Approved:
Date 2-5-01

MINUTES OF THE SENATE UTILITIES COMMITTEE.

The meeting was called to order by Chairperson Senator Stan Clark at 9:30 a.m. on January 30, 2001 in Room 231-N of the Capitol.

All members were present except:

Committee staff present: Bruce Kenzie, Revisor of Statutes
Raney Gilliland, Legislative Research
Ann McMorris, Secretary
Chris Crowder, Intern to Sen. Clark

Conferees appearing before the committee:
Steve Thomas, Hydronics L.L.C., Wichita
Steve Sloan, Hydronics L.L.C., Wichita
Jerry Fizzell, EPA Consultant

Others attending: See attached sheet

Chair Clark handed out a list of Gas Production Companies and Oil Operators which was provided by Tim Carr in response to a request when Mr. Carr appeared before the committee on January 29. (Attachment 1)

The committee was also provided information entitled "Petroleum and Ethanol Fuels; Tax Incentives and Related GAO Work" prepared by U.S.General Accounting Office. (Attachment 2)

Additional written testimony provided by Clay Loyd of Topeka for public comment on high natural gas prices hearing on January 24. (Attachment 3)

Hydronics Energy Technologies Presentation

Steve Thomas conducted several demonstrations on how hydrogen produced power and utilized scrap metals, waste water and alcohol. This is a clean burning fuel with no smoke or carbon. He holds 7 patents in 81 countries on this technology. Steve Sloan and Jerry Fizzell explained the applications involving environmental cleanup and desalinization of waste water. It was noted that this process is cost effective compared to other methods used for waste disposal and providing power systems for industrial and automotive. It is easily available to remote areas and commercial plants. Venture capital is being sought to launch this program which has been in testing for over a year. (Attachment 4)

Many questions and comments from the committee members on venture capital, availability of magnesium and other metals, size of power plant for industrial companies, safety, what would be required to convert from natural gas to hydrogen and cost factors.

Approval of Committee Minutes
Moved by Senator Lee, seconded by Senator Barone, approval of the minutes for committee meetings held on January 23, 2001 (joint meeting with House Utilities); January 24, 2001; January 24, 2001 (joint meeting with House Committee); January25, 2001; and January 25, 2001 (at the rail).

Next meeting will be January 31, 2001.

Adjournment.

Respectfully submitted,
Ann McMorris, Secretary

Attlachments - 4

SENATE UTILITIES COMMITTEE GUEST LIST

DATE: JANUARY 30 - 2001

NAME	REPRESENTING
JC Long	UtiliCorp United Inc.
Jim Allen	EKOGA
John Cranda	Sen. Stan Clark
Sandra DePoe	Farm Bureau Anderson Co.
Larry DePoe	Farm Bureau Anderson Co
Clyde Parks	Farm Bureau Anderson Co
Janice Parks	Farm Bureau Anderson Co
Nancy Vandenberg	~~EL~~ El Paso Energy
[illegible]	CBBA
Craig E. [illegible]	Farm Bureau Harvey Co.
John McFarland	Franklin Co. Farm Bureau
Andy Shaw	Kearney Law Office
[illegible]	Kansas Farm Bureau
JOHN PENDLETON	KANSAS FARM BUREAU
John Milburn	Associated Press
[illegible]	PH - Duke - Williams
James Wulf	Farm Bureau Harvey Co
Cindy Wulf	" " " "
Chris Wilson	KGC

Gas Production

(Note to gas production: The purchase of Vastar by BP-Amoco and Union Pacific by Anadarko will make these producers much larger players.)

OPERATOR_NAME	PRODUCTION	Percentage	Cum % Production
EXXON-MOBIL	98,229,841	17.78%	17.78%
BP-AMOCO PRODUCTION CO	78,954,778	14.29%	32.06%
OXY USA INC	66,407,959	12.02%	44.08%
ANADARKO PETROLEUM CO	63,598,050	11.51%	55.59%
MESA OPERATING CO	46,196,114	8.36%	63.95%
HELMRICH & PAYNE INC	17,782,602	3.22%	67.17%
PLAINS PETROLEUM CO	13,723,924	2.48%	69.65%
VASTAR RESOURCES INC	13,555,342	2.45%	72.10%
HUGOTON ENERGY CORP	7,742,657	1.40%	73.50%
UNION PACIFIC RESOURCES	7,159,513	1.30%	74.80%
KANSAS NATURAL GAS CO	6,551,917	1.19%	75.98%
OSBORN HEIRS CO	5,549,226	1.00%	76.99%
TEXACO EXPLORATION	4,654,421	0.84%	77.83%
CROSS TIMBERS OPERATING	4,112,111	0.74%	78.58%
AMERICAN EXPLORATION	3,881,497	0.70%	79.28%
BEREXCO INC	3,382,403	0.61%	79.89%
WOOLSEY PETROLEUM CO	2,849,449	0.52%	80.41%
HORSESHOE OPERATING	2,584,322	0.47%	80.87%
OIL PRODUCERS INC OF KS	2,453,951	0.44%	81.32%
CABOT PETROELUM CORP	2,160,399	0.39%	81.71%

é

OPERATOR_NAME	PRODUCTION	Percentage
BEREXCO INC	1,690,338	4.93%
OXY USA INC	1,468,092	4.28%
VESS OIL CORP	1,117,452	3.26%
NORTH AMERICAN RESOURCES	900,506	2.63%
MURFIN DRILLING CO INC	839,995	2.45%
ANADARKO PETROLEUM	726,949	2.12%
HELMERICK & PAYNE	591,020	1.72%
HUGOTON ENERGY CORP	581,963	1.70%
MCCOY PETROLEUM CORP	549,847	1.60%
AMERICAN WARRIOR INC	479,121	1.40%
RITCHIE EXPLORATION	428,033	1.25%
ABERCROMBIE A L	367,038	1.07%
PICKRELL DRILLING CO	361,349	1.05%
EQUINOX OIL COMPANY	327,927	0.96%
PETROLEUM PROPETY SERV	271,480	0.79%
HALLWOOD PETROLEUM	247,638	0.72%
RANGE OIL COMPAN	232,026	0.68%
THUNDERBIRD DRILLING	230,437	0.67%
CITATION OIL & GAS	203,338	0.59%
AMOCO PRODUCTION CO	186,924	0.55%
MULL DRILLING CO INC	184,944	0.54%
HOLL F G CO	184,083	0.54%
SCHMITT CARMEN INC	182,914	0.53%
FARMER JOHN O INC	178,192	0.52%
RAMA OPERATING CO INC	177,650	0.52%
HANSEN DANE G. TRUST	171,812	0.50%
BEREDCO INC	163,835	0.48%
PALOMINO PETROLEUM	163,020	0.48%
HESS OIL COMPANY	162,172	0.47%
COLT ENERGY INC	160,871	0.47%
DAMAR RESC INCOR	155,065	0.45%
L D DRILLING INC	152,245	0.44%
MUSTANG DRILLING	151,600	0.44%
KAISER-FRANCIS OIL	147,075	0.43%
OIL PRODUCERS INC	145,564	0.42%
CHESAPEAKE OPERATING	143,527	0.42%
SONAT EXPLORATION CO	142,778	0.42%
GORE OIL COMPANY	142,010	0.41%
HARTMAN OIL CO	139,871	0.41%
VINTAGE PETROLEUM INC	139,667	0.41%
GRAHAM-MICHAELIS	139,603	0.41%
VIKING RESOURCES INC	137,699	0.40%
WHITE EAGLE RESOURCE	137,440	0.40%
MAI OIL OPERATIONS	136,806	0.40%
AFG ENERGY INCOR	133,044	0.39%
LOEB HERMAN L	126,532	0.37%
CODA ENERGY INC	124,272	0.36%
STAR RESOURCES	121,878	0.36%
HARRIS OIL & GAS CO	120,238	0.35%
STELBAR OIL CORP	118,825	0.35%
SHIELDS OIL PRODUCER	117,546	0.34%
BEREN CORP	114,202	0.33%
WABASH ENERGY CORP	109,083	0.32%
KAHAN AND ASSOCIATES	108,899	0.32%

1-2

G A O

Accountability * Integrity * Reliability

United States General Accounting Office
Washington, DC 20548

Resources, Community, and
Economic Development Division

B-286311

September 25, 2000

The Honorable Tom Harkin
Ranking Minority Member
Committee on Agriculture,
Nutrition, and Forestry
United States Senate

Subject: Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work

Dear Senator Harkin:

Over the years, the federal government has granted tax incentives, direct subsidies, and other support to the petroleum industry, as well as some tax and other benefits to the ethanol industry, in an effort to enhance U.S. energy supplies. The tax incentives generally decrease revenues accruing to the U.S. Treasury. In earlier reports, we addressed various issues related to these incentives, including their impact on federal revenues and effectiveness in accomplishing their objectives.

You requested that we provide you with information on the tax incentives[1] that benefit the petroleum and ethanol[2] industries. Accordingly, we are providing revenue loss estimates for tax incentives designed to encourage the exploration and production of petroleum and the production of ethanol (see enc. I). In addition to this specific information, we are providing a summary of key findings from our earlier reports on these and related issues (see enc. II). We used the enclosed material to brief your staff on June 30, 2000. A summary of the tax incentive information follows.

---

[1]Tax incentives are federal tax provisions that grant special tax relief designed to encourage certain kinds of behavior by taxpayers or to aid taxpayers in special circumstances. The revenue losses that result from these provisions--called tax expenditures--may, in effect, be viewed as spending channeled through the tax system. The Congressional Budget and Impoundment Control Act of 1974 requires that a list of tax expenditures be included in the budget. The act defines "tax expenditures" as "revenue losses attributable to provisions of Federal tax laws which allow a special exclusion, exemption, or deduction from gross income or which provide a special credit, a preferential rate of tax, or a deferral of tax liability." Each year, estimates of tax expenditure revenue losses are prepared by the Department of the Treasury and by the staff of the Joint Committee on Taxation. According to the Committee, these special income tax provisions are referred to as tax expenditures because they may be considered as analogous to direct outlay programs, and the provisions and programs can be considered as alternative means of accomplishing similar budget policy objectives.

[2]Under the Internal Revenue Code, a tax exemption and/or tax credits are available for any biomass-derived alcohol fuel, including ethanol and methanol. However, alcohol fuel derived from petroleum or natural gas does not qualify for the exemption or the credits.

Senate Utilities Committee
January 30, 2001
Attachment 2-1

Table 1 shows inflation-adjusted summations of estimated revenue losses for petroleum and ethanol fuel tax incentives from 1968 to 2000. We developed these data from unadjusted annual revenue loss estimates made by the Department of the Treasury and the staff of the Joint Committee on Taxation (JCT).[3] Specific petroleum tax incentives range from about $330 million for the expensing of tertiary injectants[4] (1980-2000) to about $82 billion for certain cost depletion deductions (1968-2000). Some of the tax incentives for the petroleum industry have been in place for many decades, but over the past 25 years, these incentives have generally been scaled back.

Table 1: Tax Incentives for Petroleum and Ethanol Fuels: Estimates of Revenue Losses Over Time

Dollars in millions

Tax incentive	Summed over years	Adjusted to year 2000 dollars
Petroleum industry		
Excess of percentage over cost depletion[a]	1968-2000	$81,679-$82,085
Expensing of exploration and development costs[a]	1968-2000	42,855-54,580
Alternative (nonconventional) fuel production credit	1980-2000	8,411-10,542
Oil and gas exception from passive loss limitation	1988-2000	1,065[b]
Credit for enhanced oil recovery costs	1994-2000	482-1,002
Expensing of tertiary injectants	1980-2000	330[c]
Ethanol industry		
Partial exemption from the excise tax for alcohol fuels	1979-2000	7,523-11,183
Income tax credits for alcohol fuels	1980-2000	198-478

Note: When two figures are provided for an incentive, they represent the estimates developed from Treasury's and JCT's data. The lower figure is presented first, regardless of which agency's data it is based on. Some of the estimated revenue losses for the tax incentives have a considerable range because of, among other things, (1) differences between Treasury's and JCT's estimates of individual and corporate gross income, deductions and expenditures, and (2) differences in the lower bound for the annual revenue loss estimates they present. See enclosure I for details.

[a]In some years, revenue losses associated with other fuels and nonfuel minerals were included with revenue losses from oil and gas. See enclosure I for details.

[b]There is no JCT revenue estimate because only Treasury recognizes this tax code provision as a separate tax incentive. See enclosure I for details.

[c]There is no Treasury revenue estimate because only JCT recognizes this tax code provision as a separate tax incentive. See enclosure I for details.

Source: GAO's compilations based on annual estimates of tax expenditures published by Treasury and JCT.

Ethanol fuel tax incentives ranged from $198 million for alcohol fuel tax credits (1980-2000) to about $11 billion for the excise tax exemption for alcohol fuels (1979-2000). These tax incentives were instituted in 1979-80. In the past decade, these incentives have been extended, but the rates of exemption and credit have been reduced somewhat.

---

[3]For each tax incentive, the years over which we report annual revenue loss estimates are limited to the years for which both Treasury and JCT made estimates. Thus, the first year is the first period for which revenue loss estimates are available from both Treasury and JCT; it may not be the year when the incentive was first implemented. Estimates include both corporate and individual income tax revenue losses except for the partial exemption from the excise tax for alcohol fuels, which represents revenue losses from the federal excise tax on gasoline.

[4]Tertiary injectants are fluids, gases, and other chemicals that are pumped into oil and gas reservoirs to extract reserves that cannot be extracted by conventional primary or secondary recovery techniques.

2-2

The estimated revenue losses for these tax incentives should not be added together. The estimate for each tax incentive is made independently of any other tax incentive, and the effect of making more than one change might be greater than or less than the sum of the changes. Enclosure I contains more detailed information on these estimates of revenue losses from the petroleum and ethanol tax incentives (see tables 2-9), as well as descriptions of the incentives and summaries of their legislative histories.

Scope and Methodology

To prepare the information for this report, we compiled Treasury's and JCT's yearly revenue loss estimates for tax incentives received by the petroleum and ethanol industries. Treasury's estimates are from annual editions of the *Budget of the United States Government*, Analytical Perspectives volume, Tax Expenditures section. JCT's estimates are from annual editions of the *Estimates of Federal Tax Expenditures*. To put the dollar amounts for different years on a comparable basis, we adjusted these estimates for inflation, using a fiscal year gross domestic product (GDP) deflator.[5] Descriptions of the tax incentives and their legislative histories are from JCT's *Present-Law Tax Rules Relating to Domestic Oil and Gas Exploration and Production and Description of H.R. 53 and H.R. 423* (JCX-8-99, Feb. 23, 1999) and the Senate Committee on the Budget's *Tax Expenditures: Compendium of Background Material on Individual Provisions* (Dec. 1996). Additionally, we reviewed and summarized previous GAO studies related to petroleum and ethanol tax incentives and other subsidy programs. We conducted our work from July through September 2000 in accordance with generally accepted government auditing standards.

- - - - -

Unless you publicly announce its contents earlier, we plan no further distribution of this report until 14 days after the date of this letter. At that time, we will send copies to interested Members of Congress and make copies available to others on request.

If you have any questions about this report or need additional information, please call Daniel Haas or Godwin Agbara at (202) 512-3841.

Sincerely yours,

Jim Wells

Jim Wells
Director, Energy, Resources,
and Science Issues

Enclosures - 2

[5]The deflator was obtained from the *Budget of the United States Government, Fiscal Year 2001*, Historical Tables volume, table 10.1.

2-3

Tax Incentives for Petroleum and Ethanol Fuels: Descriptions, Legislative Histories, and Revenue Loss Estimates

Activities associated with exploring for and producing petroleum--crude oil and natural gas--within the United States receive several types of favorable tax treatment. The production of alcohol fuels, such as ethanol, also receives favorable tax treatment. Tax incentives for petroleum and ethanol take the form of special exemptions, deductions, credits, and deferrals of tax. Tax incentives result in revenue losses to the federal government. As a result, they may be viewed as spending programs channeled through the tax system.

Enclosure I contains yearly estimates of revenue losses for the petroleum and ethanol tax incentives, both unadjusted and adjusted for inflation (see tables 2-9). Also included are a description and a summary of the legislative history of each tax incentive associated with the petroleum and ethanol industries.

We use both Treasury's and JCT's estimates because they differ in some respects. For example, Treasury and JCT use slightly different classifications of tax code incentives for petroleum. In addition, their revenue loss estimates depend on their respective estimates and/or projections of taxpayers' gross income, deductions, and spending patterns.[1] Also, Treasury and JCT differ in the way they present their annual revenue loss estimates. Treasury reports its estimates in millions of dollars. In contrast, after 1985, JCT reports its estimates in billions of dollars (rounded to one decimal point) and does not report an estimate in years when the estimate is less than $50 million (in current year dollars). For Treasury, our sources are annual editions of the *Budget of the United States Government.* For JCT, our sources are the Committee staff's annual *Estimates of Federal Tax Expenditures.*[2]

We provide both unadjusted and inflation-adjusted annual revenue loss estimates for those who may find it helpful to see the magnitudes of the amounts involved each year. The unadjusted estimates we used are those most recently published by Treasury or JCT for each year.[3] We adjusted these estimates for inflation in order to put the estimates for earlier years on a comparable basis with the estimates for later years. This allowed us to sum the estimates over time. We do not provide summations over time of dollar figures that have not been adjusted for inflation because we do not consider it appropriate to sum dollar figures over a long period of time if they have not been adjusted for inflation. We adjusted these estimates for inflation using a fiscal year gross domestic product (GDP) deflator, which we obtained from the *Budget of the United States Government, Fiscal Year 2001,* Historical Tables volume, Table 10.1.

We do not add revenue losses from different tax incentives because it is not appropriate to do so. The estimate for each tax incentive is made separately, assuming that all other tax incentives

---

[1]JCT's tax expenditure revenue loss estimates are always forecasts. JCT does not later re-estimate tax expenditure revenue losses on the basis of the actual economic conditions prevailing at the time. Thus, the JCT estimates we used were based on projected, rather than actual, economic conditions.

[2]For each tax incentive, the years over which we report annual revenue loss estimates are generally limited to the years for which both Treasury and JCT have made estimates. Estimates are for both corporate and individual income tax revenue losses except in table 8, which contains revenue losses from the federal excise tax on gasoline.

[3]We report annual estimates when available. However, when JCT does not provide an annual revenue loss figure because it estimates a tax incentive's revenue loss to be below $50 million in that year, if they provide a 5-year revenue loss estimate, we calculate and report the average annual loss.

remain in the tax code. If two or more incentives were estimated simultaneously, the total change in tax liability might have a lesser or a greater effect on revenue than the sum of the amounts shown for each item separately. Neither Treasury nor JCT considers it appropriate to add revenue loss estimates for different tax incentives.

We note that a revenue loss estimate for a tax incentive--or tax expenditure--is not equivalent to a revenue estimate for the repeal of that tax expenditure because the two may be confused. A revenue loss estimate for a tax expenditure is measured by the difference between the tax liability under present law and the tax liability that would result from a recomputation of tax assuming that particular tax expenditure did not exist. For the purpose of estimating a tax expenditure, taxpayer behavior is assumed to remain unchanged. For example, Treasury's and JCT's tax expenditure estimates do not account for any effects that changes to that tax expenditure might have on investment patterns, consumption, or other aspects of economic activity. Because tax expenditure estimates do not account for such effects, they do not measure the amount by which government revenue would change if the tax expenditure were changed. When Treasury or JCT's staff do make a revenue estimate for the repeal of a tax expenditure, they incorporate the effects of the behavioral changes that are anticipated to occur in response to the repeal of that tax provision.

Excess of Percentage Over Cost Depletion, for Oil and Gas

Independent oil and gas producers and royalty owners are generally allowed to take percentage depletion deductions rather than cost depletion deductions on limited quantities of domestic output.

Description

Depletion, like depreciation, is a form of cost recovery for capital investments. Capital investment includes the costs of discovering, purchasing, and developing an oil or a gas reserve. In both cases, a taxpayer is allowed a deduction because an asset is being expended to produce income. In the case of depletion for oil and gas, the oil or gas reserve itself is being expended in order to produce income.

Two methods of depletion are currently allowable under the Internal Revenue Code (IRC)--cost depletion and percentage depletion. Under cost depletion, the taxpayer recovers the actual capital investment over the period during which the reserve produces income. Each year, the taxpayer deducts a portion of the original capital investment, less previous deductions, that is equal to the fraction of the estimated remaining recoverable reserves that have been extracted and sold that year. The overall amount recovered under cost depletion can never exceed the taxpayer's original capital investment.

Under percentage depletion, the deduction for the recovery of the capital investment is a fixed percentage of the gross income--sales revenue--from the sale of the oil or gas. Because percentage depletion, unlike cost depletion, is computed without regard to the taxpayer's actual capital investment in the depletable property, cumulative depletion deductions may be greater than the amount spent by the taxpayer to acquire or develop the property. Currently, under percentage depletion, 15 percent of the gross income from certain oil- or gas-producing property is allowed as a deduction in each taxable year.[4] Information on percentage depletion for oil and gas properties can be found in IRC sections 611, 612, 613, and 613A.

[4]Currently, only independent oil and gas producers and royalty owners--those producing less than 50,000 barrels per day--are allowed to take percentage depletion and only on up to 1,000 barrels of oil output, or its equivalent in gas, per day. The amount deducted

2-5

Legislative History

As part of the Tariff Act of 1913, a "reasonable allowance for depletion," not to exceed 5 percent of the value of output, was permitted as a tax deduction for oil and gas and other minerals. Treasury regulation number 33 limited total deductions to the amount of the original capital investment. Between 1918 and 1926, depletion was allowed, based on the market value of the deposit after discovery, which could exceed the value of the original capital investment. The Revenue Act of 1926 replaced discovery-value depletion with percentage depletion limited to 27.5 percent of the gross income from an oil- or a gas-producing property.

Beginning with the Tax Reform Act of 1969, several changes to the tax code have reduced the ability of oil and gas producers to use percentage depletion. In 1969, the top depletion rates were reduced to 22 percent. The 1969 act also made percentage depletion subject to a minimum tax starting in 1970.[5]

The Tax Reduction Act of 1975 repealed the deduction for percentage depletion with respect to much oil and gas production and reduced the rate of depletion on the remaining eligible production. Following the 1975 act, major integrated oil producers[6] were no longer allowed to claim the percentage depletion allowance. And, starting in 1984, independent producers and royalty owners were allowed to claim percentage depletion on only 15 percent of gross income from the sale of oil or gas. The Tax Reform Act of 1986 denied percentage depletion for lease bonuses, advance royalties, or other payments unrelated to actual oil and gas production.

The Omnibus Budget Reconciliation Act of 1990 increased the statutory percentage depletion rate for oil and gas production from marginal properties--that is, "stripper well" properties or properties producing mostly "heavy oil"--held by independent producers or royalty owners. The 1990 act also raised the limit on the amount deducted from 50 percent to 100 percent of the net income from the property in any year and made percentage depletion available to transferred properties. The Energy Policy Act of 1992 repealed the alternative minimum tax (AMT) on percentage depletion for oil and gas.

Revenue Losses

Table 2 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation. Between 1968 and 1980, revenue losses associated with other fuels and nonfuel minerals were included with revenue losses for oil and gas. After 1980, revenue losses included only those for oil and gas.

---

generally may not exceed 100 percent of the net income from that property in any year. Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income in any year.

[5]In 1969, the Congress enacted an add-on minimum tax that served as the predecessor to the current alternative minimum tax (AMT). The minimum tax was amended a number of times, including in 1976, 1978, 1982, 1986, 1990, and 1993. Through these amendments, the minimum tax was changed from essentially a surcharge on certain tax preference items (i.e., items excludable from taxable income under the regular income tax but taxable under the minimum tax) to a separate tax system—the AMT. The AMT, in general, parallels the regular income tax system, having its own definitions of income subject to tax and its own tax rates. The AMT, like its predecessor the minimum tax, in effect limits the use of certain tax incentives available under the regular income tax.

[6]An integrated oil producer is generally a producer that is not an independent producer.

Legislative History

As part of the Tariff Act of 1913, a "reasonable allowance for depletion," not to exceed 5 percent of the value of output, was permitted as a tax deduction for oil and gas and other minerals. Treasury regulation number 33 limited total deductions to the amount of the original capital investment. Between 1918 and 1926, depletion was allowed, based on the market value of the deposit after discovery, which could exceed the value of the original capital investment. The Revenue Act of 1926 replaced discovery-value depletion with percentage depletion limited to 27.5 percent of the gross income from an oil- or a gas-producing property.

Beginning with the Tax Reform Act of 1969, several changes to the tax code have reduced the ability of oil and gas producers to use percentage depletion. In 1969, the top depletion rates were reduced to 22 percent. The 1969 act also made percentage depletion subject to a minimum tax starting in 1970.[5]

The Tax Reduction Act of 1975 repealed the deduction for percentage depletion with respect to much oil and gas production and reduced the rate of depletion on the remaining eligible production. Following the 1975 act, major integrated oil producers[6] were no longer allowed to claim the percentage depletion allowance. And, starting in 1984, independent producers and royalty owners were allowed to claim percentage depletion on only 15 percent of gross income from the sale of oil or gas. The Tax Reform Act of 1986 denied percentage depletion for lease bonuses, advance royalties, or other payments unrelated to actual oil and gas production.

The Omnibus Budget Reconciliation Act of 1990 increased the statutory percentage depletion rate for oil and gas production from marginal properties--that is, "stripper well" properties or properties producing mostly "heavy oil"--held by independent producers or royalty owners. The 1990 act also raised the limit on the amount deducted from 50 percent to 100 percent of the net income from the property in any year and made percentage depletion available to transferred properties. The Energy Policy Act of 1992 repealed the alternative minimum tax (AMT) on percentage depletion for oil and gas.

Revenue Losses

Table 2 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation. Between 1968 and 1980, revenue losses associated with other fuels and nonfuel minerals were included with revenue losses for oil and gas. After 1980, revenue losses included only those for oil and gas.

---

generally may not exceed 100 percent of the net income from that property in any year. Additionally, the percentage depletion deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income in any year.

[5]In 1969, the Congress enacted an add-on minimum tax that served as the predecessor to the current alternative minimum tax (AMT). The minimum tax was amended a number of times, including in 1976, 1978, 1982, 1986, 1990, and 1993. Through these amendments, the minimum tax was changed from essentially a surcharge on certain tax preference items (i.e., items excludable from taxable income under the regular income tax but taxable under the minimum tax) to a separate tax system—the AMT. The AMT, in general, parallels the regular income tax system, having its own definitions of income subject to tax and its own tax rates. The AMT, like its predecessor the minimum tax, in effect limits the use of certain tax incentives available under the regular income tax.

[6]An integrated oil producer is generally a producer that is not an independent producer.

2-7

Table 2: Revenue Loss Estimates for the Excess of Percentage Over Cost Depletion, Oil and Gas

Dollars in millions

	JCT		Treasury	
Fiscal year	Not adjusted for inflation	Adjusted to 2000 dollars[a]	Not adjusted for inflation	Adjusted to 2000 dollars[a]
1968	$1,300	$5,279	$1,300	$5,279
1969	1,430	5,559	1,430	5,559
1970	1,470	5,424	1,470	5,424
1971	980	3,438	980	3,438
1972	985	3,296	985	3,296
1973	1,700	5,439	1,700	5,439
1974	2,120	6,333	2,120	6,333
1975	2,475	6,724	2,475	6,724
1976	1,580	4,004	1,295	3,282
1977	1,310	3,079	1,395	3,279
1978	1,460	3,214	1,500	3,302
1979	1,625	3,318	1,830	3,737
1980	2,130	4,005	1,490	2,802
1981	2,125	3,645	1,865	3,199
1982	1,970	3,163	2,100	3,372
1983	1,800	2,766	1,280	1,967
1984	1,215	1,800	1,175	1,740
1985	1,140	1,635	1,355	1,944
1986	1,300	1,822	1,105	1,548
1987	700	956	725	990
1988	500	661	450	595
1989	400	509	390	497
1990	300	368	650	797
1991	400	473	555	656
1992	500	578	885	1,023
1993	100	113	995	1,122
1994	600	661	785	865
1995	600	648	945	1,020
1996	400	424	1,125	1,191
1997	600	625	830	864
1998	500	514	250	257
1999	500	507	265	269
2000	700	700	275	275
Total	[b]	**$81,679**	[b]	**$82,085**

[a]Data were adjusted for inflation by GAO.

[b]Not applicable. GAO does not consider it appropriate to sum dollar figures that are unadjusted for inflation over several years.

Expensing of Exploration and Development Costs, for Oil and Gas

Independent oil and gas producers are generally allowed to expense--deduct from gross income in the period incurred, rather than over the productive life of a property--intangible drilling and development costs, associated with successful investments in domestic oil and gas wells. Integrated companies can expense 70 percent of such costs and must deduct the remaining 30 percent over 5 years.

Description

In general, costs that benefit future periods must be capitalized and recovered over those periods for income tax purposes, rather than being expensed in the period they are incurred. However,

2-8

special rules have been provided for the treatment of certain intangible drilling costs and other intangible exploration and development costs, commonly referred to as "IDCs." IDCs include all spending by an operator or contractor for labor, fuel, repairs, hauling, supplies, and other items incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas.[7] Under the special rules for intangible costs, an operator or owner of a working interest that pays or incurs IDCs may elect to expense rather than capitalize those costs for property located in the United States, including certain wells drilled offshore.[8]

The excess of expensed IDCs over their capitalized value is a tax preference item that is subject to the AMT, to the extent that it exceeds 65 percent of the net income from the property. Independent producers are required to include only 70 percent of their IDCs as a tax preference item. Information on the expensing of exploration and development costs for oil and gas properties can be found in IRC sections 263(c), 291, 616-617, 57(2), and 1254.

Legislative History

Expensing for IDCs was originally established in a 1916 Treasury regulation, number 45, article 223, which stated that such costs were ordinary operating expenses. Expensing for IDCs was subsequently codified in the IRC of 1954.

The Tax Reform Act of 1976 made expensing for IDCs subject to the minimum tax. Under the 1976 act, the difference between the amount of a taxpayer's IDC deductions and the amount that would have been currently deductible had IDCs been capitalized and recovered over a 10-year period became subject to minimum taxation provisions.

The Tax Equity and Fiscal Responsibility Act of 1982 limited the expensing of IDCs for integrated oil companies to 85 percent of IDCs and required the remaining 15 percent to be deducted over 3 years. The Deficit Reduction Act of 1984 further limited such expensing for integrated companies to 80 percent. The Tax Reform Act of 1986 repealed the expensing of IDCs for foreign properties and further limited such expensing for integrated companies to 70 percent. The Energy Policy Act of 1992 repealed AMT coverage of IDCs for taxpayers other than integrated companies and limited AMT coverage for integrated companies to 70 percent of IDCs.

Revenue Losses

Table 3 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation. Estimates are negative numbers in some years.[9] Between 1968 and 1980,

---

[7]Amounts paid for items that have a salvage value, such as pipe, casings, valves and other tangible equipment, or for equipment used on foreign properties cannot be expensed but must be recovered over time through depletion or depreciation.

[8]If IDCs are not expensed but are capitalized, they may be recovered through depletion or depreciation as appropriate. For a nonproductive well or "dry hole," IDCs may be deducted.

[9]Allowing petroleum exploration and development costs to be expensed in the period they are incurred rather than requiring that they be capitalized and depreciated over time constitutes a deferral of taxes. The methodology used by Treasury and JCT for estimating the annual values of tax provisions that are deferrals of taxes may not accurately reflect the true economic costs of those provisions. Treasury and JCT use the same method for estimating the annual value of a tax provision that is a deferral of taxes. They report the difference between the total amount of taxes deferred through that provision in the current year, aggregated across taxpayers, and the total amount of incoming revenues that are received due to the deferrals in prior years through that provision, aggregated across taxpayers. Although such an estimate is useful as an estimate of the cash flow into the government for that tax provision, it does not accurately reflect the true economic cost of that provision. A feature of tax deferrals, is that they can cause the tax expenditure to be negatively valued in some years. For, example, for a provision where activity levels have declined, so that incoming tax receipts from past deferrals are greater than deferred receipts from new activity, the cash-basis tax expenditure estimate will be negative. A negative tax expenditure implies an increase in government revenues in that year. However, in present-value terms, current deferrals do have a real, positive cost to the government. For Treasury's discussion of this issue, see the *Budget of the United States*

2-9

revenue losses associated with other fuels and nonfuel minerals were included with the revenue losses for oil and gas. After 1980, revenue losses included only those for oil and gas.

Table 3: Revenue Loss Estimates for the Expensing of Exploration and Development Costs, Oil and Gas

Dollars in millions

	JCT		Treasury	
Fiscal year	**Not adjusted for inflation**	**Adjusted to 2000 dollars[a]**	**Not adjusted for inflation**	**Adjusted to 2000 dollars[a]**
1968	$300	$1,218	$300	$1,218
1969	330	1,283	330	1,283
1970	340	1,255	340	1,255
1971	325	1,140	325	1,140
1972	325	1,087	325	1,087
1973	650	2,080	650	2,080
1974	830	2,479	830	2,479
1975	620	1,684	620	1,684
1976	805	2,040	800	2,027
1977	715	1,681	1,030	2,421
1978	1,185	2,608	1,390	3,060
1979	1,490	3,043	1,745	3,563
1980	2,190	4,118	2,175	4,090
1981	2,735	4,691	3,525	6,046
1982	4,070	6,534	3,430	5,507
1983	1,535	2,359	3,160	4,856
1984	1,810	2,681	1,415	2,096
1985	2,210	3,170	585	839
1986	2,300	3,223	-510	-715
1987	2,700	3,686	-675	-921
1988	-600	-793	-385	-509
1989	-300	-382	-65	-83
1990	100	123	-500	-613
1991	200	237	-315	-373
1992	600	694	125	145
1993	200	226	185	209
1994	500	551	-85	-94
1995	500	540	-300	-324
1996	100	106	-210	-222
1997	200	208	-160	-167
1998	200	206	-110	-113
1999	400	406	-80	-81
2000	400	400	-15	-15
Total	[b]	**$54,580**	[b]	**$42,855**

[a]Data were adjusted for inflation by GAO.

[b]Not applicable.

Alternative (Nonconventional) Fuel Production Credit

A nontaxable credit is provided for the production of several forms of alternative fuels.

Government, Fiscal Year 2001, Analytical Perspectives volume, page 108, section on "Interpreting Tax Expenditure Revenue Estimates." For JCT's discussion of this issue, see JCT's *Estimates of Federal Tax Expenditures for Fiscal Years 2000-2004*, pages 11-12, section on "Tax Expenditure Estimates Generally."

2-10

Description

Taxpayers that produce certain qualifying fuels from nonconventional sources, including some types of oil and gas, are eligible for a tax credit equal to $3 per barrel or Btu oil barrel equivalent.[10] The credit is generally available if the price of oil stays below $29.50 per barrel, adjusted to 1979 dollars. The credit generally expires on December 31, 2002.

For purposes of the credit, qualified fuels include (1) oil produced from shale and tar sands; (2) gas produced from geopressured brine, Devonian shale, coal seams, a tight formation, or biomass;[11] and (3) various synthetic fuels produced from coal. Fuels qualifying for the credit must be produced domestically from a well drilled or a facility placed in service before January 1, 1993. The tax credit generally is available for qualified fuels sold to unrelated persons before January 1, 2003. The amount of the credit generally is multiplied by an inflation adjustment factor for the calendar year in which the sale occurs.

The credit is offset by benefits from government grants, subsidized or tax-exempt financing, energy investment credits, and the enhanced oil recovery credit. The credit is nonrefundable and may not be used to offset AMT liability. Information on the tax credit for producing alternative fuels can be found in IRC section 29.

Legislative History

The alternative fuel production credit was adopted as part of the Crude Oil Windfall Profit Tax Act of 1980, with an original placed-in-service deadline of 1989.

Revenue Losses

Table 4 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation.

---

[10]A BTU oil barrel equivalent is that amount of a qualifying fuel that has a British thermal unit content of 5.8 million.

[11]Biomass is any organic material other than oil, natural gas, or coal, or any product thereof.

Table 4: Revenue Loss Estimates for the Alternative (Nonconventional) Fuel Production Credit

Dollars in millions

	JCT		Treasury	
Fiscal year	Not adjusted for inflation	Adjusted to 2000 dollars[a]	Not adjusted for inflation	Adjusted to 2000 dollars[a]
1980	$4	$8	$5	$9
1981	25	43	25	43
1982	95	153	15	24
1983	5	8	10	15
1984	10	15	10	15
1985	25	36	10	14
1986	20	28	20	28
1987	20	27	10	14
1988	20	26	10	13
1989	20	25	10	13
1990	20	25	10	12
1991	20	24	255	302
1992	400	462	680	786
1993	800	902	760	857
1994	1,000	1,102	900	992
1995	1,100	1,187	970	1,047
1996	1,000	1,059	570	604
1997	1,300	1,354	710	739
1998	1,400	1,439	860	884
1999	1,300	1,319	1,025	1,040
2000	1,300	1,300	960	960
Total	[b]	**$10,542**	[b]	**$8,411**

[a]Data were adjusted for inflation by GAO.

[b]Not applicable.

Oil and Gas Exception From Passive Loss Limitation

Owners of working interests in oil and gas properties are exempt from the passive income limitations.

Description

A taxpayer's deductions from passive trade or business activities, to the extent they exceed income from all such passive activities of the taxpayer (not including portfolio income), generally may not be deducted against other, nonpassive income. Thus, for example, an individual taxpayer generally may not deduct losses from a passive activity against income from wages.[12]

An activity generally is treated as passive if the taxpayer does not materially participate in it. A taxpayer is treated as materially participating in an activity only if the taxpayer is involved in the operations of the activity on a regular, continuous, and substantial basis. However, a working interest in an oil or a gas property generally is not treated as a passive activity, whether or not the taxpayer materially participates in the activities related to that property. Moreover, the

[12]Losses suspended under this passive activity loss limitation may be carried forward and treated as deductions from passive activities in the following year and thus may offset any income from passive activities generated in that later year. Suspended losses from a passive activity generally may be deducted in full when a taxpayer disposes of his or her entire interest in that activity.

passive activity rules—and, consequently, the oil and gas working interest exception to those rules—apply to the utilization of tax credits such as the nonconventional fuels production credit and the enhanced oil recovery credit. Information on exceptions to the passive activity rules for working interests in oil or gas properties can be found in IRC section 469.

Legislative History

The rules on passive activity losses and the exception to these rules for working interests in oil and gas properties were included in the Tax Reform Act of 1986.

Revenue Losses

Table 5 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation. Revenue loss estimates are available only from Treasury because JCT does not view exceptions to passive loss activity rules as a separate tax incentive. The passive loss activity rules have the effect of reducing the magnitude of the tax incentives to which they apply. Exceptions to the passive loss rules have the effect of restoring the magnitude of the tax incentives to which they apply. JCT incorporates revenue losses for exceptions to passive loss rules into its estimates of revenue losses for other tax incentives.

Table 5: Revenue Loss Estimates for the Oil and Gas Exception From Passive Loss Limitation

Dollars in millions

	Treasury	
Fiscal year	**Not adjusted for inflation**	**Adjusted to 2000 dollars[a]**
1988	$55	$73
1989	135	172
1990	180	221
1991	80	95
1992	90	104
1993	50	56
1994	90	99
1995	55	59
1996	50	53
1997	45	47
1998	30	31
1999	30	30
2000	25	25
Total	[b]	**$1,065**

[a]Data were adjusted for inflation by GAO.

[b]Not applicable.

Credit for Enhanced Oil Recovery Costs

A credit is provided for qualified tertiary oil recovery costs incurred in the production of oil and gas on U.S. projects.

Description

Taxpayers are permitted to claim a general business credit for a taxable year, one component of which is the enhanced oil recovery (EOR) credit. The credit is equal to 15 percent of certain costs attributable to EOR projects undertaken by a taxpayer in the United States during a taxable

2-13

year. Qualifying costs include tertiary injectant expenses, intangible drilling and development costs on a qualified EOR project, and amounts incurred for tangible depreciable property. To the extent that the EOR credit is allowed for such costs, the taxpayer must reduce the amount otherwise deductible or required to be capitalized and recovered through depreciation, depletion, or amortization, with respect to these costs. As part of the general business credit, this credit may not be used to offset AMT liability.[13]

The amount of the EOR credit is reduced in a taxable year following a calendar year during which the annual average price per barrel for domestic crude oil from an unregulated wellhead exceeds a $28 threshold (adjusted for inflation). If the average unregulated wellhead price exceeds the threshold amount, the credit will be reduced ratably over a $6 phaseout range. The EOR credit is effective for taxable years beginning after December 31, 1990, with respect to costs paid or incurred in EOR projects begun or significantly expanded after that date. Information on the tax credit for enhanced oil recovery costs can be found in IRC section 43.

Legislative History

The enhanced oil recovery costs tax credit was enacted by the Omnibus Budget and Reconciliation Act of 1990.

Revenue Losses

Table 6 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation.

Table 6: Revenue Loss Estimates for the Credit for Enhanced Oil Recovery Costs

Dollars in millions

	JCT		Treasury	
Fiscal year	Not adjusted for inflation	Adjusted to 2000 dollars[a]	Not adjusted for inflation	Adjusted to 2000 dollars[a]
1994	$60	$66	$85	$94
1995	80	86	85	92
1996	60	64	80	85
1997	80	83	95	99
1998	60	62	140	144
1999	60	61	225	228
2000	60	60	260	260
Total	[b]	**$482**	[b]	**$1,002**

[a]Data were adjusted for inflation by GAO.

[b]Not applicable.

Expensing of Tertiary Injectants

A deduction is provided for qualified spending incurred for certain tertiary injectants used in the production of oil and gas in the tax year in which such substances are injected.

[13]The general business credit is limited under the AMT. The general business credit for a taxable year may not exceed the excess (if any) of the taxpayer's net income over the greater of (1) the tentative minimum tax or (2) 25 percent of so much of the taxpayer's net regular tax liability as exceeds $25,000. Any unused general business credit generally may be carried back 3 taxable years and carried forward 15 taxable years.

Description

Tertiary oil and gas recovery projects inject fluids, gases, and other chemicals into the oil and gas reservoir to extract oil too viscous to be extracted by conventional primary and secondary waterflooding techniques. Nine tertiary recovery methods qualify for expensing—that is, deducting costs when incurred. Expenditures for qualified tertiary injectants also qualify for the 15-percent EOR credit, although the credit must be subtracted from the deduction if both are claimed for the same expenditure.

The tax incentive for tertiary injectant spending is a tax deferral. As with certain exploration and development expenditures, the tax law allows certain tertiary injectant spending to be expensed rather than capitalized and deducted over the income-producing life of the oil or gas property. Information on the tax treatment of costs incurred for tertiary injectants used in producing oil or gas can be found in IRC section 193.

Legislative History

The expensing of tertiary injectants incentive was enacted as part of the Crude Oil Windfall Profit Tax Act of 1980.

Revenue Losses

Table 7 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation. Revenue loss estimates are available only from JCT because Treasury does not consider the expensing of tertiary injectants to be a tax incentive.

2-15

Table 7: Revenue Loss Estimates for the Expensing of Tertiary Injectants

Dollars in millions

	JCT	
Fiscal year	**Not adjusted for inflation**	**Adjusted to 2000 dollars[a]**
1980	$4	$8
1981	14	24
1982	9	14
1983	8	12
1984	7	10
1985	6	9
1986	0[b]	0
1987	0[b]	0
1988	20	26
1989	20	25
1990	20	25
1991	20	24
1992	20	23
1993	20	23
1994	20	22
1995	20	22
1996	20	21
1997	20	21
1998	20	21
1999	0[c]	0
2000	0[c]	0
Total	[d]	**$330**

[a]Data were adjusted for inflation by GAO.

[b]Estimated revenue loss of less than $10 million.

[c]Estimated revenue loss of less than $50 million over this year plus the following 4 years.

[d]Not applicable.

Partial Exemption From the Excise Tax for Alcohol Fuels

A partial exemption from the federal excise tax on motor fuels is provided for alcohol fuels, including ethanol, that are derived from biomass materials and used as fuel.

Description

The partial exemption from the federal excise tax on gasoline, diesel fuel, and other motor fuels applies to biomass alcohol—ethanol and methanol derived from renewable resources. Alcohol derived from petroleum, natural gas, or coal does not qualify for the exemption. The size of the partial exemption depends on how much and what type of alcohol is contained in each gallon of fuel. Most of the fuel mixtures that have received excise tax exemptions have been mixtures of gasoline and ethanol.[14]

Currently, motor fuels consisting of at least 10 percent biomass-derived ethanol are exempt from 5.4 cents of the 18.4-cents-per-gallon federal excise tax. The exemption is also available at lower

[14]In 1995, for example, virtually all of the federal excise tax exemptions for alcohol fuels claimed were for fuel mixtures of gasoline and ethanol.

2-16

rates per gallon of fuel for blends that are at least 7.7 percent or 5.7 percent ethanol. For all of these fuel blends, the exemptions provide a subsidy of 54 cents per gallon of ethanol used.[15]

In addition to the partial excise tax exemption, there are 3 income tax credits available for motor fuels containing biomass alcohol. In lieu of the excise tax exemption, an equivalent federal blender's income tax credit is available to fuel distributors that blend ethanol with gasoline. Also available are a credit for pure alcohol fuels, which is typically available to retailers, and a small ethanol producer's credit.[16] However, the partial excise tax exemption has been much more important than the income tax credits in terms of the amount of tax benefits claimed.[17] Information on the excise tax exemption for ethanol fuels can be found in IRC sections 4041 and 4081.

Legislative History

The partial exemption for ethanol fuel from federal fuel excise taxes was first enacted as part of the Energy Tax Act of 1978 and first became effective in 1979. It established a 4-cents-per-gallon exemption from excise taxes for motor fuels that contained at least 10 percent biomass-derived alcohol. During the 1980s, the rate of exemption was raised to 6 cents per gallon of fuel. Later, the Omnibus Budget Reconciliation Act of 1990 reduced the rate of exemption to 5.4 cents per gallon.

The exemption for ethanol fuel was extended to fuel blends containing smaller amounts of ethanol in the Energy Policy Act of 1992. The 1998 Transportation Equity Act for the 21st Century extended the exemption through September 30, 2007. The act also reduced the rate of exemption from 5.4 cents per gallon of gasoline to 5.3 cents for the years 2001 and 2002, 5.2 cents for the years 2003 and 2004, and 5.1 cents for the years 2005 through 2007.

Revenue Losses

Table 8 contains estimates of annual revenue losses for this tax incentive, both unadjusted and adjusted for inflation. Revenue loss estimates for the income tax credits for alcohol fuels are presented in table 9.

Reasons for the difference in Treasury's and JCT's estimates of revenue losses for this tax incentive include possible differences in their respective estimates of taxpayers' incomes, deductions, and spending, as discussed above. Another source of difference is that Treasury and JCT use different methodologies for projecting revenue losses from excise tax incentives. For this tax incentive, Treasury estimates the reduction in excise tax revenues due to the partial exemption of alcohol fuels from the motor fuels excise tax. In contrast, JCT estimates the reduction in total federal revenues due to the excise tax exemption, net of income tax effects. JCT's adjustment for income tax effects reduces the magnitude of its estimates, relative to Treasury's.[18]

---

[15]Straight, or neat, alcohol fuels—mixtures that contain a minimum of 85 percent alcohol—also qualify for the excise tax exemption.

[16]Revenue loss estimates for these income tax credits for alcohol fuels are found in table 9.

[17]See *Tax Policy: Effects of the Alcohol Fuels Tax Incentives* (GAO/GGD-97-41, Mar. 6, 1997), p. 2.

[18]For further explanation, see *Tax Policy: Effects of the Alcohol Fuels Tax Incentives* (GAO/GGD-97-41, Mar. 6, 1997), pp. 43-44.

The excise tax revenue loss estimates for alcohol fuel blends in our 1997 report are not directly comparable to the estimates in table 8. Our report provides annual estimates of the excise tax revenues forgone because of the partial exemption for alcohol fuels between 1979 and 1995. Our estimates in that report for 1987-95 are based on IRS' quarterly reports of excise tax receipts, by type of fuel. They are not Treasury's or JCT's estimates.

Table 8: Revenue Loss Estimates for the Partial Exemption From the Excise Tax for Alcohol Fuels

Dollars in millions

	JCT		Treasury	
Fiscal year	**Not adjusted for inflation**	**Adjusted to 2000 dollars[a]**	**Not adjusted for inflation**	**Adjusted to 2000 dollars[a]**
1979	[b]		[b]	
1980	[b]		$50	$94
1981	[b]		55	94
1982	$50	$80	55	88
1983	40	61	160	246
1984	145	215	215	318
1985	150	215	375	538
1986	200	280	400	560
1987	200	273	475	648
1988	200	264	480	635
1989	300	382	485	617
1990	400	491	445	546
1991	400	473	465	550
1992	400	462	544	629
1993	400	451	567	639
1994	500	551	575	634
1995	600	648	615	664
1996	600	635	670	710
1997	500	521	675	703
1998	500	514	680	699
1999	500	507	760	771
2000	500	500	800	800
Total	[c]	**$7,523**	[c]	**$11,183**

Note: Estimated revenue losses are included for all years in which JCT or Treasury made estimates.

[a]Data were adjusted for inflation by GAO.

[b]No estimate

[c]Not applicable.

Income Tax Credits for Alcohol Fuels

Income tax credits are provided for alcohol fuels, including ethanol, that are derived from biomass materials and used as fuel.

Description

The income tax credits for alcohol-based motor fuels apply to biomass alcohol—ethanol and methanol derived from renewable resources. Alcohol derived from petroleum, natural gas, or coal does not qualify for the credits. There are three income tax credits for alcohol fuels: the alcohol mixtures credit, the pure alcohol fuel credit, and the small ethanol producer's credit. The alcohol mixtures--or blender's--credit and the pure alcohol fuel credit are 54 cents per gallon of

2-18

ethanol. The alcohol blender's credit is typically available to the fuel blender, and the pure alcohol credits is typically available to the retail fuel seller. The small ethanol producer's credit is 10 cents per gallon of ethanol produced, used, or sold for use as a transportation fuel. This credit is limited to 15 million gallons of annual alcohol production for each small producer, defined as one with a production capacity of under 30 million gallons.

In lieu of the blender's credit, fuel ethanol blenders may claim the 5.4-cents-per-gallon excise tax exemption for blends of ethanol and gasoline. The three income tax credits for alcohol fuels are components of the general business credit, which is limited under the AMT.[19] Information on the income tax credits for alcohol fuels can be found in IRC sections 38, 40, and 87.

Legislative History

Two income tax credits for ethanol fuels--including the alcohol mixtures (or blender's) tax credit and the pure alcohol fuel credit--were enacted as part of the Crude Oil Windfall Profit Tax Act of 1980. The rate of credit was 40 cents per gallon of alcohol that was 190 proof or more and 30 cents for alcohol that was between 150 and 190 proof. The credit was increased during the 1980s. Later, the Omnibus Budget Reconciliation Act of 1990 reduced the rate of credit to 54 cents and 40 cents, respectively. The 1990 act also introduced a small ethanol producer's income tax credit of 10 cents per gallon of alcohol.

The 1998 Transportation Equity Act for the 21st Century extended the ethanol tax credits through December 31, 2007. The act also reduced the rate of credit from 54 cents per gallon of alcohol to 53 cents for the years 2001 and 2002, 52 cents for the years 2003 and 2004, and 51 cents for the years 2005 through 2007.

Revenue Losses

Table 9 contains estimates of annual revenue losses for these tax incentives, both unadjusted and adjusted for inflation. Revenue loss estimates for the excise tax exemption for ethanol are in table 8.

[19]See footnote 13 above.

Table 9: Revenue Loss Estimates for the Income Tax Credits for Alcohol Fuels

Dollars in millions

	JCT		Treasury	
Fiscal year	Not adjusted for inflation	Adjusted to 2000 dollars[a]	Not adjusted for inflation	Adjusted to 2000 dollars[a]
1980	$1	$2	[b]	
1981	2	3	$5	$9
1982	20	32	5	8
1983	5	8	1	2
1984	5	7	2	3
1985	5	7	11	16
1986	13	18	6	8
1987	14	19	6	8
1988	33	44	5	7
1989	10	13	1	1
1990	13	16	1	1
1991	8	9	1	1
1992	100	116	10	12
1993	50	56	15	17
1994	40	44	15	17
1995	40	43	10	11
1996	20	21	10	11
1997	5	5	20	21
1998	5	5	15	15
1999	5	5	15	15
2000	5	5	15	15
Total	[c]	**$478**	[c]	**$198**

Note: Estimated revenue losses are included for all years in which JCT or Treasury made estim ates.

[a]Data were adjusted for inflation by GAO.

[b]No estimate.

[c]Not applicable.

2-20

		would be premature to draw conclusions about the relative potential of reformulated gasoline and other alternative fuels.
Energy Security and Policy: Analysis of the Pricing of Crude Oil and Petroleum Products (GAO/RCED-93-17, Mar. 1993)	During the first week after Iraq invaded Kuwait on August 2, 1990, crude oil prices in the United States rose from about $22 per barrel to $30 per barrel—an increase of about 36 percent. The prices of petroleum products also rose, by between 28 percent and 30 percent. A number of congressional requesters asked GAO to, among other things, • explain the pricing of crude oil and selected petroleum products under normal market conditions and market shocks and • describe the federal government's authorities to respond to disruptions in the supply of oil and the government's use of these authorities during the Persian Gulf crisis.	Since their decontrol in late 1981, U.S. crude oil prices have been linked to world oil prices. The world price of oil is not necessarily related to the cost of its production or acquisition. Rather, it is mostly determined by the Organization of Petroleum Exporting Countries' (OPEC) supply decisions; the relative scarcity of oil; the lack of substantial substitutes for oil in certain uses (transportation), especially in the short term; and seasonal demand. The price of crude oil, seasonal demand, and the extent of local market competition largely determine the prices of refined products. The Energy Policy and Conservation Act (EPCA), which authorized the United States in 1975 to develop and use the Strategic Petroleum Reserve (SPR) and to participate in the International Energy Agency (IEA), is a key federal law addressing oil supply disruptions. The SPR was created to reduce the impact of severe interruptions of petroleum supplies on the U.S. economy. Current U.S. policy relies on the free market during an oil supply disruption to allocate the supply to meet demand at the current price. If necessary, an early and large release of oil from the SPR can be authorized. As of August 1992, the SPR contained 569.5 million barrels and a total of about $20.7 billion had been appropriated for the SPR through fiscal year 1992.
Energy Security: Evaluating U.S. Vulnerability to Oil Supply Disruptions and Options for Mitigating Their Effects (GAO/RCED-97-6, Dec 1996)	Since the early 1970s, the world has experienced three major oil supply disruptions that harmed the U.S. economy. Concerned that the nation's growing dependence on low-cost imported oil, especially from the Persian Gulf, increases the economy's vulnerability to oil supply disruptions and price shocks, the Clinton Administration, through its 1995 National Energy Policy Plan (NEPP), adopted policies and programs intended to reduce that vulnerability and its associated economic costs. At the request of the Chairman, House Committee on the Budget, GAO addressed the following questions: • What are the economic benefits of importing oil compared with the potential economic costs of vulnerability to oil shocks? • To what extent would the U.S. economy's vulnerability to oil shocks be likely to change over time, given the policies and programs contained in the 1995 NEPP and other relevant factors? • What options exist to reduce	GAO estimated that the U.S economy realizes hundreds of billions of dollars in benefits annually by using relatively low-cost imported oil rather than relying on more expensive domestic sources of energy. By comparison, oil shocks impose large but infrequent economic costs that, when annualized, are estimated to cost the U.S. economy tens of billions of dollars per year. More importantly, substituting more costly domestic oil for imported oil without lowering overall oil consumption would be unlikely to substantially lower the costs of oil supply disruptions. In essence, the economic costs of oil price shocks depend largely on the rise in the price of oil coupled with the nation's level of oil consumption, rather than on the level of imports. As long as market forces prevail, the prices of domestic and world oil will be the same and will rise and fall with changes in world oil market conditions. However, this report also pointed out that studies by other researchers have estimated, using different assumptions, that the cost of preserving the stability of oil supplies ranges from a few billion dollars per year to as much as $65 billion per year. While adopting NEPP's initiatives may keep the economy's vulnerability to oil supply disruptions below what it otherwise would be, according to the Department of Energy's (DOE) Energy Information Administration (EIA), by most measures, the economy would not likely be significantly less vulnerable through 2015, primarily because U.S. oil demand is projected to increase. (Among the NEPP's initiatives were programs to increase domestic oil production, as well as promote alternative and renewable fuels and energy efficiency). Only over a longer period do energy analysts anticipate significant improvement—and that depends on technological advances in such areas as energy efficiency and alternative fuels.

	the economy's vulnerability to oil shocks?	While their views varied, almost all of the experts consulted by GAO about options for reducing the economy's vulnerability to oil supply disruptions said that, in the short run, the United States should rely on rapid and large releases of oil from the SPR to blunt price increases at the onset of an oil supply disruption. Monetary policy tools, such as adjusting interest rates and the money supply, were also cited as potentially helpful. In the long run, the experts generally favored research to develop cost-competitive alternatives to petroleum, particularly in the transportation sector, which accounts for most of the nation's oil consumption. While some experts suggested raising taxes on domestic gasoline consumption to increases the price, lower the demand, and make alternatives more cost-competitive, they also recognized the existence of opposing views on this option and the potential for public opposition to it.
Department of Energy: Fossil Energy Programs (GAO/RCED-98-63, Jan 1998)	At the request of the Chairman, House Committee on the Budget, this study, among other things, provided information on • the research and development (R&D) goals and technologies being developed by DOE's Fossil Energy R&D programs and • the level of funding committed to R&D activities within these programs from fiscal year 1996 through fiscal year 1998.[1]	DOE's overall R&D goal for its Fossil Energy R&D programs is to improve the efficiency and environmental performance of current methods for producing and using petroleum and natural gas. The oil technology subprogram addresses exploration and production research; recovery and demonstrations; exploration and production environmental research; and processing research and downstream operations. The natural gas research subprogram addresses exploration and production; delivery and storage; ultilization; turbines; and environmental regulation. Total funding for basic and applied R&D for both the oil and gas programs was $165.64 million for fiscal year 1996, $170.61 million for fiscal year 1997, and $157.09 million for fiscal year 1998.
Ethanol and related studies		
Air Pollution: Air Quality Implications of Alternative Fuels (GAO/RCED-90-143, July 1990)	This study examined the impact of alternative motor fuels on air quality.[2]	The study found that using ethanol as a motor fuel would have some advantages and disadvantages. For example, using ethanol mixed with gasoline (85 percent ethanol and 15 percent gasoline) reduces ozone-forming hydrocarbon and toxic emissions by up to 40 percent. Using ethanol also reduces carbon dioxide emissions. However, ethanol emits more acetaldehyde, would cost consumers substantially more without a federal tax exemption, and would require vehicle modifications estimated to cost $300 per vehicle.
Alcohol Fuels: Impacts From Increased Use of Ethanol-Blended Fuels (GAO/RCED-90-156, July 1990)	Congressional proposals to encourage greater use of alternative motor fuels could increase the demand for ethanol. In view of this, the study examined • the ability of the domestic ethanol industry to expand to meet the increased demand that such legislation could create, • the effects of expanded ethanol production on the	The study found that the ethanol industry would be capable of doubling or tripling domestic ethanol production to 2.2 billion or 3.3 billion gallons per year during the next 8 years and U.S. farmers could supply the corn needed for this production increase. However, industry officials cautioned that continued government incentives and/or a legislative requirement for the use of alternative fuels, such as ethanol, would be needed to maintain such growth. GAO's modeling showed that the expanded use of ethanol fuels would have mixed effects on various sectors of American agriculture. Corn producers would benefit the most because of the increased demand for corn to make ethanol and the resulting

[1] The study also provided information on clean coal technology.

[2] The fuels examined included methanol, ethanol, liquefied petroleum gas, compressed natural gas, oxygenated fuels, and reformulated gasoline. These other alternative fuels had their own advantages and disadvantages, and some had more disadvantages than ethanol.

	agricultural sector and on consumer food prices, and • the effects of increased ethanol production and use on the federal budget.	higher corn prices. However, through a complex system of economic relationships, some other sectors would not fare as well. For example, soybean processors and producers would face lowered demand and prices for their products because the conversion of corn into ethanol generates protein-rich feed and corn oil by-products that compete with soybean meal and soybean oil. Increased corn prices would raise feed costs and hurt cattle producers, but the lower cost of high-protein feeds could benefit poultry producers. Overall, net farm income would increase, and there would be a slight increase in consumer food prices. GAO's modeling also showed that expanded ethanol production would, with some fluctuations, decrease federal farm program outlays because increases in the demand for and price of grains, primarily corn, would cause fewer farmers to participate in these support programs. At the same time, the increased use of ethanol fuels would reduce federal motor fuel tax revenues because of ethanol's partial tax exemption. On average, the reductions in farm program outlays would exceed the increased tax revenue losses over the 8-year period.
Alternative Fuels: Experience of Brazil, Canada, and New Zealand in Using Alternative Motor Fuels (GAO/RCED-92-119, May 1992)	Worldwide, ethanol; liquid propane gas (LPG), also known as propane; and CNG are the most commonly used alternative fuels, with far more ethanol- and LPG-based vehicles than others. This study assessed the experiences of other countries that have used alternative fuels. In particular, it examined the perspectives of • their respective governments, in encouraging the use of alternative fuels and alternative-fuel vehicles; • industry, in developing and marketing them; and • consumers, in using them.	The oil price and supply crises in the 1970s prompted the governments of Brazil, Canada, and New Zealand to look to domestic alternatives for their motor fuels. Their experiences, however, have shown that introducing and sustaining the use of alternative fuels would most likely not be achieved easily or quickly. Each government was the catalyst for action on alternative fuels, and this leadership proved important in helping remove economic and technological barriers and persuading industry and consumers that alternative fuels were important. Government planning and cooperation with industry was also important in developing technologies and marketing these fuels. But consistent, long-term government commitment was somewhat difficult to maintain because of resource constraints and other reasons. Failing to maintain this commitment, in some cases, had a strong negative impact on sustaining the use of alternative fuels. Participation by the fuel, automotive, and utility industries was vital in attracting and retaining consumers for alternative fuels and alternative-fuel vehicles in each country. Alternative-fuel initiatives struggled when industry was not actively involved in developing vehicle technologies, building a fueling infrastructure, and marketing programs. Consumer acceptance was essential to the use of alternative fuels in these countries. A favorable price for the fuel relative to gasoline created a strong incentive for private motorists and fleet operators to use alternative fuels. Regulations, lower taxes on alternative fuels, higher taxes on gasoline, or subsidies were used to create or enlarge a price advantage. Consumer acceptance was also influenced by such factors as vehicle performance and reliability and the availability of convenient fueling. When the price of alternative fuels did not compare favorably with the price of gasoline, or when these other factors made alternative fuels less attractive, their use was adversely affected, according to officials in each country.

2-23

Ethanol Tax Exemption (GAO/RCED-95-273R, Sept. 1995)	This study analyzed the possible effects of eliminating the current tax exemption for ethanol. Specifically, the study estimated • the decline in ethanol use if the tax exemption were eliminated and • the net fiscal effect on the U.S. Treasury and the changes in farm income that would result from a decline in ethanol use.	The study found that it was not possible to calculate with precision the decline in ethanol use that could be expected if the ethanol tax exemption were eliminated. However, GAO's interviews of experts from industry and government indicated that the decline would be at least 50 percent. On the basis of GAO's discussions with these experts, the study further analyzed declines in ethanol use for two Acreage Reduction Program (ARP) scenarios—reductions in use of 50 percent and 90 percent--to represent possible immediate and significant declines. Under both of the ARP scenarios, eliminating the tax exemption results in a net loss to the U.S. Treasury and lower farm income from corn. Using the ARP levels set forth in a baseline developed by the Food and Agriculture Policy Research Institute, GAO estimated that the losses to the Treasury from 1996 through 2000 would be $2.5 billion if ethanol use dropped by 50 percent and $5.4 billion if it dropped by 90 percent. With no ARP for corn, the losses to the Treasury would be $3.2 billion for a 50-percent decline in ethanol use or $6.3 billion for a 90-percent decline. In both scenarios, farm income from corn declined. However, if different assumptions about the ARP were used, the model's results would differ.
Motor Fuels: Issues Related to Reformulated Gasoline, Oxygenated Fuels, and Biofuels (GAO/RCED-96-121, June 1996)	Reformulated gasoline is required for use in those areas of the United States with the most severe ozone air pollution. To meet this requirement, oxygenates, such as MTBE, or ethanol, are added to gasoline to enhance combustion and reduce the vehicle emissions that cause ground-level ozone problems as well as reduce air toxic emissions. Oxygenates are also sometimes added to gasoline to increase octane levels and, according to DOE, can also help reduce the growing U.S. need for petroleum. Biofuels—primarily ethanol developed from corn or biomass (such as fast-growing trees or grasses)—also have the potential to reduce air pollution and the demand for petroleum. Such ethanol can be used as an oxygenate or, in its pure form, as an alternative transportation fuel. This study responded to Senator Daschle's request for GAO to, among other things, summarize • the results of federal and other studies on the cost-effectiveness of using reformulated gasoline compared to other measures to control automotive emissions and compare the price estimates used in the studies for reformulated	Studies by the Environmental Protection Agency (EPA), the American Petroleum Institute (API), and others suggest that reformulated gasoline may be more cost-effective than some automotive emission control measures and less cost-effective than other measures, but the studies varied in approaches and assumptions, making comparisons difficult. Projected versus actual incremental prices for reformulated gasoline varied but were close to the range of the actual prices experienced during the first 14 months of the reformulated gasoline program, which began in January 1995. Estimates varied from a low of 3.3 cents to 4.0 cents per gallon more for phase I reformulated gasoline than for conventional gasoline (cited by DOE) to a high of 8.1 cents to 13.7 cents per gallon more (cited by API). EPA estimated an increase of 3.0 cents to 4.9 cents per gallon. Actual prices, monitored by EIA, showed that reformulated gasoline prices were as much as 12 cents per gallon over conventional gasoline prices during the early weeks of the program but narrowed to about 5 cents per gallon by March 1996. According to estimates based on EIA's projections, oxygenates would potentially displace about 305,000 barrels per day of petroleum used to produce gasoline in 2000, and 311,000 barrels per day in 2010. This displacement would amount to 3.7 percent and 3.6 percent of the estimated gasoline consumption in those years. At the time of this study, DOE and USDA were the primary federal agencies with ongoing research on biofuels. DOE focused primarily on reducing the cost of growing and converting biomass feedstocks, such as trees and grasses, into ethanol. USDA focused primarily on reducing the cost of growing and converting agricultural feedstocks, such as corn, into ethanol. DOE and USDA data indicated that research had reduced the cost of producing ethanol from both cellulosic biomass and from corn. Further cost reductions in producing ethanol from corn, and subsequent increases in the demand for corn-based ethanol, may be constrained by the price of corn and its use for

	gasoline with more recent actual prices; • the results of studies estimating the potential for oxygenates to reduce the use of petroleum; and • ongoing federal research into biofuels, including any related past or projected cost-reduction goals, and any increased demand estimates based on such research goals.	other purposes. DOE believed that the demand for ethanol made from cellulosic biomass for use as an oxygenate and as an alternative fuel could increase significantly, assuming the successful development and commercialization of biofuels technologies and the achievement of the agency's cost-reducing goals.
Tax Policy: Effects of the Alcohol Fuels Tax Incentives (GAO/GGD-97-41, Mar. 1997)	In the late 1970s and early 1980s, the Congress enacted tax incentives for biomass-derived alcohol fuels. This study addressed the following questions: • Whom do the incentives benefit and disadvantage economically? • What environmental benefits, if any, have the incentives produced? • Have the incentives increased the nation's energy independence? • To what extent has the partial exemption from the excise tax for alcohol fuels reduced the flow of revenue into the Highway Trust Fund?	The study found the following: The value of the ethanol tax incentives is shared, directly or indirectly, among different groups in the economy, including alcohol fuel blenders, ethanol producers, and corn farmers. The tax incentives allow ethanol to be priced to compete with substitute fuels, such as gasoline and MTBE; thus, without the incentives, ethanol fuel production would largely cease. Available evidence, including the views of analysts interviewed by GAO, indicates that the ethanol tax incentives have had little effect on the environment. Although the available evidence suggests that the tax incentives for alcohol fuels increase ethanol fuel use, it also indicates that these incentives do not significantly reduce petroleum imports. Therefore, the tax incentives do not significantly contribute to U.S. energy independence. The share of oil imports in total U.S. energy or petroleum consumption has remained the same or higher than it was before ethanol incentives were offered. Ethanol currently accounts for less than 1 percent of U.S. motor vehicle fuel consumption. In addition, ethanol tax incentives have not significantly enhanced U.S. energy security because they have not created enough usage to reduce the likelihood of oil price shocks and their consequences, which are increased U.S. fuel prices and reduced economic output and employment. According to GAO's estimates, the partial exemption for alcohol fuels reduced motor fuels excise tax revenues by about $7.1 billion from fiscal year 1979 through fiscal year 1995.

(141472)

2-25

Testimony
before a joint meeting of the
Kansas Senate and House utilities committees
Jan. 24, 2001
Room 313 South
Statehouse

Thank you for remembering the citizens in your deliberations concerning astronomically-high natural gas prices.

Fortunately for me, I have enough money in my bank account to keep my house warm for the rest of this winter. But I don't know how many more winters I can weather (no pun intended) at current or higher rates. And I know there are many citizens less fortunate than I.

I don't pretend to understand all the intricacies, but, on the surface, I see some measures that I respectfully ask government at whatever level to consider:

1. Return to regulation. Deregulation, we're finding out, is not working to the good of the people. Could regulation be much worse?

2. Find ways to be sure that the poor don't freeze to death and that lower-income citizens aren't financially ruined -- even if it means holding down on less critical program funding increases.

3. Establish an investigation team -- whether it's KCC staff, the KBI, a legislative committee or a special investigator -- to see if there's any mismanagement or funny stuff like collusion or gouging going on in the natural gas industry.

Again, thanks for hearing us, and may God bless us all as you deal with this life-threatening situation in Kansas. Surely the problem is far too serious to leave entirely to private enterprise.

Clay Loyd

Clay Loyd
319 SW Elmwood
Topeka KS 66606

785/357-1619

(This submitted as written in lieu of appearing).

Senate Utilities Committee
January 30, 2001
Attachment 3-1

Hydronics Energy Technologies Presentation

January 2, 2001

Confidentiality

All information included herein and/or transferred for the purposes of due diligence information is the sole property of Hydronics L.L.C. and is considered as confidential and proprietary except as is available in the public domain.

Technology

Intellectual property represented in U.S. Patent number 6,018,091 – *Methods For Thermally Degrading Unwanted Substances Using Particulate Metal Compositions* And subsequent revisions issued and/or applied for including U.S. Patent numbers 6,113,860, 6117206, Docket Numbers 26639c, 26639d, and 30619 have been allowed *Electrical Cell Including Particulate Elemental Iron and Magnesium.*

Applications of Technology

- Hydrogen Generation
- Energy Cells
- Environmental Cleanup
- Desalinization

Applications of Technology

Hydrogen Generation

- On demand Hydrogen generation
    - Fuel cell applications
    - Conventional power systems (Automotive and industrial)
    - Electrical generation plants (Utility)
    - Heating systems

Hydrogen Generation from Scrap Metals

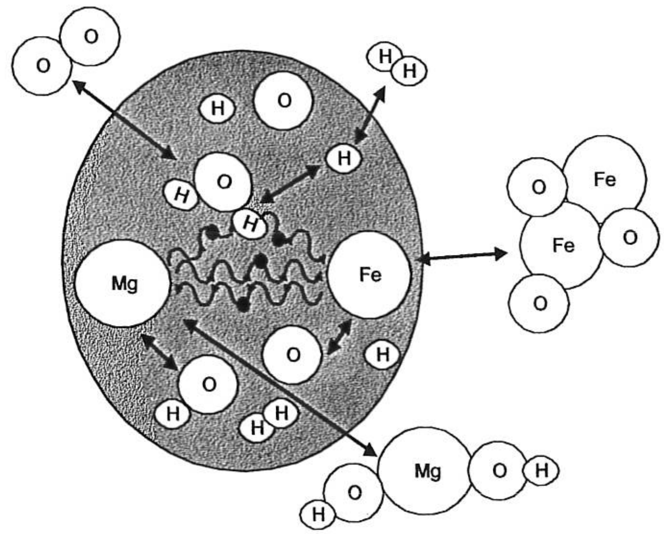
- Utilizes Pulverized Mixture of Scrap Metals Containing Mg, Fe, and other metals and combined with water or alcohol/water mixture to produce large volumes of Hydrogen gas and/or steam.

- With the addition of water, the metal particles act as very small electrochemical cells all acting in parallel.

- This process causes large volumes of hydrogen to be evolved due to the action of free electron motion between the metals in the mixture and the hydrogen containing fluid (water, etc.)

- The electron motion is tuned to the frequency at which the hydrogen bonds are broken by controlling the metal mixture.

- The electron motion is analogous to a laser, where all of the electron motion is at one frequency and can be used to perform the work function of breaking the hydrogen bond or they can be collected on plates and then provided to a load as in the Energy Cell.



Verification of Technology

- Hydrogen Generation Technology Verified by Shrader Labs Report attached (Appendix A)

Energy Cell Technology Applications

- Primary Energy Storage System
  - Replacement of conventional primary battery systems
  - Safe replacement for Lithium primary technologies
  - Inexpensive, non-hazardous materials
  - Recyclable

- Rechargeable Energy Storage
    - Mechanical and Electrical recharge capabilities demonstrated

Hydronics Technology Summary

The technology that Hydronics has presented is a semi-primary (possibly rechargeable) cell. The cell is based on materials disclosed in US Patent 6,018,091. These materials are primarily Magnesium and Iron with smaller percentages of other metals as mentioned in the patent.

The cell is composed of current collecting plates made of a conductive metal such as aluminum, a source of moisture, the powder metal material, and a separating membrane.
The moisture acts on the Magnesium and Iron to form many mini-shunted batteries, which cause electron motion to take place between the metals. Electrons are freed by this motion and are collected on one of the two plates forming a difference in potential between the plates. In addition, Hydrogen nuclei are released from the water, allowing them to migrate across the barrier, further reinforcing the potential difference. When the circuit outside of the cell is closed, the current will flow and the reaction of the metals will continue to keep the current sustained until the metals or the water in the cell is exhausted.

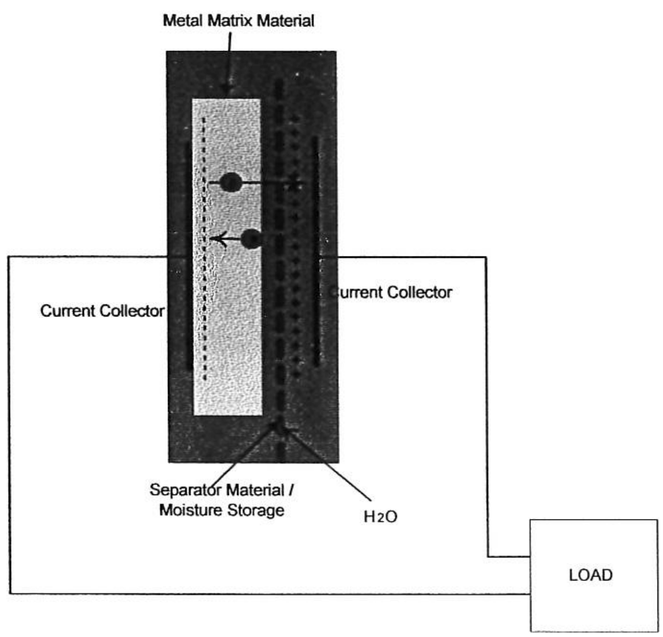
The cell has demonstrated capability to be electrically recharged (See the test report). If the cell is constructed so that it is water limited, it can be rejuvenated by injecting more water into the cell. This can be repeated many times until all of the metal powder in the cell has been consumed by reaction.

The cells have demonstrated a high energy density with respect to the active material weight.

Electrical Power From Scrap Metals

- Energy Cell Technology
  - Operation based on same principals as hydrogen generation
  - Moisture stored in the separator material is released upon heat generated by application of a load to provide continuous metered activation of the metals.
  - Metals are activated and free electrons are collected on current collectors until load is applied, at which time the electrons flow to the load.
  - Cell may be able to be optimized with feedback on the water release to regulate cell output at a constant voltage for duration of discharge until metals are consumed.
  - Use of this technology provides for extremely high energy and power densities.

Waste Metal Based "Energy Cell"



Applications of Technology
Environmental Cleanup

- Environmental Cleanup of Agricultural Lagoon systems
- PCB Mitigation
- Thermal degradation of blood waste and soil contaminants
- Sewage cleanup
- Petroleum contamination in soil and water

Applications of Technology
Desalinization Applications

- Residential
  - Household
    - Self Powered
    - Hot water source
    - Water Softener replacement
  - Community
    - Reclamation of effluents
- Commercial
  - Possible combination with power generation
- Military and Space
  - Water reclamation on self-contained craft

Appendix A

Shrader Labs Test Report

SHRADER
Analytical and Consulting
LABORATORIES INC.

REPORT OF ANALYTICAL SERVICES

SUBMITTED TO:

IDM CORPORATION
P.O. BOX 1225
GREAT BEND, KS 67530
316-792-1584
FAX: 316-792-6925

We are pleased to provide the enclosed analytical results for the following samples. Should you have any questions regarding the methods and/or results, please feel free to write or call.

Customer sample	:	FINE METAL POWDER
Sample description	:	FOR HYDROGEN GENERATION
Project #	:	I668
Analysis performed	:	HEADSPACE GC MASS SPECTROMETRY
Date received	:	March 17, 2000
Date completed	:	March 21, 2000
Report date	:	March 22, 2000

Analyst
John A. Defever, Research Department

Approved
Stephen R. Shrader, Ph.D.

Enclosure

- Continued -

3814 VINEWOOD · DETROIT, MICHIGAN 48208 · (313) 894-4440 FAX (313) 894-4489

ANALYTICAL PROCEDURE:

A sample of fine metal powder was submitted for testing. The testing was to include mixing with water to generate a gas, and analyzing the gas to determine its major component and impurities. The analyses were performed using gas chromatography mass spectrometry (GCMS).

Three analyses were performed. The first was a blank analysis, using an empty gas sampling bottle. The second was a sample analysis, observing both the bulk gas and the impurities. The third was a sample analysis, observing only the impurities.

The analyses were performed in the following manner. A portion of metal powder, approximately one gram, was placed in a gas tight vial with about one milliliter of pure water. The vial was capped; the cap was punctured to permit sample gas collection. The sample was shaken to start gas evolution. The GC column was inserted into the vial to collect the evolved gases. A portion of the column was immersed in liquid nitrogen to cold trap the volatiles. The bulk gas passed through the cold trap and was analyzed by the mass spectrometer (first sample analysis only). When sufficient sampling time had passed, the column was removed from the sample vial, the cold trap was withdrawn, and the volatiles were analyzed by the GCMS system.

GC conditions were as follows:

Column: 30 meter 5% phenyl methylsilicone
Temperature: 30 - 250°C at 20°C / minute

RESULTS:

The bulk gas was confirmed to be hydrogen.

Water was the major contaminant.

One organic contaminant was reliably detected. It was dibutyl phenol. Dibutyl phenol is used as an antioxidant and UV stabilizer.

Pertinent mass chromatogram plots and mass spectra are enclosed.

CONCLUSION:

During the process of evolving gas, the metal powder and water produce heat. The combination of heat and gas evolution would be expected to volatilize many of the organics present in either of the starting materials.

HYDROGEN ENERGY
TECHNOLOGIES
32474 Sheridan
Beverly Hills, MI 48025

HydroGen Energy Technologies

Business Plan

Engineering Innovative Solutions to Environmental and Energy Systems

4-9

Commercial Hydrogen Production

Existing Hydrogen System

Up until now, it was evident that there is no means to produce hydrogen that does not consume more energy than it delivers. As demonstrated by the magnesium/iron powder mixture, the only energy needed to produce hydrogen is the amount needed to fill a container with water and the energy to pour in the powder

How can the magnesium/iron process be used to generate hydrogen at an industrial level? First let's look at the existing hydrogen system. Compared with the hundreds of thousands of miles of existing natural gas network, the hydrogen pipeline system is very small, totaling only 460 miles. Air Products and Chemical, Inc. have two gaseous hydrogen pipelines in the United States, one near Houston and one in Louisiana. Their total length is approximately 110 miles, and they carry an average of 190,000 kilograms of hydrogen per day to more than 20 customers at refineries and chemical plants. Air Products also operates a 30-mile, 50,000-kg/day pipeline in the Netherlands. Praxair, Inc., operates pipelines near Houston and in Indiana, totaling 160 miles and delivering about 200,000 kg/day to refineries, chemical plants, and steel manufacturers. More than 30 "over the fence" plants exist to deliver hydrogen to individual industrial customers.

Existing Hydrogen Uses

Most of the common applications of hydrogen in the United States today do not involve its use as a fuel. Hydrogen is widely used as a feedstock in the production of ammonia, the refining of petroleum products, and the production of methanol. It is also used in smaller quantities for the production of other chemicals, for food hydrogenation, in making steel and glass, and in the electronics industry. Overall demand for uses of hydrogen in the commercial sector is expected to grow at about 5 percent per year in the near term. These non-fuel applications are likely to help stimulate further development of general hydrogen-related technologies and infrastructure.

Cost of Hydrogen Production

Currently the most cost-effective way to produce hydrogen is steam reforming using natural gas. According the U.S. Department of Energy (DOE), in 1995 the cost was $7.39 per million Btu in large plant production. One million Btu is approximately three thousand cubic feet of pure hydrogen gas and one thousand cubic feet of natural gas. DOE assumed a cost of natural gas of $2.43 per million Btu. Currently, natural gas costs 3 to 4 times the more than the 1995 cost basis. Commercial steam reformation is approximately 68 percent efficient.

The production of hydrogen by electrolysis occurs when a low dc voltage is applied to water, at one germinal hydrogen is produced and oxygen is produced from the other. Electrolysis using hydroelectricity at off perk rates costs between $10.55 to 21.10 per million Btu. Electrolysis is approximately 62 percent efficient.

Environmental Remediation

Applications

HydroGen has identified environmental remediation opportunities in the following areas;

- Municipal Sludge Treatment
- Wastewater Treatment
- Hazardous Waste Treatment
- Superfund Cleanup Applications
- Hazardous metals

In addition, Hydronics and Steve Thomas are developing a process for degradation of waste tires which could lead to a license agreement with HydroGen receiving Fifty percent of license fees and royalties. HydroGen has identified wastewater sludge remediation as the initial focus of development efforts.

Treatment of Wastewater Sludge

Wastewater sludge is a mixture of organic material and bacteria removed from the wastewater treatment process. Wastewater sludge is about 1% solids and 99% water. About 30% of the sludge produced is returned to the aeration tanks to assist with the biological process of sewage treatment. The remaining 70% must be disposed of.

Since wastewater sludge is 99 percent water the first problem of disposal is the removal of all available water. There are various ways to dispose of sludge, but in all cases the first goal is to reduce the water content. Removing water decreases the volume of sludge. This makes storage and transportation much cheaper. If the sludge will be incinerated, removing water first also cuts costs because there is less water to boil off before the solids can burn.

Equipment treatment plants typically utilize centrifuges and belt presses to remove water. Centrifuges work like a washing machine on spin cycle, water is forced out as the centrifuge spins. Belt presses remove water by essentially squeezing it out of the sludge. Sludge entering a belt press is 96 –99% water with the consistency of dirty water. By the time it leaves the belt press, the sludge is still 80% water with the consistency of mud. This sludge is “dewatered sludge cake”.

To date, municipalities have disposed of their sewage sludge in the least troublesome and most affordable ways possible; they send barges of sludge to be dumped at sea, bury sludge in landfills or burn in incinerators. However, communities are now reassessing their sludge management practices because of increasing landfill tipping fees and closure costs, more stringent environmental standards, and increased public concern about air, land and water.

Sewage sludge has many characteristics that, if applied properly, are good for soils and plants. Research has shown that the organic matter in sludge, sometimes reffered to as biosolids, can improve the physical properties of soil. As a soil additive, sludge improves the bulking density, aggregation, porosity and water retention of the soil. In other words, if added properly, sludge enhances soil quality and makes it better for vegetation. Plants also benefit from the nitrogen, phosphorus and potassium in the sludge. When applied to soils at recommended volumes and rates, sludge can supply most of the nitrogen, phosphorus needed for good plant growth, as well as magnesium and many other essential trace elements like copper and nickel.

Regulation of Sewage Sludge

In the United States, the use and disposal of treated sewage sludge is regulated under 40 CFR Part 503. This regulation, promulgated on February 19, 1993, was issued under the authority of the Clean Water Act.

Part 503 regulations protect public health and the environment through requirements designed to reduce the potential for contact with disease-bearing microorganisms (pathogens) in sewage sludge applied to the land or placed on a surface disposal site. These requirements are divided into:

- Requirements designed to control and reduce pathogens in treated sewage sludge.
- Requirements designed to reduce the ability of the treated sewage sludge to attract vectors (insects and other living organisms that can transport pathogens away from the land application or surface disposal site).

Part 503 regulations list sewage sludge treatment technologies that are judged to produce sludge with pathogens sufficiently reduced to protect public health and the environment. The regulation allows the use of any other technologies that produce sludge with adequate pathogen reduction as demonstrated through microbiological monitoring. The Part 503 regulation establishes two classification of sludge based on the level of pathogen reduction. Class A sludge is treated to the point at which pathogens are no longer detectable. For Class B sludge, a combination of treatment and site restrictions are designed to protect public health and environment.

Treatment of Sludge with Magnesium/Iron Mixtures

The use of magnesium/iron mixtures (powder) to treat wastewater sludge is the ideal application of the technology, which meets both the pathogen and vector reduction requirements of the Part 503 regulations.

Pathogen reduction occurs when the sludge is heated by reaction of the water in the sludge and the HydroGen proprietary powder. Testing has been completed which indicates the temperature of the sludge is elevated to 195 °F, without the capture of off-gasses and steam. Testing conducted by Hydronics indicates that if treated in a pressure vessel, with the capture of steam, the temperature could be elevated to 300 to 550°F. Either scenario meets requirements for pathogen reduction. This temperature elevation is a significant feature of the powder. The ability to heat large volume of liquid to temperatures in excess of 300 °F would not be cost effective using typical means. Vector reduction occurs in two forms, only one of which is needed; when the volatile solids content of the sludge is reduced by 38%, or the percent moisture in the sludge is 25% or below. The attached laboratory analysis depicts this vector reduction action. Sample S-1 is a control sample that was not treated. Sample S-2 is a sample treated with the powder that was allowed to generate temperatures in excess of 190 °F, but was not allowed to drive off volatile solids or moisture. Sample S-3 is a sample which following elevated temperature treatment similar to S-2 was allowed to air dry. Sample S-3 reduced volatile solids to acceptable levels necessary to meet vector reduction requirements. In addition, the percent moisture content of the sludge sample S-3 was below the required 25%.

The HydroGen process is the only process that can satisfy both pathogen and vector reduction requirements without additional energy input and within minutes. Other existing methods require incineration, heating, or extended treatment of the sludge, in some cases taking in excess of 40 days.

Once both pathogen and vector reduction are achieved, the sludge is classified as a Class A sludge. In most cases, this sludge can be land applied or given away without restrictions. Municipalities cherish this type of sludge because the public will haul the sludge offsite for land application, saving the municipality from trucking, land application or landfill costs.

Implementation Approach

HydroGen has determined the best method to implement the use of the powder in treatment of sewage sludge to be targeting large municipalities. These municipalities usually have the largest cost since they either have to incinerate the sludge ($0.10 to $0.15 per gallon of sludge) or haul the sludge to landfills or land application areas far from the city. By generating a Class A sludge, much or all of the transportation costs can be saved. Class A sludge is also prized for it fertilizer value creating a potential secondary market. The municipality could enter into a license agreement with HydroGen for the use of the technology, or the municipality could be required to purchase the powder from HydroGen, at a profit.

Another approach is to enter into a license agreement with other sludge processors. Most sludge processors are at best regional in scope. There are only a few companies that operate on a national basis. These companies are:

- N-Viro Energy Systems
- Synox Corporation
- CBI Walker, Inc.
- International Process Systems, Inc.
- K-F Environmental Technologies, Inc.
- ATW, Inc.
- UltraClear
-

Anticipated Cost of Treatment

HydroGen anticipates the cost for sludge processing, using the HydroGen process, to be within the $0.02 to $0.05 per gallon range. This would be significantly below incineration and in many areas below land disposal and land application.

A pilot scale test unit will need to be constructed to demonstrate the application on a commercial scale. The cost for this pilot scale unit will take less than one million dollars , and 6 months to 1 year of testing and development,. Commercial use of the material should occur directly after pilot prove out. HydroGen estimates that within 3 to 5 years, this powder application for sludge processing would be the preferred method nationwide to produce a Class A sludge.