United States Senate
Committee on Finance

Energy Tax
Briefing Book

June 13, 2007
Finance Committee Staff

Table of Contents

United States Senate

COMMITTEE ON FINANCE

WASHINGTON, DC 20510–6200

June 13, 2007

Dear Colleagues:

This briefing book has been prepared by the staff of the Senate Finance Committee to provide practical information to you and your staff on energy-tax issues. The book is based on a series of 15 bipartisan roundtable discussions hosted by the Committee, and contains sections on each of the following issues:

1) Pipelines
2) Refineries
3) Marginal Wells
4) Independent Oil and Gas Companies
5) Integrated Oil and Gas Companies
6) Electricity Transmission
7) Electricity Production Tax Credit
8) Electricity Investment Tax Credit
9) Electric Utilities
10) Coal 101
11) Gasification Technologies
12) Efficient Commercial Buildings
13) Energy Efficient New Homes
14) Alternative Vehicles
15) Biofuels

Each section contains a short memorandum compiled by Senate Finance staff, including supplementary material from the speakers' presentations. The book also includes a detailed explanation of current law on each of the 15 topics, compliments of the Joint Committee on Taxation.

We hope this notebook will be a useful resource. Please feel free to contact the Finance Committee staff if you have any further questions or concerns regarding any tax-related issue or legislation.

With Best Personal Regards,

Max Baucus
Chairman

Charles Grassley
Ranking Member

Roundtable 1: Pipelines
January 5, 2007

Speakers:

Shirley Neff – President, Association of Oil Pipelines
Bruce Heine – Director of Government Affairs, Magellan Midstream Partners
Paul Wilkinson – Vice President, Policy Analysis, American Gas Association
Mike Eggl – Senior Vice President, Basin Electric Power Cooperative

Pipeline Roundtable (1/5/07):

The Roundtable focused on both crude and finished petroleum product pipeline transportation (Shirley Neff) as well as natural gas pipeline transportation (Paul Wilkinson). Bruce Heine discussed the fungible nature of finished fuels, pipeline ownership and the storage flow of different products in the pipeline system. Finally, Mike Eggl offered a first-hand account of the only dedicated pipeline that captures CO_2 from a commercial coal gasification facility in North Dakota and delivers the product to the tar sands oil fields in Saskatchewan. Following this summary is a technical description of current law tax provisions related to encourage the investment in oil and natural gas pipelines.

Background:

The first oil pipeline in the U.S. was built in 1865, following discovery of oil in Pennsylvania. By the early 1900s, with discoveries of oil in Texas, Oklahoma and Kansas, pipelines had become a common method of moving crude oil. Today, roughly 160,000 miles of oil pipeline in the U.S. carry over 75% of the nation's crude oil and around 60% of its refined petroleum products.

Crude Oil Pipelines:

The network of crude oil pipelines in the U.S. is extensive. There are approximately 55,000 miles of crude oil trunk lines (usually 8 - 24 inches in diameter) in the U.S. that connect regional markets. The U.S. also has an estimated 30,000 to 40,000 miles of small gathering lines (usually 2 to 6 inches in diameter) located primarily in Texas, Oklahoma, Louisiana, and Wyoming with small systems in a number of other oil producing states. These small lines gather the oil from wells, both onshore and offshore, and connect to the larger oil trunk lines.

The petroleum products pipeline distribution system is the primary means of transporting diesel fuel and other liquid petroleum products within the United States (See Chart 2). Pipelines are distinguished by the region they serve, the type of service they offer, their mode of operation, their size, the size of the interfaces between batches, and how they dispose of these batches.

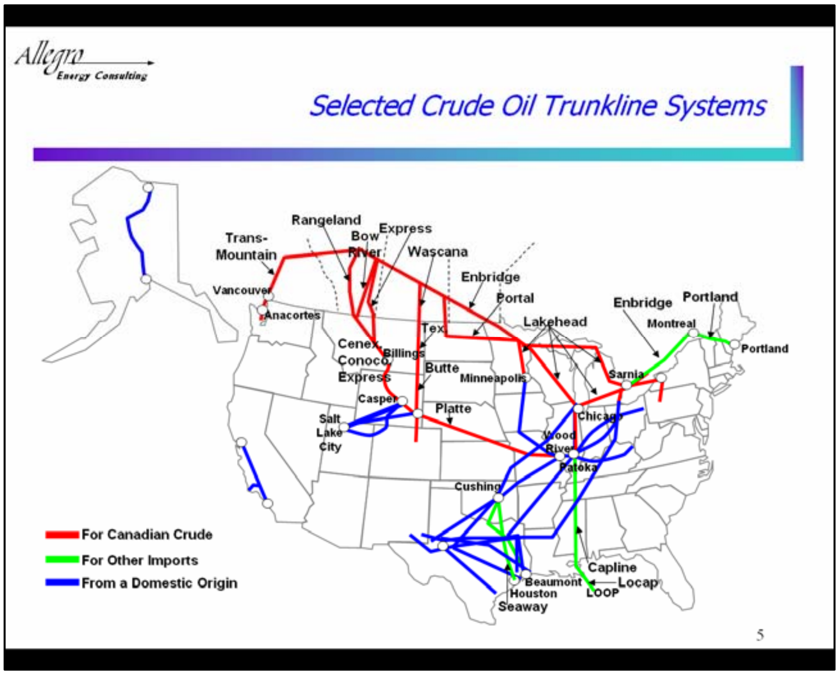


Chart 1

Refined Petroleum Pipelines:

Refined petroleum product pipelines in the United States fall into two service categories. Trunk lines serve high-volume, long-haul transportation requirements; delivering pipelines transport smaller volumes over shorter distances to final market areas. Typically, refined oil products are transported from a source location, such as a refinery or bulk terminal, to a distribution terminal near a market area. (See Chart 3) Large aboveground storage tanks at an origin location accumulate and hold a given petroleum product pending its entry into the pipeline for transport. Petroleum products are also stored temporarily in aboveground storage tanks at destination terminals. Such tanks usually are dedicated to holding a single petroleum product or grade. Most storage tanks used in pipeline operation are filled and drained up to four or more times per month.

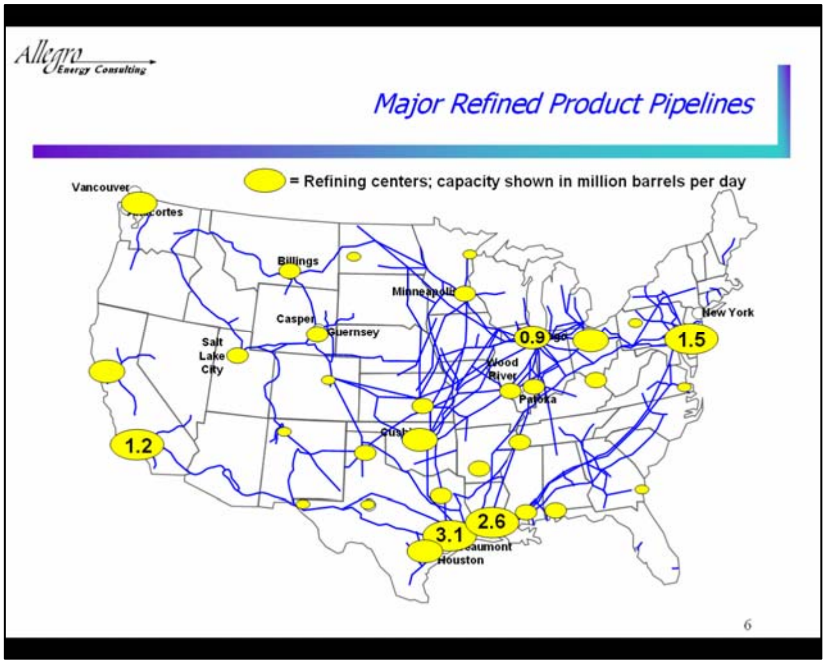


Chart 2

Product pipelines routinely transport various grades of motor gasoline, diesel fuel, and aircraft turbine fuel in the same physical pipeline. (Generally, crude oil and refined petroleum products are not transported in the same pipeline.) To carry multiple products or grades in the same pipeline, different petroleum products or grades are held in separate storage facilities at the origin of a pipeline and are delivered into separate storage facilities at the destination. The different types or grades of petroleum product are transported sequentially through the pipeline. While traversing the pipeline, a given refined product occupies the pipeline as a single batch of material. At the end of a given batch, another batch of material, a different petroleum product, follows. A 25,000-barrel batch of product occupies nearly 50 miles of a 10-inch diameter pipeline.

Generally, such batches are butted directly against each other, without any means or devices to separate them. At the interface of two batches in a pipeline, some (but relatively little) mixing occurs. As a guide to understanding the volume of interface generated, it would be typical for 150 barrels of mixed material ("transmix") to be generated in a 10-inch pipeline over a shipment distance of 100 miles. Trunk pipelines operate on cycles (typically 5 to 10 days). (See Chart 3)

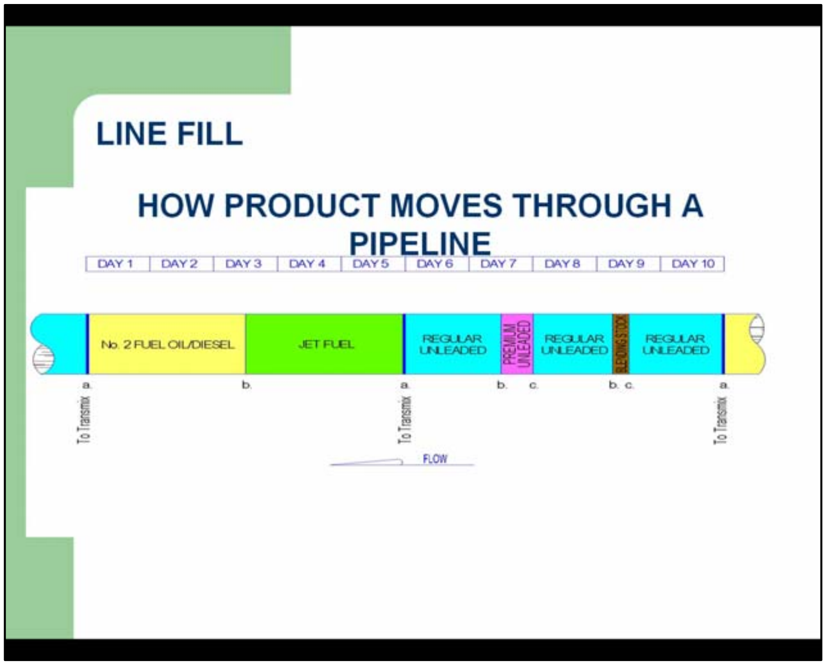


Chart 3

Pipeline ownership is varied. Proprietary owners own both the pipeline and the product in the pipeline. Common carriers are "for hire" transportation (similar to trucking companies) and typically do not own any of the product transported.

Natural Gas Pipelines:

There are three types of natural gas pipelines. (See Chart 4) During the natural gas production process, wells are drilled into porous rock, and pipes are used to bring the natural gas to the surface. Typically, pressure is sufficient to force the gas to the surface and into a gathering a line. Gathering lines link production areas to central collection points. Some natural gas gathering systems include a processing facility, which removes such impurities as natural gas liquids, water, carbon dioxide or sulfur that might corrode a pipeline, or inert gases, such as helium, that could reduce the energy value of the gas.

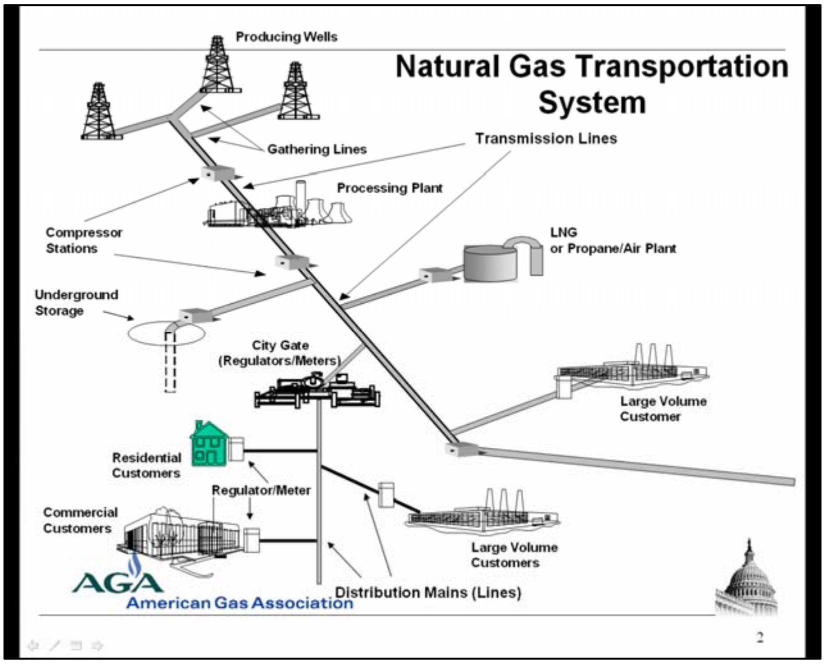


Chart 4

The pipeline transmission system consists of 280,000 miles of high-strength steel pipe 20 inches to 42 inches in diameter, moving huge amounts of natural gas thousands of miles from producing regions to local natural gas utilities. Compressor stations every 70 miles boost pressure that is lost through the friction of gas moving through pipe.

Local distribution companies measure the gas through metering, and add a sour-smelling odorant to help customers smell even small quantities of natural gas. The local gas company then uses distribution pipes, or "mains," to bring natural gas to most U.S. homes and nearly 5 million businesses. To help ensure reliable service, local natural gas companies can store natural gas underground for use during peak demand. Underground storage accounts for about 20 percent of the natural gas consumed each winter.

Another type of product pipeline is a CO_2 pipeline. Until recently, most of the CO_2 used for enhanced oil recovery (EOR) has come from naturally-occurring reservoirs. But new technologies are being developed to produce CO_2 from industrial applications such as natural gas processing, fertilizer, ethanol, and hydrogen plants in locations where naturally occurring reservoirs are not available. The Dakota Gasification Company's *Great Plains Synfuels Plant* in Beulah, North Dakota is the only commercial coal gasification facility producing synthetic natural gas. Dakota captures and sequesters up to 150 million cubic feet of CO_2 per day and delivers it by a 204-mile CO_2 pipeline to the Weyburn oil field in Saskatchewan, Canada. (See Chart 5) EnCana, the field's operator, is injecting the CO_2 to extend the field's productive life, hoping to add another 25 years and as much as 130 million barrels of oil that might otherwise have been abandoned (See Charts 6).

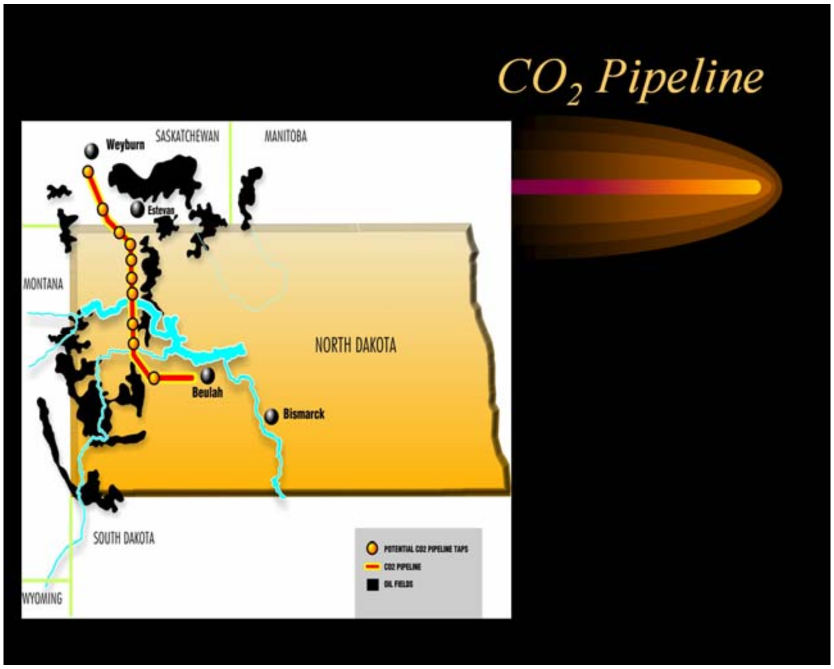


Chart 5

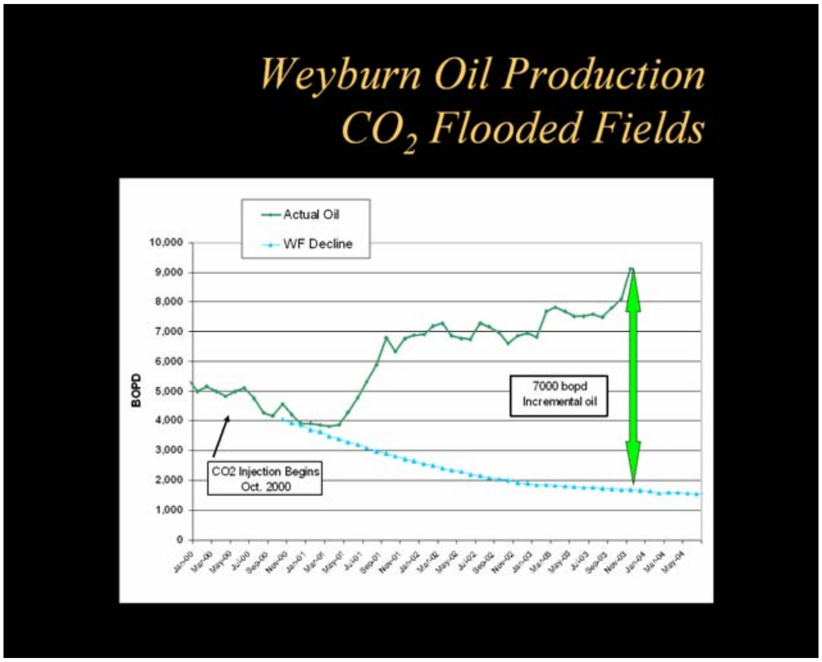


Chart 6

Tax Provisions:

Section 167 of the tax code accounts for the progressive exhaustion of plant equipment and other long-lived business and investment property, by allowing an annual deduction for depreciation. Generally, the cost of the property, less salvage value, is recovered on a year-by-year basis over the period during which the property is expected to be economically useful to the taxpayer.

In 1954, Congress enacted an accelerated method of depreciation. Prior to 1954, taxpayers were generally required to use the straight-line method of depreciation (described in the JCT attachment). Unlike the straight-line method, accelerated depreciation concentrates larger deductions in the earlier years of the asset's life, allowing a faster return on the greater part of the taxpayer's cost. To stimulate investment, the accelerated depreciation system allows business taxpayers to depreciate property over periods that are shorter than the periods of actual service of the property. Net cash flows are larger in the early years and smaller in the later years due to the greater tax payments in the later years.

Accelerated depreciation methods have the effect of increasing after-tax returns to the owners of depreciable property, stimulating investment that might not have otherwise been made. Businesses are encouraged through accelerated depreciation to expand, add new stock or replace existing stock. However, the increase in after-tax returns is achieved not through a tax-exemption, but by allowing a business to defer their current income tax liability to later periods. In essence, money today is preferred over money tomorrow.

Attached is a JCT description of cost recovery methods currently available to oil and gas pipeline companies as well as background on recent statutory developments in this area.

I. PRESENT LAW AND BACKGROUND RELATING TO DEPRECIATION OF OIL AND GAS PIPELINES

A. Depreciation

In general

A taxpayer is allowed to recover, through annual depreciation deductions, the cost of certain property used in a trade or business or for the production of income. The amount of the depreciation deduction allowed with respect to tangible property for a taxable year is determined under the modified accelerated cost recovery system ("MACRS"). Under MACRS, different types of property are generally assigned applicable recovery periods and depreciation methods. The recovery periods applicable to most tangible personal property (generally tangible property other than residential rental property and nonresidential real property) range from three to 25 years. The depreciation methods generally applicable to tangible personal property are the 200-percent and 150-percent declining balance methods, switching to the straight-line method for the taxable year in which the depreciation deduction would be maximized.[1] In general, the recovery periods applicable to real property are 39 years for non-residential real property and 27.5 years for residential rental property. The depreciation method for real property is the straight-line method.

Under MACRS, the full basis of depreciable property is recovered by the taxpayer over the applicable recovery period; there is no need to estimate salvage value. Furthermore, under MACRS, the applicable recovery period need not (and typically does not) correspond to the actual economic life of the asset subject to depreciation. In general, however, MACRS generally provides for longer recovery periods for longer lived assets.

Placed-in-service conventions

Depreciation of an asset begins when the asset is deemed to be placed in service under the applicable convention. Under MACRS, nonresidential real property, residential rental property and any railroad grading or tunnel bore are generally subject to the mid-month convention, which treats all property placed in service during any month (or disposed of during any month) as placed in service (or disposed of) on the mid-point of such month. All other property is generally subject to the half-year convention, which treats all property placed in service during any taxable year (or disposed of during any taxable year) as placed in service (or disposed of) during the mid-point of such taxable year. However, if substantial property is placed in service during the last three months of a taxable year, a special rule requires use of the mid-quarter convention, designed to prevent the recognition of disproportionately large amounts of first-year depreciation under the half-year convention.

[1] For certain property, including tangible property used predominantly outside the United States, tax-exempt use property, tax-exempt bond-financed property, and certain other property, the MACRS "alternative depreciation system" of section 168(g) applies, generally increasing recovery periods and requiring straight-line depreciation as described below.

Recovery periods

The applicable recovery period for an asset is determined in part by statute and in part by historic Treasury guidance. In 1987, and again in 1988, the Treasury Department published "class lives" for various categories of depreciable property. The "class life" of an asset is then used to determine the "type of property" of the asset, which in turn dictates the applicable recovery period for the asset. In addition, the MACRS provisions of the Internal Revenue Code explicitly categorize certain assets by type of property, effectively superseding any administrative guidance with regard to such property.

Table 1, on the following page, summarizes the various types of property and applicable recovery periods under MACRS:

Table 1.–Selected Property Classes and Recovery Periods under MACRS

Type of Property	General Rule-Class Life of:	Specific Classifications by Statute	Applicable Recovery Period
3-year property	4 years of less	Certain race horses and most other horses; qualified rent-to-own property.	3 years
5-year property	More than 4 but less than 10 years	Automobiles and light general purpose trucks; semi-conductor manufacturing equipment; computer-based telephone central office switching equipment; qualified technological equipment;[1] certain research property; certain solar, wind or geothermal energy property.	5 years
7-year property	10 or more but less than 16 years; also, property (other than real property) without a class life	Railroad track; certain motorsports entertainment complexes; certain Alaska natural gas pipeline; natural gas gathering lines.	7 years
10-year property	16 or more but less than 20 years	Any single purpose agricultural or horticultural structure; any tree or vine bearing fruit or nuts.	10 years
15-year property	20 or more but less than 25 years	Any municipal wastewater treatment plant; certain telephone distribution equipment; certain retail motor fuels outlet property; qualified leasehold improvements placed in service before January 1, 2006; qualified restaurant property placed in service before January 1, 2006; initial clearing and grading land improvements with respect to gas utility property; pipeline transportation, including assets used in the private, commercial, and contract carrying of petroleum, gas and other products by means of pipes and conveyors (the trunk lines and related storage facilities of integrated petroleum and natural gas producers are included in this class); liquefied natural gas plant.	15 years
20-year property	25 or more years	Initial clearing and grading land improvements with respect to any electric utility transmission and distribution plant	20 years
Water utility property			25 years
Residential rental property			27.5 years
Nonresidential real property			39 years
Any railroad grading or tunnel bore			50 years

[1] The term "qualified technological equipment" is defined as computers and related peripheral equipment, high technology telephone station equipment installed on a customer's premises, and high technology medical equipment. Sec. 168(i)(2).

3

Depreciation under the alternative minimum tax regime

In determining the amount of alternative minimum taxable income for any taxable year, taxpayers are generally required to calculate depreciation for certain assets under modified rules. Specifically, assets to which the 200-percent declining balance method is applicable under MACRS are depreciated using the 150-percent declining balance method for purposes of computing alternative minimum taxable income.

Alternative depreciation system

When MACRS was enacted, Congress also created the alternative depreciation system ("ADS"), which is required to be used for property used predominantly outside the United States and certain tax-exempt use property. Under ADS, all property is depreciated using the straight-line method, over recovery periods which are generally longer than those used under MACRS.

B. Recent Statutory Developments for Specific Types of Property

Recovery period for Alaska natural gas pipeline

AJCA establishes a statutory seven year recovery period and a class life of 22 years for any Alaska natural gas pipeline. The term "Alaska natural gas pipeline" is defined as any natural gas pipeline system (including the pipe, trunk lines, related equipment, and appurtenances used to carry natural gas, but not any gas processing plant) located in the State of Alaska that has a capacity of more than 500 billion Btu of natural gas per day and is placed in service after December 31, 2013. A taxpayer who places an otherwise qualifying system in service before January 1, 2014 may elect to treat the system as placed in service on January 1, 2014, thus qualifying for the seven-year recovery period. Absent such an election, the system is subject to the prior law recovery period of 15 years.

Natural gas distribution lines treated as fifteen-year property

The Energy Tax Incentives Act of 2005 establishes a statutory 15-year recovery period and a class life of 35 years for natural gas distribution lines (20-year recovery period under prior law). This provision is effective for property, the original use of which begins with the taxpayer after April 11, 2005, which is placed in service after April 11, 2005 and before January 1, 2011. The provision does not apply to property subject to a binding contract on or before April 11, 2005.[2]

Natural gas gathering lines

Revenue Procedure 87-56 includes two asset classes either of which could describe natural gas gathering lines owned by non-producers of natural gas. Asset class 46.0, describing pipeline transportation, provides a class life of 22 years and a recovery period of 15 years. Asset class 13.2, describing assets used in the exploration for and production of petroleum and natural gas deposits, provides a class life of 14 years and a depreciation recovery period of seven years. Prior to the Energy Tax Incentives Act of 2005 ("the Act"), there was controversy as to the appropriate recovery period for natural gas gathering lines. However, the Act establishes a statutory seven-year recovery period and a class life of 14 years for natural gas gathering lines. In addition, no adjustment will be made to the allowable amount of depreciation with respect to this property for purposes of computing a taxpayer's alternative minimum taxable income. A natural gas gathering line is defined to include any pipe, equipment, and appurtenance that is (1) determined to be a gathering line by the Federal Energy Regulatory Commission, or (2) used to deliver natural gas from the wellhead or a common point to the point at which such gas first reaches (a) a gas processing plant, (b) an interconnection with an interstate transmission line, (c) an interconnection with an intrastate transmission line, or (d) a direct interconnection with a local distribution company, a gas storage facility, or an industrial consumer.

The statutory change was made to provide clarity and certainty with regard to the recovery period for natural gas gathering lines. The seven-year recovery period, along with the clarity and certainty, was also thought to foster investment in natural gas fields that will enhance the domestic supply of natural gas.

This provision is effective for property, the original use of which begins with the taxpayer, placed in service after April 11, 2005. The provision does not apply to property with respect to which the taxpayer (or a related party) had a binding acquisition contract on or before April 11, 2005.

Roundtable 2: Refineries
January 12, 2007

Speakers:

Ron Chittim – American Petroleum Institute, Refining Manager
Kevin Brown – Executive Vice President, Operations, Sinclair Oil Corp., Salt Lake City, Utah
Dan Knepper – Vice President of Energy Operations, Cenex Harvest States Inc., Billings, MT

Refineries Roundtable (1/12/07):

The Roundtable discussed the major issues currently facing refineries. Market instability, refining capacity and refining processing to meet environmental regulations. Namely, the purpose of the second Roundtable was to connect the dots between the transportation infrastructure (pipelines) and the refineries. Our speakers were Ron Chittim, who provided a basic groundwork of refinery needs, Kevin Brown who provided a perspective from a mid-size, independent refiner, and Dan Knepper who discussed the issues facing a small, cooperative-owned refinery.

Background:

As discussed in the first Roundtable, pipelines are essential to refineries. Pipelines are the infrastructure that deliver crude oil to refineries and finished product to retailers. Finished fuel is delivered to terminals via pipeline or barge. Tanker trucks then deliver fuel from the terminal to the bulk plant and eventually to the service station. (See Chart 1)

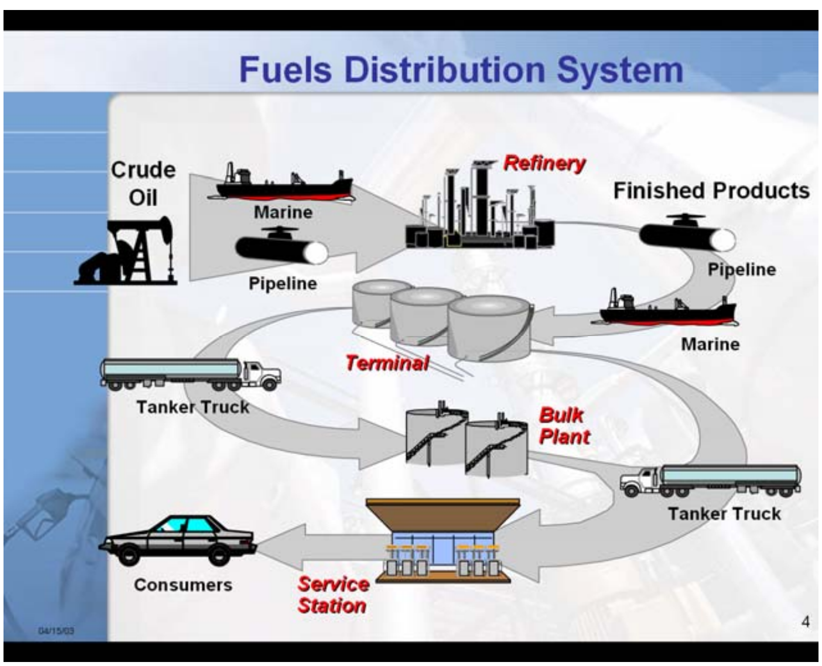


Chart 1

Refineries are the critical step in fuel delivery where the actual manufacturing of the crude oil into useful end products takes place. Crude oil is a practically useless product until a refinery converts it into useful petroleum and petrochemical products. Among the many products manufactured at a refinery are gasoline, jet fuel, diesel fuel, asphalt and other end products used to make everything from lip balm to synthetic T-shirts. (See Chart 2)

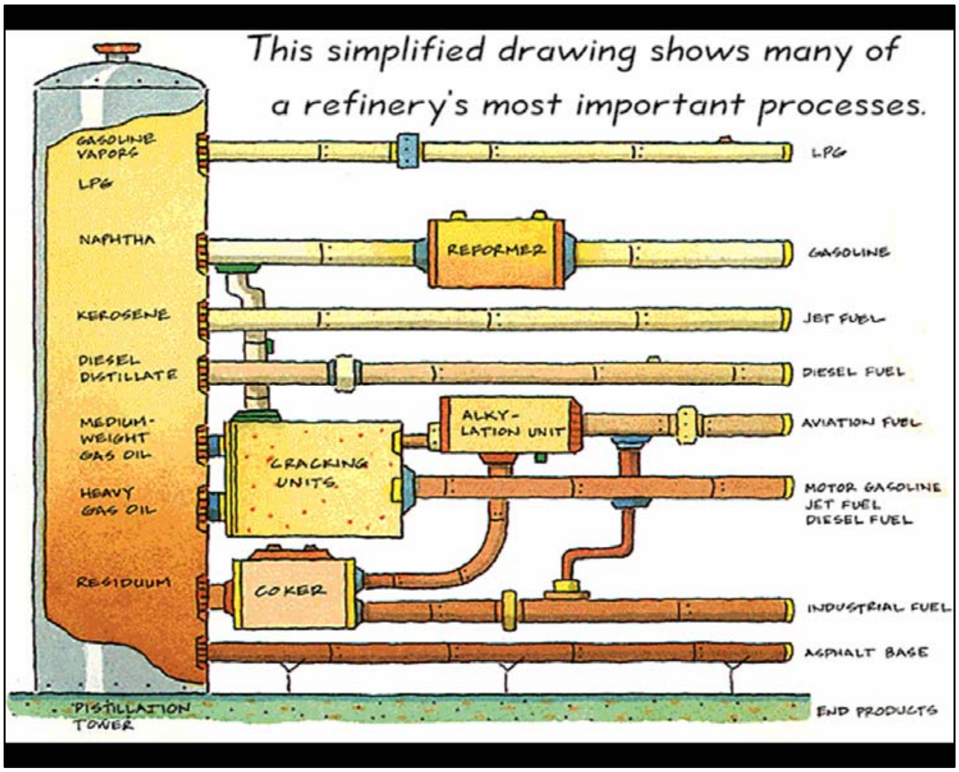


Chart 2

The process of turning crude oil into finished products is characterized by three distinct processes: separation, conversion and treatment. First, separation begins with vaporizing crude oil, by pumping it through pipes in hot furnaces. The vapors separate inside the towers, based on density and boiling point. Light vapors rise to the top of the tower and the heavier vapors descend to the bottom. The vapors then condense back into liquids. Gasoline, being one of the lighter products produced by the refinery, layers at the top of the distillation tower; diesel fuel and kerosene in the middle, and heavier products like gas oils and asphalt products accumulate at the bottom. Conversion is the second process of and involves transforming the separated streams into finished products. Different refineries utilize different techniques. One method of conversion is called cracking, in which heat and pressure are applied in the cracking unit to break heavy hydrocarbon molecules into lighter molecules. The third step in the process involves the products must be treated to meet government regulations. This requires further processing to remove impurities, such as sulfur and nitrogen, so that federal and state air pollution requirements can be met.

Refineries are predominantly located along the Gulf Coast. (See Chart 3) The Gulf Coast refines 39.8% of the crude oil refined which is more than twice the capacity of any other region in the U.S. The Gulf Coast supplies both the East Coast (supplying more than half of that region's needs for gasoline, heating oil, diesel, and jet fuel) and the Midwest.

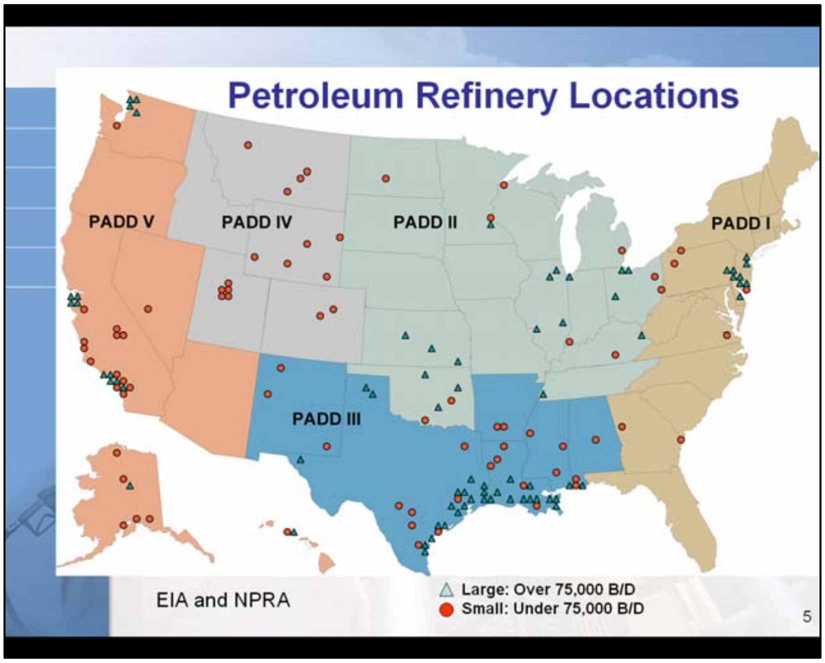


Chart 3

There have been no new refineries built in the U.S. since 1970. (There are currently 144 refineries operating in the U.S.) However, investment has taken place to enhance the capacity of existing facilities. Generally, relative to construction of a new refinery, its cheaper to add capacity to an existing facility. Satisfying regulatory requirements for an expansion at an existing facility is also likely to be less costly, less time-consuming, and less subject to challenge by local groups compared to a new facility. In general, a new refinery can take up to 10 years to construct while an upgrade to an existing facility can be done in three years.

"Capacity creep," in which existing refineries create additional capacity from the same physical structure, has lead to a significant increase in U.S. refining capacity in recent years. Capacity creep is realized through investment in items such as catalytic cracking units and other “de-bottlenecking” (upgrades to refineries that allow fuller use of the facility) measures, and has led to expansion in U.S. refinery capacity of over 340,000 barrels per day since 1990. Capacity creep over the last decade has added the equivalent of 12 new 200,000 barrel per day refineries. (See Chart 4)

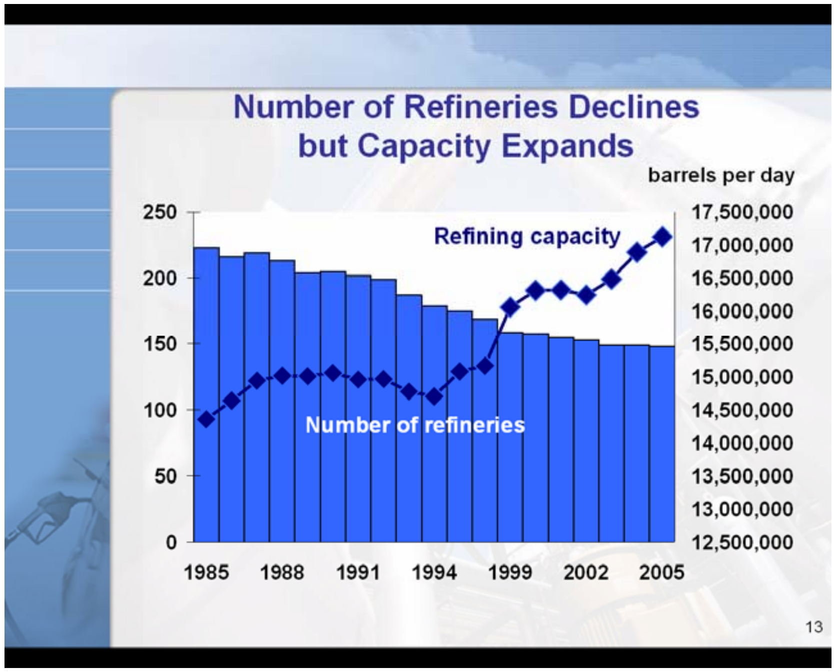


Chart 4

U.S. refineries are increasingly turning to North American feedstock for processing, most of which is heavy crude, including oil from shale and Canadian tar sands. (See Chart 5) These tar sands (also known as oil sands) are a combination of clay, sand, water, and bitumen. They are heavy, black and viscous, but can be mined and processed to extract the oil-rich bitumen, which is then refined into oil. As the price of oil has increased in the past few years, and technology improves, it is commercially viable to recover and produce finished product from oil sands. The total potential recoverable reserves of oil sands in Canada rival the largest oil producing countries. (See Chart 6)


NORTHWEST TERRITORIES
Wood Buffalo National Park
Lake Athabasca
Clearwater River Provincial Park
Fort McMurray
Athabasca Oil Sands
Peace River Oil Sands
SASKATCHEWAN
Grande Prairie
ALBERTA
Cold Lake Oil Sands
Meadow Lake Provincial Park
Edmonton
Lloydminster
BRITISH COLUMBIA
Jasper National Park
Red Deer
Banff National Park
Calgary
Canada
United States
Medicine Hat
Lethbridge
MONTANA
NORTH
0 50 100 200
Kilometres

Chart 5

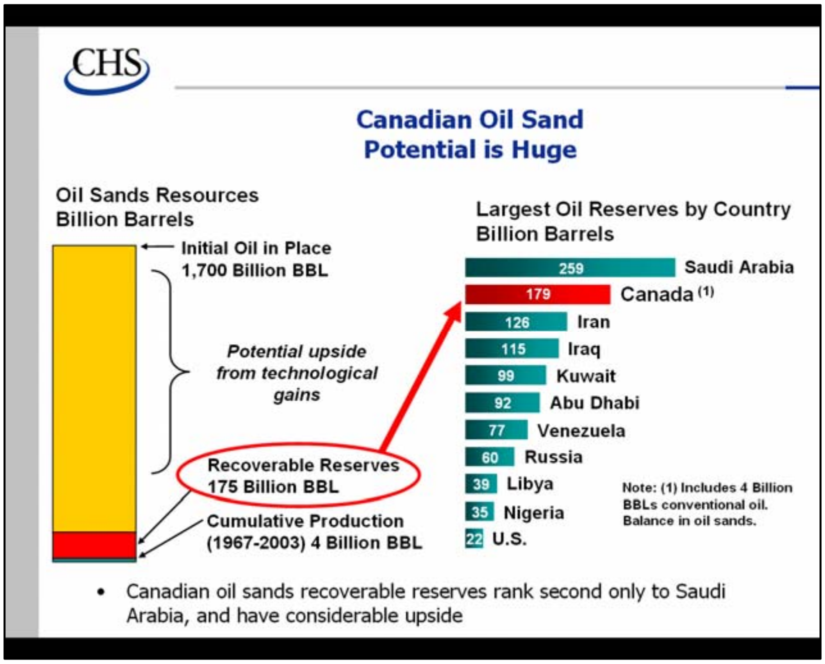


Chart 6

Tax Provisions:

As previously mentioned (see pipeline memorandum), a business can depreciate the cost of an investment over a number of years. The depreciation is meant to reflect the diminution in value of the asset purchased (i.e., a machine will wear out). "Expensing" is the term used for describing a front-loaded accelerated depreciation schedule. Whether a given expenditure is treated as an expense (Section 162) or a capital expenditure (Section 263) is a question of timing. As an expense, the cost is deductible at once and reduces taxable income in a current year. As a capital expenditure, it is deductible over a period of years that relates to an asset's useful life.

Recognizing the need for more finished fuel on the market, and realizing that capacity expansions can be expensive, Congress provided a 50% bonus depreciation provision for refineries in the Energy Policy Act of 2005. In other words, the taxpayer can expense 50% of the cost of investment in the first year and recover the rest over the life of the property. The investment must be for new equipment, and must either increase the total output of fuel by 5%, or increase the use of a non-conventional feedstock (such as bitumen, described above) to 25%.

In the Jobs Bill, which passed into law in October of 2004, Congress included two provisions that subsidize investments small refiners make to comply with EPA's ultra low sulfur diesel (ULSD) regulations . The EPA regulations bring the amount of sulfur allowed in on-road diesel down to 15 parts per million (ppm) from 500 ppm, requiring refineries to sell diesel that meets the ULSD standard by June 1, 2006 retailers were required to comply with the ULSD standard by October 15, 2006.

The Jobs Bill provisions help small refiners make the (necessary to meet ULSD standards) investment by providing two incentives. The first allows refiners to expense 75% of the cost of complying with the ULSD regulations. The second is a credit of 5¢ per gallon of ULSD fuel produced; this credit is limited to 25% of the capital costs of complying with ULSD.

Also in the Jobs Bill, Congress created a new tax deduction for American manufacturers, including gas and oil producers. When fully phased in 2010, the deduction will effectively reduce these manufacturers' corporate tax rates from 35% down to 32%.

Finally, as part of the Energy Policy Act of 2005, Congress reinstated the Oil Spill Liability Trust Fund tax. The tax applies on April 1, 2006, or later, if the Secretary estimates that, as of the close of that quarter, the unobligated balance in the Oil Spill Liability Trust fund will be less that $2 billion.

Please see the attached JCT description for greater detail on the tax provisions for refineries. Also see the attached "U.S. Refineries Operable Atmospheric Crude Oil Distillation Capacity" List for more information.

For additional information on the oil and gas industry and tax incentives, please see "Oil and Gas Tax Subsidies: Current Status and Analysis." http://www.congress.gov/erp/rl/pdf/RL33763.pdf

PRESENT LAW AND RECENT DEVELOPMENTS RELATING TO OIL REFINERS

General rule for depreciating refinery assets (Code section 168)

Under present law, depreciation allowances for property used in a trade or business generally are determined under the Modified Accelerated Cost Recovery System ("MACRS") of section 168 of the Internal Revenue Code (the "Code"). Under MACRS, petroleum refining assets are depreciated for regular tax purposes over a 10-year recovery period using the double declining balance method. Petroleum refining assets are assets used for distillation, fractionation, and catalytic cracking of crude petroleum into gasoline and its other components.

Temporary election to expense 50 percent of qualified property used in refining liquid fuels (Code section 179C)

Taxpayers may elect to expense 50 percent of the cost of any qualified property used for processing liquid fuel from crude oil or qualified fuels (as defined in section 45K(c)[1] of the Code). The remaining 50 percent is recovered under the otherwise applicable rules. Qualified refinery property includes assets located in the United States that are used in the refining of liquid fuels: (1) with respect to the construction of which a binding construction contract has been entered into before January 1, 2008;[2] (2) which are placed in service before January 1, 2012; (3) which increase the capacity of an existing refinery by at least five percent or increase the percentage of total throughput attributable to qualified fuels such that it equals or exceeds 25 percent; and (4) which meet all applicable environmental laws in effect when the property is placed in service.

The election to expense 50 percent of the cost of qualified refinery property was added by the Energy Policy Act of 2005. The provision is effective for property placed in service after the date of enactment (August 8, 2005) of that Act, where the original use of the property begins with the taxpayer, provided the property was not subject to a binding contract for construction on or before June 14, 2005.

[1] Under Code section 45K(c), qualified fuels are (1) oil produced from shale and tar sands, (2) gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation, or biomass, and (3) liquid, gaseous, or solid synthetic fuels produced from coal (including lignite).

[2] This requirement also may be met by placing the property in service before January 1, 2008 or, in the case of self-constructed property, by beginning construction after June 14, 2005 and before January 1, 2008.

Special expensing rule for capital costs incurred by small refiners to comply with EPA sulfur regulations (Code section 179B)

Under present law, a small business refiner may immediately deduct as an expense 75 percent of the costs paid or incurred for purposes of complying with the Highway Diesel Fuel Sulfur Control requirement of the Environmental Protection Agency (EPA). A cooperative that qualifies as a small business refiner may elect to pass this deduction through to its owners.

Costs qualifying for the deduction are those costs paid or incurred with respect to any facility of a small business refiner during the period beginning on January 1, 2003 and ending on the earlier of the date that is one year after the date on which the taxpayer must comply with the applicable EPA regulations or December 31, 2009. A small business refiner is a crude oil refiner that has no more than 1,500 individuals engaged in refinery operations on any given day and that had an average daily domestic refinery run or average retained production of not more than 205,000 barrels for the one-year period ending on December 31, 2002.

This deduction was added by the American Jobs Creation Act of 2004 and modified by the Energy Policy Act of 2005. The modification added the rule permitting a cooperative to pass the deduction through to the co-op owners.

Credit for small refiners for production of diesel fuel in compliance with EPA sulfur regulations (Code section 45H)

Under present law, a small business refiner (as defined above) may claim a credit of five cents per gallon for each gallon of low sulfur diesel fuel produced during the taxable year that is in compliance with the Highway Diesel Fuel Sulfur Control Requirements of the EPA.

The total production credit claimed by the taxpayer is limited to 25 percent of the capital costs incurred to come into compliance with the EPA diesel fuel requirements. The percentage limitation phases down *pro rata* for refiners that had runs in 2002 exceeding 155,000 barrels but less than 205,000 barrels.

Costs qualifying for the credit are those costs paid or incurred with respect to any facility of a small business refiner during the period beginning on January 1, 2003 and ending on the earlier of the date that is one year after the date on which the taxpayer must comply with the applicable EPA regulations or December 31, 2009. The taxpayer's basis in property with respect to which the credit applies is reduced by the amount of the production credit claimed. This credit was added by the American Jobs Creation Act of 2004.

Small refiner exception to oil cost depletion deduction (Code section 613A)

Present law classifies oil and gas producers as independent producers or integrated companies. The Code provides special tax rules for operations by independent producers. One such rule allows independent producers to claim percentage depletion deductions rather than deducting the costs of their asset, a producing well, based on actual production from the well (i.e. cost depletion).

A producer is an independent producer only if its refining and retail operations are relatively small. For example, an independent producer may not have refining operations the average daily runs from which exceed 75,000 barrels. A refinery run is the volume of inputs of crude oil (excluding any product derived from oil) into the refining stream. Prior to the Energy Policy Act of 2005, the refining operations of independent producers were limited to runs not exceeding 50,000 barrels per day.

Deduction for domestic production activities (Code section 199)

Present law provides a deduction from taxable income (or, in the case of an individual, adjusted gross income) that is equal to a portion of the taxpayer's qualified production activities income. For taxable years beginning after 2009, the deduction is nine percent of such income. For taxable years beginning in 2005 and 2006, the deduction is three percent of income and, for taxable years beginning in 2007, 2008 and 2009, the deduction is six percent of income. However, the deduction for a taxable year is limited to 50 percent of the wages paid by the taxpayer during the calendar year that ends in such taxable year.

Qualified production activities income generally is equal to domestic production gross receipts, reduced by the sum of: (1) the costs of goods sold that are allocable to such receipts; and (2) other expenses, losses, or deductions which are properly allocable to such receipts. In general, "domestic production gross receipts" means the gross receipts of the taxpayer which are derived from the sale, lease, license, exchange, or other disposition of (1) certain property which was manufactured, produced, grown, or extracted in the United States; (2) any qualified film produced by the taxpayer, or (3) electricity, natural gas, or potable water produced by the taxpayer in the United States. Certain construction, architectural, and engineering gross receipts also qualify.

In the case of natural gas, production activities generally are all activities involved in extracting natural gas from the ground and processing the gas into pipeline quality gas. Such activities would produce qualifying domestic production gross receipts. However gross receipts of a taxpayer attributable to transmission of pipeline quality gas from a natural gas field (or from a natural gas processing plant) to a local distribution company's city gate (or to another customer) are not qualified domestic production gross receipts. Likewise gas purchased by a local gas distribution company and distributed from the city gate to the local customers does not give rise to domestic production gross receipts.

Reinstatement of Oil Spill Liability Trust Fund tax (Code section 4611)

The Oil Spill Liability Trust Fund financing rate was reinstated effective April 1, 2006 (Code sec. 4611(f), as amended by the Energy Policy Act of 2005). The tax rate is 5 cents per barrel and generally applies to crude oil received at a U.S. refinery and to petroleum products entered into the United States for consumption, use, or warehousing. The tax also applies to certain uses and the exportation of domestic crude oil. The oil spill tax supports the Oil Spill Liability Trust Fund and is used to clean up oil spills. The tax terminates after December 31, 2014.

Energy Information Administration
Official Energy Statistics from the U.S. Government

U.S. Refineries Operable Atmospheric Crude Oil Distillation Capacity
(Barrels per Calendar Day)
as of January 1, 2006

Rank	COMPANY NAME	STATE	SITE	Barrels per Calendar Day
1	EXXONMOBIL REFINING & SUPPLY CO	Texas	BAYTOWN	562,500
2	EXXONMOBIL REFINING & SUPPLY CO	Louisiana	BATON ROUGE	501,000
3	BP PRODUCTS NORTH AMERICA INC	Texas	TEXAS CITY	437,000
4	CITGO PETROLEUM CORP	Louisiana	LAKE CHARLES	429,500
5	BP PRODUCTS NORTH AMERICA INC	Indiana	WHITING	410,000
6	EXXONMOBIL REFINING & SUPPLY CO	Texas	BEAUMONT	348,500
7	SUNOCO INC (R&M)	Pennsylvania	PHILADELPHIA	335,000
8	DEER PARK REFINING LTD PARTNERSHIP	Texas	DEER PARK	333,700
9	CHEVRON USA INC	Mississippi	PASCAGOULA	330,000
10	CONOCOPHILLIPS COMPANY	Illinois	WOOD RIVER	306,000
11	Flint Hills Resources LP	Texas	CORPUS CHRISTI	288,126
12	Motiva Enterprises LLC	Texas	PORT ARTHUR	285,000
13	Flint Hills Resources LP	Minnesota	SAINT PAUL	279,300
14	LYONDELL CITGO REFINING CO LTD	Texas	HOUSTON	270,200
15	BP West Coast Products LLC	California	LOS ANGELES	260,000
16	CHEVRON USA INC	California	EL SEGUNDO	260,000
17	PREMCOR REFINING GROUP INC	Texas	PORT ARTHUR	260,000
18	CONOCOPHILLIPS COMPANY	Louisiana	BELLE CHASSE	247,000
19	CONOCOPHILLIPS COMPANY	Texas	SWEENY	247,000
20	MARATHON PETROLEUM CO LLC	Louisiana	GARYVILLE	245,000
21	CHEVRON USA INC	California	RICHMOND	242,901
22	CONOCOPHILLIPS COMPANY	Louisiana	WESTLAKE	239,400
23	EXXONMOBIL REFINING & SUPPLY CO	Illinois	JOLIET	238,500
24	CONOCOPHILLIPS COMPANY	New Jersey	LINDEN	238,000
25	Motiva Enterprises LLC	Louisiana	CONVENT	235,000
26	TOTAL PETROCHEMICALS INC	Texas	PORT ARTHUR	232,000
27	Motiva Enterprises LLC	Louisiana	NORCO	226,500
28	BP West Coast Products LLC	Washington	FERNDALE (CHERRY POINT)	225,000
29	MARATHON PETROLEUM CO LLC	Kentucky	CATLETTSBURG	222,000

30	VALERO REFINING CO TEXAS	Texas	TEXAS CITY	213,750
31	FLINT HILLS RESOURCES ALASKA LLC	Alaska	NORTH POLE	210,000
32	CONOCOPHILLIPS COMPANY	Oklahoma	PONCA CITY	194,000
33	MARATHON PETROLEUM CO LLC	Illinois	ROBINSON	192,000
34	Chalmette Refining LLC	Louisiana	CHALMETTE	188,160
35	VALERO REFINING NEW ORLEANS LLC	Louisiana	NORCO	185,003
36	CONOCOPHILLIPS COMPANY	Pennsylvania	TRAINER	185,000
37	PREMCOR REFINING GROUP INC	Delaware	DELAWARE CITY	181,500
38	PREMCOR REFINING GROUP INC	Tennessee	MEMPHIS	180,000
39	SUNOCO INC	Pennsylvania	MARCUS HOOK	175,000
40	PDV Midwest Refining LLC	Illinois	LEMONT (CHICAGO)	167,000
41	TESORO REFINING & MARKETING CO	California	MARTINEZ	166,000
42	SUNOCO INC	Ohio	TOLEDO	160,000
43	VALERO REFINING CO NEW JERSEY	New Jersey	PAULSBORO	160,000
44	VALERO ENERGY CORPORATION	Texas	SUNRAY	158,327
45	CITGO REFINING & CHEMICAL INC	Texas	CORPUS CHRISTI	156,000
46	Shell Oil Products US	California	MARTINEZ	155,600
47	EXXONMOBIL REFINING & SUPPLY CO	California	TORRANCE	149,500
48	PREMCOR REFINING GROUP INC	Ohio	LIMA	146,900
49	CONOCOPHILLIPS COMPANY	Texas	BORGER	146,000
50	Shell Oil Products US	Washington	ANACORTES	145,000
51	SUNOCO INC	New Jersey	WESTVILLE	145,000
52	VALERO REFINING CO CALIFORNIA	California	BENICIA	144,000
53	VALERO REFINING CO TEXAS	Texas	CORPUS CHRISTI	142,000
54	CONOCOPHILLIPS COMPANY	California	WILMINGTON	139,000
55	BP PRODUCTS NORTH AMERICA INC	Ohio	TOLEDO	131,000
56	MURPHY OIL USA INC	Louisiana	MERAUX	120,000
57	Tesoro West Coast	Washington	ANACORTES	120,000
58	WESTERN REFINING COMPANY LP	Texas	EL PASO	116,000
59	COFFEYVILLE RESOURCES LLC	Kansas	COFFEYVILLE	112,000
60	FRONTIER EL DORADO REFINING CO	Kansas	EL DORADO	106,000
61	MARATHON PETROLEUM CO LLC	Michigan	DETROIT	100,000
62	PASADENA REFINING SYSTEMS INC	Texas	PASADENA	100,000
63	Shell Oil Products US	California	WILMINGTON	98,500
64	CONOCOPHILLIPS COMPANY	Washington	FERNDALE	96,000
65	TESORO HAWAII CORP	Hawaii	KAPOLEI	93,500
66	VALERO ENERGY CORPORATION	Texas	THREE RIVERS	90,000

67	SUNOCO INC	Oklahoma	TULSA	85,000
68	VALERO REFINING CO OKLAHOMA	Oklahoma	ARDMORE	83,640
69	VALERO REFINING CO TEXAS	Texas	HOUSTON	83,000
70	NCRA	Kansas	MCPHERSON	81,200
71	ULTRAMAR INC	California	WILMINGTON	80,887
72	CHEVRON USA INC	New Jersey	PERTH AMBOY	80,000
73	Shell Chem. LP	Alabama	SARALAND	80,000
74	VALERO REFINING CO LOUISIANA	Louisiana	KROTZ SPRINGS	80,000
75	CONOCOPHILLIPS COMPANY	California	RODEO	76,000
76	NAVAJO REFINING CO	New Mexico	ARTESIA	75,000
77	MARATHON PETROLEUM CO LLC	Ohio	CANTON	73,000
78	MARATHON PETROLEUM CO LLC	Texas	TEXAS CITY	72,000
79	TESORO PETROLEUM CORP	Alaska	KENAI	72,000
80	SINCLAIR OIL CORP	Oklahoma	TULSA	70,300
81	LION OIL CO	Arkansas	EL DORADO	70,000
82	MARATHON PETROLEUM CO LLC	Minnesota	SAINT PAUL PARK	70,000
83	ALON USA ENERGY INC	Texas	BIG SPRING	67,000
84	BIG WEST OF CALIFORNIA	California	BAKERSFIELD	66,000
85	SINCLAIR OIL CORP	Wyoming	SINCLAIR	66,000
86	UNITED REFINING CO	Pennsylvania	WARREN	65,000
87	SUNCOR ENERGY (USA) INC	Colorado	COMMERCE CITY	62,000
88	EXXONMOBIL REFINING & SUPPLY CO	Montana	BILLINGS	60,000
89	GIANT YORKTOWN REFINING	Virginia	YORKTOWN	58,600
90	CONOCOPHILLIPS COMPANY	Montana	BILLINGS	58,000
91	DELEK REFINING LTD	Texas	TYLER	58,000
92	Tesoro West Coast	North Dakota	MANDAN	58,000
93	Tesoro West Coast	Utah	SALT LAKE CITY	58,000
94	PLACID REFINING CO	Louisiana	PORT ALLEN	56,000
95	Cenex Harvest States Coop	Montana	LAUREL	55,000
96	Shell Chem. LP	Louisiana	SAINT ROSE	55,000
97	CHEVRON USA INC	Hawaii	HONOLULU	54,000
98	WYNNEWOOD REFINING CO	Oklahoma	WYNNEWOOD	54,000
99	PARAMOUNT PETROLEUM CORPORATION	California	PARAMOUNT	50,000
100	PETRO STAR INC	Alaska	VALDEZ	48,000
101	FRONTIER REFINING INC	Wyoming	CHEYENNE	47,000
102	CHEVRON USA INC	Utah	SALT LAKE CITY	45,000
103	CONOCOPHILLIPS COMPANY	California	ARROYO GRANDE	44,200
104	CALUMET SHREVEPORT LLC	Louisiana	SHREVEPORT	42,000
105	US OIL & REFINING CO	Washington	TACOMA	37,850
106	HUNT REFINING CO	Alabama	TUSCALOOSA	34,500
107	MURPHY OIL USA INC	Wisconsin	SUPERIOR	34,300

108	CITGO ASPHALT REFINING CO	New Jersey	PAULSBORO	32,000
109	SUNCOR ENERGY(USA)INC	Colorado	DENVER	32,000
110	CALCASIEU REFINING CO	Louisiana	LAKE CHARLES	30,000
111	BIG WEST OIL CO	Utah	NORTH SALT LAKE	29,400
112	CITGO ASPHALT REFINING CO	Georgia	SAVANNAH	28,000
113	EDGINGTON OIL CO INC	California	LONG BEACH	26,000
114	KERN OIL & REFINING CO	California	BAKERSFIELD	26,000
115	HOLLY CORP REFINING & MARKETING	Utah	WOODS CROSS	24,700
116	LITTLE AMERICA REFINING CO	Wyoming	EVANSVILLE (CASPER)	24,500
117	COUNTRYMARK COOPERATIVE INC	Indiana	MOUNT VERNON	23,000
118	ERGON REFINING INC	Mississippi	VICKSBURG	23,000
119	GIANT REFINING CO	New Mexico	GALLUP	20,800
120	ERGON WEST VIRGINIA INC	West Virginia	NEWELL (CONGO)	20,000
121	PETRO STAR INC	Alaska	NORTH POLE	17,000
122	GIANT INDUSTRIES INC	New Mexico	BLOOMFIELD	16,800
123	GULF ATLANTIC OPERATIONS LLC	Alabama	MOBILE	16,700
124	SAN JOAQUIN REFINING CO INC	California	BAKERSFIELD	15,000
125	CONOCOPHILLIPS ALASKA INC	Alaska	KUPARUK	14,000
126	CALUMET LUBRICANTS CO LP	Louisiana	COTTON VALLEY	13,020
127	BP EXPLORATION ALASKA INC	Alaska	PRUDHOE BAY	12,500
128	WYOMING REFINING CO	Wyoming	NEWCASTLE	12,500
129	AGE REFINING INC	Texas	SAN ANTONIO	12,200
130	HUNT SOUTHLAND REFINING CO	Mississippi	SANDERSVILLE	11,000
131	Silver Eagle Refining	Utah	WOODS CROSS	10,250
132	AMERICAN REFINING GROUP INC	Pennsylvania	BRADFORD	10,000
133	Greka Energy	California	SANTA MARIA	9,500
134	LUNDAY THAGARD CO	California	SOUTH GATE	8,500
135	CALUMET LUBRICANTS CO LP	Louisiana	PRINCETON	8,300
136	MONTANA REFINING CO	Montana	GREAT FALLS	8,200
137	CROSS OIL REFINING & MARKETING INC	Arkansas	SMACKOVER	7,200
138	VALERO REFINING CO CALIFORNIA	California	WILMINGTON	6,200
139	HUNT SOUTHLAND REFINING CO	Mississippi	LUMBERTON	5,800
140	SOMERSET REFINERY INC	Kentucky	SOMERSET	5,500
141	GOODWAY REFINING LLC	Alabama	ATMORE	4,100
142	Silver Eagle Refining	Wyoming	EVANSTON	3,000
143	TENBY INC	California	OXNARD	2,800
144	FORELAND REFINING CORP	Nevada	EAGLE SPRINGS	2,000

Source: Refinery Capacity Data by individual refinery as of January 1, 2006

Roundtable 3: Marginal Wells
January 19, 2007

Speakers:

James Martin – Head Chief, Office of Oil and Gas, Dept of Environmental Protection, State of West Virginia
Ed Cross – Executive Vice President, Kansas Independent Oil & Gas Association, Topeka, Kansas
Dick Findley – President and Founder, Prospector Oil, Billings, Montana

Marginal Wells Roundtable (1/19/07):

After discussing the pipeline infrastructure needed to deliver both crude and finished products to and from refineries in the first week, and the after discussing the major issues facing refineries in the second week, the third Roundtable examined the extraction of oil and gas. While much of our oil and natural gas comes from wells that produce large numbers of barrels (and their cubic feet equivalent for natural gas,) marginal wells account for about 17% of oil produced onshore in the U.S., and about 9% of natual gas supplies.

The Roundtable featured representatives of marginal oil and gas producers in Kansas and West Virginia, as well as an oil "wildcatter" from Montana. Ed Cross, who represents oil and gas producers in Kansas, discussed the marginal natural gas development throughout Kansas, which has the largest contiguous natural gas reservoir in the lower forty-eight states. James Martin discussed the marginal oil and gas industry in West Virginia, and provided a brief synopsis a the 2006 study commissioned by the Interstate Oil and Gas Compact Commission (IOGCC). Much of the data in this presentation is from that report, which can be found at:
http://www.iogcc.state.ok.us/PDFS/2006-Full-Marginal-Well-Report.pdf.
Finally, Dick Findley discussed his work as a petroleum geologist in Montana, which largely involves providing seismic data to marginal oil and gas producers.

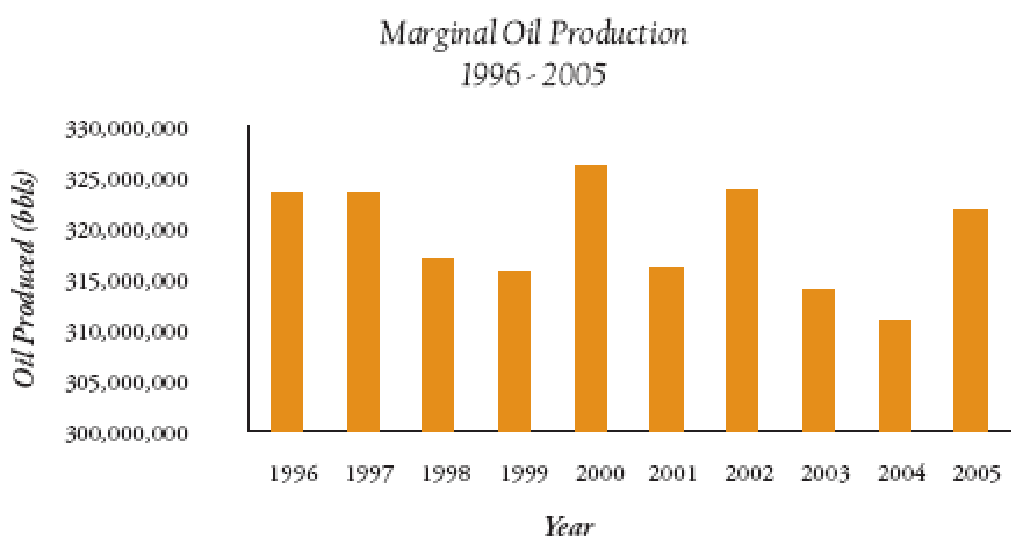
Background:

Marginal gas is natural gas produced from a well that operates on the lower edge of profitability. Generally speaking, these are low-volume “stripper” gas wells – defined by the IOGCC as a well that produces 60 thousand cubic feet (Mcf) per day or less. (The Tax Code defines a marginal gas well as one producing 90 thousand McF per day.) Marginal gas wells represent more than 9 percent of the total natural gas produced onshore in the lower forty-eight states. The table on the following page indicates the status of marginal gas production over the past 10 years. The number of gas wells in the marginal category has steadily increased during the past decade, and production has increased accordinly. Domestic oil production is about 5.1 million barrels per day. Of that, production from marginal wells, also known as low rate wells or “stripper wells” are more than 881 thousand barrels per day, accounting for more than 17 percent of domestic oil production. The table on the following pages indicates the status of marginal oil production over the past 10 years. Generally, IOGCC defines a marginal well as one which produces 10 barrels of oil per day or less. The Code defines a marginal well as one producing 15 barrels per day or less.

the data

U.S. Marginal Oil Well Data – Past 10 Years

Year	Number of Marginal Oil Wells	Marginal Oil Production (bbls)	Average Daily Production Per Well (bbls)	Oil Wells Plugged/ Abandoned
1996	428,842	323,468,274	2.06	16,674
1997	420,674	323,487,914	2.11	15,172
1998	406,380	316,870,286	2.14	13,912
1999	410,680	315,514,283	2.10	11,227
2000	411,629	325,947,181	2.16	10,718
2001	403,459	316,099,192	2.15	12,234
2002	402,072	323,776,606	2.21	13,635
2003	393,463	313,748,001	2.18	14,300
2004	397,362	310,922,122	2.14	11,977
2005	**401,072**	**321,761,570**	**2.20**	**11,058**

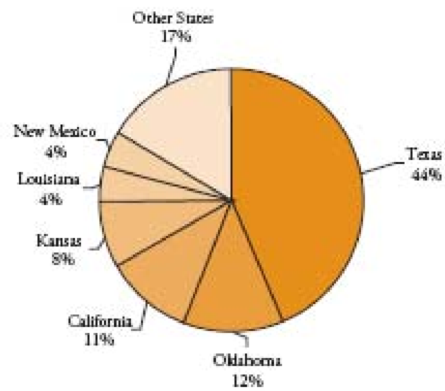


5

While each individual well contributes only a small amount of oil (2.2 barrels a day, on average), there are 401,072 wells in the United States accounting for 80% of oil wells nationwide. Combined, these marginal wells produced more than 321 million barrels of oil in 2005. Marginal wells are most common in older gas-producing regions such as Appalachia, Texas, and Oklahoma.

u.s. state rankings

	Number of Marginal Oil Wells	Production from Marginal Oil Wells (bbls)	Oil Wells Plugged and Abandoned	Average Daily Production per Well
1	Texas	Texas	Texas	South Dakota
2	Oklahoma	Oklahoma	California	Arizona
3	Kansas	California	Kansas	North Dakota
4	Ohio	Kansas	Oklahoma	Utah
5	California	Louisiana	Louisiana	Alabama
6	Louisiana	New Mexico	Illinois	California
7	Kentucky	Illinois	New Mexico	Michigan
8	Pennsylvania	Wyoming	Ohio	Colorado
9	Illinois	Colorado	Wyoming	Texas
10	New Mexico	Ohio	Kentucky	Nebraska
11	Wyoming	Pennsylvania	Pennsylvania	New Mexico
12	West Virginia	Arkansas	Colorado	Oklahoma
13	Colorado	Michigan	New York	Arkansas
14	Indiana	North Dakota	Arkansas	Tennessee
15	Arkansas	Kentucky	Montana	Montana
16	New York	Montana	Michigan	Louisiana
17	Montana	Utah	Mississippi	Wyoming
18	Michigan	Nebraska	Utah	Kansas
19	Mississippi	Indiana	West Virginia	Illinois
20	Nebraska	West Virginia	North Dakota	Mississippi
21	North Dakota	Alabama	Indiana	Virginia
22	Utah	Mississippi	Nebraska	Indiana
23	Alabama	Tennessee	Tennessee	Pennsylvania
24	Missouri	New York	Missouri	Missouri
25	Tennessee	Missouri	Virginia	Ohio
26	South Dakota	South Dakota	South Dakota	West Virginia
27	Arizona	Arizona	Alabama	Kentucky
28	Virginia	Virginia	Arizona	New York



Percent of Total Marginal Oil Well Production in Survey States (bbls)

7

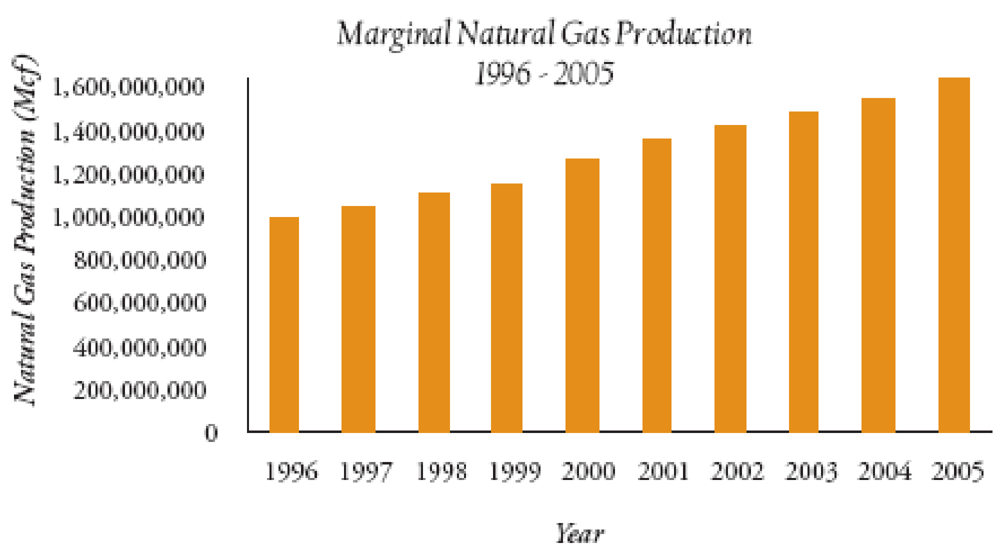
Marginal Natural Gas Survey as of January 1, 2006

State	Number of Marginal Wells	Production from Marginal Gas Wells (Mcf)	Gas Wells Plugged and Abandoned	Avg. Daily Production Per Well (Mcf)	Total 2005 Gas Production (MMcf)
Alabama	2,620 **	26,757,739 **	18 **	28.0	318,954
Arizona	2	17,212	4	23.6	233
Arkansas	2,114	18,707,824	21	24.2	181,695
California	527	4,428,540	86	23.0	87,599
Colorado	8,861	88,788,233	101	27.5	1,509,194
Illinois	551	184,000	10	0.9	347
Indiana	2,110	3,134,583	5	4.1	3,135
Kansas	15,120	283,712,000	172	5.1	380,316
Kentucky	16,618	82,323,314	58	13.6	92,623
Louisiana	10,035	42,130,824 *	333 *	11.5	1,184,330
Maryland	7	36,468	0	14.2	36
Michigan	6,003	77,388,412	84	35.3	176,429
Mississippi	1,226	9,486,746	19	21.2	174,470
Montana	4,162	27,426,557	105	18.1	91,628
Nebraska	108	720,360	0	18.3	939
New Mexico	10,858	97,358,159	272	24.6	1,353,776
New York	5,607	9,896,329	5	4.8	54,595
North Dakota	68	401,057	3	16.2	14,543
Ohio	33,355	68,267,000	520	5.6	84,135
Oklahoma	18,706	169,439,950	392	24.8	1,605,654
Pennsylvania	46,654 *	151,651,000 *	149 *	8.9	168,501 *
South Dakota	50	399,891	0	21.9	446
Tennessee	315	2,200,000	10 *	19.1	2,200
Texas	37,396	302,083,547	1,438	22.1	5,120,528
Utah	1,419	14,429,074	36	27.9	280,296
Virginia	285	3,651,691	40 *	35.1	88,893
West Virginia	40,900	186,000,000	277	12.5	203,500 *
Wyoming	23,221	89,043,042	359	10.5	1,821,365
Totals	**288,898**	**1,760,063,552**	**4,517**	**16.7**	**15,000,360 •**

** Estimated* *** Includes natural gas from coal seams* *• This figure represents only states with marginal natural gas production; does not include production figures from states without marginal natural gas production.*

U.S. Marginal Gas Well Data – Past 10 Years

Year	Number of Marginal Gas Wells	Marginal Gas Production (Mcf)	Pluggings/ Abandonments	Average Daily Production Per Well (Mcf)
1996	168,702	986,676,219	4,671	16.0
1997	189,756	1,042,153,002	4,661	15.0
1998	199,745	1,104,683,975	4,203	15.2
1999	207,766	1,138,979,506	3,546	15.3
2000	223,222	1,258,726,664	3,534	15.4
2001	234,507	1,353,516,378	3,600	15.8
2002	245,961	1,418,273,779	3,870	15.8
2003	260,563	1,478,105,524	3,883	15.5
2004	271,856	1,539,960,495	4,129	15.5
2005	**288,898**	**1,760,063,552**	**4,517**	**16.7**



The U.S. produces more oil and natural gas from marginal wells than any other country. 90% of marginal oil and gas production comes from independent oil and gas firms. Independents provide 82% of America's natural gas supply and produce 68% of the crude oil in the lower forty-eight states.

A major problem facing marginal oil wells is premature abandonment, leaving significant quantities of oil remaining untapped. A common misperception is that oil left behind remains readily available for production when oil prices rise again. When marginal fields are abandoned, the surface infrastructure - pumps, piping, storage vessels, and other processing equipment - is removed and the lease is forfeited. Since much of this equipment was probably installed over many years, replacing it over a short period is enormously expensive. Oil prices would have to stay at today's elevated record levels for many years before there would be sufficient economic justification to bring many marginal fields back into production. As a result, once a marginal field abandoned, the oil that remains behind is often lost permanently. Marginal wells plugged and abandoned between 1994 and 2003 hold an estimated 110 million barrels of crude oil.

Primary and secondary recovery methods are utilized to prevent premature abandonment. Primary recovery refers to the first phase of production, where oil and natural gas flows based on the natural pressure in the reservoir. The term "secondary recovery" encompasses a variety of techniques designed to increase oil recovery from an existing well. Pressure in an underground formation pushes oil upward, allowing it to be extracted. In older wells and mature fields, this pressure has diminished over time, decreasing the flow of oil. Secondary recovery techniques permit the injection of a substance, such as water or gas, into the formation. This increases the pressure and encourages the oil to flow more easily. For example, in Eastern Montana, fracture stimulation is accomplished by injecting sand laden fluid under high pressure into low permeability formations, resulting in increased ability of the oil to flow through the rock. This, combined with horizontal drilling, allows companies to extract previously unrecoverable oil reserves.

Please refer to the additional charts at the end of this section for further information on Marginal Wells.

Tax Provisions:

Recognizing the diminution in value of oil and gas assets, similar to depreciation, the Tax Code allows depletion deductions to recover investments in mineral reserves.

There are two ways to calculate depletion: cost and percentage. Cost depletion, like depreciation, bases the deduction on the original cost of the income-generating property. The tax law permits the taxpayer to divide the cost of the investment by the estimated total of recoverable units in the natural deposit. This cost per unit is subsequently multiplied by the number of units sold annually, which results in the depletion deduction permitted for that year. The taxpayer can deplete up to the total cost of the property.

Under percentage depletion, a percentage of annual income, rather than cost, is deductible each year, even if the owner has recovered all cost of the depletable asset. The amount is determined based on the gross income from the property multiplied by a fixed percentage rate. The percentage is fixed and varied from year to year and mineral to mineral. For example, sulfur is depleted at a 22% rate while gold and oil shale are depleted at a 15% rate. Coal is depleted at a 10% rate.

The other tax incentive discussed at the Roundtable was the marginal well production tax credit. The credit is a maximum of \$3.00 per barrel (\$0.50 per mcf) applied proportionally as the price falls below a trigger point. It begins when the annual average domestic first purchase price of oil falls below \$18.00 per barrel (\$2.00 per mcf) and is fully applied if this price falls below \$15.00 per barrel (\$1.67 per mcf). Because of the price of oil and natural gas, this incentive is totally phased out.

Please see the following JCT description for greater detail on marginal wells.

PRESENT LAW RELATING TO DEPLETION AND MARGINAL WELLS

Depletion (section. 613 and 613A[1])

In general

Depletion, like depreciation, is a form of capital cost recovery. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset--in the case of depletion for oil or gas interests, the mineral reserve itself--is being expended in order to produce income.[2] Certain costs incurred prior to drilling an oil or gas property are recovered through the depletion deduction. These include the cost of acquiring the lease or other interest in the property.

Depletion is available to any person having an economic interest in a producing property. An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in minerals in place, and secures, by any form of legal relationship, income derived from the extraction of the mineral, to which it must look for a return of its capital. Thus, for example, both working interests and royalty interests in an oil- or gas producing property constitute economic interests, thereby qualifying the interest holders for depletion deductions with respect to the property. A taxpayer who has no capital investment in the mineral deposit, however, does not acquire an economic interest merely by possessing an economic or pecuniary advantage derived from production through a contractual relation.

Two methods of depletion are currently allowable under the Internal Revenue Code (the “Code"): (1) the cost depletion method, and (2) the percentage depletion method (section. 611-613). Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the depletable property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the end of taxable year plus the number of units sold during the taxable year. Thus, the amount recovered under cost depletion may never exceed the taxpayer's basis in the property.

The Code generally limits the percentage depletion method for oil and gas properties to independent producers and royalty owners. Under the percentage depletion method generally, 15 percent of the taxpayer's gross income from an oil- or gas-producing property is allowed as a deduction in each taxable year (sec. 613A(c)). The amount deducted generally may not exceed 100 percent of the net income from that property in any year (the "net-income limitation") (sec.613 (a)). For marginal production, discussed infra, this limitation is suspended for taxable years

[1] All section references are to the Internal Revenue Code of 1986, as amended.

[2] In the context of mineral extraction, depreciable assets are generally used to recover depletable assets. For example, natural gas gathering lines, used to collect and deliver natural gas, have a class life of 14 years and a depreciation recovery period of seven years.

beginning after December 31, 1997, and before January 1, 2008**.** Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income for the year (determined before such deduction and adjusted for certain loss carry backs and trust distributions) (sec. 613A (d) (1)). Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's basis in the depletable property, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine the depletion deduction for each oil or gas property under both the percentage depletion method (if the taxpayer is entitled to use this method) and the cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question (sec. 613(a)).

<u>Limitation on oil and gas percentage depletion to independent producers and royalty owners</u>

As stated above, percentage depletion of oil and gas properties generally is not permitted, except for independent producers and royalty owners, certain fixed-price gas contracts, and natural gas from geopressured brine. For purposes of the percentage depletion allowance, an independent producer is any producer that is not a "retailer" or "refiner." A retailer is any person that directly, or through a related person, sells oil or natural gas (or a derivative thereof):

(1) Through any retail outlet operated by the taxpayer or related person, or

(2) to any person that is obligated to market or distribute such oil or natural gas (or a derivative thereof) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the taxpayer or a related person (sec. 613A(d)(2)).

Bulk sales of crude oil and natural gas to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are not treated as retail sales. Further, if the combined gross receipts of the taxpayer and all related persons from the retail sale of oil, natural gas, or any product derived; therefore do not exceed $5 million for the taxable year, the taxpayer will not be treated as a retailer.

A refiner is any person that directly or through a related person engages in the refining of crude oil in excess of an average daily refinery run of 75,000 barrels during the taxable year (sec. 613A(d)(4)).

Percentage depletion for eligible taxpayers is allowed only for up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas (sec. 613A(c)). For producers of both oil and natural gas, this limitation applies on a combined basis. All production owned by businesses under common control and members of the same family must be aggregated (sec. 613A(c) (8)); each group is then treated as one producer for application of the 1,000-barrel limitation.

In addition to independent producers and royalty owners, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressured brine, are eligible for percentage depletion, at rates of 22 percent and 10 percent, respectively. These exceptions apply without regard to the 1,000-barrel-per-day limitation and regardless of whether the producer is an independent producer or an integrated oil company.

Before enactment of the Omnibus Budget Reconciliation Act of 1990, (the "1990 Act"), if an interest in a proven oil or gas property was transferred (subject to certain exceptions), the production from such interest did not qualify for percentage depletion. The 1990 Act repealed the limitation on claiming percentage depletion on transferred properties effective for property transfers occurring after October 11, 1990.

<u>Percentage depletion on marginal production</u>

The 1990 Act also created special percentage depletion provisions for oil and gas production from so-called marginal properties held by independent producers or royalty owners (sec. 613A(c) (6)). Under this provision, the statutory percentage depletion rate is increased (from the general rate of 15 percent) by one percent for each whole dollar that the average price of crude oil for the immediately preceding calendar year is less than $20 per barrel. In no event may the rate of percentage depletion under this provision exceed 25 percent for any taxable year. The increased rate applies for the taxpayer's taxable year that immediately follows a calendar year for which the average crude oil price falls below the $20 floor. To illustrate the application of this provision, the average price of a barrel of crude oil for calendar year 1999 was $15.56. Thus, the percentage depletion rate for production from marginal wells was increased to 19 percent for taxable years beginning in 2000. Since the price of oil currently is above the $20 floor, there is no increase in the statutory depletion rate for marginal production.

The Code defines the term "marginal production" for this purpose as domestic crude oil or domestic natural gas which is produced during any taxable year from a property which (1) is a stripper well property for the calendar year in which the taxable year begins, or (2) is a property substantially all of the production from which during such calendar year is heavy oil (i.e., oil that has a weighted average gravity of 20 degrees API or less, corrected to 60 degrees Fahrenheit) (sec. 613A(c)(6)(D)). A stripper well property is any oil or gas property which produces a daily average of 15 or less equivalent barrels of oil and gas per producing oil or gas well on such property in the calendar year during which the taxpayer's taxable year begins (sec.613A(c) (6) (E)).

The determination of whether a property qualifies as a stripper well property is made separately for each calendar year. The fact that a property is or is not a stripper well property for one year does not affect the determination of the status of that property for a subsequent year. Further, a taxpayer makes the stripper well property determination for each separate property interest (as defined under section 614) held by the taxpayer during a calendar year. The determination is based on the total amount of production from all producing wells that are treated as part of the same property interest of the taxpayer. A property qualifies as a stripper well property for a calendar year only if the wells on such property were producing during that period at their maximum efficient rate of flow.

If a taxpayer's property consists of a partial interest in one or more oil- or gas-producing wells, the determination of whether the property is a stripper well property or a heavy oil property is made with respect to total production from such wells, including the portion of total production attributable to ownership interests other than the taxpayer's interest. If the property satisfies the requirements of a stripper well property, then that person receives the benefits of this provision with respect to its allocable share of the production from the property. The deduction is allowed for the taxable year that begins during the calendar year in which the property so qualifies.

The allowance for percentage depletion on production from marginal oil and gas properties is subject to the 1,000-barrel-per-day limitation discussed above. Unless a taxpayer elects otherwise, marginal production is given priority over other production for purposes of utilization of that limitation.

Marginal wells credit (sec. 45I)

The Code provides a $3-per-barrel credit (adjusted for inflation) for the production of crude oil and a $0.50-per-1,000-cubic-feet credit (also adjusted for inflation) for the production of qualified natural gas. In both cases, the credit is available only for production from a "qualified marginal well."

Qualified marginal well is defined as domestic well:

(1) Production from which is treated as marginal production for purposes of the Code percentage depletion rules; or

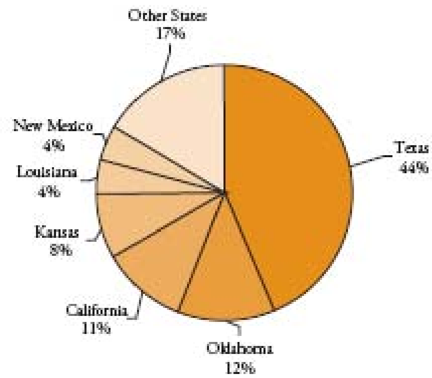
(2) That during the taxable year had average daily production of not more than 25 barrel equivalents and produces water at a rate of not less than 95 percent of total well effluent. The maximum amount of production on which credit could be claimed is 1,095 barrels or barrel equivalents.

The credit is not available to production occurring if the reference price of oil exceeds $18 ($2.00 for natural gas). The credit is reduced proportionately as for reference prices between $15 and $18 ($1.67 and $2.00 for natural gas). Currently the credit is totally phased out.

In the case of production from a qualified marginal well which is eligible for the credit allowed under section 45K for the taxable year, no marginal well credit is allowable unless the taxpayer elects not to claim the credit under section 45K with respect to the well. The credit is treated as a general business credit. Unused credits can be carried back for up to five years rather than the generally applicable carry back period of one year. The credit is indexed for inflation.

u.s. state rankings

	Number of Marginal Oil Wells	Production from Marginal Oil Wells (bbls)	Oil Wells Plugged and Abandoned	Average Daily Production per Well
1	Texas	Texas	Texas	South Dakota
2	Oklahoma	Oklahoma	California	Arizona
3	Kansas	California	Kansas	North Dakota
4	Ohio	Kansas	Oklahoma	Utah
5	California	Louisiana	Louisiana	Alabama
6	Louisiana	New Mexico	Illinois	California
7	Kentucky	Illinois	New Mexico	Michigan
8	Pennsylvania	Wyoming	Ohio	Colorado
9	Illinois	Colorado	Wyoming	Texas
10	New Mexico	Ohio	Kentucky	Nebraska
11	Wyoming	Pennsylvania	Pennsylvania	New Mexico
12	West Virginia	Arkansas	Colorado	Oklahoma
13	Colorado	Michigan	New York	Arkansas
14	Indiana	North Dakota	Arkansas	Tennessee
15	Arkansas	Kentucky	Montana	Montana
16	New York	Montana	Michigan	Louisiana
17	Montana	Utah	Mississippi	Wyoming
18	Michigan	Nebraska	Utah	Kansas
19	Mississippi	Indiana	West Virginia	Illinois
20	Nebraska	West Virginia	North Dakota	Mississippi
21	North Dakota	Alabama	Indiana	Virginia
22	Utah	Mississippi	Nebraska	Indiana
23	Alabama	Tennessee	Tennessee	Pennsylvania
24	Missouri	New York	Missouri	Missouri
25	Tennessee	Missouri	Virginia	Ohio
26	South Dakota	South Dakota	South Dakota	West Virginia
27	Arizona	Arizona	Alabama	Kentucky
28	Virginia	Virginia	Arizona	New York



Percent of Total Marginal Oil Well Production in Survey States (bbls)

Marginal Oil Well Survey: as of

State	Number of Marginal Oil Wells	Production from Marginal Oil Wells (bbls)	Oil Wells Plugged and Abandoned	Average Daily Production Per Well
Alabama	665	911,785	1	3.76
Arizona	17	31,432	0	5.07
Arkansas	4,000	3,317,410	55	2.27
California	26,444	35,563,813	2,410	3.68
Colorado	5,982	7,001,499	105	3.21
Illinois	16,407 *	8,461,222 *	547 *	1.42
Indiana	5,364	1,594,296	22	0.81
Kansas	38,692	25,827,950	2,207	1.83
Kentucky	19,012	1,958,015	178	0.28
Louisiana	20,041	14,152,725	618 *	1.93
Michigan	2,011 *	2,657,497	52	3.62
Mississippi	1,858	895,452	40	1.32
Missouri	495	85,406	7	0.47
Montana	2,424	1,947,855	54	2.20
Nebraska	1,478	1,598,224	19	2.96
New Mexico	14,069	14,065,576	349	2.74
New York	2,553	211,292	70	0.23
North Dakota	1,416	2,217,706	25	4.29
Ohio	28,828	4,840,874	298	0.46
Oklahoma	46,798	39,318,486	1,015	2.30
Pennsylvania	16,662 *	3,652,770 *	171 *	0.60
South Dakota	27	54,169	2	5.50
Tennessee	290	235,127	15 *	2.22
Texas	124,116	139,959,142	4,722	3.09
Utah	1,163	1,618,810	37	3.81
Virginia	3	1,233	4	1.13
West Virginia	7,900	1,300,000	31	0.45
Wyoming	12,357	8,281,804	211	1.84
Totals	**401,072**	**321,761,570**	**13,265**	**2.20**

* *Estimated*

8

January 1, 2006

State	Total 2005 Oil Production (Mbbls)	Marginal Oil Well Reserves (Mbbls)		
		Primary	*Secondary*	*Total*
Alabama	5,159	995	1,035	2,030
Arizona	50	154	0	154
Arkansas	6,338	37,265	31,745	69,010
California	255,676	69,395	62,286	131,681
Colorado	22,918	17,396	13,669	31,065
Illinois	8,889 *	12,736	13,151	25,887
Indiana	1,594	8,824	8,512	17,336
Kansas	33,592	59,107	56,789	115,896
Kentucky	2,454	11,708	17,563	29,271
Louisiana	51,479	59,949	58,761	118,710
Michigan	5,448 *	13,157	9,908	23,065
Mississippi	17,917	10,861	10,026	20,887
Missouri	85	1,342	1,263	2,605
Montana	32,870	29,673	34,834	64,507
Nebraska	2,413	2,568	4,672	7,240
New Mexico	54,179	22,560	19,216	41,776
New York	211	1,205	117	1,322
North Dakota	35,672	24,361	23,500	47,861
Ohio	5,652	34,187	113	34,300
Oklahoma	60,939	86,472	93,678	180,150
Pennsylvania	3,653 *	8,483	11,715	20,198
South Dakota	1,469	180	173	353
Tennessee	327	194	135	329
Texas	346,351	495,958	532,634	1,028,592
Utah	16,658	1,618	3,141	4,759
Virginia	26	40	38	78
West Virginia	1,300 *	3,548	3,244	6,792
Wyoming	51,626	75,000	100,000	175,000
Totals	**1,024,945 ****	**1,088,936**	**1,111,918**	**2,200,854**

* *Estimated*

** *Total represents only oil production from states with stripper wells.*

Roundtable 4: Independents
January 26, 2007

Speakers:

John M. Colglazier – Director, Investor Relations, Anadarko Petroleum Corp.
Gina Sewell - VP for Tax, Devon Energy Corp.
Alan Harrison – VP, Williams Production RMT Company, Denver

Independent Oil and Gas Company Roundtable (1/26/07):

This roundtable focused on 'independent' oil and gas producers -- companies ranging in size from small firms like Prospector Oil, operating in Eastern Montana, to large companies like Valero and Marathon, both of which had income of over $5 billion in 2006. While the 'independent' definition is inexact, the term generally refers to companies engaged in exploration and production of oil and natural gas. This differs from the definition of major integrated firms (ExxonMobil, Chevron, BP, Shell and ConocoPhilips, aka the 'Majors'), whose activities extend beyond exploration and production to refining and marketing of oil and gas. The Majors are defined in the Code as firms which have: average daily worldwide production of crude oil of at least 500,000 barrels for the taxable year; gross receipts in excess of $1 billion for its last taxable year ending during CY 2005; and (generally) an ownership interest in a crude oil refiner of 15 percent or more. See the Integrateds roundtable (week 5) for more information.

Background:

Speakers at the Independents roundtable provided background on some of the larger players in this sector, including their efforts toward enhanced oil recovery in the Northern Plains (see below). Speakers stressed both dramatic advances in exploration and production know-how in recent years, as well as a sharp rise in the costs of procuring and using that technology. New means of exploration and production include the use of 3D seismic instrumentation, as well as advanced drill-bit technology (next page).

Hard-rock bit; lasts approx. 10k ft.
Figure 1

Soft-rock/sand bit; lasts 500-3000 ft.
Figure 2

Oil Exploration and Production:

Crude oil, a yellow-to-black liquid, is a product of the decayed remains of prehistoric marine animals and plants. Over many centuries, organic matter in mud was buried under additional thick sedimentary layers which, when subject to heat and pressure, caused crude oil-saturated shales to form. Oil oozed from these shales, and then moved through adjacent rock layers until it became trapped underground in porous reservoirs. These reservoir rocks hold the oil like a sponge, confined by other; non-porous layers that form a "trap." (See Figure 4)

Crude oil is measured in barrels. A barrel of 42-U.S. gallons of crude oil yields more than 44 gallons of petroleum products. This "process gain" of volume is due to a reduction in the density during the refining process. In 2005, one barrel of crude oil, when refined, yielded 19.4 gallons of finished motor gasoline, as well as smaller quantities of many other petroleum products. (See Table 1)

In 2005, total domestic crude oil field production, including offshore, averaged just over 5.1 million barrels per day. The top crude oil-producing States are Texas, Alaska, California, Louisiana, Oklahoma, and New Mexico. Gulf of Mexico offshore production in 2005 was 1,282,000 barrels per day.

Petroleum Products Yielded from One Barrel of Crude, 2005	
Product	**Gallons**
Finished Motor Gasoline	19.40
Distillate Fuel Oil	10.50
Kero-Type Jet Fuel	4.12
Petroleum Coke	2.23
Still Gas	1.81
Residual Fuel Oil	1.68
Liquefied Refinery Gas	1.51
Asphalt and Road Oil	1.34
Naptha for Feedstocks	0.59
Other Oils for Feedstocks	0.46
Lubricants	0.46
Kerosene	0.17
Miscellaneous Products	0.17
Special Naphthas	0.08
Finished Aviation Gasoline	0.04
Waxes	0.04
Total	**44.60**

Table 1

Exploration: To identify a prospective site for oil production, companies use a variety of techniques, including core sampling -- physically removing and testing a cross section of the rock -- and seismic testing, where the return vibrations from shockwaves are measured and calibrated. This exploration is treated in the Code as Geological and Geophysical (G&G) cost. (See Below)

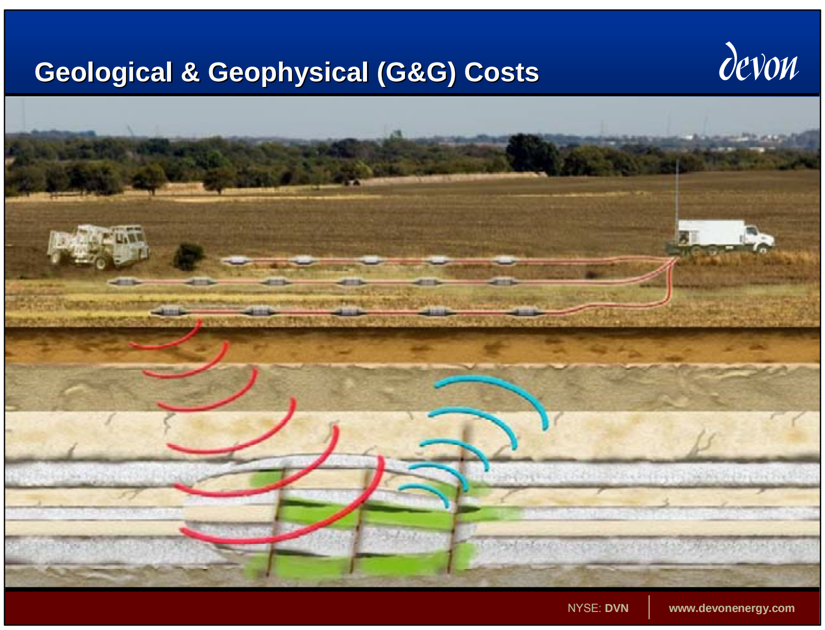


Figure 3 G&G Activity

After these exploratory tests, companies must then drill to confirm the presence of oil or gas. A "dry hole" is an unsuccessful well, one where the drilling did not find oil or gas, or not enough to be economically viable. A successful well may contain either oil or gas, and often both, because the gas is dissolved in the oil. When gas is present in oil, it is extracted from the liquid at the surface in a process separate from oil production.

***Preparing to Drill*:** Once the site has been selected, then a number of procedures must be followed before drilling can begin. These may include environmental impact studies, completion of lease agreements, and determination of titles and rights-of way for the land. For off-shore sites, legal jurisdiction must be determined. After these issues have been settled, the land is cleared and leveled, and access roads may be built. Because water is used in drilling, there must be a source of water nearby. If there is no natural source a water well is drilled.

Once the land has been prepared, several holes must be dug to make way for the rig and the main hole. A rectangular pit, called a cellar, is dug around the location of the actual drilling hole. The cellar provides a work space around the hole, for the workers and drilling accessories. The crew then begins drilling the main hole, often with a small drill truck rather than the main rig. The first part of the hole is larger and shallower than the main portion, and is lined with a large-diameter conductor pipe. Additional holes are dug off to the side to temporarily store equipment -- when these holes are finished, the rig equipment can be brought in and set up.

Drilling: Before production can begin, the rig must be set up. This process begins by drilling a hole down to a pre-set depth somewhere above where the petroleum trap is located. (See Figure 5). Once the pre-set depth is reached, the crew must 'run and cement' the casing -- place casing-pipe sections into the hole to prevent it from collapsing in on itself. The casing pipe has spacers around the outside to keep it centered in the hole The casing crew puts the casing pipe in the hole while the cement crew pumps cement down the casing pipe using a bottom plug, cement slurry, a top plug and drill mud. The pressure from the drill mud causes the cement slurry to move through the casing and fill the space between the outside of the casing and the hole. Finally, the cement is allowed to harden and then tested for such properties as hardness, alignment and a proper seal.

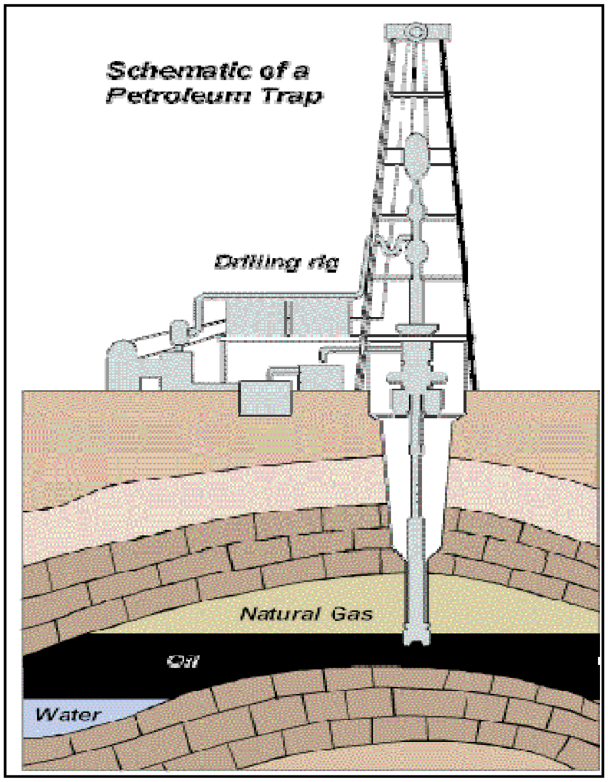


Figure 4 - Petroleum Trap

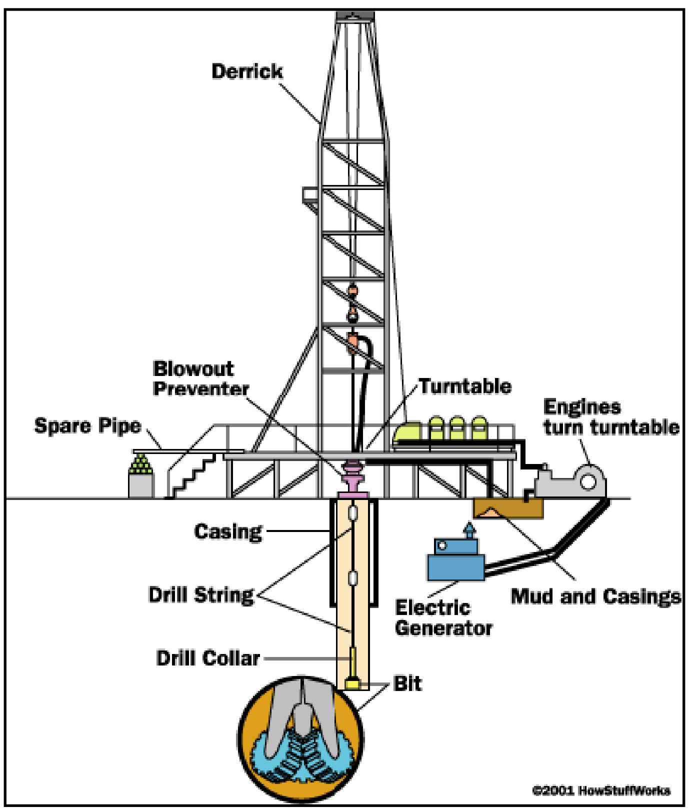


Figure 5 - Schematic of a Drilling Rig

Drilling continues in stages the crew drills, then run and cement new casings, then drills again. When the rock cuttings from the mud reveal the oil sand from the reservoir rock, they may have reached the final depth. At this point, they remove the drilling apparatus from the hole and perform several tests to confirm that the appropriate depth has been reached. Once the crew has reached the final depth, oil is allowed to flow into the casing in a controlled manner. This is done by lowering a perforating gun into the well to the production depth. The gun has explosive charges to create holes in the casing through which oil can flow. After the casing has been perforated, they run a small-diameter pipe (tubing) into the hole as a conduit for oil and gas to flow up the well. A device called a packer is run down the outside of the tubing. When the packer is set at the production level, it is expanded to form a seal around the outside of the tubing. Finally, they connect a multi-valve structure called a Christmas tree to the top of the tubing and cement it to the top of the casing. The Christmas tree allows for control of the flow of oil from the well.

Production: Once the oil is flowing, the oil rig is removed, a pump is placed on the wellhead, and production begins. (See Below)

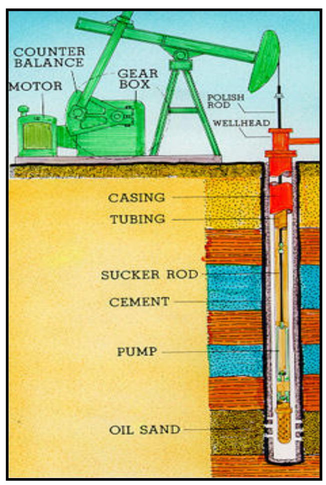


Figure 6 Oil Pump

Over time, the production method depicted above becomes ineffective, and secondary production methods are needed. One common method uses water to displace oil, using a method called water flood, which forces the oil to the drilled shaft or "well bore." Finally, producers may need to turn to enhanced oil recovery (EOR) methods, techniques often requiring the use of steam, CO_2 or other gases or chemicals. Examples of primary, secondary and EOR are shown in the diagrams below. (Figure 7)

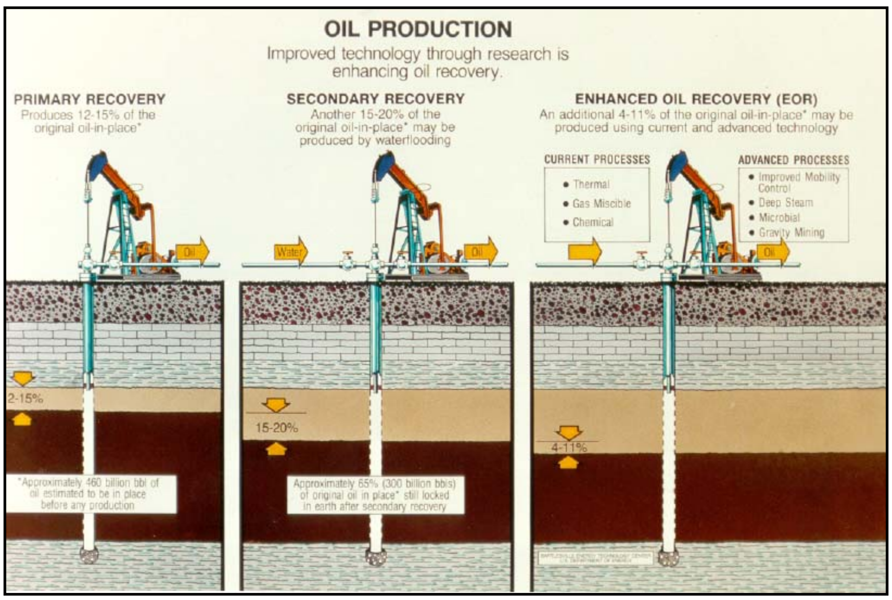


Figure 7- Oil Recovery Methods

PRESENT LAW REGARDING GEOLOGICAL AND GEOPHYSICAL EXPENSES AND INTANGIBLE DRILLING COSTS

Amortization of Geological and Geophysical Expenditures (sec. 167(h))[1]

Geological and geophysical expenditures ("G&G costs") are costs incurred by a taxpayer for the purpose of obtaining and accumulating data that will serve as the basis for the acquisition and retention of mineral properties by taxpayers exploring for minerals. G&G costs incurred by independent producers and smaller integrated oil companies in connection with oil and gas exploration in the United States may generally be amortized over two years.[2]

Major integrated oil companies are required to amortize all G&G costs over five years for costs incurred after May 17, 2006 (the date of enactment of the Tax Increase Prevention and Reconciliation Act of 2005, Pub. L. No. 109-222). A major integrated oil company, as defined in section 167(h) (5) (B), is an integrated oil company which has an average daily worldwide production of crude oil of at least 500,000 barrels for the taxable year, had gross receipts in excess of one billion dollars for its last taxable year ending during the calendar year 2005, and generally has an ownership interest in a crude oil refiner of 15 percent or more.

In the case of abandoned property, remaining basis may not be recovered in the year of abandonment of a property as all bases are recovered over the applicable amortization period.

Intangible Drilling and Development Costs (section. 263(c), 291(b) (1) (A), and 59(e) (1))

The Code provides special rules for the treatment of intangible drilling and development costs ("IDCs"). Under these special rules, an operator or working interest owner[3] that pays or incurs IDCs in the development of an oil or gas property located in the United States may elect either to expense or capitalize those costs (sec. 263(c)).

IDCs include all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. In addition, IDCs include the cost

[1] Unless otherwise noted, all section references are to the Internal Revenue Code of 1986, as amended (the "Code").

[2] This amortization rule applies to G&G costs incurred in taxable years beginning after August 8, 2005, the date of enactment of the Energy Policy Act of 2005, Pub. L. No. 109-58. Prior to the effective date, G&G costs associated with productive properties were generally deductible over the life of such properties, and G&G costs associated with abandoned properties were generally deductible in the year of abandonment.

[3] An operator or working interest owner is defined as a person that holds a working or operating interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting working or operating rights.

To operators of any drilling or development work done by contractors under any form of contract, including a turnkey contract. Such work includes labor, fuel, repairs, hauling, and supplies which are used (1) in the drilling, shooting, and cleaning of wells; (2) in the clearing of ground, draining, road making, surveying, and geological works as necessary in preparation for the drilling of wells; and (3) in the construction of such derricks, tanks, pipelines, and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Generally, IDCs do not include expenses for items that have a salvage value (such as pipes and casings) or items that are part of the acquisition price of an interest in the property.[4] They also do not include the cost to operators (1) payable only out of production or gross or net proceeds from production, if the amounts are depletable income to the recipient, and (2) amounts properly allocable to the cost of depreciable property.

If an election to expense IDCs is made, the taxpayer deducts the amount of the IDCs as an expense in the taxable year the cost is paid or incurred. Generally, if IDCs are not expensed, but are capitalized, they may be recovered through depletion or depreciation, as appropriate. In the case of a nonproductive well ("dry hole"), IDCs may be deducted at the election of the operator.[5] for an integrated oil company that has elected to expense IDCs, 30 percent of the IDCs on productive wells must be capitalized and amortized over a 60-month period (sec. 291(b) (1) (A)).[6]

Notwithstanding the fact that a taxpayer has made the election to deduct IDCs, the Code provides an additional election under which the taxpayer is allowed to capitalize and amortize certain IDCs over a 60-month period beginning with the month the expenditure was paid or incurred (sec. 59(e)(1)). This rule applies on an expenditure-by-expenditure basis; that is, for any particular taxable year, a taxpayer may deduct some portion of its IDCs and capitalize the rest under this provision. This allows the taxpayer to reduce or eliminate the IDC adjustments or preferences under the alternative minimum tax.

The election to deduct IDCs applies only to those IDCs associated with domestic properties.[7] For this purpose, the United States includes certain wells drilled offshore.[8]

[4] Treas. Reg. sec. 1.612-4(a).

[5] Treas. Reg. sec. 1.612-4(b)(4).

[6] The IRS has ruled that, if a company that has capitalized and begun to amortize IDCs over a 60-month period pursuant to section 291 ceases to be an integrated oil company, it may not immediately write off the unamortized portion of the capitalized IDCs, but instead must continue to amortize the IDCs so capitalized over the 60-month amortization period. Rev. Rul. 93-26, 1993-1 C.B. 50.

[7] In the case of IDCs paid or incurred with respect to an oil or gas well located outside of the United States, the costs, at the election of the taxpayer, are either (1) included in adjusted basis for purposes of computing the amount of any deduction allowable for cost depletion or (2) capitalized and amortized ratably over a 10-year period beginning with the taxable year such costs were paid or incurred (sec. 263(i)).

[8] The term "United States" for this purpose includes the seabed and subsoil of those submarine areas that are adjacent to the territorial waters of the United States and over which the United States has exclusive rights, in accordance with international law, with respect to the exploration and exploitation of natural resources (i.e., the Continental Shelf area) (sec. 638).

Pursuant to a special exception, the uniform capitalization rules do not apply to IDCs incurred with respect to oil or gas wells that are otherwise deductible under the Code (sec.263A(c)(3)).

Roundtable 5: Integrateds
February 2, 2007

Speakers:

Terry O'Connor – Vice President, External and Regulatory Affairs, Shell
Gary Schoonveld – Manager Fuels and Regulatory Affairs, Conoco Phillips

Integrated Oil and Gas Company Roundtable (2/2/07):

Over the last several Roundtables, we have connected the dots between the extractions of mineral resources, the transportation infrastructure required for delivery of unfinished and finished product, and the facilities that convert unfinished product into useful end products. Last week we focused on independent oil and gas companies. At the third Roundtable, we discussed tax issues facing all refineries, but we also discussed large integrated oil companies in the downstream market. Rather than revisit the downstream market, we focused this Roundtable on next-generation technologies two major oil and gas companies are utilizing or planning to utilize.

Background:

Oil Shale:

Oil shale is prevalent in the western states of Colorado, Utah, and Wyoming. The resource potential of this shale is estimated to be as much as 1.9 trillion barrels of oil. (See Chart 1) In comparison, Saudi Arabia reportedly holds proved reserves of 267 billion barrels. (See Chart 2) However, because oil shale has not proved to be economically recoverable, it is considered a contingent resource, and not true reserves. It remains to be demonstrated whether an economically significant oil volume can be extracted under existing operating conditions.

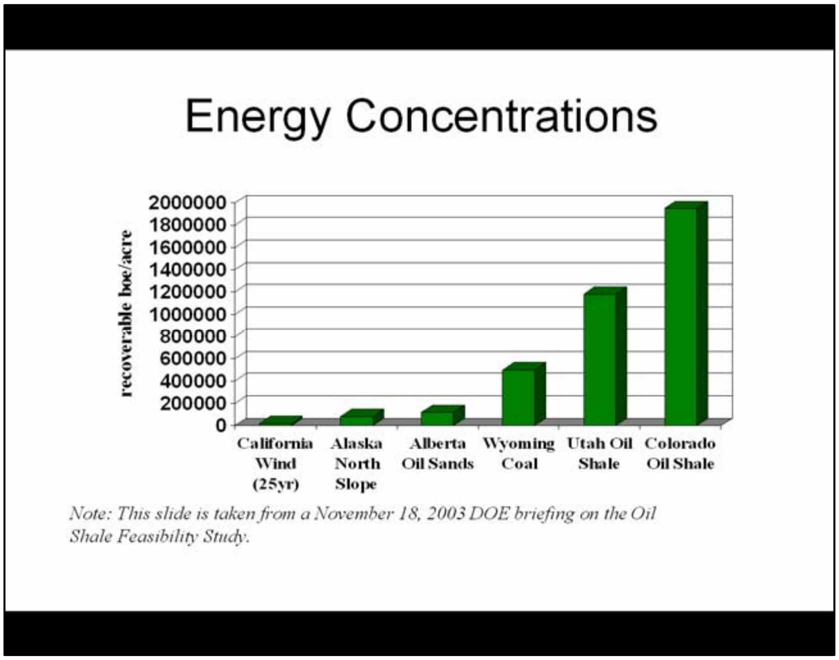


Chart 1

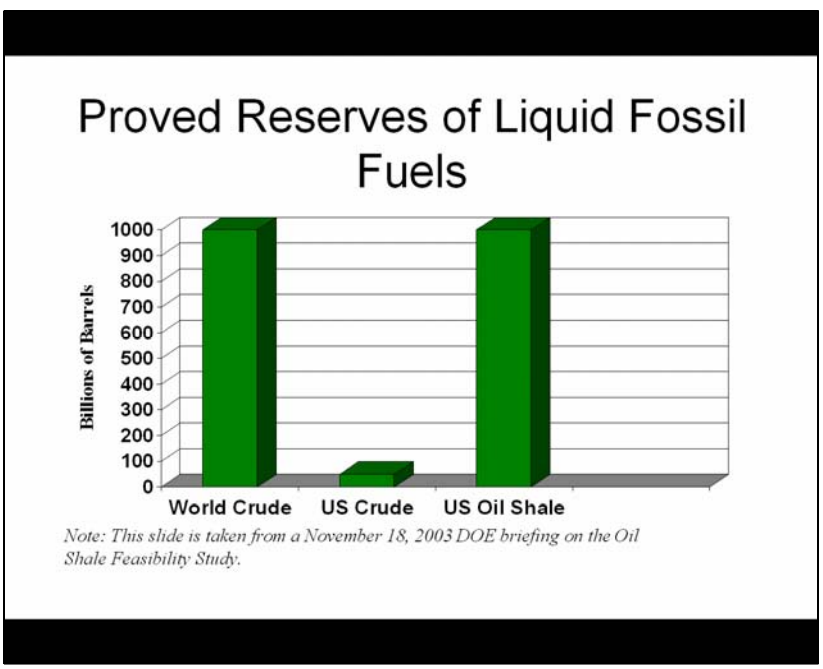


Chart 2

Federal interest in oil shale dates back to the early 20th Century, when the Naval Petroleum and Oil Shale Reserves were set aside. Out of World War II concerns for a secure oil supply, a Bureau of Mines program began research into exploiting the resource. Commercial interest followed during the 1960s. After a second oil embargo in the 1970s, Congress created a synthetic fuels program to stimulate large-scale commercial development of oil shale and other unconventional resources. The federal program proved short-lived, and commercially backed oil shale projects ended in the early 1980s when oil prices began declining.

Current high oil prices have revived the interest in oil shale. The 2005 Energy Bill identified oil shale as a strategically important domestic resource, among others, that should be developed. The 2005 Energy Bill also directed the Secretary of Defense to develop a separate strategy to use oil shale in meeting Department of Defense (DOD) requirements when doing so is in the national interest. Tapping unconventional resources, such as oil shale, has been promoted as a means of reducing dependence on foreign oil and improving national security. The bottom line in developing a large oil shale industry will be governed by the price of petroleum-based crude oil. When the price of shale oil is comparable to that of crude oil because of diminishing resources of crude, then shale oil may find a place in the world fossil energy mix.

Oil shale can either be mined through traditional underground mining where the rock is brought to the surface and then transported to a processing facility, or it can be processed through a method called "in-situ" (where it is). In-situ processing is the fracturing, heating and processing of the oil shale in the ground. Mr. O'Connor, of Shell, described the process as "phantom refining" because the product brought out of the ground is much closer to being a finished fuel, needing very minimal refining relative to traditional petroleum.

<u>Shell:</u>

Shell Oil Company has developed a new method of in-situ processing that it is utilizing under the name of the Mahogany Research Project in the Green River Basin of Western Colorado, approximately 200 miles west of Denver. The goal is to heat sections of the oil shale field deep underground, releasing the oil and pumping it to the surface. The process heats the oil shale rock to a temperature of 700 degrees Fahrenheit using heating elements that are embedded down into the rock, sometimes as far as 2,000 feet. The oil and natural gas is then baked out of the rock creating pools that are pumped to the surface.

A problem with the process is that the oil soaks down and into the ground shortly after being turned into liquid. Groundwater, much like a river on the surface of the Earth, flows like a river. To mitigate this problem, Shell buried refrigeration pipes in a ring around the heating site so that the edges of the extraction site will remain solid and hold the liquid oil in place. This process requires drilling 2,000 foot holes eight feet apart and piping into these holes a refrigerant at -45 degrees Fahrenheit. (See Charts) The refrigerant which is the same used in conventional refrigerators, creates an ice wall approximately 30 to 40 feet thick around the oil shale. Mr. O'Connor analogized the functioning of the ice wall to a barrel in a river - the water flows around the barrel. The area inside the ice wall is then dewatered. This process requires a great deal of electricity, but the process produces more energy than it expends (approximately 3.5 times as much energy comes out as goes in).

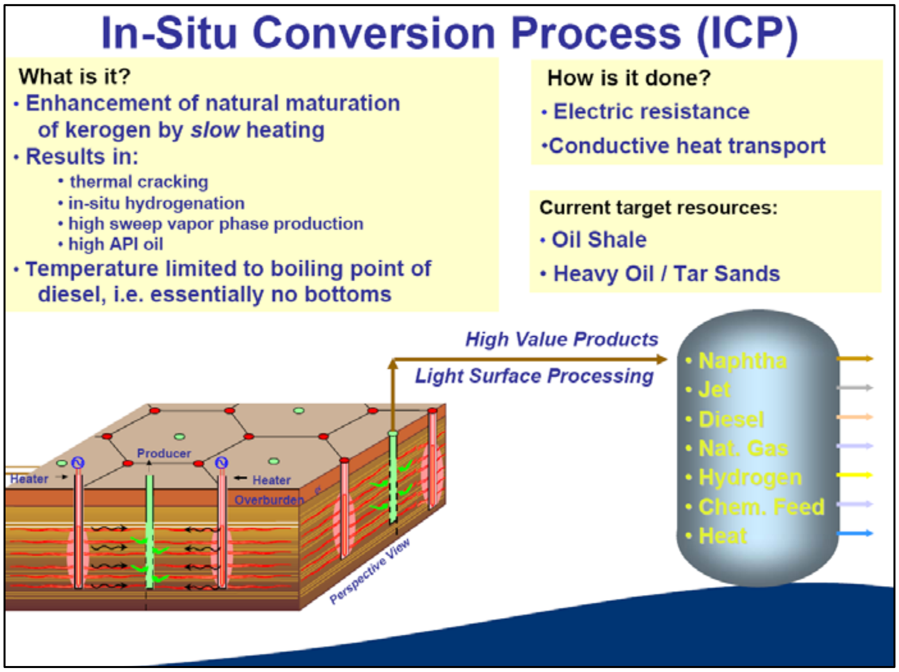


Chart 3

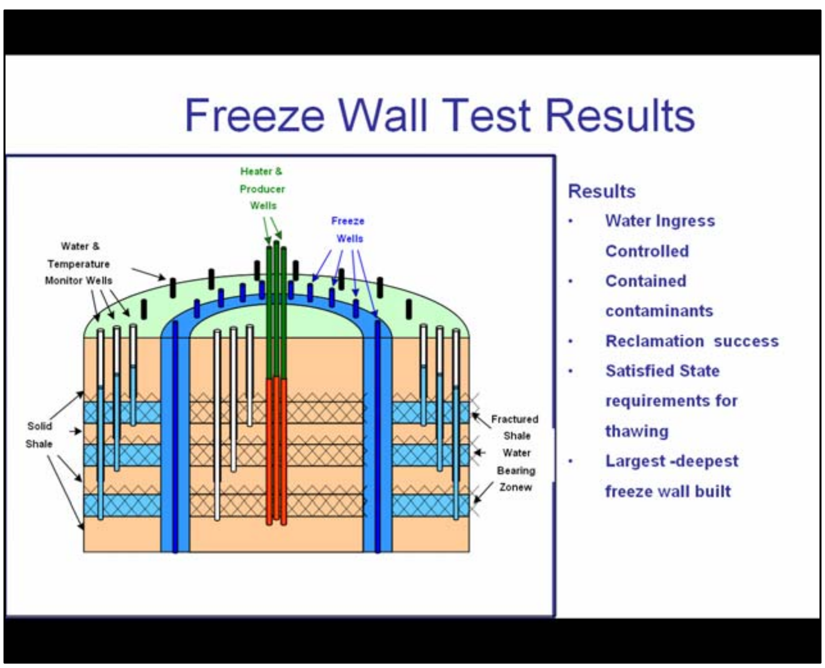


Chart 4

Recovery wells are then drilled approximately 40 feet apart inside the freeze wall, called the working zone. Electrical heating elements are lowered into each recovery well and heat the oil shale to approximately 700 degrees Fahrenheit over a period of four years. The oil shale is gradually broken down into oils and gases which are then pumped to the surface. To maximize the use of the freeze walls, the working zones are placed adjacent to each other.

The traditional underground mining method for oil shale is essentially open-pit mining. And similar to open-pit mines for coal and other minerals, there are significant environmental considerations that must be factored in, such as reclamation of the surface, water needs and disposal of waste material. The in-situ process is a much more environmentally attractive method to extract the oil from shale due to the reduction in standard surface environmental problems. However, there is still the possibility of significant environmental costs to groundwater aquifers if the ice wall were to break.

Renewable Diesel:

Diesel fuel can be produced from biomass via several types of technologies. Some use specific biomass components, while others can convert many forms of biomass into fuel. Currently, the tax code distinguishes between different technologies in several ways. Without getting into detail covered in the the bio-fuels roundtables, bio-diesel receives a 50 cent per gallon tax credit and agribio-diesel (from virgin oils) receives $1 per gallon.

In the 2005 Energy Policy Act, Congress established a new $1 per gallon tax credit for renewable diesel, or diesel derived from biomass as defined in Section 45K(c)(3) using "thermal depolymerization." In this process, biomass is reacted with water at an elevated temperature and pressure to form oils and residual solids. Renewable diesel technology has been deployed by Changing World Technologies (CWT). CWT states that its product meets the requirements of the American Society of Testing and Materials (ASTM) for D975, bio-diesel fuel.

ConocoPhillips:

ConocoPhillips is commercializing renewable diesel technology through a traditional hydroprocessing technology. The process starts with crude oil, which is processed in the crude distillation tower at the refinery and converted into straight-run diesel fuel. Biomass-derived oils are then hydroprocessed as a co-feed into the straight-run diesel. The final product is compatible with exsisting pipelines infrastructure, and Conocophillips claims that the finished fuel meets ultra-low-sulfur-diesel (ULSD) specifications. (See Chart 5)

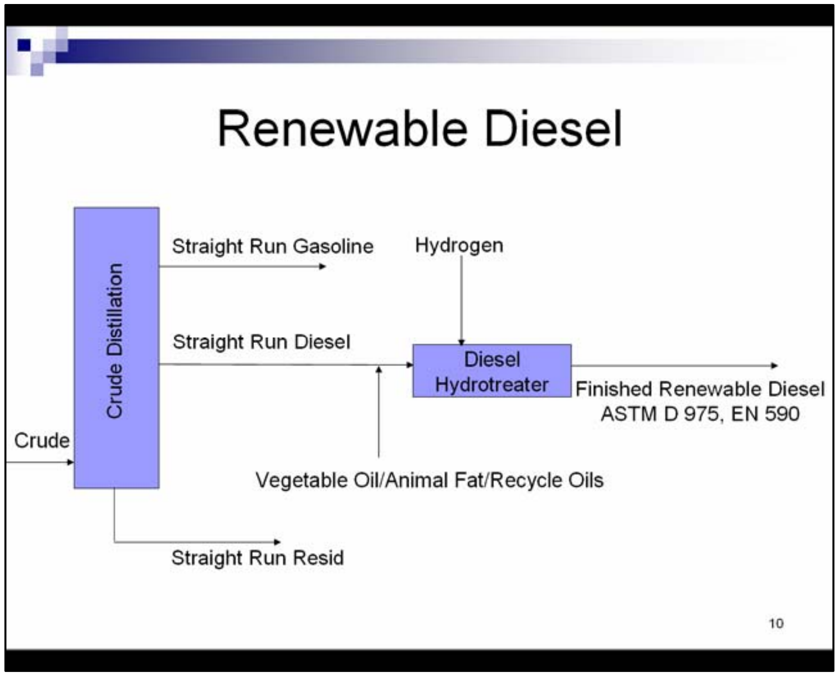


Chart 5

ConocoPhillips is not the only company utilizing or attempting to utilize renewable diesel. Neste has announced a commercial facility in Finland. Petrobras has announced plans to introduce several refineries in Brazil and BP is active in Australia.

For more information on petroleum and biomass fuels please see the 2004 NREL report titled, "Biomass Oil Analysis: Research Needs and Recommendations." http://www1.eere.energy.gov/biomass/pdfs/34796.pdf

PRESENT LAW REGARDING ENHANCED OIL RECOVERY COSTS AND FUEL PRODUCED FROM A NONCONVENTIONAL SOURCE

Credit for Enhanced Oil Recovery Costs (sec. 43) [1]

Taxpayers may claim a credit equal to 15 percent of enhanced oil recovery ("EOR") costs (sec. 43). Qualified EOR costs include the following costs associated with an EOR project: (1) amounts paid for depreciable tangible property; (2) intangible drilling and development expenses; (3) tertiary injectant expenses; and (4) construction costs for certain Alaskan natural gas treatment facilities.

The EOR credit is ratably reduced over a $6 phase-out range when the reference price for domestic crude oil exceeds $28 per barrel (adjusted for inflation after 1991). The reference price is determined based on the annual average price of domestic crude oil for the calendar year preceding the calendar year in which the taxable year begins (section. 43(b) and 45K(d)(2)(C)).[2]

Taxpayers claiming the EOR credit must reduce by the amount of the credit any otherwise allowable deductions associated with EOR costs. In addition, to the extent a property's basis would otherwise be increased by any EOR costs, such basis is reduced by the amount of the EOR credit.

Credit for Producing Fuel from Unconventional Sources (sec. 45K)

Certain fuels produced from "non-conventional sources" and sold to unrelated parties are eligible for an income tax credit equal to $3 (generally adjusted for inflation)[3] per barrel or Btu oil barrel equivalent ("non-conventional source fuel credit").[4] Qualified fuels must be produced within the United States.

Qualified fuels include:

- oil produced from shale and tar sands;
- gas produced from geopressured brine, Devonian shale, coal seams, tight formations, or biomass; and
- Liquid, gaseous, or solid synthetic fuels produced from coal (including lignite).

[1] Unless otherwise noted, all section references are to the Internal Revenue Code of 1986, as amended (the "Code").

[2] The inflation adjustment factor for 2006 was 1.3743, so the $6 phase-out range for the EOR credit begins as the reference price for domestic crude oil exceeds $38.48 per barrel. Since the reference price for 2005 was $50.26 per barrel there was no EOR credit for 2006.

[3] The inflation adjustment is generally calculated using 1979 as the base year. Generally, the value of the credit for fuel produced in 2005 was $6.79 per barrel-of-oil equivalent produced, which is approximately $1.20 per thousand cubic feet of natural gas. In the case of fuel sold after 2005, the credit for coke or coke gas is indexed for inflation using 2004 as the base year instead of 1979.

[4] Sec. 29 (for tax years ending before 2006); sec. 45K (for tax years ending after 2005).

Generally, the non-conventional source fuel credit has expired, except for certain biomass gas and synthetic fuels sold before January 1, 2008, and produced at facilities placed in service after December 31, 1992, and before July 1, 1998.

The non-conventional source fuel credit provision also includes a credit for coke or coke gas produced at qualified facilities during a four-year period beginning on the later of January 1, 2006, or the date the facility was placed in service. For purposes of the coke production credit, qualified facilities are facilities placed in service before January 1, 1993, or after June 30, 1998, and before January 1, 2010. Qualified facilities do not include facilities that produce petroleum-based coke or coke gas. The amount of credit-eligible coke produced at any one facility may not exceed an average barrel-of-oil equivalent of 4,000 barrels per day.

Except with respect to coke or coke gas, the non-conventional source fuel credit is reduced (but not below zero) over a $6 (inflation-adjusted) phase-out period as the reference price for oil exceeds $23.50 per barrel (also adjusted for inflation). The reference price is the Secretary's estimate of the annual average wellhead price per barrel for all domestic crude oil. The credit did not phase-out for 2005 because the reference price for that year of $50.26 did not exceed the inflation adjusted threshold of $53.20. Beginning with taxable years ending after December 31, 2005, the non-conventional source fuel credit is part of the general business credit (sec. 38).

OTHER PROVISIONS AFFECTING INTEGRATED OIL COMPANIES DISCUSSED IN PREVIOUS BRIEFINGS

Cost Recovery Provisions

1. Alaska natural gas pipeline (sec. 168) - Discussed January 5, 2007

2. Natural gas gathering lines (sec. 168) - Discussed January 5, 2007

3. Temporary election to expense 50 percent of qualified property used in refining liquid fuels (sec. 179C) - Discussed January 12, 2007

4. Depletion (section. 613 and 613A) - Discussed January 19, 2007 (integrated oil companies may only use cost depletion, not percentage depletion)

5. Geological and geophysical expenditures (sec. 167(h)) - Discussed January 26, 2007 (major integrated oil companies required to amortize over five years)

6. Intangible drilling and development costs (section. 263(c), 291(b)(1)(A), and 59(e)(1)) - Discussed January, 26, 2007 (integrated oil companies can elect to expense only 70 percent of IDCs in the year incurred and capitalize the remaining portion to be recovered over 60 months)

Other Provisions

1. Deduction for domestic production activities (sec. 199) - Discussed January 12, 2007

2. Oil Spill Liability Trust Fund tax (sec. 4611) - Discussed January 12, 2007

Roundtable 6: Electricity Transmission
February 9, 2007

Speakers:

Robert P. Powers – Executive Vice President, American Electric Power Utilities-East
Timothy A. King – Chief Tax Counsel, American Electric Power Service Corporation, Columbus, Ohio
Jonathan M. Weisgall – Vice President, Legislative and Regulatory Affairs, MidAmerican Energy Holdings Company

Electricity Transmission Roundtable (2/9/07):

The Roundtable focused on the electric transmission infrastructure in the United States. Robert Powers discussed the transmission and integration of renewable power. Tim King spoke about the tax normalization requirements to compute the income tax component of a regulated utility's rates. Finally, Jonathan Weisgall focused on renewable energy transmission and the production tax credit. A technical description of the tax provisions relating to electricity transmission, depreciation, and the qualifying advanced coal project credit is attached to this memo.

Background:

The electric power system was developed to fit the regulatory framework established in the 1920 Federal Power Act. Today, the electric power industry operates under a changing regulatory system at both the federal and state level. The most recent comprehensive energy bill, the 2005 Energy Bill, attempted to address electric reliability and infrastructure investment, by providing more than $3 billion in incentives to bolster U.S. electricity infrastructure. Also, the bill established an electric reliability organization to enforce reliability standards for the bulk-power system. In addition to Congressional activity, the Department of Energy issued the first *National Electric Transmission Congestion Study* in August 2006, and additional studies are required every three years. The DOE study identified Southern California and the eastern coastal area from metropolitan New York south to Northern Virginia as congested areas. The 2005 Energy Bill also streamlined the placing of sites for transmission facilities. The placing and building of transmission sites can be controversial because of civic opposition and environmental impact issues.

There are three core elements of the electric power delivery: generation, transmission and distribution. Transmission is analogous to the U.S. highway system and is generally considered an interstate operation, whereas distribution is considered intrastate. (See Chart 1) Robert Powers noted that there are thermal and voltage limits to transmission, which affect system operations. The resistance created by the movement of electrons in transmission can cause heat to be produced; overheating can lead to efficiency loss and transmission line expansion, reducing the life of the line.

The amount of electricity that can be transmitted across these three systems is determined by the voltage class of the power line. The higher the voltage, the higher the efficiency this way more electricity can be transmitted over long distances.

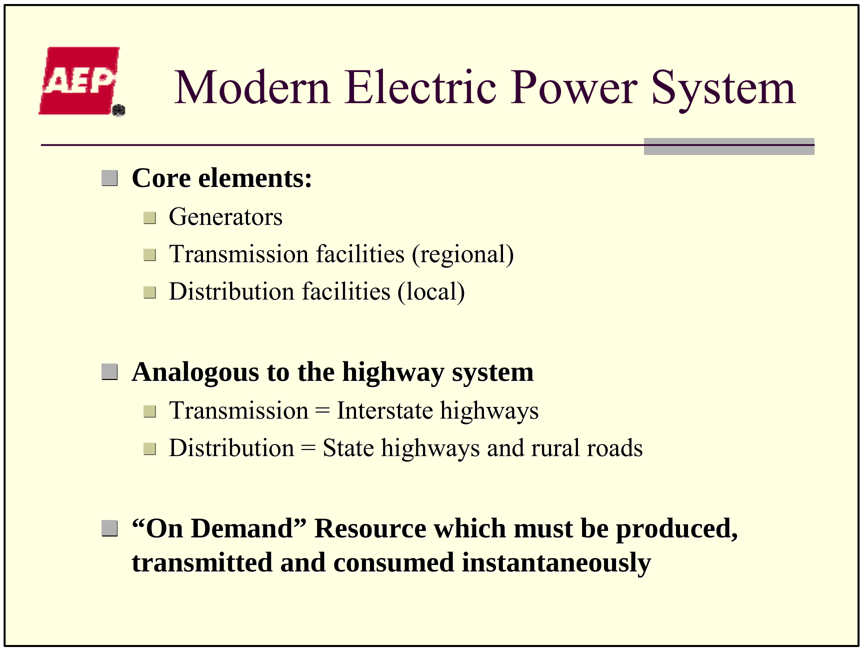


Chart 1

Finally, the speakers discussed the effect of the Section 45 production tax credit on electricity transmission. Powers gave examples of how different renewable resources tie into the transmission system, depending on their size. The larger resources have to connect to a transmission system, which presents a challenge for energy produced in remote areas, such as wind. Absent a coordinated plan for distribution and transmission of wind power, generators of electricity will not be able to move the resource to market where there is a weak transmission grid.

Jonathan Weisgall explained that MidAmerican, as well as other companies, has already developed the "low-hanging renewable fruit," namely developing projects close to existing transmission lines with the capacity to receive that power. The production tax credit helps make projects located further from transmission lines economical, but the short-term nature of the credit discourages long-term investment planning especially for more capital intensive renewable energy such as geothermal, biomass, small hydro, and landfill gas.

Rising transmission costs are also an impediment to expanding electric transmission systems. Of the 460 megawatts of wind that MidAmerican Energy Company owns and operates, the company has spent about $7 million on transmission upgrades, which amounts to only about $15.25/kilowatt installed. The next 75 megawatts that MidAmerican develops will require about $12 million in transmission upgrades, or $160/kilowatt installed – a more than 10-fold increase in transmission costs. For wind, in

2004, the average cost was about $1,000-1,100/kilowatt installed. The price has nearly doubled in three years. Of this increase, about 20% of it is attributable to necessary technology (taller towers, longer blades, and higher capacity turbine). The rest of the cost reflects supply-demand price hikes and increased commodity costs, especially for steel.

Tax Provisions:

The Joint Committee on Taxation discussed accelerated depreciation for transmission lines as well as the clean coal investment tax credit, both created in the 2005 Energy Policy Act. There was also brief discussion of the Section 45 production tax credit, which is intimately tied to electricity transmission. Both the clean coal investment tax credit and the electricity production tax credit will be the topic of future roundtables.

To encourage build-out of the U.S. transmission infrastructure, Congress provided 15-year accelerated depreciation for electric transmission lines in the 2005 Energy Policy Act. This change is a permanent provision and cost just over $1 billion.

In addition, AEP focused on a system of taxation unique to the regulated utility industry: tax normalization. The normalization rules in the Internal Revenue Code govern how, and when, certain tax benefits are included in tax expense in setting rates for regulated utilities. Normalization spreads the tax benefits attributable to utility assets ratably over the useful life of the assets, and prohibits public utility commissions from taking these tax benefits into account over a shorter period than the regulatory life of the assets. The penalty for violation of the normalization rules is the loss of the tax benefits.

Tax benefits that are subject to the normalization rules are accelerated depreciation, currently modified accelerated cost recovery system (MACRS) and the investment tax credit. Normalization does not apply to the production tax credit under section 45 of the Internal Revenue Code (Sec. 45 a business credit, not an investment credit). Normalization is required because accelerated depreciation and the investment credit were intended to provide an incentive for investment in capital equipment and plant modernization, for public utilities as well as other capital intensive industries. For public utilities, if the tax benefits were immediately passed through to electricity consumers to reduce electric rates, there would be no tax incentive for utility investment.

For example, accelerated depreciation has been described as an interest-free loan from the government. The taxpayer receives cash now, in the form of lower current tax payments, with an agreement to repay that card in the future, when the tax depreciation benefit turns around. If the benefit is immediately flowed through to consumers, the incentive of the low-cost capital is lost.

By the use of tax normalization, consumers receive the tax benefits that result from investment in assets, but over the regulatory life of the assets. The utility's current tax expense is reduced by the tax benefit, which is a cash benefit. Normalization is accomplished by recording a deferred tax expense, at the statutory tax rate, on the difference between tax depreciation, which is accelerated, and book depreciation, which is straight-line over a longer regulatory life. The deferred tax represents a tax that will be paid in the future when the depreciation timing difference turns around.

Consumers begin to receive the tax benefit when the deferred tax is reflected in rates, because the deferred tax balance is an offset to the rate base. The tax benefit is returned to ratepayers as the deferred tax is reversed, corresponding to the reversal of the depreciation timing difference over the life of the asset.

There are proposed IRS regulations pending regarding the application of the normalization rules to utility assets that are sold or deregulated. The IRS has consistently ruled that when utility assets are sold or deregulated, they cease to be public utility property, and the flow-through of deferred tax and investment tax credit must cease. The IRS issued proposed regulations in 2003 that included a retroactive election to allow flow-through of certain deferred tax and accumulated deferred investment tax credit. There was an outcry from the industry about the retroactive election, because many utilities had already settled their deregulation rate proceedings and were concerned they would be forced to reopen them and pass-through tax benefits that were no longer on their books. In December 2005, the IRS withdrew the 2003 proposed regulations and replaced them with new proposed regulations that did not include a retroactive election.

Please see the following JCT description for greater detail on electricity transmission.

PRESENT LAW RELATING TO ELECTRICITY TRANSMISSION DEPRECIATION AND QUALIFYING ADVANCED COAL PROJECT CREDIT

Depreciation of Electricity Transmission Property (sec. 168(e) (3) (E) (vii))[1]

The applicable recovery period for assets placed in service under the Modified Accelerated Cost Recovery System is based on the class life of the property.[2] The class lives of assets placed in service after 1986 are generally set forth in Revenue Procedure 87-56.[3] Generally, assets used in the transmission and distribution of electricity for sale and related land improvements are assigned a 20-year recovery period and a class life of 30 years. The Energy Policy Act of 2005[4] established a statutory 15-year recovery period and a class life of 30 years for certain assets used in the transmission of electricity for sale and related land improvements.[5] Such assets include section 1245 property[6] used in the transmission at 69 or more kilovolts of electricity for sale, the original use of which commences with the taxpayer after April 11, 2005.

Qualifying Advanced Coal Project Credit (sec. 48A)

The Energy Policy Act of 2005 established an investment tax credit to produce power generation capacity using integrated gasification combined cycle ("IGCC") and other advanced coal-based electricity generation technologies.[7] The credit amount is 20 percent for investments in qualifying IGCC projects and 15 percent for investments in qualifying projects that use other advanced coal-based electricity generation technologies.

[1] All section references are to the Internal Revenue Code of 1986, as amended.

[2] For additional information on MACRS depreciation, see "Present Law and Background Relating to Depreciation of Oil and Gas Pipelines" document from January 5, 2007, briefing.

[3] 1987-2 C.B. 674 (as clarified and modified by Rev. Proc. 88-22, 1988-1 C.B. 785).

[4] Pub. L. No. 109-58 (2005).

[5] During Conference consideration, the Joint Committee on Taxation staff estimated the budget effects of this proposal for fiscal years 2005 through 2015 to be a revenue loss of approximately $1.2 billion. *See* Estimated Budget Effects Of The Conference Agreement For Title XIII. of H.R. 6, The "Energy Tax Incentives Act of 2005" (JCX-59-05, July 27, 2005).

[6] Generally, sec. 1245 property includes personal property. For a complete definition, *see* sec. 1245(a) (3).

[7] During Conference consideration, the Joint Committee on Taxation staff estimated the budget effects of this proposal, including credits for investments in clean coal facilities under both section. 48A and 48B, for fiscal years 2005 through 2015 to be a revenue loss of approximately $1.6 billion. *See* Estimated Budget Effects Of The Conference Agreement For Title XIII. of H.R. 6, The "Energy Tax Incentives Act of 2005" (JCX-59-05, July 27, 2005).

[8] For advanced coal project certification applications submitted after October 2, 2006, an electric generation unit using advanced coal-based generation technology designed to use subbituminous coal can meet the performance requirement relating to the removal of sulfur dioxide if it is designed either to remove 99 percent of the sulfur dioxide or to achieve an emission limit of 0.04 pounds of sulfur dioxide per million British thermal units on a 30-day average.

[9] The Secretary issued guidance establishing the certification program on February 21, 2006 (IRS Notice 2006-24).

To qualify, an advanced coal project must be located in the United States and use an advanced coal-based generation technology to power a new electric generation unit or to retrofit or re-power an existing unit. Generally, an electric generation unit using an advanced coal-based technology must be designed to achieve a 99 percent reduction in sulfur dioxide and a 90 percent reduction in mercury, as well as to limit emissions of nitrous oxide and particulate matter.[8]

The fuel input for a qualifying project, when completed, must use at least 75 percent coal. The project, consisting of one or more electric generation units at one site, must have a nameplate generating capacity of at least 400 megawatts, and the taxpayer must provide evidence that a majority of the output of the project is reasonably expected to be acquired or utilized.

Credits are available only for projects certified by the Secretary of Treasury, in consultation with the Secretary of Energy. Certifications are issued using a competitive bidding process. The Secretary of Treasury must establish a certification program no later than 180 days after August 8, 2005,[9] and each project application must be submitted during the three-year period beginning on the date such certification program is established. An applicant for certification has two years from the date the Secretary accepts the application to provide the Secretary with evidence that the requirements for certification have been met. Upon certification, the applicant has five years from the date of issuance of the certification to place the project in service.

The Secretary of Treasury may allocate $800 million of credits to IGCC projects and $500 million to projects using other advanced coal-based electricity generation technologies. Qualified projects must be economically feasible and use the appropriate clean coal technologies. With respect to IGCC projects, credit-eligible investments include only investments in property associated with the gasification of coal, including any coal handling and gas separation equipment. Thus, investments in equipment that could operate by drawing fuel directly from a natural gas pipeline do not qualify for the credit.

In determining which projects to certify that use IGCC technology, the Secretary must allocate power generation capacity in relatively equal amounts to projects that use bituminous coal, subbituminous coal, and lignite as primary feedstock. In addition, the Secretary must give high priority to projects which include greenhouse gas capture capability, increased by-product utilization, and other benefits.

Roundtable 7: Electricity Production Tax Credit
February 16, 2007

Speakers:

Rupert Fraser - CEO of Homeland Renewable Energy LLC and Fibrowatt LLC
Dany St-Pierre - Marketing Manager, Siemens Wind Power

Electricity Production Tax Credit Roundtable (2/16/07):

Following discussion on electricity transmission issues writ large and a brief discussion on renewable generation on February 9, 2007, this Roundtable focused exclusively on the Section 45 electricity production tax credit (PTC) from renewable resources. Given the familiarity of most Senate tax staff with this provision, the Roundtable attempted to provide a new perspective on the credit, through speakers with international and systems-specific infrastructure perspectives on renewable electricity. There is high global demand for renewable energy, and many in the industry have expressed concern that the stop-and-start nature of the Section 45 credit has sent mixed signals reguarding U.S. commitment to renwable power. However, the two-year extension in the 2005 Energy Bill, combined with an additional one-year extension in the 2006 Tax Relief Health Care Act has revived U.S. investment in renewable power. However, this has put a pinch on already tight supply chains for renewable energy equipment - everything from piping for biomass boilers to wind turbines. For this reason, we selected the marketing manager for Siemens Wind Power to discuss the global demand and supply chain for her company, the world's fourth largest manufacturer of renewable power generation and the CEO of Fibrowatt, a poultry litter-fired international biomass company with a long history with the PTC.

Background:

Today, the renewable energy sector (excluding large-scale hydropower) represents only 3% of global electricity production. However, the global demand for renewables has grown by more than 20% annually over the last five years. In 2005, global installed capacity was 182 gigawatts (GW) rising to 200 GW in 2006.[1]

In the U.S., renewable electricity, excluding hydropower, supplied just 2.7% of our electricity needs in 2006, and consisted of biomass and municipal waste (60%), wind (25%), geothermal (14%), and solar (0.5%). Including hydropower, the contribution of renewables increases to roughly 10% of U.S. retail electricity sales.

After a lull in 1990s, new renewable electricity investments have been accelerating in recent years Led by a resurgence in wind power. The U.S. totaled the world in wind capacity additions to the grid in 2006, at adding 2,400 megawatts (MW). For the second consecutive year, this made wind power the second largest new resource added to the U.S. electrical grid in capacity terms well behind new natural gas plants, but

[1]Krenicki, J (2007). Written Testimony of John Krenicki, Jr.. from Senate Finance Committee Web site: http://finance.senate.gov/hearings/testimony/2007test/032907testjk.pdf

ahead of coal. New wind plants contributed roughly 19% of the new capacity added to the U.S. grid in 2006, compared to 12% in 2005. While U.S. wind-power capacity has increased dramatically in recent years, the U.S. still only get about 1% of our electricity from wind, compared to Denmark's 20% and Spain's 10%.[2]

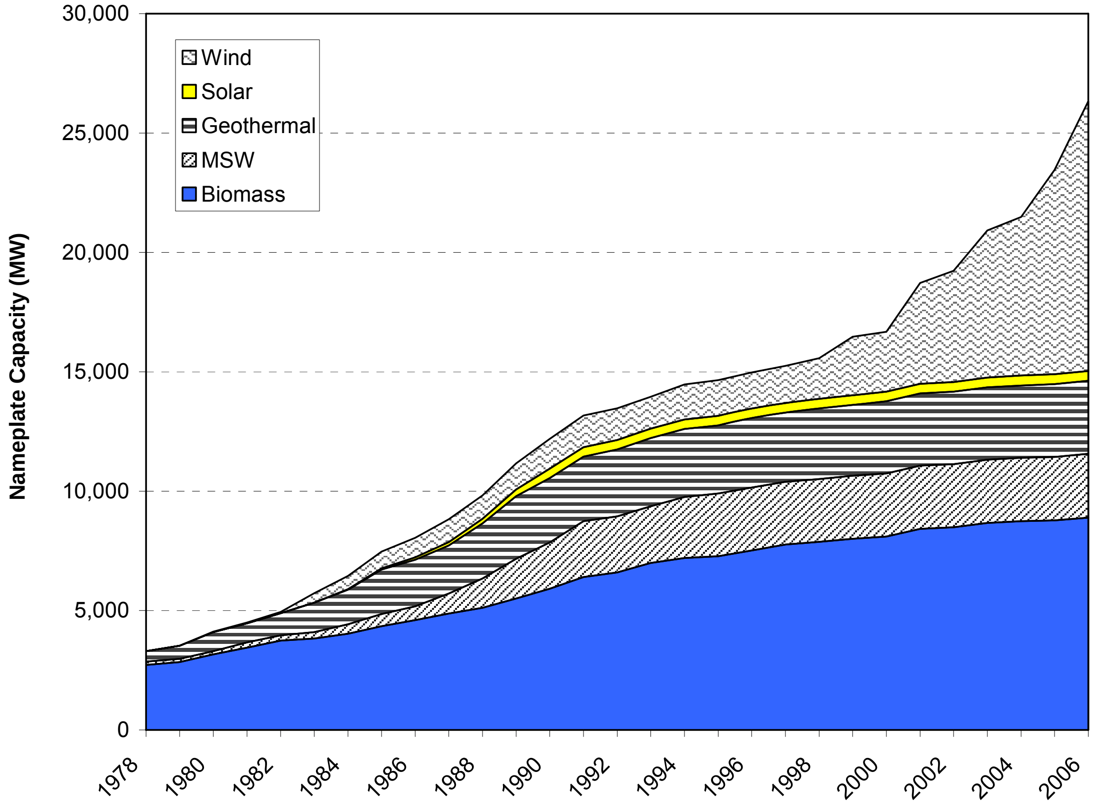


Figure 2. Cumulative U.S. Renewable Electricity Capacity, Excluding Hydropower
(Source: Black & Veatch 2007)

Cost:

Developers of electricity generating stations look at the total cost to supply electricity to the market. Location is a key factor in this determination. Renewable electricity requires a developer to consider a different set of factors than conventional generation. For example, for a new coal-fired plant, a developer will consider whether the location has: 1) a transportation network to move feedstock to the plant; 2) a water supply; and 3) access to the bulk transmission grid. The closer these plants can be located to population and load centers, the better. Bulk power flows on to the grid in highly economical fashion, hundreds of megawatts at a time.

---

2 Krenicki, J (2007). Written Testimony of John Krenicki, Jr.. from Senate Finance Committee Web site: http://finance.senate.gov/hearings/testimony/2007test/032907testjk.pdf

Renewables are different. For the most part, renewable sources of power are not located near load centers. Population centers are, for the most part, located on the coasts, but the best wind resources are located in the Mid-West. Similarly, the best geothermal resources are spread throughout the Rocky Mountain States. Transmission becomes a disproportionately larger component of the retail cost compared to conventional resources because of the remote location. This situation will only grow more pronounced as we increase the amount of renewable generation, because the most cost-effective locations have already been developed.

However, renewables do offer the advantage of emissions-free generation which may prove very important in a carbon-constrained world. In addition, wind, geothermal and hydro energy do not suffer from fluctuating feedstock prices like coal, natural gas, and petroleum. As such, the fixed cost source of electricity serves as a hedge against the rising prices of conventional resources. And improvements in the efficiency of wind turbines, economy of scale and familiarity with renewable generation are driving down the costs of wind energy. Today, depending on a site's wind resources, development costs and capacity factor, the range of the cost of electricity for wind, exclusive of any incentives is approximately 8 - 10 cents/kWh.

Dispatchability:

A problem with wind and other renewable resources is dispatchability of the electricity. Dispatchability refers to the ability of an electricity generating source to respond to surging power demands. A system operator is responsible for maintaining power flow on the grid. Typically, the operator has a sizeable portfolio of resources at hand to turn on and off, but the system operator wants reliability. When the operator tells the power to go up or down, he or she needs to know that it will respond.

A problem with incorporating wind and other intermittent resources into the grid is that wind only produces power when the wind is blowing, and the operator can't control the wind. It's not like powering a gas turbine up or down. With regard to geothermal, hydro, biomass and waste-to-energy generation, the problem is less acute because these resources function as base load resources, enhancing their value (i.e., the input of water through the dam or biomass into the burner can be more easily controlled than wind).

Intermittent resources, if they are to be a large part of U.S. or global portfolio will require firming power or back-up generation to ensure constant power flow on the grid.

Tax Provisions:

Congress created the PTC in the Energy Policy Act of 1992 to stimulate use of renewable technologies for power production. At present, the PTC provides a 10-year credit of 2¢/kWh (adjusted for inflation in future years) for wind, "closed-loop" biomass, and geothermal power, and half that rate for traditional "open-loop" biomass, eligible hydropower, landfill gas, and municipal solid waste. Projects must be in service by the end of 2008 to be eligible for the current PTC. The purpose of the PTC is to help make renewables cost competitive with cheaper conventional resources because of their environmental and energy security benefits.

The PTC has expired on three occasions, and has been extended on five occasions since 1999. Typically, the PTC has been reinstated for 1- to 2-year periods, with resource eligibility rules and other statutory details often also witnessing some change. Table 1 shows the legislative history of the PTC, along with its impact on wind project development.[3]

Table 1. History of the PTC and Installed Capacity

Legislation	Date Enacted	PTC Eligibility Window	Effective Duration (considering lapses)	Wind Capacity Built in PTC Window (MW)
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 Improvement Act of 1999 (P.L. 106-170)	12/19/99	July 1999-2001	24 months	1,764
Section 603, Job Creation and Worker Assistance Act (P.L. 107-147)	03/09/02	2002-2003	22 months	2,078
Section 313, The Working Families Tax Relief Act, (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**

*5,454 MW based on 2,454 MW installed in 2006, and AWEA projection of 3,000 MW to be installed in 2007.

**Estimate assuming AWEA's 3,000 MW 2007 projection holds throughout 2008.

It is fair to say that the PTC is the driver for renewable energy. Wind, for example, has seen massive cumulative increases in MW installation when the PTC was available followed by dramatic reductions when the PTC has lapsed.[4]

[3] Wiser, R (2007). Wind Power and the Production Tax Credit: An Overview of Research Results. Web site: http://finance.senate.gov/hearings/testimony/2007test/032907testrw.pdf

[4] Wiser, R (2007). Wind Power and the Production Tax Credit: An Overview of Research Results. Web site: http://finance.senate.gov/hearings/testimony/2007test/032907testrw.pdf

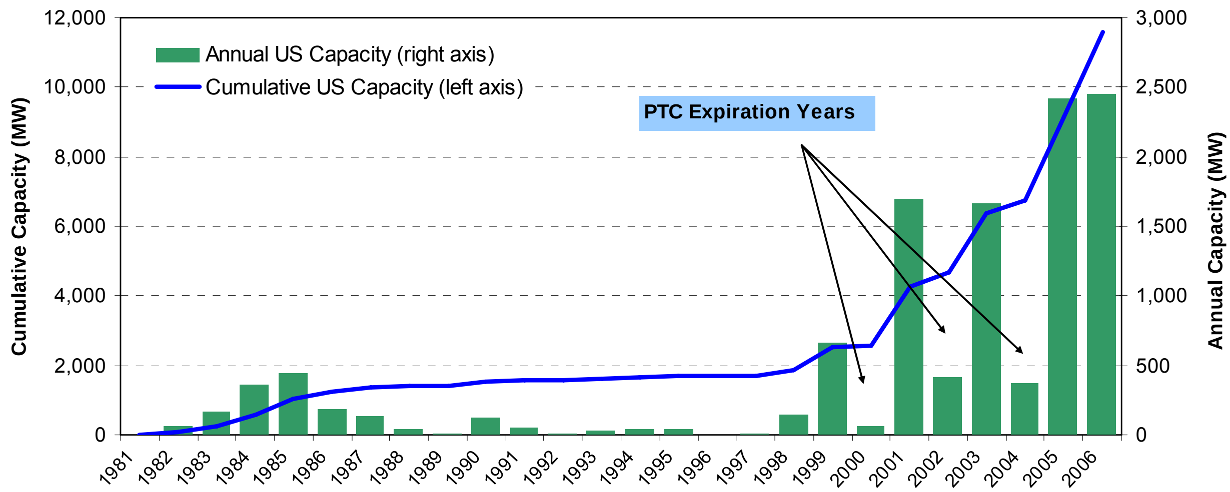


Figure 2. U.S. Wind Power Capacity (annual and cumulative)

Other renewables have not fared so well under the PTC. Drilling new geothermal wells or upgrading existing hydro facilities to create incremental power expansions is highly capital intensive. The vast majority of these projects cannot be completed within the short placed-in-service time frames under the existing PTC legislation, thus severely limiting new investments.

Please see the following JCT description for greater detail on the Section 45 PTC.

PRESENT LAW AND LEGISLATIVE HISTORY REGARDING THE PRODUCTION OF ELECTRICITY FROM CERTAIN RENEWABLE RESOURCES AND THE PRODUCTION OF REFINED COAL AND INDIAN COAL (SEC. 45)[1]

A. Present Law

<u>In general</u>

An income tax credit is allowed for the production of electricity from qualified energy resources at qualified facilities (sec. 45). Qualified energy resources comprise wind, closed-loop biomass, open-loop biomass, geothermal energy, solar energy, small irrigation power, municipal solid waste, and qualified hydropower production. Qualified facilities are, generally, facilities that generate electricity using qualified energy resources. To be eligible for the credit, electricity produced from qualified energy resources at qualified facilities must be sold by the taxpayer to an unrelated person.

In addition to the electricity production credit, income tax credits are allowed for the production of refined coal and Indian coal at qualified facilities.

<u>Credit amounts and credit period</u>

<u>In general</u>

The base amount of the electricity production credit is 1.5 cents per kilowatt-hour (indexed annually for inflation) of electricity produced. The amount of the credit is 1.9 cents per kilowatt-hour for 2006. A taxpayer may generally claim a credit during the 10-year period commencing with the date the qualified facility is placed in service. The credit is reduced for grants, tax-exempt bonds, subsidized energy financing, and other credits.

<u>Credit applicable to refined coal</u>

The amount of the credit for refined coal is $4.375 per ton (also indexed for inflation after 1992 and equaling $5.679 per ton for 2006).

<u>Credit applicable to Indian coal</u>

A credit is available for the sale of Indian coal to an unrelated third party from a qualified facility for a seven-year period beginning on January 1, 2006, and before January 1, 2013. The amount of the credit for Indian coal is $1.50 per ton for the first four years of the seven-year period and $2.00 per ton for the last three years of the seven-year period. Beginning in calendar years after 2006, the credit amounts are indexed annually for inflation using 2005 as the base year.

[1] Unless otherwise noted, all section references are to the Internal Revenue Code of 1986, as amended (the "Code").

Credit phase-out

The amount of credit a taxpayer may claim is phased out as the market price of electricity (or refined coal in the case of the refined coal production credit) exceeds certain threshold levels. The electricity production credit is reduced over a 3 cent phase-out range to the extent the annual average contract price per kilowatt-hour of electricity sold in the prior year from the same qualified energy resource exceeds 8 cents (adjusted for inflation). The refined coal credit is reduced over an $8.75 phase-out range as the reference price of the fuel used as feedstock for the refined coal exceeds the reference price for such fuel in 2002 (adjusted for inflation).

Reduced credit periods and credit amounts

Generally, in the case of open-loop biomass facilities (including agricultural livestock waste nutrient facilities), geothermal energy facilities, solar energy facilities, small irrigation power facilities, landfill gas facilities, and trash combustion facilities, the 10-year credit period is reduced to five years commencing on the date the facility was originally placed in service, for qualified facilities placed in service before August 8, 2005. However, for qualified open-loop biomass facilities (other than a facility described in sec. 45(d) (3) (A) (i) that uses agricultural livestock waste nutrients) placed in service before October 22, 2004, the five-year period commences on January 1, 2005. In the case of a closed-loop biomass facility modified to co-fire with coal, to co-fire with other biomass, or to co-fire with coal and other biomass, the credit period begins no earlier than October 22, 2004.

In the case of open-loop biomass facilities (including agricultural livestock waste nutrient facilities), small irrigation power facilities, landfill gas facilities, trash combustion facilities, and qualified hydropower facilities the otherwise allowable credit amount is 0.75 cent per kilowatt-hour, indexed for inflation measured after 1992 (currently 0.9 cents per kilowatt-hour for 2006).

Other limitations on credit claimants and credit amounts

In general, in order to claim the credit, a taxpayer must own the qualified facility and sell the electricity produced by the facility (or refined coal or Indian coal, with respect to those credits) to an unrelated party. A lessee or operator may claim the credit in lieu of the owner of the qualifying facility in the case of qualifying open-loop biomass facilities and in the case of closed-loop biomass facilities modified to co-fire with coal, to co-fire with other biomass, or to co-fire with coal and other biomass. In the case of a poultry waste facility, the taxpayer may claim the credit as a lessee or operator of a facility owned by a governmental unit.

For all qualifying facilities, other than closed-loop biomass facilities modified to co-fire with coal, to co-fire with other biomass, or to co-fire with coal and other biomass, the amount of the credit a taxpayer may claim is reduced by reason of grants, tax-exempt bonds, subsidized energy financing, and other credits, but the reduction cannot exceed 50 percent of the otherwise allowable credit. In the case of closed-loop biomass facilities modified to co-fire with coal, to co-fire with other biomass, or to co-fire with coal and other biomass, there is no reduction in credit by reason of grants, tax-exempt bonds, subsidized energy financing, and other credits.

The credit for electricity produced from renewable sources is a component of the general business credit (sec. 38(b) (8)). Generally, the general business credit for any taxable year may not exceed the amount by which the taxpayer's net income tax exceeds the greater of the tentative minimum tax or so much of the net regular tax liability as exceeds $25,000. Excess credits may be carried back one year and forward up to 20 years.

A taxpayer's tentative minimum tax is treated as being zero for purposes of determining the tax liability limitation with respect to the section 45 credit for electricity produced from a facility (placed in service after October 22, 2004) during the first four years of production beginning on the date the facility is placed in service.

Qualified facilities

Wind energy facility

A wind energy facility is a facility that uses wind to produce electricity. To be a qualified facility, a wind energy facility must be placed in service after December 31, 1993, and before January 1, 2009.

Closed-loop biomass facility

A closed-loop biomass facility is a facility that uses any organic material from a plant which is planted exclusively for the purpose of being used at a qualifying facility to produce electricity. In addition, a facility can be a closed-loop biomass facility if it is a facility that is modified to use closed-loop biomass to co-fire with coal, with other biomass, or with both coal and other biomass, but only if the modification is approved under the Biomass Power for Rural Development Programs or is part of a pilot project of the Commodity Credit Corporation.

To be a qualified facility, a closed-loop biomass facility must be placed in service after December 31, 1992, and before January 1, 2009. In the case of a facility using closed-loop biomass but also co-firing the closed-loop biomass with coal, other biomass, or coal and other biomass, a qualified facility must be originally placed in service and modified to co-fire the closed-loop biomass at any time before January 1, 2009.

Open-loop biomass (including agricultural livestock waste nutrients) facility

An open-loop biomass facility is a facility that uses open-loop biomass to produce electricity. For purposes of the credit, open-loop biomass is defined as (1) any agricultural livestock waste nutrients or (2) any solid, non-hazardous, cellulosic waste material or any lignin material that is segregated from other waste materials and which is derived from:

• Forest-related resources, including mill and harvesting residues, precommercial thinning, slash, and brush;
• solid wood waste materials, including waste pallets, crates, dunnage, manufacturing and construction wood wastes, and landscape or right-of-way tree trimmings; or
• Agricultural sources, including orchard tree crops, vineyard, grain, legumes, sugar, and other crop by-products or residues.

Agricultural livestock waste nutrients are defined as agricultural livestock manure and litter, including bedding material for the disposition of manure. Wood waste materials do not qualify as open-loop biomass to the extent they are pressure treated, chemically treated, or painted. In addition, municipal solid waste, gas derived from the biodegradation of solid waste, and paper which is commonly recycled does not qualify as open-loop biomass. Open-loop biomass does not include closed-loop biomass or any biomass burned in conjunction with fossil fuel (co-firing) beyond such fossil fuel required for start up and flame stabilization.

In the case of an open-loop biomass facility that uses agricultural livestock waste nutrients, a qualified facility is one that was originally placed in service after October 22, 2004, and before January 1, 2009, and has a nameplate capacity rating which is not less than 150 kilowatts. In the case of any other open-loop biomass facility, a qualified facility is one that was originally placed in service before January 1, 2009.

Geothermal facility

A geothermal facility is a facility that uses geothermal energy to produce electricity. Geothermal energy is energy derived from a geothermal deposit that is a geothermal reservoir consisting of natural heat that is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure). To be a qualified facility, a geothermal facility must be placed in service after October 22, 2004, and before January 1, 2009.

Solar facility

A solar facility is a facility that uses solar energy to produce electricity. To be a qualified facility, a solar facility must be placed in service after October 22, 2004, and before January 1, 2006.

Small irrigation facility

A small irrigation power facility is a facility that generates electric power through an irrigation system canal or ditch without any dam or impoundment of water. The installed capacity of a qualified facility must be at least 150 kilowatts but less than five megawatts. To be a qualified facility, a small irrigation facility must be originally placed in service after October 22, 2004, and before January 1, 2009.

Landfill gas facility

A landfill gas facility is a facility that uses landfill gas to produce electricity. Landfill gas is defined as methane gas derived from the biodegradation of municipal solid waste. To be a qualified facility, a landfill gas facility must be placed in service after October 22, 2004, and before January 1, 2009.

Trash combustion facility

Trash combustion facilities are facilities that burn municipal solid waste (garbage) to produce steam to drive a turbine for the production of electricity. To be a qualified facility, a trash combustion facility must be placed in service after October 22, 2004, and before January 1, 5 2009. A qualified trash combustion facility includes a new unit, placed in service after October 22, 2004, that increases electricity production capacity at an existing trash combustion facility. A new unit generally would include a new burner/boiler and turbine. The new unit may share certain common equipment, such as trash handling equipment, with other pre-existing units at the same facility. Electricity produced at a new unit of an existing facility qualifies for the production credit only to the extent of the increased amount of electricity produced at the entire facility.

Hydropower facility

A qualifying hydropower facility is (1) a facility that produced hydroelectric power (a hydroelectric dam) prior to August 8, 2005, at which efficiency improvements or additions to capacity have been made after such date and before January 1, 2009, that enable the taxpayer to produce incremental hydropower or (2) a facility placed in service before August 8, 2005, that did not produce hydroelectric power (a non-hydroelectric dam) on such date, and to which turbines or other electricity generating equipment have been added after such date and before January 1, 2009.

At an existing hydroelectric facility, the taxpayer may claim credit only for the production of incremental hydroelectric power. Incremental hydroelectric power for any taxable year is equal to the percentage of average annual hydroelectric power produced at the facility attributable to the efficiency improvement or additions of capacity determined by using the same water flow information used to determine an historic average annual hydroelectric power production baseline for that facility. The Federal Energy Regulatory Commission will certify the baseline power production of the facility and the percentage increase due to the efficiency and capacity improvements. At a non-hydroelectric dam, the facility must be licensed by the Federal Energy Regulatory Commission and meet all other applicable environmental, licensing, and regulatory requirements and the turbines or other generating devices must be added to the facility after August 8, 2005 and before January 1, 2009. In addition, there must not be any enlargement of the diversion structure, construction or enlargement of a bypass channel, or the impoundment or any withholding of additional water from the natural stream channel.

Refined coal facility

A qualifying refined coal facility is a facility producing refined coal that is placed in service after October 22, 2004, and before January 1, 2009. Refined coal is a qualifying liquid, gaseous, or solid synthetic fuel produced from coal (including lignite) or high-carbon fly ash, including such fuel used as a feedstock. A qualifying fuel is a fuel that, when burned, emits 20 percent less nitrogen oxides and either sulfur dioxide or mercury than the burning of feedstock coal or comparable coal predominantly available in the marketplace as of January 1, 2003, but only if the fuel sells at prices at least 50 percent greater than the prices of the feedstock coal or comparable coal. In addition, to be qualified refined coal, the taxpayer must sell the fuel with the reasonable expectation that it will be used for the primary purpose of producing steam.

Indian coal facility

A qualified Indian coal facility is a facility that is placed in service before January 1, 2009, and that produces coal from reserves that on June 14, 2005, were owned by a federally recognized tribe of Indians or were held in trust by the United States for a tribe or its members.

Summary of credit rate and credit period by facility type

Table 1, on the following page, is a summary of Section 45 Credit for Electricity Produced from Certain Renewable Resources, for Refined Coal, and for Indian Coal.

Eligible electricity production or coal production activity	**Credit amount for 2006 (cents per kilowatt-hour; dollars per ton)**	**Credit period for facilities placed in service on or before August 8, 2005 (years from placed-in-service date)**	**Credit period for facilities placed in service after August 8, 2005 (years from placed-in-service date)**
Wind	1.9	10	10
Closed-loop biomass	1.9	10[1]	10[1]
Open-loop biomass (including agricultural livestock waste nutrient facilities)	0.9	5[2]	10
Geothermal	1.9	5	10
Solar	1.9	5	10
Small irrigation power	0.9	5	10
Municipal solid waste (including landfill gas facilities and trash combustion facilities)	0.9	5	10
Qualified hydropower	0.9	N/A	10
Refined Coal	5.679	10	10
Indian Coal	1.50	7[3]	7[3]

[1] In the case of certain co-firing closed-loop facilities, the credit period begins no earlier than October 22, 2004.

[2] For certain facilities placed in service before October 22, 2004, the 5-year credit period commences on January 1, 2005.

[3] For Indian coal, the credit period begins for coal sold after January 1, 2006.

Taxation of cooperatives and their patrons

For Federal income tax purposes, a cooperative generally computes its income as if it were a taxable corporation, with one exception: the cooperative may exclude from its taxable income distributions of patronage dividends. Generally, a cooperative that is subject to the cooperative tax rules of subchapter T of the Code[2] is permitted a deduction for patronage dividends paid only to the extent of net income that is derived from transactions with patrons who are members of the cooperative.[3] The availability of such deductions from taxable income has the effect of allowing the cooperative to be treated like a conduit with respect to profits derived from transactions with patrons who are members of the cooperative. For taxable years ending on or before August 8, 2005, cooperatives may not pass any portion of the income tax credit for electricity production through to their patrons.

For taxable years ending after August 8, 2005, eligible cooperatives may elect to pass any portion of the credit through to their patrons. An eligible cooperative is defined as a cooperative organization that is owned more than 50 percent by agricultural producers or entities owned by agricultural producers. The credit may be apportioned among patrons eligible to share in patronage dividends on the basis of the quantity or value of business done with or for such patrons for the taxable year. The election must be made on a timely filed return for the taxable year and, once made, is irrevocable for such taxable year.

B. Legislative History

• The Energy Policy Act of 1992 created section 45 as a production credit for electricity produced from wind and closed-loop biomass for production from certain facilities placed in service before July 1, 1999.

• The Ticket to Work and Work Incentives Improvement Act of 1999 added poultry waste as a qualifying energy source, extended the placed-in-service date through December 31, 2001, and made certain modifications to the requirements of qualifying wind facilities.

• The Job Creation and Worker Assistance Act of 2002 extended the placed-in-service date through December 31, 2003.

• The Working Families Tax Relief Act of 2004 extended the placed-in-service date for wind facilities, closed-loop biomass facilities, and poultry waste facilities through December 31, 2005.

[2] Sections. 1381-1383.

[3] Sec. 1382.

• The American Jobs Creation Act of 2004 (“AJCA”) modified the provision to add as qualified facilities open-loop biomass (including agricultural livestock waste nutrients[4]), geothermal energy, solar energy, small irrigation power, and municipal solid waste (both landfill gas and trash combustion facilities). AJCA also added refined coal production facilities to the list of credit eligible facilities and defined refined coal as a qualifying resource eligible for credit. AJCA also made other modifications.

• The Energy Policy Act of 2005 extended the placed-in-service date by two years (through December 31, 2007) for the following qualified facilities: wind facilities; closed-loop biomass facilities (including a facility co-firing the closed-loop biomass with coal, other biomass, or coal and other biomass); open-loop biomass facilities; geothermal facilities; small irrigation power facilities; landfill gas facilities; and trash combustion facilities. It also (1) equalized (at ten years) the credit period for all qualified electricity production facilities placed in service after August 8, 2005; (2) modified section 45 to add qualified hydropower and Indian coal facilities to the list of credit eligible facilities; and (3) made other modifications to the section 45 credit.

• The Tax Relief and Health Care Act of 2006 extended the placed-in-service date by one year (through December 31, 2008) for all qualified facilities except qualified solar (December 31, 2005), refined coal (December 31, 2008), and Indian coal facilities (December 31, 2008).

[4] The definition of agricultural livestock waste nutrients subsumes poultry waste, so AJCArepealed, prospectively; poultry waste facilities as a separate category of qualified facility.

Roundtable 8: Renewable Electricity ITC
February 23, 2007

Speakers:

Julie Blunden – Vice President, Public Policy and Corporate Communications, Sun Power Corporation (Solar)
Bob Rose – Executive Director, U.S. Fuel Cell Council (Fuel Cells)
Pete Disser – Vice President Energy USA, NiSource Inc. (Micro turbines)
Lawrence Plitch – Vice President and General Counsel, The Trigen Companies (CHP)

Electricity Investment Tax Credit Roundtable (2/23/07):

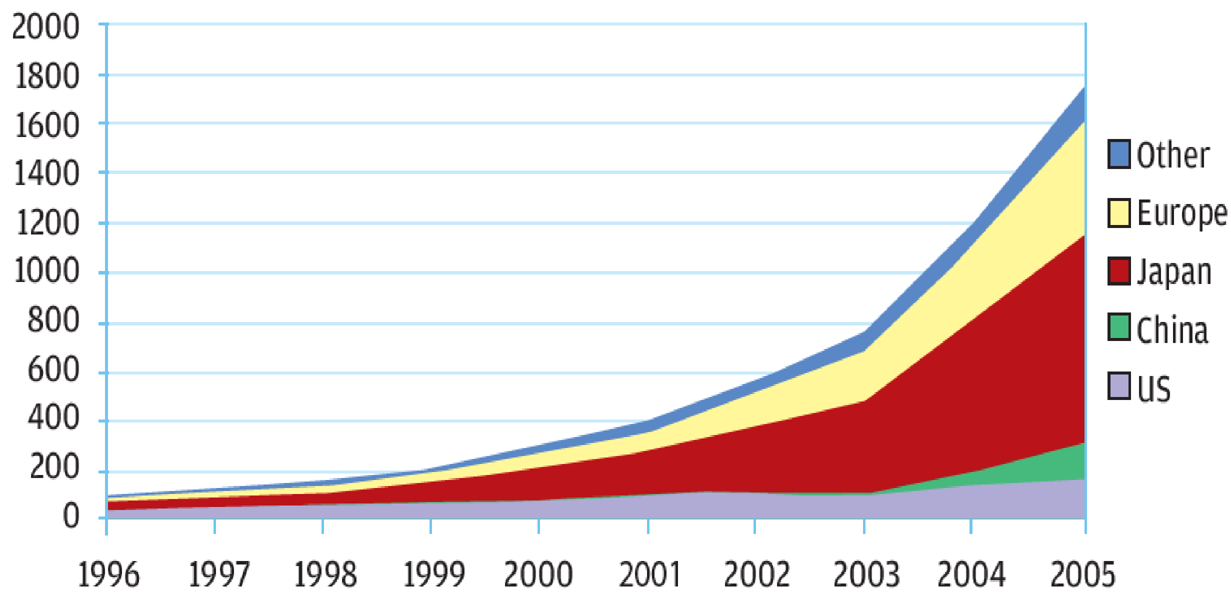
This roundtable focused on renewable energy incentives through investment tax credits (ITCs). Section 48 of the tax code provides a 30% ITC for solar, fuel cell and micro turbine investments which generate electricity.

Background:

The energy technologies in Section 48 can be characterized as "distributed generation," which is also known as on-site generation, dispersed generation, or distributed energy. Distributed generation is a method of generating electricity from numerous small sources, such as solar panels on the roofs of buildings and micro turbines and reciprocating engines located in homes and office buildings, which produce waste heat that can be used for space or water heating. The United States generates the vast majority of its electricity in large power plants, which have excellent economies of scale, but which must transmit electricity long distances, and generally do not allow for the use of waste heat. Distributed generation lacks economy of scale, but reduces the amount of energy lost in transmission because the electricity is generated near to the place that it is used.

Solar Power:

While the U.S. has some of the best solar potential, electricity from this source accounts for less that 1/10 of 10% of the total U.S. electricity generation. in the world. But while the average U.S. location S. receives about 1,700 hours of energy-producing sunlight per year (about 4.6 hours per day), solar power still accounts for less than 1/10 of 1% of our total electricity generation. Contrast this with Germany, which, despite receiving an average of about 1,050 hours of sunlight per year (about 2.9 hours per day), gets about 0.5% of its electricity from solar power. The German government plans to increase that figure to 3 percent by 2020, and has accordingly pursued a very aggressive strategy toward solar power installation. Germany installs 8 times as much solar capacity each year, compared to the U.S.



Solar energy has not had the commercial success wind has experienced in recent years. One major reason is the cost of solar power. Solar panels are not cheap and, because they are constructed from fragile materials, must be maintained and replaced more regularly than other sources of renewable power. Solar technology is improving, but the cost of electricity from solar is still at least three times the price from wind.

Much of the advances in solar electricity production in recent years have centered around concentrating solar power (CSP) plants. These facilities produce electric power by converting the sun's energy into high-temperature heat with various mirror configurations. The plants consist of two parts: one that collects solar energy and converts it to heat, and another that converts heat energy to electricity. There are three main CSP technologies: parabolic trough, power tower, and parabolic dish.

1. Parabolic Trough:

With this system, the sun's energy is concentrated by parabolically curved, trough-shaped reflectors onto a receiver pipe running along the inside of the curved surface. This energy heats oil flowing through the pipe and the heat energy is then used to generate electricity in a conventional steam generator. A collector field is comprised of many troughs in parallel rows aligned on a north-south axis. This configuration enables the single-axis troughs to track the sun from east to west during the day to ensure that the sun is continuously focused on the receiver pipes. Individual trough systems currently can generate about 80 megawatts of electricity.

Parabolic Trough

2. Power Tower:

A power tower converts utilizes many large, sun-tracking mirrors (heliostats) to focus sunlight on a receiver at the top of a tower. A heat transfer fluid heated in the receiver is used to generate steam, which, in turn, is used in a conventional turbine-generator to produce electricity.

Power Tower

3. Parabolic dish:

These systems consist of a parabolic-shaped point focus concentrator in the form of a dish that reflects solar radiation onto a receiver mounted at the focal point. These concentrators are mounted on a structure with a two-axis tracking system to follow the sun. The collected heat is typically utilized directly by a heat engine mounted on the receiver moving with the dish structure.

Parabolic Dish

4. Fuel Cells:

Fuel cells use a chemical reaction, rather than combustion, to produce electricity by converting hydrogen and oxygen into water. Fuel cells are essentially batteries that don't "go dead." A battery has chemicals stored inside which are converted into electricity. A fuel cell has chemicals constantly flowing into the cell so it never goes dead, as long as there is a flow of chemicals into the cell.

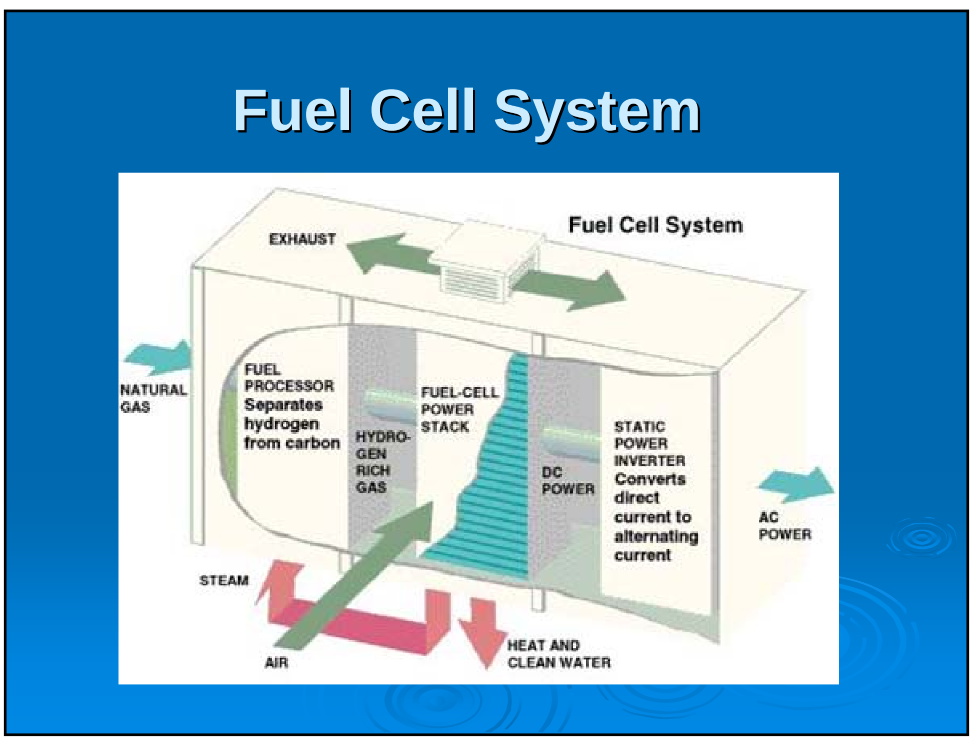
The fuel cell stack is the heart of a fuel cell power system. It generates electricity in the form of direct current (DC) from chemical reactions that take place in the fuel cell. A single fuel cell produces enough electricity for only the smallest applications. Therefore, individual fuel cells are typically combined in series into a fuel cell stack. A typical fuel cell stack may consist of hundreds of fuel cells. The amount of power produced by a fuel cell depends upon several factors, such as fuel cell type, cell size, the temperature at which it operates, and the pressure at which the gases are supplied to the cell.

Fuel cell systems are not primarily used to generate heat. However, since significant amounts of heat are generated by some fuel cell systems especially those that operate at high temperatures such as solid oxide and molten carbonate systems this excess energy can be used to produce steam or hot water or converted to electricity via a gas turbine or other technology, increasing the overall energy efficiency of the systems.

Today, fuel cells are being developed to power passenger vehicles, commercial buildings, homes, and even small devices such as laptop computers. Fuel cell systems can be extremely efficient over a large range of sizes (from 1 kW to hundred of megawatts). Some systems can achieve overall efficiencies of 80% or more when heat production is combined with power generation. Fuel cell systems integrated with hydrogen production and storage can provide fuel for vehicles, energy for heating and cooling, and electricity to power our communities.

Fuel cells also utilize cogeneration. Stationary fuel cell systems generate waste heat that can be captured and used to provide heating, cooling or to turn steam-turbine generators for additional electricity.

Fuel cells have many applications including transportation and portable power. Portable applications include replacement of traditional batteries such as for cell phones as well as fuel cell vehicles. See attached pictures for telecomm and mini-fuel cell applications.



5. Micro Turbines:

Micro turbines are small combustion turbines which have the ability to produce electricity and heat simultaneously. Most micro turbines operate on natural gas, propane, or diesel. Micro turbines can be incorporated into commercial buildings to not only save on utility bills, but efficiently produce hot water and electricity. Among the benefits of micro turbines are their compact size, light weight, greater efficiency, lower emissions, and lower electricity costs. Micro turbines can also cleanly burn waste gases to create power and heat which makes this technology suitable for burning the methane and other toxic gases formed at landfills, sewage treatment plants, livestock farms and other sites.

Because of their compact size, relatively low capital costs, low operations and maintenance costs, and automatic electronic control, micro turbines are expected to capture a significant share of the distributed generation market.

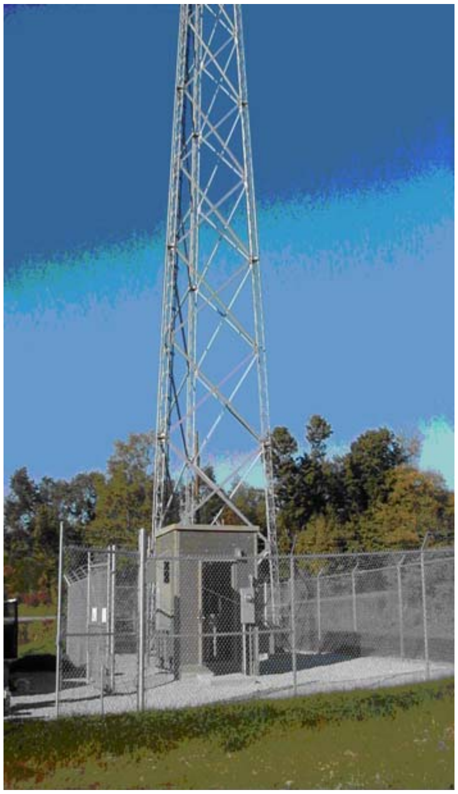
Microturbine

Tax Provisions:

Tax incentives for the investment in solar property have been in the Code since the Energy Tax Act of 1978. When Congress enacted the PTC (Section 45) in 1992, solar, biomass and wind were the three renewable energy sources included. Congress removed solar from the PTC in the 2005 Energy Bill, and increased the then- 10% ITC for solar in Section 48 of the Code to 30%. This provision expires at the end of 2008 along with the PTC.

The 2005 Energy Policy Act also created a 30% ITC for fuel cells, not to exceed $1,000 per kilowatt of capacity, and a 10% ITC for micro turbine property, not to exceed $200 per kilowatt of capacity. This provision also expires at the end of 2008. The credit for fuel cells and micro turbines cannot be claimed by public utilities except for telecommunications companies, and the solar credit cannot be claimed by public utilities. Please see the following JCT description for greater explanation of the Section 48 ITC for renewable property.

Micro-Fuel Cell Application



Fuel Cell Telecomm Applications

Energy Investment Tax Credit for Solar, Geothermal, Fuel Cell and Micro turbine Property (Sec. 48)

Present Law

In general

A nonrefundable, 10-percent business energy credit is allowed for the cost of new property that is equipment that either (1) uses solar energy to generate electricity, to heat or cool a structure, or to provide solar process heat, or (2) is used to produce, distribute, or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to the electric transmission stage. Property used to generate energy for the purposes of heating a swimming pool is not eligible solar energy property.

The energy credit is a component of the general business credit (sec. 38(b)(1)) and as such is subject to the alternative minimum tax. An unused general business credit generally may be carried back one year and carried forward 20 years (sec. 39). The taxpayer's basis in the property is reduced by the amount of the credit claimed. For projects whose construction time is expected to equal or exceed two years, the credit may be claimed as progress expenditures are made on the project, rather than during the year the property is placed in service. Similarly, the credit only applies to expenditures made after the effective date of the provision.

In general, property that is public utility property is not eligible for the credit. Public utility property is property that is used predominantly in the trade or business of the furnishing or sale of (1) electrical energy, water, or sewage disposal services, (2) gas through a local distribution system, or (3) telephone service, domestic telegraph services, or other communication services (other than international telegraph services), if the rates for such furnishing or sale have been established or approved by a State or political subdivision thereof, by an agency or instrumentality of the United States, or by a public service or public utility commission. This rule is waived in the case of telecommunication companies' purchases of fuel cell and micro turbine property.

Special rules for solar energy property

The credit for solar energy property is increased to 30 percent in the case of periods after December 31, 2005 and prior to January 1, 2009. Additionally, equipment that uses fiber-optic distributed sunlight to illuminate the inside of a structure is solar energy property eligible for the 30-percent credit.

Fuel cells and microturbines[1]

The business energy credit also applies for the purchase of qualified fuel cell power plants, but only for periods after December 31, 2005 and prior to January 1, 2009. The credit rate is 30 percent.

A qualified fuel cell power plant is an integrated system composed of a fuel cell stack assembly and associated balance of plant components that (1) converts a fuel into electricity using electrochemical means, and (2) has an electricity-only generation efficiency of greater than 30 percent and a capacity of at least on-half kilowatt. The credit may not exceed $500 for each 0.5 kilowatt of capacity.

The business energy credit also applies for the purchase of qualifying stationary micro turbine power plants, but only for periods after December 31, 2005 and prior to January 1, 2009. The credit is limited to the lesser of 10 percent of the basis of the property or $200 for each kilowatt of capacity.

A qualified stationary micro turbine power plant 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 that converts a fuel into electricity and thermal energy. Such system also includes all secondary components located between the existing infrastructure for fuel delivery and the existing infrastructure for power distribution, including equipment and controls for meeting relevant power standards, such as voltage, frequency and power factors. Such system must have an electricity-only generation efficiency of not less that 26 percent at International Standard Organization conditions and a capacity of less than 2,000 kilowatts.

Additionally, for purposes of the fuel cell and micro turbine credits, and only in the case of telecommunications companies, the general present-law section 48 restriction that would otherwise prohibit telecommunication companies from claiming the new credit due to their status as public utilities is waived.

[1] Section 1525 of the Senate passed version of the Energy Policy Act of 2005 also modified section 48 to include a credit for combine heat and power ("CHP") property.
CHP property is property that uses the same energy source for the simultaneous or sequential generation of electrical power, mechanical shaft power, or both, in combination with the generation of steam or other forms of useful thermal energy (including heating and cooling applications). The provision was dropped in conference.

Roundtable 9: Electric Utilities
March 9, 2007

Speakers:

Lynn LeMaster – Senior Vice President of Policy, Issue Management and Internal Operations, Edison Electric Institute
Joy Ditto – Director of Legislative Affairs, American Public Power Association
Susan Pettit – Senior Principal on Tax Issues, National Rural Electric Cooperative Association
Christopher Schoenherr – Senior Manager of the Federal Office, Alliant Energy

Electric Utility Roundtable (2/23/07):

After discussing electricity transmission issues and the Section 45 renewable electricity production tax credit, the purpose of this Roundtable was to focus on specific tax policy geared toward the electricity utility industry. As such, speakers represented investor-owned utilities, municipal utilities, and electric cooperatives. The discussion covered the basics of the electric utility industry, financing of electricity property through private and municipal bonds (with special attention given to the Section 54 Clean Renewable Energy Bonds program), the treatment of the sales of transmission assets, and the 85/15 rule for cooperatives.

Background:

The electric utility industry in the United States includes 3,170 investor-owned, publicly owned, cooperative, and Federal electric utilities. There are generally three types of utilities:

1. Investor-Owned Utilities:

These are privately owned entities. While they represent just eight percent of the total number of electric utilities nationwide, they account for approximately 75 percent of electric utility generating capability, generation, sales, and revenue in the United States. Like all private businesses, investor-owned electric utilities have the fundamental objective of producing a return for their investors. These utilities either distribute profits to stockholders as dividends or reinvest the profits. Investor-owned electric utilities are granted service monopolies in certain geographic areas and are obliged to serve all consumers. As franchised monopolies, these utilities are regulated and are required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to services under similar conditions. Most investor-owned electric utilities are operating companies that provide basic services for the generation, transmission, and distribution of electricity. These entities operate in all States except Nebraska, where electric utilities consist primarily of municipal systems and public power districts.

2. Publicly-owned electric utilities:

These are nonprofit local government agencies established to provide service to their communities and nearby consumers at cost, returning excess funds to consumers in the form of community contributions, increased economies and efficiencies in operations, and reduced rates. Publicly owned electric utilities include:

- municipals,
- public power districts,
- State authorities,
- irrigation districts, and
- other State organizations.

There are 2,009 publicly-owned electric utilities in the United States, accounting for about 63 percent of all electric utilities in the U.S. Publicly-owned utilities supply approximately 10 percent of generation and generating capability, and account for about 15 percent of retail sales and 14 percent of revenue nationwide. They obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sale of electricity. Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California. Voters in a public utility district elect commissioners or directors to govern the district independent of any municipal government. State authorities, like the Power Authority of the State of New York or the South Carolina Public Service Authority, are agencies of their respective State governments. Irrigation districts may have other forms of organization. In the Salt River Project in Arizona, for example, votes for the board of directors are apportioned according to the size of landholdings.

3. Cooperative electric utilities (co-ops):

Co-ops are utilities owned by their customers. These electric utilities operate in rural areas, which have historically been viewed as uneconomical operations for investor-owned utilities. There are 912 cooperatives operating in 47 States; none operate in Connecticut, Hawaii, Rhode Island, or the District of Columbia. Cooperative electric utilities represent about 29 percent of U.S. electric utilities, 9 percent of sales and revenue, and around 4 percent of generation and generating capability. Cooperatives are incorporated under State laws and are usually directed by an elected board of directors, which in turn selects a manager. The Rural Utilities Service (formerly the Rural Electrification Administration), the National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank for Cooperatives are important sources of debt financing for cooperatives.

Tax Provisions:

The 2005 Energy Policy Act created a new financing tool for tax-exempt entities to finance renewable electricity projects. The incentive is called a Clean Renewable Energy Bond (CREB), and it provides electric cooperatives and public power systems the ability to deliver a comparable incentive to the Section 45 production tax credit (PTC), which was described in the February 16 Roundtable. A CREB is a tax-credit bond that offers public entities the equivalent of an interest-free loan for financing qualified energy projects.

Entities seeking CREBs must apply through the Department of Treasury. On November 20, 2006, the Internal Revenue Service released summary information regarding the awarding of tax credit allocations for the CREBs program. Overall, there were 786 applicants from 40 states seeking a total of $2.5 billion in bond authorization (three times what was available). $2 billion of the requests came from governmental entities and $500 million from cooperatives.

610 projects were approved in the first round of CREB applications. The 532 governmental projects that were approved ranged in size from $23,000 to $3.2 million, while the 78 co-op projects ranged from $120,000 to $31 million. Governmental projects were funded in 22 states and co-op projects in 24 states. Of the governmental projects, 401 were solar photovoltaic, 99 wind generators, 23 landfill gases, 8 hydropower and one biomass. Of the co-op projects, there were 33 solar, 13 wind, 13 landfill gas, 12 biomass, 6 hydropower and one refined coal. All of these technologies were included in the extension of the Section 45 tax credits last year.

25 percent of the applicants were in California (presumably reflected in the high solar pv project count); other active states were New Mexico, Montana, Minnesota and Colorado. There were few applicants from the East and South other than Massachusetts.

<u>85/15 Rule For Cooperatives</u>**:**

The rule for tax-exempt electric cooperatives requires that 85 percent of the cooperative's income consists of amounts collected from members of the cooperative to meet losses and expenses of providing service to its members (85/15 test). This has made it difficult for the cooperatives to participate in electricity market deregulation and open access transmission of electricity. In the Jobs Bill of 2004, Congress excluded certain income related to electricity restructuring from the 85/15 test. In the 2005 Energy Policy Act, this provision was made permanent.

<u>Transmission Sales</u>:

The Roundtable also discussed the treatment of sales of transmission assets. While investment in transmission has increased in recent years, significant increases in spending on transmission will be needed to provide for the growing demand in electricity generation. To encourage electric utilities to sell transmission lines, Congress, rather than requiring gain to be recognized in the year of sale, allows capital gain from the sale of qualified transmission infrastructure to be recognized over eight years. This provision expires on December 31, 2007.

Please see the following JCT description for greater explanation of the CREBs program, the 85/15 rule for cooperatives, and transmission sales.

I. PRESENT LAW RELATING TO TAX-EXEMPT AND TAX-CREDIT BOND FINANCING OF POWER FACILITIES

A. Overview

Interest on State and local governmental bonds generally is excluded from gross income for Federal income tax purposes if the proceeds of the bonds are used to finance direct activities of these governmental units or if the bonds are repaid with revenues of the governmental units. Because the interest is excluded from gross income, investors generally are willing to accept a lower rate on tax-exempt bonds than they might otherwise accept on a taxable investment. Thus, issuers of such bonds receive an implicit Federal subsidy equal to the difference between the tax-exempt interest rate paid and the taxable rate that otherwise would be paid. In this way, the income exclusion lowers the cost of capital for State and local governments. Activities that can be financed with tax-exempt bonds issued by State and local governments include public power facilities (i.e., generation, transmission, distribution, and retailing).

As an alternative to traditional tax-exempt bonds, the Energy Policy Act of 2005 provided State and local governments and certain cooperative entities authority to issue clean renewable energy bonds ("CREBs"), a type of tax credit bond. Generally, CREBs may be issued for facilities that qualify for the tax credit under section 45. Unlike bonds traditionally issued by State and local governments, CREBs are not interest-bearing obligations. Rather, the taxpayer holding a CREB on a credit allowance date is entitled to a tax credit based on the face amount on the holder's bond.

B. Tax-exempt bonds

In general

Bonds issued by State and local governments may be classified as either governmental bonds or private activity bonds. Governmental bonds are bonds the proceeds of which are primarily used to finance governmental functions or which are repaid with governmental funds. Private activity bonds are bonds in which the State or local government serves as a conduit providing financing to nongovernmental persons. For these purposes, the term "nongovernmental person" generally includes the Federal Government and all other individuals and entities other than States or local governments. The exclusion from income for interest on State and local bonds does not apply to private activity bonds; unless the bonds are issued for certain permitted purposes ("qualified private activity bonds") and other Code requirements are met.

Private activity bond tests

Present law provides two tests for determining whether a State or local bond is in substance a private activity bond, the private business test and the private loan test.[1]

[1] Section. 141(b) and (c).

Private business tests

Private business use and private payments result in State and local bonds being private activity bonds if both parts of the two-part private business test are satisfied--

> 1. More than 10 percent of the bond proceeds is to be used (directly or indirectly) by a private business (the "private business use test"); and
>
> 2. More than 10 percent of the debt service on the bonds is secured by an interest in property to be used in a private business use or to be derived from payments in respect of such property (the "private payment test").[2]

Private business use generally includes any use by a business entity (including the Federal government), which occurs pursuant to terms not generally available to the general public. For example, if bond-financed property is leased to a private business (other than pursuant to certain short-term leases for which safe harbors are provided under Treasury regulations), bond proceeds used to finance the property are treated as used in a private business use, and rental payments are treated as securing the payment of the bonds. Similarly, in the case of public power entities, if output of an electric generating plant or transmission or distribution facilities is provided to a private business on terms not generally available to other customers of the entity, an allocable portion of bonds financing the facilities is treated as used in a private business use and as secured by the payments from the private business.

Private business use also can arise when a governmental entity contracts for the operation of a governmental facility by a private business under a management contract that does not satisfy Treasury regulatory safe harbors regarding the types of payments made to the private operator and the length of the contract.[3] These rules require public power entities to restrict the period of contracts with private businesses as well as the aggregate amount of electric service provided to private businesses on terms that are not generally available to customers of the entity, if interest on their bonds is to remain tax-exempt.

[2] The 10-percent private business use and payment threshold is reduced to five percent for private business uses that are unrelated to a governmental purpose also being financed with proceeds of the bond issue. In addition, as described more fully below, the 10-percent private business use and private payment thresholds are phased-down for larger bond issues for the financing of certain "output" facilities. The term output facility includes electric generation, transmission, and distribution facilities.

[3] See Treas. Reg. sec. 1.141-3(b) (4) and Rev. Proc. 97-13, 1997-1 C.B. 632.

Private loan test

The second standard for determining whether a State or local bond is a private activity bond is whether an amount exceeding the lesser of (1) five percent of the bond proceeds or (2) $5 million is used (directly or indirectly) to finance loans to private persons. Private loans include both business and other (e.g., personal) uses and payments by private persons; however, in the case of business uses and payments, all private loans also constitute private business uses and payments subject to the private business test. Present law provides that the substance of a transaction governs in determining whether the transaction gives rise to a private loan. In general, any transaction which transfers tax ownership of property to a private person is treated as a loan. In the context of public power, longer-term contracts for the sale of output may violate the private loan test, because these contracts have the substantive characteristics of a loan.

Special legislative rules for tax-exempt financing of governmental "output" facilities

In addition to the general private business use and payment tests, the Code includes specific provisions governing the issuance of governmental tax-exempt bonds to finance "output" facilities. Output facilities include facilities for electric and gas generation, transmission, and distribution.

$15 million limit on private business use.--Present law imposes an additional restriction on private business use of State or local government bonds whose proceeds are to be used to finance output facilities.[4] A bond is treated as issued to finance an output facility (and subject to this restriction) if five percent or more of the proceeds is to be used with respect to any output facility. Under this restriction, the 10-percent private business use and private payment tests in substance are phased down for facilities that receive more than $15 million in tax-exempt bond financing. Significantly, unlike most tax-exempt bond restrictions, which are determined on a bond-issue by bond-issue basis, this restriction is measured by reference to all outstanding tax-exempt financing from which a facility benefits.

Bonds for acquisition of existing output property *per se* private activity.--In general, any bond with respect to which five percent or more ($5 million if less) of the proceeds is to be used, directly or indirectly, by a governmental entity to acquire existing output property is per se a private activity bond.[5] As such, interest on the bond is taxable, unless the use of the acquired facility satisfies the provisions applicable to tax-exempt private activity bonds for the local furnishing of electricity (described below). The two-county (or a city and a contiguous county) service area requirement that applies to facilities for the local furnishing of electricity does not apply in this circumstance.

[4] Sec. 141(b) (4).

[5] Sec. 141(d).

There are two exceptions to the rule regarding the acquisition of existing output property. First, the rule does not apply to bonds for the acquisition of existing facilities that will provide service in a "qualified service area" of the issuer. A qualified service area is defined as an area throughout which the acquiring entity has provided electric service for at least the 10-year period preceding the date of the acquisition. Second, the rule does not apply to bonds issued to acquire existing output property to be used in a "qualified annexed area" of a public power entity. The term qualified annexed area includes only areas (1) that are contiguous to existing service areas, (2) that are annexed for general governmental purposes, and (3) the size of which does not exceed 10 percent of the public power entity's service area before the annexation occurs.

Qualified private activity bonds

In general

As stated above, interest on private activity bonds is taxable unless the bonds meet the requirements for qualified private activity bonds. Qualified private activity bonds permit States or local governments to act as conduits providing tax-exempt financing for certain private activities. In most cases, the aggregate volume of these tax-exempt private activity bonds is restricted by annual aggregate volume limits imposed on bonds issued by issuers within each State. The Code further imposes several additional restrictions on tax-exempt private activity bonds that do not apply to bonds for governmental activities.

The definition of qualified private activity bonds includes an exempt facility bond, or qualified mortgage, veterans' mortgage, small issue, redevelopment, 501(c)(3), or student loan bond (sec. 141(e)). The definition of exempt facility bond includes bonds issued to finance certain transportation facilities (airports, ports, mass commuting, and high-speed intercity rail facilities); qualified residential rental projects; privately owned and/or operated utility facilities (sewage, water, solid waste disposal, and local district heating and cooling facilities, certain private electric and gas facilities, and hydroelectric dam enhancements); public/private educational facilities; qualified green building and sustainable design projects; and qualified highway or surface freight transfer facilities (sec. 142(a)).

Private activity bonds for the local furnishing of electricity

Qualified private activity bonds may be issued by States or local governments acting as conduits to finance generation, transmission, and distribution facilities for private businesses engaged in the local furnishing of electricity ("local furnishers"). A business is treated as engaged in local furnishing of electricity if the service territory in which the electricity is provided does not exceed (1) two contiguous counties, or (2) a city and a contiguous county. Historically, local furnishers eligible for this tax-exempt financing have included both investor-owned utilities ("IOUs") and independent power ventures. These bonds may be issued for the benefit of only those persons that were engaged in local furnishing of electricity in the service territory in which the new facilities will be used as of January 1, 1997, or in qualified expansions of those service territories. A "qualified expansion" is limited to service territory that is a part of a county in which the local furnisher was providing electric service on that date. For example, if a local furnisher was providing electric service to one county and a portion of a contiguous county on January 1, 1997, bonds may be issued for the continued provision of service both within that area and also for service to be provided in the remaining portion of the contiguous county in the future. In addition to persons actually engaged in local furnishing activities on January 1, 1997, the Code allows certain successors in interest to persons that qualified as local furnishers on that date to "step into the shoes" of the predecessor local furnishers provided that the service territories served otherwise satisfy the requirements for local furnishing.

Notwithstanding the general limits on service territories of local furnishers, the Code includes special rules allowing these electric service providers to transmit ("wheel") electricity through their systems, if ordered by the Federal Energy Regulatory Commission to do so under sections 211 or 213 of the Federal Power Act, provided that the size of the transmission lines or other facilities used in these wheeling activities does not exceed the capacity required to serve their otherwise qualified two contiguous county service area or city and contiguous county service area.

<u>Hydro-electric generating facilities</u>

Present law also permits the issuance of qualified private activity bonds for "environmental enhancements of hydro-electric generating facilities." Eligible facilities include those that protect or promote fisheries or other wildlife resources and those for recreational purposes or other improvements required by the terms of a Federal license for the operation of a hydro-electric generating facilities. This provision was enacted to permit tax-exempt financing of certain renovations to the dams and accompanying hydroelectric electric generating facilities along the Columbia River that are a part of the Bonneville Power Administration system. Bonds issued for these purposes are not subject to the State volume limitations applicable to most qualified private activity bonds.

C. Clean Renewable Energy Bonds

In general

CREBs are a type of tax credit bond and, thus, are not interest-bearing obligations. Rather, the taxpayer holding a CREB on a credit allowance date is entitled to a tax credit that is determined by multiplying the bond's credit rate by the face amount on the holder's bond. The credit accrues quarterly, is includible 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 credit rate on CREBs is determined by the Secretary and is to be a rate that permits issuance of CREBs without discount and interest cost to the qualified issuer. Thus, under present law credit rates, issuers of CREBS should pay no interest on such obligations, only principal. As a result, the subsidy associated with CREBs is deeper than that provided to issuers of tax-exempt bonds.

Requirements for clean renewable energy bonds

CREBs are defined as any bond issued by a qualified issuer if, in addition to the requirements discussed below, 95 percent or more of the proceeds of such bonds are used to finance capital expenditures incurred by qualified borrowers for qualified projects. "Qualified projects" are facilities that qualify for the tax credit under section 45 (other than Indian coal production facilities), without regard to the placed-in-service date requirements of that section.[6] The term "qualified issuers" includes (1) governmental bodies (including Indian tribal governments); (2) mutual or cooperative electric companies (described in section 501(c)(12) or section 1381(a)(2)(C), or a not-for-profit electric utility which has received a loan or guarantee under the Rural Electrification Act); and (3) clean renewable energy bond lenders. The term "qualified borrower" includes a governmental body (including an Indian tribal government) and a mutual or cooperative electric company. A clean renewable energy bond lender means a cooperative which is owned by, or has outstanding loans to, 100 or more cooperative electric companies and is in existence on February 1, 2002.

To qualify as CREBs, 95 percent or more of the proceeds of such bonds must be spent on qualified projects within the five-year period that begins on the date of issuance. To the extent less than 95 percent of the proceeds are used to finance qualified projects during the five-year period, bonds will continue to qualify as CREBs if unspent proceeds are used within 90 days from the end of such five-year period to redeem certain outstanding bonds. The five-year spending period may be extended by the Secretary if the issuer can establish that any failure to satisfy the spending requirement is due to reasonable cause and that qualified projects will continue to proceed with due diligence.

CREBs are subject to the arbitrage restrictions that generally restrict the ability of issuers of State and local bonds to earn arbitrage profits by investing tax-exempt bond proceeds in higher yielding investments. Principles under section 148 apply for purposes of determining the yield restriction and arbitrage rebate requirements applicable to CREBs. For example, for arbitrage purposes, the yield on an issue of CREBs is computed by taking into account all payments of interest, if any, on such bonds, i.e., whether the bonds are issued at par, premium, or discount. However, for purposes of determining yield, the amount of the credit allowed to a taxpayer holding CREBs is not treated as interest, although such credit amount is treated as interest income to the taxpayer.

CREBs also are subject to a maximum maturity limitation. 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 CREBs being equal to 50 percent of the face amount of such bond. In addition, the Code requires level amortization of CREBs during the period such bonds are outstanding.

[6] In addition, Notice 2006-7 provides that qualified projects include any facility owned by a qualified borrower that is functionally related and subordinate to any facility described in sections 45(d)(1) through (d)(9) and owned by such qualified borrower.

There is a national limitation of $1.2 billion of CREBs issuance authority that the Secretary may allocate, in the aggregate, to qualified projects. However, no more than $750 million of CREBs may be allocated to qualified projects for qualified borrowers that are governmental bodies. In Notice 2005-98, the IRS provided that CREBs volume cap allocations would be made based on a "smallest-to-largest" project amount methodology, beginning with the project requesting the smallest dollar amount and proceeding thereafter to projects for successively larger dollar amounts until the total national volume cap is consumed. The authority to issue CREBs expires December 31, 2008.

II. PRESENT LAW RELATING TO INCOME OF ELECTRIC COOPERATIVES

In general

Under present law, an entity must be operated on a cooperative basis in order to be treated as a cooperative for Federal income tax purposes. Although not defined by statute or regulation, the two principal criteria for determining whether an entity is operating on a cooperative basis are: (1) ownership of the cooperative by persons who patronize the cooperative; and (2) return of earnings to patrons in proportion to their patronage. The Internal Revenue Service requires that cooperatives must operate under the following principles: (1) subordination of capital in control over the cooperative undertaking and in ownership of the financial benefits from ownership; (2) democratic control by the members of the cooperative; (3) vesting in and allocation among the members of all excess of operating revenues over the expenses incurred to generate revenues in proportion to their participation in the cooperative (patronage); and (4) operation at cost (not operating for profit or below cost).[7]

In general, cooperative members are those who participate in the management of the cooperative and who share in patronage capital. As described below, income from the sale of electric energy by an electric cooperative may be member or non-member income to the cooperative, depending on the membership status of the purchaser. A municipal corporation may be a member of a cooperative.

For Federal income tax purposes, a cooperative generally computes its income as if it were a taxable corporation, with one exception− the cooperative may exclude from its taxable income distributions of patronage dividends. In general, patronage dividends are the profits of the cooperative that are rebated to its patrons pursuant to a pre-existing obligation of the cooperative to do so. The rebate must be made in some equitable fashion on the basis of the quantity or value of business done with the cooperative.

[7] Announcement 96-24, "Proposed Examination Guidelines Regarding Rural Electric Cooperatives," 1996-16 I.R.B. 30.

Except for tax-exempt farmers' cooperatives, cooperatives that are subject to the cooperative tax rules of subchapter T of the Code[8] are permitted a deduction for patronage dividends from their taxable income only to the extent of net income that is derived from transactions with patrons who are members of the cooperative.[9] The availability of such deductions from taxable income has the effect of allowing the cooperative to be treated like a conduit with respect to profits derived from transactions with patrons who are members of the cooperative.

Cooperatives that qualify as tax-exempt farmers' cooperatives are permitted to exclude patronage dividends from their taxable income to the extent of all net income, including net income that is derived from transactions with patrons who are not members of the cooperative, provided the value of transactions with patrons who are not members of the cooperative does not exceed the value of transactions with patrons who are members of the cooperative.[10]

Taxation of electric cooperatives exempt from subchapter T

In general, the cooperative tax rules of subchapter T apply to any corporation operating on a cooperative basis (except mutual savings banks, insurance companies, other tax-exempt organizations, and certain utilities), including tax-exempt farmers' cooperatives (described in sec. 521(b)). However, subchapter T does not apply to an organization that is "engaged in furnishing electric energy, or providing telephone service, to persons in rural areas."[11] Instead, electric cooperatives are taxed under rules that were generally applicable to cooperatives prior to the enactment of subchapter T in 1962. Under these rules, an electric cooperative can exclude patronage dividends from taxable income to the extent of all net income of the cooperative, including net income derived from transactions with patrons who are not members of the cooperative.[12]

Tax exemption of rural electric cooperatives

In general

Section 501(c) (12) provides an income tax exemption for rural electric cooperatives if at least 85 percent of the cooperative's income consists of amounts collected from members for the sole purpose of meeting losses and expenses of providing service to its members.

[8] Sec. 1381, et seq.

[9] Sec. 1382.

[10] Sec. 521.

[11] Sec. 1381(a) (2) (C).

The IRS takes the position that rural electric cooperatives also must comply with the fundamental cooperative principles described above in order to qualify for tax exemption under section 501(c)(12).[13] The 85-percent test is determined without taking into account any income from: (1) qualified pole rentals; (2) open access electric energy transmission services; (3) open access electric energy distribution services; (4) any nuclear decommissioning transaction; (5) any asset exchange or conversion transaction.[14]

<u>Income from open access transactions</u>

Income received or accrued by a rural electric cooperative (other than income received or accrued directly or indirectly from a member of the cooperative) from the provision or sale of electric energy transmission services or ancillary services on a nondiscriminatory open access basis under an open access transmission tariff approved or accepted by FERC or under an independent transmission provider agreement approved or accepted by FERC (including an agreement providing for the transfer of control, but not ownership, of transmission facilities) is excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c)(12).

In addition, income is excluded for purposes of the 85-percent test if it is received or accrued by a rural electric cooperative (other than income received or accrued directly or indirectly from a member of the cooperative) from the provision or sale of electric energy distribution services or ancillary services, provided such services are provided on a nondiscriminatory open access basis to distribute electric energy not owned by the cooperative: (1) to end-users who are served by distribution facilities not owned by the cooperative or any of its members; or (2) generated by a generation facility that is not owned or leased by the cooperative or any of its members and that is directly connected to distribution facilities owned by the cooperative or any of its members.

<u>Income from nuclear decommissioning transactions</u>

Income received or accrued by a rural electric cooperative from any "nuclear decommissioning transaction" also is excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c) (12). The term "nuclear decommissioning transaction" is defined as—

1. any transfer into a trust, fund, or instrument established to pay any nuclear decommissioning costs if the transfer is in connection with the transfer of the cooperative's interest in a nuclear power plant or nuclear power plant unit;

2. any distribution from a trust, fund, or instrument established to pay any nuclear decommissioning costs; or

3. any earnings from a trust, fund, or instrument established to pay any nuclear decommissioning costs.

[12] See Rev. Rul. 83-135, 1983-2 C.B. 149.

[13] Rev. Rul. 72-36, 1972-1 C.B. 151.

[14] Sec. 501(c) (12) (C).

Income from asset exchange or conversion transactions

Gain realized by a tax-exempt rural electric cooperative from a voluntary exchange or involuntary conversion of certain property is excluded in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c) (12). This provision only applies to the extent that: (1) the gain would qualify for deferred recognition under section 1031 (relating to exchanges of property held for productive use or investment) or section 1033 (relating to involuntary conversions); and (2) the replacement property that is acquired by the cooperative pursuant to section 1031 or section 1033 (as the case may be) constitutes property that is used, or to be used, for the purpose of generating, transmitting, distributing, or selling electricity or natural gas.

Treatment of income from load loss transactions

Tax-exempt rural electric cooperatives

Under present law, income received or accrued by a tax-exempt rural electric cooperative from a "load loss transaction" is treated under section 501(c) (12) as income collected from members for the sole purpose of meeting losses and expenses of providing service to its members.[15] Therefore, income from load loss transactions is treated as member income in determining whether a rural electric cooperative satisfies the 85-percent test for tax exemption under section 501(c) (12). In addition, income from load loss transactions does not cause a tax-exempt electric cooperative to fail to be treated for Federal income tax purposes as a mutual or cooperative company under the fundamental cooperative principles described above.

The term "load loss transaction" is generally defined as any wholesale or retail sale of electric energy (other than to a member of the cooperative) to the extent that the aggregate amount of such sales during a seven-year period beginning with the "start-up year" does not exceed the reduction in the amount of sales of electric energy during such period by the cooperative to members. The "start-up year" is defined as the first year that the cooperative offers nondiscriminatory open access or, if later and at the election of the cooperative, 2004.

Present law also excludes income received or accrued by rural electric cooperatives from load loss transactions from the tax on unrelated trade or business income.

Taxable electric cooperatives

The receipt or accrual of income from load loss transactions by taxable electric cooperatives is treated as income from patrons who are members of the cooperative.[16] Thus, income from a load loss transaction is excludible from the taxable income of a taxable electric cooperative if the cooperative distributes such income pursuant to a pre-

[15] Sec. 501(c) (12) (H).

[16] Sec. 501(c) (12) (H).

existing contract to distribute the income to a patron who is not a member of the cooperative. In addition, income from load loss transactions does not cause a taxable electric cooperative to fail to be treated for Federal income tax purposes as a mutual or cooperative company under the fundamental cooperative principles described above.

III. PRESENT LAW RELATING TO THE SALE OF ELECTRIC TRANSMISSION PROPERTY

Generally, a taxpayer recognizes gain to the extent the sales price (and any other consideration received) exceeds the seller's basis in the property. The recognized gain is subject to current income tax unless the gain is deferred or not recognized under a special tax provision. With regard to the disposition of certain electric transmission property, taxpayers may elect to recognize gain from qualified electric transmission transactions ratably over an eight-year period if the amount realized from such sale is used to purchase exempt utility property within four years after the close of the taxable year in which the transaction takes place.[17] If the amount realized exceeds the amount used to purchase reinvestment property, any realized gain shall be recognized to the extent of such excess in the year of the qualifying electric transmission transaction, with any remaining realized gain recognized ratably over the eight-year period.

A qualifying electric transmission transaction is the sale or other disposition of property used by the taxpayer in the trade or business of providing electric transmission services, or an ownership interest in such an entity, to an independent transmission company prior to January 1, 2008. In general, an independent transmission company is defined as: (1) an independent transmission provider[18] approved by the Federal Energy Regulatory Commission ("FERC"); (2) a person (i) who the FERC determines under section 203 of the Federal Power Act (or by declaratory order) is not a "market participant" and (ii) whose transmission facilities are placed under the operational control of a FERC-approved independent transmission provider before the close of the period specified in such authorization, but not later than December 31, 2007; or (3) in the case of facilities subject to the jurisdiction of the Public Utility Commission of Texas, (i) a person which is approved by that Commission as consistent with Texas State law regarding an independent transmission organization, or (ii) a political subdivision, or affiliate thereof, whose transmission facilities are under the operational control of an organization described in (i).

[17] Sec. 451(i).

[18] For example, a regional transmission organization, an independent system operator, or an independent transmission company.

Exempt utility property is defined as: (1) property used in the trade or business of generating, transmitting, distributing, or selling electricity or producing, transmitting, distributing, or selling natural gas, or (2) stock in a controlled corporation whose principal trade or business consists of the activities described in (1).

If the taxpayer is a member of an affiliated group of corporations filing a consolidated return, the reinvestment property may be purchased by any member of the affiliated group (in lieu of the taxpayer).

Roundtable 10: Coal
March 16, 2007

Speakers:

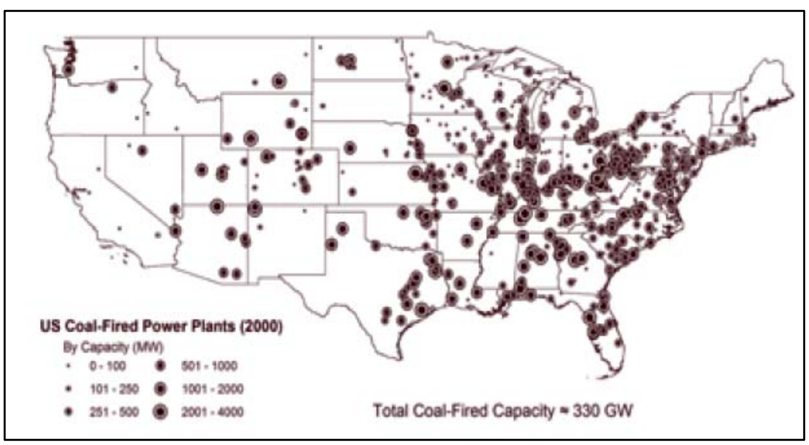
Ben Yamagata – Executive Director, Coal Utilization Research Council
Dr. Nina French – Director, Clean Coal Solutions, (ADA-ES & NexGen Resources)

Coal 101 Roundtable (3/16/07):

This roundtable reviewed the basics of coal and coal-based electricity generation. Ben Yamagata provided an overview of where coal is located, how much is consumed, and how much it costs. He also discussed coal-based electricity generation, including the use of conventional pulverized, advanced pulverized, and IGCC coal-burning technologies. Dr. French provided background on synthetic coal (the old Section 29), refined coal (Section 45), as well as an overview of her firm's work on pollution mitigation for coal-fired plants. Both speakers provided context on the current debate over carbon sequestration, and the potential technologies that may be used to that end.

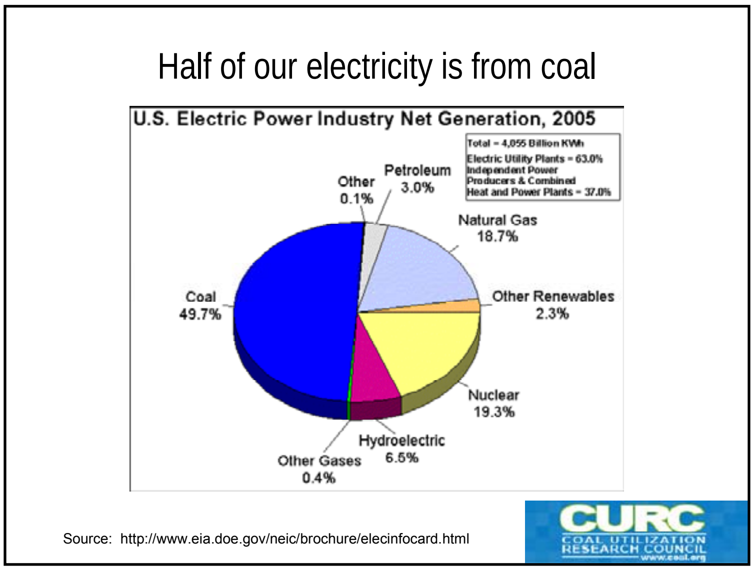
Background:

About 50% of U.S. electricity is generated by coal, from the equivalent of over five hundred 500-megawatt, coal-fired plants (plant capacity varies in size; see graphic below). Coal-fired electricity is U.S.'s the largest source of CO_2 emissions, accounting for over a third of energy-related CO_2 output annually. One 500 megawatt coal-fired power plant produces about 3 million tons of CO_2 per year, the equivalent of about 600,000 cars. Discussion also included tax treatment for depletion (a form of capital cost recovery) of coal properties, as well as provisions related to pollution-control facilities. Both of these topics are discussed in the attached Joint Tax description.

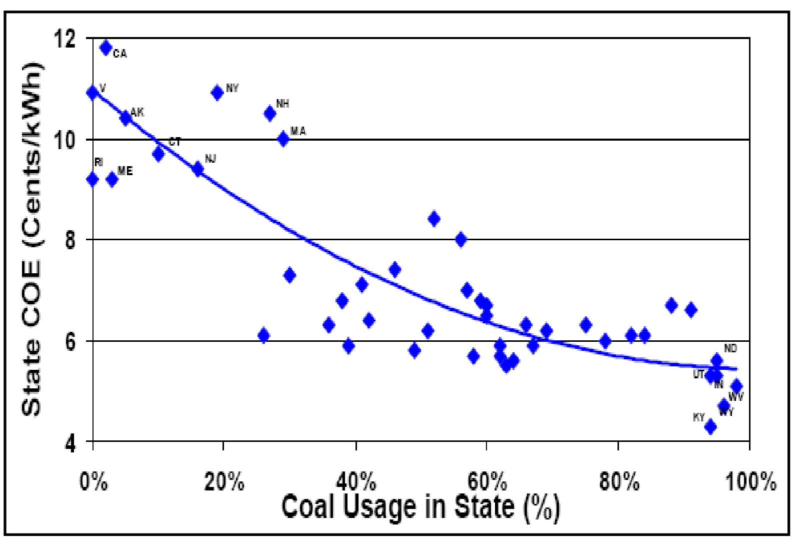


Distribution of U. S. Coal-Based Power Plants. (Source: *MIT*: *The Future of Coal*)

There are two main reasons why coal dominates the U.S. (and other countries') electricity-production landscape: coal is both abundant and cheap. At a cost of $1–2 per-million BTUs, coal is far cheaper than the $ 6–12 per-million-BTU cost of natural gas and oil. And with about a quarter of the world's reserves, the United States has enough coal to last it an estimated 250 years. Not surprisingly, coal is expected to provide a great deal of the expected 50% growth in U.S. electricity capacity over the next two decades. The Energy Information Administration projects that coal's share of U.S. electricity production will grow to 57% by 2030. Given this expected growth, there is heightened interest in curbing the emissions that will result from increased coal use. Following is an overview of "Coal 101", including description on the how coal is mined; how it is converted into electricity; and steps that may be taken to mitigate the impact of its emissions.



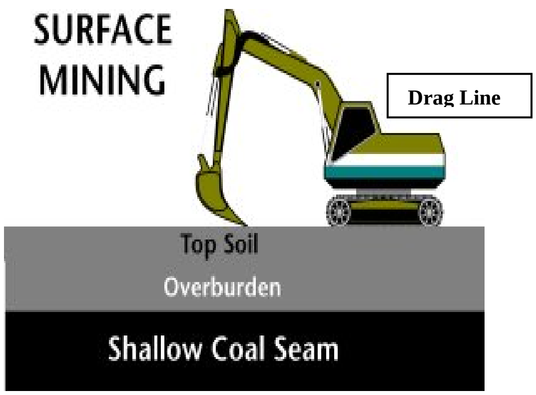
Electricity Production in U.S.



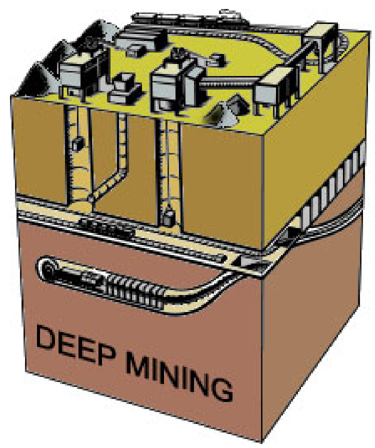
Cost of Electricity Relative to % of Coal Usage

Coal Mining:

Coal is produced from two main types of mines-- underground and surface (see diagram below). The methods for recovering coal from the earth have undergone drastic changes in the past 25 years, the result of technological advances. Fifty years ago, when most coal mining was done manually, underground mines accounted for 96 percent of the coal produced each year. Today, almost 60 percent is produced from surface mines. Most underground mines in the U.S. are located east of the Mississippi River, although there are some in the West, particularly in Utah and Colorado.



If the coal seams are near the surface, the coal is extracted by surface mining, using giant machines known as 'drag lines', which remove the top-soil and layers of rock to expose large beds of coal. As the coal is exposed and extracted, the overburden from the still covered coal fills the former pit. Surface mining can be used when the coal is buried less than 200 feet underground.



Underground mining, sometimes called deep mining, is used when the coal is buried several hundred feet below the surface. Some underground mines are 1,000 feet deep. To remove coal in these underground mines, miners ride elevators down deep mine shafts where they run machines that dig out the coal.

Types of Coal:

There are four main types of coal, each with different characteristics in terms of energy output and content of carbon, moisture, ash and sulfur. These differences have a significant impact on the price paid for coal, as well as how it is transported and used in generating power.

Lignite is the lowest rank of coal. Lignite deposits tend to be relatively young, and the material is relatively crumbly, with a high moisture content. There are about 20 lignite mines in the United States, producing about seven percent of U.S. coal.

Subbituminous coal has a higher heating value than lignite. Subbituminous coal typically contains 35-45 percent carbon, compared to 25-35 percent for lignite. Most subbituminous coal in the U.S. is at least 100 million years old. About 42 percent of the coal produced in the United States is subbituminous. Wyoming is the leading source of subbituminous coal, while Montana has the largest reserves.

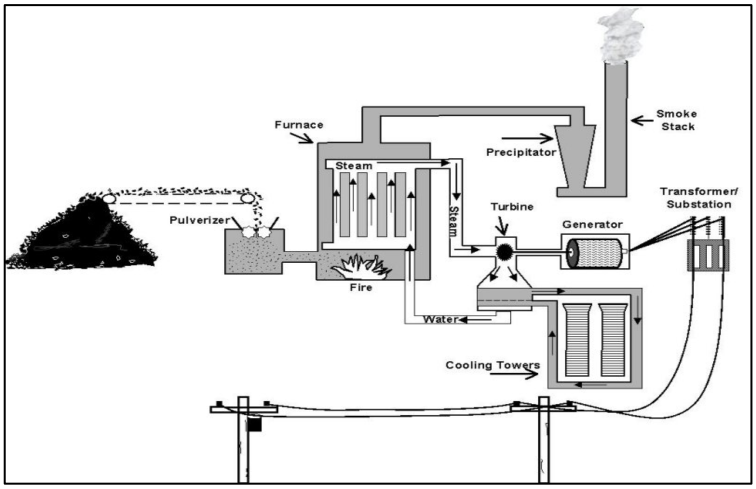
Bituminous coal contains 45-86 percent carbon, and has two to three times the heating value of lignite. Bituminous coal was formed under high heat and pressure. Bituminous coal in the United States is between 100 to 300 million years old. It is the most abundant rank of coal found in the United States, accounting for about half of U.S. coal production. Bituminous coal is used to generate electricity and is an important fuel and raw material for the steel and iron industries. West Virginia, Kentucky, and Pennsylvania are the largest producers of bituminous coal.

Anthracite contains 86-97 percent carbon, and has a heating value slightly lower than bituminous coal. It is very rare in the U.S., accounting for less than one-half of a percent of all coal mined. All of the anthracite mines in the United States are located in northeastern Pennsylvania.

Coal-Fired Electricity:

Just as types of coal are markedly different, so too are the means of producing electricity from coal. Following is a description of traditional pulverized coal-fired electricity production, as well as background on integrated gas combined cycle (IGCC) production.

***a) Conventional Pulverized Coal Plant*:** In a conventional coal power plant, coal is pulverized to a fine powder and burned. The resulting heat is used to produce steam, which in turn spins a turbine to generate electricity. While generating efficiency depends on coal type and unit design, typically only about one-third of the energy value of coal is actually converted into electricity by most conventional plants.



Conventional Pulverized Coal Plant

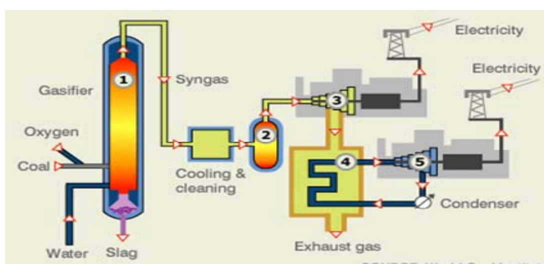
1) **Pulverizer:** Mined coal is delivered by a conveyor belt to the generating plant, where it is pulverized (crushed) to a fine powder, mixed with air and blown into the boiler (furnace) for combustion.
2) **Furnace:** The coal/air mixture ignites instantly in the boiler.
3) **Precipitator, stack:** Burning coal produces CO2, SO2, and NOx. It also produces bottom ash (coarse fragments that fall to the bottom of the boiler), and fly ash, light particles of ash. These materials can be used in cement and/or brick manufacture. A precipitator (huge air filter) removes 99.4% of fly ash before the flue gases are dispersed into the atmosphere.
4) **Turbine, generator:** Water in the boiler tubes picks up heat from the boiler and turns it to steam. The high-pressure steam from the boiler passes into the turbine (a massive drum with thousands of propeller blades). Once the steam hits the turbine blades, it makes the turbine spin, causing a shaft to turn inside the generator, creating an electric current.
5) **Substation, transformer, transmission line:** Once the electricity is generated, transformers increase the voltage so it can be carried across transmission lines. When electricity is delivered to substations in cities and towns, the voltage flowing into the distribution lines is reduced. Voltage is reduced further when distributed to consumers.

***b) Integrated Gasification Combined Cycle (IGCC)*:** As the name implies, IGCC involves producing electricity with a combined (gas turbine and steam turbine) process. In an IGCC facility, coal is fed into a gasifier, where heat and pressure convert the feedstock to coal to combustible gas, or "syngas." This syngas is cleaned to remove sulfur and other contaminants, before being burned in combustion turbine, which spins a generator, which creates electricity.

The 'combined' terminology refers to the next step of the process, where exhaust heat from the combustion turbine is recovered and used to produce steam in a boiler that spins another generator. Thus, the "combined cycle" portion of IGCC — both a combustion turbine cycle and a steam cycle — are used to produce electricity. The IGCC process converts much more of coal's energy value – up to 50 percent or more – into useable electricity, resulting in far-greater efficiency relative to a conventional plant. This improved efficiency means that less coal is used to generate power, resulting in fewer greenhouse gases (a 60%-efficient gasification power plant can cut the formation of carbon dioxide by 40% compared to a typical coal combustion plant). Moreover, the purified syngas can also be used in chemical production. Finally, another advantage of IGCC-based electricity production is that when oxygen is used in the gasifier (rather than air), the CO2 produced by the process is in a concentrated gas stream, making it easier and less expensive to separate and capture.

IGCC is cutting-edge technology, and has not yet been adopted for widespread use, in part because IGCC is significantly more expensive than conventional pulverized-coal electricity production. There are two coal-based IGCC demonstration plants operating in the U.S.: the 250 MW Tampa Electric Polk Power Station, which began operation in 1996; and the Wabash River Coal Gasification Repowering Project, a 292 MW plant which began operations in late 1995.

IGCC: Integrated Gasification Combined Cycle



1. Gasifier converts coal, oxygen & steam to syngas
2. Cleaned syngas is burned
3. Combustion gases expand in gas turbine, generates power
4. Waste heat generates steam (HRSG)
5. Steam expands in steam turbine, generates more power

Tax Provisions:

1) Section 48A: The Energy Policy Act of 2005 included two new investment tax credits (ITCs) in the Code: Sections 48A and 48B. The Section 48A credits are for electricity projects using IGCC or 'advanced coal' technology. The 48B credits are for projects that convert coal or other materials into gas for industrial uses, such chemical or fertilizer production. Section 48B is discussed in greater detail under the 'Gasification' roundtable of March 23.

Section 48A provides a 20% ITC for coal projects using IGCC, and a 15% investment tax credit for projects using an advanced coal-based generation technology other than IGCC. Treasury was authorized to allocate a maximum of $800 million in tax credits for IGCC projects under Section 48A ($267 million to projects using bituminous coal, $267 million to projects using subbituminous coal and $266 million to project using lignite), and a maximum $500 million in credits for project using non-IGCC advanced coal technology.

Applications for the first round of 48A funding were due June 30, 2006, and DOE received 22 requests (while IRS ultimately allocates the credits, DOE must certify that applications meet certain standards, such 99% removal of sulfur dioxide). Eighteen of the 22 applicants for 48A credits were for IGCC plants, and IRS allocated funding in the following manner: two IGCC bituminous coal projects ($133.5 million each); an IGCC lignite project ($133 million); and two non-IGCC advanced coal electricity generation projects ($125 million each). Note that DOE did not certify any of the Section 48A IGCC projects using subbituminous coal, based on the assumption that such projects could not meet the 99% sulfur dioxide removal requirement. Section 203 of the Tax Relief and Health Care Act, which passed in December 2006, modified the sulfur dioxide removal requirement for subbituminous projects, clarifying that the sulfur dioxide requirement is satisfied if the project is designed either to remove 99% of the sulfur dioxide or to achieve an emission limit of 0.04 pounds of sulfur dioxide/MMBtu, on a 30-day average.

2) Refined Coal: The 2004 Jobs Act included a production tax credit designed to promote the use of 'refined coal' under Section 45 of the Code. Projects meeting the following thresholds qualify for $4.375/ton (indexed) refined coal credit: 20% NO_x reduction, and either 20% mercury or SO_2 reduction. An additional market value test, requiring that the product result in a 50% increase in market value over the baseline feedstock coal, was also included in the law. The refined coal credit was geared toward helping relatively older, smaller coal plants meet emission reductions through the use of cleaner-burning coal -- rather than with investment in large capital expenditures. Dr. French argued that because the price of coal has fluctuated dramatically in recent years, the market-value standard must be clarified order to realize the potential refined coal has for improving performance of these facilities.

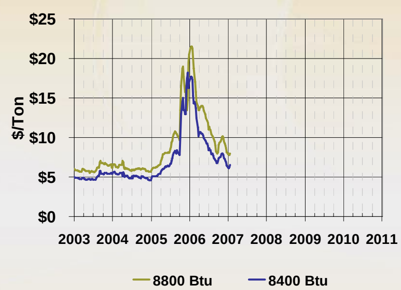
"Refined Coal" Tax Credit for Clean Coal: Goal-Specific Incentives

- Section 29 'syn-fuel' done right
- Tax credit requires:
  1. 20% reduction in NO_x, **and**
  2. 20% reduction in SO_2 **or** mercury
  3. 50% increase in market value of coal
- Refined Coal incentivizes:
  - Technologies that work up-front, on the coal
  - Older & smaller plants to meet emission reductions with cleaner-burning coal, not large capital expenditures.
  - Stop-gap until new capacity can be built (7 to 10 years)
  - These are plants that would otherwise shut down

20 ADA-ES

Market Value Test: PRB coal tripled from 2005 to 2006

Average spot price of PRB coal as published by DOE/EIA



•Business uncertainty

•Difficult to enforce

21 ADA-ES

PRESENT LAW RELATING TO COAL PROPERTY

Depletion

Depletion, like depreciation, is a form of capital cost recovery. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset is being expended in order to produce income. Depletion is available to any person having an economic interest in a producing property. An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in minerals in place, and secures, by any form of legal relationship, income derived from the extraction of the mineral, to which it must look for a return of its capital.

Two methods of depletion are currently allowable under the Internal Revenue Code: (1) the cost depletion method, and (2) the percentage depletion method. Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the depletable property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the end of taxable year plus the number of units sold during the taxable year.[1] Thus, the amount recovered under cost depletion may never exceed the taxpayer's basis in the property.

Under the percentage depletion method, 10 percent of the taxpayer's gross income from coal producing property is allowed as a deduction in each taxable year.[2] The amount deducted generally may not exceed 50 percent of the net income (computed without allowances for depletion and without the deduction under section 199) from that property in any year (the "net-income limitation").[3] Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's basis in the depletable property, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine the depletion deduction for each property under both the percentage depletion method and the cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question.[4]

Pollution control facilities

In general, a taxpayer may elect to recover the cost of any certified pollution control facility over a period of 60 months.[5] A certified pollution control facility is defined as a new, identifiable treatment facility which

[1] Treas. Reg. sec. 1.611-2(a)(1).

[2] Sec. 613(b)(4).

[3] Sec. 613(a).

[4] Id.

[5] Sec. 169.

(1) is used in connection with a plant in operation before January 1, 1976, to abate or control water or atmospheric pollution or contamination by removing, altering, disposing, storing, or preventing the creation or emission of pollutants, contaminants, wastes or heat; and (2) does not lead to a significant increase in output or capacity, a significant extension of useful life, a significant reduction in total operating costs for such plant or other property (or any unit thereof), or a significant alteration in the nature of a manufacturing production process or facility. Certification is required by appropriate State and Federal authorities that the facility complies with appropriate standards.

For a pollution control facility with a useful life greater than 15 years, only the portion of the basis attributable to the first 15 years is eligible to be amortized over a 60-month period.[6] In addition, a corporate taxpayer must reduce the amount of basis otherwise eligible for the 60-month recovery by 20 percent.[7] The amount of basis not eligible for 60-month amortization is depreciable under the regular tax rules for depreciation.

A certified air pollution control facility (but not a water pollution control facility) used in connection with an electric generation plant which is primarily coal fired will be eligible for 84-month amortization if the associated plant or other property was not in operation prior to January 1, 1976.[8] The 60-month amortization period remains in effect for any certified air pollution control facility used in connection with an electric generation plant which is primarily coal fired and which was in operation prior to January 1, 1976.

Other provisions affecting coal discussed in previous weeks

1. Synthetic fuel from coal production tax credit (sec. 45K) - February 2, 2007
2. Advanced coal project investment tax credit (sec. 48A) - February 9, 2007
3. Refined coal and Indian coal production tax credit (sec. 45) - February 16, 2007

[6] The amount attributable to the first 15 years is equal to an amount which bears the same ratio to the portion of the adjusted basis of the facility, which would be eligible for amortization but for the application of this rule, as 15 bears to the number of years of useful life of the facility.

[7] Sec. 291(a)(5).

[8] This provision was added by the Energy Policy Act of 2005 (Pub. Law No. 109-58) and is generally applicable to property that is constructed or acquired after April 11, 2005.

Roundtable 11: Gasification Roundtable
March 23, 2007

Speakers:

Harry T. Morehead – Manager, IGCC Business Development, Siemens Energy
John Henley – Process Scientist, Dow Chemical Company
Ed Lowe – General Manager, Gasification Market Development, GE Energy
James Edward Burns – Business Development Manager, Shell Clean Coal Energy

Gasification Roundtable (3/23/07):

This roundtable featured discussion on gasification technology, with a focus on Section 48B, the investment tax credits for gasification projects passed as part of the 2005 Energy Bill. Speakers for the gasification roundtable represented the four largest world suppliers of gasification technology (Shell, Siemens, GE and Dow), all of whom have a significant presence in China.

Shell Gasifier, China

Background:

Gasification is the process of converting material such as coal, petroleum, petroleum coke (a byproduct of petroleum refining) or biomass into carbon monoxide and hydrogen. Gasification's first widespread use was in the 19th Century, when 'town gas,' made from gasified coal, was used to power street lamps and homes in urban areas.

The gasification process was refined further in the 1920s, by German scientists Franz Fischer and Hans Tropsch. The Fischer-Tropsch process was used to create a coal-based petroleum substitute (both for powering machines and for lubrication), and its discovery led to the production of over 120,000 barrels of synfuels per day at the height of WWII. It wasn't until Allied bombing of German synfuel plants in 1944 and 1945 that the Nazi war machine began to grind to a halt. While the U.S. led that bombing effort, Germany's success with coal-to-liquids prompted Congress to explore whether the Fischer-Tropsch technology might apply on a large scale in the U.S. Congress passed the Synthetic Liquid Fuels Act in 1944, to research the viability of synfuels from coal, oil shale, and 'other substances.' Funding for the initiative was provided until 1952, when the House Appropriations Committee – citing high costs – ended the program.

Synfuel interest in the U.S. was renewed after oil prices spiked during the 1973 embargo, and in 1975 President Ford created the Energy Research and Development Administration (ERDA), consolidating existing energy R&D programs from several agencies. In 1977, ERDA became part of the new Department of Energy, and three years later President Carter signed legislation establishing the Synthetic Fuels Corporation, a quasi-government entity tasked with promoting synfuels research.

While the Synthetic Fuels Corporation was terminated just five years later (oil prices had fallen sharply, and the Corporation had come under criticism for alleged conflicts of interest), the program did help illustrate the viability of the integrated gasification combined cycle (IGCC) process for electricity production, through support of the Cool Water project near Barstow, California. The Cool Water project operated periodically from 1984–1989, and provided the technical foundation for IGCC technology used in the 250 MW Tampa Electric Polk Power Station, which began operation in 1996.

Polk Power Station, Florida

Wabash River Plant, Indiana

According to the recently-issued coal report from MIT (*The Future of Coal)*, the Polk project "has led to some optimism that costs (for future IGCC plants) will come down significantly with economies of scale, component standardization, and technical and design advances." The other major IGCC demonstration plant in the U.S. – the 292 MW Wabash River Coal Gasification Repowering Project – began operations in late 1995. Further experience in gasification and IGCC technology is expected to be gained through projects that receive investment tax credits per Sections 48A and 48B of the 2005 Energy Policy Act.

Gasification in China:

As mentioned above, much of discussion at the Roundtable centered on coal gasification in China. Speakers noted that while China is petroleum-poor, it has an abundance of coal, which is gasified to support China's fast-growing chemical industry. As shown in the following slides, coal gasification is widespread in China, and is the source of the majority of China's methanol and ammonia production.

Introduction

China has become the world's test-bed for large scale coal utilization processes

- China produces/consumes 1/3 of the world's coal
  - ➢ China's total consumption is only 15 to 20% of the world's energy.
- China produces the majority of its ammonia and methanol from coal.
- China will have the world's first:
  - ➢ Direct coal liquefaction plant (20,000 bpd, 2008)).
  - ➢ World scale coal to chemicals plants (0.6 and 1 million tpa, startup 2010/2014).
  - ➢ Modern indirect coal to liquid fuel plants since South Africa (two at 80,000 bpd, 2012).
  - ➢ Dimethyl ether plant (LPG type fuel).

J. P. Henley 3/07

Page 2

Recent Orders of GE's Gasification Licenses

Total Licenses:	29
Solids Feed	19
Liquid Feed	8
Gas Feed	2

Coal Company
Coal to MeOH
1Q 08

Shenmu II
Coal to MeOH
4Q 07

Private Company
Coal to MeOH
3Q 08

Dalian
Coal to Ammonia
4Q 08

Sinopec Qilu
Coal to Oxochem
3Q 07

Coal Company
Coal to MeOH
3Q 07

Wison
Coal to CO/MeOH
1Q 07

SCCC III
Coal to CO/MeOH
3Q 07

Project
Coal to Product
COD

imagination at work

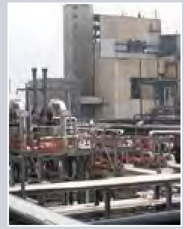
8

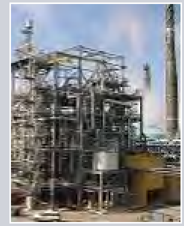
SIEMENS

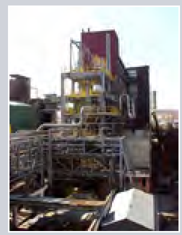
Siemens Gasification Experience

Projects

	Gasifier Size	Start-up	Fuel	Products
Schwarze Pumpe SZV (Germany)	200MW$_{th}$	1984	Lignite, natural gas, tar oils, and waste	Syngas for methanol and power
Future Energy Test Facility (Freiberg, Germany)	5MW$_{th}$	1996	hard coal, lignite, slurries	Syngas
BASF Seal-Sands (UK)	30MW$_{th}$	2001	liquid chemical residuals	Fuel Gas
Vřesová (Czech Republic)	175 MW$_{th}$	2007	tar oils, liquid residuals	syngas for IGCC
Shenhua Ningxia Coal Group (China) Equipment Ordered	2x 500MW$_{th}$	Q1/2009	Bituminous coal	DME
Confidential Client Selected	4 x 500 MW$_{th}$	2011	Sub-Bit Coal	H_2
Shenhua Ningxia Coal Group (China) In Discussions	4 x 500 MW$_{th}$	2009	Bituminous coal	Polypropylene


Schwarze Pumpe


Seal-Sands


Vřesová


Siemens Test Center

Shell China coal gasification licences

1. Yueyang Sinopec & Shell Coal Gasification Co Ltd
2,000 t/d plant to supply a fertiliser plant.
2. Hubei Shuanghuan Chemical Group Co Ltd
900 t/d plant to supply a fertiliser plant.
3. Liuzhou Chemical Industry Co ltd
1100 t/d plant to supply fertiliser plant.
4. Sinopec Hubei Chemical Fertiliser Co
2000 t/d plant to supply a fertiliser plant.
5. Sinopec Anqing Company
2000 t/d plant to supply a fertiliser plant.
6. Yunnan Tianan Chemical Co Ltd
2700 t/d plant to supply a fertiliser plant.
7. Yunnan Zhanhua Co Ltd
2700 t/d plant to supply a fertiliser plant.
8. Dahua Group Ltd
1100 t/d plant to supply methanol plant.
9. Yongcheng Coal and Power Group
2100 t/d plant to supply a methanol plant.
10. China Shenhua Coal Liquefaction Corporation
2x2200 t/d plant to supply hydrogen for DCL.
11. Henan Zhongyuan Dahua Group
2100 t/d plant to supply a methanol plant.
12. Henan Yima Kaixiang Group
1100 t/d plant to supply a methanol plant.
13. A Power Company in Inner Mongolia
3x 4000 t/d plant to supply a methanol plant.
14. Tianjin Soda Plant of Tianjin Bohai Chemical Group
2x2000 t/d plant to supply ammonia and methanol plants.
15. A Chemical Company in Guizhou
2000 t/d plant to supply ammonia and methanol plants.

Tax Provisions:

To encourage the coal industry to establish the first fleet of next generation 'clean coal' facilities, the 2005 Energy Bill established two new investment credits (ITC) under Sections 48A and 48B of the Code. Section 48A provides investment tax credits for clean-coal facilities producing electricity, with a total of $1.3 billion in federal funds allotted. This section was discussed in greater depth at the March 16 roundtable ("Coal 101").

Section 48B of the 2005 Energy Bill provides a 20% ITC for projects engaged in industrial gasification. Projects eligible under 48A are those involved in converting a solid or liquid product from coal, petroleum residue, biomass, or other materials into a syngas. The syngas must be composed primarily of carbon monoxide and hydrogen, and must have an industrial purpose such as chemical or fertilizer production. The total amount allocated for 48B was $350 million, and 27 projects submitted applications for funding in the first round. IRS announced the recipients of the 48B credits in November, and four gasification projects were provided funding, with amounts ranging from $40,663,000 to $130 million.

One of the beneficiaries of the 48B credits is BP's Carson refinery, near Long Beach, California. The project is expected to gasify 4,500 tons per day of petcoke, producing 800 tons daily of hydrogen and about 400 MW of electricity. Approximately 4 million tons of CO2 will be sent off-site each year for enhanced oil recovery (EOR).

Carson Refinery -- Long Beach, CA

PRESENT LAW RELATING TO COAL GASIFICATION PROJECTS (SEC.48B)

A 20 percent investment tax credit is available for investments in certain qualifying coal gasification projects. Only property which is part of a qualifying gasification project and necessary for the gasification technology of such project is eligible for the gasification credit.

Qualified gasification projects convert coal, petroleum residue, biomass, or other materials recovered for their energy or feedstock value into a synthesis gas composed primarily of carbon monoxide and hydrogen for direct use or subsequent chemical or physical conversion. Qualified projects must be carried out by an eligible entity, defined as any person whose application for certification is principally intended for use in a domestic project which employs domestic gasification applications related to (1) chemicals, (2) fertilizers, (3) glass, (4) steel, (5) petroleum residues, (6) forest products, and (7) agriculture, including feedlots and dairy operations.

Credits are available only for projects certified by the Secretary of Treasury, in consultation with the Secretary of Energy. Certifications are issued using a competitive bidding process. The Secretary of Treasury must establish a certification program no later than 180 days after August 8, 2005,[1] and each project application must be submitted during the 3-year period beginning on the date such certification program is established. The Secretary of Treasury may not allocate more than $350 million in credits. In addition, the Secretary may certify a maximum of $650 million in qualified investment as eligible for credit with respect to any single project.

[1]The Secretary issued guidance establishing the certification program on February 21, 2006 (IRS Notice 2006-25

Roundtable 12: Energy Efficiency and Commercial Buildings
March 30, 2007

Speakers:

David Goldstein – MacArthur Fellow, Natural Resources Defense Council, San Francisco, CA
Joseph Mikrut – Partner, Capital Tax Partners, Washington, D.C.
Hannibal Blocker – Tax Manager, Tax Policy and Research, Wal-Mart Corporation, Bentonville, AR

Commercial Buildings Roundtable (3/30/07):

This Roundtable focused on current-law energy efficiency programs, including tax incentives for commercial buildings under Section 179D of the Code. Joe Mikrut provided context on Section 179D, including general information on which buildings qualify for the deduction, and the components (lighting, building envelope, etc.) considered in meeting the section's requirements. David Goldstein stated that the 179D provision, if designed correctly, could save trillions of dollars in lifetime energy costs, and cut carbon emissions by millions of metric tons on an annual basis. Hannibal Blocker described Wal-Mart's work in the area of energy efficiency, and said the computation and measurement requirements for the commercial-buildings deduction need to be simplified.

Background:

The amount of energy used to operate residential and commercial buildings is about 40 percent of total US energy consumption, and accounts for about 38 percent of U.S. carbon dioxide emissions. While building efficiency has improved significantly in the last 20 to 30 years (a home built today consumes 12 percent less energy for heating and cooling than a comparable home twenty years ago), total energy consumption in US buildings continues to rise. This is due to a number of factors, including population growth, larger houses, and increased demand for air conditioning, computers and other consumer electronics. According to projections from the Energy Information Administration, by 2025, energy consumption by residential buildings will increase by 25 percent, and commercial building energy use will increase by 40 percent.

According to a recent report from the McKinsey Global Institute, the growth of energy consumption could be cut in half over the next 15 years, through a series of policies including use of compact fluorescent light bulbs, improved building insulation, an accelerated push for appliance-efficiency standards, and use of solar water heaters (http://www.mckinsey.com/mgi/publications/Curbing_Global_Energy/index.asp).

Indeed, many view improvements in building efficiency as the "low hanging fruit" in the energy debate, including in the area of commercial buildings. With nearly 170,000 commercial buildings constructed each year, policies that advance cleaner and greener structures can have a tremendous impact on reducing carbon emissions.

Energy efficiency is increased when an energy conversion device, such as a household appliance, automobile engine, or steam turbine, undergoes a technical change that enables it to provide the same service (lighting, heating, motor drive) while using less energy. The energy efficiency of buildings can be improved through the use of certain materials (e.g., attic insulation), components (e.g., insulated windows), and design aspects (e.g., solar orientation and shade tree landscaping).

In 1992, the US Environmental Protection Agency (EPA) introduced ENERGY STAR as a voluntary labeling program designed to identify and promote energy-efficient products to reduce greenhouse gas emissions. Computers and monitors were the first labeled products. Through 1995, EPA expanded the label to additional office equipment products and residential heating and cooling equipment. In 1996, EPA partnered with the US Department of Energy for particular product categories. The ENERGY STAR label now appears on major appliances, office equipment, lighting, home electronics, and more. EPA has also extended the label to cover new homes and commercial and industrial buildings. It is estimated that ENERGY STAR produced cost savings to American consumers of $14 billion in 2006, and a reduction in greenhouse gases equivalent to those from 23 million vehicles.

Attached is a three page document describing the different improvements in energy efficiency Wal-Mart has made to its stores, including energy management systems and motion sensor lighting.

For more information on energy efficient commercial buildings please visit the following web sites:

- http://www.efficientbuildings.org
- http://www.lightingtaxdeduction.org
- http://www.energytaxincentives.org/tiap-commercial-bldgs.html
- http://www.advancedbuildings.net/

Tax Provisions:

The 2005 Energy Bill provided a deduction for energy-efficient commercial buildings that meet a 50 percent energy reduction standard. The maximum deduction is $1.80 per square foot of the building. The law also allows a 60-cents-per-square-foot deduction if 25 to 40 percent efficiency is attained. The provision is effective beginning in 2006, and applies to property placed in service before 2008.

Please see the following JCT description for greater detail on the tax incentives for energy efficient commercial buildings.

Tax Policy and Wal-Mart Environmental Sustainability
Senate Finance Committee Roundtable
March 30, 2007

ENERGY EFFICIENT WAL-MART STORES

Daylight Harvesting System In most of our stores we use skylights, electronic dimming ballasts and computer controlled daylight sensors.

- *Savings: 600,627,600 KWH annually or enough power to supply approximately 53,390 homes each year.*

Energy Management System Since most of our stores are open 24 hours, we utilize this state-of-the-art system to dim sales floor lighting during the evening and night hours which is barely noticeable to our customers and associates.

- *Savings: 32,300 KWH per location annually. This equals another annual savings of 44,000,000 KWH, or enough energy to power an additional 3,860 U.S. homes each year.*

Efficient Lighting Systems We use T-8 Fluorescent Lamps and Electronic Ballasts in our stores which are the most efficient lighting systems on the market.

- *Savings: 15-20% reduction in energy load.*

Signs We use LED lighting in all of our internal and external building signage. LEDs provide an extended life span of 12 to 20-plus years significantly reducing the need to manufacture and dispose of fluorescent lamps.

- *Savings: 70% more energy-efficient operation than fluorescent illumination.*

Motion Sensor Lighting We have now begun to install motion activated LED lighting in our frozen and refrigerated food cases so in it turning itself off whenever it is not needed. We also use occupancy sensors in non-sales areas in our new stores to turn off lights when unoccupied.

- *Savings: Up to 50% energy over traditional lighting and last 3-4 times longer.*

Centralized Energy Management The heating, air conditioning, refrigeration and lighting systems in all our stores are monitored for energy usage, analyze refrigeration temperatures, and observe HVAC and lighting performance. It also allows us to adjust lighting, temperature and/or refrigeration set points from a central location

High Efficiency HVAC Units Our units have a weighted Energy Efficiency Ratio of 11.25. This is a 10% increase over the industry standard, weighted average, efficiency guideline (ASHRAE 90-1). These units are more efficient than required by the most stringent U.S. energy code (California's Title 24).

COMPARISONS TO STANDARD ENERGY CODES

- Wal-Mart's lighting system is 24% more efficient than the ASHRAE (American Society of Heating, Refrigerating, and Air Conditioning Engineers) baseline minimum. This is what the Energy Policy Act of 2005 uses as the benchmark.
- Our overall building (all systems) is 9% more efficient than the most stringent of all U.S. energy codes, California Title 24.

Energy Efficient Commercial Buildings Deduction
(sec. 179D)

In general

Code section 179D provides a deduction equal to energy-efficient commercial building property expenditures made by the taxpayer. Energy-efficient commercial building property expenditures is defined as property (1) which is installed on or in any building located in the United States that is within the scope of Standard 90.1-2001 of the American Society of Heating, Refrigerating, and Air Conditioning Engineers and the Illuminating Engineering Society of North America ("ASHRAE/IESNA"), (2) which is installed as part of (i) the interior lighting systems, (ii) the heating, cooling, ventilation, and hot water systems, or (iii) the building envelope, and (3) which is certified as being installed as part of a plan designed to reduce the total annual energy and power costs with respect to the interior lighting systems, heating, cooling, ventilation, and hot water systems of the building by 50 percent or more in comparison to a reference building which meets the minimum requirements of Standard 90.1-2001 (as in effect on April 2, 2003). The deduction is limited to an amount equal to $1.80 per square foot of the property for which such expenditures are made. The deduction is allowed in the year in which the property is placed in service.

Certain certification requirements must be met in order to qualify for the deduction. The Secretary, in consultation with the Secretary of Energy, will promulgate regulations that describe methods of calculating and verifying energy and power costs using qualified computer software based on the provisions of the 2005 California Nonresidential Alternative Calculation Method Approval Manual or, in the case of residential property, the 2005 California Residential Alternative Calculation Method Approval Manual.

The Secretary shall prescribe procedures for the inspection and testing for compliance of buildings that are comparable, given the difference between commercial and residential buildings, to the requirements in the Mortgage Industry National Accreditation Procedures for Home Energy Rating Systems. Individuals qualified to determine compliance shall only be those recognized by one or more organizations certified by the Secretary for such purposes.

For energy-efficient commercial building property expenditures made by a public entity, such as public schools, the Secretary shall promulgate regulations that allow the deduction to be allocated to the person primarily responsible for designing the property in lieu of the public entity.

If a deduction is allowed under this section, the basis of the property shall be reduced by the amount of the deduction.

The deduction is effective for property placed in service after December 31, 2005 and prior to January 1, 2009.

Partial allowance of deduction

In the case of a building that does not meet the overall building requirement of a 50- percent energy savings, a partial deduction is allowed with respect to each separate building system that comprises energy efficient property and which is certified by a qualified professional as meeting or exceeding the applicable system-specific savings targets established by the Secretary of the Treasury. The applicable system-specific savings targets to be established by the Secretary are those that would result in a total annual energy savings with respect to the whole building of 50 percent, if each of the separate systems met the system specific target. The separate building systems are (1) the interior lighting system, (2) the heating, cooling, ventilation and hot water systems, and (3) the building envelope. The maximum allowable deduction is $0.60 per square foot for each separate system.

Interim rules for lighting systems

In the case of system-specific partial deductions, in general no deduction is allowed until the Secretary establishes system-specific targets.[1] However, in the case of lighting system retrofits, until such time as the Secretary issues final regulations, the system-specific energy savings target for the lighting system is deemed to be met by a reduction in Lighting Power Density of 40 percent (50 percent in the case of a warehouse) of the minimum requirements in Table 9.3.1.1 or Table 9.3.1.2 of ASHRAE/IESNA Standard 90.1-2001. Also, in the case of a lighting system that reduces lighting power density by 25 percent, a partial deduction of 30 cents per square foot is allowed. A pro-rated partial deduction is allowed in the case of a lighting system that reduces lighting power density between 25 percent and 40 percent. Certain lighting level and lighting control requirements must also be met in order to qualify for the partial lighting deductions under the interim rule.

[1] IRS Notice 2006-52 has set a target of a 16 2/3 percent reduction in total energy and power costs for each of the three subsystems.

Roundtable 13: Energy Efficient & Residential Buildings
April 13, 2007

Speakers:

Eric Borsting – Vice President of Operations, ConSol, Stockton, CA
Ben Beckelman – Controller, Gage Homes Inc., Dallas, TX
Emanuel Levy – Executive Director, Manufactured Housing Institute, Washington, DC

Residential Buildings Roundtable (4/13/07):

This Roundtable focused on current-law residential efficiency programs and tax incentives. Eric Borsting and Emanuel Levy stressed the importance of xtending the credits for energy-efficient homes, while Ben Beckelman said that high administrative costs are preventing many from pursuing the credits.

Background:

Energy used to heat and cool residential and commercial buildings accounts for nearly 40 percent of US energy consumption, and nearly as much of U.S. carbon dioxide emissions. Despite advances in building efficiency over the last couple of decades, energy consumption by residential buildings will increase by 25 percent, and commercial building energy use will increase by 40 percent.

Numerous studies, such as the 2004 *National Commission on Energy Policy Report*, have pointed out that although energy efficient products and building practices are widely available, market failures discourage efficiency investments even when they are highly cost-effective. For example, consumers often lack the information or time to research efficient products; and compensation for building designers is often a percentage of building cost, causing them to ignore efficiency features that are generally low cost.

Government programs can help overcome some of these market failures. California is a leading example of successful state energy efficiency programs. Since 1975, per capita electricity use in California has remained relatively stable, while nationwide electricity use has increased by 50 percent. This result is largely due to the adoption of energy efficient building and appliance standards and the investments by California utilities in energy efficiency programs.

In the private sector, a number of corporations, non-profits and educational institutions have embraced voluntary "green building" standards. These include energy efficiency requirements as well as environmental and sustainability requirements. A recent Federal Executive Order #13423 "Strengthening Federal Environmental, Energy, and Transportation Management" (January 24, 2007) endorsed green building practices for federal buildings.

Tax Provisions:

The 2005 Energy Bill provided a credit between $1,000 and $2,000 for new homes meeting energy-efficiency standards ($2,000 credit for a new home that is at least 50 percent more efficient than a typical home, $1,000 credit for a new home that is as least 30 percent more efficient). A 30 percent efficiency standard applies to manufactured homes, which can receive a $1,000 credit.

The 2005 Energy Bill provides a taxpayer of an existing home making energy efficient improvements a one-time income tax credit of up to $500 for installing efficient new windows, insulation, doors, roofs, and heating and cooling equipment in a home. This credit can be used in several ways, including purchase of the following:

- Exterior windows:
    - Credit is allowed for 10 percent of the total cost of windows, with a maximum $200 credit. .
- Insulation, exterior doors, or pigmented metal roofs:
    - Credit is allowed for 10 percent of the cost of the product (but not installation), up to $500. Includes seals to limit air infiltration, such as caulk, weather stripping, and foam sealants, as well as storm doors. Windows, doors, and insulation must meet the regional requirements of the 2001 or 2004 International Energy Conservation Code for buildings. All ENERGY STAR windows qualify
- Central air conditioner, heat pump, or water heater:
    - Up to $300 in credit allowed towards purchase price, including installation costs. Heating and cooling equipment must meet stringent efficiency requirements – not even all ENERGY STAR products qualify.
- Furnace or boiler:
    - Up to $150 towards the full purchase price, and/or $50 for an efficient air-circulating fan in a furnace, including installation cost.

In addition, windows, doors, insulation, and roofs must be expected to last at least five years (a two-year warranty is sufficient to demonstrate this). Manufacturers can certify (in packaging or on the company's web site) which of their products qualify for the tax credit. All the improvements must be installed in or on the taxpayer's principal residence in the United States. The credit cannot be taken against the Alternative Minimum Tax (AMT).

The home improvement tax credits apply for improvements "placed in service" from January 1, 2006, through December 31, 2007. They are not available in 2005. The IRS defines "placed in service" as when the products or materials are ready and available for use.

Please see the attached Joint Committee on Taxation description for greater detail on the tax incentives for energy efficiencies and residential buildings.

New Energy Efficient Home Credit (sec. 45L)

The new energy efficient home credit is available to an eligible contractor for the construction of a qualified new energy-efficient home. To qualify as a new energy-efficient home, the home must be: (1) a dwelling located in the United States, (2) substantially completed after August 8, 2005, and (3) certified in accordance with guidance prescribed by the Secretary to achieve either a 30-percent or 50-percent reduction in heating and cooling energy consumption compared to a comparable dwelling constructed in accordance with the standards of chapter 4 of the 2003 International Energy Conservation Code as in effect (including supplements) on August 8, 2005, and any applicable Federal minimum efficiency standards for heating and cooling equipment.

The credit equals $1,000 in the case of a new home that meets the 30 percent standard and $2,000 in the case of a new home that meets the 50 percent standard.

With respect to homes that meet the 30-percent standard, one-third of such 30 percent savings must come from the building envelope, and with respect to homes that meet the 50- percent standard, one-fifth of such 50 percent savings must come from the building envelope.

Only manufactured homes are eligible for the $1,000 credit. In lieu of meeting the 30 percent efficiency improvement relative to the standards of chapter 4 of the 2003 International Energy Conservation Code, manufactured homes certified by a method prescribed by the Administrator of the Environmental Protection Agency under the Energy Star Labeled homes program are eligible for the $1,000 credit provided criteria (1) and (2), above, are met.

Manufactured homes are homes that conform to Federal manufactured home construction and safety standards. The eligible contractor is the person who constructed the home, or in the case of a manufactured home, the producer of such home. The credit is part of the general business credit.

The credit applies to homes whose construction is substantially completed after December 31, 2005, and which are purchased after December 31, 2005 and prior to January 1, 2009.

Roundtable 14: Alternative Vehicles Roundtable
April 20, 2007

Speakers:

Brian Wynne – President, Electric Drive Transportation Association
Jerry Roussell – Ford Motor Company
Barry Felrice – Director, Washington Regulatory Affairs, Daimler-Chrysler
Mark Kemmer – Director of Legislative & Regulatory Affairs – Energy; General Motors

Alternative Vehicles Roundtable (4/20/07):

The Roundtable featured discussion of alternative vehicle technology and tax incentives to encourage early development of these technologies. Brian Wynne discussed electric drive vehicles, which provide an alternative to the internal combustion engine or can be a component of the hybrid or plug-in hybrid vehicle and stressed that acceleration of the development and deployment of electric drive vehicle technology will reduce petroleum use, green house gas emissions and build U. S. employment and competitiveness in this field. Barry Felrice focused on improving diesel and flex fuels vehicles. Mark Kemmer discussed his plan for converting petroleum vehicles to bio-fuels, electricity and hydrogen. Finally, Jerry Roussell discussed the need for incentives future alternatives development.

Background:

Many issues, including the oil crises of the 1970s, the rise in awareness of environmental issues, concerns over energy security, increasing vehicle emissions, and high gasoline prices have created an interest in moving the United States away from petroleum fuels for transportation and toward alternative fuels and advanced vehicle technologies. Alternative vehicles are seen as integral to improving urban air quality, decreasing dependence on foreign oil, and reducing emissions of greenhouse gases. Because of these potential benefits, there is continued congressional interest in providing incentives and other support for their development and commercialization.

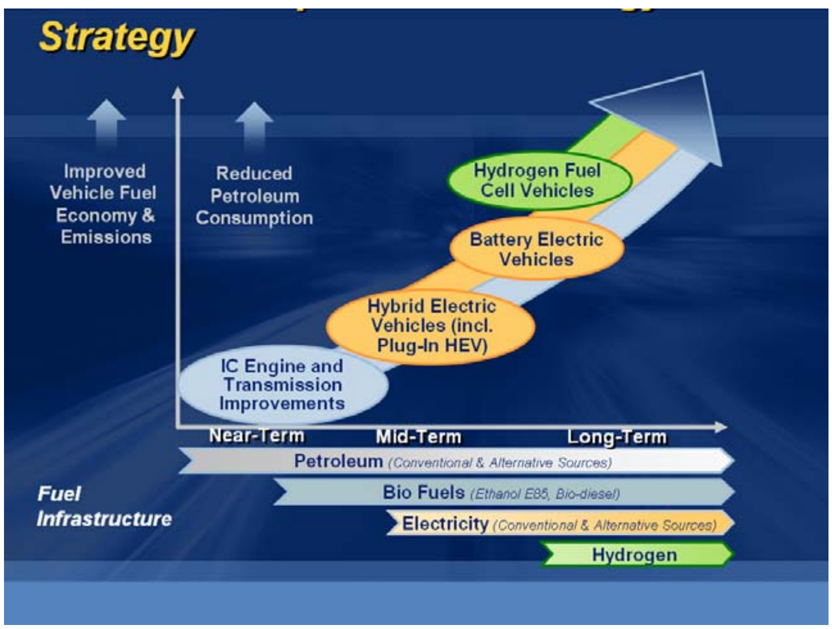
<u>Hybrid Vehicles</u>:

Hybrid vehicles are propelled by a standard electric gasoline (or diesel) internal combustion engine in combination with an electric motor (and battery storage system), which improves vehicle economy. Some hybrids offer smaller engines that run at various speeds, creating more efficiency. Others recover waste energy through regenerative braking allowing the vehicle to shut down the combustion engine.

The utilization of battery and combustion engine technology has been used for over a hundred years. In 1898, Ferdinand Porsche designed a gasoline engine to power a generator. The vehicle, called the Lohner-Porsche carriage, broke the Austrian speed record. More recently, the man known as the "Godfather of the Hybrid," Victor Wouk (brother of author Herman Wouk) developed the working prototype of the modern electric-hybrid vehicle. However, it wasn't until the 1990s that Honda and Toyota built commercially successful hybrid vehicles with the Honda Insight and Toyota Prius.

Today, plug-in hybrid electric vehicles, which can be recharged from the electrical power grid and do not require conventional fuel for short trips, are widely considered the next generation of hybrid-electric technology. In addition to reduced emissions from the combustion engine, depending on the fuel source for the electricity. Even a vehicle powered by electricity generated from coal is much cleaner than pure gasoline propulsion, due to the much greater efficiencies of a central plant. Utilizing natural gas and renewable energies would create even greater environmental benefits.

Next generation vehicle technologies also include hydrogen fuel cell and fuel cell vehicles. Hydrogen can be obtained through various methods that result in no net carbon dioxide emissions. However, commercially available hydrogen fuel cell vehicles are only likely in the long-term. Major car manufacturers, such as GM, plan to take advantage of these technologies using a glide path from hybrid-electric to hydrogen fuel cells.



Advanced Diesel Technology:

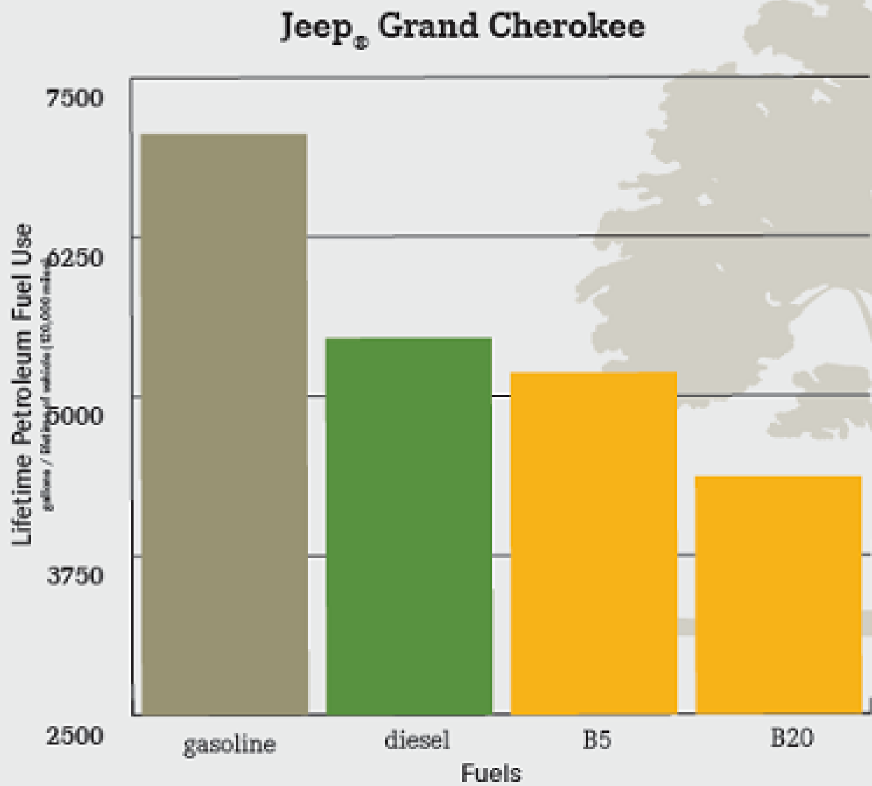
Interest has also grown in advanced diesel engine technology. Diesel engines have higher energy efficiencies than gasoline engines, but have traditionally had high particulate emissions such as nitrogen oxide. Daimler Chrystler has placed much emphasis on a new fleet of clean, diesel vehicles. Diesel engines today are vastly superior to the preceding generation of diesel-powered vehicles, which created the lingering consumer perception that diesel-powered vehicles are noisy, smoky, and generally customer-unfriendly.

Today's advanced technology clean diesels achieve 20 to 40 percent better fuel economy than an equivalent gasoline engine and the lifetime fuel savings are substantial. Based on data from EPA's 2007 Fuel Economy Guide, a diesel Grand Cherokee will use 418 fewer gallons of fuel each year than the gasoline-powered Grand Cherokee. This fuel savings is nearly three times that of the hybrid Honda Civic - which would save only 154 gallons of fuel per year compared to the gasoline-only Civic.

Through engineering advancements that include exhaust-gas recirculation with electrically controlled valves, new diesels can optimize the combustion process with the aim of further reducing fuel consumption and exhaust emissions. Daimler Chrystler reduces raw emissions inside the engine and treats exhaust gases with a high degree of efficiency. By utilizing biodiesel, total emissions (CO2) can be furthered reduced (See Chart 2).

As the chart on the next page shows, a diesel-powered vehicle achieves a 30% savings in lifetime fuel usage due to improved fuel efficiency which can be enhanced further through the use of biofuels.

the benefits of clean diesel and biodiesel



Using diesel saves nearly 30% on fuel consumption over the lifetime of the vehicle - that's more than 1600 gallons of fuel per diesel vehicle. Using biofuels reduces the fuel consumption even further, saving up to almost 2700 gallons when B20 is used.

clean diesel facts

Clean diesel provides up to 40% better fuel economy than gasoline engines

Clean diesel cuts CO_2 emissions by up to 20%

If B5 (5 percent biodiesel) was used in all U.S. on-road diesel we could save 1.85 billion gallons of fuel per year

Ongoing technological developments in hybrid vehicles, bio-diesel and advanced diesel engines, ethanol fuel, fuel cells, and hydrogen fuel have raised key policy questions. These questions include whether more generous tax incentives for plug-in hybrid and/or fuel cell vehicles should be established and whether research and development funds should be focused on technologies for fuel cells and hybrids.

Tax Provisions:

The 2005 Energy Bill contained many provisions relevant to alternative vehicles. It significantly expanded and extended vehicle purchase incentives, establishing tax credits for the purchase of fuel cell, hybrid, alternative fuel, and advanced diesel vehicles. For passenger vehicles, the credit is worth as much as $3,400 for hybrids and advanced diesels, and as much as $4,000 for alternative fuel vehicles, depending on vehicle attributes. The expiration date for the incentives also varies depending on the technology.

In the case of hybrid and advanced diesel vehicles, the number of vehicles eligible for the credit is limited for each vehicle manufacturer. Starting the second calendar quarter after a manufacturer sells the 60,000th vehicle eligible for the credit; the credit for that manufacturer's vehicles is reduced. Currently, only Toyota has sold enough vehicles to trigger a phase-out. For Toyota (and Lexus) hybrids purchased after September 31, 2006, the credit is reduced by 50%; the credit is reduced to 25% for vehicles purchased after March 31, 2007, and is zero for vehicles purchased after September 31, 2007. Other manufacturers have yet to hit the 60,000 vehicle mark.

Please see the following JCT description for greater detail on tax incentives for alternative vehicles.

PRESENT LAW RELATING TO ALTERNATIVE FUEL VEHICLES

In general

A credit is available for each new qualified fuel cell vehicle, hybrid vehicle, advanced lean burn technology vehicle, and alternative fuel vehicle placed in service by the taxpayer during the taxable year.[1] In general, the credit amount varies depending upon the type of technology used, the weight class of the vehicle, the amount by which the vehicle exceeds certain fuel economy standards, and, for some vehicles, the estimated lifetime fuel savings. The credit generally is available for vehicles purchased after 2005. The credit terminates after 2009, 2010, or 2014, depending on the type of vehicle.

In general, the credit is allowed to the vehicle owner, including the lesser of a vehicle subject to a lease. If the use of the vehicle is described in paragraphs (3) or (4) of section 50(b) (relating to use by tax-exempt organizations, governments, and foreign persons) and is not subject to a lease, the seller of the vehicle may claim the credit so long as the seller clearly discloses to the user in a document the amount that is allowable as a credit. A vehicle must be used predominantly in the United States to qualify for the credit.

Fuel cell vehicles

A qualified fuel cell vehicle is a motor vehicle that is propelled by power derived from one or more cells that convert chemical energy directly into electricity by combining oxygen with hydrogen fuel that is stored on board the vehicle and may or may not require reformation prior to use. A qualified fuel cell vehicle must be purchased before January 1, 2015. The amount of credit for the purchase of a fuel cell vehicle is determined by a base credit amount that depends upon the weight class of the vehicle and, in the case of automobiles or light trucks, an additional credit amount that depends upon the rated fuel economy of the vehicle compared to a base fuel economy. For these purposes, the base fuel economy is the 2002 model year city fuel economy rating for vehicles of various weight classes.[2] Table 1, below, shows the base credit amounts.

Table 1: Base Credit Amount for Fuel Cell Vehicles

Vehicle Gross Weight Rating (pounds)	Credit Amount
Vehicle ≤ 8,500..	$8,000
8,500 < vehicle ≤ 14,000..................................	$10,000
14,000 < vehicle ≤ 26,000.................................	$20,000
26,000 < vehicle..	$40,000

[1] Sec. 30B.

[2] See discussion surrounding Table 6, below.

In the case of a fuel cell vehicle weighing less than 8,500 pounds and placed in service after December 31, 2009, the $8,000 amount in Table 1, above is reduced to $4,000.

Table 2, below, shows the additional credits for passenger automobiles or light trucks.

Table 2: Credit for Qualified Fuel Cell Vehicles

Credit	If Fuel Economy of the Fuel Cell Vehicle Is:	
	at least	**but less than**
$1,000	150% of base fuel economy	175% of base fuel economy
$1,500	175% of base fuel economy	200% of base fuel economy
$2,000	200% of base fuel economy	225% of base fuel economy
$2,500	225% of base fuel economy	250% of base fuel economy
$3,000	250% of base fuel economy	275% of base fuel economy
$3,500	275% of base fuel economy	300% of base fuel economy
$4,000	300% of base fuel economy	

Hybrid vehicles and advanced lean burn technology vehicles

Qualified hybrid vehicle

A qualified hybrid vehicle is a motor vehicle that draws propulsion energy from on-board sources of stored energy that include both an internal combustion engine or heat engine using combustible fuel and a rechargeable energy storage system (e.g., batteries). A qualified hybrid vehicle must be placed in service before January 1, 2011 (January 1, 2010 in the case of a hybrid vehicle weighing more than 8,500 pounds).

[3] For hybrid passenger vehicles and light trucks, the term "maximum available power" means the maximum power available from the rechargeable energy storage system, during a standard 10 second pulse power or equivalent test, divided by such maximum power and the SAE net power of the heat engine. (Sec. 30B (d) (3) (C) (i)).

Hybrid vehicles that are automobiles and light trucks

In the case of an automobile or light truck (vehicles weighing 8,500 pounds or less), the amount of credit for the purchase of a hybrid vehicle is the sum of two components: (1) a fuel economy credit amount that varies with the rated fuel economy of the vehicle compared to a 2002 model year standard and (2) a conservation credit based on the estimated lifetime fuel savings of the qualified vehicle compared to a comparable 2002 model year vehicle that is powered solely by a gasoline or diesel internal combustion engine. A qualified hybrid automobile or light truck must have a maximum available power[3] from the rechargeable energy storage system of at least four percent. In addition, the vehicle must meet or exceed certain Environmental Protection Agency ("EPA") emissions standards. For a vehicle with a gross vehicle weight rating of 6,000 pounds or less the applicable emissions standards are the Bin 5 Tier II emissions standards. For a vehicle with a gross vehicle weight rating greater than 6,000 pounds and less than or equal to 8,500 pounds, the applicable emissions standards are the Bin 8 Tier II emissions standards.

Table 3, below, shows the fuel economy credit available to a hybrid passenger automobile or light truck whose fuel economy (on a gasoline gallon equivalent basis) exceeds that of a base fuel economy.

Table 3: Fuel Economy Credit

If Fuel Economy of the Hybrid Vehicle Is:		
Credit	**at least**	**but less than**
$400	125% of base fuel economy	150% of base fuel economy
$800	150% of base fuel economy	175% of base fuel economy
$1,200	175% of base fuel economy	200% of base fuel economy
$1,600	200% of base fuel economy	225% of base fuel economy
$2,000	225% of base fuel economy	250% of base fuel economy
$2,400	250% of base fuel economy	

Table 4, below, shows the conservation credit.

Table 4: Conservation Credit

Estimated Lifetime Fuel Savings (gallons of gasoline)	Conservation Amount
At least 1,200 but less than 1,800...................	$250
At least 1,800 but less than 2,400...................	$500
At least 2,400 but less than 3,000...................	$750
At least 3,000..	$1,000

<u>Advanced lean burn technology vehicles</u>

The amount of credit for the purchase of an advanced lean burn technology vehicle is the sum of two components: (1) a fuel economy credit amount that varies with the rated fuel economy of the vehicle compared to a 2002 model year standard as described in Table 3, above, and (2) a conservation credit based on the estimated lifetime fuel savings of a qualified vehicle compared to a comparable 2002 model year vehicle as described in Table 4, above. The amounts of the credits are determined after an adjustment is made to account for the different Btu content of gasoline and the fuel utilized by the lean burn technology vehicle.

A qualified advanced lean burn technology vehicle is a passenger automobile or a light truck that incorporates direct injection, achieves at least 125 percent of the 2002 model year city fuel economy, and for 2004 and later model vehicles meets or exceeds certain EPA emissions standards. For a vehicle with a gross vehicle weight rating of 6,000 pounds or less the applicable emissions standards are the Bin 5 Tier II emissions standards. For a vehicle with a gross vehicle weight rating greater than 6,000 pounds, and less than or equal to 8,500 pounds, the applicable emissions standards are the Bin 8 Tier II emissions standards. A qualified advanced lean burn technology vehicle must be placed in service before January 1, 2011.

<u>Limitation on number of qualified hybrid and advanced lean burn technology vehicles eligible for the credit</u>

There is a limitation on the number of qualified hybrid vehicles and advanced lean burn technology vehicles sold by each manufacturer of such vehicles that are eligible for the credit. Taxpayers may claim the full amount of the allowable credit up to the end of the first calendar quarter after the quarter in which the manufacturer records the 60,000 hybrids and advanced lean burn technology vehicle sale occurring after December 31, 2005. Taxpayers may claim one half of the otherwise allowable credit during the two calendar quarters subsequent to the first quarter after the manufacturer has recorded its 60,000 such sale. In the third and fourth calendar quarters subsequent to the first quarter after the manufacturer has recorded it's 60,000 such sale, the taxpayer may claim one quarter of the otherwise allowable credit.

[4] In the case of such heavy-duty hybrid motor vehicles, the percentage of maximum available power is computed by dividing the maximum power available from the rechargeable energy storage system during a standard 10-second pulse power test, divided by the vehicle's total traction power. A vehicle's total traction power is the sum of the peak power from the rechargeable energy storage system and the heat (e.g., internal combustion or diesel) engine's peak power. If the rechargeable energy storage system is the sole means by which the vehicle can be driven, then the total traction power is the peak

Thus, for example, summing the sales of qualified hybrid vehicles of all weight classes and all sales of qualified advanced lean burn technology vehicles, if a manufacturer records the sale of its 60,000th qualified vehicle in February of 2007, taxpayers purchasing such vehicles from the manufacturer may claim the full amount of the credit on their purchases of qualified vehicles through June 30, 2007. For the period July 1, 2007, through December 31, 2007, taxpayers may claim one half of the otherwise allowable credit on purchases of qualified vehicles of the manufacturer. For the period January 1, 2008, through June 30, 2008, taxpayers may claim one quarter of the otherwise allowable credit on the purchases of qualified vehicles of the manufacturer. After June 30, 2008, no credit may be claimed for purchases of hybrid vehicles or advanced lean burn technology vehicles sold by the manufacturer.

Hybrid vehicles that are medium and heavy trucks

In the case of a qualified hybrid vehicle weighing more than 8,500 pounds, the amount of credit is determined by the estimated increase in fuel economy and the incremental cost of the hybrid vehicle compared to a comparable vehicle powered solely by a gasoline or diesel internal combustion engine and that is comparable in weight, size, and use of the vehicle. For a vehicle that achieves a fuel economy increase of at least 30 percent but less than 40 percent, the credit is equal to 20 percent of the incremental cost of the hybrid vehicle. For a vehicle that achieves a fuel economy increase of at least 40 percent but less than 50 percent, the credit is equal to 30 percent of the incremental cost of the hybrid vehicle. For a vehicle that achieves a fuel economy increase of 50 percent or more, the credit is equal to 40 percent of the incremental cost of the hybrid vehicle.

The credit is subject to certain maximum applicable incremental cost amounts. For a qualified hybrid vehicle weighing more than 8,500 pounds but not more than 14,000 pounds, the maximum allowable incremental cost amount is $7,500. For a qualified hybrid vehicle weighing more than 14,000 pounds but not more than 26,000 pounds, the maximum allowable incremental cost amount is $15,000. For a qualified hybrid vehicle weighing more than 26,000 pounds, the maximum allowable incremental cost amount is $30,000.

A qualified hybrid vehicle weighing more than 8,500 pounds but not more than 14,000 pounds must have a maximum available power from the rechargeable energy storage system of at least 10 percent. A qualified hybrid vehicle weighing more than 14,000 pounds must have a maximum available power from the rechargeable energy storage system of at least 15 percent.

[4] power of the rechargeable energy storage system.

Alternative fuel vehicle

The credit for the purchase of a new alternative fuel vehicle is 50 percent of the incremental cost of such vehicle, plus an additional 30 percent if the vehicle meets certain emissions standards. The incremental cost of any new qualified alternative fuel vehicle is the excess of the manufacturer's suggested retail price for such vehicle over the price for a gasoline or diesel fuel vehicle of the same model. To be eligible for the credit, a qualified alternative fuel vehicle must be purchased before January 1, 2011.

The amount of the credit varies depending on the weight of the qualified vehicle. The credit is subject to certain maximum applicable incremental cost amounts. Table 5, below, shows the maximum permitted incremental cost for the purpose of calculating the credit for alternative fuel vehicles by vehicle weight class as well as the maximum credit amount for such vehicles.

Table 5: Maximum Allowable Incremental Cost for Calculation of Alternative Fuel Vehicle Credit

Vehicle Gross Weight Rating (pounds)	Maximum Allowable Incremental Cost	Maximum Allowable Credit
Vehicle ≤ 8,500...	$5,000	$4,000
8,500 < vehicle ≤ 14,000..................................	$10,000	$8,000
14,000 < vehicle ≤ 26,000................................	$25,000	$20,000
26,000 < vehicle..	$40,000	$32,000

Alternative fuels comprise compressed natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, and any liquid fuel that is at least 85 percent methanol. Qualified alternative fuel vehicles are vehicles that operate only on qualified alternative fuels and are incapable of operating on gasoline or diesel (except to the extent gasoline or diesel fuel is part of a qualified mixed fuel, described below).

Certain mixed fuel vehicles, that is vehicles that use a combination of an alternative fuel and a petroleum-based fuel, are eligible for a reduced credit. If the vehicle operates on a mixed fuel that is at least 75 percent alternative fuel, the vehicle is eligible for 70 percent of the otherwise allowable alternative fuel vehicle credit. If the vehicle operates on a mixed fuel that is at least 90 percent alternative fuel, the vehicle is eligible for 90 percent of the otherwise allowable alternative fuel vehicle credit.

Base fuel economy

The base fuel economy is the 2002 model year city fuel economy by vehicle type and vehicle inertia weight class. For this purpose, "vehicle inertia weight class" has the same meaning as when defined in regulations prescribed by the EPA for purposes of Title II of the Clean Air Act. Table 6, below, shows the 2002 model year city fuel economy for vehicles by type and by inertia weight class.

Table 6: 2002 Model Year City Fuel Economy

Vehicle Inertia Weight Class (pounds)	Passenger Automobile (miles per gallon)	Light Truck (miles per gallon)
1,500	45.2	39.4
1,750	45.2	39.4
2,000	39.6	35.2
2,250	35.2	31.8
2,500	31.7	29.0
2,750	28.8	26.8
3,000	26.4	24.9
3,500	22.6	21.8
4,000	19.8	19.4
4,500	17.6	17.6
5,000	15.9	16.1
5,500	14.4	14.8
6,000	13.2	13.7
6,500	12.2	12.8
7,000	11.3	12.1
8,500	11.3	12.1

Other rules

The portion of the credit attributable to vehicles of a character subject to an allowance for depreciation is treated as a portion of the general business credit; the remainder of the credit is allowable to the extent of the excess of the regular tax (reduced by certain other credits) over the alternative minimum tax for the taxable year.

Roundtable 15: Biofuels
April 20, 2007

Speakers:

Mr. John Diesch, President, Rentech Energy Midwest Corp., East Dubuque, IL
Dr. Gregory Luli, VP of R&D, Celunol Bioresearch Laboratory, Gainesville, FL
Dr. Stephen Paul, Scientist, Professor of Plasma Physics and Founder of Planet Fuels, LLC, Princeton, NJ

Alternative Fuels Roundtable (4/27/07):

This roundtable focused on the various incentives in the Code for alternative fuels, including ethanol, biodiesel, renewable diesel and fuels made from the conversion of coal to liquids. Dr. Stephen Paul discussed the technical aspects of turning biomass into fuels, including the process of anaerobic and aerobic digestion, hydrolysis and pyrolysis. Dr. Luli provided perspective on Celunol's cellulosic ethanol demonstration project in Jennings, Louisiana, and its prospects for developing into a commercial-grade operation. Mr. Diesch outlined Rentech's efforts to develop Fischer-Tropsch (FT) fuels, including the company's plan to produce between 1500 and 2000 barrels of FT fuels per day at its East Dubuque facility. Following this memorandum is a technical description of the current-law tax consideration of alternative fuels.

Background:

Whether derived from biomass or other feedstocks such as coal, alternative transportation fuels have existed since the automobile era began over a century ago. Henry Ford's first car– the Quadricycle, introduced in 1896 – was powered by ethanol. At the 1900 World's Fair, Rudolph Diesel displayed the invention that would make him famous by powering it with peanut oil (although peanut oil, since it's not transesterified, is technically a biofuel, not biodiesel). And Ford's Model T, introduced in 1908, was the world's first 'flex-fuel vehicle', capable of running on either ethanol or gasoline. As for coal-based fuels, Germany's ability to power its war machine with Fischer-Tropsch diesel prompted the U.S. to pass legislation in 1944 to research the viability of large-scale use of synthetic fuels. While the 'synfuel' program was ultimately terminated, the recent dramatic increase in crude-oil prices has sparked renewed Congressional interest in coal-to-liquids technology.

The first alternative-fuel tax incentive was passed as part of the Energy Tax Act of 1978, in the form of a 4¢/gallon excise tax exemption for fuels blended with at least 10% ethanol ("gasohol"). This amounted to a full exemption for gasohol from the then-4¢/gallon federal gasoline excise tax (the gas excise tax is now 18.4¢/gallon).
In 1990, Congress built on the ethanol incentive, by establishing a 10¢/gallon income tax credit for the first 15 million gallons of ethanol output from a 'small producer' (now defined as an entity with output of less than 60 million gallons of ethanol per year). An identical credit for producers of agri-biodiesel (fuel created from "virgin oils," such as soybean oil or canola oil) was established in the 2004 Jobs Act.

The 2004 bill also dramatically restructured the ethanol tax incentive, modifying the long-standing excise tax *exemption* to an excise tax *credit*. The new Volumetric Ethanol Excise Tax Credit (VEETC) provides a 51¢/gallon credit for ethanol blenders, currently in effect until 12/31/2010. The Jobs Act also established a $1.00 per gallon credit for agri-biodiesel, and a 50¢/gallon credit for biodiesel produced from recycled oils, such as yellow grease. Both credits expire on December 31, 2008.

In 2005's Energy Policy Act, Congress established a $1.00 per-gallon credit for 'renewable diesel', defined as fuel produced from biomass using a "thermal depolymerization" process. On April 2, 2007, Treasury issued regulations on this provision, interpreting thermal depolymerization broadly. Finally, the December 2006 Tax Relief and Health Care Act established a modest provision for cellulosic ethanol, allowing 50% bonus depreciation for new qualified cellulosic ethanol plants placed in service by 12/31/2012.

Major Federal Biofuel Tax Incentives

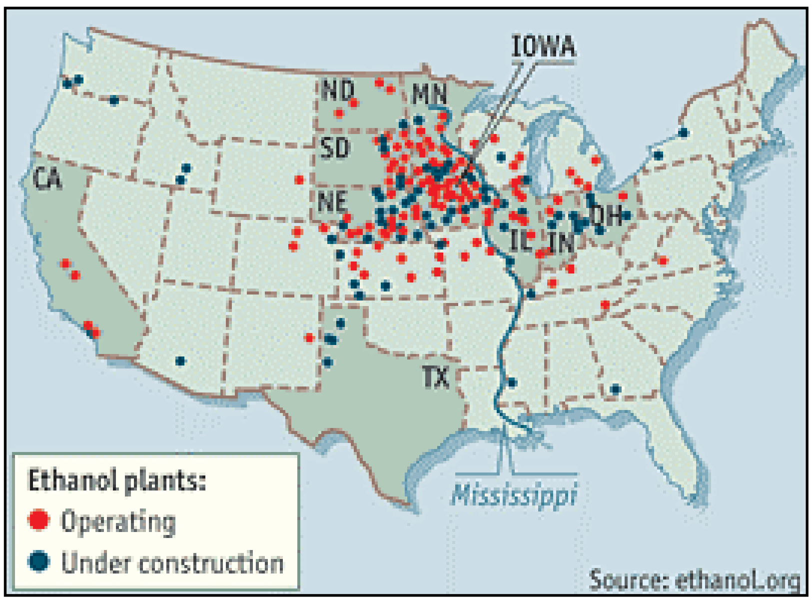
Title	Code or Law[a]	Fuel Type	Incentive	Qualifying Period	Limits[c]
Volumetric Ethanol Excise Tax Credit (VEETC)	Public Law 108-357[b]	ethanol of 190 proof or greater from biomass (e.g. corn grain, cellulosics)	$0.51 per pure gal of ethanol used or blended.	January 2005 – December 2010	Available to blenders/ retailers
Volumetric Excise Tax Credit for Biodiesel	EPACT 2005 [c] §1344, Title XIII, Subtitle D	Agri-biodiesel (e.g. from soybeans or other oil seeds)	$1.00 per pure gal of agri-biodiesel used or blended	Expires December 31, 2008	Available to blenders/ retailers
Volumetric Excise Tax Credit for Biodiesel	EPACT 2005 §1344, Title XIII, Subtitle D	Waste-grease biodiesel	$0.50 per pure gal of waste-grease biodiesel used or blended	Expires December 31, 2008	Available to blenders/ retailers
Volumetric Excise Tax Credit for Biodiesel	EPACT 2005 §1344, Title XIII, Subtitle D	Renewable diesel – made from biomass by thermal deploymerization	$1.00 per gal of diesel fuel used or blended	Expires December 31, 2008	Available to blenders/ retailers
Small Ethanol Producer Credit	EPACT 2005 §1347, Title XIII, Subtitle D	Ethanol from biomass (e.g. corn grain, cellulosics)	$0.10 per gallon ethanol or biodiesel produced up to 30 million gallons	Expires December 31, 2008	< 60 million gallon production capacity Cap at $1.5 million per yr per producer Can offset the alternative minimum tax
Small Biodiesel Producer Credit	EPACT 2005 §1345, Title XIII, Subtitle D	Agri-biodiesel	$0.10 per gallon ethanol or biodiesel produced up to 15 million gallons	Expires December 31, 2008	Same as above
Income Tax Credit for E85 and B20 Infrastructure	EPACT 2005 §1342, Title XIII, Subtitle D	Ethanol or biodiesel	Permits taxpayers to claim a 30% credit for cost of installing clean-fuel vehicle refueling property at business or residence	January 2006 – December 2007	$30,000 limit on tax credit

[a] Most recent Internal Revenue Service code or public law affecting the status of the incentive. In several cases, the most recent action is a modification of prior actions.
[b] Public Law 108-357 was the American Jobs Creation Act of 2004.
[c] EPACT 2005 is the Energy Policy Act of 2005. See brief summary of all biofuel related provisions in the final version of the Energy Policy Act at:
http://www.ethanolrfa.org/policy/regulations/federal/standard/

The complete EPACT 2005 can be found at: http://thomas.loc.gov/home/c109query.html.
Search bill text for the 109th Congress; browse by bill number 0-100. Select H.R.6 ENR. The items in this table will be found under title XII - Energy Policy Tax Incentives and Subtitle D - Alternative Motor vehicle and Fuels Incentives.

Major Alternative Fuels:

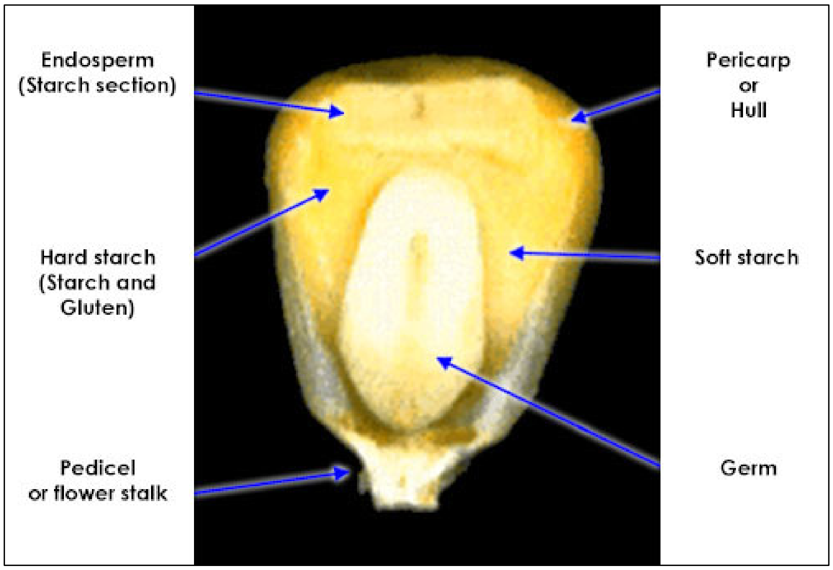
<u>Corn Ethanol</u>: Essentially non-drinkable grain alcohol, ethanol is produced by fermenting plant sugars, and can be made from corn, sugar cane, barley, wheat and other starchy agricultural products. About 99% of ethanol in the U.S. is used as E10 (gasohol), with only about 1% used as E85 (85% ethanol). Ethanol production in the U.S. occurs predominantly located in the Midwest (see figure, below). Cellulose in agricultural wastes such as waste woods and corn stalks ("cellulosic ethanol") can also be used as a feedstock, although cellulosic ethanol is currently not economically viable to produce on a large scale (see below).



Ethanol Plants – Current and Pending

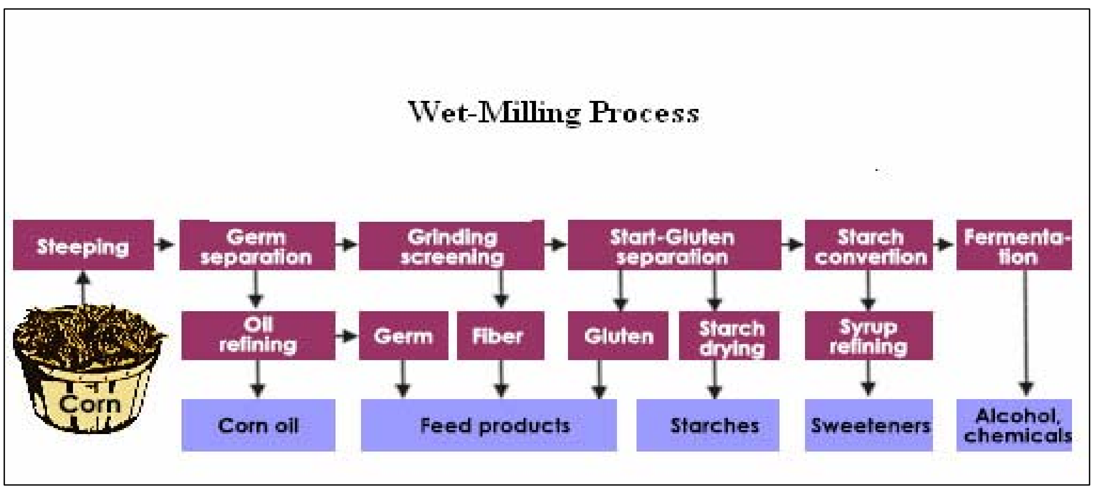
Corn Ethanol Production:

Ethanol production entails fermenting and then distilling starch and sugar crops. Most of the ethanol produced in the U.S. comes from about 15% of the U.S. corn crop. When corn is harvested, the kernels (diagram below) make up about half of the above-ground biomass, and corn stover (e.g., stalks, leaves, cobs, husks) makes up the other half. There are two main types of ethanol production: dry milling and wet milling.



Cornponents of a Kernel

Wet Milling: Many larger ethanol producers use the process of wet-milling ethanol, which also yields products such as high-fructose corn sweetener. The wet-milling is conducted in the steps outlined below.



1) **Cleaning:** Shelled corn is delivered to the wet milling plant, primarily by rail or truck, and is unloaded into a receiving pit. After being elevated to temporary storage bins and scale hoppers for weighing and sampling, the corn passes through mechanical cleaners designed to remove unwanted material, such as pieces of cobs, sticks, and husks, as well as meal and stones.

2) **Steeping:** After the corn is cleaned it is “steeped”, by soaking in warm water and dilute acid for 24-48 hours. This process conditions the grain for subsequent

milling and recovery of corn constituents, by softening the kernel for milling, helping break down the protein holding the starch particles, and removing certain soluble constituents. Steeping takes place in a series of tanks, usually referred to as steeps, which are operated in continuous-batch process.

3) **Germ Separation:** After steeping, the corn is coarsely ground to break the germ loose from other components. Steepwater is condensed to capture nutrients in the water for use in animal feeds and for a nutrient for later fermentation processes. The ground corn, in a water slurry, flows to the germ separators, where the corn germ, which contains about 85% of corn's oil, is spun out of the slurry. The germ is pumped onto screens and washed to remove any starch left in the mixture. A combination of mechanical and solvent processes extracts the germ’s oil, which is then refined and filtered into finished corn oil. The germ residue is saved used as a component in animal feed.

4) **Grinding:** After germ separation, the corn and water slurry undergoes a second, more thorough, grinding in order to release the starch and gluten from the fiber in the kernel. The mixture of starch, gluten and fiber flows over screens which catch fiber but allow starch and gluten to pass through. The fiber is collected, slurried and screened again to reclaim any residual starch or protein, then piped to the feed house as a major ingredient of animal feeds. The starch-gluten suspension, called mill starch, is piped to the starch separators.

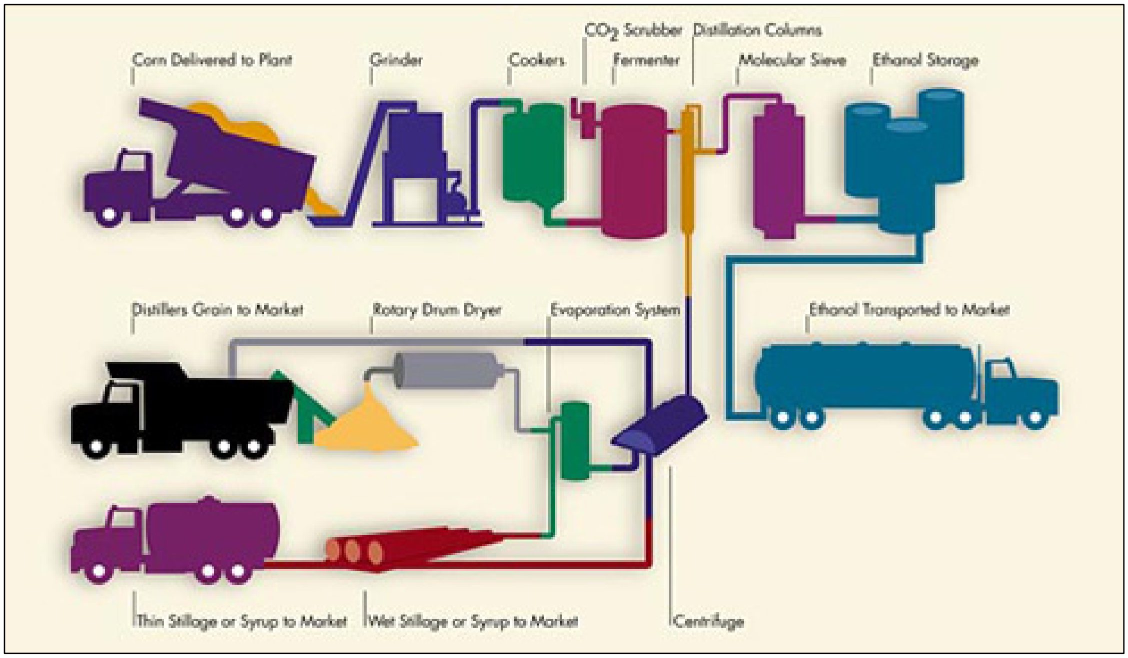
5) **Starch Separation**: After the grinding process, the remaining gluten is spun out via centrifuge, and used in animal feeds. The starch, with just one or two percent protein remaining, is diluted, washed 8 to 14 times, re-diluted and washed again to remove the last traces of protein and produce high quality starch, typically more than 99.5% pure. Some of the starch is dried and marketed as unmodified corn starch, and some is modified into specialty starches. Most is converted into corn syrups and dextrose.

6) **Syrup Conversion:** Starch, suspended in water, is liquefied in the presence of acid and/or enzymes, which convert the starch to a low-dextrose solution. Treatment with another enzyme continues the conversion process, throughout which refiners can halt acid or enzyme actions to produce the right mixture of sugars like dextrose and maltose. In some syrups, the conversion of starch to sugars is halted at an early stage to produce low-to-medium sweetness syrups. In others, the conversion is allowed to proceed until the syrup is nearly all dextrose. The syrup is refined, and sold directly, crystallized into pure dextrose, or processed further to create high-fructose corn syrup.

7) **Fermentation:** Ethanol is produced by the addition of enzymes to the pure starch slurry to hydrolyze the starch to fermentable sugars. Following hydrolysis, yeast is added to initiate the fermentation process. After about 2 days, approximately 90 percent of the starch is converted to ethanol. The fermentation broth is transferred to a still where the ethanol (about 50 vol%) is distilled. Subsequent distillation and treatment steps produce 95 percent, absolute, or denatured ethanol.

Dry Milling: Under the dry milling process**,** (see below) the entire corn kernel or other grain is first ground into meal. Water is then added to turn the meal into mash, and enzymes are added to convert the starch in the meal to dextrose, a simple sugar. The mash is processed in a high-temperature cooker to reduce bacteria ahead of fermentation. The mash is cooled and transferred to fermenters where yeast is added and the conversion of sugar to ethanol and CO2 begins.

The fermentation process generally takes 40 to 50 hours. During this process, the mash is agitated and kept cool to facilitate yeast activity. After fermentation, the resulting "beer" is transferred to distillation columns, where the ethanol is separated from the remaining mixture. The ethanol is concentrated to 190 proof using conventional distillation, and then dehydrated until it's about 200 proof. A denaturant (such as methanol) is then added to render the ethanol undrinkable. The ethanol is then ready for shipment to gasoline terminals or retailers.



Dry-Milling Process

<u>Cellulosic Ethanol:</u> In his 2007 State of the Union Address, President Bush called for a reduction in gasoline consumption by 20 percent by 2017, in part by requiring the use of 35 billion gallons of renewable and alternative fuels. Bush's proposal represents a dramatic increase in the 'renewable fuels standard' (RFS) enacted by Congress in the 2005 Energy Bill, which mandated that the U.S. gasoline supply contain 7.5 billion gallons of ethanol or other renewable fuel by 2012). The U.S. used about 5.4 billion gallons of ethanol last year, and our system may use upwards of 6 billion gallons of ethanol in 2007, well exceeding the target RFS. But with experts predicting that corn-based ethanol can ultimately account for only about 15 billion gallons of annual U.S. production, achievement of Bush's goal will necessarily include large-scale use of cellulosic ethanol, derived from switchgrass , bagasse (the biomass remaining after sugar cane is crushed), rice hulls, woody waste, etc.

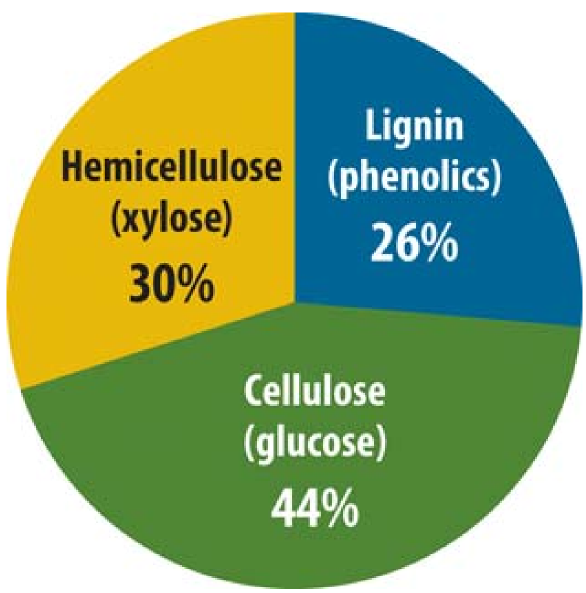
Switchgrass **Bagasse**

Cellulosic Ethanol Production:

Conversion of cellulosic biomass to ethanol is more expensive than the conversion of corn grain to ethanol. But because cellulosic biomass is a cheaper and more abundant feedstock than corn grain, it holds great promise as a mass-produced fuel of the future. The challenge in making cellulosic ethanol commercially viable is largely a function of finding efficient ways to break cellulosic biomass into simple sugars for conversion to ethanol.

Most plant matter consists of three key polymers: Cellulose (35 to 50%), hemicellulose (20 to 35%), and lignin (10 to 25%). These polymers are assembled into a complex, interconnected matrix within plant cell walls. Cellulose and hemicellulose, which are carbohydrates, can be converted into fuel. Lignin, which is not a carbohydrate, cannot be made into ethanol.

.



Composition of Biomass

Following is a description of how cellulosic material is converted into fuel (source: http://genomicsgtl.energy.gov/biofuels/ethanolproduction.shtml)

1) **Mechanical Preprocessing:** Dirt and debris are removed from incoming biomass (e.g., bales of corn stover, wheat straw, or grasses), which is shred into small particles.

2) **Pretreatment**: Heat, pressure, or acid treatments are applied to release cellulose, hemicellulose, and lignin and to make cellulose more accessible to enzymatic breakdown (hydrolysis). Hemicellulose is hydrolyzed into a soluble mix of 5- and 6-carbon sugars. A small portion of cellulose may be converted to glucose. If acid treatments are used, toxic by-products are neutralized by the addition of lime. Since cellulose biomass can come from many different sources (grasses, corn stover, bagasse etc.), a single pretreatment process suitable for all forms of biomass does not exist.

3) **Solid-Liquid Separation**: The liquefied syrup of hemicellulose sugars is separated from the solid fibers containing crystalline cellulose and lignin.

4) **Fermentation of Hemicellulosic Sugars**: Through a series of biochemical reactions, bacteria convert xylose and other hemicellulose sugars to ethanol.

5) **Enzyme Production**: Some of the biomass solids are used to produce cellulase (not cellulose) enzymes that break down crystalline cellulose. The enzymes are harvested from cultured microbes.

6) **Cellulose Hydrolysis**: The fiber residues containing cellulose and lignin are transferred to a fermentation tank, where cellulase enzymes are applied. A cocktail of different cellulases work together to attack crystalline cellulose, pull cellulose chains away from the crystal, and ultimately break each cellulose chain into individual glucose molecules.

7) **Fermentation of Cellulosic Sugars (Glucose)**: Yeast or other microorganisms consume glucose and generate ethanol and carbon dioxide as products of the glucose fermentation pathway.

8) **Distillation**: Dilute ethanol broth produced during the fermentation of hemicellulosic and cellulosic sugars is distilled to remove water and concentrate the ethanol. Solid residues containing lignin and microbial cells can be burned to produce heat or used to generate electricity consumed by the ethanol-production process. Alternately, the solids could be converted to co-products (e.g., animal feed, nutrients for crops), as occurs with corn ethanol.

9) **Dehydration**: As with corn ethanol, the last remaining water is removed from the distilled ethanol through a dehydration process.

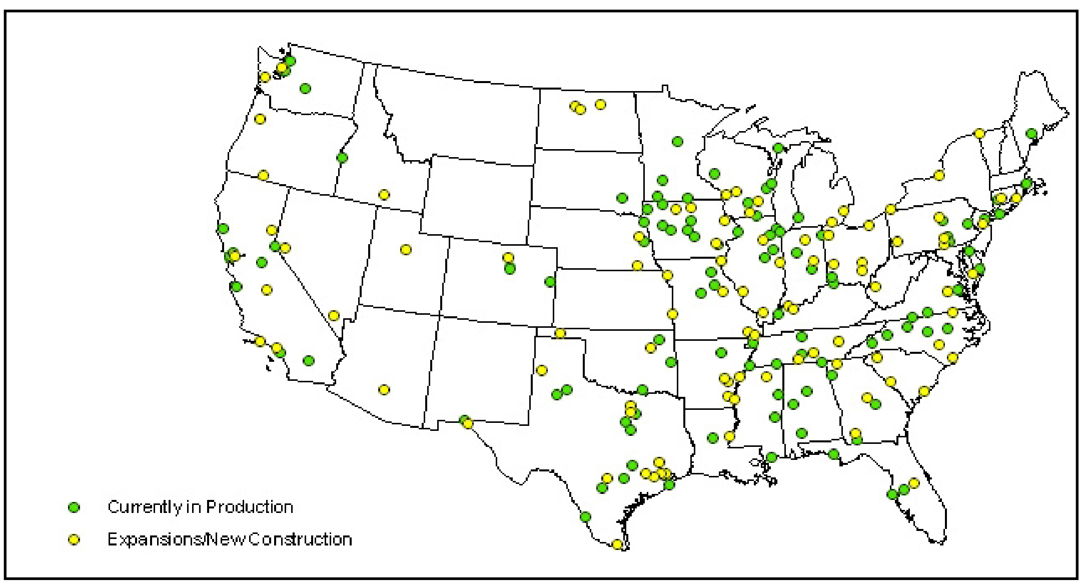
Biodiesel:

Biodiesel is a diesel fuel substitute made from vegetable and animal oils, as well as recycled cooking grease. Like petroleum diesel, operates in compression-ignition engines, although in the U.S. the fuel is typically used in a blend with regular diesel fuel as B20 (20% biodiesel, 80% diesel). Biodiesel is produced through a process called 'transesterification', in which vegetable oil (typically soybean oil, the source of about 90% of U.S. biodiesel) or cooking grease is combined with alcohol (usually methanol).

B20 can be used in nearly all diesel equipment, and is compatible with most storage and distribution equipment. These low-level blends (20% and less) generally do not require engine modifications. In Europe, biodiesel is widely available in both its 'neat' form (100% biodiesel, also known as B100) and in blends with petroleum diesel. Most European biodiesel is made from rapeseed oil (a cousin of canola oil).

In addition to biodiesel, the production process typically yields as co-products crushed bean "cake", an animal feed, and glycerine. Glycerine is a valuable chemical used for making many types of cosmetics, medicines and foods, and its co-production improves the economics of making biodiesel.

While biodiesel production has increased significantly in recent years, U.S. biodiesel production remains small relative to national diesel consumption levels. According to the Energy Information Administration, biodiesel production was 91 million gallons in 2005, (EIA Annual Energy Outlook, Feb. 2007), the last year for which data is available. While this represents a dramatic growth in U.S. biodiesel use, 91 million gallons amounts to less about 0.2% of the 43 billion gallons of diesel fuel used nationally for vehicle transportation.

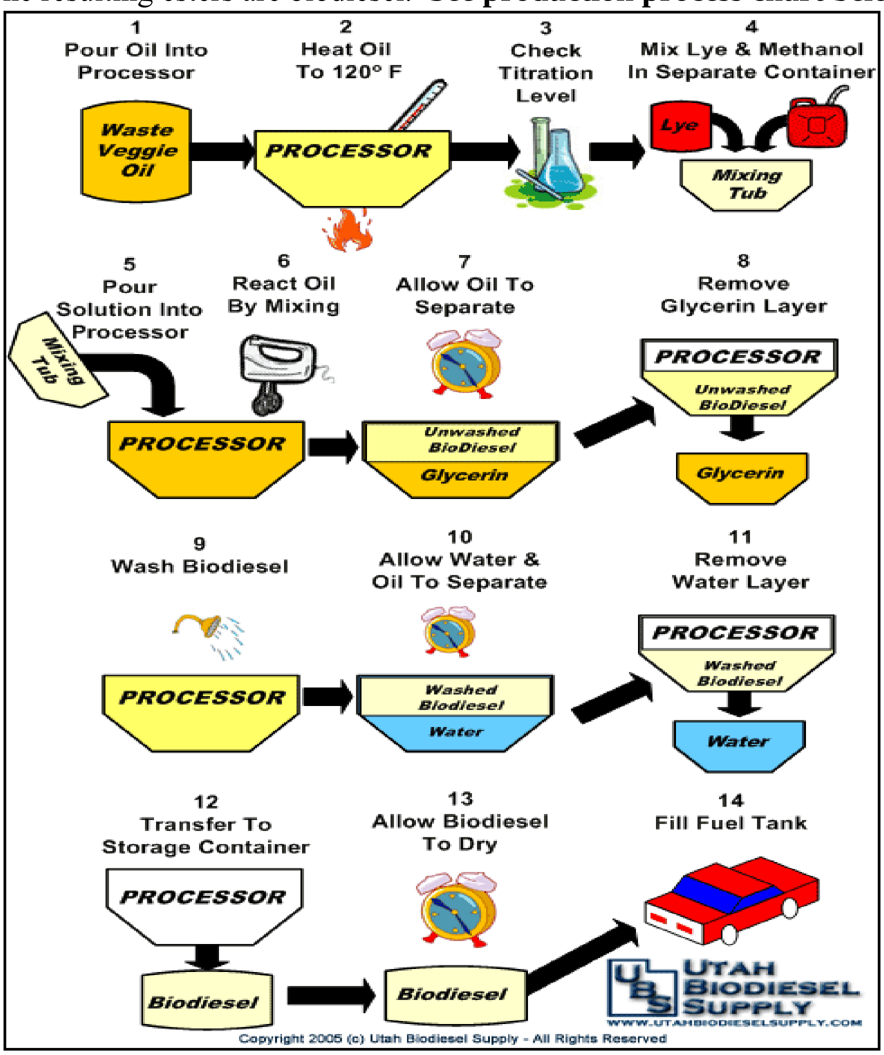


Biodiesel Plants – Current and Pending (source: Iowa St. University)

The physical and chemical properties of biodiesel are similar to those of petroleum diesel. But biodiesel has a number of advantages, including better lubricity (lower engine friction), virtually no aromatic compounds or sulfur, and a higher cetane (diesel's equivalent to gasoline's octane) number. Both pure biodiesel and biodiesel blends generally exhibit lower emissions of most pollutants than petroleum diesel. Although emissions vary with engine design, vehicle condition and fuel quality, the EPA found that, with the exception of nitrogen oxide, potential reductions from biodiesel blends are considerable relative to conventional diesel, and increase nearly linearly with increasing blend levels.

Biodiesel Production:

Biodiesel can be produced by a variety of esterification technologies, although most processes use the following basic approach. approach. First, the oil is filtered and pre-processed to remove water and contaminants. If free fatty acids are present, they can be removed or transformed into biodiesel using pre-treatment technologies. The pre-treated oils and fats are then mixed with an alcohol (usually methanol) and a catalyst (usually sodium or potassium hydroxide). The oil molecules (triglycerides) are broken apart and reformed into esters and glycerol, which are then separated from each other and purified. The resulting esters are biodiesel. **See production process chart below.**



Renewable Diesel:

As mentioned above, the 2005 Energy Bill included a $1.00 per-gallon tax credit for the production of "renewable diesel," defined as fuel produced from biomass using "thermal depolymerization". This process has traditionally been associated with petroleum refining, in contrast to the means used to create biodiesel from oilseeds. Thermal depolymerization requires the use of a hydrotreater, a unit which cleans and improves finished fuels. (Many existing refineries use hydrotreaters for sulfur removal, to comply with new ultra-low-sulfur-diesel (ULSD) regulations.) On April 2, 2007, Treasury issued guidance on the renewable diesel issue, interpreting thermal depolymerization broadly.

The renewable diesel issue has engendered considerable controversy in recent months, not least because extension of the renewable diesel credit (at $1.00 per gallon) will become considerably more expensive with the addition of significant new capacity for renewable diesel production. Treasury's decision makes eligible for the credit methods of renewable diesel production employed by ConocoPhillips, which is partnering with Tyson Foods to add animal fats to its traditional diesel refining processes. According to news reports, the companies plan to start production of renewable diesel later this year, eventually increasing production of renewable diesel to 175 million gallons per year.

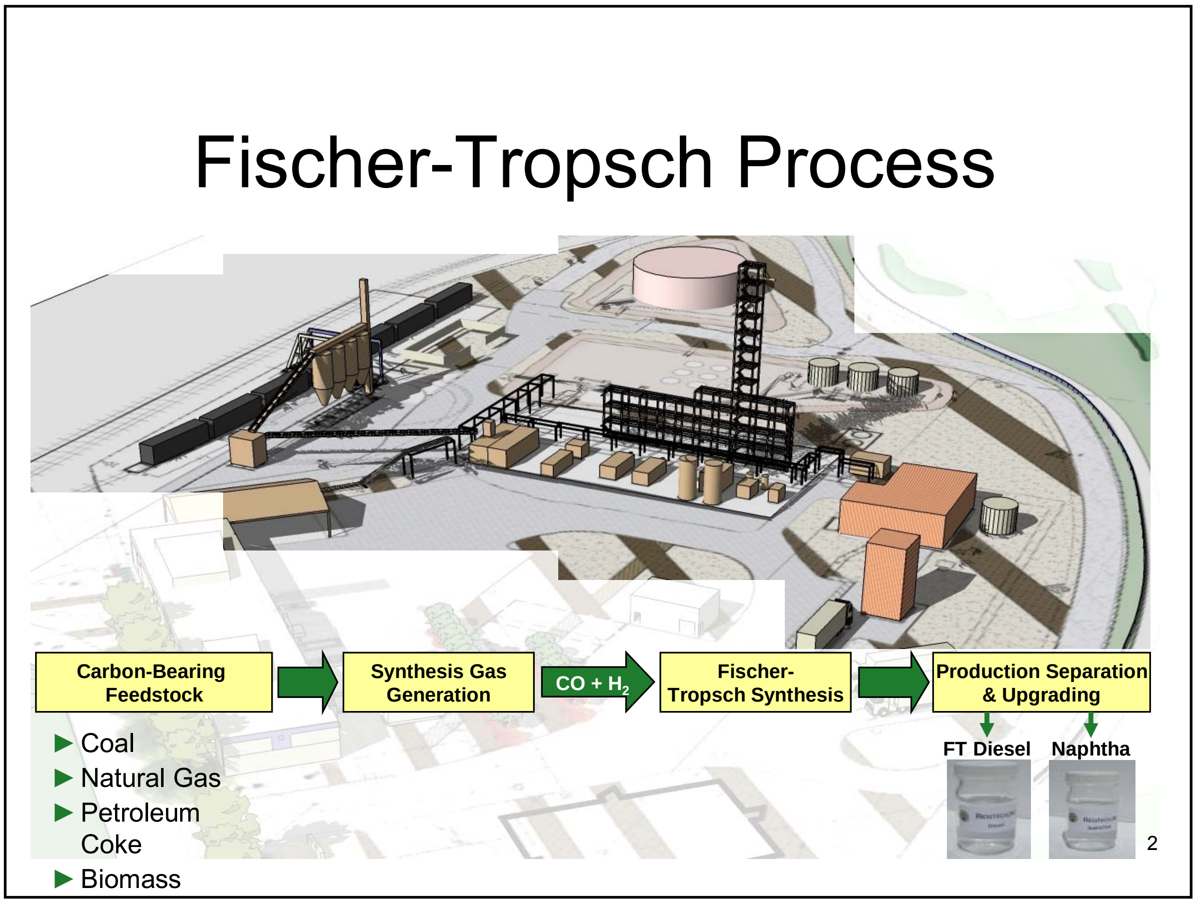
Fischer-Tropsch Diesel:

Before WWII, experts scoffed at Hitler's war plans, largely because Germany had no oil. But because of a discovery made by German scientists Fischer and Tropsch in 1923, Germany ultimately produced more than the equivalent of 124,000 barrels of synfuels per day – plenty enough to run its war machine. It wasn't until Allied bombing of German synfuel plants in late 1944 and early 1945 that the Nazi war machine began to grind to a halt.

In part due to Germany's experience with synfuels, interest in the topic grew in Congress in the 1940s. Congressman Jennings Randolph (D-WV) flew from Morgantown to DC in a synfuel-powered plane in 1943 to call attention to the potential for a U.S. synfuels industry. Six months later, Congress passed the Synthetic Liquid Fuels Act, to research the viability of synfuels from coal, oil shale, and 'other substances.' Funding for the initiative was provided consistently until 1952, when the House Approps Committee – citing high costs – ended the program.

Interest in synfuels was renewed after the 1973 OPEC embargo. Government reports recommending significant increases in energy R&D (including for synfuels) were issued. In 1975 President Ford created the Energy Research and Development Administration (ERDA), consolidating existing R&D energy programs from several agencies. In 1977, ERDA became part of the new Dept. of Energy. But as the price of oil fell dramatically in the 1980s, synfuel interest waned again. In response to a GAO report, Congress terminated large-scale government synfuel research in 1984.

Prompted by the most recent spike in oil prices, on September 19, 2006, the Air Force tested synfuel in a B-52 bomber, using a blend of 50% standard jet fuel and 50% synfuel. Just two of the B-52's eight engines were powered by the synfuel in the test, which was conducted for two hours. Press reports indicate that the synfuel-powered engines performed the same as the petroleum-powered engines.



ALTERNATIVE FUELS
A. Incentives for Alcohol, Biodiesel, Renewable Diesel and Certain Alternative Fuels (secs. 40, 40A, 6426, and 6427(e))[1]

In general

The Code provides per-gallon incentives for the following qualified fuels: alcohol (including ethanol), biodiesel (including agri-biodiesel), renewable diesel, and certain alternative fuels.[2] If the qualified fuel is part of a qualified fuel mixture, the incentives apply only to the amount of qualified fuel in the mixture.

For alcohol, other than ethanol, the amount of the credit is 60 cents per gallon. For ethanol, the credit is 51 cents per gallon. The alcohol incentives expire after December 31, 2010. The amount of the credit for biodiesel is 50 cents. For agri-biodiesel and renewable diesel, the credit amount is $1.00 per gallon. The biodiesel, agri-biodiesel and renewable diesel incentives expire after December 31, 2008. The credit amount for alternative fuels is 50 cents per gallon. The incentives for alternative fuels expire after September 30, 2009 (after September 30, 2014, in the case of liquefied hydrogen).

The Code provides taxpayers with several mechanisms to obtain the incentives: excise tax credits, direct payments, and income tax credits. The mechanisms are coordinated such that gallons are not double counted.

For fuel mixtures, the excise tax credits may be taken against the taxes imposed by section 4081 of the Code (relating to the taxes on gasoline, diesel fuel and kerosene). The alternative fuel excise tax credit may be taken against the tax imposed by section 4041 (relating to taxes on diesel fuel and special motor fuels).[3] The credits and payments are made out of the General Fund and do not reduce the amount of fuel tax transferred to the Highway Trust Fund.

The Code also provides a 10-cents-per-gallon income tax credit for small producers of ethanol and small producers of agri-biodiesel, if certain conditions are met. This credit is in addition to the credits mentioned above. Finally, the Code provides for reduced rates of tax for alcohol fuels produced from natural gas or coal.

[1] Unless otherwise provided, all section references are to the Internal Revenue Code of 1986, as amended (the "Code").

[2] See secs. 40, 40A, 6426, and paragraph (e) of section 6427. The specific definitions for each type of fuel are listed at the end of this section in Table 1, below.

[3] The various fuel excise tax rates imposed by sections 4081 and 4041 are summarized in Table 2 below.

Alcohol, biodiesel and renewable diesel

Generally, for qualified alcohol mixtures, biodiesel mixtures, and renewable diesel mixtures, the incentive can be realized through an excise tax credit, direct payment, or income tax credit. For qualified mixtures containing alcohol, biodiesel, or renewable diesel, the qualified mixture must be produced by the taxpayer and either (1) sold by such taxpayer to any person for use as a fuel, or (2) used as a fuel by the taxpayer.

Alcohol, biodiesel, and renewable diesel, not in a qualified mixture, are eligible for the income tax credit only. A taxpayer may claim an income tax credit for alcohol, biodiesel, or renewable diesel if the alcohol, biodiesel, or renewable diesel is not part of a qualified fuel mixture, and (1) is used by the by the taxpayer as a fuel in a trade or business, or (2) sold by the taxpayer at retail to a person and placed in the fuel tank of such person's vehicle.

Alternative fuels

Alternative fuels are the only qualified fuels for which an excise tax credit or direct payment may be claimed without the fuel being part of a qualified mixture. Unlike biodiesel and alcohol, the Code does not provide an income tax credit specific to alternative fuels. The taxpayer may claim the excise tax credit or direct payment with respect to alternative fuel not in a qualified mixture if the fuel is sold by the taxpayer for use as a fuel in a motor vehicle or motorboat, or used by the taxpayer in that manner. For qualified alternative fuel mixtures, the qualified mixture must be produced by the taxpayer and either (1) sold by such taxpayer to any person for use as a fuel or (2) used as a fuel by such taxpayer.

Small producer incentives

Present law also provides a separate 10-cents-per-gallon incentive to small producers of ethanol and to small producers of agri-biodiesel for up to 15 million gallons. The Code defines small producers generally as persons whose production capacity does not exceed 60 million gallons per year. The agri-biodiesel or ethanol must:

1. be sold by such producer to another person (a) for use by such other person in the production of a qualified fuel mixture in such person’s trade or business (other than casual off-farm production), (b) for use by such other person as a fuel in a trade or business, or, (c) who sells such ethanol or agri-biodiesel at retail to another person and places such ethanol or agri-biodiesel in the fuel tank of such other person; or
2. be used by the producer for any purpose described in (a), (b), or (c) above.

A cooperative may pass through the small producer credits to its patrons.

Other incentives

Reduced rate of tax for alcohol fuels produced from natural gas

A reduced rate of fuel tax is provided for "partially exempt methanol or ethanol fuel." The term "partially exempt methanol or ethanol fuel" means any liquid at least 85 percent of which consists of methanol, ethanol or other alcohol (including methanol and ethanol) produced from natural gas. Partially exempt methanol (or other alcohol) is taxed at 9.25 cents per gallon. Partially exempt ethanol is taxed at 11.4 cents per gallon.[4] After September 30, 2011, these rates drop to 2.25 cents per gallon and 4.4 cents per gallon, respectively.

Reduced rate of tax for alcohol fuels produced from coal

A reduced rate of fuel tax is also provided for "qualified methanol and ethanol fuel." The term "qualified methanol or ethanol fuel" means any liquid at least 85 percent of which consists of methanol, ethanol or other alcohol produced from coal (including peat). Qualified ethanol is taxed at 13.25 cents per gallon. Qualified methanol is taxed at 12.35 cents per gallon.[5] The incentive rates terminate on January 1, 2009.

Table 1: Summary of Certain Alternative Fuel Incentives

Fuel Type	Per Gallon Incentive Amount	Incentive Expires
Agri-biodiesel	$1.00 per gallon, plus $0.10 per gallon for small producers	After December 31, 2008
Renewable diesel	$1.00 per gallon	After December 31, 2008
Alcohol fuel (not ethanol)	$0.60 per gallon	After December 31, 2010
Ethanol fuel	$0.51 per gallon, plus $0.10 per gallon for small producers	After December 31, 2010
Biodiesel fuel	$0.50 per gallon	After December 31, 2008
Alternative fuel: • liquefied petroleum gas • P Series Fuels • compressed or liquefied natural gas • liquefied hydrogen • any liquid fuel derived from coal through the Fischer-Tropsch process • liquid hydrocarbons derived from biomass	$0.50 per gallon	After September 30, 2009 (after September 30, 2014, in the case of liquefied hydrogen)

[4] These rates include the Leaking Underground Storage Tank Trust Fund tax.

[5] These rates include the Leaking Underground Storage Tank Trust Fund tax.

Definitions:

Alcohol includes methanol and ethanol, but does not include alcohol produced from petroleum, natural gas, or coal (including peat) or alcohol with a proof of less than 150 (for the excise tax and direct payment mechanism, alcohol with a proof of less than 190.

Biodiesel is monoalkyl esters of long chain fatty acids derived from plant or animal matter that meet (1) the registration requirements established by the Environmental Protection Agency under section 211 of the Clean Air Act and (2) the requirements of the American Society of Testing and Materials D6751.

Agri-biodiesel is biodiesel derived solely from virgin oils, including oils from corn, soybeans, sunflower seeds, cottonseeds, canola, crambe, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, or animal fats.

Renewable diesel means diesel fuel derived from biomass (as defined in section 45K(c)(3), thus excluding petroleum oil, natural gas, coal, or any product thereof) using a thermal depolymerization process.[6] Renewable diesel must meet the requirements of the American Society of Testing and Materials D975 or D396, and meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act (42 USC 7545).

Alternative fuel is liquefied petroleum gas, P Series Fuels (as defined by the Secretary of Energy under 42 U.S.C. sec 13211(2)), compressed or liquefied natural gas, liquefied hydrogen, any liquid fuel derived from coal through the Fischer-Tropsch process, and liquid hydrocarbons derived from biomass. For purposes of the tax incentives, alternative fuel does not include ethanol, methanol, or biodiesel.

Section 13211(2) of Title 42 permits the Secretary of Energy to determine, by rule, that a fuel is an alternative fuel if it is substantially not petroleum and would yield substantial energy security benefits and substantial environmental benefits. Under 10 CFR 490.2 alternative fuel is defined to include three P Series Fuels (specifically known as Pure Regular, Pure Premium and Pure Cold Weather) as described by United States Patent number 5,697,987, dated December 16, 1997, and containing at least 60 percent non-petroleum energy content derived from methyltetrahydrofuran, which must be manufactured solely from biological materials, and ethanol, which must be manufactured solely from biological materials.

The Fischer-Tropsch process was discovered by German scientists and used to make fuels during World War II. In general, the Fischer-Tropsch reaction converts a mixture of hydrogen and carbon monoxide -- derived from coal, methane, or biomass-- to liquid fuels. The coal-based process is referred to by the Department of Energy as "Coal-to-Liquids."[7]

[6] The Code does not define thermal depolymerization. Pursuant to Treasury Notice 2007-37, thermal depolymerization is a process for the reduction of complex organic materials through the use of pressure and heat to decompose long-chain polymers of hydrogen, oxygen, and carbon into short-chain hydrocarbons with a maximum length of around 18 carbon atoms. A process may qualify as thermal depolymerization even if catalysts are used in the process.

[7] See U.S. Department of Energy, National Energy Technology Laboratory, *R&D Facts: Clean Fuels, Fischer-Tropsch Fuels* (January 2007).

Table 2: Fuel Excise Tax Rates

Fuel	Excise Tax Rates (includes Leaking Underground Storage Tank Trust Fund tax where applicable)
Gasoline (sec. 4081)	18.4 cents per gallon (19.4 cents per gallon for aviation gasoline)
Diesel fuel (sec. 4041 and 4081)	24.4 cents per gallon
Diesel fuel used in trains (sec. 4041)	2.4 cents per gallon
Diesel-water fuel emulsions (sec. 4081)	19.8 cents per gallon
Special motor fuel (sec. 4041)	18.4 cents per gallon
Liquid fuel (other than ethanol or methanol) derived from coal (sec. 4041)	24.4 cents per gallon
Liquid hydrocarbons derived from biomass (sec. 4041)	24.4 cents per gallon
Liquefied natural gas (sec. 4041)	24.4 cents per gallon
Qualified ethanol (from coal) (sec. 4041)	13.25 cents per gallon
Qualified methanol (from coal) (sec. 4041)	12.35 cents per gallon
Partially exempt ethanol (from natural gas) (sec. 4041)	11.4 cents per gallon
Partially exempt methanol (from natural gas) (sec. 4041)	9.25 cents per gallon
Compressed natural gas (sec. 4041)	18.3 cents per energy equivalent of a gallon of gasoline
Kerosene (sec. 4081)	24.4 cents per gallon (4.4 cents per gallon for commercial aviation fuel and 21.9 cents per gallon for noncommercial aviation fuel)

B. Special Depreciation Allowance for Cellulosic Biomass Ethanol Plant Property (sec. 168(l))

The Tax Relief and Healthcare Act of 2006 added a provision that allows an additional first-year depreciation deduction equal to 50 percent of the adjusted basis of qualified cellulosic biomass ethanol plant property. In order to qualify, the property generally must be placed in service before January 1, 2013.

Qualified cellulosic biomass ethanol plant property means property used in the U.S. solely to produce cellulosic biomass ethanol. For this purpose, cellulosic biomass ethanol means ethanol produced by enzymatic hydrolysis of any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis. For example, lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis includes bagasse (from sugar cane), corn stalks, and switchgrass. The additional first-year depreciation deduction is allowed for both regular tax and alternative minimum tax purposes for the taxable year in which the property is placed in service.

The additional first-year depreciation deduction is subject to the general rules regarding whether an item is deductible under section 162 or subject to capitalization under section 263 or section 263A. The basis of the property and the depreciation allowances in the year of purchase and later years are appropriately adjusted to reflect the additional first-year depreciation deduction.

In addition, the provision provides that there is no adjustment to the allowable amount of depreciation for purposes of computing a taxpayer's alternative minimum taxable income with respect to property to which the provision applies. A taxpayer is allowed to elect out of the additional first-year depreciation for any class of property for any taxable year. In order for property to qualify for the additional first-year depreciation deduction, it must meet the following requirements. The original use of the property must commence with the taxpayer on or after the date of enactment of the provision. The property must be acquired by purchase (as defined under section 179(d)) by the taxpayer after the date of enactment and placed in service before January 1, 2013. Property does not qualify if a binding written contract for the acquisition of such property was in effect on or before the date of enactment.[8]

Property any portion of which is financed with the proceeds of a tax-exempt obligation under section 103 is not eligible for the additional first-year depreciation deduction. Recapture rules apply under the provision if the property ceases to be qualified cellulosic biomass ethanol plant property. Property with respect to which the taxpayer has elected 50 percent expensing under section 179C is not eligible for the additional first-year depreciation deduction under the provision.

[8] Property that is manufactured, constructed, or produced by the taxpayer for use by the taxpayer qualifies if the taxpayer begins the manufacture, construction, or production of the property after the date of enactment, and the property is placed in service before January 1, 2013 (and all other requirements are met). Property that is manufactured, constructed, or produced for the taxpayer by another person under a contract that is entered into prior to the manufacture, construction, or production of the property is considered to be manufactured, constructed, or produced by the taxpayer.

C. Previously Discussed Provisions

Temporary election to expense 50 percent of qualified property used in refining liquid fuels (sec. 179C) - discussed January 12, 2007

Taxpayers may elect to expense 50 percent of the cost of any qualified refinery property used for processing liquid fuel from crude oil or qualified fuels (as defined in section 45K(c)[9] of the Code, including fuel produced from biomass). The remaining 50 percent is recovered under the otherwise applicable rules. Qualified refinery property includes assets located in the United States that are used in the refining of liquid fuels: (1) with respect to the construction of which a binding construction contract has been entered into before January 1, 2008;[10] (2) which are placed in service before January 1, 2012; (3) which increase the capacity of an existing refinery by at least five percent or increase the percentage of total throughput attributable to qualified fuels such that it equals or exceeds 25 percent; and (4) which meet all applicable environmental laws in effect when the property is placed in service.

The election to expense 50 percent of the cost of qualified refinery property was added by the Energy Policy Act of 2005. The provision is effective for property placed in service after the date of enactment (August 8, 2005) of that Act, where the original use of the property begins with the taxpayer, provided the property was not subject to a binding contract for construction on or before June 14, 2005.

[9] Under section 45K(c), qualified fuels are (1) oil produced from shale and tar sands, (2) gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation, or biomass, and (3) liquid, gaseous, or solid synthetic fuels produced from coal (including lignite).

[10] This requirement also may be met by placing the property in service before January 1, 2008 or, in the case of self-constructed property, by beginning construction after June 14, 2005 and before January 1, 2008.