue Code (IRC or Code) Section 48 (relating to energy credits) by adding qualified microturbines and fuel cells. In order to qualify for the credit, the plant must have an electricity-only efficiency of 30-percent or more and generate at least 0.5 kilowatts of power. For fuel cells the credit is scheduled to terminate on December 31, 2007. Qualified microturbine power plants are eligible for a 10-percent credit. In order to qualify, microturbine power plants need to have an electricity-only efficiency of 26 percent or greater and a capacity of less than 2,000 kilowatts. The credit shall not exceed $200 for each kilowatt of capacity. A qualified microturbine is "an integrated system comprised of a gas turbine engine, a combustor, a recuperator or regenerator, a generator or alternator, and associated balance of plant components which converts a fuel into electricity and thermal energy."

Revenue Loss/Outlays

For the year 2007, the value of this tax expenditure is an estimated $90 million. The "Revenue Loss" data in Table A6 was prepared by the Treasury Department. The Revenue Loss is the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that there are no exceptions to the passive loss limitations.

Table A6. Estimated Revenue Loss: Qualified Fuel Cells and Microturbines, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	Corporations	Total
2006	20	60	80
2007	20	70	90
2008	30	100	130
2009	10	40	50
2010	0	(10)	(10)
2011	0	(10)	(10)
2012	0	(10)	(10)

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2. Also earlier editions.

Rationale

Provide greater incentives for distributive power.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas, hydrogen, and diesel demand.

9. Credit for the Construction of New Energy-Efficient Homes

Description

Section 1332 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides a tax credit of $2,000 for the construction of a qualified new energy-efficient home if the home achieves 50-percent energy savings over a comparable unit constructed to the International Energy Conservation Code (IECC). Energy savings must come from improved home heating and cooling efficiencies rather than from a more efficient hot water heater. The Secretary of the Treasury, in consultation with the Secretary of Energy, is to provide guidance in calculating the procedures and methods of estimating efficiency gains.

For new homes realizing 30-percent savings over a comparable unit constructed pursuant to the IECC, a $1,000 tax credit is provided. Initially, the tax credit was available for the period January 1, 2006, through December 31, 2007. However, the eligibility window was extended to December 31, 2008, by the Tax Relief and Health Care Act of 2006 (Public Law 109-432).

The credit is limited to properties within the United States used as residences and substantially completed by August 8, 2005.

Revenue Loss/Outlays

For the year 2007, the value of this tax expenditure is an estimated $20 million (Table A7). The "Revenue Loss" is calculated by the Treasury Department as the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes there are no credits taken for qualified home construction. The actual case assumes that credits are taken for qualified home construction.

Table A7. Estimated Revenue Loss: Energy-Efficient Homes Credit, 2006 to 2009 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2006	10
2007	20
2008	10
2009	10

NOTE: All estimates have been rounded to the nearest $10 million.

Source: Office of Management and Budget, *Budget of the United States Government, Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

Rationale

To reduce home-related fuel consumption.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

The major fuels affected are natural gas, home heating oil, and electricity. The stage affected is end use.

10. Credit for Energy Efficiency Improvements of Existing Homes

Description

Section 1333 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides a 10-percent tax credit for expenditures made to improve the energy efficiency of existing homes that are principal residences located within the United States. This credit applies to windows, furnaces, boilers, fans, and building envelope components such as exterior doors and any metal roof that has appropriated pigmented coatings. The credit per dwelling is capped at $500 for all taxable years with the following application. Labor costs are considered eligible for the credit. In case of jointly-held properties, special proration rules are applied. The credit amount for each respective item is summarized below:

Component	Maximum Credit
• Windows	$200
• Furnace	$150
• Boiler	$150
• Fan	$50

The effective date of the subsidy is January 1, 2006, through December 31, 2007. The effect of this credit is to reduce U.S. demand for electricity and natural gas.

Revenue Loss/Outlays

In 2007, the estimated revenue loss is expected to total $380 million (Table A8).

Table A8. Estimated Revenue Loss: Existing Home Efficiency Improvement Credits, 2005 to 2011 (million nominal dollars)

Fiscal Year	Revenue Loss-Individuals
2005	0
2006	220
2007	380
2008	150
2009	0
2010	0
2011	0

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: Office of Management and Budget, *Analytical Perspectives of the U.S. Budget, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.; Internal Revenue Service, “Highlights of the Energy Policy Act of 2005 for Individuals,” http://www.irs.gov/newsroom/article/0,,id=153397,00.html, accessed October 16, 2007.

Rationale

Improve the energy efficiency of existing homes.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Residential electricity and natural gas consumption.

11. Credit for Efficient Appliances

Description

Section 1334 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides tax credits for the manufacturing of energy-efficient dishwashers, clothes washers, and refrigerators. The credits apply to appliances manufactured between December 31, 2005, and January 1, 2008. The tax credit is limited to 2 percent of the gross revenue for the three taxable years preceding the taxable year in which the credit occurs. For comparison purposes the appliance efficiency is measured against ENERGY STAR 2007 efficiency standards. ENERGY STAR is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy promoting the greater penetration of energy efficient appliances. The tax credits are calculated in the following manner:

Dishwashers: $3 X (2007 standard/ 2005 standard); up to $100 per dishwasher.

Clothes washers: $100 for each unit manufactured in 2006 and 2007 that meets ENERGY STAR standards.

Refrigerators: 15 to 20-percent energy savings receive a $75 credit if manufactured in 2006. Refrigerators that achieve a 20 to 25-percent increase in energy savings receive a $125 credit if manufactured in 2006 or 2007.

Individual manufactures are limited to claims no greater than $75 million for all years. Of the $75 credit, manufacturers are limited to $20 million for 2006.

Revenue Loss/Outlays

A reduction in corporate tax receipts of $80 million in 2007 (Table A9).

Table A9. Estimated Revenue Loss: Efficient Appliances Credit, 2006 to 2007 (million nominal dollars)

Fiscal Year	Revenue Loss Corporations
2006	120
2007	80

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: Office of Management and Budget, *Analytical Perspectives of the U.S. Budget, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

Rationale

To increase the energy efficiency of home appliances.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Residential electricity demand and to a lesser extent, natural gas demand.

12. Credit for Holding Clean Renewable Energy Bonds

Description

Section 1303 of the Energy Policy Act of 2005 (EPACT 2005) (Public Law 109-58) introduced a provision which provided for up to $800 million in aggregate issuance of Clean Renewable Energy Bonds (CREBs) through December 31, 2007. Tax payers holding CREBs on a credit allowance date are entitled to a tax credit.[217] Prior to passage of the Energy Incentives Act of 2005, only investor- owned utilities (IOUs) qualified to receive tax incentives for producing electricity from renewable energy resources. In essence, CREBS provide non-IOU electricity providers with interest free loans to finance qualified energy projects.

Section 202 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432) increased the allocation of CREBs to $1.2 billion and extended the deadline to December 31, 2008.[218]

CREBs are non-interesting bearing obligations. The taxpayer holding CREBs on a credit allowance date is entitled to a tax credit, which, in effect, lowers borrowing costs for investments in certain energy facilities. The amount of the credit is determined by multiplying the bond's credit rate by the face amount on the holder's bond. The credit rate on the bonds is determined by the Secretary of the Treasury and is to be a rate that permits issuance of CREBs without discount and interest cost to the qualified issuer. The credit accrues quarterly and is included in gross income (as if it were an interest payment on the bond), and can be claimed against regular income tax liability and alternative minimum tax liability.

The provision also imposes a maximum maturity limitation on the CREBs. The maximum maturity is the term which the Secretary estimates will result in the present value of the obligation to repay the principal on a CREB being equal to 50-percent of the face amount of such bond. Moreover, the provision requires level amortization of CREBs during the periods such bonds are outstanding.

For purposes of the provision, "qualified issuers" include (1) governmental bodies (including Indian Tribal governments); (2) the Tennessee Valley Authority; (3) mutual or cooperative electric companies (described in section 501(c)(12) or section 1381(a)(c)(C), or a not-for-profit electric utility which has received a loan or guarantee under the Rural Electrification Act); and (4) clean energy bond lenders."[219] A qualified issuer is defined as a "clean renewable energy bond lender, a cooperative electric company or a governmental body.

CREBs are an unique debt instrument, as only one other tax credit bond program exists that is similar, i.e., investment tax credit used to finance the reconstruction of school facilities, Qualified Zone Academy Bonds, which allow schools and educational organizations to borrow at 0-percent interest, with holders receiving Federal tax credits in lieu of interest.

Revenue Loss/Outlays

Estimated revenue losses associated with this tax expenditure equal $60 million in 2007 (Table A10).

Rationale

CREBs are intended to extend to governmental bodies (such as State and local governments, the District of Columbia, Indian Tribal governments) and rural electric cooperatives access to interest free loans for investment in certain qualifying facilities. Qualified facilities eligible for CREBs financing are the same as those which qualify under Internal Revenue Code (IRC or Code) Section 45: geothermal, wind, biomass, landfill gas, municipal solid waste, refined coal production, and hydroelectric power. This incentive is similar to that of IRC Section 45provided to investor-owned utilities.

[217] Office of Management and Budget, Analytical Perspectives of the Budget of the United States Government, 2007.
[218] The U.S. House of Representatives Ways and Means Committee: http://waysandmeans.house.gov/media/pdf/taxdocs/hr6408taxdetailedsummary.pdf, accessed October 16, 2007.
[219] Joint Committee on Taxation, "Description and Technical Explanation of the Conference Agreement of H.R. 6, Title XIII, The Energy Tax Incentives Act of 2005," (JCX-60-50), July 28, 2005.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Geothermal, wind, biomass, landfill gas, municipal solid waste, refined coal production, and hydroelectric power.

Table A10. Estimated Revenue Loss: Clean Renewable Energy Bonds, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	Corporations	Total
2006	10	10	20
2007	30	30	60
2008	40	40	80
2009	50	50	100
2010	50	50	100
2011	50	50	100
2012	50	50	10

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: Office of Management and Budget*, Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2**.** and earlier issues.

13. Credit for Investment in Clean Coal Technologies

Description

Section 1307 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58), which applies to Internal Revenue Code Sections 46, 48a, and 48b, establishes a credit for advanced coal-fired power plants and qualified gasification projects. A 20-percent credit is applied to coal gasification projects using integrated gasification combined cycle (IGCC) technology and 15-percent for other advanced coal technologies. A tax credit ceiling of $1.3 billion was set with $800 million allocated towards IGCC projects, $500 million towards other advanced coal technologies and $350,000 towards industrial gasification facilities.

A qualified plant must have a designed heat rate of 8,530 Btu per kilowatt or have a 40-percent efficiency. In the case of retrofitted units, the resulting heat rate would achieve a minimum 35-percent efficiency rating. In order to qualify for the tax credit, the following emission performance must be met:

- 99-percent sulfur dioxide (SO_2) removal;
- 90-percent reduction in mercury;
- No more then 0.07 pounds per million Btu of nitrogen oxides (NO_x) emissions; and
- No more then 0.015 pounds per million Btu of particulate matter emissions.

The allocation of the tax credit by fuel rank is as follows:

- $267 million to bituminous coal (with no more than $134 million going to a single plant);
- $267 million to sub-bituminous coal (with no more than $134 million going to a single plant);
- $266 million to lignite coal (with no more than $133 million to a single project);
- The $500 million allocated towards other advanced coal technologies stipulates that no more than $125 million would go to a single project; and
- This tax credit is to be allocated in annual rounds over a 3-year time frame.

For non-IGCC projects, the selection will be based upon projects having the highest ratio of capacity to the requested allocation of the credit. For IGCC power projects, a priority pool will be created. The allocation will be based upon greenhouse gas reduction capability.

Revenue Loss

For the year 2007, the estimated revenue loss equals $30 million (Table A11).

Rationale

The objective of coal research and development is to provide scientific and engineering knowledge base to foster technological advances in the private sector. Also, coal-burning power plants are at the center of the controversies involving global warming.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal mining, combustion, liquefaction, and gasification.

Table A11. Estimated Revenue Loss: Clean Coal Investment Credit, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2006	0
2007	30
2008	50
2009	80
2010	130
2011	180
2012	250

NOTE: All estimates have been rounded to the nearest $10 million.

Source: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

14. Credit for the Production from Advanced Nuclear Power Facilities

Description

Section 1306 of Title XIII of the Energy Policy Act of 2005 (Public Law 109-58) provides for a credit for the production of electricity from advanced nuclear power facilities under the new Section 45J of the Internal Revenue Code. This tax expenditure allows the Secretary of Treasury, in consultation with the Secretary of Energy, to permit a production tax credit (PTC) of 1.8 cents (not adjusted for inflation) per kilowatthour to qualified advanced nuclear power facilities for an 8-year period after the facility is placed in service after enactment of the Act and before January 1, 2021. The legislation limits the national megawatt capacity for production tax credits to 6,000 megawatts-electric (MWe). The credit limitation is based on the Secretary of Treasury's allocated capacity per facility with an annual limitation of $125 million per 1,000 MWe per taxable year with a total nationwide limit of 6,000 megawatts which would be allocated by the Secretary of Energy. The allowable credit is also reduced by reason of grants, tax exempt bond, subsidized energy financing, and other credits but such reduction cannot exceed 50 percent of the allowable credit. The Code defines “advanced nuclear power” as a unit technology that has been approved by the Nuclear Regulatory Commission after 1993.

The Energy Information Administration’s *Annual Energy Outlook 2008* (*AEO2008)* assumes that up to 9 gigawatts of new capacity will receive the Title 13 PTC and an additional 7 gigawatts of new capacity is expected to be built without the credit.[220]

Revenue Loss/Outlays

N/A.

Rationale

To promote the introduction of advanced nuclear technologies.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power.

[220] Energy Information Administration, *Annual Energy Outlook, 2008*, Early Release, EIA/DOE-0383 (2007)(Washington, DC, 2008).

15. Tax Credit and Deduction for Clean-Fuel, Alternative-Fuel, and Electric Vehicles

Description

The Clean Air Act Amendments of 1990 (CAAA90) (Public Law 101-549) and the Energy Policy Act of 1992 (EPACT1992) (Public Law 102-486) mandate that vehicle fleets owned by fuel providers and State governments, as well as certain vehicle fleets operating in air quality nonattainment areas, gradually acquire and use low-emission vehicles in increasing percentages through the year 2010. CAAA90 includes measures directed at reducing the amount of pollutants emitted from vehicles. Petroleum-based gasoline and diesel fuels are acceptable under CAAA90, as long as the vehicles satisfy the prescribed emissions standards. EPACT1992 requires the use of vehicles that operate primarily on fuels other than gasoline or diesel (called alternative-fuel vehicles or AFVs). The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) encourages Federal and State fleets to purchase fuel cell vehicles through 2015.

To encourage the use of clean-fuel vehicles and AFVs, Federal and State incentives are available, such as tax credits, deductions, and exemptions for purchases of AFVs, purchases of alternative fuels used in AFVs, and the costs of building and maintaining fueling and electric charging facilities. EPACT1992 provides Federal incentives for the purchase or conversion of individual AFVs through Federal income tax deductions for clean-fuel vehicles and income tax credits for electric vehicles (EVs).[221]

The amount of the tax deduction for qualified clean-fuel vehicles (in nominal dollars) is based on the gross vehicle weight (GVW) and vehicle type as follows:

- $2,000 for automobiles, small vans and pickup trucks, and other small vehicles (excluding off-road vehicles);
- $5,000 for trucks or vans with gvw 10,000 to 26,000 pounds;
- $50,000 for trucks or vans with gvw more than 26,000 pounds; and,
- $50,000 for buses with seating capacity of more than 20 adults.

The tax deduction for clean-fuel vehicles is available for business or personal vehicles, except for EVs, which are eligible for the separate Federal tax credit described below. The deduction is not amortized and must be taken in the year the vehicle is acquired. A tax deduction of up to $100,000 per location is available for qualified clean-fuel refueling properties and EV recharging properties, provided that the equipment is used in a trade or business.

EPACT1992 also provides an Electric Vehicle Tax Credit for purchases of qualified EVs and hybrid electric vehicles (HEVs). The amount of the credit is 10 percent of the cost of the vehicle, up to a maximum of $4,000. To qualify for the credit, the vehicle must be powered primarily by an electric motor drawing current from batteries or other portable sources of electric current. All dedicated, plug-in only EVs qualify for the tax credit. All series and some parallel HEVs meet these qualifications. The tax credit for EVs is available for business or personal vehicles.

Except for deductions for the purchase or conversion of AFVs and the Federal tax credits for EVs, most of the Federal incentives for advanced vehicle technologies are programmatic grants oriented toward large investments. The lead Federal agencies for AFV programs are the Department of Energy, the Department of Transportation, and the Environmental Protection Agency.

The Transportation Equity Act of the 21st Century (TEA-21) (Public Law 105-178) was signed into law by the President on June 9, 1998. TEA-21 authorizes a wide range of programs, including

[221] Federal Energy Regulatory Commission, Energy Policy Act of 1992, http://ferc.gov/legal/maj-ord-reg/epa.pdf. Accessed December 6, 2007.

Federal surface transportation programs for highways, highway safety, and mass transit, for the 6-year period from 1998 to 2003. It includes initiatives to promote infrastructure development in support of AFVs. The Highway Trust Fund (HTF) is the source of funding for most of the programs in TEA-21. Federal motor fuel taxes are the major source of income for the HTF. The full authorizations for the highway and transit programs in TEA-21 total almost $218 billion.

EPACT2005 contains number of provisions that affect clean-fuel, alternative-fuel, and electric vehicles.[222] Summaries of the major provisions follow:

Sections 721 – 723 establish a competitive grant program, administered by Clean Cities,[223] to fund up to 30 geographically-dispersed advanced vehicle demonstration projects. EPACT2005 authorizes $200 million (until expended) for this program. Grant recipients will be limited to State and local government agencies and metropolitan transportation authorities. Applications must include a registered participant in the Clean Cities initiative. Participants can be public or private entities. AFVs, including neighborhood electric vehicles, fuel cell vehicles, and ultra-low sulfur diesel vehicles are eligible grant recipients. Projects are limited to $15 million with a 50-percent cost share.

Section 1341 contains provisions for an 1) Alternative Motor Vehicle Credit; 2) Fuel Cell Motor Vehicle Credit; and 3) Hybrid Motor Vehicle Credit.

The Alternative Motor Vehicle Credit provides a tax credit to purchasers of new dedicated AFVs. The tax credit equals 50 percent of the incremental cost of the vehicle, plus an additional 30 percent of the incremental cost for vehicles with near-zero emissions (weight-based cost limits apply). The credit is available on the purchase of light-, medium-, and heavy-duty vehicles and fuel-cell, hybrid, and dedicated natural gas, propane, and hydrogen vehicles. Light-duty lean-burn diesel vehicles are also eligible. For non-tax-paying entities, the credit can be passed back to the vehicle seller. The tax credit can be applied to vehicle purchases made after December 31, 2005. It expires December 31, 2010. This legislation replaces the Clean Fuel Tax Credit, which expired December 31, 2005.

The Fuel Cell Motor Vehicle Credit provides a base tax credit of $8,000 for the purchase of light-duty fuel cell vehicles (less than 8,501 lb GVW). The $8,000 credit is valid until December 31, 2009. After that, the value of the credit is $4,000. To qualify, the vehicles must meet certain minimal emission levels.

Base tax credits are also available for medium- and heavy-duty fuel cell vehicles. The Internal Revenue Service will determine the credit amount based on a sliding scale by vehicle weight. The credit is available until December 31, 2014. For tax-exempt entities, the credit can be passed back to the vehicle seller.

The Hybrid Motor Vehicle Credit provides a fuel economy and conservation credit for light-duty hybrid vehicles and trucks (less than 8,501 lb GVW). The fuel economy credit, $400 to $2,400, is based on a sliding scale of efficiency gains over model year 2002 baselines. The conservation credit increases the fuel economy credit by $250 to $1,000 based on a sliding scale of lifetime fuel savings. Weight-based cost limitations apply for heavy-duty hybrid vehicles. In general, the credit phases out after a manufacturer has sold 60,000 qualified vehicles.

Revenue Loss/Outlays

The estimated 2007 revenue loss associated with this credit equals $260 million (Table A12).

[222] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, State & Federal Incentives & Laws, http://www.eere.energy.gov/afdc/incentives_laws_epact.html, accessed December 6, 2007.
[223] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, “Clean Cities,”http://www.eere.energy.gov/cleancities/, accessed December 6, 2007.

Table A12. Estimated Revenue Loss: Alternative-Vehicle Credit, 1998 to 2012 (million nominal dollars)

Fiscal Year	Tax Credit and Deduction for Clean-Fuel Burning Vehicles
1998	95
1999	105
2000	115
2001	130
2002	100
2003	90
2004	70
2005	70
2006	110
2007	260
2008	150
2009	130
2010	(20)
2011	(50)
2012	(60)

NOTE: All estimates have been rounded to the nearest $5 million from 1998 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: Office of Management and Budget, *Budget of the United States Government, Analytical Perspectives, Fiscal Year 2000; Analytical Perspectives, Fiscal Year 2004; Analytical Perspectives, Fiscal Year 2005; Analytical Perspectives, Fiscal Year 2006;* and *Analytical Perspectives, Fiscal Year 2008,* Table 19-2.

Rationale

EPACT1992 and EPACT2005 encouraged alternative fuels use (fuels other than gasoline or diesel) for domestic transportation in order to decrease the Nation's dependence on foreign oil, increase energy security through the use of domestically-produced alternative fuels, reduce the balance of payments deficit, and stimulate domestic employment. CAAA90 created several initiatives to reinforce one of the original goals of the Clean Air Act, to reduce vehicle emissions.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Energy Forms: alternative fuels (methanol, ethanol, and other alcohols; and fuels other than alcohol derived from biological materials, including neat biodiesel); natural gas; propane; hydrogen; electricity (including electricity from solar energy); and any other fuel the Secretary of Energy determines, by rule, is substantially not petroleum and would yield substantial energy security benefits and substantial environmental benefits.

Fuel Cycle Stages: Energy transformation (refining and blending) and end use (light-duty and heavy-duty vehicles).

16. Deferral of Gain from Disposition of Transmission Property to Implement Restructuring

Description

Section 909 of the American Jobs Creation Act of 2004 (Public Law 108-357) amended Section 451 of the Internal Revenue Service Code to permit taxpayers to realize a gain from qualifying electric transmission transactions ratably over an 8-year period. Section 909 states: "Sets forth a special rule for the recognition of gain from the sale of a qualifying electric transmission transaction. Taxpayer may elect to recognize gain from such sale ratably over an 8-year period if gain from the sale is reinvested in certain exempt utility property. A "'qualifying electric transmission transaction'" is defined as a sale or other disposition occurring before January 1, 2007, to an independent transmission company of: (1) property used in the trade or business of providing electric transmission services, or (2) any stock or partnership interest in such a trade or business. Section 1305 of the EPACT 2005, extended of the deferral of gains to December 30, 2007."

Section 909 defers tax on gain realized from the sale of qualified assets. The deferred taxes are recovered ratably. This results in some front loading of investment, which in time will reverse. The Treasury Department expects transactions that will result in a net deferral of tax revenue through 2008, which fully reverses in 2009.

Revenue Loss/Outlays

The revenue loss associated with this tax expenditure is estimated to equal $530 million in 2007 (Table A13).

Table A13. Estimated Revenue Loss: Deferred Gain on Transmission Asset Sales, 2005 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2005	490
2006	620
2007	530
2008	230
2009	(100)
2010	(360)
2011	(510)
2012	(540)

NOTE: All estimates have been rounded to the nearest $10 million.

Source: Office of Management and Budget, *Budget of the United States Government, Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2.

Rationale

To improve the efficiency of bulk power markets and non-discriminatory open access transmission service.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity transmission.

17. Enhanced Oil Recovery

Description

Taxpayers are able to claim a general business credit allowing for the expensing of enhanced oil recovery investment. The credit was provided by Section 11511 of the Omnibus Budget Reconciliation Act of 1990 (Public Law 101-508). The enhanced oil recovery credit applies to 15-percent of the costs of one or more tertiary recovery methods. A credit equal to 15-percent of the taxpayer's costs is provided for tertiary oil recovery on U.S. projects. The credit phases out when the inflation-adjusted price of oil exceeds $28-per-barrel (in 1991 dollars) or $39-per-barrel (in 2007 dollars) in the preceding year. Enhanced oil recovery (EOR) is the extraction of the oil that can be produced from a petroleum reservoir greater than that which can be economically recovered by conventional primary and secondary methods. EOR methods usually involve injecting heated fluids, pressurized gases, or special chemicals into an oil reservoir in order to produce additional oil.

The American Jobs Creation Act of 2004 (Public Law 108-357) applied the 15-percent credit to the construction of a natural gas treatment plant in Alaska to prepare Alaska for natural gas pipeline transportation.

Revenue Loss/Outlays

After oil prices began increasing in 2002, revenue losses from the enhanced oil recovery tax credit began to diminish. That is because the amount of the allowed credit declines as oil prices rise and vanishes completely when the inflation-adjusted price of oil exceeds $28-per-barrel (in 1991 dollars). This happened in 2005, when nominal crude oil prices went above $40-per-barrel. By 2006, revenue losses on this credit dropped to zero, where it is expected to remain unless oil prices drop significantly (Table A14).

Rationale

Significant amounts of oil and natural gas can be left in reservoirs after a field is abandoned. The use of enhanced oil and natural gas production methods allows for greater recovery of those resources. The purpose of the credit for enhanced oil recovery is to boost levels of domestically-produced oil and natural gas bypassed by conventional production.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil and natural gas production.

Table A14. Estimated Revenue Loss: Enhanced Oil Recovery Credit, 1993 to 2011 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	Corporations	Total
1993	NA	NA	NA
1994	5	80	85
1995	5	80	85
1996	5	75	80
1997	5	90	95
1998	10	130	140
1999	20	205	225
2000	30	280	310
2001	30	280	310
2002	30	300	330
2003	40	360	400
2004	30	300	330
2005	30	270	300
2006	NA	NA	NA
2007	NA	NA	NA
2008	NA	NA	NA
2009	NA	NA	NA
2010	NA	NA	NA
2011	NA	NA	NA

NOTES: NA = Not available.

All estimates have been rounded to the nearest $5 million from 1993 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: Office of Management and Budget, *Budget of the United States Government, Analytical Perspectives, Fiscal Year 2000; Analytical Perspectives, Fiscal Year 2004; Analytical Perspectives, Fiscal Year 2005; Analytical Perspectives, Fiscal Year 2006;* and *Analytical Perspectives Fiscal Year 2008,* Table 19-2.

18. Exception from Passive Loss Limitation for Working Interests in Oil and Natural Gas Properties

Description

The Tax Reform Act of 1986 (Public Law 99-514) allowed owners of working interests in oil and natural gas properties to be exempt from the "passive income" limitations, which limit the ability of individuals to offset their losses from passive activities against active income.

Passive income is income an investor derives from a rental property, limited partnership, or other enterprise in which he or she is typically not actively involved. A passive loss is a loss incurred in these investments. For income tax purposes, passive losses can normally be used to offset income generated only from passive activities, not active income. Active income comes from such things as wages and salaries.

Passive losses remaining after being netted against passive income normally can only be carried over to reduce passive income realized in future tax years. The exception allows passive losses from these activities to offset the investor's active income. The passive loss limitation provision and the oil and natural gas exception to it apply principally to partnerships and individuals rather than to corporations.

The major impact of the exception from the passive loss limitation is on business organizations that develop oil and natural gas properties. A shift toward the partnership form (which has unlimited liability) is encouraged, because the exception applies mainly to that form. Any shift is likely to be small because of the increased risk associated with unlimited liability. Nevertheless, some increase in exploration and development of oil and natural gas properties is likely as the subsidy attracts new capital.

Revenue Loss/Outlays

The "Revenue Loss" data is estimated by Treasury Department (Table A15). It the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that there are no exceptions to the passive loss limitations. The actual case assumes that passive loss limitation exception applies to unincorporated taxpayers.

Rationale

Working interests in oil and natural gas properties were exempted from the loss limitations in the Tax Reform Act of 1986. Factors that contributed to the adoption of the exemption included concern about the availability of investment funds for oil and natural gas development, given the collapse in oil prices that occurred during the same year the Act was passed.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil and natural gas production.

Table A15. Estimated Revenue Loss: Oil and Natural Gas Passive Loss Limitation Exception, 1988 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Individuals
1988	55
1989	135
1990	180
1991	80
1992	80
1993	50
1994	90
1995	55
1996	60
1997	45
1998	30
1999	35
2000	20
2001	20
2002	10
2003	20
2004	20
2005	40
2006	30
2007	30
2008	30
2009	30
2010	30
2011	30
2012	30

NOTE: All estimates have been rounded to the nearest $5 million from 1988 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: **1987-1993:** Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions. **1994-2012:** Office of Management and Budget, *Analytical Perspectives*, *Fiscal Year* 2008 (Washington, DC, 2007), Table 19-2. Also earlier editions.

19. Excess of Percentage over Cost Depletion: Oil, Natural Gas, and Other Fuels

Description

Depletion on a discovery basis became an accepted practice between 1918 and 1926. Percentage depletion for oil and natural gas properties became law in 1926 with the 1926 Revenue Act. It was extended to most other minerals, including mineral fuels, in 1932. Whoever is eligible for percentage depletion must use it rather than cost depletion. Independent oil and natural gas producers and royalty earners, and all producers and royalty owners of certain other natural resources, including mineral fuels, may take percentage depletion deductions rather than cost depletion deductions to recover their capital investments. Under cost depletion, the annual deduction is equal to the unrecovered cost of acquisition and development of the resource multiplied by the proportion of the resource removed during that year. Under percentage depletion, taxpayers deduct a percentage of gross income from resource production at rates of 10 percent for coal; 15 percent for oil, natural gas, oil shale, and geothermal deposits; and 22 percent for uranium. However, two special provisions apply to oil and natural gas. First, percentage depletion for independent producers and royalty earners is limited to 1,000-barrels–per-day. Second, the 15-percent rate is increased by 1 percentage point for each dollar that the average wellhead price of domestically produced crude oil is less than $20 a barrel. The maximum increase allowed is 10 percentage points. This special provision applies only to oil and natural gas wells with marginal production, generally defined to include production from stripper wells from which substantially all of the production is heavy oil. Marginal production eligible for the higher rate has a prior claim on the 1,000-barrel-per-day limitation.

The percentage depletion deductions based on gross income have generally been subject to net income limitations. Since percentage depletion is based on gross income, the resultant allowances can exceed the actual acquisition and development costs for the property from which the resource is extracted. Oil and natural gas property has often received relatively favorable treatment. A limit on the annual deduction of 50-percent of net income from a property had applied both to oil and natural gas and to other mineral fuels, until the Omnibus Budget Reconciliation Act of 1990 raised the limit to 100-percent for oil and natural gas beginning in 1991. That Act also increased the percentage depletion rate for marginal wells-stripper wells and those where substantially all of the production is heavy oil to as much as 25 percent, depending on the price of crude oil (this has not applied during recent years with high oil prices). Further, the 100-percent-of-net income limitation on the deduction has at times been suspended completely, with extensions of this suspension most recently to the end of 2005 as a result of Section 314 of the Working Families Tax Relief Act of 2004 (Public Law 108-311), and again, until the end of 2007, by the Tax Relief and Health Care Act of 2006 (Public Law 109-432).

Excess preferences are preferences that are added back to the regular tax base in calculating income tax liability under the alternative minimum tax (AMT) system. The oil and natural gas provisions have been changed several times since they were first introduced in 1926. The Energy Policy Act of 2005 (EPACT2005) broadened this tax expenditure: while this provision is not available to vertically integrated producers, that is, those with refinery operations larger than a certain minimum size, EPACT2005 loosened the definition of a small refiner to include operations refining less than 75,000-barrels-per-day, up from 50,000-barrels-per-day. It also changed the calculation to a 75,000-barrel daily average over the course of the year rather than applying the limit to each day.

Percentage depletion has the effect of substantially increasing the development of existing property, because the total depletion claimed can exceed the original investment. The increase in output benefits producers (operators and royalty holders) through higher after-tax profits. The benefits to producers were considered so substantial that beginning in 1969 percentage depletion rates were reduced for oil and natural gas, and eventually major oil and natural gas companies were excluded from the percentage depletion provisions in 1975.

Revenue Loss/Outlays

The “Revenue Loss” data is estimated by the Treasury Department (Table A16). The difference between estimated Federal income tax payments in a reference case and actual Federal income tax payments is presented. The reference case assumes that cost depletion is used. The actual case assumes that percentage depletion is used. In 2007 the estimated loss was $790 million. Between 1968 and 2007, the estimated loss was equal to $102 billion in 2007 dollars.[224]

Table A16. Estimated Revenue Loss: Excess of Percentage of Cost over Depletion, 1987 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
1987	595	345	940
1988	385	205	590
1989	320	205	525
1990	550	245	795
1991	470	245	715
1992	490	255	745
1993	265	830	1,095
1994	265	845	1,110
1995	265	800	1,165
1996	275	830	1,105
1997	285	860	1,145
1998	50	200	250
1999	45	220	265
2000	50	290	340
2001	30	220	250
2002	510	100	610
2003	110	530	640
2004	110	1210	1320
2005	60	530	590
2006	80	680	760
2007	80	710	790
2008	80	710	790
2009	80	710	790
2010	80	700	780
2011	80	680	760
2012	70	670	740

NOTE: All estimates have been rounded to the nearest $5 million from 1987 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: **1987-1993:** Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). Also earlier editions. **1994-2012:** Office of Management and Budget, *Analytical Perspectives*, *Fiscal Year* 2008 (Washington, DC, 2007), Table 19-2. Also earlier editions.

224 Based upon estimates for 1968 to 2000 appearing in General Accounting Office publication, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work*, GAO/RCED-00-301R (Washington, DC, September 2000) and EIA estimates based upon data appearing in the Office of Management and Budget’s *Analytical Perspectives of the U.S. Budget, Fiscal Years 2008, 2006, 2004*, and *2002*.

Rationale

To increase domestic oil and gas production and to reduce the nation's reliance on petroleum imports.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil, natural gas, and coal production, as well as minor energy forms, including uranium, oil shale, and geothermal.

20. Renewable Transportation Fuels and Volumetric Ethanol Excise Tax Credit (VEETC)

Description

At nearly $3 billion, the Volumetric Ethanol Excise Tax Credit (VEETC) is estimated to be the largest energy-related tax credit in 2007. Its predecessor, the alcohol fuel excise tax exemption, was estimated to be the largest tax-related benefit in the 1999-2000 EIA subsidy reports. VEETC is directed at the production of transportation-related fuels. The alcohol fuels excise tax exemption first appeared in Section 221 of the Energy Tax Act of 1978 (Public Law 95-618) in order to address gasoline shortages. This exemption was replaced in 2004 with VEETC by Section 301 of the American Jobs Creation Act (AJCA) (Public Law 108-357). The AJCA extended the benefit through 2010. VEETC provides ethanol blenders/retailers with 51-cents-per-pure-gallon of ethanol or $.0051 per percentage point of ethanol blended in motor gasoline. The value of VEETC is estimated at $3 billion in 2007. By 2010, the value of this credit is expected to approach $5 billion.

Although the value of this credit may not have changed due to the 2004 legislation, funds are no longer be diverted from the Highway Trust Fund but rather come from the Treasury's General Fund. A major effect of this credit has been a sizable boost in U.S. ethanol production and a significant redirection of corn production away from traditional uses.

Revenue Loss/Outlays

The lost revenue to the U.S. Treasury from the VEETC for Fiscal Year (FY) 2006 through FY 2012 is shown below. These values include the amount of the alcohol fuel credit and the foregone gasoline excise tax receipts (Table A17).

Table A17. Estimated Revenue Loss and Outlay Equivalent: VEETC, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss
2006	2,570
2007	2,990
2008	3,460
2009	4,280
2010	4,990
2011	1,440
2012	0

NOTE: All estimates have been rounded to the nearest $10 million.

The value (in millions) for the revenue loss from the alcohol (ethanol) fuel credits for each year is: FY06 = $50; FY07=$50; FY08=$60; FY09=$70; FY10=$80; FY11=$30.

Source: *Analytical Perspectives, Budget of the United States Government, Fiscal Year 2008*, Table 19-1, "Estimates of Total Income Tax Expenditures," Office of Management and Budget; http://www.whitehouse.gov/omb/budget/fy2008/pdf/spec.pdf; accessed August 13, 2007.

Rationale

To reduce U.S. dependence on imported oil used as a transportation fuel.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Imported petroleum and ethanol-blended gasoline.

21. Exclusion of Utility-Sponsored Conservation

Description

Section 111 of the Energy Policy Act of 1992 (EPACT1992) (Public Law 102-486) amended the Section 136 of the Internal Revenue Code (IRC or Code) to allow taxpayers to exclude from their gross income utility-paid rebates and subsidies for participating in conservation programs for purposes of calculating tax liability. Utilities engaged in demand side management activities often pay consumers to purchase more efficient heating or cooling equipment in order to reduce the consumption of natural gas and electricity. However, the relatively small size of the subsidy, as compared with the billions of dollars spent on household appliances each year, results in only a minor impact on U.S. demand for electricity and natural gas.

Revenue Loss/Outlays

The value of this tax expenditure is an estimated $110 million for the year 2007.

Table A18. Estimated Revenue Loss: Utility-Sponsored Conservation, 1987 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Individuals
1987	NA
1988	NA
1989	NA
1990	NA
1991	NA
1992	NA
1993	50
1994	100
1995	130
1996	100
1997	70
1998	80
1999	90
2000	90
2001	70
2002	80
2003	80
2004	100
2005	80
2006	110
2007	110
2008	110
2009	110
2010	110
2011	110
2012	110

NOTE: All estimates have been rounded to the nearest $5 million from 1987 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: **1987-1993**: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). **1994-2012**: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007).

Rationale

The rationale for the tax subsidy is to encourage consumers to take advantage of utility funds available for the upgrade of heating and cooling equipment or the operation of equipment without penalty.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas transformation, electricity end use.

22. Exclusion of Interest Income on Energy Facility and Local Bonds

Description

The Revenue Expenditure and Control Act of 1968 (Public Law 90-364) exempts interest on private activity bonds used to finance certain energy facilities from gross income for Federal tax purposes. There are three types of privately-used facilities for which such bonds may be issued: facilities for the local furnishings of natural gas and electricity; district heating and cooling facilities; and certain environmental facilities at hydroelectric dam sites.[225] Electric and natural gas services provided from facilities with bonds issued by eligible third parties are limited to providing service in no more than two adjacent counties (or one city and an adjacent county). The issuance of private activity bonds is subject to annual limits established for each State by the Internal Revenue Service (IRS), and State-specific allocation processes.

The tax exemption encourages investment in debt-financed energy projects. The subsidy lowers utility financing costs and results in product prices that are lower and product consumption that is greater than would be otherwise without the subsidy.

Revenue Loss/Outlays

The value for this expenditure is an estimated $40 million in 2007 (Table A19).

Rationale

The tax exemption is intended to encourage the development of specific types of energy facilities.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas transformation, electricity generation.

[225] Several other types of private activity bonds are also subject to these caps. The tax-free status of bonds for certain small-scale hydroelectric generating facilities, geothermal facilities, and alcohol production facilities was terminated in the 1980s.

Table A19. Estimated Revenue Loss: Interest Exclusion on Energy Facility Bonds, 1987 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
1987	0	305	305
1988	0	290	290
1989	0	315	315
1990	0	255	255
1991	0	125	125
1992	0	125	125
1993	100	65	165
1994	105	70	175
1995	105	70	175
1996	105	70	175
1997	105	70	175
1998	80	30	110
1999	85	30	115
2000	70	20	90
2001	70	20	90
2002	80	30	110
2003	70	20	90
2004	80	20	100
2005	60	20	30
2006	30	10	40
2007	30	10	40
2008	40	10	50
2009	40	10	50
2010	40	10	50
2011	40	10	50
2012	40	10	50

NOTE: All estimates have been rounded to the nearest $5 million from 1987 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: **1987-1993**: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1993* (Washington, DC, 1992). **1994-2012**: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007). Also subsequent and earlier editions.

23. Exclusion of Special Benefits for Disabled Coal Miners

Description

Department of Labor, Health and Human Services, and Education and Related Agencies Appropriation Act of 1986, (Public Law 99-178) allows for non-taxable disability payments out of the Black Lung Trust Fund. The Departments of Labor, Health and Human Services, and Education, and Related Agencies Appropriation Act of 1993 (Public Law 102-394, Title II) provides that:

> "For carrying out title IV of the Federal Mine Safety and Health Act of 1977, and thereafter the payment of travel expenses on an actual cost or commuted basis to an individual, for travel incident to medical examinations, and when travel of more than 75 miles is required, to parties, their representatives, and all reasonably necessary witnesses for travel within the United States, Puerto Rico and the Virgin Islands."

Title II, also made appropriations to the Department of Health and Human Services for the Social Security payments to fund special benefits for disabled coal miners.

Revenue Loss/Outlays

The expected revenue loss associated with this tax expenditure is estimated at $40 million for 2007 (Table A20).

Table A20. Estimated Revenue Loss: Exclusion of Disabled Coal Miner Benefits, 2001 to 2011 (million nominal dollars)

Fiscal Year	Revenue Loss-Individuals
2001	70
2002	70
2003	60
2004	60
2005	50
2006	50
2007	40
2008	40
2009	40
2010	40
2011	0

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: **2006-2012**: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 2008* (Washington, DC, 2007). Also earlier editions.

Rationale

To reduce medical costs of coal miners and to allow them to seek treatment at appropriate medical care facilities.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal.

24. Expensing of Capital Costs with Respect to Complying with EPA Sulfur Regulations

Description

Sections 338 and 339 of the American Jobs Creation Act of 2004 (AJCA) (Public Law 108-357) created a new 5-cent-per-gallon tax credit for small petroleum refiners who must incur capital costs complying with the Environmental Protection Agency's (EPA) rules limiting the sulfur content of diesel fuel.[226] Eligible refiners may claim the credit until they have recovered 25-percent of such costs.[227]

For these purposes a small refiner is one that employs not more than 1,500 persons directly in refining and has less than 205,000-barrels-per-day (average) of total refining capacity.[228] The credit is reduced for refiners with a capacity between 155,000-barrels-per-day and 205,000-barrels-per-day.[229] The conferee's report states that when capacity "differs substantially" from average daily output of refined product, capacity should be measured by reference to daily average output.[230]

Cooperatives may also choose to pass some or all of this credit to their patrons. As with the small ethanol producer credit, any pass-through is to be apportioned among patrons on the basis of patronage, and any credit not passed through to patrons is treated as a general business credit by the cooperative.[231]

Section 1324 of the Energy Policy Act of 2005 (Public Law 109-58) allows small refiners to deduct 75-percent of qualified capital costs related to complying with EPA sulfur regulations. This provision applies to Section 338 of the AJCA.

Revenue Loss/Outlays

The estimated value of this credit was $10 million in 2007 (Table A21).

Table A21. Estimated Revenue Loss: Expensing EPA Sulfur Compliance Capital Costs, 2005 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2005	10
2006	10
2007	10
2008	10
2009	10
2010	10
2011	10
2012	10

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: **2006-2012**: Office of Management and Budget*, Budget of the United States Government, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2, and earlier years; *Income Tax Treatment of Cooperatives: Patronage Refunds and other Income Issues*, Cooperative Information Report 44, Part 2, 2005 Edition, Donald A. Frederick. http://www.rurdev.usda.gov/RBS/pub/cir442.pdf, p. 120, accessed August 27, 2007.

[226] American Job Creation Act of 2004, Section 339, Pub. L. No. 108-357, 118 Stat. 1481 (codified at 26 U.S.C. Section 45H). See also, H.R. Conf. Rept. No. 755, 108th Cong., 2d Sess. At 538-539.
[227] I.R.C. Section 45H (b)(1).
[228] I.R.C. Section 45H (c)(1).).
[229] I.R.C. Section 45H (b)(2).
[230] H.R. Conf. Rept. No. 755, 108th Cong., 2d Sess. at 313.
[231] I.R.C. Section 45H (g).

Rationale

The purpose of this provision is to aid small refiners by way of financial assistance for capital costs incurred due to EPA rules limiting the sulfur content of diesel.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Diesel fuels.

25. Expensing of Exploration and Development Costs: Oil, Natural Gas, and Other Fuels

Description

Tax law allows energy producers, principally oil and natural gas producers, to write off, i.e., expense, certain exploration and development (E&D) expenditures rather than capitalizing them and depreciating them over time. The most important of these expenditures consist of intangible drilling costs (IDCs) associated with oil and natural gas investments. Integrated oil companies can expense 70 percent of their IDCs for successful domestic wells and 100 percent for unsuccessful domestic wells. The remaining 30 percent must be amortized over 5 years. Nonintegrated (independent) oil producers can expense 100 percent of their IDCs for all domestic wells. The 70-percent provision also applies to surface stripping and other selected expenditures for fuel minerals other than oil and natural gas (principally coal). The remainder must be amortized over 5 years. This tax expenditure, estimated at $860 million, was the fourth largest tax expenditure in 2007.

The option to expense IDCs (and dry hole costs) of oil and natural gas wells was originally based on regulations issued in 1916. A court invalidated the regulations in 1945, but Congress subsequently gave its approval to the treatment and it became law in 1954. The option to expense mine development expenditures and the option to expense mine exploration expenditures were formalized into law in 1951 and 1966, respectively.

Integrated oil companies were constrained to expensing only 85 percent of their IDCs by a 1982 tax law. The percentage was subsequently reduced to 80 percent by the Tax Reform Act of 1984 and to its present 70 percent by the Tax Reform Act of 1986.

Revenue Loss/Outlays

The "Revenue Loss" data are estimated by the Treasury Department (Table A22). They are the difference between estimated Federal income tax payments in a reference case and estimated actual Federal income tax payments. The reference case assumes that relevant IDCs and certain other E&D expenditures are cost-depleted. The actual case assumes that they are expensed.

The data in the table are mostly negative from fiscal year 1987 through 1999. The negative values imply a payment to the Federal government of funds that it had loaned (tax deferrals), mostly to oil companies, in earlier periods. In a normal growth situation, the values would be positive. However, as a result of the sharp drop in oil E&D expenditures resulting from generally lower oil prices during that period, repayments of old "loans" outweighed the receipt of new ones. That trend reversed itself starting in 2000, as oil prices started increasing in the late 1990s through the present. Since 1967, the total revenue losses associated with this expenditure are estimated to be roughly $53 billion.[232]

[232] Based upon estimates for 1968-2000 appearing in the General Accounting Office, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work*, GAO/RCED-00-301R (Washington, DC, September 2000) and EIA estimates based upon data appearing in the Office of Management and Budget's *Analytical Perspectives of the U.S. Budget, Fiscal Year 2008, 2006, 2004*, and *2002.*

Table A22. Estimated Revenue Loss: Expensing of Exploration and Development Costs, 1987 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
1987	425	(1,065)	(640)
1988	455	(805)	(350)
1989	560	(590)	(30)
1990	(70)	(385)	(455)
1991	(95)	(185)	(280)
1992	(40)	(15)	(55)
1993	(15)	90	80
1994	0	(70)	(70)
1995	(70)	(215)	(285)
1996	(60)	(180)	(240)
1997	(35)	(115)	(150)
1998	(20)	(90)	(110)
1999	(10)	(70)	(80)
2000	0	20	20
2001	10	40	50
2002	20	130	150
2003	30	180	210
2004	30	230	260
2005	50	340	390
2006	90	590	680
2007	110	750	860
2008	110	730	840
2009	90	620	710
2010	80	520	600
2011	60	390	450
2012	40	270	310

NOTE: All estimates have been rounded to the nearest $5 million from 1987 through 2001. Thereafter, all estimates are rounded to the nearest $10 million.

Sources: **1987-1996**: Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1996* (Washington, DC, 1996). Also earlier editions. **1997-2012**: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007), Table 19-2. Also earlier editions.

Rationale

Intangible drilling costs were asserted by producers to be conventional operating expenses that therefore should be expensed. The provision is intended to encourage additional mineral exploration and development. It was explicitly codified to reduce uncertainty concerning its status in order to encourage further exploration and development.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil, natural gas, and coal production.

26. Natural Gas Distribution Pipelines Treated as 15-Year Property

Description

Section 1325 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides that natural gas distribution pipelines be given a 15-year capital cost recovery period. Prior to this, natural gas distribution pipelines were assigned a 20-year recovery period. This 15-year cost recovery period applies to the original user of property which is placed in service before January 1, 2011. It does not apply to property contracted for before April 12, 2005.

Revenue Loss/Outlays

The "Revenue Loss" data are estimated by the Treasury Department (Table A23). The difference between estimated Federal income tax payments in a reference case and actual Federal income tax payments is presented. The reference case assumes that natural gas distribution pipelines have a 20-year capital cost recovery period. The actual case assumes that natural gas distribution pipelines have a 15-year capital cost recovery period.

Table A23. Estimated Revenue Loss: 15-Year Life for Natural Gas Pipelines, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2006	20
2007	50
2008	90
2009	120
2010	150
2011	150
2012	120

NOTE: All estimates have been rounded to the nearest $10 million.

Source: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* Washington, DC, 2007), Table 19-2

Rationale

To increase natural gas distribution pipeline capacity.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas distribution pipelines.

27. New Technology Credit

Description

The New Technology Credit , also known as the Renewable Electricity Production Tax Credit (REPC),[233,234] as well as the Production Tax Credit (PTC), was first introduced as part of the Energy Policy Act of 1992 (EPACT1992) (Public Law 102-486). The corresponding Internal Revenue Service Code Section 45 credit was defined as a 1.5-cents-per-kilowatthour (kWh) payment (adjusted annually for inflation), payable for 10 years, to private investors as well as to investor-owned electric utilities for electricity from wind power and closed-loop (dedicated crops) biomass facilities placed in service after December 31, 1993, and before July 1, 1999.

The Tax Relief Extension Act of 1999 (Public Law 106-170) extended and modified the PTC. It expanded the tax credit to include poultry litter facilities and poultry waste facilities, landfill gas, and certain other biomass. These and wind power and closed-loop biomass facilities qualified for the PTC if placed in service before January 1, 2001. The poultry waste and poultry litter facilities must have been in service after December 31, 1999, and before January 1, 2001. The PTC expired at the end of 2001. The credit for electricity produced from poultry litter is available to the lessor/operator of a qualified facility that is owned by a government entity.

The PTC was extended in March 2002 through December 31, 2003, by the Job Creation and Worker Assistance Act of 2002 (Public Law 107-147). The PTC expired at the end of 2003 and lapsed until October 2004, when it was renewed as part of the Working Families Tax Relief Act of 2004 (Public Law 108-311), which extended it through December 31, 2005.

The American Jobs Creation Act of 2004 (AJCA) (Public Law 108-357) expanded the PTC to include open-loop biomass, geothermal energy, solar energy, small irrigation power, and municipal solid waste (landfill gas and trash combustion facilities).

The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) expanded the credit to include certain hydropower facilities and Indian (Native American) coal and extended it through December 31, 2007. EPACT2005 also made solar facilities placed into service after December 31, 2005, ineligible for the PTC. Also, geothermal facilities that claim the 2005 Federal Business Energy Tax Credit (10 percent on equipment installed from January 1, 2006, through December 31, 2008) may not also claim the PTC. (The Business Energy Tax Credit is commonly known as the Investment Tax Credit.)

In December 2006, the credit was extended through the end of 2008 by the Tax Relief and Health Care Act of 2006 (Public Law 109-432).

The following resources are now eligible for the REPC:

- wind energy,
- closed-loop biomass,
- open-loop biomass (including agricultural livestock waste nutrients),
- geothermal energy,
- small irrigation power (150 kilowatts - 5 megawatts),
- municipal solid waste (trash combustion),
- landfill gas,

[233] New Technology Credit is the term used by the U.S. Department of Treasury to describe the production tax credit and an investment tax credit in Office of Management and Budget, *Analytical Perspectives, Budget of the United States Government, Fiscal Year 2008*, http://www.whitehouse.gov/omb/budget/fy2008/pdf/spec.pdf, accessed December 11, 2007. Production tax credit (PTC) is the more commonly-used term.

[234] For a summary of the history of the renewable electricity production tax credit, see, Database of State Incentives for Renewable Energy, http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=Federal¤tpageid=1, accessed December 11, 2007. Details regarding the PTC as promulgated in EPACT2005 are contained in "Renewable Electricity Production Tax Credit," Northeast Regional Biomass Program, http://www.nrbp.org/pdfs/energy_policy_act_2005.pdf, accessed December 11, 2007.

- refined coal,
- Indian coal,
- solar energy, and
- hydropower.

Revenue Loss

The lost revenue to the Treasury related to this tax expenditure is estimated at $690 million in 2007 (Table A24). By 2008, the New Technology Credit is expected to be the second largest tax expenditure.

Table A24. Estimated Revenue Loss: New Technology Credit, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss		
	Individuals	**Corporations**	**Total**
2006	40	470	510
2007	50	640	690
2008	60	900	960
2009	60	1,060	1,120
2010	60	1,090	1,150
2011	60	1,090	1,150
2012	60	1,090	1,150

NOTE: All estimates have been rounded to the nearest $10 million.

Source: Office of Management and Budget, *Budget of the United States. Government, Fiscal Year 2008,* Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008,* Table 19-2, "Estimates of Total Income Tax Expenditures, "http://www.whitehouse.gov/omb/budget/fy2008/pdf/spec.pdf. Accessed August 9, 2007.

Rationale

This credit aims to improve the economics to developers of affected renewable generating technologies, such that they are cost-competitive in the electricity generating market.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Renewable generating technologies.

28. Nuclear Production Tax Credit

Description

Section 1306 of Title XIII of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides for a credit for the production of electricity from advanced nuclear power facilities by amending the Internal Revenue Code with the addition of Section 45J. This tax expenditure allows the Secretary of Treasury, in consultation with the Secretary of Energy, to permit a production tax credit (PTC) of 1.8 cents (not adjusted for inflation) per kilowatthour to qualified advanced nuclear power facilities for an 8-year period after the facility is placed in service after enactment of the Act and before January 1, 2021. The legislation limits the national megawatt capacity for PTCs to 6,000 megawatts-electric (MWe). The credit limitation is based on the Secretary of Treasury's allocated capacity per facility with an annual limitation of $125 million per 1,000 MWe per taxable year with a total nationwide limit of 6,000 megawatts which would be allocated by the Secretary of Energy. The allowable credit is also reduced by reason of grants, tax exempt bond, subsidized energy financing, and other credits but such reduction cannot exceed 50 percent of the allowable credit.

The Energy Information Administration's *Annual Energy Outlook 2008* (*AEO2008)* "assumes that up to 9 gigawatts of new capacity will receive the Title XIII PTC. *AEO2008* also assumes that participating utilities will be able to take all the tax credits in each of the first 8 years of their qualifying units' operation."

Revenue Loss/Outlay

The Treasury Department did not estimate the value of this tax expenditure as no nuclear power plants are expected to go into operation within the Treasury's forecasting horizon which goes out to the year 2012.

Rationale

Section 1306 of EPACT2005 is intended to remove investment barriers to the funding of the construction of new nuclear power plants. The intent is to reduce the chance that investors will be exposed to construction-delay-related risks

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power.

29. Modification to Special Rules for Nuclear Decommissioning Costs

Description

Section 1310 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) modifies the rules governing the funding of qualified Internal Revenue Code (IRC or Code) Section 468A decommissioning trust funds, which prior to the modification required utilities to make payments into a qualified fund over the life of the fund subject to a level funding (payment) requirement. The change in law permits utilities to transfer funds from non-qualified trust funds, i.e., Grantor Trusts, notwithstanding the level of funding requirement. Furthermore, it permits an additional exception for utilities to fully fund the present value of a Section 468A trust fund with a lump sum payment. Section 1310 of EPACT2005 also eliminated the requirement that a nuclear utility's rates be set on a cost-of-service basis in order to qualify for a tax deduction in the current period for amounts contributed to a qualified decommissioning trust fund.

Revenue Loss/Outlay

The Treasury Department did not estimate the value of this tax expenditure. The Joint Committee on Taxation estimated it to be $199 million in 2007, with a cumulative cost of $1.3 billion through 2015.[235]

Rationale

The amendments to IRC Section 468A allow utilities to transfer non-qualified funds to a qualified trust and make a one-time payment to fully fund the trust. These actions are taken by a nuclear power plant owner prior to the sale of the plant, in order to facilitate the sale of the plant. It facilitates the buyer assuming the decommissioning liability, with the Section 468A trust fully funded consistent with the Nuclear Regulatory Commission decommissioning assurance regulations.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Section 1310 is limited to the disposition of nuclear power plants. It mitigates tax liabilities that could have accrued under pre-existing law. As a result, it facilitates the sale of nuclear assets in instances where nuclear utilities are required to divest generation under State deregulation initiatives or when utilities make a business decision to sell nuclear assets.

[235] Joint Committee on Taxation, "Estimated Effects of the Conference Agreement for Title XIII of H.R. 6, The Energy Tax Incentives Act of 2005, " JCX 05-95, July 27, 2005.

30. Partial Expensing for Advanced Mine Safety Equipment

Description

Section 404 of the Tax Relief and Welfare Act of 2006 (Public Law 109-432) amended the Internal Revenue Code by addition Section 179E, which allows for 50-percent expensing of qualified new advance mine safety equipment property used in underground mines. This underground mine equipment must exceed the effectiveness of current safety equipment requirements. The equipment can include: communications technology, enabling continuous contact between miners and above ground personnel, electronic tracking devices, emergency breathing apparatuses, and monitoring equipment to detect levels of carbon monoxide, methane, and oxygen. The equipment must be placed in service after December 20, 2006, and before January 1, 2009. Section 405 also provides a business tax credit for mine rescue teams training costs.

Revenue Loss/Outlay

Estimated revenue losses associated with this tax expenditure equal $10 million in 2007 (Table A25).

Table A25. Estimated Revenue Loss: Partial Expensing of Mine Safety Equipment, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2006	0
2007	10
2008	20
2009	0
2010	0
2011	0
2012	0

NOTE: All estimates have been rounded to the nearest $10 million.

Sources: Office of Management and Budget, *Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007).

Rationale

Improve the safety of mine operations.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal production.

31. Temporary 50-Percent Expensing for Equipment Used in the Refining of Liquid Fuels

Description

Section 1323 of the Energy Policy Act of 2005 (Public Law 109-58) allows refineries to expense 50 percent of the cost of equipment used in the refining of liquid fuels. The deduction becomes available in the taxable year in which the refinery is placed in service. The remaining 50 percent of the cost remains eligible for regular depreciation treatment. This provision applies to the original user of the refinery property, for which construction must begin after June 14, 2005, and before January 1, 2008. The property must be placed in service before January 1, 2012.

Revenue Loss/Outlays

The "Revenue Loss" data were estimated by the Treasury Department (Table A26). The difference between estimated Federal income tax payments in a reference case and actual Federal income tax payments is presented. The reference case assumes that the temporary 50-percent expensing provision is in place. The actual case assumes that conventional capital cost recovery applies.

Table A26. Estimated Revenue Loss: Temporary 50-Percent Expensing of Refining Equipment, 2006 to 2012 (million nominal dollars)

Fiscal Year	Revenue Loss-Corporations
2006	10
2007	30
2008	120
2009	240
2010	260
2011	180
2012	(50)

NOTE: All estimates have been rounded to the nearest $10 million.

Source: Office of Management and Budget, *Budget of the United States Government, Analytical Perspectives, Fiscal Year 2008* (Washington, DC, 2007).

Rationale

To increased liquid fuels refinery capacity.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Liquid fuels.

32. Transmission Property Treated as 15-Year Property

Description

Section 1308 of the Energy Policy Act of 2005 (Public Law 109-58) amended subparagraph E of Section 168(e)(3) of the Internal Revenue Code by adding transmission property rated 69 kilovolts and above to property qualifying as 15-year property under the Modified Accelerated Cost Recovery System (MACRS). The tax law prior to passage of Section 1308 assigned a 30-year class life and 20-year amortization period for transmission facilities. This amendment to the Code is one of the tax-related transmission infrastructure incentives included in EPACT2005. Shortening the amortization period reduces taxable income in the current tax year and increases deferred taxes associated with the timing difference between book and tax depreciation. This increases internally generated funds that may be available for reinvestment in transmission facilities. The 15-year property rate is applicable to eligible facilities placed in service after April 11, 2005.

The North American Electric Reliability Corporation (NERC) projects an 8.8-percent (14,500 circuit miles) increase in transmission investment in the United States over the next 10 years. According to NERC, the current 10-year projection of transmission capacity additions amounts to more than a 30-percent increase from the prior year's assessment. NERC further states the pace of additions over the next 5 years "appears to be accelerating" relative to original schedules.[236] Some of the projected transmission additions will be made by tax-exempt transmission-owners (i.e., publicly-owned utilities and cooperatives). Thus, not all of the anticipated additions will be eligible for this tax benefit. Nor are there any data available to indicate that the acceleration of construction of already planned additions or the increase in planned additions that is for treatment as 15-year property is entirely a function of the change in the property classification from 20 years to 15 years.

Revenue Loss/Outlays

According to the Treasury Department, the estimated of the value of this tax expenditure is included in the total estimate of the cost of accelerated depreciation for machinery and equipment. The Treasury Department referred EIA to the estimate prepared by the Joint Committee on Taxation (JCT) of the cost of this provision.[237] JCT estimated that reclassifying transmission facilities from 20-year property to 15-year property cost $18 million in 2007, with a total cost of $1.2 billion between 2005 and 2015.[238,239]

Rationale

The rationale for the provision is to provide investor-owned utilities with a tax incentive to increase investment in critical transmission infrastructure facilities.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

This tax expenditure is targeted at increasing transmission capacity and improving system reliability. It is related to deliverability of electricity without consideration or preference to a particular fuel used in electricity production.

[236] North American Electric Reliability Corporation, "2007 Long-term Reliability Assessment 2007-2016," (Princeton, New Jersey), October 25, 2007, p. 18.
[237] Email correspondence with Curtis Carlson, Office of Tax Analysis, Department of the Treasury, November 2, 2007.
[238] Joint Committee on Taxation, Estimated Budget Effects of the Conference Agreement for Title XIII of H.R. 6, JCX-59-05, July, 27, 2005.
[239] This revenue loss is actually a tax deferral. Over time, there is no change in depreciation (except in present value terms). Depreciation taken earlier can no longer be taken later in the asset's life. If the rate of transmission investment is constant over time, the tax expenditure would fall to zero as the timing difference between book and tax depreciation reverses, such that the deferred tax is recovered.

33. Treatment of Income of Certain Cooperatives

Description

Section 319 of the American Jobs Creation Act of 2004 (Public Law 108-357) amended Section 501(c)(12) of the Internal Revenue Code to provide for the exclusion of certain non-member income from the calculation of the "85-percent test."[240] Section 319(a) allows cooperatives to exclude income from nuclear decommissioning trust fund transactions, income received for services provided to non-members under a Federal Energy Regulatory Commission (FERC) approved open access tariff[241] and income received from a FERC-approved independent transmission provider.[242] Nuclear decommissioning trust fund transactions are defined to include income realized from the transfer of the trust in connection with the sale of a cooperative's interest in a nuclear plant,[243] and trust fund distributions to pay for decommissioning expenses and earnings on trust fund investments. Section 319(a) also permits cooperatives to exclude from the 85-percent test any gain that would normally receive deferred recognition as income arising from a like kind exchange or involuntary conversion of generation, transmission, distribution and natural gas distribution property. Section 319(b) permits cooperative to treat wholesale and retail sales to non-member as member sales to the extent such sale mitigate member load lost as a result of competition. This provision applies to non-members that supplant member load lost as a result of the cooperative providing mandatory, non-discriminatory open access. Qualify sales are accorded this treatment for a 7-year period.

A sunset provision limited the benefit of Section 319 through December 31, 2006. The sunset provision was eliminated in Section 1304 of EPACT2005.

Eleven generation and transmission cooperatives own undivided interests in nuclear plants and may benefit from the exclusion of decommissioning trust income from the 85-percent test were decommissioning trust income to otherwise pose a challenge. Exclusion of trust fund income from the 85-percent test may lift a potential barrier for cooperatives to participate in new nuclear plants. With regard to the transmission-related provisions, some cooperatives voluntarily joined RTOs/ISOs prior to Congress amending Section 501(c)(12). There has not been a wave of transmission-owning cooperatives joining subsequent to the amendment. One could interpret the lack of activity to mean that while the elimination of potential tax liability associated with providing open access transmission reduces a cost, the costs providing open access transmission under a FERC-approved tariff, or joining an RTO/ISO, exceed the benefits.

[240] The 85-percent test is designed to ensure that organizations exempt under IRC 501(c)(12) provide services at cost to their members. Accordingly, each year a cooperative's income, with certain modifications, is determined and the total amount received from members for the sole purpose of meeting losses and expenses must be at least 85 percent of the income. The 85-percent test is applied on the basis of an annual accounting period. Failure to meet the requirement in a particular year precludes exemption for that year, but has no effect upon exemption for years in which the 85-percent test is satisfied. Rev. Rul. 65-99, 1965-1 C.B. 242. Source: Internal Revenue Service: http://www.irs.gov/pub/irs-tege/eotopicd94.pdf.

[241] In Order No. 888, the FERC required non-public utilities that own, operate or control transmission facilities, as a condition of receiving open access transmission service from a public utility under its Open Access Transmission Tariff (OATT), to provide reciprocal transmission service under comparable terms. FERC adopted a voluntary "safe harbor" process as one method of satisfying this reciprocity requirement. Non-public utilities (e.g., electric cooperatives participating in the Rural Utilities Service loan program) can file an OATT with the Commission under the voluntary "safe harbor" provision. Under this provision, the Commission issues a declaratory order finding the OATT appropriate for "safe harbor" status if its provisions "substantially conform or are superior to" the pro forma OATT. See, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) at 31,760-61 (Order No. 888), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1997), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[242] For purposes of ensuring the applicability of the transmission-related provisions to electric cooperatives with in the Electric Reliability Council of Texas (ERCOT), the statute defines FERC to include the Public Utilities Commission of Texas with respect to cooperatives operating in ERCOT.

[243] The transfer of a nuclear decommissioning trust fund by a cooperative in conjunction with the sale of its interest in a nuclear plant can create a tax liability arising from the realized gain on trust fund assets and the discharge of the decommissioning liability assumed by the buyer. See Internal Revenue Service, PLR 2000334002, Release Date August 8, 2000.

Revenue Loss/Outlay

The Treasury Department did not estimate the value of this tax expenditure. The Joint Committee on Taxation estimated the value at $14 million for 2007. The cumulative value through 2010 is estimated at $93 million. The Joint Committee report does not provide a breakdown as to how the estimated tax expenditure is divided between the certain treatment provide to nuclear-related transactions, income received under FERC-approved open-access tariffs, revenue received from independent transmission providers, or loss of load mitigation.[244]

Rationale

Under Internal Revenue Code Section 501(c)(12) cooperatives' tax-exempt status is in part preserved by maintaining compliance with the 85-percent test, which requires that they conduct the bulk of their business with members. This places the promotion of competition through open access in direct conflict with providing open access transmission service to non-members. Similarly, mandatory retail access, which has been imposed on cooperatives in some States, could result in cooperatives facing either stranded costs or the loss of exempt status if they make sales to non-members to mitigate loss of member load induced by open access. Excluding income from these transactions from the calculation of the 85-percent test eliminates an income tax-related barrier in to cooperatives providing open access and participating in competitive markets.

The nuclear-related provision precludes the loss of tax-exempt status that may otherwise occur in the course of a cooperative meeting its decommissioning funding obligations. The provision also mitigates a tax-related barrier to the potential sale of nuclear assets.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

The portion of the provision pertaining to the treatment of nuclear decommissioning trust for purposes of computing the 85-percent test impacts that indirect cost associated with cooperatives' ownership of nuclear generation. It eliminates potential income tax liability to the extent it precludes non-member nuclear decommissioning trust income from causing cooperatives to lose their tax-exempt status based on the 85-percent test. Excluding decommissioning trust income from non-member decommission trust income for purposes of computing the test could factor into cooperatives' decisions to acquire an ownership interest in new nuclear plants.

The portion of the provision that provides for the exclusion of Regional Transmission Organization/Independent System Operator (RTO/ISO)-related income from the calculation of the test is intended to eliminate a barrier to transmission-owning cooperatives' participation in such organizations. The provision is neutral with regard to the fuels used in electric generation in the sense that cooperative participation in RTOs/ISOs increases the scope of transmission facilities over which all forms of generation would have non-discriminatory access to transmission services.

[244] Joint Committee on Taxation, "Estimated Effects of the Conference Agreement for Title XIII of H.R. 6, The Energy Tax Incentives Act of 2005, " JCX 05-95, July 27, 2005.

34. United States Department of Agriculture Energy Programs

Description

In Fiscal Year (FY) 2000, the United States Department of Agriculture (USDA) initiated the Commodity Credit Corporation (CCC) Bioenergy Program to alleviate crop surpluses and stimulate production of biofuels. The Agricultural Risk Protection Act of 2000 (Public Law 106-224) included the Biomass Research and Development Act, which directed the USDA and the Department of Energy (DOE) to cooperate and coordinate polices to promote research and development leading to the production of bioproducts.

The Farm Security and Rural Investment Act of 2002 (Public Law 107-171), the 2002 Farm Bill, contained the first energy title (Title IX) in farm bill history. The 2002 Farm Bill authorized a range of programs through 2007 to promote bioenergy and bioproduct production and consumption. Key provisions included the Federal Biobased Products Preferred Procurement Program (FB4P), which requires Federal agencies to procure bio-based products. Another program, the Biodiesel Fuel Education Program, awards competitive grants to educate government and private entities with vehicle fleets about the benefits of biodiesel fuel use.

The 2002 Farm Bill extended the CCC Bioenergy Program through FY 2006, expanded the Conservation Reserve Program (CRP) pilot biomass authority to a nationwide general authority, and authorized placement of wind turbines on land enrolled in CRP. The program was funded at $50 million annually.

The Biomass Research and Development Program is operated jointly by USDA and DOE. This program supports research and development of biomass-based products, bioenergy, biofuels, and related processes. Eligible entities are institutions of higher learning, national laboratories, Federal or State research agencies, private sector entities, and nonprofit organizations. Fiscal year 2006 funding for the Biomass Research and Development Program was $12 million.

USDA’s Agricultural Research Service (ARS) is USDA's primary research agency. Specific energy-related work being conducted by ARS follows:

- The process of cellulose degradation is not well understood. This research provides new information on the regulation of cellulose degradation by an organism that shows particular promise for converting cellulosic biomass.
- Inhibitors formed during pretreatment of lignocellulosic material reduce the performance of ethanol-producing fermentation organisms. ARS scientists are using a method called directed adaptation, developing strains of organisms that have enhanced ability to convert toxic compounds into less toxic compounds. Development of these more tolerant organisms is a significant step toward achieving the technology necessary for commercial production of ethanol from cellulosic plant material.
- There is a need to identify genes that regulate cell wall composition of alfalfa so that new varieties can be developed that have greater potential as biofuel feedstocks. ARS scientists identified and characterized a gene, UDP-sugar pyrophosphorylase (USP), which plays an important role in cell wall biosynthesis in plants. The isolation of the USP gene and new knowledge learned about the protein it produces will allow cell walls of alfalfa plants to be modified to improve the value of this crop as a bioenergy feedstock.

USDA’s Cooperative State Research, Education, Extension and Service (CSREES) provides funding for about 60 projects that include an energy-related objective.

USDA’s Forest Service (FS) is working to increase production of all energy sources in an environmentally-sound manner, capitalizing on the potential of woody biomass as a renewable energy resource, and contributing to the improvement of infrastructure for transmitting energy across the country. Increasing domestic energy supply includes providing energy facility corridors, ensuring that lands are available for energy mineral development and production, developing renewable energy resources such as woody biomass, wind, solar power, and geothermal energy, and re-licensing hydropower facilities.

The FS actively participates in a government-wide initiative aimed at promoting development and use of bio-based products and bioenergy. Programs include research on enhancing opportunities to use forest biomass to produce energy and other value-added products; developing economical, environmentally-acceptable woody cropping systems to produce energy and other value-added products; exploring new processes to convert wood into ethanol; and, identifying ways to increase energy conservation through changes in manufacturing technologies, harvesting technologies, building construction practices, and designed landscapes.

The focus of the FS biomass and bioenergy efforts is woody materials that are not part of the commercial forest product material flows. Woody biomass includes forest vegetation treatment residuals (tree limbs, tops, needles, leaves, and other woody parts) that are by-products of forest management and ecosystem restoration.

EPACT2005 authorized up to $50 million for grants to improve the commercial value of forest biomass for electric energy, useful heat, transportation fuels, and other commercial purposes. In FY 2006, 88 applications were received, totaling almost $18 million in requests. Eighteen proposals were funded at a Federal cost of $4.2 million. These projects leveraged approximately $9 million in non-Federal funds.

Between FY 2001 and FY 2005, USDA funds expended on bio-based products, bioenergy, and other energy-related programs totaled $1.4 billion. USDA outlays in FY 2006 on bio-based products, bioenergy, and other energy-related programs is estimated at $272 million. In addition, Federal and State income tax credits and other tax incentives that promote the use of ethanol and biodiesel reduce tax collections by over $2 billion annually.

The CCC Bioenergy Program began on December 1, 2000, and ended on June 30, 2006. Under the program, cash payments were made to bioenergy producers who increased their annual bioenergy production from eligible agricultural commodities. Eligible commodities included barley, corn, grain sorghum, oats, rice, wheat, soybeans, other oilseeds, cellulosic crops, and animal fats and oils. From December 2000 through March 2006, the program reimbursed bioenergy producers $537 million for 2.5 billion gallons of increased ethanol production, 146.4 million gallons of increased biodiesel production, and 26.7 million gallons of base biodiesel production.

Revenue Loss/Outlays

Expenditures for the various biomass and biofuels programs managed by USDA agencies totaled $41.8 million in FY 2007. Regarding the Rural Business Service (RBS) program, not all of the RBS programs focus exclusively on providing financial assistance for the development of energy infrastructure and promotion of energy efficiency or conservation. Therefore, it is difficult to precisely identify the budget subsidy for energy-related activities within particular loan programs. As a result, the budget subsidies, and authorized lending, grant, and guarantee levels discussed in this section do not reflect the totality of RBS loan and grant programs.

Rationale

Alleviate crop surpluses and to promote the development of biofuels.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Wind, solar, geothermal, bioenergy, biofuels for electric generation, transportation fuels, biomass co-products, and energy efficiency.

Direct Expenditures

35. Building Technology Assistance Program

Description

The U.S. Department of Energy (DOE) provides conservation assistance in a number of areas, primarily through the Building Technology Assistance Program, which complements DOE's research and development efforts and accelerates the deployment of new technologies and the adoption of advanced building practices through technical and financial assistance, outreach, and selective demonstration projects. According to the Office of Energy Efficiency and Renewable Energy, "The Building Technology Assistance Program works to improve the energy efficiency of the Nation's buildings—through innovative new technologies and better building practices." The Building Technology Assistance Program supports two grant programs: the Weatherization Assistance Program, which provides support for the weatherization of low-income homes, and the State Energy Program, which provides grants to promote innovative State energy efficiency and renewable energy activities. The Energy Conservation and Production Act (Public Law 94-385) and the Department of Energy Organization Act of 1977 (Public Law 95-91) provided the legislative framework for the weatherization program. The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) authorized $500 million for fiscal year (FY) 2006, $600 million for 2007, and $700 million for FY 2008 for the weatherization program. EPACT2005 authorized funding of $100 million, successively, for FY 2006 and FY2007 and $125 million for FY 2008 for the State Energy Program

Revenue Loss/Outlays

Federal appropriations outlays for the Building Technology Assistance Program amounted to $278 million (nominal dollars) in FY 2006 versus $155 million in FY 1998. $242 million of this total was directed to the weatherization program while $36 million was directed to the State Energy Program.[245]

Rationale

To increase the efficiency of homes occupied by low-income citizens who least can afford rising energy bills.

The Building Technology Assistance Program subsidizes energy conservation and is designed to reduce energy consumption. Although the technologies supported often are cost-effective on their own, cost sharing with nonprofit and government agencies make the first-cost barrier less prohibitive.[246]

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Renewable fuels, oil, natural gas, and electricity end use.

[245] Department of Energy budget 2007.
[246] See http://www.eere.energy.gov/buildings/about/mypp.html.

36. Low Income Home Energy Assistance Program

Description

LIHEAP is a block grant program under which the Federal government gives States, the District of Columbia, U.S. territories, and Indian tribal organizations annual grants to provide home energy assistance for needy households. LIHEAP assistance does not reduce eligibility or benefits under other aid programs. LIHEAP grantees are, however, allowed some flexibility as the program allows "maximum policy discretion to grantees." Federal law permits income eligibility to be established at either 60 percent of the State's median income or 150 percent of the HHS poverty income guidelines, whichever is greater. Sixty percent of a State's median income is usually higher than 150 percent of the HHS poverty level. For a four-person family in Fiscal Year 2007, 60 percent of the median was estimated at $66,111.[247] [248] LIHEAP provides two sources of funds: regular funds, which are allocated to the states as prescribed by LIHEAP legislation; and, contingency funds, which are released and allocated at the discretion of the president and the Secretary of Health and Human Services.[249]

The year 2003 was the latest year for which disaggregated program data were available. In that year fifty States were provided heating assistance for that year in the amount of $1.1 billion while cooling assistance was provided to 15 States in the amount of $73 million.[250] Approximately, 4.4 million households received heating assistance and 494,000 households cooling assistance. In 2003, for residential units, space heating and cooling accounted for about 43 percent of low-income, energy expenditures. Households receiving heating assistance fell at 102 percent of the poverty line while those receiving cooling assistance, fell at 124 percent of the poverty line. Annual cooling assistance averaged $65 dollars while heating assistance amounted to $258.[251]

Although LIHEAP funds are available for both cooling and heating, a preponderance of expenditures goes to relatively cold-weather States. In 2007, the largest recipient states of LIHEAP funds were New York, Pennsylvania, Illinois, Michigan, and Ohio.[252] LIHEAP funds are only used by a fraction of eligible participants. In 2005, 34.8 million households were eligible for LIHEAP, while 5.3 million households received LIHEAP benefits, amounting to 15 percent of all eligible households.[253] By comparison, in 1983, 6.8 million households received LIHEAP benefits, which amounted to 31 percent of eligible households. The aging of the population and increased independence of handicapped persons means that these groups will account for a growing share of LIHEAP payments. For 2002, according to HHS:

> "of the 4.1 million households receiving heating assistance, approximately 1.4 million households had at least one household member 60 years or older; approximately 1 million of these households had at least one child 5 years or under. Some of these households contained both an elderly person and a young child. Although available, State data on households with disabled members are not comparable as each State can use its own definition of 'disabled.'"[254]

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[247] U.S. Department of Health and Human Services, Low Income Home Energy Assistance Program, State Median Income Estimates for Optimal Use in Federal Fiscal Year 2006 LIHEAP Programs and Mandatory Use in Federal Fiscal Year 2007 LIHEAP Programs, (Washington, DC, March 6, 2006): http://www.acf.hhs.gov/programs/liheap/guidance/information_memoranda/im06-05.html; accessed October 16, 2007.

[248] Ibid. Accessed October 16, 2007.

[249] Congressional Research Service, *The Low-Income Home Energy Assistance Program (LIHEAP): Program and Funding*, Order Code RL 31865 (Washington, DC, October 2007), p. 1.

[250] U.S. Department of Health and Human Services, Low Income Home Energy Assistance Program, http://www.acf.hhs.gov/programs/liheap/, accessed October 16, 2007.

[251] U.S. Department of Health and Human Services, LIHEAP, Executive Summary—Low Income Home Energy Assistance Report to Congress for Fiscal Year 2003, http://www.acf.hhs.gov/programs/liheap/data/execsum.html, accessed October 16, 2007.

[252] Department of Health and Human Services, LIHEAP, http://www.acf.hhs.gov/programs/liheap/guidance/information_memoranda/07-allotments.xls.

[253] Department of Health and Human Services. http://www.acf.hhs.gov/programs/liheap/data/notebook/figure_11.html.

[254] Department of Health and Human Services, http://www.acf.hhs.gov/programs/opre/acf_perfplan/ann_per/apr2005/apr_sg3_73.html.

Federal rules also require LIHEAP outreach activities, coordination with the U.S. Department of Energy's Weatherization Assistance Program, and annual audits. Grantees decide the mix and dollar range of benefits, choose how benefits are provided, and decide what agencies will administer the program components. In addition to funds used for heating and/or cooling assistance, however, a reasonable amount of the funds must be set aside by grantees for energy crisis intervention. Up to 15 percent of grantees' allotments (up to 25 percent with a waiver) may be used for low-cost residential weatherization or other energy-related home repair.

Payments may be made directly to eligible households or to home energy suppliers. Assistance may be provided in the form of cash, vouchers, or payments to third parties, such as utility companies or fuel dealers. In practice, the majority of the funds are paid directly to energy providers.

Revenue Loss/Outlay

In the early years of the LIHEAP program, funding ranged at around $3.5 billion. Since 1988, funding for the program, has generally ranged from $1 billion to $2.4 billion, with the exception of the year 2006 when funding exceeded $3 billion. Section 121 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) authorized LIHEAP funding at $5.1 billion for the fiscal years 2005 through 2007. EPACT2005 also allowed LIHEAP funds to be use to purchase renewables fuel and requested that HHS conduct a study on how LIHEAP could reduce deaths related to extreme temperatures. In FY 2006, Congress appropriated an additional $1 billion in emergency LIHEAP expenditures due to high energy costs. A portion of the funding was also directed at Gulf Coast states most affected by Hurricane Katrina.

Rationale

To help lower income families, including the elderly and the handicapped, maintain their standard of living in the face of high energy costs.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

No. 2 fuel oil, natural gas, coal, and electricity end use.

37. Renewable Energy Production Incentive (REPI)

Description

The Renewable Energy Production Incentive (REPI) originated in the Energy Policy Act of 1992 (EPACT1992) (Public Law 102-486) with the purpose of promoting increases in the generation and utilization of electricity from renewable energy sources, and to advance renewable energy technologies. This program, authorized under Section 1212, provides financial incentive payments to electricity produced and sold by new qualifying renewable energy generation facilities. EPACT1992 designated eligible electricity production facilities that commenced operation between October 1, 1993, and September 30, 2003. Eligible electric production facilities that may be considered to receive REPI payments include not-for-profit electrical cooperatives; public utilities; State governments; Commonwealths; territories of the United States; the District of Columbia; Indian tribal governments, or a political subdivision thereof; or Native Corporations that sell the facility's electricity. The Code of Federal Regulations, Part 451.4 provides more information on qualifying facilities and who may apply.

As non-profits, REPI beneficiaries do not pay Federal income taxes. Therefore, they are ineligible for the investment energy tax credit available to investor-owned utilities. Initially, qualifying facilities were eligible for annual incentive payments of 1.5 cents per kilowatthour (1993 dollars and indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations in each Federal fiscal year of operation. Criteria for qualifying facilities and application procedures were contained in the final rule for this program. Initially, qualifying facilities included solar, wind, geothermal (with certain restrictions as contained in the final rule), or closed-loop biomass (except for municipal solid waste combustion) generation technologies. The U.S. Department of Energy is responsible for managing REPI.

REPI expired in 2003 even though several projects continued to receive funding subsequently. REPI appropriations were reauthorized with Section 202 of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) for fiscal years 2006 through 2007. Section 202 also expanded the list of eligible technologies and facility owners and the procedure for which funds were distributed so that funding would sufficiently pay for all approved applications but with an allocation of 60 percent for Tier 1 customers and 40 percent for Tier 2 customers (see paragraphs below). Section 202 also extended the kilowatt subsidy to ocean and wave energy. REPI was extended through December 31, 2008 by Section 207 of the Tax Relief and Health Care Act of 2006 (Public Law 109-432). Section 202 included Indian tribal governments and subdivisions thereof among the owners of qualified renewable energy facilities.

REPI payments consist of Federal outlays of funds. Procedures for annual payments to qualifying facilities for the REPI program are contained in the final rule. Payments are dependent upon the availability of annual appropriations. If there are insufficient appropriations to make full payments for electricity production from all qualifying facilities, Tier 1 applicants receive incentive payments first. Tier 1 qualifying facilities include use solar, wind, geothermal, or closed-loop (dedicated energy crops) biomass technologies to generate electricity. Tier 1 receives either full payments or pro rata payments if funds are insufficient to cover all requests. If funds are available after making full payments to these facilities, payments from the remaining funds are then made to Tier 2 qualifying facilities. These facilities use open-loop biomass technologies, such as landfill methane gas, biomass digester gas, and plant waste material that is co-fired in a generation facility to generate electricity. If there are insufficient funds to make full payments to all Tier 2 qualifying facilities, payments are made to those facilities on a pro rata basis. Pro rata payments result in a portion of the electricity production being fully paid and the remainder not receiving payment. Electricity for which payment is not made may be added to the next fiscal year’s electricity production and submitted by the qualifying facility for payment consideration, providing the annual application is made in a timely manner within the 10-fiscal-year eligibility window.

Revenue Loss/Outlay

In the first year of the REPI program 1994 (payment year 1995), there were sufficient appropriations to make full production incentive payments of $693,120 (nominal dollars) to the owners of all qualifying facilities. In the second year of the REPI program, there were sufficient appropriations to make full production incentive payments of $2,398,472 (nominal dollars) to the owners of all qualifying facilities (Table A27). For the third year of the REPI program, the available funds of $2,490,893 (nominal dollars) were insufficient to make full production incentive payments to the owners of all qualifying facilities. Therefore, full payments were made for electricity produced by Tier 1 facilities, and partial payments on a pro rata basis were made for Tier 2 facilities. For the fourth year of the REPI program, the available funds of $2,853,997 (nominal dollars) were insufficient to make full production incentive payments to the owners of all qualifying facilities. Therefore, full payments were made for electricity produced by Tier 1 facilities and partial payments were made for Tier 2 facilities on a pro rata basis. The fifth year of the REPI program received $4,000,000 from Congress. This appropriation did not cover requests for reimbursement. Tier 1 was fully funded; Tier 2 funding was prorated on the basis of production. Underfunding of Tier 2 programs has continued since. Only in the first 2 years of the program were Tier 2 customers fully funded. Tier 2 funding fell to 87 percent in 1996 and to a low of 0 percent for 2003 and 2004. Funding for Tier 2 programs rose to 40 percent for 2005. Meanwhile, the years 2003 through 2005 saw funding for the Tier 1 group fall below 100 percent. In 2005 (payment year 2006), funding for Tier 1 customers was $6.3 million and just under $2.0 million for Tier 2 customers.[255]

Rationale

To promote increased generation from renewable energy and to improve the performance of renewable energy technologies.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Solar, wind, ocean wave energy, geothermal (with certain restrictions as contained in the rulemaking), or biomass (except for municipal solid waste combustion) generation technologies used to produce electricity by new generating facilities (which started operation between October 1, 1993, and September 30, 2003) owned by publicly-owned utilities.

[255] Net electricity production by qualified REPI facilities averaged 894,483 million kilowatthours between 2001 and 2005.

Table A27. REPI Appropriations (Dollars)

Year of Production (FY)	Year of Payment (FY)	Appropriated Funds	Tier 1 Paid	Tier 1 Unpaid	Percent Tier 1 Paid	Tier 2 Paid	Tier 2 Unpaid	Percent Tier 2 Paid
EPACT1992								
1994	1995	$693,120	$100,725	-	100%	$592,395	-	100%
1995	1996	$2,398,472	$218,604	-	100%	$2,178,217	-	100%
1996	1997	$2,490,893	$195,902	-	100%	$2,294,991	$347,038	87%
1997	1998	$2,853,997	$154,504	-	100%	$2,699,493	$6,519,682	29%
1998	1999	$4,000,000	$122,167	-	100%	$3,877,833	$9,747,420	28%
1999	2000	$1,500,000	$603,182	-	100%	$896,818	$15,664,879	5%
2000	2001	$3,991,000	$1,339,377	-	100%	$2,651,625	$24,755,332	10%
2001	2002	$3,787,000	$1,365,846	-	100%	$2,421,154	$33,679,732	7%
2002	2003	$4,815,033	$1,810,911	-	100%	$3,004,122	$40,211,074	7%
2003	2004	$3,714,911	$3,714,911	$1,091,206	77%	-	$58,145,027	0%
2004	2005	$4,960,000	$4,960,000	$2,205,009	69%	-	$43,393,560	0%
EPACT2005								
2005	2006	$4,925,375	$2,955,225	$6,323,364	60%	$1,970,150	$41,178,610	40%
2006	2007	$4,900,000	$2,940					
2007		$4,690,000						
2008		$4,690,000						
2009		$4,690,000						
2010		$4,690,000						
2011		$4,690,000						
2012		$4,690,000						
2013		$4,690,000						
2014		$4,690,000						
2015		$4,690,000						
2016		$4,690,000						
2017		$4,690,000						
2018		$4,690,000						
2019		$4,690,000						
2020		$4,690,000						
2021		$4,690,000						
2022		$4,690,000						
2023		$4,690,000						
2024		$4,690,000						
2025		$4,690,000						
2026		$4,690,000						

Sources: Department of Energy, Office of Energy Efficiency and Renewable Energy,http://www.eere.energy.gov/repi/projects.cfm, accessed October 16, 2007. Forecast*:* Department of Energy*,* Office of Energy Efficiency and Renewable Energy, *"Appendix J, "Weatherization and Intergovernmental Assistance Program (WIP) Inputs for FY 2008 Benefit Estimates. NREL/TP-620-39684.*

Research and Development

38. Advanced Turbine Systems

Description

There is a growing national need for increased electricity and reduced emissions from electric power generating plants. The objective of the Advanced Turbine Systems (ATS) program, which is currently being phased out, was to develop ultra-high-efficiency natural gas turbine systems for utilities, independent power producers, and industrial markets. The ATS program was striving for revolutionary, yet achievable advances that include: industrial turbine systems for distributed power generation that show a 15-percent improvement over today's best natural gas turbine systems; and large central power plants for utility systems that break the 60-percent barrier in net thermal efficiency.

Revenue Loss/Outlays

There was no funding for advanced turbine systems in 2007.

Rationale

The intent behind this program was to improve the fuel efficiency of electric turbine systems while reducing emissions.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Natural gas. Although the ATS program will demonstrate performance with natural gas fuel, advanced turbine design systems will make use of fuels other than natural gas, such as coal and renewable biomass.

Basic Research

39. Basic Energy Research

Description

The Basic Energy Sciences (BES) program supports research and operates facilities to provide the foundation for new and improved energy technologies and for understanding and mitigating the environmental impacts of energy use. There are two BES subprograms. Materials Sciences and Engineering supports basic research to explore the scientific foundations for the development of materials that improve their efficiency, economy, environmental acceptability, and safety for energy generation, conservation, transmission, and use. Applications include lighter, stronger materials to increase fuel economy in automobiles, alloys and ceramics that improve the efficiency of combustion engines, and more efficient photovoltaic materials for solar energy conversion. The Department of Energy (DOE) Chemical Sciences, Geosciences and Energy Biosciences program, supports research crucial for improving combustion systems, solar photo-conversion processes, and for applications to renewable fuel resources, environmental remediation, and photosynthesis. The $1.4 billion (total project cost) Spallation Neutron Source at Oak Ridge National Laboratory, the world's most powerful neutron scattering facility, will be in its first full year of operations in fiscal year (FY) 2007. Four of the five Nanoscale Science Research Centers, part of the National Nanotechnology initiative, will be fully operational in FY 2007. Construction is also underway on the next -generation $379 million (total project cost) Linac Coherent Light Source at the Stanford Linear Accelerator Center (SLAC).

Revenue Loss/Outlays

The operating plan for basic energy sciences excluding fusion is about $1.3 billion in fiscal FY 2007. About $1.1 billion is funding for Basic Energy Sciences. Construction is funded at $125 million and science laboratories infrastructure is funded at $42 million.

Rationale

To undertake basic research where commercial payoffs are uncertain, long-term, or unavailable to the public.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

All forms of energy.

40. Building Technology, State and Community Programs Research and Development

Description

Section 109 of the Energy Policy Act of 2005 authorized the Department of Energy (DOE) to develop, test, and demonstrate advanced Federal and private building efficiency standards. The mission of the DOE building technology (BTS) research and development (R&D) program, within the Office of Energy Efficiency and Renewable Energy, is to make buildings more efficient and affordable and communities more livable. The goal of the Building Research and Standards program is to accelerate the introduction of highly efficient building technologies and practices through R&D and increase the minimum energy efficiency of buildings and equipment through appliance standards, building codes, and guidelines. The building technology R&D (non-grant) programs complement other DOE grant programs that help demonstrate and increase consumer awareness of the benefits and costs of energy-efficient technologies. The program develops technologies, techniques and tools for making residential and commercial buildings more energy efficient, productive, and affordable. The portfolio of activities includes efforts to improve the energy efficiency of building components and equipment, including the advancement of solid state lighting technologies for general illumination, and their effective integration using whole -building-system-design techniques; the development of energy efficient building codes and equipment standards; and integration of clean renewable energy systems into building design and operation.

Revenue Loss/Outlays

Appropriations for the BTS program appropriations were $68 million per year for fiscal year (FY) 2007 and $77 million in FY 2008.

Rationale

To increase energy efficiency and reduce the carbon footprint of residential and commercial buildings.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Oil, natural gas, and electricity end use.

41. Clean Coal Power Initiative

Description

The Clean Coal Power Initiative (CCPI), an industry/government cost-shared partnership, responds to the government's commitment to increase investment in Clean Coal Technology (CCT). CCPI provides the means to demonstrate those technologies proven through research and development to have commercial potential. Demonstrations are at a commercial scale in actual operating environments, which is essential to moving them to the threshold of commercialization. The CCPI provides government co-financing for new coal technologies that can help utilities meet the President's Clear Skies Initiative to cut sulfur dioxide (SO_2), nitrogen oxides (NO_2) and mercury pollutants from power plants by nearly 70 percent by the year 2018. Also, some of the early projects are showing ways to reduce greenhouse emissions by boosting the efficiency at which coal plants convert coal to electricity or other energy forms.

Eight projects were selected under the first-round CCPI solicitation, of which two were withdrawn. Of the remaining six projects supported by the first round of the CCPI, three projects are currently in the operational phase, two are in the construction phase, and one is still in the pre-award phase.

Four projects were recently selected from the second-round CCPI solicitation and are in various stages of development. Of the four projects recently chosen, two will demonstrate advanced integrated gasification combined cycle (IGCC) technology; one will demonstrate an innovative multi-pollutant control process for NOx, SOx, and mercury; and one will demonstrate a neural-network control process for advanced multi-pollutant controls by means of plant optimization.

Revenue Loss/Outlays

The fiscal year (FY) 2007 operating plan for coal research and development appropriations is $60.5 million.

Rationale

The objective of the program is to sharply reduce the air emissions and other pollutants from coal-burning power plants.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal.

42. Fusion Energy Sciences

Description

The Fusion Energy Sciences (FES) program is the national research effort to advance plasma science, fusion science, and the fusion technology knowledge-base required for an economically- and environmentally-attractive fusion energy source. Facilities include the DIII-D at General Atomics in San Diego, the Alcator C-Mod at the Massachusetts Institute of Technology, and the National Spherical Tokamak Experiment at the Princeton Plasma Physics Laboratory (PPPL). Assembly of the National Compact Stellarator Experiment (NCSX) is ongoing at PPPL. The Department of Energy is also participating in the President's initiative on ITER (Latin, for "the way") , an international burning plasma fusion experiment.

The goal of the FES program is to "acquire the knowledge base for an economically and environmentally attractive fusion energy source." Although there is not a schedule for developing and deploying fusion energy systems, the availability of fusion as an option for large central station power plants could eventually provide valuable insurance against possible environmental concerns related to fossil and nuclear energy. In addition, there may be nearer-term applications of fusion in transmutation of wastes and isotope production.

Revenue Loss/Outlays

The fiscal year 2007 operating plan for this appropriation was $319 million.

Rationale

To further the understanding of fusion energy.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear energy.

43. FutureGen

Description

FutureGen was initiated on February 27, 2003, in response to the National Energy Policy Report of May 2001, prepared under the National Energy Policy Developmental Group. The objective of FutureGen was to create a 275-MW coal-fired power plant that would be the world's first to produce electricity and hydrogen while sequestering carbon dioxide emissions. This prototype plant was to serve as a laboratory for clean-coal and hydrogen technology development. The latter being in connection with the development of technology to facilitate the transition to a hydrogen-based economy, including emission-free vehicles. The program was to be partially funded by the FutureGen Alliance, a consortium of major coal companies and electric companies. Other countries were urged to participate in the project. Four potential plant sites were considered by the FutureGen Alliance, which led to the December 2007 announcement of the selection of Matoon, Illinois as the site of the prototype plant.

The project will employ coal gasification technology integrated with combined-cycle electricity generation and the sequestration of carbon dioxide emissions. The project will be supported by the ongoing coal research program, which will also be the principal source of technology for the prototype. The project is expected to require 10 years to complete and will be led by the FutureGen Industrial Alliance Inc., a non-profit industrial consortium representing the coal and power industries, with the project results being shared among all participants and industry as a whole.[256]

Revenue Loss/Outlays

The funding for this program was $54 million in fiscal year 2007.

Rationale

To prove the technical feasibility and economic viability of the near-zero atmospheric emissions of sulfur dioxide, nitrogen oxides, mercury, particulates, and carbon dioxide.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal.

[256] The prospects for FutureGen grew uncertain when, in January 2008, the U.S. Department of Energy announced that it intended to restructure FutureGen. The DOE's new FutureGen vision called for "Federal-funding to demonstrate cutting edge CCS (Carbon Capture and Storage) at multiple commercial-scale integrated gasification combined-cycle (IGCC) demonstration plants…Under this new approach multiple plants would produce at least 3000 megawatts of electricity and jointly these projects will capture and safely sequester at least double the amount of carbon dioxide annually compared to the concept announced in 2003." Source: DOE, Fact Sheet, "DOE to Demonstrate Cutting-Edge Carbon Capture and Sequestration Technology at Multiple FutureGen Clean Coal Projects." The DOE cited higher than expected costs for the restructuring. The DOE also stated that the program would be revamped so that DOE would only fund the carbon sequestration element of the program. The restructuring cast strong doubts over whether the prototype plant, selected in December, 2007 for Mattoon, Illinois, would continue.

44. Fuel and Power Systems

Description

The Fuel and Power systems program provides research for FutureGen intended to reduce dramatically coal power plant emissions (especially mercury) and significantly improve efficiency to reduce carbon emissions, leading to a viable near-zero atmospheric emissions coal energy system.

The Innovations for Existing Plants (IEP) program has a near-to mid-term focus to improve overall power plant efficiency and develop advanced cost-effective environmental control technologies, with a focus on mercury, for retrofitting existing power plants and other coal technologies including those developed in support of the FutureGen project.

The Integrated Gasification Combined Cycle (IGCC) program is intended to develop technologies for gas stream purification to meet quality requirements for use with fuel cells and conversion processes.

The Advanced Turbines program is focused on creating the technology base for turbines that will permit the design of near-zero atmospheric emission IGCC plants and a class of FutureGen plants with carbon capture and sequestration

The Carbon Sequestration program's purpose is to develop a portfolio of technologies that would reduce greenhouse gas emissions. The program's goal is to research and develop a portfolio of safe and cost-effective greenhouse gas capture, storage, and mitigation technologies by 2012, leading to substantial market penetration beyond 2012.

The mission of the Fuels program is to conduct the research necessary to promote the transition to a hydrogen economy. Research is intent on targeting cost reduction and increased efficiency of hydrogen production from coal feedstocks.

Advanced Research projects seek a greater understanding of the physical, chemical, biological, and thermodynamic barriers that limit the use of coal and other fossil fuels. The program funds two categories of activity. The first includes applied research programs to develop the technology base needed for the development of super-clean, very high efficiency coal-based power and coal-based fuel systems. The second is a set of crosscutting studies and assessment activities in environmental, technical and economic analyses, coal technology export, and integrated program support.

The objectives of the Fuel Cells activity are to provide the technology-based development of low-cost, scalable, and fuel flexible fuel cell systems that can operate in central coal based power systems as well as having applications in other electric utility (both central and distributed), industrial, and commercial/residential markets.

Revenue Loss/Outlays

The fiscal year 2007 operating plan for coal research and development (R&D) appropriations, excluding the unallocated component, is $311.3 million.

Rationale

To provide an adequate scientific and engineering knowledge base to foster technological advances in the private sector. Also, coal-burning power plants are at the center of the controversies involving global warming.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Coal mining, combustion, liquefaction, and gasification.

45. Industrial Sector Research and Development

Description

The mission of the U.S. Department of Energy (DOE) industrial sector research and development (R&D) program, within the Office of Energy Efficiency and Renewable Energy (EERE), is to improve the energy efficiency, environmental performance, and productivity of energy-intensive industries by rapidly developing and delivering advanced science and technology options that will lower raw material and energy use per unit of output; improve labor and capital productivity; and reduce generation of wastes and pollutants. The energy-intensive industries include forest products, steel, glass, aluminum, chemicals, metal casting, agriculture, petroleum, and mining.

The fiscal year (FY) 2007 goal of this program is to reduce primary nonrenewable energy by 0.03 quadrillion Btu per year in 2010. Carbon dioxide emissions would be reduced by 0.7 million metric tons carbon equivalent per year in 2010.

Revenue Loss/Outlays

The industrial sector program appropriations were $56.6 million in FY 2007.

Rationale

To improve energy efficiency in the industrial sector.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

All fuels, end use.

46. Nuclear Energy Research Initiative and Energy Policy Act of 2005 Related Research and Development

Description

The Department of Energy (DOE) created the Nuclear Energy Research Initiative (NERI) with the intent to address and help overcome technical and scientific obstacles to the future use of nuclear energy in the United States. There are several programs that have been implemented as part of NERI. They include the Generation IV Nuclear Energy Systems Initiative (Gen IV), Nuclear Hydrogen Initiative (NHI), Advanced Fuel Cycle Initiative (AFCI), and Nuclear Power 2010.[257,258]

The goal of Gen IV is to address fundamental research and development issues necessary to establish the viability of next-generation nuclear energy system concepts. The 2007 operating plan provides $45.6 million for the Gen IV initiative to expand research and development that could help achieve the desired goals of sustainability, economics, and proliferation resistance.

The NHI, with funding of $19.3 million, is intended to conduct research and development on enabling technologies, demonstrate nuclear-based hydrogen production technologies, and develop technologies that will apply heat from Gen IV nuclear energy systems to produce hydrogen.

The Advanced Fuel Cycle Initiative, which is an element of the Gen IV effort, is intended to develop a better, more efficient, and proliferation-resistant nuclear fuel cycle. This research and development program focuses on methods to reduce the volume and long-term toxicity of high-level waste from spent nuclear fuel, to reduce the long-term proliferation threat posed by civilian inventories of plutonium in spent fuel, and to provide for proliferation-resistant technologies to recover the energy content in spent nuclear fuel. The focus of this initiative is to be the Global Nuclear Energy Partnership (GNEP). It is funded at $167.5 million in the 2007 operating plan.

GNEP is intended to accelerate work being done under the AFCI program. Advanced recycling technologies are expected to be able to extract highly radioactive elements of commercial spent nuclear fuel and use that material as fuel in fast spectrum reactors to generate additional electricity. The extracted material, which includes all transuranic elements (e.g., plutonium, neptunium, americium, and curium), would be consumed by fast reactors to significantly reduce the quantity of material requiring disposal in a repository with the further benefit of producing power. The plutonium would remain bound with other highly radioactive isotopes, thereby preserving its proliferation resistance and reducing security concerns. With the transuranic materials separated and used for fuel, the volume of waste that would require disposal in a repository would be reduced by 80 percent.

The Nuclear Power 2010 program is funded at $80.3 million in FY 2007 to complete the issuance of three Early Site Permits by the U.S. Nuclear Regulatory Commission (NRC). In addition, the program will complete the industry cost-shared project initiated in FY 2003 to develop generic guidance for the Construction and Operating License (COL) application preparation, to resolve generic COL regulatory issues and to continue the implementation phase of the two New Nuclear Plant Licensing Demonstration Projects awarded in FY 2005.

The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) contained several provisions intent on promoting current and future nuclear programs.

Subtitle C of Title 5 of EPACT 2005 funds a prototype Next Generation Nuclear Plant Project to produce both electricity and hydrogen. The prototype nuclear reactor and associated hydrogen plant is to be sited at the Idaho National Laboratory (INL) in Idaho. A consortium of industrial

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[257] The following objectives have been established for the NERI program: develop advanced reactor and fuel cycle concepts and scientific breakthroughs in nuclear technology to overcome scientific and technical obstacles to expanded future use of nuclear energy in the United States, including issues involving nuclear proliferation, unfavorable economics, and nuclear waste disposition; advance the state of U.S. nuclear technology to maintain a competitive position in overseas and domestic markets; and promote and maintain nuclear science and engineering infrastructure to meet future technical challenges and improve the performance, efficiency, reliability, economics, and other attributes to enhance nuclear energy applications.

[258] Source: U.S. Department of Energy, Nuclear Energy, www.ne.doe.gov/neri/neNERIresearch.html.

partners is to carry out the cost-shared research, development, design, construction and operations of the integrated plant.[259]

Section 951 of Title IX cites eight objectives of nuclear energy research and development. They are: enhancing nuclear power's viability; reducing the likelihood of proliferation; maintaining a cadre of nuclear scientists and engineers; maintaining national laboratory and university programs, supporting individual and multidisciplinary researchers; developing, planning, constructing, acquiring, and operating special research equipment/facilities; supporting technology transfer; and, reducing the environment impact of nuclear energy-related activities.

Section 952 of Title IX (Research and Development) lists the Office of Nuclear Energy's core programs as the Nuclear Energy Research Initiative, Nuclear Energy Systems Support Program, Nuclear Power 2010 Program, Generation IV Nuclear Energy Systems Initiative, and the Reactor Production of Hydrogen. The Nuclear Power 2010 program shall include the use of expertise and capabilities of industry, higher education, and the national laboratories. The Generation IV initiative must examine advanced proliferation-resistant and passively-safe reactor designs that are economically competitive, high in efficiency, low in cost, and improved safety and instrumentation.

Section 953 provides for an Advanced Fuel Cycle Initiative under Title IX (Research and Development, Subtitle E - Nuclear Energy). This section authorizes the Secretary of Energy to conduct an advanced fuel recycling technology, research, development, and demonstration program to evaluate proliferation-resistant fuel recycling and transmutation technologies that minimize environmental and public health and safety impacts.

Section 954 - University Nuclear Science and Engineering Support under Title IX - Research and Development, Subtitle E - Nuclear Energy authorizes the Secretary of Energy to conduct a program to invest in human resources and infrastructure in the nuclear sciences and related fields. This section references the requirements in the program to conduct an undergraduate/graduate fellowship program to attract new talent; conduct a junior faculty research initiation grant program; support fundamental nuclear sciences, engineering, and health physics research; encourage collaborative nuclear research; and, support communication and outreach related to these areas. This section also requires the Secretary of Energy to conduct a fellowship program for university professors and to set up a visiting scientist program at the national laboratories.

Revenue Loss/Outlays

The operating plan for these programs is $319.2 million in FY 2007: $302.6 million for NERI and $16.5 million for university research.

Rationale

To improve the commercial prospects of nuclear power.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear energy.

[259] Source: U.S. Department of Energy, Nuclear Energy. http://www.ne.doe.gov/energyPolicyAct2005/neEPACT2a.html, accessed October 16, 2007.

47. Oil Technology Research and Development

Description

This program is being phased out. The overall approach of oil technology research and development (R&D) was, first, to identify those types of oil deposits that have both the greatest potential for improved oil recovery and the greatest risk of abandonment within the next 5 to 10 years and, second, to apply available technologies. The technologies to be further investigated are called secondary and enhanced oil recovery. The first generally involves drilling and improved production methods based on sophisticated geological and geophysical interpretation. Enhanced oil recovery includes the injection of chemicals, gases, or heat to overcome physical barriers in the reservoir.

Revenue Loss/Outlays

Oil R&D appropriations were $2.7 million in fiscal year 2007 for the management of the closeout of this program.

Rationale

The enhanced oil recovery research was aimed at capturing a significant portion of the estimated 300 billion barrels left in the ground from past recovery rates and methods. The goal is to preserve access to identified deposits while developing and testing technologies designed to overcome the specific problems that prevent increased oil recovery.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Crude oil production.

48. Renewable Energy Technology Research and Development

Description

The Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE) energy supply and conservation activities promote the development and use of clean, reliable, efficient, and cost-effective power technologies to meet growing national energy needs, to reduce dependence on foreign energy sources, and to enhance energy security.

The Hydrogen Technology Program, aligned with the Energy Policy Act of 2005 (EPACT2005), focuses on hydrogen production, delivery, storage, and fuel cell technologies. This program supports a $1.2 billion Hydrogen Fuel Initiative to accelerate the development of hydrogen fuel cell vehicle and infrastructure technologies. The program is intended to enable a commercialization decision by industry on fuel cell vehicles and hydrogen infrastructure by 2015. A positive commercialization decision in 2015 could lead to market introduction of hydrogen fuel cell vehicles by 2020. The overall request in fiscal year (FY) 2007 is $289.5 million. Other organizations also contribute to this Presidential Initiative, including:

- Basic hydrogen research in the Office of Science;
- Coal-based hydrogen production research in the Office of Fossil Energy;
- Nuclear-based hydrogen production research in the Office of Nuclear Energy, Science and Technology; and,
- Hydrogen safety-related activities at the U.S. Department of Transportation.

The Biomass and Biorefinery Systems Research and Development (R&D) program intends to accelerate critical research, development and deployment resulting in industrial-scale validation of biorefinery pathways. The program focuses on three areas: (1) platforms R&D, to reduce the cost of outputs and byproducts from biochemical and thermochemical processes; (2) utilization of platform outputs, to develop technologies and processes that co-produce liquid and gaseous fuels, chemicals and materials, and/or heat and power, and integrate those technologies and processes into biorefinery configurations; and (3) feedstock infrastructure, to develop cost-effective biomass harvesting, storage and delivery systems, and to develop energy supply crops suitable for diverse regions and climates.

The Solar Energy Program focuses on R&D to enable cost effective development of solar power that will reduce U.S. demand for natural gas and promote a cleaner environment. Through the Department's new Solar America Initiative (SAI), the Solar Energy Program intends to accelerate the market competitiveness of solar electricity from photovoltaic (PV) systems

The Wind Energy Program intends to develop and promote the use of advanced technologies to harness wind resources. The program focus is on developing low-wind-speed utility scale technology, through leveraged partnerships with industry, to substantially increase the economically viable wind resource base across the country.

Since 1974, the Geothermal Technology Program has worked in partnership with U.S. industry to establish geothermal energy as an economically competitive contributor to the U.S. energy supply. The Department planned to conclude the Geothermal Technology program in FY 2007 and transfer results of its research and development work related to geothermal technology to industry and state and local governments. However, the program was resuscitated with appropriations in 2008 and an appropriation request in 2009.[260]

The Vehicle Technologies Program supports the Freedom CAR and Fuel Partnership and the 21st Century Truck Partnership, to enable light-and heavy-duty highway transportation to become more efficient. Technology research includes advanced lightweight materials, advanced batteries, improved power electronics, electric motors, and advanced combustion engines and fuels.

[260] A Massachusetts Institute of Technology report prepared under a Idaho National Laboratories Subcontract sponsored by the Department of Energy's Assistant Secretary for Energy Efficiency and Renewable Energy, Office of Geothermal Technologies, concluded that Enhanced Geothermal Systems could provide 100,000 Megawatts of base-load electric-generating capacity by 2050. Source: "The Future of Geothermal Energy, Impact of Enhanced Geothermal Systems (EGS) in the United States in the 21st Century," Massachusetts Institute of Technology, ISBN: 0-615-13438-6, 2006.

Building Technologies (BT) Program develops technologies, techniques and tools for making residential and commercial buildings more energy efficient, productive, and affordable. The portfolio of activities includes efforts to improve the energy efficiency of building components and equipment , including the advancement of solid state lighting technologies for general illumination, and their effective integration using whole -building-system-design techniques; the development of energy efficient building codes and equipment standards; and integration of clean renewable energy systems into building design and operation.

Industrial Technologies Program (ITP) works to reduce the energy intensity of the U.S. industrial sector through a coordinated program of research and development, validation, and dissemination of energy -efficiency technologies and operating practices.

The Federal Energy Management Program (FEMP) advances energy efficiency and water conservation and promotes the use of renewable energy in federal agencies, including the Department of Energy. FEMP also evaluates and reports the progress in these areas to the President and Congress.

The Facilities and Infrastructure activity supports capital investments to support research and development program at the National Renewable Energy Lab (NREL). The Weatherization and Intergovernmental Activities program deploys energy efficient and renewable energy products into the marketplace, and funds Weatherization Assistance and State Energy Program grants.

The Program Support account provides for program measurement and strategic direction, as well as for technology advancement and outreach. Technical Advancement and Outreach activities provide the public with accurate information on energy efficiency and renewable energy technologies to help the public make better energy choices.

Revenue Loss/Outlays

The fiscal year 2007 operating plan for Renewable Energy Technology R&D is $962.6 million.

Rationale

EERE conducts research, development, and deployment activities in partnership with industry to advance a diverse supply of reliable and affordable energy efficiency and clean power technologies and practices.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

The program includes wind, solar, hydrogen technology, biofuels and biomass, geothermal, hydroelectric, and electricity delivery and energy reliability.

49. Environmental Management

Description

After the Department of Energy (DOE) ceased most nuclear weapons production operations in the late 1980s, it established a program to manage the legacy of contamination resulting from the operation of the largest government-owned industry. DOE manages thousands of contaminated areas and buildings, huge waste volumes, and nuclear materials left over from the nuclear weapons production and process and nuclear-related research efforts. This program supports activities that manage and address the environmental legacy resulting from civilian nuclear energy research. The nuclear energy research and development of DOE and its predecessor agencies generated waste and contamination that pose unique problems, including large quantities of contaminated soil and groundwater and a number of contaminated structures. Upon completion of cleanup activities, these sites or portions of a site will be turned over to other DOE program landlords or to the Office of Legacy Management for long-term surveillance and maintenance.

Non-Defense Environmental Cleanup provides funding in several accounts: Fast Flux Test Reactor Decontamination and Decommissioning (D&D), Gaseous Diffusion Plants, Small Sites, and the West Valley Demonstration Project. Funding for the Small Sites account includes projects at Argonne National Laboratory, Brookhaven National Laboratory, the Energy Technology Engineering Center (ETEC), Idaho National Laboratory, the Inhalation Toxicology Laboratory, Los Alamos National Laboratory, Moab, and the Stanford Linear Accelerator Center.

Revenue Loss/Outlays

The Non-Defense Environmental Management fiscal year 2007 budget in the operating plan is $349.7 million.

Rationale

To clean up and close contaminated nuclear weapons sites. After cleanup there will be no further DOE presence, with the exception of long-term surveillance and maintenance.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear contamination.

50. Clean Cities Program

Description

The Clean Cities program, sponsored by the Department of Energy's Office of Energy Efficiency and Renewable Energy's FreedomCAR and Vehicle Technologies Program (FCVT), was established in 1993 to advance the economic, energy, and environmental security of the United States by partnering with local jurisdictions to reduce petroleum consumption in the transportation sector. Clean Cities works through a network of 80 volunteer, community-based coalitions, which develop public/private partnerships to promote the use of alternative fuels and vehicles, expand the use of fuel blends, encourage the use of fuel economy practices, increase the acquisition of hybrid vehicles by fleets and consumers, and advance the use of idle-reduction technologies in heavy-duty vehicles.

The Clean Cities program provides its coordinators support in the following areas: market and technology analysis; tools and information; technical assistance; funding; partnerships and alliances; and training; and events. Clean Cities has a sister program "Clean Cities International."

Clean Cities coalitions have increased the number of alternative-fuel vehicles (AFVs) on the road every year since 1993, with gains averaging 15-percent in recent years. In 2005, the program reached the milestone of displacing one billion gallons of petroleum.

Rationale

Reduce petroleum consumption in urban transportation.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Petroleum end use.

51. Army Corps of Engineers/Bureau of Reclamation Hydropower Projects

Description

The Department of the Interior's Bureau of Reclamation and the Army Corps of Engineers are both engaged directly and indirectly in hydroelectric power. Both agencies are charged with the construction, operation, and maintenance of Federal hydroelectric facilities. The Corps of Engineers operates nationwide, whereas the Bureau of Reclamation conducts its activities only in 17 western States.

The direct costs of maintenance and operation in producing hydroelectricity are paid by the Power Marketing Administrations (PMAs), which purchase and resell the power; however, the indirect costs of the projects are not allocated to electricity production. Typically, construction of dams has been primarily for the benefits of irrigation, municipal water supply, and flood control, and only secondarily for the production of power. Construction costs incurred for flood control, recreation, and fish and wildlife purposes are nonreimbursable and are borne by users of irrigation, municipal water supply, and power generation. Thus, the costs of construction for power generation need to be pro-rated accordingly. Moreover, when the Corps of Engineers dredges a waterway to facilitate navigation, and that waterway flows to a hydroelectric facility, silting at the dam is reduced, increasing the life of the dam and reducing maintenance costs. The costs are registered not for hydroelectric power generation but for navigation.

Essentially, most of the fixed costs of developing the hydroelectric sites have been paid by the Federal government for other reasons. It may well be that, were it not for the other reasons, electric power would not have been available until later in the affected areas. The value of the economic development, although difficult to estimate, can be seen as resulting from the availability of relatively inexpensive hydropower.

Revenue Loss/Outlays

The direct costs of power are reimbursed by the PMAs. The imputation of indirect costs borne by the Corps of Engineers or the Bureau of Reclamation for electricity production is difficult to estimate, in part because Federal reclamation law allows cross-subsidization among projects. Thus, users of the electricity reimburse not only the construction costs allocated to power generation but also some portion of the construction costs incurred for irrigation.

Rationale

The original rationale for Federal involvement with hydroelectric plants was that the cost of adding hydroelectric capability to dams was small in comparison with the perceived benefits of economic development.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Hydropower, electricity generation.

52. ENERGY STAR Program

Description

According to the Department of Energy: “ENERGY STAR is a voluntary labeling program sponsored by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA). The ENERGY STAR label helps businesses and consumers easily identify highly efficient products, homes, and buildings that save energy and money, while protecting the environment.”

DOE works with manufacturers and standards organizations to develop technical requirements and qualifications defining ENERGY STAR status. A number of manufacturers have redesigned their products to achieve maximum energy and even water savings. ENERGY STAR-labeled clothes washers, for example, use 35 percent to 50 percent less water and 50 percent less energy per load than conventional washers.

More than 100 lighting manufacturers produce ENERGY STAR-qualified compact fluorescent bulbs (CFLs). With advanced technology, CFLs use 75 percent less energy than a standard incandescent bulb and last up to 10-times longer. Likewise, over 350 manufacturers produce ENERGY STAR-qualified windows and window components. ENERGY STAR-qualified windows can save 15-percent on a household's total energy bill. All together, the ENERGY STAR label appears on over 30 categories of products.

ENERGY STAR retail partners promote recognition and purchase of ENERGY STAR-labeled products. In 2001, they sold more than 1.7 million ENERGY STAR-labeled appliances sold. Many retail partners also support a wide range of ENERGY STAR promotional activities such as radio ads, in-store displays, and appliance rebates to educate consumers about the benefits of ENERGY STAR.

The typical U.S. household spends about $1,300 on home energy bills. ENERGY STAR states that its approved products can save consumers up to 30 percent on those energy bills, without sacrificing features, style, or comfort.

Rationale

Promotes energy efficiency, lower energy costs to consumers and environmental quality.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity and residential natural gas.

53. Federal Energy Management Program

Description

The Federal Energy Management Program (FEMP) was established in 1974 to provide direction, guidance, and assistance to Federal agencies in planning and implementing energy management programs. The mission of FEMP is to reduce the cost of the Federal government by advancing energy and water efficiency, promoting renewables, and managing utility costs. Section 543 of the National Energy Conservation Policy Act, as amended by the Energy Policy Act of 1992 (EPACT1992), requires each agency to achieve: a 10-percent reduction in energy consumption in its Federal buildings by fiscal year (FY) 1995, when measured against a FY 1985 baseline on a Btu-per-gross-square-foot basis; and a 20-percent reduction in Btu per gross square foot by FY 2000. Furthermore, agencies were required to achieve a 30-percent reduction by fiscal year FY 2005 per Executive Order 12902, issued in 1994.Executive Order 13123, issued in June of 1999, “Greening the Government Through Efficient Energy Management” supersedes Executive Order 12902. Executive Order 13123 encourages effective energy management in the Federal government and builds on work begun under EPACT1992 and previous Executive Orders. The goals of the order include:

- Through life-cycle cost-effective energy measures, each agency shall reduce its greenhouse gas emissions attributed to facility energy use by 30 percent by 2010, compared to such emissions levels in 1990.
- Through life-cycle cost-effective energy measures, each agency shall reduce energy consumption per gross square foot of its facilities, excluding facilities covered in other sections of this order, by 30 percent by 2005 and 35 percent by 2010 relative to 1985.
- Through life-cycle cost-effective energy measures, each agency shall reduce energy consumption per square foot, per unit of production, or per other unit as applicable by 20 percent by 2005 and 25 percent by 2010 relative to 1990.
- Each agency shall try to expand the use of renewable energy within its facilities and in its activities by implementing renewable energy projects and by purchasing electricity from renewable energy sources. In support of the Million Solar Roofs initiative, the Federal government shall strive to install 2,000 solar energy systems at Federal facilities by the end of 2000 and 20,000 solar energy systems at Federal facilities by 2010.
- Through life-cycle cost-effective energy measures, each agency shall reduce the use of petroleum within its facilities.
- The Federal government shall strive to reduce total energy use and associated greenhouse gas and other air emissions, as measured at the source.
- Through life-cycle cost-effective measures, agencies shall reduce water consumption and associated energy use in their facilities to reach the goals set in the Order.

Section 104 The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides further direction to Federal agencies implementation of FEMP. Specifically, it directs Federal agencies to purchase ENERGY STAR and FEMP-designated products, except when it is not cost-effective or does not meet functional requirements.

Revenue Loss/Outlays

Funding for FEMP, $23.8 million in FY 1999 and zero in FY 2007, is not included in the tables of this report, although it appears in the End Use R&D category of the Department of Energy budget, because the impact of the program is primarily internal to the Federal government. Funds are used for education, training, and encouragement of third-party investments.

Rationale

The purpose of FEMP is to reduce the Federal government's total cost of utility services, i.e. energy and water through adoption of energy efficiency measures evaluated on a life-cycle cost basis. The program also promotes the expanded use of renewable technologies.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Energy and water efficiency, renewable energy technologies, end-use.

54. Loan Guarantees for Innovative Technologies

Description

Title XVII of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provides loan guarantee incentives for Innovative Technologies. This title allows the Secretary of Energy to provide loan guarantees for up to 80 percent of eligible project costs after consultation with the Secretary of the Treasury. The guarantee is applicable for projects that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases and employ new or significantly improved technologies as compared to commercial technologies in service in the United States today. No guarantee shall be made unless an appropriation for the cost has been made or the Secretary of Energy has received from the borrower a payment in full for the cost of the obligation and deposited the payment into the Treasury. The incentive covers a broad range of technologies and also includes advanced nuclear energy facilities. Other projects eligible for loans include wind, photovoltaic, biomass, hydropower facilities, and advanced fossil energy technologies, such as integrated gasification combined cycle, industrial gasification, petroleum coke gasification. Efficiency improvements to end-use technologies also qualify for loans. These may include: hydrogen fuel technology for residential, industrial, or transportation applications, carbon capture and sequestration technologies, and agriculture and forestry technologies that reduce carbon dioxide emissions.

On February 15, 2007, Section 20320(a) of the Revised Continuing Appropriations Resolution (Public Law 110-5) authorized the Department of Energy (DOE) to issue loan guarantees under Title XVII of EPACT2005 for loans in the total principal amount of $4 billion. EPACT2005 also required that not later than 120 days after the date of enactment of this division, and annually thereafter, the Secretary of Energy shall transmit to the Committees on Appropriations of the House of Representatives and the Senate a report containing a summary of all activities under Title XVII of the Energy Policy Act of 2005. On May 16, 2007, DOE issued a Notice of Proposed Rulemaking (NOPR, 72 FR 27471) to establish regulations for the loan guarantee program. On October 4, 2007, DOE invited 16 project sponsors, who submitted pre-applications in late 2006, to submit full applications for loan guarantees. The projects submitted included advanced technologies including biomass, fossil energy, industrial energy efficiency, electricity deliverability, and energy reliability, hydrogen, and alternative-fuel vehicles. On October 23, 2007, DOE issued final rules (10 C.F.R.609) establishing policies, procedures, and requirements for the loan guarantee program in the Federal Register. The final regulation specified DOE decision to guarantee up to 100 percent of a qualifying loan, as long as the loan does not exceed 80 percent of the cost of a project. The guaranteed portion of a partially guaranteed loan may be separated from or "stripped" from the non-guaranteed portion, except in cases where the guarantee exceeds 90 percent of the loan amount.

The final regulation also required that eligible projects must deploy new or significantly improved technologies that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases as compared to commercial technologies in service in the United States at the time the loan guarantee agreement is executed. DOE also stipulated that a project's receipt of other government assistance does not disqualify a project from receiving a Title XVII loan guarantee; however, when evaluating a projects application for a loan guarantee, DOE will consider the extent to which the project will receive other government assistance, e.g., grants, tax credits, other loans.

In a report released in April of 2007, the Government Accountability Office (GAO) noted that the DOE will "have to estimate the subsidy costs to determine the fees to charge borrowers." GAO also noted that "estimated subsidy costs could be difficult because the program targets innovative technologies whose future success is uncertain, and loan performance could depend heavily on future economic conditions, including energy prices, which are hard to predict accurately."[261]

[261] Government Accountability Office, *Department of Energy Observations on Actions to Implement the New Loan Guarantee for Innovative Technologies*, GAO-07-798T (Washington, DC, April 2007).

Revenue Loss/Outlay

No loans were guaranteed in fiscal year (FY) 2007. Therefore, there were no costs associated with default risk and the only expenses were administrative. FY 2006 administrative budget amounted to roughly $503,000. In the full-year Continuing Resolution that was enacted into law on February 15, 2007, Congress provided DOE with $7 million to fund the operation of its Loan Guarantee Office, and authority to issue guarantees for up to $4 billion in loans. The President has requested $8.4 million for operation of the DOE Loan Guarantee Office in FY 2008.

Rationale

To promote innovative technologies in energy production and energy usage.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Projects eligible for loans include advanced nuclear, wind, photovoltaics, biomass, hydropower facilities, solar and advanced fossil energy technologies, such as integrated gasification combined cycle, industrial gasification, and petroleum coke gasification. Efficiency improvements to end-use technologies also qualify for loans. These may include: hydrogen fuel technology for residential, industrial, or transportation applications, carbon capture and sequestration technologies, and agriculture and forestry technologies that reduce carbon dioxide emissions. Also included are alternative-fuel vehicles, electricity reliability investments, industry energy efficiency projects, and pollution control equipment.

55. Nuclear Power Plant Construction Delay Support

Description

Section 638 under Title VI of the Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) provided standby support for certain nuclear power plant delays. This section allows the Secretary of Energy to enter into contracts for standby support for delays for up to a total of six reactors of no more than three different reactor designs. Covered delays include the failure of the Nuclear Regulatory Commission (NRC) to comply with schedules for review and approval of inspections or the conduct of hearings, in addition to litigation that delays full-power operation. The Secretary of Energy would pay 100 percent of the covered costs for the first two reactors that have received a combined license and for which construction has begun. However, the Department of Energy would not cover any costs that result in a failure of the project sponsor to take any action required by law or regulation or any events within the sponsor's control. Covered costs would include principle or interest on debt coverage, and the difference on the fair market price of purchase power and contractual price of power from the plant, up to a total of $500 million. For the next four reactors, the Secretary would pay 50 percent of the covered costs (principal and interest and purchase power difference) of a delay, up to $250 million. Covered costs are subject to the Secretary of Energy receiving appropriations or payments from project sponsors sufficient to pay such covered cost.

Revenue Loss/Outlays

NA.

Rationale

To remove barriers to new nuclear power investment related to uncertainty regarding construction time horizons.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power.

56. Nuclear Waste Fund[262]

Description

The Nuclear Waste Policy Act of 1982 (NWPA)(Public Law 97-425) established the Federal government's responsibility and statutory framework to provide for permanent disposal of commercially-generated spent nuclear fuel and the high-level radioactive waste generated by the Nation's nuclear defense activities. The Department of Energy (DOE), as directed by the Act, initially undertook a national screening exercise to evaluate candidate repository sites. In 1986, at the conclusion of this scientific screening activity, DOE recommended three sites to the President for further study as potential repositories. Congress, however, in the Nuclear Waste Policy Amendments Act of 1987, directed DOE to investigate only one site at Yucca Mountain, Nevada, for possible development as a geologic repository.

The Conference Report to the fiscal year 1997 Energy and Water Appropriations Act directed DOE to complete a Viability Assessment for the Yucca Mountain site. This report was completed and sent to Congress in December 1998. In 2002, Congress approved and the President signed into law the Yucca Mountain Development Act (House Joint Resolution 87, Public Law 107-200) which completed the site selection process mandated by the Nuclear Waste Policy Act and approved the development of a repository at Yucca Mountain. In 2006, DOE announced that it had plans to submit to the Nuclear Regulatory Commission a license application for a Yucca Mountain repository by June 2008. Currently, under the DOE’s "best-achievable" schedule, the repository will open in 2017. The Yucca Mountain Project is the primary activity of the Office of Civilian Radioactive Waste Management. DOE studied Yucca Mountain for 20 years to determine its potential as a repository.

In March 2007, the Secretary of Energy announced that he would send to Congress a legislative proposal to improve the Nation’s ability to manage and dispose of defense-related and commercially-produced nuclear waste.

Revenue Loss/Outlays

The fund is paid for by the users of the disposal service. The NWPA provides for two types of fees to be paid by utilities for management and disposal of commercial spent nuclear fuel: an ongoing fee of 1 mill (one tenth of a cent) per kilowatthour (kWh) of electricity generated and sold on or after April 7, 1983, and a one-time fee for electricity generated and sold prior to April 7, 1983. The NWPA directed that the utility fees be paid into the Nuclear Waste Fund, a separate account established in the U.S. Treasury. The funding for the program's activities consist of appropriations principally from two sources: the Nuclear Waste Disposal Appropriation and the Defense Nuclear Waste Disposal Appropriation. The budget requests a total of $651 million in budget resources for the Civilian Radioactive Waste Management Program in fiscal year (FY) 2006. Appropriations totaled $495 million. The FY 2007 request was $545 million with appropriations of $445 million. (All figures are expressed in nominal dollars.) In early 2007, payments and interest credited to the fund were approximately $28 billion.

Rationale

To develop a permanent repository site that will enable the Nation to advance its plans for the disposition of nuclear waste.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power waste storage.

[262] In addition to the direct expenditures, tax expenditures, R&D expenditures, and government support for Federal electricity discussed in the body of this report, the Federal government intervenes in energy markets through its sponsorship of trust funds, which are related to energy production. These funds are intended to be self supporting. However, the Federal government faces potential risks in the event that these funds should face revenue shortfalls.

57. Power Marketing Administrations

Description

In the past, the Federal government has sought to advance development in rural areas through its Power Marketing Administrations (PMAs): Bonneville (BPA), Southeastern (SEPA), Southwestern (SWPA), and Western Area (WAPA). The Alaska Power Administration was sold in 1998, more than 10 years after privatization of all the PMAs was first proposed by the Executive Branch. The sale of the Alaska Power Administration was achievable largely because of its small size (by far the smallest of the PMAs) and because it operated strictly as an electricity generator, with no transmission operations or non-energy activities, such as flood control, irrigation, or recreation. Much of the activity of the PMAs consists of marketing power produced by the U.S. Army Corps of Engineers and Bureau of Reclamation hydropower projects. The four PMAs sell electricity primarily generated by hydropower projects located at Federal dams. Preference in the sale of power is given to public entities and electric cooperatives. Support to the PMAs include: (1) low-interest loans; (2) preferential repayment schedules; (3) debt forgiveness; and (4) no primary taxation, such as property or income tax.

Bonneville Power Administration

BPA, by far the largest PMA, can be used as an example to describe Federal support. As part of the New Deal, BPA was created by Congress to sell the power generated from Federal dams in the Columbia Basin. Publicly-owned utilities were given preferential customer status to the power. The law called for the PMAs to be self-supporting by offsetting their cost from the fees charged for power; however, even if BPA always repaid its debt on time and covered all its other accounting (historical) costs, the rates charged for electric power still would not cover the true cost of providing the power.

BPA serves 3 million customers and supplies about half of all power in the Northwest. Its 15,000 mile transmission network accounts for 75 percent of the bulk transmission system in the Northwest. BPA markets power from 31 dams and 1 nuclear power plant. [263] Its service territory includes Oregon, Washington, Idaho, Western Montana, and small parts of California, Eastern Montana, Nevada, Utah, and Wyoming. BPA provides about 35 percent of the power consumed in the Pacific Northwest. BPA's service territory covers 300,000 miles and 12 million people. BPA serves 57 electric cooperatives, 41 municipalities, 29 public utility districts, 7 Federal agencies, 6 investor-owned utilities (IOU), 5 direct-service industries, 1 port district and 2 Indian tribes.[264] Forty-seven percent of BPA's power sales goes to public utilities, 18 percent is sold outside the Northwest, and 13 percent is sold to IOUs.

Southeastern Power Administration

SEPA markets electricity in 11 States: Alabama, Florida, Georgia, Illinois, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia. In 2005, the utility had 22 hydroelectric projects with 3,392 megawatts of generating capacity and sold 8.7 billion kilowatthours of electricity to 494 wholesale customers for $220 million. It sold power to 293 public bodies, 199 electric cooperatives, and 2 IOUs.[265] Unlike the other PMAs, SEPA does not own a transmission system.

Southwestern Power Administration

SWPA markets power from 24 hydroelectric power plants operated by the Army Corps of Engineers to customers in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. SWPA has 2,174 megawatts of generation capacity and operates 1,380 miles of transmission lines. In 2006 it marketed and delivered 2.3 billion kilowatthours of electricity, 57 percent of which went to electric cooperatives, 25 percent to municipalities and 2 percent to government agencies.[266]

[263] All of these dams were completed prior to 1977, the first to be completed in 1909.
[264] BPA fast facts, http://www.bpa.gov/corporate/about_BPA/Facts/FactDocs/BPA_Facts_2006.pdf, accessed October 11, 2007.
[265] Southeastern Power Administration, Southeastern Power Administration 2005 Annual Report, p 2.
[266] Southwestern Power Administration 2004-2006 Annual Report, pp. 4 and 15.

Western Area Power Administration

WAPA was established by the Congress in the 1977 under Section 302 of the Department of Energy Organization Act (Public Law 95-91) to manage power marketing and transmission operations that previously were under the responsibility of the U.S. Department of Interior's Bureau of Reclamation. WAPA markets power in Arizona, California, Colorado, Iowa, Kansas, Montana, Minnesota, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Wyoming, and Utah. It operates 17,000 miles of transmission lines and sells power from 56 hydroelectric generation facilities owned and operated by the Army Corps of Engineers, the Bureau of Reclamation, and the International Boundary and Water Commission.[267] In 2005, WAPA sold 36 billion kilowatthours of electricity, 25 percent to municipalities, 23 percent to State agencies, 20 percent to cooperatives, and the remaining 32 percent to various other users. The utility receives annual appropriations from the Congress to cover all expenses associated with its power and other activities. Its power rates are set to recover those costs, along with all costs associated with debt servicing.[268]

Similar to the Tennessee Valley Authority (TVA), WAPA also engages in some non-Federal capital acquisition. In some cases, WAPA has relied on customers as a source of funds for expanding its electric power capacity through customer advance payments on power under co-sponsoring arrangements with entities for construction, operation and maintenance.[269] WAPA has also received loans from State governments.

Revenue Loss/Outlays

In 2006, the Treasury's estimated net financing costs for the PMAs ranged from $89 million (2007 dollars) to $393 million.

Rationale

PMA were intended to promote economic development in areas where it was felt that private enterprise would not offer electric power and in part because of the nature of the regional economy. The flexible repayment approach was adopted in view of the significant variability in revenues associated with hydroelectric power, a major source of power for some PMAs. The PMAs calculate and repay interest expenses, and all other expenses, in accordance with their statutes and applicable DOE orders.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Electricity generation, transmission, distribution, and end use.

[267] The one thermal plant that WAPA markets power from is the Navajo Generating Station. This unit is, however, not owned by WAPA, and is therefore not added into the subsidy calculation. Source: Western Area Power Administration, Western Area Power Administration 2006 Annual Report, p. 35.
[268] Western Area Power Administration 2005 Western Profile, p. 5.
[269] Western Area Power Administration 2006 Annual Report, p. 39.

58. Price-Anderson Fund[270]

Description

A Federal regulation that continues to have a cost-reducing effect on the nuclear power industry is the Price-Anderson Act of 1959, which placed a limit of $560 million on the liability of individual nuclear power plants for damage resulting from any one accident This limit provides a subsidy to the nuclear industry to the extent that insurance premiums paid by the operators of individual plants are reduced.

The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) introduced significant modifications to Price-Anderson. Section 602 of EPACT2005 extends the indemnification authority of the Atomic Energy Act. The indemnification of certain Nuclear Regulatory Commission licensees is extended from December 31, 2003, to December 31, 2025. The indemnification of department contractors is extended from December 31, 2006, to December 31, 2025, and the indemnification of nonprofit educational institutions is extended from August 1, 2002, to December 31, 2025. This is the fifth time that the Price Anderson Act has been extended since it inception in 1957.

For commercial nuclear power plants, the Price-Anderson Act provides for a two-layer compensation system to pay public liability claims. The first layer consists of a set amount of insurance for each reactor site currently available from the private insurance market. Licensed reactors in the United States. are also required to carry private insurance which is now valued at $300 million.[271] The second is provided by funds made available through an assessment on each licensed reactor of a pro-rated share not to exceed a specified amount. EPACT2005 raised the maximum total charge per reactor per accident to $95.8 million from $63 million and added an inflation adjustment factor. Section 603 of EPACT2005 also raised the annual secondary level payout from $10 million to $15 million, which will be adjusted for inflation.

This is not the first time that the insurance premiums have been raised. In order to make a larger pool of money available to pay public liability claims, the 1988 amendments to the Act increased maximum secondary insurance assessments from the $5 million (nominal dollars) established in 1975 to $63 million per reactor per incident, which was to be adjusted for inflation at 5-year increments effective in August. The 1988 amendments also increased potential liability limits to $7.34 billion ($200 million primary insurance and $7.14 billion secondary insurance coverage) per accident. The 1988 amendments extended the Price-Anderson Act for 15 years, to August 1, 2002.

The Department of Energy (DOE) is required by the Price-Anderson Amendments Act, a Federal law, to protect its contractors from legal claims that may arise as the result of a nuclear accident that occurs at a DOE facility. Price-Anderson also allows the DOE to establish nuclear safety rules that its contractors must follow, and gives DOE authority to fine contractors for violating those rules.

Section 604 of EPACT2005 limits the indemnity provided by the DOE for its contractors to $10 billion, subject to adjustment for inflation, for each nuclear incident, including legal costs.

Section 608 of the EPACT2005 clarifies the treatment of modular reactors as a single facility or multiple facilities. Two or more facilities located at a single site, each having a rated capacity of 100,000 electrical kilowatts or more but not more than 300,000 electrical kilowatts, will be considered a single facility, with a combined rated capacity of not more than 1,300,000 electrical kilowatts.

In a 1983 study, the Nuclear Regulatory Commission concluded that the liability limits established by the Price-Anderson Act constitute a subsidy; however, the subsidy was not quantified. At issue are the probability distributions for various kinds of accidents on a plant-by-plant basis. From

[270] In addition to the direct expenditures, tax expenditures, R&D expenditures, and government support for Federal electricity discussed in the body of this report, the Federal government intervenes in energy markets through its sponsorship of trust funds, which are related to energy production. These funds are intended to be self supporting. However, the Federal government faces potential risks in the event that these funds should face revenue shortfalls.

[271] Congressional Research Service, *Energy Policy Act of 2005: Summary and Analysis of Enacted Provisions* (Order Code RL33302) (Washington, DC, March 2005), p.39.

those distributions, the amount of the subsidy can be estimated by calculating the effect of the liability limit on the operators' insurance premiums.

There is an implied subsidy in the form of reduced insurance premiums per operating unit which reduces the operating costs of commercial nuclear power plants. The Federal government acts as an insurer for DOE contractors against any finding of liability arising from nuclear activities of the contractor within the scope of the contract. Price-Anderson coverage could become more critical with the significant increase in potential radioactive waste shipments which can be anticipated in both the near- and long–term horizon. An increase in shipments is likely to stem from a variety of sources, including the decommissioning and decontamination of nuclear reactors, DOE and Department of Defense environmental restoration activities, and shipments of spent nuclear fuel and high-level radioactive waste under the Nuclear Waste Disposal Act.

Revenue Loss/Outlays

There are no associated revenue losses or budgetary outlays at this time. However, Federal outlays could rise if the Federal government is forced to clean up a nuclear incident in excess of individual liability limits. As the Act limits liability, it reduces the cost of insurance to the owners of nuclear power plants and nuclear activities at DOE sites and, hence, reduces the cost of nuclear power and other nuclear activities.

Rationale

To meet two basic objectives: remove the deterrent to private-sector participation in atomic energy presented by the threat of potentially enormous liability claims in the event of a catastrophic nuclear accident, and ensure that adequate funds are available to the public to satisfy liability claims if such an accident were to occur.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power production and other nuclear activities.

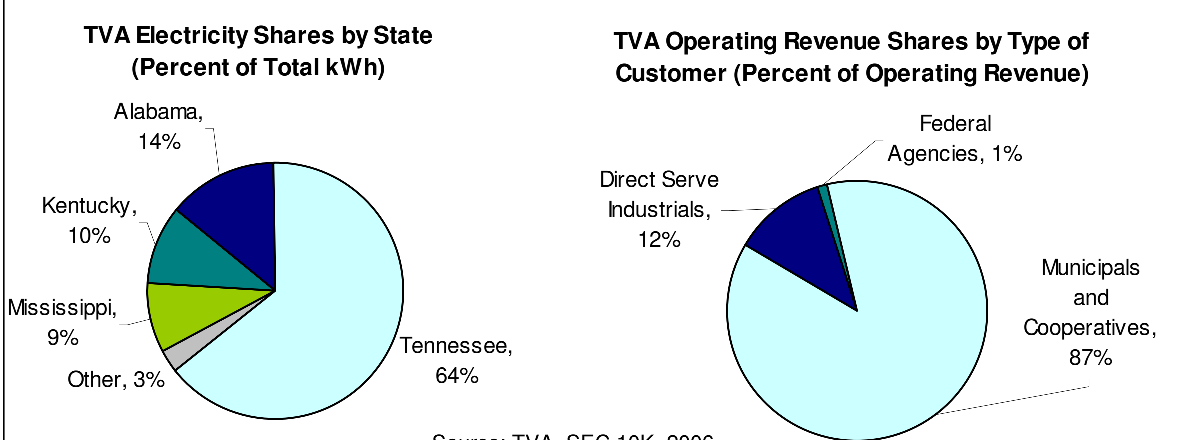
59. Tennessee Valley Authority

Description

The Tennessee Valley Authority (TVA) was established in 1933 under the Tennessee Valley Act (Public Law 73-17, 48 Stat. 58). Its original purpose was to promote economic development in the Tennessee Valley, to improve navigation, and to aid in flood control. TVA is far and away the largest of the Federal utilities, having an asset base greater than that of the four PMAs combined. TVA is operated as an independent government-owned corporation for the unified development of the Tennessee River Basin, which comprises parts of 7 States . The company's retail customers include 62 large industrial concerns and Federal agencies. In 2006, it operated 17,000 miles of transmission lines and 29 hydropower dams, 11 fossil fuel plants, 5 nuclear units, 6 combustion turbine plants, and 8 diesel units. With the restart of Browns Ferry I in 2007, TVA now operates 6 nuclear units at 3 plants with a total nuclear generation capacity of 7,000 megawatts (MW). In total, TVA has 34,951 MW of winter generating capacity[272] and is one of the Nation's largest wholesalers of electricity, with sales of 156 billion kilowatthours in 2006. TVA's operating revenues totaled $9.2 billion in 2006.

TVA's service territory covers 8.7 million people located in nearly all of Tennessee and parts of Alabama, Kentucky, North Carolina, Mississippi, Georgia, and Virginia. Tennessee accounted for 64 percent of TVA's electricity sales. Its wholesale customers include 108 utilities and 20 electric cooperatives. TVA received 87 percent of its revenue from cooperatives. In 2006, generation from fossil fuels accounted for 64 percent of TVA's total generation in 2006, while nuclear generation accounted for 29 percent, and hydroelectric generation accounted for 6 percent of the total.[273]

Figure A1. TVA Electricity Shares by State & Operating Revenue Shares by Customer



Source: TVA, SEC 10K, 2006.

The Stewardship Program includes maintaining a system of dams, reservoirs, and navigational facilities and, among other things, maintaining and managing 230,000 acres of public land and 11,000 miles of shoreline. TVA operates and maintains the navigation channel from Paducah, Kentucky, to Knoxville, Tennessee; operates a system of multipurpose reservoirs to retain excessive seasonal runoff and regulate discharges at flow rates that can be accommodated by downstream channels and reservoirs (resulting in the reduction of flood crests); performs dam safety modifications and maintenance activities; operates dewatering areas associated with TVA's

[272] Tennessee Valley Authority, Tennessee Valley Authority 10-K, 2006, p. 14.
[273] Tennessee Valley Authority, Tennessee Valley Authority 10-K, 2006, pp. 6, 14, 11, 18.

reservoir system; and performs environmental research services at its Muscle Shoals Reservation.

The Water and Land Program is intended to aid conservation. TVA operates an air-quality monitoring network, monitors water quality, promotes the wise use of forest resources in the region, and prepares maps for its own needs and to help the U.S. Geological Survey.

The Power Program provides power to an area of 80,000 square miles in the seven Tennessee Valley States. TVA owns and operates a substantial mix of hydroelectric, coal, natural gas turbine, and nuclear power plants.

Revenue Loss/Outlays

The TVA has a complicated financial structure, historically funded through a combination of power and nonpower revenues, borrowing, and direct Federal appropriations. In comparison with the interest rates paid by investor-owned utilities (IOUs), TVA is estimated to have benefited from Federal government support of $65 million to $189 million (2007 dollars) in 2006 because of the utility's artificially low borrowing costs.

Although TVA is unregulated and was committed early on to hydropower, the cost of debt associated with its nuclear program caused its rates to rise to a level close to the average of neighboring IOUs. According to the 2000 Federal budget, "Prior to 2000, appropriations provided for public services to maintain and operate public resources—navigable channels, flood control, recreation and non-regulatory, community-based programs that protect the water quality of the Tennessee river system... .The Budget proposes that beginning in 2000, these services be funded entirely by TVA's power revenues, user fees, and sources other than appropriations, except for Land Between the Lakes National Recreation Area."

How the TVA Sets Rates

Section 15 d. (f) of the TVA Act requires it to "charge rates for power which will produce gross revenues sufficient to provide funds for operation, maintenance, and administration of its power system; payments to States and Counties in lieu of taxes; debt service on outstanding bonds… the Corporation's power business having due regard for the primary objectives of the Act, including the objective that power shall be sold at rates as low as feasible." In order to derive its revenue requirements, the TVA employs a debt-service coverage (DSC) methodology.[274] The DSC method gauges an organization's ability to cover its operating costs and to satisfy its obligations to pay principal and interest on debt. The TVA states that is revenue requirements (or projected costs) are typically calculated under the DSC method as the sum of the following components: fuel and purchased power costs, operating and maintenance costs, taxes, and debt service coverage. The TVA then compares its revenue requirements to the projected revenues for the test year at existing rates to determine whether the result will be a shortfall or surplus. Rates are than adjusted so as to remove the short fall or surplus.

Rationale

According to President Franklin Roosevelt's promotion of the TVA, "[The] potential usefulness of the Tennessee River... transcends mere power development; it enters the wide fields of flood control, soil erosion, afforestation, elimination from production use of marginal agricultural lands, and distribution and diversification of industry."

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Hydropower, coal, natural gas, and nuclear electricity generation, transmission, distribution and end use.

[274]Tennessee Valley Authority, Tennessee Valley Authority 10-K, 2006, p. 10.

60. Uranium Facilities Maintenance and Remediation Fund[275]

Description

Two programs are contained within the Uranium Facilities Maintenance and Remediation fund: The Uranium Enrichment Decontamination and Decommissioning and Other Uranium Activities. The Uranium Enrichment Decontamination and Decommissioning Fund was established by the Energy Policy Act of 1992 (EPACT1992), (Public Law 102-486) to carry out environmental management responsibilities at the Nation's three gaseous diffusion plants, located in the East Tennessee Technology Park in Tennessee, at the Portsmouth site in Ohio, and at the Paducah site in Kentucky. EPA1992 also directs that this fund be used to reimburse licensees operating uranium or thorium processing sites for the costs of environmental cleanup at those sites, subject to a site-specific reimbursement limit. The Oak Ridge Operations Office is charged with carrying out the fund's mandates. EPACT1992 required that annual contributions to the fund would be made for 15 years, terminating at the earlier of 2007 or the collection of $2.25 billion (adjusted for inflation), from annual assessments to domestic utilities. (The costs are recorded as a fuel cost by the licensees and are recovered through electricity customer rates.) The annual assessment is not to exceed $150 million, adjusted for inflation, with Federal appropriations making up the difference when expenditures exceed the assessed values.

The Department of Energy's (DOE) Office of Environmental Management was charged with the responsibility for managing the fund and operational control over the three clean-up facilities through 2003. In October 2003, the DOE transferred these responsibilities to a new office in Lexington, Kentucky, although the Oak Ridge Operations Office was left with responsibility for cleanup activities at the Oak Ridge plant.

The other uranium activities program involves the management of highly-enriched uranium at the Paducah and Portsmouth sites. It also involves the management of the DOE's inventory of depleted uranium hexafluoride and other uranium inventories. This responsibility was transferred to the Office of Environmental Management in 2001 from the Office of Nuclear Energy's Science and Technology program. Operations at the Portsmouth site ceased in 2001, although the clean-up effort is expected to take several years.

The Uranium Enrichment Decontamination and Decommissioning Fund is an integral component of legislation to privatize uranium enrichment activities in the United States. The fund addresses the cleanup liabilities at the three gaseous diffusion plants that are attributable to past DOE operations for weapons and commercial fuel. The future operations of the enrichment facilities are managed by the commercial United States Enrichment Corporation (USEC). The Decontamination and Decommissioning Fund includes contributions from annual budget appropriations and contributions from commercial utilities based upon historical enrichment services, measured in "separative work units."

In a 2004 study, the General Accounting Office found that funding will be: "insufficient to cover the cleanup activities at the three plants. Specifically, our Baseline model demonstrated that by 2044, the most likely time frame for completing cleanup of the plants, costs will have exceeded revenues by $3.5 billion to $5.7 billion."[276]

Revenue Loss/Outlays

Cash income is estimated at $556 million for fiscal year 2007 and $574 million for 2008.

[275] In addition to the direct expenditures, tax expenditures, R&D expenditures, and government support for Federal electricity discussed in the body of this report, the Federal government intervenes in energy markets through its sponsorship of trust funds, which are related to energy production. These funds are intended to be self supporting. However, the Federal government faces potential risks in the event that these funds should face revenue shortfalls.

[276] Government Accounting Office, *Uranium Enrichment, Decontamination and Decommissioning Fund is Insufficient to Cover Cleanup Costs*, GAO-04-692 (Washington, DC, July 2004), Summary.

Rationale

The goal of the Uranium Enrichment Decontamination and Decommissioning Fund is to clean-up the surplus enrichment plants as soon as possible and reimburse licensees for their remediation activities at uranium and thorium sites. The enrichment plants include valuable facilities and equipment, and the clean-up costs will be offset to the extent that DOE is able to recover the value from these surplus assets.

Major Form(s) of Energy/Fuel Cycle Stage(s) Affected

Nuclear power waste storage.

Appendix B
Alternative Methods of Estimating Federal Electricity Subsidies and Interventions

Alternative Methods of Estimating Federal Electricity Financial Support

In Chapter 4 a measure of capital investment support (based on interest obligations) was used to measure Federal government support to Federally-owned utilities. This appendix presents two alternative measures of support: market price support and return on asset support. Due to data limitations, these measures of support were not deemed to be as accurate as the interest support described in Chapter 4. As such, the methodologies described below are of perhaps greater value than the specific estimates of support, which should be viewed as rough.

Market Price Support

The market price estimate of support involves the price differential for Federal power sold in wholesale electricity markets and investor-owned utility (IOU) power sold in wholesale electricity markets. It should be kept in mind that wholesale prices embody more than pure power costs. Often included in wholesale prices are such transaction specific items as: capacity fees, delivery fees, and fees for the use of facilities. This qualification, however, should not obscure the fact that electricity generation is the largest component of wholesale electricity prices[277] and that some Federal power is priced significantly below that of neighboring utilities.

There are a number of different measures of wholesale electricity prices. The one used in this analysis, “sales for resale,” was the only available measure that could be readily derived from published EIA data. It was also used because Federal utilities sell almost all of their electricity in wholesale markets. In a competitive market, the prices charged by different companies for the same commodity would be similar, with some variation resulting from such factors as transportation costs, as competitive forces would not allow significant price differences to persist over time. Where well-functioning markets exist, market prices can be observed directly. If Federal utilities sell power at below-market prices, the value of their preferential rates is the difference between the revenues that would be earned by selling electricity at the market price and the actual revenues of the utility. In essence, this price differential amounts to the opportunity cost of Federal power. For several reasons, however, caution should be exercised in estimating competitive market prices for electricity. First, although U.S. electricity markets have become more competitive, they are still significantly regulated. Because the prices charged by IOUs for wholesale transactions are often based on their embedded costs, a true competitive price cannot be derived. Furthermore, Federal utilities are currently required to sell electricity at rates that cover both power and some non-power costs. These latter costs, including environmental protection and aid to irrigation, have been found to be relatively higher for Federal utilities than for most IOUs.[278]

Wholesale electricity flowing over the grid is fungible; however, it is not necessarily a liquid commodity in all regions of the country. Thus, the underlying terms and conditions of bilateral transactions, and power purchased and sold in centralized markets, must be relied upon to determine whether two or more transactions are similar for price comparison purposes. For example, the price of hourly opportunity sales, which reflects current market conditions, is not comparable to long-term requirements where the supplier assumes a contractual obligation to serve the customer’s current and future needs, including the provision of reserve capacity. Essentially, these two transactions involve different goods, and the prices for them are not directly comparable. The market price approach implicitly assumes that wholesale power sales by Federal utilities are directly comparable to private-utility power sales within the same regions; however, this may not always be the case.

Still, Federal power is in general low-price power particularly when measured against electricity prices in regions without access to Federal electricity. In part, this is due to the historic role the Federal government has played in the development of the Nation’s hydroelectric resources, particularly in the areas of the Columbia and Tennessee River valley basins. Much Federal power comes from relatively cheap hydroelectricity, some of which was built long ago when construction costs and interest rates were relatively low. Moreover, to a large measure, these original asset investments have been depreciated. In a purely rate-regulated environment, conventional ratemaking policy allows low-cost producers to pass on

[277] Energy Information Administration, Electric Power Annual, 2006, DOE/EIA-348(2006) (Washington, DC, Nov 2007), Table 8.3.
[278] TVA has substantial nonpower costs related to its substantial support of a water transportation network and its stewardship role as conservator of public lands. General Accountability Office, Bonneville *Power Administration, Better Management of BPA’s Obligation to Provide Power is Needed to Control Future Costs*, GAO-04-694, (Washington, DC, July 2004), p. 18.

the benefits of cheap power to their customer base. In a regulated environment, selling relatively cheap power at below-market prices does not involve a form of government support, as long as the power is sold without preference. However, by law certain classes of customers, such as municipalities, cooperatives, etc., have preferential access to Federal electricity. Thus, one could argue that it is the policy of preference, not price, which is the conveyance of Federal government support. However, this conveyance has a value in any economic environment, whether rate-regulated or free market, but it can more readily be estimated in a market where prices are freely set by supply and demand.

As wholesale electricity markets have been making a transition to more complete competition (a transition that has been in effect for a number of years), market forces have played a greater role in determining price.[279] In contrast to the rate-regulated environment, in a pure market-based environment, low-cost power producers become profit maximizers. Whatever cost advantage these producers possess relative to their competitors could be captured in the form of rents. Low-cost producers would have little incentive to price their power at anything other than market clearing rates, which in a competitive environment would be equal to the industry's marginal cost of power. Moreover, in a pure market environment, producers would be free to sell their electricity to the highest bidders without the constraints of a preferential customer class. In a purely competitive environment, the extent to which Federal power prices fell below the prices charged for similar power by competing utilities would constitute Federal support to the buyers of Federal power.

Electricity Markets

The electricity market has two distinct segments, wholesale and retail power markets. Wholesale markets comprise the resale and purchase of electricity among utilities and nonutility power producers for sale to ultimate consumers. Wholesale trade transactions are categorized by the service provided: full or partial requirements, firm or non-firm, etc. Generally, different services have different associated costs of service and, under cost-of-service regulation, have different prices. Prices of wholesale electricity sales (including the PMAs) are subject to approval by the Federal Energy Regulatory Commission, with the exception of the TVA.[a] Retail electric sales are sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes.

[a] The TVA and its regulatory exception are discussed later in this chapter.

A comparison is made in this appendix between wholesale power prices charged by the four power marketing administrations (PMAs), along with the Tennessee Valley Authority (TVA), and wholesale prices charged by nearby IOUs. The intent of the comparison is to ascertain whether Federal utilities provide power at rates below those charged by neighboring IOUs, thus providing their customers with an advantage unavailable to other consumers. Accordingly, the value of the price differential between rates charged by Federal utilities and those charged by neighboring IOUs should be seen as a rough estimate of any price advantage enjoyed by the customers of Federal utilities.

Federal utilities as a group have mainly wholesale customers, none of their end-use customers are classified as residential or commercial.[280] In general, their end-use customers are bulk purchasers, such as the U.S. Department of Energy's National laboratories and aluminum smelters in the Pacific Northwest.

Although most Federal utilities' power prices are often set in advance (and in the case of the PMAs, with oversight by the U.S. Department of Energy and the Federal Energy Regulatory Commission), prices can fluctuate due to a number of circumstances. For instance, low water levels can force Federal utilities to purchase relatively high-cost power to meet their load needs. As a result, even though Federal utilities price their power in advance to meet their operational and borrowing needs, in some years Federal utilities post modest profits or losses. The PMAs also have some flexibility in terms of rate adjustments and in some years mid-year rate adjustments are needed to avoid losses. In making a rate adjustment, the PMAs are required to notify their customers through a Federal Register Notice, followed by public

[279] There have been some notable reversals in the trend toward State deregulation, such as in the cases of Arizona and Virginia.
[280]The customers of Federal utilities in turn sell Federal power to municipals, cooperatives, and IOUs do in turn sell that power to residential and commercial end users. For instance, the Memphis Light Gas and Water Division accounted for 9.1 percent of TVA's sales in 2006. Source: Tennessee Valley Authority, Tennessee Valley Authority 2006 Annual Report, p. 9.

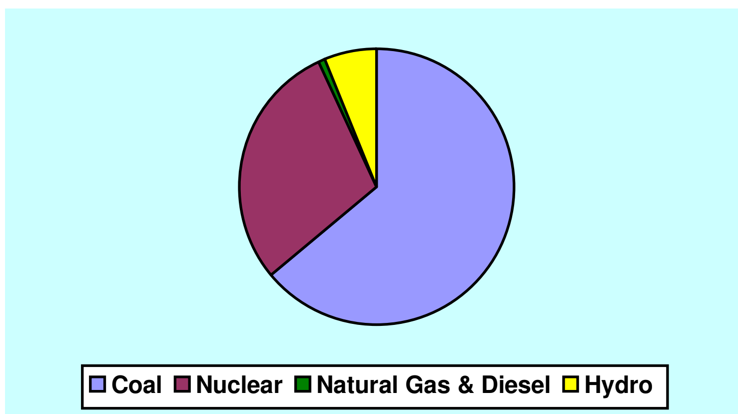
hearings.[281] The Secretary of Energy and the Federal Energy Regulatory Commission must approve any rate adjustments.[282]

TVA's Prices Relative to Neighboring IOUs

In 2006, TVA's average wholesale revenues were somewhat higher than the rates in the territories of neighboring utilities as measured by the Southeastern Electric Reliability Council (SERC) region's average wholesale power costs. In 2006, TVA's average wholesale revenues were 5.8 (2007 dollars) cents per kilowatthour, compared with an average of 5.5 cents per kilowatthour for utilities operating in the SERC region as a whole. As a result, EIA estimates an implicit negative subsidy value of $421 million is being paid for by recipients of TVA power. TVA's prices relative to SERC prices vary from year to year and in some years TVA's wholesale prices are greater than SERC prices and sometimes lower. Since 1998, TVA's prices have exceeded the SERC average wholesale prices in 5 years. In those years where TVA's prices fell below those of surrounding utilities, the price-based subsidy estimate would be positive.

TVA's current electricity prices in large measure reflect past investment decisions. TVA maintains an asset base which combines relatively low-cost hydroelectric and coal plants with relatively high- cost nuclear plants. Although the TVA faces very favorable variable costs largely due to its hydroelectric and coal plants, due to its inoperable nuclear power plants, its financing costs relative to revenues are significantly higher than neighboring utilities, thus raising TVA's fixed costs. Even though the TVA has not brought deferred assets and terminated nuclear assets of $5.4 billion (2007 dollars) into its rate base,[283] interest payments on the underlying borrowings are passed on to ratepayers and thus serve to elevate TVA's electricity prices.[284]

Figure B1. TVA Net Generation by Energy Source (percent)



Source: TVA, SEC 10-K, 2006.

Nuclear power accounted for 64 percent of TVA's investment in generating assets in 2006, while providing 29 percent of its gross generation (Figure B1). In contrast, fossil fuels and hydropower, which accounted for 33 percent of the utility's generation assets, provided 70 percent of its generation.[285] Due to its dependence upon coal and nuclear, and to a lesser extent hydro, TVA's variable costs tend to be low relative to surrounding utilities. However, this cost advantage is eroded to a great extent by TVA's high debt payments relative to surrounding utilities—a result of its past high-cost, nuclear-related investments.

BPA's Prices Relative to Neighboring Investor-Owned Utilities

More than 90 percent of the electricity sold by BPA is produced from Federal hydroelectric facilities; the remainder comes from one nuclear power plant. The average revenues derived from BPA's wholesale electricity sales are, in general, lower than those of competing utilities in BPA's operating region and much

[281] In a General Accountability Office report entitled *Power Marketing Administrations Repayment of Power Needs Closer Monitoring,* the GAO found Department of Energy and Federal Energy Regulatory Commission oversight on PMA rate adjustments to be perfunctory. *Power Marketing Administrations Repayment of Power Needs Closer Monitoring* GAO/AIMD-98-164 (Washington, DC, June 1998), pp. 7 and 8.

[282] Federal Energy Regulatory Commission (FERC) review is required under Department of Energy Delegation Order 0204-108. Department of Energy review is required under the Department of Energy Organization Act of 1977 (Public Law 95-91). Bonneville is an exception as it is required to only obtain FERC approval.

[283]At $3.3 billion (2007 dollars) in 2006, TVA's deferred assets and terminated nuclear assets were down substantially from the $7.8 billion in terminated nuclear assets in 1998

[284]Over the course of a year utilities' prices can fluctuate apart from any preset rates. In a low rainfall year, utilities are sometimes forced to purchase higher priced power to meet their load requirements.

[285] Tennessee Valley Authority SEC 10-K, 2006, pp. 11, 90 and 93.

lower than those of IOUs operating outside the Pacific Northwest. Clearly, BPA's lower average revenue is due to its heavy dependence on relatively inexpensive hydroelectric power. BPA hydroelectric capacity accounts for more than 90 percent of its total capacity. By comparison, 67 percent of the total capacity in the Pacific Northwest is hydroelectric. Only one major utility in the Pacific Northwest region sold more hydroelectricity than BPA, although, in general, other utilities in the region also tend to be heavily dependent on hydropower. The ample hydroelectric resources in the Pacific Northwest also allow neighboring utilities to charge rates substantially lower than those in the rest of the Nation.

Traditionally, electric power in the Northwestern United States has been much cheaper than in most of the rest of the country. In 2006, electricity prices averaged 9.04 cents (2007 cents) per kilowatthour for the United States as a whole, 5.01 cents per kilowatthour in Idaho, 6.28 cents per kilowatthour in Washington, and 6.68 cents per kilowatthour in Oregon (Table B1).

Table B1. Average Price per Kilowatthour for the United States, Selected States by End-Use Sectors, 2006 (2007 Cents per kWh)

State	All Sectors	Residential	Commercial	Industrial
Washington	6.28	6.96	6.69	6.47
Oregon	6.68	7.64	7.14	6.65
Idaho	5.01	6.25	5.23	5.54
Nationwide	9.04	10.63	9.57	6.22

Source: Energy Information Administration *Electric Power Monthly, March 2007*, DOE/EIA-0226 (2007/03) Table 5.6.B, http://tonto.eia.doe.gov/ftproot/electricity/epm/02260703.pdf. Accessed October 15, 2007.

Residential users in the Pacific Northwest are also among the beneficiaries of BPA's low-cost hydropower production. Residential electricity prices in Idaho averaged 6.25 cents per kilowatthour in 2006 (2007cents), the lowest in the United States. In contrast, the average price per kilowatthour for residential users in the United States as a whole was 10.63 cents. Similar price benefits were realized by commercial and industrial electricity consumers in the Pacific Northwest.

To measure the value of BPA's relative price advantage, a comparison was made between BPA's average wholesale revenue per kilowatthour and those of nearby utilities. In 2006, BPA's average revenue per wholesale kilowatthour was 3.0 cents (2007 cents), as compared with 4.8 cents for surrounding utilities (Table B2).[286]

Table B2. Implied Support for BPA Based on Market Rates,1998 and 2006 (million 2007 dollars)

Year	Wholesale Revenues (Million 2007 Dollars)	Revenues at Implied Market Prices (Million 2007 Dollars)	Implied Revenue Foregone (Million 2007 Dollars)	Average Prices of Wholesale Electricity Sales (2007 Cents per Kilowatthour)		Revenue Foregone per Unit of Electricity Sold (2007 Cents per Kilowatthour)
				WECC Regional Average	BPA Average	
1998	1,333,447	2,195,299	861,853	3.2	1.9	1.2
2006	2,716,306	4,333,116	1,616,809	4.8	3.0	1.8

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report," 1998 and 2006.

[286] Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report, "

The difference in revenue provides a measure of the price support provided to the recipients of BPA's low-cost Federal power. If BPA were able to sell its electricity at the same prices as surrounding utilities, its revenues would increase by $1.6 billion (2007 cents). This amounts to the difference in revenues that would be realized by BPA if BPA raised its electricity rates to the levels of competing utilities, minus the revenue actually realized by BPA. In 1998, the implied revenue foregone associated with BPA's relatively lower prices was $862 million (2007 cents). Even though BPA saw an increase in its wholesale prices between 1998 and 2006, the percent increase in wholesale prices for surrounding utilities was even greater.

BPA's price advantage is in large measure due to its low-cost hydroelectric power plants, which were built with relatively cheap Federal government financing. Although its prices are among the lowest in the region, the utility has a high concentration of nonperforming assets and debt, which causes its prices to be higher than they would be otherwise. For the most part, BPA's nonproductive assets and debt, like those of TVA, were accumulated as a result of a large-scale nuclear power program occurring in the 1970s. BPA guaranteed much of the debt of the Washington Public Power Supply System (WPPSS), which was owned by a group of municipal utilities in Washington State. WPPSS began construction of five nuclear power plants in the mid-1970s, but the projects were beset by cost overruns, schedule delays, and mudslides. BPA is currently financing debt on three of the five nuclear power plants (Projects 1, 2, and 3).[287] In 2006, BPA carried $3.9 billion in partially completed nuclear power plants on its balance sheet.

BPA's wholesale electricity prices have risen considerably since 1998 but so too have those of competing utilities. In the future, BPA will have slightly more leeway in raising prices; effective Oct. 1, 2006, BPA has the ability to formulaically adjust rates up to $300 million annually to make up for any revenue shortfalls. In the fiscal year 2007 budget, the Office of Management and Budget proposed a revenue enhancer for BPA, stipulating that whatever profits BPA realizes as a result of a high precipitation year were to be used to pay down debt rather than to reduce rates.

PMA Prices Relative to Neighboring Investor-Owned Utilities

The prices charged by the three smaller PMAs are among the lowest available in the United States. Since their establishment, Congress has mandated that the three smaller PMAs sell their power at the "lowest possible rates consistent with sound business principles." Like BPA and TVA, the three smaller PMAs are required to provide certain classes of customers with preference power.

Average wholesale prices charged by the three smaller PMAs are considerably below those charged by nearby IOUs; however, they have increased significantly since 1998. The average price realized by SEPA in 2006 was 4.0 cents (2007 cents) per kilowatthour. Although considerably higher than the average price in 1998 (2.3 cents per kilowatthour), it was still cheaper than the surrounding North American Electric Reliability Corporation (NERC) region, (i.e., the Southeastern Electric Reliability Council or SERC). The SERC price was 5.5 cents per kilowatt hour in 2006 (Table B3).

For SWPA, the average wholesale price was 4.5 cents per kilowatthour (versus 1.7 cents in 1998), compared with 4.8 cents for neighboring IOUs in 2006. For WAPA, average wholesale prices equaled 2.4 cents (versus 1.9 cents in 1998) cents per kilowatthour, compared with 4.8 cents for neighboring IOUs in 2006. If the three smaller PMAs charged the same prices as those of competing IOUs, their combined average wholesale prices would climb by $873 million (2007 dollars). These differences in revenue and price can be viewed as a form of Federal support to the customers of the three smaller PMAs.

[287] Projects 4 and 5 defaulted on the dept in the 1980s, an event known at the time as the "Whoops Default." This default, at $2.25 billion, was the largest municipal default in U.S. history.

Table B3. Computation of Implied Support for Small PMAs on a Market Price Basis, 1998 and 2006 (millions 2007 dollars)

PMA	Wholesale Revenues (Million 2007 Dollars)	Revenues at Implied Market Prices (Million 2007 Dollars)	Implied Revenue Foregone (Million 2007 Dollars)	Average Prices from Wholesale Electricity Sales (2007 Cents per Kilowatthour)		Revenue Foregone per Unit of Electricity Sold (2007 Cents per Kilowatthour)
				Nearby NERC Regional Average	Federal PMA Average	
Power Marketing Administration (1998)						
SEPA	208	455	247	5.1	2.3	2.8
SWPA	113	249	136	3.2	1.7	1.5
WAPA	770	1,263	493	3.2	1.9	1.3
Power Marketing Administration (2006)						
SEPA	209	290	82	5.5	4.0	1.5
SWPA	106	117	11	4.8	4.5	0.3
WAPA	816	1,596	780	4.8	2.4	2.4

Sources: Energy Information Administration, Form EIA-861, "Annual Utility Report," 1998 and 2006, Southeastern 2005 Annual Report, Southwestern 2004-2006 Annual Report, and Western Area Power Administration 2006 Annual Report and corresponding 1998 reports.

Return on Asset Support

Another measure is used to estimate the value of Federal revenues forgone when returns on Federal electricity assets fall short of the returns on similar assets held by IOUs. This measure is comparable to the standard method used by electricity regulatory bodies to determine the appropriate rate base in reviews of IOU rate filings. Historically, the structure of the electric utility industry has been predicated on the concept that the industry was a natural monopoly. The result was traditional rate base regulation for IOUs, designed to protect consumers by ensuring reliability and a fair revenue requirement to electric utility shareholders. The revenue requirement was based on operating costs and a reasonable return on the rate base (invested capital) of the utility. Rate schedules were based on the cost of service for different customer classes and projected sales for each customer class to capture the necessary revenue requirement. This section compares Federal utility rates of return against those of IOUs to estimate the value of Federal support to consumers of Federal power.

Over the long term, IOUs must earn a sufficient return on invested capital to satisfy their shareholders. Historically, U.S. regulators have taken this into account when setting the price of electricity for private utilities. If sales of services provided by government-owned assets provide a below-market return on the assets, a preferential benefit is being conferred on customers. This approach measures the value of forgone Federal utility revenue required for the Federal utilities to realize a market rate of return on their assets, i.e., the “opportunity cost” of the return on those assets. A simplified textbook definition of cost for a private-sector electric utility equates with operating cost less depreciation of capital assets plus some allowance for cost of capital. The extent to which actual Federal utility earnings from electricity sales fall below what they would have earned by charging market rates consistent with IOU rates of return constitutes a support to the purchasers of Federal power, with the amount of the support equal to the difference between revenues sufficient to provide a market return on capital and revenues at the actual selling price.

Like the estimates of market price and interest rate support, estimates of return on asset support are not perfect measures of the support provided to the preferred customers of Federal utilities. As stated above, U.S. electricity markets are heavily regulated, and the assets utilities have in place today were not fully developed under competitive market conditions. There are also two notable distinctions between the IOUs and the Federal utilities. One, is Federal utilities are not subject to paying Federal taxes; the other is that Federal utilities do not have to raise equity, as they are entirely debt-financed. The return on asset calculation addresses these issues in part by comparing a Federal utility rates of return (net operating income over plant and equipment) with an IOU rate of return prior to taxation and payments of dividends (again net operating income over plant and equipment).

Although most Federal utility power prices are often set in advance (and in the case of the PMAs, approved by the U.S. Department of Energy and the Federal Energy Regulatory Commission), prices can fluctuate due to a number of circumstances. Low water levels can force Federal utilities to purchase power to meet their load needs. As a result, even though Federal utilities price their power to meet their operational and borrowing needs, in some years Federal utilities post modest profits or loses.

TVA's Return on Capital

The TVA sets electricity prices, unlike IOUs, not based upon a just and reasonable rate of return but instead based upon its cash requirements which include servicing its debt. The TVA needs neither Federal Energy Regulatory Commission nor State utility commission approval to set its rates. This report uses two measures of comparative financial performance to measure TVA's return on capital against the return on capital realized by IOUs. The first measure is net income before interest divided by net utility assets, without consideration of deferred assets such as TVA's inoperable nuclear plants. The second measure incorporates these assets of into the denominator.

IOUs as a group earned a 9.61-percent operating rate of return on investment in 2006 (Table B4). In contrast, TVA, excluding its deferred assets, realized a 7.16-percent rate of return and a 5.43-percent rate of return including its deferred assets in 2006.[288] Without its deferred assets, TVA's generating revenues sufficient to earn an 9.61-percent operating return for TVA would require that TVA increase its prices so that revenue rose by $509 million. To generate a rate of return equal to the IOUs when including TVA's deferred nuclear assets would imply a revenue increase of $1.1 billion.

Table B4. Tennessee Valley Authority's Return On Assets Estimates, 1998 and 2006

IOU Comparison	Net Plant and Equipment	Actual Revenue	Operating Income	Average Return (Percent)	Implied IOU Rate of Return (Percent)	Implied Federal Government Support	Operating Income with IOU Rate of Return
1998 (million 2007 dollars)							
No Deferred Assets	25,277	8,272	2,666	10.55	12 49	490	3,156
Deferred Assets	34,420	8,272	2,666	7.75	12.49	1,632	4,298
2006 (million 2007 dollars)							
No Deferred Assets	20,769	9,185	1,486	7.16	9.61	509	1,995
Deferred Assets	27,355	9,185	1,486	5.43	9.61	1,141	2,628

Sources: Tennessee Valley Authority, SEC 10-K, *2006* and 1998 Annual Report, FERC Form 1 data via Global Energy Decisions Inc.

The operating return on assets measures were chosen, rather than the more familiar net income or return on equity, in order to abstract from the differing roles of debt for public-sector versus private-sector utilities. Public-sector utilities sometimes have debt that equals or exceeds their assets, and they set prices so that there is little or no net income remaining after interest payments.

BPA's Return on Capital

As with the TVA, an assumption is made here that if BPA were to realize the same rate of return on assets as IOUs, then an appropriate adjustment to its prices, revenues, and operating income would be needed. Like the other Federal utilities, BPA is not expected, on average, to realize a positive rate of return. Rather, its rates are expected to cover costs and nothing more. A positive rate of return is possible, however, given unforeseen changes in the operating environment. For instance, BPA is heavily reliant on

[288] Because TVA does not pay Federal taxes, the after-tax and pre-tax net income values are the same. The TVA does make payments to States in lieu of taxes. These payments equaled $376 million in 2006, or about 4 percent of revenues (Source: Tennessee Valley Authority, Tennessee Valley Authority 10K 2006, p. 22.

hydropower. With rates set in advance, income can vary considerably based on annual precipitation in the Pacific Northwest.

The first measure of operating rate of return uses operating income over net utility assets excluding deferred nuclear assets. The IOUs realized a 9.61-percent rate of return in 2006, as compared with a 7.76-percent rate for BPA (Table B5). The second measure includes deferred regulatory assets as plant and equipment. In the case of BPA, its $4 billion in deferred assets are primarily related to its non-operational nuclear power plants. Excluding BPA's deferred assets, realizing a 9.61-percent rate of return would provide BPA with additional revenues of $294 million. Including BPA's deferred nuclear power plants in calculating a return on assets yields a 6.16-percent rate of return. Using this measure, BPA would have had to raise revenue by $693 million in order to achieve the IOU rate of return Although the interest costs associated with BPA's deferred nuclear power plants are recovered in BPA's prices, these facilities provide limited, if not negative value, to the utility's asset base.

Table B5. Return On Assets Estimates for Bonneville Power Administration, 1998 and 2006

IOU Comparison	Net Plant and Equipment	Actual Revenue	Operating Income	Average Return (Percent)	Implied IOU Rate of Return (Percent)	Implied Federal Government Support	Operating Income with IOU Rate of Return
1998 (million 2007 dollars)							
No Deferred Assets	18,445	2,844	1,073	5.82	12.49	1,230	2,303
Deferred Assets	23,680	2,844	1,073	4.53	12.49	1,883	2,957
2006 (millions 2007 dollars)							
No Deferred Assets	15,939	3,692	1,237	7.76	9.61	294	1,531
Deferred Assets	20,095	3,692	1,237	6.16	9.61	693	1,930

Sources: Bonneville Power Administration 1998 and 2006 Annual Reports and FERC Form 1 via Global Energy Decisions Inc.

PMA Returns on Capital

The method used to measure the difference between the returns on assets for the three smaller PMAs and those for the IOU comparison group is exactly the same as used for BPA and TVA. As a group the 3 PMAs realized revenue in excess of expenses in 2006 so their rate of return on investment was nearly zero.[289] The first measure of operating rate of return uses net income before interest and taxes divided by net utility assets. For the comparative IOUs this rate equaled 9.61 percent versus 0.77-percent for the 3 smaller PMAs. The two other measures incorporate the deferred assets of the IOUs—largely involving unfinished nuclear power plants—into a before-tax and after-tax basis.

Generating revenues sufficient to earn a 9.61-percent operating return for three smaller PMAs would require that they increase their prices sufficient to achieve a revenue gain of $512 million (Table B6) versus $735 million to realize the IOU 12.49-percent rate of return seen in 1998. The 3 smaller PMAs carry no significant inoperable plant and equipment.

[289] Note: For SWPA, balance sheet data for the Army Corp of Engineers assets were not available for the years 2004 through 2006. For WAPA and SEPA, 2006 data were not available. As a consequence, subsidy data were extrapolated based upon the latest reported data year using the gross domestic product (GDP) implicit price deflator. Also note that the Western Area Power Administration reported a loss in 2006, as it did in the prior 6 years. These losses have been attributable to an unusually low precipitation in the western United States.

Table B6. Three Smaller PMAs Returns on Net Power Plant and Equipment (million 2007 dollars)

IOU Comparison	Net Plant and Equipment	Actual Revenue	Operating Income	Average Return (Percent)	Implied IOU Rate of Return (Percent)	Implied Federal Government Support)	Operating Income with IOU Rate of Return
1998 (millions 2007 dollars)							
No Deferred Assets	7,343	1,070	182	2.48	12.49	735	917
Deferred Assets	7,343	1,070	182	2.48	12.49	735	917
2006 (millions 2007 dollars)							
No Deferred Assets	5,795	1,131	44	0.77	9.61	512	557
Deferred Assets	5,795	1,131	44	0.77	9.61	512	557

Sources: Western Area Power Administration 2006 Annual Report, Southwestern Power Administration 2004-2006 Annual Report, Southeastern Power Administration 2005 Annual Report. FERC Form 1 data via Global Energy Decisions Inc.

Appendix C
Historic Perspectives on Energy Tax Expenditures

Historic Perspectives on Energy Tax Expenditures

This appendix provides a historic perspective on energy-related tax expenditures in the United States. The Treasury Department began to report tax expenditures in 1967 (Table C1). The reporting of tax expenditures as a part of the budget process was mandated by the Congressional Budget Act of 1974 (Public Law 93-344). The budget of the U.S. Government defines tax expenditures as "revenue losses due to preferential provisions of the Federal tax laws, such as special exclusions, exemptions, deductions, credits, deferrals, or tax rates." Although the concept of what constitutes a tax expenditure is clear, the determination of what exactly is a preferential provision is subject to interpretation. In preparing this section on energy-related tax expenditures, the EIA relied entirely on the definitions of tax expenditures presented in Office of Management and Budget (OMB) documents and the staff of the Joint Committee on Taxation.

Energy policy has been shaped by the prevailing condition of the overall economy, political concerns, and the condition of energy markets. The introduction of new tax expenditures are generally associated with major milestones in energy policy. As a result, the focus of energy-related tax expenditures has changed considerably over time. The earliest energy-related tax expenditures go back to World War I and were directed at encouraging more domestic oil and natural gas production. The expensing of exploration and production and percentage depletion were the primary agents used to achieve this goal.[290,291] Prior to the second oil embargo of 1979, oil and natural gas remained the focus of most tax expenditures.

In 1967, overall energy tax expenditures were estimated at $8.0 billion (2007 dollars). There were only three energy-related tax expenditures reported that year. Excess over cost depletion, at $6.4 billion (2007 dollars) was far and away the largest tax expenditure for that year, amounting to 81 percent of all revenue foregone as a result of energy-related tax expenditures. Between 1967 and 2007, the estimated loss was equal to $108 billion.[292] The next largest item, expensing of exploration and development costs, was estimated at $1.5 billion (2007 dollars). Since 1967, the revenue losses associated with this expenditure are estimated to be roughly $54 billion.[293] Capital gains treatment from royalties on coal came in third in 1967, at $25 million (2007 dollars).

[290] Expensing of exploration and development costs was based on regulations issued in 1916 while the excess of percentage over cost depletion appeared in 1926. The percentage over cost depletion stems from the Revenue Act of 1916 which first recognized that the depletion of oil and natural gas as a tax deduction. Source: Congressional Budget Office, Tax Expenditures Budget Control Options and Five-Year Budget Projections for Fiscal Years 1983-1987 (Washington, DC, November 1992), Table C1.

[291] A court invalidated the expensing of exploration and development costs in 1945, but Congress subsequently gave its approval to the treatment, and it became law in 1954.

[292] Based upon estimates appearing in the United States General Accounting Office publication, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work*, GAO/RCED-00-301R (Washington, DC, September 2000) and data appearing in the Office of Management and Budget's *Analytical Perspectives of the U.S. Budget* 2008, 2006, 2004, and 2002.

[293] Based upon estimates appearing in the United States General Accounting Office publication, *Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work*, GAO/RCED-00-301R (Washington, DC, September 2000) and EIA estimates based upon data appearing in the Office of Management and Budget's *Analytical Perspectives of the U.S. Budget* 2008, 2006, 2004, and 2002.

Table C1. Current and Historic Tax Expenditures, Selected Years, 1967 to 2007 (million 2007 dollars)

	1967	1974	1976	1981	1984	1992	1996	2004	2005	2006	2007
Expensing of Exploration and Development Costs	1,489	2,835	2,375	5,537	2,226	-76	-265	282	410	695	860
Expensing of Tertiary Outlays	-	-	-	-	-	27	-	-	-	-	-
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	-	-	-	-	-	110	63	22	42	31	30
Excess of Percentage over Cost Depletion	6,453	7,240	4,662	5,366	3,629	1,023	1,422	672	621	777	790
Capital Gains Treatment of Royalties on Coal	25	17	177	181	324	14	19	76	95	164	170
Alternative Fuel Production Credit	-	-	-	50	35	618	720	1,127	2,441	3,046	2,370
Alcohol Fuel Credit	-	-	-	-	9	110	13	33	42	51	50
Exclusion of Interest on state and local Industrial Development Bonds used for Energy Production Facilities	-	-	-	-	53	172	398	-	-	-	-
Exclusion of Interest on Energy Facility Bonds	-	-	-	-	-	-	-	108	84	41	40
Enhanced Oil Recovery	-	-	-	-	-	-	101	358	316	-	-
Residential Energy Credits	-	-	-	231	-	-	-	-	-	-	-
New Technology Credit	-	-	-	-	-	62	38	358	252	521	690
Alternative Conservation and New Technology Credits Supply Incentives	-	-	-	451	368	-	-	-	-	-	-

Table C1. Current and Historic Tax Expenditures, Selected Years, 1967 to 2007 (million 2007 dollars)

	1967	1974	1976	1981	1984	1992	1996	2004	2005	2006	2007
Residential Energy Credits Conservation Incentives	-	-	-	853	-	-	-	-	-	-	-
Tax Credit and Deduction for Clean-Burning Vehicles and Properties	-	-	-	-	-	-	82	-	-	-	-
Tax Credit and Deduction for Clean-Burning Vehicles	-	-	-	-	-	-	-	76	74	112	260
Alternative Conservation and New Technology Credits Conservation Incentives	-	-	-	592	61	-	-	-	-	-	-
Alcohol Fuel Exemption	-	-	-	177	377	747	847	1,571	1,578	2,627	2,990
Exclusion from Income of Conservation Subsidies Provided by Public Utilities	-	-	-	-	-	-	190	108	84	112	110
Credit for Holding Clean Renewable Energy Bonds	-	-	-	-	-	-	-	-	-	20	60
Deferral of Gain From Dispositions of Transmission Property to Implement FERC Restructuring Policy	-	-	-	-	-	-	-	-	-	634	530
Credit for Production from Advanced Nuclear Power Facilities	-	-	-	-	-	-	-	-	-	-	-
Credit for Investment in Clean Coal Facilities	-	-	-	-	-	-	-	-	515	-	30
Temporary 50-Percent Expensing for Equipment used in the Refining of Liquid Fuels	-	-	-	-	-	-	-	-	-	10	30
Pass Through from Sulfur Diesel Expensing to Cooperative Owners	-	-	-	-	-	-	-	-	42	-	-

Table C1. Current and Historic Tax Expenditures, Selected Years, 1967 to 2007 (million 2007 dollars)

	1967	1974	1976	1981	1984	1992	1996	2004	2005	2006	2007
Natural Gas Distribution Pipelines being Treated as 15-Year Property	-	-	-	-	-	-	-	-	-	20	50
Amortized all Geological and Geophysical Expenditures over 2 Years	-	-	-	-	-	-	-	-	-	10	60
Allowance for the Deduction of Certain Energy Efficient Commercial Building Property	-	-	-	-	-	-	-	-	-	82	190
Credit for Construction of New Energy Efficient Homes	-	-	-	-	-	-	-	-	-	10	20
Credit for Energy Efficiency Improvements to Existing Homes	-	-	-	-	-	-	-	-	-	235	380
Credit for Energy Efficient Appliances	-	-	-	-	-	-	-	-	-	123	80
30 % Credit for Residential Purchase/Installation of Solar and Fuel Cells	-	-	-	-	-	-	-	-	-	10	10
Credit for Business Installation of Qualified Fuel Cells and Stationary Microturbine Power Plants	-	-	-	-	-	-	-	-	-	82	90
Alternative Fuel and Fuel Mixture Tax Credit	-	-	-	-	-	-	-	-	158	-	-
Partial Expensing for Advanced Mine Safety Equipment	-	-	-	-	-	-	-	-	-	-	10
Expensing of Capital Goods with Respect to Complying with EPA Sulfur Regulations	-	-	-	-	-	-	-	-	11	10	10
Biodiesel and Small Agri-Biodiesel Producer Tax Credits	-	-	-	-	-	-	-	-	32	92	180

Table C1. Current and Historic Tax Expenditures, Selected Years, 1967 to 2007 (million 2007 dollars)

	1967	1974	1976	1981	1984	1992	1996	2004	2005	2006	2007
Exclusion of Special Benefits for Disabled Coal Miners	-	-	-	-	-	-	-	-	-	51	50
Transmission Property Treated as Fifteen-Year Property	-	-	-	-	-	-	-	-	-	3	18
Five-Year Net Operating Loss Carryover for Electric Transmission Equipment	-	-	-	-	-	-	-	-	-	74	43
Treatment of Income of Certain Electric Cooperatives	-	-	-	-	-	-	-	-	-	-	14
84-Month Amortization of Certain Pollution Control Facilities	-	-	-	-	-	-	-	-	2	10	30
Nuclear Decommissioning	-	-	-	-	-	-	-	-	-	123	199
Total	7,967	10,092	7,214	13,260	7,082	2,779	3,627	4,790	6,956	9,775	10,444

NOTE: Values for the Alcohol Fuel Credit were unobtainable for the years prior to 1996.

Sources: Office of Management and Budget, *Analytical Perspectives, 2006-2008*, Table 19-1. Congressional Budget Office, *The President's Fiscal Year 1979 Tax Expenditure Proposals*, (Washington, DC, April 1978); Congressional Budget Office, *The Effects of Tax Reform on Tax Expenditures*, (Washington, DC, March 1988), Table A-1, and Energy Information Administration, *Federal Energy Subsidies, Federal Interventions in Energy Markets*, (SR/EMEU/92-02)(Washington, DC, February 1992).

The late 1970s saw a second world oil supply shock and heightened environmental concerns brought on by a nuclear accident at the Three Mile Island nuclear plant and the Love Canal disaster. During this period, energy policy attempted to address energy security and environmental protection. In order to address prevailing gasoline shortages, the National Energy Act of 1978 (NEA 1978, Public Law 95-618) came into law. NEA 1978 included an alcohol fuels excise exemption, which eventually became one of the largest energy-related tax credits by the mid-1990s, and the largest tax expenditure in the year 2007. An important component of NEA 1978 was the Energy Tax Act. ETA 1978 established a 10-percent business investment tax credit for solar photovoltaic projects. The Act also established a 15-percent energy tax credit added to an existing 10-percent investment tax credit for solar thermal and wind generation facilities. For residences, ETA 1978 established a credit of 30 percent for the first $2,000 invested and 20 percent for the next $8,000 for investment in solar and wind energy equipment. This credit, along with its production tax credit counterpart, eventually fell under the category of new technology credit as defined by the Treasury. ETA also implemented a percentage depletion rate of 22 percent for geothermal deposits for 1978 to 1980, and 15 percent after 1983.

In anticipation that the NEA's removal of domestically-produced crude oil price controls would quickly lead to higher prices, the Crude Oil Windfall Profit Tax of 1980 (Public Law 96-223) was signed into law. Prior to passage of the act, the price of most domestically-produced crude oil was regulated. A phase-out of price controls was determined to be necessary to increase domestic supply. The Crude Oil Windfall Profit Tax also introduced an alternative fuels credit. This credit was directed at promoting the use of unconventional fuels. The tax credit, initially set at $3.00 per barrel of oil equivalent, was directed at the following fuels: (1) oil produced from shale and tar sands; (2) natural gas produced from geopressurized brine, Devonian shale, coal seams, tight formations, or biomass; (3) liquid, gaseous, or solid synthetic fuel produced from coal liquefaction and pressurization; (4) fuel from qualified processed wood; and (5) steam from solid agricultural byproducts. The alternative fuel production credit is often referred to as the Section 29 credit based upon its former Internal Revenue Service code.[294] In 2007, the alternative fuel credit was the second largest tax expenditure.

The second oil price shock also gave rise to several tax expenditures focusing on conservation and producing alternative sources of energy. By 1981, energy-related tax expenditures had climbed to $13.3 billion. This was probably a historic highpoint for energy-related tax expenditures even though the U.S. economy was less than half its current size and the population was about 25 percent smaller than today.[295] Although traditional tax expenditures continued to grow, new expenditures focused on alternative fuels, technologies, and conservation. The expensing of exploration and development now exceeded excess of percentage over cost depletion and amounted to a revenue reduction at $5.5 billion (2007 dollars). The value of excess over cost depletion fell considerably from 1967, and in 1981 equaled $5.4 billion (2007 dollars). Due to such legislation as the Energy Tax Act of 1978 and the Windfall Profit Tax of 1980, the number of energy-related tax expenditures climbed to 12, although two expenditures had de minimis values. In 1981, new tax expenditures included: residential energy credits conservation incentives ($853 million), new technology conservation incentives ($592 million), alternative conservation and new technology credit supply incentives ($451 million), residential energy credits supply incentives ($231 million), and the alternative fuel production credit ($50 million). The alcohol fuel credit was in effect for the first time that year but with a de minimis value, as was the case of the exclusion of interest on State and local government industrial development bonds for energy production facilities.

After peaking in 1981, energy prices moderated. For most of the low-energy price 1980s, there was little in the way of new tax expenditure initiatives and the 1980s witnessed a diminishment of the role of the Federal government in providing tax incentives to promote energy supply. During the 1980s, the Energy Tax Act of 1978 business energy tax credits was allowed to expire. The Tax Reform Act of 1986 (Public Law 99-514) eliminated the 10-percent investment tax credit and extended the energy tax credit until 1988, but it reduced that credit from 15 percent to 10 percent and eliminated wind as a candidate for any credits. By 1984, energy-related tax expenditures had fallen sharply, and overall revenue reductions

[294] The Treasury refers to the credit as the alternative fuel production credit. The IRS calls the credit the nonconventional fuel source credit. The corresponding IRS code is Section 29. See: http://www.irs.gov/irb/2006-18_IRB/ar06.html . Also, see *Budget of the United States Government Analytical Perspectives, Fiscal Year 2008* (Washington, 2007), p. 301.

[295] Tax expenditures are revised every year but not for all historic data. Revisions only go back a couple of years so it is difficult to discern which exact year saw a peak in these revenue loses. In constant dollars it appears that they peaked in the early 1980s.

related to energy amounted to $6.7 billion (2007 dollars) as the value of some programs were reduced or allowed to expire altogether. The value of tax expenditures related to the capital gains treatment of royalties on coal, the exclusion of interest on State and local industrial development bonds for certain energy facilities, the alternative conservation and technology credits, the alternative fuel production credit, and the alcohol fuel credit all declined. In addition to the eight electricity-related tax expenditures listed in the budget for that year, there was one tax exemption (alcohol fuels tax exemption).

During the early 1990s, once again, concerns over energy security and the environment led to passage of an omnibus energy bill, the Energy Policy Act of 1992 (EPACT 1992) (Public Law 102-486). EPACT 1992 was the most significant piece of energy legislation since 1980. The tax provisions of EPACT1992 focused on providing incentives that encouraged energy efficiency, renewable energy, and alternative fuels. Some of these incentives were directed at geothermal, electric vehicles, and solar power. The business tax credit (EPACT1992, Section 1916), which had been extended on a year-to-year basis up until 1992, was established as a permanent 10- percent business energy tax credit for investments in solar and geothermal equipment. Section 1914 of EPACT1992 established a 10-year, 1.5 cents per kilowatthour (kWh) production tax credit (PTC) for wind projects (privately-owned and investor-owned) and biomass plants using dedicated crops (closed-loop) placed in service between 1994 and 1993, respectively, and June 30, 1999.[296]

In 1992, the value of all tax expenditures (including the excise tax exemption) was estimated at $2.0 billion (2007 dollars). By 1995, the value of tax expenditures (again, including the excise tax exemption) had risen to $3.9 billion (2007 dollars). Still this was far less than the estimated 1981 value of $13.3 billion (2007 dollars) even though the number of energy subsidies had grown from seven to ten. The percentage over cost depletion tax expenditure retained its major role in the order of tax expenditures. However, the value of the alternative fuel production credit began to gain prominence. In 1995, at an estimated at $1.2 billion, this credit accounted for almost one-third of total tax expenditures.

The 1990s began with the first Persian Gulf War and a brief surge in petroleum prices. However, for the remainder of the decade, energy prices remained stable and concerns over energy security were diminished. For over a decade, no omnibus energy legislation was passed after EPACT1992. During most of the 1990s, the number of energy-related tax expenditures remained the same. However, in dollar terms, the Section 29 credit grew considerably, rising from $18 million (2007 dollars) in 1983 to $2.4 billion by 2005 (2007 dollars). The value of the Section 29 credit is expected to fall by more than half by 2008 and then disappear after that as the credit is phased out.[297] Largely due to rapidly growing usage of wind to supply electricity, the production tax credit, reported by the Treasury under the category “new technology credit,” has been the fastest growing major tax expenditure over the last few years. The value of the new technology credit is expected to remain strong throughout the remainder of the decade. In 2008, the new technology credit is expected to be the second largest tax expenditure and the second largest tax expenditure directed toward renewables.

The Energy Policy Act of 2005 and Other Recently Enacted Energy Tax Expenditures

The Energy Policy Act of 2005 (EPACT2005) (Public Law 109-58) and accompanying legislation moved the orientation of energy tax expenditures further towards energy efficiency and electricity. EPACT2005 represented the first major piece of Federal government energy legislation to emerge since the Energy Policy Act of 1992 (EPACT1992). The purpose of EPACT2005 was to address several energy issues such as America’s growing dependence on imported oil, rising environmental concerns, electricity industry restructuring, and the reliability of the Nation’s transmission system.

EPACT2005 embodied several new energy initiatives as well as expanding on several tax expenditures already on the books. Mainly as a result of EPACT2005 and accompanying legislation, there were 38 tax expenditure programs listed in the U.S. budget in 2007 versus 11 in the 1999 budget. Those tax expenditures aimed at

[296]Closed-looped biomass consist of crops grown, in a sustainable manner, for the sole purpose of bioenergy and bioproduct uses, which might include annual crops, such as corn and wheat, perennial crops, such as trees and shrubs, and grasses, such as switchgrass. Open-looped biomass is biomass that can be used to produce energy even though it was not grown specifically for this purpose. Examples of open-loop biomass include agricultural livestock waste and residues from forest harvesting operations and crop harvesting.

[297] The current primary recipient of the fuel, synthetic coal, loses its eligibility after January 1, 2008.

energy production totaled $10.4 billion (2007 dollars) in fiscal year (FY) 2007, a substantial rise from $4.8 billion (2007 dollars) in 2004, the year prior to passage of EPACT2005. EPACT2005 was intended to double the use of biofuels. EPACT2005 also added a number of measures that encouraged households and businesses to engage in greater conservation efforts.

EPACT2005 contained several provisions for alternative fuels and advanced technologies. The expenditures focused on achieving greater end-use energy efficiency are, however, short-lived or of relatively small monetary value. Due to EPACT2005, nuclear power for the first time became a beneficiary of future Federal tax expenditures. The production tax credits (PTC) allocated towards nuclear as a result of EPACT2005 are substantial. The PTCs target the construction of “new technology” nuclear plants. The owners of eligible plants will receive a 1.8-cents-per-kilowatthour credit. The credit is in effect for the first 8 years of plant operation. The Treasury Department has not projected the value of this expenditure because it anticipates no new eligible plants in commercial operation within its current forecast horizon, which runs through 2012. EIA’s *Annual Energy Outlook 2008* forecasts that 16,600 megawatts of new capacity will be added by 2030. Section 638 of EPACT2005 provided an insurance program, “standby support,” which provides up to $500 million to defer costs resulting from construction delays for the first two reactors and $250 million for the next four reactors.

By one estimate, EPACT2005 provided for about $14.5 billion in tax expenditures over an 11-year period.[298] Of this amount, $4.5 billion was allocated to renewables, $3 billion to coal, $3 billion to electricity, and $2.6 billion to oil and natural gas.[299] EPACT2005 places a considerable emphasis on renewable energy.[300]

Other legislation enacted contemporaneously with EPACT2005 also had a noteworthy impact upon energy-related tax expenditures. The Job Creation and Worker Assistance Act of 2002 (Public Law 107-147) extended the PTC through 2003 in March 2002. The PTC expired at the end of 2003 and lapsed until October 2004. It was extended through the end of 2005 by Section 313 of the Working Families Tax Relief Act of 2004 (Public Law 108-311). Section 710 of the American Jobs Creation Act of 2004 (Public Law 108-357) expanded the PTC to include open-loop biomass, geothermal energy, solar energy, small irrigation power, and municipal solid waste (landfill gas and trash combustion facilities).

Section 909 American Jobs Creation Act of 2004 also included provisions, which for the first time, addressed investment incentives for expanding Nation’s transmission grid. Although not an omnibus piece of energy-related tax legislation, the AJCA had a significant number of energy measures, the value of which is estimated at $5 billion.[301] The law amended the Internal Revenue Code to permit taxpayers to realize a gain from investments in qualifying electric transmission transactions ratably over an 8-year period if the gain from the sale is reinvested in certain exempt utility property. The law defined "qualifying electric transmission transaction" as the sale or other disposition before January 1, 2007, to an independent transmission company of: (1) property used in the trade or business of providing electric transmission services, or (2) any stock or partnership interest in such a trade. Section 1305 of EPACT 2005, extended the special tax treatment of capital through December 30, 2007.

In 2007, Congress also scaled back some of tax expenditures benefiting the oil and natural gas industry and to use the funds to promote renewable energy and energy efficiency. Title I of the Clean Energy Act of 2007 would have reduced oil and natural gas tax expenditures by $7.6 billion between 2007 and 2017.[302] These provisions were not included in the Energy Independence and Security Act of 2007 (Public Law 110-140).

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[298] Congressional Research Service, *Energy Policy Act of 2005: Summary and Analysis of Enacted Provisions*, (Order Code RL33302) (Washington, DC, March 8, 2006), p. 3.

[299] Congressional Research Service, *Energy Policy Act of 2005: Summary and Analysis of Enacted Provisions*, (Order Code RL33302) (Washington, DC, March 8, 2006), p. 3.

[300] Ibid.

[301] Congressional Research Service, CRS Report for Congress, *Energy Tax Policy: History and Current Issues*, (Order Code: RL33578) (Washington, DC, November 7, 2007), p. 11.

[302] Congressional Budget Office, H.R. 6, Clean Energy Act of 2007, Letter to Congressman Rahall, Chairman of the Committee on Natural Resources, January, 2007. Estimates were provided by the Joint Committee on Taxation.

Synthetic Fuels Corporation

Oil shale has long been used as a fuel source for naval vessels. In the early 20th century, three oil major oil shale reserve deposits were dedicated for naval use. The United States has the largest know oil shale deposits. Most oil shale deposits lie in Colorado, Utah, and Wyoming. The United States is estimated to have as much as 1.8 trillion barrels of oil shale, although not all of that is currently treated as an economically-recoverable fuel.[303] One midpoint range of recoverable reserves estimates indicates that the United States has more than triple the proven reserves of Saudi Arabia.[304] Although a relic of the past, the long defunct Synthetic Fuels Corporation (SFC) bears mentioning in this report because at one time it was intended to be the largest direct expenditure program in the Nation's history outside of wartime. Direct Federal spending on energy-related projects totaled $2 billion in 2007. Relative to spending during the last oil price spike during the late 1970s and early 1980s, this value looks quite moderate. The SFC was established as a government agency in the midst of the second oil price shock by the Energy Security Act of 1980 (Public Law 96-294). In 1981, crude oil prices reached roughly $37 per barrel (or $73 per barrel in 2007 dollars)[305] with widespread expectations that they were destined to go much higher. The SFC was abolished under the Consolidated Omnibus Budget Reconciliation Act (Public Law 99-272) in 1986, when oil prices declined to near-record lows. At one point, Congress and the President were negotiating spending a possible $88 billion on the program. In 1979, the Interior Department and Appropriation Act (Public Law 96-126) and the Supplemental Appropriations Act (Public Law 96-304) budgeted $18 billion ($42 billion in 2007 dollars) in financial incentives. By the time the program was terminated, total spending was estimated at $8 billion. The Windfall Profit Tax of 1980 provided funding for the SFC which was directed to develop synthetic gas, liquids from tar sands, coal, and shale.

The intention was for the SFC to team with private sector entities to eventually develop 0.5 million barrels of oil equivalent a day by 1987 and 2 million barrels by 1992. In essence, the SFC was to be an independent Federal entity, which was to function as an investment bank. Before being legislated out of existence, SFC funded four projects with long-term price guarantees. A Congressional Research Service report released in 1983 described the endeavor: "the Federal government and U.S. industry are embarking on the largest and most intensive effort ever undertaken to increase the production of synfuels..."[306]

Oil shale is currently eligible for a couple of tax credits in the form of the percentage depletion and the Section 29 credit discussed above. The Section 29 credit grew out of the Windfall Profit Tax of 1980 which occurred around the time of the genesis of the SFC. EPACT2005 showed renewed interest in oil shale declaring that "the development of oil shale, tar sands, and other strategic unconventional fuels are strategically important domestic resources that should be developed to reduce the growing dependence of the United States on politically and economically unstable sources of foreign oil imports." [307]To that end, EPACT2005 called for the development of a leasing of Federally-owned lands. The Secretary of the Interior is directed to make land in the states of Colorado, Utah, and Wyoming available for research and development activities to develop technologies capable of recovering liquid fuels from oil shale. For the

[303] Congressional Research Service, Oil Shale: History, Incentives, and Policy, (Order Code RL33359) (Washington, DC, April, 2006), Summary.
[304] Bartis, James, T, et al, "Oil Shale in the United States, Prospects and Policy Issues," Rand Corporation, ISBN 0-8330-3848-6, Prepared for the Department of Energy's National Energy Technology Laboratory, 2005. This study estimated that the price of low-sulfur, light crude oil, such as Texas intermediate, would need to be at least $75 to $95 per barrel for a first-of-a-kind oil shale operation to be profitable.
[305] Prices are the average U.S. wellhead price. Source: Energy Information Administration, Annual Energy Review 2006 (DOE/EIA-0384 (2006) (Washington, DC, June 2007), Table 5.18
[306] Congressional Research Service, Synthetic *Fuels Corporation and National Synfuels Policy* (Issue Brief Number IB81139) (Washington, DC, February, 1983), p. 1.
[307] Section 369, Energy Policy Act 2005, Public Law 109-58.

first 10 years, the royalty rate will be set at 1 to 3 percent of the value of gross production with States receiving half the value. The Mineral Leasing Act of 1920 (MLA) authorized the leasing of land for developing deposits of coal, phosphates, petroleum, natural gas and other minerals. MLA limited the size of a lease tract to 5,120 acres with the further restriction of preventing any corporation or individual from obtaining any more than one lease. Section 369 of EPACT 2005 increased the size of a lease tract to 5,760 acres, and allowed an individual to obtain up to 50,000 acres of oil shale leases in any one State.

Appendix D
Description of Bond Ratings

This appendix consists of a description of the various bond ratings used by bond-rating firm of Moody's Investor Services. The information was obtained from the State Treasury Office of the State of California.

Moody's - Definitions of Bond Ratings
Long-Term Issue Credit Ratings

Aaa	Bonds that are rated Aaa are judged to be of the best quality. They carry the smallest degree of investment risk and are generally referred to as "gilt edge." Interest payments are protected by a large or by an exceptionally stable margin and principal is secure. While the various protective elements are likely to change, such changes as can be visualized are most unlikely to impair the fundamentally strong position of such issues.
Aa	Bonds rated Aa are judged to be of high quality by all standards. Together with the Aaa group they comprise what are generally known as high grade bonds. They are rated lower than best bonds because margins of protection may not be as large as for Aaa securities, fluctuation of protective elements may be of greater amplitude, or there may be other elements present that make the long-term risks appear somewhat larger than in Aaa securities.
A	Bonds that are rated A possess many favorable investment attributes and are to be considered as upper medium grade obligations. Factors giving security to principal and interest are considered adequate, but elements may be present that suggest a susceptibility to impairment some time in the future.
Baa	Bonds that are rated Baa are considered as medium grade obligations, i.e., they are neither highly protected nor poorly secured. Interest payments and principal security appear adequate for the present but certain protective elements may be lacking or may be characteristically unreliable over any great length of time. Such bonds lack outstanding investment characteristics and in fact have speculative characteristics as well.
Ba	Bonds that are rated Ba are judged to have speculative elements; their future cannot be considered as well assured. Often the protection of interest and principal payments may be very moderate, and thereby not well safeguarded during both good and bad times over the future. Uncertainty of position characterizes bonds in this class.
B	Bonds that are rated B generally lack characteristics of the desirable investment. Assurance of interest and principal payments or maintenance of other terms of the contract over any long period of time may be small.
Caa	Bonds that are rated Caa are of poor standing. Such issues may be in default or there may be present elements of danger with respect to principal or interest.
Ca	Bonds that are rated Ca represent obligations that are speculative in a high degree. Such issues are often in default or have other marked shortcomings.
C	Bonds that are rated C are the lowest rated class of bonds, and issues so rated can be regarded as having extremely poor prospects of ever attaining any real investment standing.

NOTE: Since October 1996, Moody's has applied numerical modifiers 1, 2, and 3 in each generic rating classification from Aa to B. (see Moody's Expanded Public Finance Rating Symbols chart below). The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking, and the modifier 3 indicates that the issue ranks in the lower end of its generic category.

Source: State of California, State Treasurers Office: http://www.treasurer.ca.gov/ratings/moodys.asp, accessed October 11, 2007.

Appendix E
Types of Loans Available Through the Rural Utilities Service

Hardship Loans

Eligible Facilities: Distribution, subtransmission, and headquarters (service & warehouse) facilities

Eligible Borrowers: Retail providers that meet rate disparity thresholds and whose consumers fall below average per capita and household income thresholds or that have suffered a severe, unavoidable hardship, such as a natural disaster, as determined by the RUS Administrator

Interest Rate: 5 percent

Supplemental Financing Required: No

Loan Term: Term of loan not to exceed useful life of the facilities being financed, with a maximum term of 35 years.

Municipal Rate Loans

Eligible Facilities: Distribution, subtransmission, and headquarters (service & warehouse) facilities

Eligible Borrowers: Retail providers for all facilities; power supply providers for subtransmission and headquarters facilities

Interest Rate: Interest rates will be established quarterly by RUS based on interest rates available in the municipal bond market for similar maturities and is determined at the time of the advance

Supplemental Financing Required: Yes, generally 30 percent, except in the case of financial hardship as determined by the RUS Administrator and the first loan following a merger or consolidation

Loan Term: Term of loan not to exceed useful life of the facilities being financed, with a maximum term of 35 years. Power supply borrowers' loan term is also based on the term of its wholesale power contracts.

Treasury Rate Loans

Eligible Facilities: Distribution, subtransmission, headquarters (service & warehouse), and renewable generation facilities

Eligible Borrowers: Retail providers for all facilities; power supply providers for renewable generation facilities

Interest Rate: Interest rates will be established daily by the United States Treasury and is determined at the time of each advance

Supplemental Financing Required: No

Loan Term: Term of loan not to exceed useful life of the facilities being financed, with a maximum term of 35 years. Power supply borrowers' loan term is also based on the term of its wholesale power contracts.

FFB Guaranteed Loans

Eligible Facilities: Distribution, transmission (bulk and subtransmission), generation, and headquarters (office, service and warehouse) facilities

Eligible Borrowers: Retail and power supply providers

Interest Rate: Interest rates will be established daily by the United States Treasury. Added to that rate is one-eight of 1 percent. The interest rate is determined at the time of each advance

Supplemental Financing Required: No

Loan Term: Term of loan not to exceed useful life of the facilities being financed, with a maximum term of 35 years. Power supply borrowers' loan term is also based on the term of its wholesale power contracts.

Eligible Borrowers

Eligible borrowers are corporations, States, territories, and subdivisions and agencies thereof, municipalities, people's utility districts, and cooperative, non-profit, limited-dividend, or mutual associations that provide retail or power supply service needs in rural areas

Rates

Current interest rates for these loan programs may be found on the RUS “Rates” web site (http://www.usda.gov/rus/electric/rates.shtml#ffb).

Specific language on loan eligibility and terms can be found in RUS Rules and Regulations 7CFR Part 1714 (http://www.usda.gov/rus/electric/fr2002/fr09ap02-01.pdf). Loan policies and application procedures can be found in 7CFR Part 1710.”

Source: Rural Utilities Service: http://www.usda.gov/rus/electric/loans.htm, accessed October 11, 2007.

Appendix F Table of Authorizations and Regulations

Table of Authorizations and Regulations

The laws and regulations below provided the legal basis for the programs discussed in this report.

Public Laws:

Public Law 72-154 Revenue Act of 1932
Public Law 73-17 Tennessee Valley Act of 1933
Public Law 75-329 Bonneville Projects Act 1937
Public Law 78-534 Flood Control Act of 1944
Public Law 82-183 Revenue Act of 1951
Public Law 90-364 Revenue Expenditure Control Act of 1968
Public Law 91-173 Tax Reform Act of 1969
Public Law 91-177 Federal Mine Safety and Health Act of 1977
Public Law 93-344 Congressional Budget Act of 1974
Public law 93-454 Columbia River Transmission Act of 1974
Public Law 94-12 Tax Reduction Act of 1975
Public Law 95-91 Department of Energy Organization Act of 1977
Public Law 95-227 Black Lung Benefits Revenue Act of 1977
Public Law 95-618 Energy Tax Act of 1978
Public Law 96-126 Interior and Related Agencies Appropriation Act of 1980
Public Law 96-223 Crude Oil Windfall Profits Tax of 1980
Public Law 96-294 Energy Security Act of 1980
Public Law 96-304 Supplemental Appropriations Rescission Act of 1980
Public Law 96-493 Gasohol Competition Act of 1980
Public Law 96-499 Omnibus Reconciliation Act of 1980
Public Law 97-35 Low Income Home Energy Act 1981
Public Law 97-424 Surface Transportation Assistance Act of 1982
Public Law 97-425 Nuclear Waste Policy Act of 1982
Public Law 98-369 Deficit Reduction Act of 1984
Public Law 99-178 Department of Labor, Health and Human Services and Education and Related Agencies Appropriation Act of 1986
Public Law 99-272 Consolidated Omnibus Budget Reconciliation Act of 1986
Public Law 99-499 Superfund Amendments and Reauthorization Act of 1986
Public Law 99-510 Tax Reform Act of 1986
Public Law 99-519 Tax Reform Act of 1986
Public Law 99-514 Tax Reform Act of 1986
Public Law 100-494 Alternative Motor Fuels Act of 1988
Public Law 100-647 Technical Miscellaneous Revenue Act of 1988
Public Law 101-508 Omnibus Budget Reconciliation Act of 1990
Public Law 101-549 Clean Air Act Amendments of 1990
Public Law 102-486 Energy Policy Act of 1992
Public Law 103-66 Omnibus Budget Reconciliation Act of 1993
Public Law 103-129 Rural Electric Loan Restructuring Act of 1993
Public Law 103-252 Human Service Amendments Act of 1994
Public Law 105-34 Taxpayer Relief Act of 1997
Public Law 105-178 Transportation Equity Act for the 21st Century of 1998
Public Law 106-51 Emergency Steel Loan Guarantee and Emergency Oil and Gas Guaranteed Loan
Public Law 106-170 Tax Relief Extension Act of 1999
Public Law 106-224 Agricultural Risk Protection Act of 2000
Public Law 107-171 Farm Security and Rural Investment Act of 2002
Public Law 107-147 Job Creation and Worker Assistance Act of 2002

Public Law 107-200 Yucca Mountain Development Act of 2002
Public Law 107-204 Sarbanes-Oxley Act of 2002
Public Law 108-311 Working Families Tax Relief Act of 2004
Public Law 108-357 American Jobs Creation Act of 2004
Public Law 108-447 Consolidated Appropriations Act of 2005
Public Law 109-58 Energy Policy Act of 2005
Public Law 109-97 Agricultural, Rural Development, Food and Drug Administration, and Related Agencies and Appropriations Act 2006
Public Law 109-222 Tax Increase Prevention and Reconciliation Act of 2005
Public Law 109-432 Tax Relief and Health Care Act of 2006
Public Law 110-5 Revised Continuing Appropriations Act of 2007
Public Law 110-140 Energy Independence and Security Act of 2007

United States Codes of Federal Regulations

7 U.S.C. 901, et seq.
7 U.S.C. 903
7 U.S.C. 913
7 U.S.C. 940c-1
7 CFR 1714.8
29 U.S.C. 45(e)(11)
30 U.S.C. 241
15 U.S.C. 825s
16 U.S.C. 8381
26 U.S.C. 40A
26 U.S.C. 45H
2 U.S.C. 661a

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Appendix G
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Appendix H
Letter from
Senator Lamar Alexander

LAMAR ALEXANDER
TENNESSEE

United States Senate

WASHINGTON, DC 20510

May 17, 2007

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

Dear Mr. Caruso:

I am writing to request that the Energy Information Administration (EIA) conduct an analysis of federal subsidies of the electricity industry, including a comparison of subsidies for the different fuel types (e.g., coal, natural gas, petroleum, nuclear, wind, solar, etc.). I am interested in learning – for each fuel type – both (1) the overall annual cost of those subsidies, and (2) the annual cost per unit electricity generated (e.g., cost per kilowatt-hour). My staff is familiar with the EIA report *Federal Financial Interventions and Subsidies in Energy Markets 1999: Energy Transformation and End Use* and understands that this new analysis will serve as an update of significant portions of this prior analysis with a focus on subsidies available to electricity and primary fuels used in electricity generation.

To expedite its completion, the analysis should be limited to subsidies provided by the federal government, those that are energy-specific, and those that provide a financial benefit with an identifiable federal budget impact. Broad policies or programs that are applicable throughout the economy need not be considered. The analysis should include the following types of subsidies: tax expenditures (such as deductions, credits, and loan guarantees); direct expenditures (such as direct grant programs and the Low Income Home Energy Assistance Program); federal research and development programs targeting electricity and its fuel inputs; and federal electricity programs (such as support for the Bonneville Power Administration).

The report should include an estimate on the size of each subsidy over a recent, representative year. Where there has been a significant change in the amount or scope of a particular subsidy since the 2000 report, it would be useful for the report to provide an explanation for the change. If a valid methodology can be developed, a forecast of subsidy impacts would be very informative as well. To be most helpful, I would appreciate it if the report could be completed by November 30, 2007.

Thank you for your assistance with this matter. If you have any questions, please contact Mr. Jack Wells of my staff at (202) 224-9504 or jack_wells@help.senate.gov.

Sincerely,

Lamar Alexander

Lamar Alexander
United States Senate