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**ANALYSIS OF THE EFFECTS OF SECTION 29 TAX
CREDITS ON RESERVE ADDITIONS AND
PRODUCTION OF GAS FROM
UNCONVENTIONAL RESOURCES**

**Prepared for
U.S. Department of Energy
Office Of Fossil Energy**

by

ICF Resources

September 1990

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I. Executive Summary

Federal tax credits for production of natural gas from unconventional resources can stimulate drilling and reserves additions at a relatively low cost to the Treasury. This report presents the results of an analysis of the effects of a proposed extension of the Section 29 alternative fuels production credit specifically for unconventional gas. ICF Resources estimated the net effect of the extension of the credit (the difference between development activity expected with the extension of the credit and that expected if the credit expires in December 1990 as scheduled). The analysis addressed the effect of tax credits on project economics and capital formation, drilling and reserve additions, production, impact on the U.S. and regional economies, and the net public sector costs and incremental revenues.

The analysis was based on explicit modeling of the three dominant unconventional gas resources: tight sands, coalbed methane, and Devonian shales. It incorporated the most current data on resource size, typical well recoveries and economics, and anticipated activity of the major producers. Each resource was further disaggregated for analysis based on distinct resource characteristics, development practices, regional economics, and historical development patterns.

Data and models used in this analysis were developed by ICF Resources under sponsorship of the U.S. Department of Energy and the Gas Research Institute. They represent the state of the art in unconventional gas recovery modeling and costing. Additional data on well recoveries, project economics, impact of tax credits on future development plans, and preferences about the structure of the credit to maximize effectiveness were developed in interviews with over thirty companies.

Major Findings

Current proposals to extend the credit call for a two-year (until January 1, 1993) extension of the date by which wells must be spudded. The analysis shows that implementation of this proposal would have the following net effects for unconventional gas wells drilled in 1991-1992:

- 6,600 additional wells drilled.

- 4.1 Tcf reserves added.
- Annual production of 104 Bcf in 1991, increasing to 273 Bcf in 1993, then declining at an average rate of 6% per year thereafter.
- Cumulative recovery of 1.1 Tcf by 1995 and 2.2 Tcf by 2000.
- Expected maximum costs in lost Treasury receipts from Section 29 payments on only those wells stimulated by the credit are \$848 million (undiscounted) over 1991-1995 and \$1,601 million over the life of the credit (1991-2000). Since the credit will be paid on all unconventional gas wells drilled 1991-1992 (estimated at 11,810), whether they would have been drilled even without the extension, the maximum 1991-2000 Treasury losses for all unconventional wells drilled in 1991-1992 are estimated at \$2,955 million. The amount actually paid is estimated to be about one-third less since low wellhead prices and the Alternative Minimum Tax limits many operators from claiming the full credit, or \$1,970 million. This is equal to \$0.48/Mcf (\$2.78/BOE).
- For just the 6,600 wells stimulated by the credit extension, increased production and severance taxes paid to the states of are estimated to be \$336 million, and net increased state and federal income taxes are \$1,345, and royalty payments for new production in federal lands are \$150 million. On an undiscounted basis, the net public sector cost of a two-year extension is thus \$139 million (1990 dollars) for 4.1 Tcf of added reserves, or \$0.03/Mcf (\$0.20/BOE).
- Since tax outlays occur in the early years and revenues occur over the life of the wells, discounting these cost streams is appropriate. Expected discounted (at 10%) net public sector costs of a two-year extension of the Section 29 credit is \$1,032 million, or \$0.25/Mcf (\$1.46/BOE).
- Average U.S. gas wellhead prices would have to be \$0.24/Mcf higher in 1991, \$0.17/Mcf higher in 1992 and \$0.03/Mcf higher in 1993 to stimulate the same reserves and production response from conventional resources. Based on anticipated near-term gas demand, this overall transfer cost to the consumer would be \$7.1 billion in higher gas prices to get the same increase in production from conventional sources.

Discussion

The credit has had a major effect on drilling over the past several years. Since tight sands have not been eligible to receive the credit during this period, trends in coalbed methane and Devonian shale are the most instructive as to credit effectiveness. In 1985 there were about 8,500 total U.S. gas well completions, with barely 100 coalbed and 15 Antrim (Michigan basin Devonian shale) wells drilled. In 1990, over 2,700 coalbed and 900 Antrim wells are expected to be drilled, and U.S. gas completion are estimated at about 7,500. Between 1985 and 1989, these coalbed and Antrim

wells increased their share of U.S. gas completions from 1% to almost one-half. This increase in drilling is a result of the availability of improved technology and a targeted tax credit, and has provided operators the economic support to continue to further technologies to improve recovery efficiency from these resources. Tight gas, coalbed methane and Devonian shale now make up over 10% of U.S. nonassociated gas production.

The credit cost-efficiently stimulates production because it is paid only for successful wells. Unlike investment-based incentives, in this production-based incentive the operator bears all the risk -- if no gas is produced, no credit is paid. This cost efficiency is borne out by the relative incentive costs per Mcf required to add reserves. The 4.1 Tcf reserves added by this tax credit extension would cost a maximum of \$1.6 billion undiscounted over the life of the credit (1991-2000). This is equivalent to a "finding cost" of \$0.39 per Mcf or \$2.26 per barrel of oil equivalent.

Four adjustments are needed to fully cost this incentive. First, the actual cost to the Treasury would be about one-third less due to restrictions on full credit use by some companies based on their tax circumstances. Second, the credit would also be paid on all unconventional gas wells that would have drilled in 1991-1992, even those that would have been drilled without the credit extension. Third, public sector revenues (specifically severed and production taxes, federal royalties, and state and federal income taxes) offset much of the gross costs of the credit to the U.S. Treasury. Finally, the front loaded tax losses and downstream resources must be discounted to estimate the true cost of the tax credit. After all adjustments, the discounted public sector cost is \$1,032 million or \$0.25/Mcf (\$1.46/BOE). Relative to other current proposed incentives, for which costs range up to about \$10/BOE, this is an efficient mechanism to minimize further decline in gas production during a time of significantly increasing gas demand.

Interpretation of the results of this study should not be considered merely as possible added reserves and production, but as the net effect of the extension of the credit. Because the credit has become structurally embedded in national gas completion trends over the past few years, gas well completions from conventional sources can be expected to decrease further. Since 1980, gas completions have declined 60%, during a time when unconventional gas activity (including tight sands) increased dramatically to more than half of all U.S. gas completions. Without continued aggressive development of these resources, gas completions can be expected to fall further.

The current credit mechanism, whereby a credit equal to \$3.00/BOE is paid on all production from qualified wells through 2000, could be modified to increase effectiveness or decrease cost to the Treasury. Although a national assessment of the impact of alternative credit mechanisms was beyond the scope of this analysis, single well project economics were analyzed for several alternative formulations of the credit. These include credit until project payback, a cap on daily rate eligible for the credit, limits on eligible annual or total production, and a reduction in the amount of the incentive paid per Mcf. Alternative formulations should be addressed to maximize the credit's effectiveness against its cost to the Treasury.

II. Background

A. Overview

Historically a secondary product of oil production, natural gas has come to be viewed as a primary domestic energy source with increasing demand for its use. Now supplying energy roughly equivalent to domestic oil and coal resources, gas has been called the fuel of the future for its apparent large resource base and environmentally clean combustion characteristics. As the traditionally large and inexpensive gas resources are depleted, exploration must extend to more complex, difficult reservoir settings to meet future gas demand.

Some of the largest potential sources of new gas supplies are the so-called unconventional resources: tight sands, coal seams and Devonian shales. Each of these resources is characterized by complex reservoirs of limited drainage area and low flow capacity. Although they have been produced in limited quantities for several decades, only recent improvements in extraction technology have increased the contribution of unconventional resources to a significant level. One of the factors that has led to improvements in technology over the past decade has been the availability of economic incentives, either incentive prices or tax credits. These incentives minimize some of the risks inherent in developing gas prospects in new geological settings with newly developed technologies.

This report is an analysis of the effects of one such incentive, specifically the Section 29 Alternative Fuels Production Credit. The Section 29 credit, named for its reference in the Internal Revenue Code, provides for a tax credit for fuels produced from non-traditional sources. The regulation provides for a tax credit paid on production through 2000 of fuels from facilities placed in service through the end of 1990. The largest response in production of those alternative fuels specified by the enabling legislation have been the unconventional sources of natural gas.

The current issue before Congress and the industry is whether to extend the allowed spud date for another two years to continue incentives to develop additional unconventional gas resources. The analytic objective of the analyses reported here was to estimate the impact of such an extension

on drilling, reserves, production, costs and revenues from incremental production, and the cost of this incentive relative to others under consideration.

The remainder of this Section briefly discusses the natural gas resource base, current gas markets and policy, anticipated supply and demand issues and current legislature initiatives to extend Section 29. Section III explains the purpose and scope of the analysis. Section IV describes the context, objective and approach of each of the ten subtasks conducted in this analysis. Section V presents the results of the analysis. Section VI discusses alternative formulations of the credit relative to what is currently been proposed. Section VII presents a summary of this report and conclusions from the analysis.

B. Natural Gas Resource Base

Despite geologic uncertainties, the natural gas resource base is considered by most to be large. Natural gas has been found in over 100 sedimentary basins throughout the U.S. Gas is generated as a natural byproduct of decomposition of organic materials and accumulates in reservoirs. These reservoirs vary widely in their lithology, size and the rates of flow at which they can be produced.

Reservoirs can be divided into two broad categories: conventional and unconventional. Conventional reservoirs are characterized by commercial flow rates following normal drilling and completion techniques. Unconventional reservoirs are generally more complex, are inadequately characterized by petroleum engineering correlations developed for conventional reservoirs, and rarely produce at commercial rates of flow without stimulation.

Conventional reservoirs constitute the majority of historical gas production and reserves. The producing basins in Texas, Louisiana, Kansas, New Mexico, and Oklahoma have supplied much of this gas, and currently constitute the vast majority of Lower-48 onshore reserves. Most gas production to date has come from conventional reservoirs. Only in the past 15 years have unconventional reservoirs been tapped for a significant share of total gas production. As conventional reservoirs are depleted, an increasing share of total domestic gas is expected to come from unconventional sources.

Unconventional resources, while large, are not the only potential source of future gas reserve additions. As the larger, more easily accessed fields in these regions are depleted, other conventional resources have become more important. These are, specifically, gas located in small fields, gas produced from infill drilling in old fields, and gas located in frontier areas, such as the Gulf of Mexico, deep gas, and Alaskan gas. Improvements in geology and drilling technology, as well as higher gas prices may transform some of these resources into domestic supply. The development of these sources, however, is constrained by substantial geologic risk and competing environmental concerns.

Despite its large technical potential, unconventional gas resources still face formidable technology and cost barriers before they can fully contribute to domestic supply. The National Research Council Committee on Production Technologies for Liquid Transportation Fuels recently estimated gas resources and reserves and the status of extraction technologies. Table II-1 summarizes the results of the analysis, indicating that unconventional resources provide the single largest new source of technically recoverable gas in the U.S. Due to its high costs of production, however, relatively less unconventional gas is economically recoverable at \$3.00/Mcf. At current wellhead prices, unconventional gas is even less likely to be added to reserves. While the potential exists, formation evaluation and extraction technologies need to be refined and costs and risks reduced through greater field experience to realize these reserves.

Table II-1
Estimated Recoverable Domestic Natural Gas Resources
(Tcf)

	Technically Recoverable	Recoverable at <\$3/Mcf
Proved Reserves	187	162
Inferred Reserves	111	111
Extended Reserve Growth	180	86
Unconventional Resources	463	109
Tight Sands	285	79
Coalbed Methane	90	13
Devonian Shales	88	17
Undiscovered	<u>446</u>	<u>144</u>
Totals	1,118	595

Source: National Research Council (1990)

Unconventional Gas Resources

Petroleum resources exist in varying quality, with a relatively small volume of high quality resource and a large volume of low quality resource. The higher quality resource is characterized by large accumulations of oil or gas in homogeneous reservoirs. These reservoirs are usually found in the initial stages of exploration of a basin and depleted first, often at low cost. Because there are limited amounts of this high quality resource, maintaining reserves and production requires the development of decreasing quality resources, which entails relatively more costly capital and operating expenses.

The principal difficulty with unconventional reservoirs is that the engineering knowledge developed for conventional reservoirs over the past century does not directly apply. New theories and descriptions of how gas flows in these reservoirs is required to adequately model them and predict the performance of stimulation treatments. Until this knowledge is developed with more field and laboratory experience, operators face substantial risks in developing unconventional gas reservoirs.

Unconventional gas resources have been viewed as part of this low quality resource because of their low flow capacity, complex reservoir architecture, and difficulty of producing without stimulation. Technology has improved over the past 15 years and unconventional resources now contribute over 10% of domestic supply. As the resource becomes better characterized and extraction technology improves, unconventional gas could contribute a greater share. The purpose of economic incentives and aggressive R&D is to assure that the resource is adequately characterized and technology is available to produce the gas when needed.

The DOE Energy Information Administration (EIA) has compiled data on producing unconventional gas wells and production trends. There are discrepancies between EIA data and those reported by individual states for three reasons. First, many unconventional gas wells are in geologically low permeability formations that have not yet been legally designated as such. Therefore, the EIA does not have these wells in its database even though they are really unconventional gas wells. Second, there are lags in reporting from the states, so some additional wells are not included in the database. Finally, since these data reflect only wells certified under the NGPA starting in 1979,

unconventional gas wells and production (mostly tight sands) drilled prior to 1979 are excluded from the totals. Even with these caveats, however, these data represent the best national compilation of unconventional gas wells and production (Table II-2).

The following text briefly discusses each of the three most common types of unconventional gas resources: tight sands, coalbeds, and Devonian shales. More detail is found in Appendix A.

Tight Gas Formations

When sands or carbonates have porosities and permeabilities that are low enough to inhibit gas from flowing at commercial rates, they are known as "tight formations." The most emphasis to date has been on tight gas sandstones that exist in great quantities in almost every gas province of the world. Such sands generally have less than 10% porosity, high water saturations, and in situ permeabilities to gas of less than 0.1 millidarcies.

Because of these poor quality reservoir characteristics, the costs of extracting gas is higher than the more favorable Gulf Coast reservoirs that have been the mainstay of U.S. gas production. Gulf Coast reservoirs contain 1 cubic foot of gas for every 3.3 cubic feet of reservoir rock, while tight gas formations must drain 180 cubic feet of rock, over 50 times as much, to recover the same cubic foot of gas. Consequently, typical development costs in the Gulf Coast are \$0.16/Mcf and \$0.76/Mcf in tight formations. Since the more productive, less expensive prospects were developed first, most of these are nearing depletion and will have to be replaced by a combination of more risky and costly frontier resources (OCS and deeper) and the less productive low permeability resources.

Tight sands exist wherever gas is produced, and are expected to be present in significant quantities in at least 113 U.S. basins. Currently, 21 states have known accumulations of tight gas, and 16 produce from formations approved by the Federal Energy Regulatory Commission (FERC) for incentive prices. But, like gold in seawater, large volumes of gas in place do not translate into economic reserves and production. ICF Resources, in conjunction with DOE and GRI, is conducting some of the first detailed basin appraisals of the tight gas resource in a decade.

Table II-2
DOE/EIA Unconventional Gas Databases (1984-1987)

State	Resource	Wells Producing					Production (Bcf)				
		84	85	86	87	88	84	85	86	87	88
Alabama	Warrior Basin	185	247	446	374	501	6.4	8.7	13.0	17.0	19.8
		0	0	1	1	7	0.0	0.0	0.1	<0.1	0.6
Colorado	Raton Mesa San Juan Basin Piceance Basin	48	49	54	105	134	1.1	0.5	0.4	2.2	4.5
		2,715	2,399	2,612	2,682	2,744	54.6	57.1	53.2	53.4	56.0
Kentucky	Appalachian Basin	2,666	2,696	2,741	2,779	2,786	27.2	26.7	26.8	28.2	28.2
		35	49	56	73	72	1.0	1.3	1.5	1.8	1.8
Louisiana	Cotton Valley Basin Anadarko Basin	609	751	894	1,042	1,149	33.2	30.5	31.2	32.4	31.6
Michigan	Antrim Shale	156	156	158	162	158	2.7	2.5	2.4	2.5	2.4
Mississippi	Warrior Basin	9	9	8	8	8	1.7	1.2	1.5	1.5	1.0
New Mexico	San Juan Basin Permian Basin Raton Mesa	16	17	20	23	25	1.4	1.2	2.6	3.6	8.4
		886	930	940	1,032	1,109	63.8	54.1	44.9	54.2	45.7
New York	Appalachian Basin	14	14	14	14	14	0.1	0.1	0.1	0.1	0.1
		2,011	2,383	2,647	2,831	2,741	13.1	15.2	16.5	17.9	16.8
Ohio	Appalachian Basin	2,268	2,525	2,552	2,571	2,571	11.8	11.9	11.4	11.4	11.2
		13,151	16,293	18,145	19,488	19,078	89.8	109.7	119.3	129.3	124.8
Oklahoma	Arkoma Basin	46	52	47	50	48	3.3	5.3	6.1	5.9	6.9
Pennsylvania	Appalachian Basin	0	0	1	2	1	0.0	0.0	<0.1	<0.1	<0.1
		17	28	38	43	43	0.1	0.3	0.4	0.4	0.4
		3,745	5,119	6,144	7,016	6,777	46.0	61.6	73.0	84.7	81.2

Table II-2 (Continued)
DOE/EIA Unconventional Gas Databases (1984-1987)

State	Resource	Wells Producing					Production (Bcf)				
		84	85	86	87	88	84	85	86	87	88
Tennessee	Appalachian Basin	3	5	8	8	8	<0.1	<0.1	<0.1	<0.1	<0.1
		22	23	24	26	24	<0.1	<0.1	<0.1	<0.1	<0.1
Texas	Tight Sands	5,177	5,782	5,843	6,032	6,180	590.2	693.8	764.4	763.1	740.3
	Anadarko Basin										
	Val Verde Basin										
	Permian Basin										
	Rio Grande Basin										
	Edwards Basin										
	Cotton Valley Basin										
Utah	Uinta Basin	198	201	204	207	207	16.0	12.9	11.5	9.7	10.5
Virginia	Appalachian Basin	32	34	34	35	34	0.4	0.4	0.4	0.4	0.4
		75	127	238	365	256	2.3	4.0	7.4	11.0	7.8
West Virginia	Appalachian Basin	3,459	4,184	4,621	4,931	4,955	24.8	29.9	32.8	35.3	34.9
		706	1,014	1,208	1,469	1,338	7.5	10.5	11.9	14.9	12.9
Wyoming	Power River Basin	1	1	1	1	0	<0.1	<0.1	<0.1	<0.1	0.0
		594	621	616	630	592	74.2	77.4	65.8	73.1	77.7
	Wind River Basin										
	Greater Green River Basin										
	Powder River Basin										
TOTALS							9.0	10.3	16.1	22.8	32.6
	Coalbed						67.1	71.7	74.3	78.3	77.6
	Devonian						996.8	1,130.0	1,120.0	1,250.0	1,220.0
	Tight Sands										

Over 40,000 wells have been certified since 1979 by FERC as producing from tight sands. Although the majority of these wells are found in the Appalachian basin, these generally recover less than 0.5 Bcf. A lesser number of wells are drilled in the East Texas, San Juan, Piceance, Denver and Green River basins, among others. With adequate technology, many of the better wells in these areas can recover 1-2 Bcf or more. Current production from tight sands is between 1.4 and 1.7 Tcf annually, or almost 10% of total U.S. gas production. The figure is uncertain because numbers of tight gas wells drilled prior to 1979 are unknown.

The last complete U.S. assessment of the tight sands resource was conducted by the National Petroleum Council (NPC) in 1980. The NPC estimated resource in place from detailed basin assessments and extrapolation to other basins expected to contain tight sands. Although the NPC estimated a total tight gas in place of 945 Tcf, more recent estimates exclude much of this extrapolated resource (Figure II-1).

Devonian Shales

Devonian shales have long been recognized as a potential source of gas. In fact, the first gas well ever produced (1821) was a Devonian shale well. Traditionally low volume, long-lived producers, Devonian shale wells have benefitted from aggressive technology development in the past decade. Unlike sandstones, which trap gas in pore spaces and produce by gas expansion, Devonian shales produce by release of gas both in the pore spaces as well as gas adsorbed to the surface of the shales. This leads to long producing times, with production from some wells occurring over 70 years at low volumes (10-100 Mcfd).

Devonian shale reservoir engineering is more complex than traditionally thought. When large volumes of organic mud, silt and sand are deposited in marine environments and buried to great depths, the combined effect of heat, pressure and chemical reactions can transform the organic shale to source rocks for oil or gas. Hydrocarbons may migrate to nearby porous formations and, with appropriate trapping conditions, become conventional reservoirs. In some cases, however, the source rocks themselves may become potential reservoirs. The presence of mobile water, natural fractures and desorption makes accurate prediction of recovery difficult.

Figure II-1

**U.S. Estimated Tight Gas Potential
(Gas in Place in Trillion Cubic Feet)**

Sources: ICF, GRI, NPC, UT/Austn

In the Appalachian Basin, most production has occurred in West Virginia, Ohio and Kentucky, and there are over 15,000 current shale wells producing about 100-150 Bcf annually. The resource is pervasive, since the mountains to the east eroded during the Devonian Period, supplying large amounts of sediment to create huge volumes of shale. The dark brown and black shales are especially rich in organic matter and locally produce large volumes of natural gas. Similar deposits occur in the Michigan and Illinois basins, although their potential is still being quantified.

Because of their low productivity, Devonian shale wells have traditionally been economic only in a low cost market and are sensitive to available prices. Current Appalachian production has centered on a limited area of known, but depleting potential (principally the Big Sandy field in eastern Kentucky and southwestern West Virginia). As prices declined over the past decade, total annual Appalachian gas well completions decreased 75% from a peak of about 5,800 in 1981 to around 1,500 in 1989. The 12,000 Devonian completions since 1980, stimulated in part by incentive pricing and tax credits, have kept Appalachian drilling rates from decreasing even further. Operators indicate that drilling will all but cease unless prices increase substantially or tax credits are continued.

The Devonian shale resource in place is extremely difficult to estimate. The NPC (1980) estimated that there could be nearly 2,000 Tcf of gas in place in the Appalachian basin alone. Recent studies by ICF Resources indicate that there may be another 76 Tcf in the Antrim shales of Michigan (Figure II-2). One company has risked over \$1 million on exploration and development in the Illinois basin Devonian shales to develop midwest gas supplies.

Coalbed Methane

Coal has long been recognized as the earth's most abundant form of conventional energy. In addition to burning coal for direct heat or generating electricity, it is also a reservoir for methane. The gas may be trapped within natural cleats or fractures, or within thin sand lenses imbedded in or immediately adjacent to the coal. Most of the gas within a coal seam, though, is adsorbed on the coal structure. Often, the cleat system within the coal contains large volumes of water, which must be pumped off at substantial expense before gas can be desorbed and produced. As pressure decreases, gas will be released from the coal surface and flows through the natural fracture system. Usually some form of stimulation such as hydraulic fracturing is required to achieve commercial flow rates.

Figure II-2
Estimated U.S. Coalbed Methane and Shale Gas Potential
(Trillion Cubic Feet)

Sources: ICF, GRI, DOE, NPC

Gas content, thickness, depth, coal rank, water content, and permeability all strongly influence coalbed methane economics. Often, however, these parameters are not easily productive, making development risky.

Only recently, with the increasing development of the coalbed industry, have basins been appraised of their coalbed methane potential. Studies by ICF Resources estimate that gas in place in coal seams probably exceeds 400 Tcf (Figure II-2). Most development activity to date has been in the geologically favorable portions of the San Juan basin in New Mexico and Colorado and the Black Warrior basin in Alabama. Development has also started in the Appalachian, Piceance, Raton, Green River, Western Washington, Powder River basins and other basins. The greatest well reporting lags by states to commercial data sources are in coalbed due to the dramatic increase in activity in the past few years. For example, EIA data indicate 25 San Juan New Mexico coalbed wells produced 8.4 Bcf in 1988 but New Mexico state records show 81 wells producing 14.9 Bcf.

C. Gas Markets, Policy and Incentives

For most of the post-World War II period, natural gas was subject to wellhead price controls and other Federal regulatory policies that guided the development of the industry. The price of gas dedicated to interstate commerce was kept artificially low and gas consumption grew -- doubling between 1949 and 1958, and doubling again by 1970. U.S. consumption of gas peaked in 1972 at over 22 Tcf. In the 1970s, though, occasional shortages of gas began to appear in the interstate markets. Then-prevailing interstate prices were insufficient to stimulate the development of gas supply necessary to meet the growing demand for gas in the price-regulated interstate market.

The deliverability shortfalls of the 1970s stimulated interest in supplemental sources of gas. The most notable sources were the Alaskan North Slope, synthetic natural gas from coal, liquefied natural gas imports, and gas from deep and less permeable formations, so-called unconventional gas resources. All of these sources were expensive -- too expensive to develop and market at the then-regulated prices. To encourage supplemental development, the Federal Power Commission supported "rolled-in" pricing, where more expensive gas could be averaged with low price-regulated gas to yield average prices at marketable levels.

Policies to Stimulate Gas Development

Further encouragement for the unconventional gas resources came in 1978 with passage of the Natural Gas Policy Act (NGPA) and in 1980 with the Windfall Profit Tax Act. The former provided pricing incentives to produce "high cost" gas coupled with a phased deregulation of gas prices. The latter provided what is now known as the Section 29 tax credit for qualified production of alternate fuels. Both were effective in helping industry offset the high risks and costs of unconventional gas production.

These efforts were largely successful in adding new gas reserves and production. The number of gas wells drilled each year more than doubled between 1978 and 1981. Moreover, important aspects of this intensive effort were the advance in knowledge about the U.S. resource base and the expansion of drilling in deep and unconventional formations. Major improvements were achieved in the extent of knowledge about the geology of gas resources, particularly in smaller fields and heterogenous reservoirs. Advances in drilling, stimulation, and completion technologies also began to make unconventional resources less costly to produce.

Wellhead gas prices, which had increased in the mid-1970s in response to concerns about supplies, continued to increase with incentive pricing under the NGPA for certain "high-cost" sources of gas. By 1983, average U.S. wellhead gas prices were six times their 1970 level (in constant dollars). Average prices for high cost gas increased to a peak of \$7.31 in 1982, nearly three times the U.S. average wellhead price of \$2.46/Mcf. These incentives provided the needed revenues to cover the higher risks and costs of producing unconventional gas (Figure II-3).

But the general economic recession of 1982 hit energy intensive industries particularly hard and, coupled with the decline in world oil prices, led to an abrupt decrease in gas demand which brought price increases to a halt. Gas demand fell when traditional industrial gas customers in the steel and related industries retracted or switched to alternative fuels. By 1982, consumption was about 2 Tcf below the 1980 level of 19.9 Tcf and after a brief recovery fell to 16.8 Tcf in 1986.

One effect of the downturn in demand, coming as it did after NGPA expansion in production, was the emergence of the so-called gas "bubble" -- a surplus of deliverability over demand. The gas

Figure II-3
Loss of Incentive Pricing for High Cost Gas

AVG. U.S. WELLHEAD PRICE HIGH COST GAS SECTION 107 (c) PRICE

SOURCE: EIA ANNUAL ENERGY REVIEW 1987

AND NATURAL GAS MONTHLY 1988-1989

NOTE: "HIGH COST GAS" INCLUDES SOME DEREGULATED DEEP GAS IN THE AVERAGE

bubble first appeared in 1982 and, despite regional shortages of deliverability in the winter of 1989-90, there is still an overhang of deliverability that may last into 1991.

In 1984, prices began to soften and thereafter, fell. By 1988, gas prices were 40 percent below 1983 levels. Figure II-3 shows the trend in gas prices from 1980 to 1989. The persistence of low prices affected drilling activity, which has decreased steadily since 1984. Gas well drilling in 1989 was about one-third of its 1981 levels (Figure II-4).

With excess deliverability and decreasing wellhead prices, operators could no longer sign contracts for unconventional gas at incentive prices. Figure II-3 shows the average cost paid for NGPA Section 107 (high cost) wells decreasing rapidly from its 1982 peak. Because this category included deregulated deep gas, the average price exceeds the ceiling for Section 107 regulated gas. Yet, even with this deregulated gas, by 1984 the average high cost gas price was less than the NGPA incentive ceiling. This discrepancy has increased to current where average prices paid for Section 107 gas are half of the ceiling price established by FERC. Incentive prices were de facto no longer in effect.

The Section 29 Production Tax Credit

This marked the first widescale use of the Alternative Fuels Production Credit (originally Section 44D of the Internal Revenue Code), now called the Section 29 credit. Created under regulations as part of the 1980 Windfall Profit Tax Act (P.L. 96-223), the Section 29 credit was designed as a price support mechanism for alternative fuels for precisely this kind of circumstance.

Congress felt that high risk, high cost resources developed to maintain domestic gas supplies should not bear the burden of end users switching to lower priced alternative fuels in a changed market. Both the "price support" and "incentive until competitiveness achieved" arguments had adherents:

"The committee believes that a tax credit for the production of energy from alternative sources will encourage the development of these resources by decreasing the cost of their production relative to the price of imported oil. These alternative energy sources typically involve new technologies, and some subsidy is needed to encourage these industries to develop to the stage where they can be competitive with conventional fuels. . . If the credit

Figure II-4

Decline in U.S. Successful Gas Wells

SOURCE: PETROLEUM INFORMATION RESUME 1989

leads to the development of these alternative sources, it would make a major contribution to reducing our dependence on imported energy." (Senate report No. 96-394, 1980-3 CB 131, 205.)

and

"This provision is intended to provide producers of alternative fuels with protection against significant decreases in the average wellhead price for the uncontrolled domestic oil, with which alternative fuels frequently compete." (House of Representatives report No. 96-817, 1980-3 CB 131, 299)

Fuels qualifying for this treatment were oil shale, tar sands, unconventional gas resources, coal liquids and gases, biomass and steam from agricultural byproducts. To date, the majority of the credit has been taken by oil, gas and coal companies, presumably for unconventional gas resources.

There are several additional characteristics of the credit worth noting:

- Credits are available for production through December 31, 2000 for facilities placed in service (for unconventional gas this means wells spudded) between January 1, 1980 and December 31, 1990.
- The credit is equal to \$3.00/BOE (\$0.52/Mcf) and phases out if oil prices exceed \$23.50/bbl (1979 dollars) and is eliminated at \$29.50/bbl (1979 dollars).
- The nominal value of the credit is adjusted for inflation (1990 value is \$0.89/Mcf) for all fuels except gas from tight sands, which remains a constant \$0.52/Mcf.
- Either NGPA Section 107 incentive prices or the Section 29 credit can be used in a given tax year, but not both.
- The price of gas must be regulated to receive the credit. A 1988 Supreme Court decision effectively deregulated new tight gas production (FERC v. Martin Exploration Management Co.). The effects of the 1989 Natural Gas Wellhead Decontrol Act on eligibility for the credit must also be addressed by Congress, wells drilled after July 26, 1989 will only receive the credit until May 15, 1991.
- Coalbed methane, Devonian shale, and tight sands each have explicit geological and engineering qualification criteria to be met to qualify for the incentives.

Past Impact of Incentives

Has the incentive had an impact? The answer from unconventional gas producers is an unqualified yes. The coalbed methane and Antrim shales drilling statistics show a clear combined impact of technology and economics in adding reserves. Figure II-5 shows gas well completions, during 1985-1990 when incentives were removed for tight sands and the combination of new technology and incentives stimulated coalbed and Devonian shale development.

D. Future Gas Supply and Demand Issues

Natural gas, because of its clean burning qualities, is viewed by many as an environmentally preferred fuel for the future. Predictions vary, but gas is expected to play a larger role in electricity generation and other industrial uses in response both to new clean air legislation and to potential regulation designed to address global climate change. Moreover, residential and commercial use of gas is growing after years of moratoria on residential gas hook-ups. Prospects for annual gas demand to exceed 20 Tcf again are quite favorable -- but production to meet this demand would not be sustainable without technological advances, production incentives, and/or increased gas imports.

Current Perspective

Given the likelihood that domestic natural gas demand will increase, concerns are raised about the short-term and long-term deliverability of natural gas, and the role of Government in assuring adequate deliverability. In 1988, nearly half of new gas reserve additions in the Lower-48 states came from the Federal waters of the Gulf of Mexico and from tight gas and coalbed methane deposits in the Black Warrior and San Juan basins, the result of advancements in both resource characterization and production technologies.

This trend remains strong. In 1990, over 2,500 coalbed wells will be completed in the Black Warrior and San Juan basins, almost one-fourth of all gas completions. In addition, approximately one-third of the new gas wells drilled since 1986 have been classified as NGPA Section 107 gas wells -- wells considered high-risk because they exist in technologically challenging settings. Clearly, further technological development plays a key role in the development of future gas reserves.

Figure II-5
Unconventional Gas Drilling

SOURCE: FERC 121 WELL DETERMINATION FILINGS AND
STATE REGULATORY AGENCIES

In 1985, unconventional gas development activity was dominated by tight gas, which was eligible for both incentive pricing or tax credits. Much of both tight gas and Devonian shale production in 1985 were from shallow Appalachian basin formations. As tight sands lost its eligibility for the tax credit through deregulation and market prices fell below incentive ceiling prices, tight sands development decreased rapidly.

By 1988, the combination of improved technology and the Section 29 tax credit began to take hold in Devonian shale and coalbed methane. By 1990, the decrease in tight sands activity due to loss of tax credit eligibility since 1985 has almost been offset by coalbed and Devonian drilling.

The powerful effect of the credit also can be seen in a single basin. The Cotton Valley formation in East Texas and North Louisiana was the first tight formation eligible to recover incentive pricing under the NGPA. An examination of drilling trends in Texas districts 5 and 6, both of which are entirely underlain by the Cotton Valley, provides some insight.

Prior to the late 1970's, the massive hydraulic fracturing technique needed to produce tight sands was still being developed. Cotton Valley drilling was about one-fourth that of other formations in East Texas (Figure II-6). The combination of improved fracturing and incentives by the early 1980's increased Cotton Valley completion from less than 5 per month to 50 per month by 1979, surpassing all other formations by a 2 to 1 margin. With the decline in wellhead prices from this 1982 peak, and the loss of eligibility for tight sands tax credits in 1985, Cotton Valley drilling dropped back to about 10 completions per month by 1987.

In 1989, operators realized that some Cotton Valley gas was still regulated under a provision of the NGPA and started aggressive infill drilling to take advantage of the Section 29 credit. Activity reached a peak of nearly 50 completions per month during 1989. This infill activity was great enough to make Panola County, Texas, the seventh most heavily drilled county in the U.S. in 1989. The effective elimination of eligibility for tight sands by FERC Order 519 (effective May 13, 1990) will dramatically reduce Cotton Valley drilling in the latter half of 1990.

Figure II-6
Impact of Tax Credits on Drilling
East Texas Basin

Future Concerns

Over the long term, the issue is whether and at what cost we can access the known and potential natural gas resources. Even though the gas deliverability surplus has diminished, current gas prices are insufficient for industry to commit to long-term development plays.

A prudent operator prefers to infill drill current fields than pursue riskier plays. A general rule-of-thumb is that sustained wellhead prices must be 2 to 2 1/2 times the finding cost to stimulate exploratory drilling and add new reserves. In 1989, consequently, over 90% of successful gas wells were infill wells, the highest in more than a decade. The price at which these more expensive conventional and unconventional sources of gas are economic will be determined largely by the extent of progress made by R&D now continuing in the public and private sectors.

Many reputable sources have published projections of the supply of natural gas for the next few decades. Like the projections on gas production, they are influenced by several exogenous variables. Certainly the most important of these variables is the price of crude oil. Another is the stringency of government regulations on emissions, e.g. those currently under debate for the new Clean Air Act. Finally, demand for gas powered electric generation is expected to increase by 1.4 Tcf by 1995 and 2.5 Tcf by 2000. While estimates of supply differ, all estimate the need for new gas supplies.

GRI estimates natural gas production and reserves for the next two decades as part of its annual Baseline Projection. It estimates that the percentage of overall gas reserves attributable to unconventional gas increases from 13.5% in 1988 to 48% in 2010 (Figure II-7). Production from new (not currently developed as of 1985) unconventional sources is expected to increase from 8% in 1988 to 32% in 2010 (Figure II-8). Clearly, unconventional resources will become an increasingly significant part of the domestic gas supply.

New gas reserve additions must not rely solely on tax credits for economic incentives, since the price of natural gas is expected to rise in the future. Regulation that historically kept the prices artificially low has either been removed or will be removed in the near future, and the gas bubble, which began in the early 80's seems to be almost gone. Estimates for the increases in gas prices vary,

Figure II-7
Estimated Natural Gas Reserves
(Lower-48)

CONVENTIONAL RESOURCES **UNCONVENTIONAL RESOURCES**

SOURCE: GRI BASELINE PROJECTION DATA BOOK 1989

NOTE: CURRENTLY PRODUCING TIGHT SANDS ARE

INCLUDED IN CONVENTIONAL RESOURCE ESTIMATES

Figure II-8
Estimated Natural Gas Production
(Lower-48)

■ CONVENTIONAL RESOURCES ■ UNCONVENTIONAL RESOURCES

SOURCE: GRI BASELINE PROJECTION DATA BOOK 1989

NOTE: CURRENTLY PRODUCING TIGHT SANDS ARE INCLUDED IN CONVENTIONAL RESOURCES ESTIMATES

but they all show that gas prices will rise steadily in real terms in the coming decades. ICF Resources estimates a real increase of 7.5% annually through the 90's, with a flatter 2.3% annual rise for the first decade in the next century. GRI estimates the real increases to be 5.6% and 5.3% annually during the same periods.

E. Current Legislative Initiatives

Like the rest of the federal energy policy, the dynamics of the Section 29 tax credit has changed over the last few years. Created as a complement to the NGPA, the Section 29 credit has maintained its effectiveness. As a result of the Technical Corrections Act of 1988, which extended the last qualifying spud date of unconventional gas wells from December 31, 1989 to December 31, 1990, the Section 29 tax credit became decoupled from other petroleum initiatives.

Members from both the House and the Senate have introduced bills to extend the credit. However, this year the legislative and economic environment for such a tax credit has changed drastically from what it was in 1980 when Section 29 was written. The current bipartisan Budget Summit taking place is a response to the radically different fiscal and monetary situation that the federal government now faces. Consequently, it is likely that issues that affect a relatively narrow section of the energy community, e.g. Section 29, will face difficult competition from broad-based initiatives that affect the entire petroleum industry.

The two most prominent legislative proposals on Section 29 are those introduced by Senator Domenici and Representative Andrews. Senator Domenici's proposal would extend the last allowable spud date by two years, to December 31, 1992. It also removes the effect of the recent FERC Order 519. The Order, effective May 12, 1990, removed price regulation for tight sands for wells drilled before that date, effectively eliminating the availability of the credit. The proposed legislation by Domenici would nullify the portion of the Section 29 language that makes tight gas eligible only if it is price regulated. It does not address the Martin Exploration decision, which removed credit eligibility for wells drilled prior to May 12, 1990 that were effectively removed from price regulation by FERC under the NGPA.

Representative Andrew's bill proposes the same two-year extension and reinstatement of tight sands. In addition, this proposal would address the Martin decision by qualifying for the credit wells deemed by FERC to be deregulated under the Martin decision. Finally, the proposal would retain eligibility for tight sands wells drilled after the date of enactment of this bill regardless of the effects of the Wellhead Decontrol Act or other regulatory actions. An example of the latter would be FERC Order 523 that deregulated released gas. These latter provisions are an important safeguard against the inadvertent effect of regulatory changes on the incentive value of Section 29.

III. Purpose and Scope of Analysis

The principal purpose of this analysis is to determine the impact of extension of the alternative fuels production tax credit (Section 29) on reserve additions and production of domestic natural gas from unconventional formations. Specifically, ICF Resources was charged with estimating the net impact of the credit -- activity as a result of the credit extension compared to activity without credit extension. This includes drilling, reserve additions, production, effect on market prices, and cost to the Treasury of the credit actually paid to producers.

The scope of the analysis is limited to analysis of the currently known unconventional gas resource and the anticipated incremental activity resulting from the most commonly proposed credit extension scenario. This scenario, as introduced by Rep. Andrews July 24, 1990, would extend the placed in service date for two years and reinstate tight sands eligibility for the credit.

ICF Resources conducted reservoir engineering and economic modeling using its in-house models and resource data for tight sands, coalbed methane and Devonian shale. It did not develop new estimates of resource size or characteristics and made only the stated modifications to its production and economics models for this analysis. Estimates of incremental wells drilled, reserves added, production, and credit usage were derived by ICF Resources staff based on its own analyses and the reinterpretation of the analyses of others. Preliminary results were verified with operators for plausibility and validation of analytic assumptions.

IV. Summary of Analytic Approach

Analysis of the impact of tax credits on the "unconventional gas resource" in the aggregate is inappropriate. Each type of resource has unique attributes of reserves per well, development and operating costs, production profiles, responsiveness to incentives and historical development patterns. To derive the impact on reserve additions, production, costs and market effects of production tax credits requires a disaggregate analysis of the individual resource types on a regional basis.

The analytic approach to this work required 10 subtasks:

1. Gather Baseline Data on Industry
2. Characterize Near-Term Development Prospects
3. Establish Technology Case Assumptions
4. Modify Recovery Models
5. Modify Economic Models
6. Calculate Recovery/Cost Effects of Proposed Tax Credit
7. Estimate Equivalent Required Market Response
8. Analyze Alternative Tax Structures
9. Estimate Tax Credit Effects on Treasury Receipts
10. Prepare Report and Briefing to DOE

Each of these subtasks collected data, developed modeling capabilities, or estimated impacts of credit extension. They are described in more detail below as to the methods followed and the products of each subtask.

1. Gather Baseline Data on Industry

Context - A majority of natural gas (67%) is produced by independents. Many of these are smaller companies that do not enjoy the same advantages in capital formation, technical sophistication, and economies of scale in marketing that larger companies have. As such they are difficult to characterize in terms of typical reserves per well, drilling and completion practices, and accounting sophistication. This latter characteristic is critical to determining the cost to the Treasury of tax credits, given the complex requirements for structuring deals so that the full benefits of production tax credits accrue to the operator or their investors.

Objective - Empirical data on current exploration and development activities of industry in unconventional gas, including drilling, producing rates, typical well economics, reserves, and attitudes about future responses to eligibility for production credits.

Approach - ICF Resources gathered data from its contacts in the natural gas industry by conducting interviews with more than 30 of the most active operators and service companies, as well as a thorough literature search, to establish baseline data on current activity. We developed profiles of current and anticipated development (oriented toward the effects of the current availability and imminent expiration of the tax credit), the relative emphasis of unconventional vs. other resources, average recoveries and production, development and production costs, and the extent of the usage of the tax credit.

2. Characterize Near-Term Development Prospects

Context - Most representations of the unconventional gas resource base characterize the probable, possible and speculative resource taken as a whole, with little distinction as to which portion of the resource is likely to be developed in the very near-term (i.e., the next two years). Because the characteristics of the resources vary in terms of reserves and production per well and project economics, it is critical to evaluate only that portion of the resource that will be developed in the near-term in estimating the impact of tax credits.

Objective - Reservoir property and project cost descriptions of drilling prospects that are the most likely to be developed in the next two years (the time during which wells would be drilled to qualify for the proposed tax credit extension).

Approach - The unconventional gas resource databases maintained by ICF Resources for tight sands, coalbed, and Devonian shales are the most comprehensive available. They provide detailed data on localized portions of currently active development plays and those other basins thought to contain significant deposits of unconventional gas. We worked with operators to define which portions of the well resource base represented the near-term development prospects and defined a series of typical wells in various basins that best represented the reservoir properties and project economics of wells that would be drilled in the next two years.

3. Establish Technology Case Assumptions

Context - The assumptions of extraction technology used in the next few years determines project economics and recoveries. Stimulation technology, technical and economic risks, and production practices vary by operator, basin, and resource, and, possibly, whether the tax credit is in effect or not. Since technology is continuously developing, technology parameters need to be defined to represent the manner in which operators will develop unconventional gas in the next two years.

Objective - Technology parameters that indicate the level of extraction technology sophistication used by operators to recover unconventional gas and to be used for modeling potential recovery from near-term prospects.

Approach - Although advanced technologies are developed principally as function of experimentation and field experience, this task assumes wells drilled in the next two years would use technology now used by the most sophisticated operators. Based on our regular contacts with industry, we defined technology parameters for each resource and basin for formation evaluation (e.g., dry hole rates, wells required to condemn a prospect, G&G costs) and stimulation effectiveness (e.g., fracture length, multiple completions, fracture conductivity, containment and fluid efficiency).

4. Modify Recovery Models

Context - ICF's current reservoir simulators models are capable of modeling alternative technology specifications. Some states have regulations (e.g., proration, well spacing, water disposal) that must be accounted for in modeling the specific recovery potential on a detailed analysis of recovery over the next few years.

Objective - A full set of recovery models for tight sands, coalbed and Devonian shale that can address any location and resource specific issues likely to arise in development of near-term prospects.

Approach - ICF Resources maintains recovery models of tight sands, coalbed methane, and Devonian shale resources that are more generic as to recovery (i.e., not tied to any one state's specific production requirements). Since different types of wells of the same unconventional resource

also have quite different production curves, it is inappropriate to aggregate all wells around the country and multiply them by a certain "typical" production curve. Minor modifications were made to recovery models to incorporate location-specific production requirements.

5. Modify Economic Models

Context - Each state has different well economics and petroleum tax laws. Where state incentives for oil and gas development are already in effect, the incremental effect of Section 29 production tax credits may be diminished. Each group of wells expected to be drilled in the next two years as a result of an extension of the Section 29 incentive must be explicitly modeled, considering current location-specific costs and economics.

Objective - Descriptions of the project costing and tax laws under which each prospective group of wells be drilled and produced.

Approach -ICF Resources modified its economic models and timing algorithms for tax analysis to incorporate the Section 29 rules and state-specific tax laws. We surveyed state agencies to determine any state incentives for unconventional gas production that might complement federal efforts. Like the production decline curves, different sets of assumptions had to be developed for different regions. The ability of producers to take advantage of the credit varies, depending on the tax situation of the company.

Because of carryover provisions in the law, many firms (i.e., those firms currently not profitable) cannot take advantage of the credit. We analyzed the most recent IRS statistical information and surveyed industry participants to develop a usage factor for different sizes of firms in different regions.

6. Calculate Recovery/Cost Effects of Proposed Tax Credit

Context - Because the Section 29 credit is based on production during a limited time rather than just investment, credit usage and project economics are closely tied to the recovery stream generated by a well. The volumes of gas produced under alternative technology scenarios is critical

to the impact of the credit on project economics and the availability of additional capital for new well drilling.

Objective - Calculation of a set of production streams for typical wells for each resource and region. Estimation of the project economics for each typical well with and without the application of the credit.

Approach - ICF Resources economic models solve for the minimum gas price required to develop a particular resource. Different technologies and resources have different costs. Regional economics, too, within the groupings of resource type can vary greatly, depending on deliverability constraints and regional costs. Considering these differences, we analyzed the current and near-term unconventional resource base to determine the effects of the available tax credit to lower the minimum levelized selling price (the criteria used to "compete" gas sources against one another and with alternative fuels). We then produced a series of regional cost/supply curves for each unconventional source.

7. Estimate Equivalent Market Response Required

Context - Most estimates of the cost of the credit simply multiply some estimate of incremental recovery by the amount of the incentive. The true cost of the credit is far more complex. The credit may lower required wellhead prices for those unconventional gas prospects to which it applies, but adding reserves may depress market prices in those regions as well, leading to a loss of potential reserve additions from other sources. Since much of current drilling is a result of the tax credit, loss of the credit could reduce deliverability and increase market prices to the consumer. Conversely, in the absence of the credit, gas prices would have to increase for all end users to stimulate an equivalent response in reserve additions and production.

Objective - Estimates of the required increase in average wellhead price to stimulate equivalent reserve additions and production from conventional sources.

Approach - ICF Resources developed a capital and drilling model that relates capital, drilling costs, wellhead prices, resource base, demand, and current supplies for oil and gas. The model

calculates the price track required to generate sufficient capital to drill the wells required to produce additional gas supplies equal to those estimates for the Section 29 credit. The total transfer of wealth required from end user to the gas industry is the product of incremental average U.S. wellhead price and anticipated gas demand.

8. Analyze Alternative Tax Structures

Context - The current formulation of the credit, while seen by many as effective in stimulating production, is expected to incur a substantial cost to the Treasury at a time when Congress is trying to reduce the federal budget deficit. Alternative formulations of the credit can be considered that may be effective in stimulating production at a lower cost to the Treasury. Although outside the scope of this analysis, a discussion of alternative formulations is provided.

Objective - A description of the impact of alternative credit formulations on NPV and IRR for typical wells.

Approach - The economic models were altered to evaluate a limited number of alternative scenarios for typical wells. Specifically, ICF Resources evaluated the following scenarios: (1) the current formulation (wells receive the credit until the year 2000), (2) availability of the credit for production until project payout only, (3) a 100 Mcfd cap on credit eligibility, (4) a 100 Mcfd cap until payout only, and (5) each of these same cases but with a credit of only \$1.50 per BOE instead of the current \$3.00 per BOE.

The Wharton Econometric Forecasting Associates (WEFA) Group has performed a similar, although more aggregate, analysis for the Independent Petroleum Association of America. Their work concerns the individual and cumulative effects of the Domestic Energy Security Act of 1989 on the U.S. economy and the domestic oil and gas industry. This work, particularly the estimates of the effects of the Section 29 tax credit extension is reviewed in Appendix D.

9. Estimate Tax Credit Effects on Treasury Receipts

Context - One of the largest concerns over extending the credit is the cost to the U.S. Treasury. Any tax incentive hopefully has the effect of making an investment more economic, but the cost must be weighed against the volume of production produced. Because most operators are either in a net operating loss position or under Alternative Minimum Tax, they may receive only a portion or none of the credit they have earned. And because of the carryover limitations of the credit, the incentive may be so deferred or lost that there is little value to the producer.

Objective - Estimates of the maximum and likely loss of Treasury receipts due to Section 29 and the incremental production and severance taxes, state and federal income taxes and increased industry cash flows as a result of its extension.

Approach - ICF Resources estimated the effects of this tax credit on Treasury receipts as a function of the volume of qualified gas produced, and the proportion of operators who would file for the credit. We reviewed IRS data for Section 29 credit payments on corporate returns for the latest years data have been compiled and derived the portion of unconventional gas potential credit actually paid out. Estimates of additional taxes paid to state and Federal treasuries and increased industry cash flow were based on individual project cash flow analyses and analyses with the capital model.

10. Prepare Report and Briefing to DOE

This report constitutes the deliverable required for this task. Briefing of DOE personnel and follow-up consultation has been provided by ICF Resource as required.

V. Results of Analysis

A. Summary of Analytic Assumptions

This analysis examined the ability of Section 29 production tax credits to make currently marginal gas wells economic over the next two years. Four critical factors were addressed: technology advances, gas markets, corporate planning, and regional geologic and producing distinctions between resources.

First, one of the state's purposes of the Section 29 credit is its ability to provide for operators to develop new technologies and explore new geological settings. Since only a two-year extension was analyzed, we assumed technology did not significantly improve over the 1991-1992 period. The technology modeled was that implemented by the most sophisticated operators active today.

Second, since gas markets are expected to change substantially over the next few years, only wells that are marginal at factor prices should be modeled. The minimum required price of a currently marginal well will increase if market prices increase as expected over the next few years. For this reason, many more wells will be economic when prices rise and the impact of production tax credits on marginal well economics also changes. Because wellhead prices will increase, we modeled wells that will be marginal at 1991-1992 prices instead of at current prices. Marginal wells were judged to be those requiring \$2.00/Mcf (1990 dollars), that would be made economic by eligibility for the tax credit.

Third, the rapid increase in development of coalbed and Antrim wells (affected in part by the imminent expiration of the credit), has distorted company plans for the next few years. In most cases, development will decrease with or without the extension of the credit. The magnitude of decrease depends on how much future development was accelerated into 1989-1990. Estimated development plans with and without the extension were based on extensive interviews with the most active unconventional gas operators.

Fourth, each unconventional gas geological setting and recovery mechanism is unique. Because project economics respond differently to alternative formulations of a tax credit, the near-term unconventional resource was disaggregated into eight resource/region-specific typical wells for analysis:

- Black Warrior basin coalbed methane
- San Juan basin coalbed methane
- Appalachian basin coalbed methane
- Other coalbed methane
- Appalachian Devonian shale
- Michigan (Antrim) shale
- Appalachian tight sands
- Western tight sands

Production streams were calculated using ICF Resources' in-house, resource-specific reservoir models (COMET-PC for coalbed, SRP2 for Devonian shale, and TGAS-PC for tight sands). Costing and cash flow accounting were modeled using ICF Resources' Gas Economics Model (GEM). Costs were derived from published surveys of drilling, equipment, and operating costs and confirmed during interviews with operators.

Typical well reservoir characteristics were based on ICF Resources natural gas databases and confirmed by operators. Technology scenarios were based on work completed for GRI and industry-accepted descriptions of currently implemented production technology. Additional assumptions specific to various results sections are discussed below.

B. Impact on Project Economics

The availability of the Section 29 credit (currently \$0.89/Mcf for coalbed methane and Devonian shale and \$0.52/Mcf for tight sands, if reinstated) does add significantly to an operator's revenues. A marginal well in 1991-1992 would require at least \$2.00/Mcf at the wellhead without the credit to pay back the cost of capital. This would be uneconomic at prevailing 1990 wellhead prices of \$1.53/Mcf. The credit provides an equivalent increment of revenue to effectively lower the required wellhead price required to make a well profitable.

The availability of a tax credit is assumed to affect neither ultimate recovery or rates from a well. While an operator could increase rates to capture more of the credit, it was assumed that a prudent operator would already be producing a well at the maximum efficient rate consistent with sound engineering principles and applicable regulations. Since unconventional gas wells drilled in 1991-1992 will produce beyond the expiration of the credit in 2000, no adjustment for extending the economic limit was made.

The effect on project economics of a tax credit can be assessed in two ways: in aggregate for the resource base as a whole or individual project economics. Both were analyzed and presented as bounding conditions on the impact of credit extension.

First, aggregate estimates indicate the maximum effect of the credit if it were made permanent (i.e., elimination of a fixed window of eligibility) for the entire unconventional gas resource base. Using databases of the known domestic unconventional gas resource, we estimated the effect of the credit to reduce the minimum required prices of each resource type (tight sands, coalbed, Devonian shales).

We generated price-supply curves (relating wellhead price and recoverable gas at that price) from cash flow analyses of the almost 1,000 typical wells represented in the unconventional gas resource databases. Since price supply curves are time-independent, this analysis does not define which parts of the resource would be developed during the next few years, this cannot be used to estimate explicitly the time-specific effects of a tax credit. In fact, many of these potential reserves requested in the price supply curves are in currently inactive areas that would not be heavily drilled in the next few years. As such, the amount of resource indicated as economic at low prices in any price-supply curve is only an indication of what could be produced, assuming its location was known and geological risks minimized. Price-supply curves, however, provide insight into the magnitude of the effect of the credit by indicating the increase in reserves at current wellhead prices or effective decrease in required wellhead prices (due to availability of the credit to supplement revenues) to recover the same reserves.

The analysis shows that unrestricted eligibility for the Section 29 tax credit could increase potential unconventional gas reserve additions by one-half. Under implemented (currently in use by

the most sophisticated operators) technology at a wellhead price of \$2.00/Mcf, 49 Tcf of unconventional gas reserves are potentially recoverable without the credit. Making the credit available for the entire resource base increases potential unconventional gas reserves, to 71 Tcf. Since current proposals are only for a two year extension, these estimates are most usefully interpreted as showing an increase by one-half over the potential reserves without the credit. At higher wellhead prices, the relative impact of the credit is reduced. At \$5.00/Mcf, 124 Tcf are recoverable under implemented technology conditions without the credit, where as much as 143 Tcf could be recoverable with the credit, only a 15% increase.

As an alternative to a tax credit to add reserves, technology improvements of the type anticipated by aggressive R&D could add 106 Tcf in reserves at near-term prices. Although this would eliminate direct Treasury losses associated with Section 29 payments, the costs of R&D would be paid by end users and indirectly by the Treasury as tax credits for R&D. An additional 75 Tcf over the current 49 Tcf are available from increases in prices to \$5.00/Mcf, but this would cost consumers \$225 billion (undiscounted) in increased costs. Prices at this level are not foreseen in the next decade.

Estimates of the effect of advanced technology on reserve additions is included on the following Table V-1 and Figures V-1 - V-4 to show the relative effects of price, technology, and tax incentives to add reserves (figures are for the implemented technology case only).

The second method to estimate the impact of a tax credit on project economics was to conduct cash flow analyses on typical wells. Both rate of return and net present value were estimated for wells with and without the credit.

Table V-1**Potential Impact of the Section 29 Tax Credit
on Domestic Unconventional Gas Reserves
(Tcf)**

	<u>Implemented Technology</u>		<u>Advanced Technology</u>	
	<u>\$2.00/Mcf</u>	<u>\$5.00/Mcf</u>	<u>\$2.00/Mcf</u>	<u>\$5.00/Mcf</u>
Tight Gas				
- w/o credit	24	66	93	182
- w/ credit	32	73	120	193
Coalbed Methane				
- w/o credit	9	16	30	41
- w/ credit	12	18	35	44
Devonian and Antrim Shale				
- w/o credit	16	42	32	103
- w/ credit	27	52	77	106
	—	—	—	—
Total Unconventional Gas				
- w/o credit	49	124	155	326
- w/ credit	71	143	232	343

Figure V-1
Unconventional Gas
Impact of Section 29 Tax Credit

Source: ICF Resources Inc.

Figure V-2
Coalbed Methane
Impact of Section 29 Tax Credit

Source: ICF Resources Inc.

Figure V-3
Devonian Shale
Impact of Section 29 Tax Credit

Source: ICF Resources Inc.

Figure V-4
Tight Gas
Impact of Section 29 Tax Credit

Source: ICF Resources Inc.

Companies traditionally require at least a nominal return of 25-35% to account for risks of geologic or technical failure. Given today's depressed market for gas, companies varied widely in their willingness to develop prospects that didn't meet the company's desired return on investment criteria. The impact on single well project economics for the proposed formulation of the credit is summarized in Table V-2 for three typical wells. Each well has a current required price to make a return on capital of approximately \$2.00/Mcf, and would not be economic at near-term prices. Without the credit well, NPV would be \$0 and IRR 10%. These are unrisks evaluations, and projects approved by companies would generally have to have a 15% IRR at a minimum.

Table V-2
Impact of Section 29 Tax Credit on Project Economics

	<u>NPV</u> <u>(\$MM)</u>	<u>IRR</u>	<u>D&C Cost</u> <u>(\$MM)</u>	<u>Reserves</u> <u>(Bcf)</u>
Tight Sands (Cotton Valley)	0.53	24.5%	1.13	1.7
Coalbed Methane (Warrior Basin)	0.23	25.9%	0.33	0.5
Devonian shale (Appalachian basin)	0.17	27.3%	0.30	0.5

Source: ICF Resources analysis

All three typical wells receiving the tax credit would be within the desired corporate guidelines for investment needed to attract outside capital. The credit can, therefore, turn marginal wells into economic ones.

C. Impact on Capital Formation

One of the greatest obstacles facing industry is lack of sufficient capital to develop new prospects. Many operators report a number of attractive prospects but insufficient funds to develop them. Many integrated companies have moved a substantial portion of their operations offshore or overseas. This leaves independents, who have more difficulty attracting capital, to compete for available funds. This is the prime reason cited by operators as to why the Section 29 credit and removal of preference items from alternative minimum tax calculations are important.

Capital will again become available to the industry when investors expect project revenues to stabilize. Investors in gas properties were disappointed by the decline in gas prices in 1987-1988 and are reluctant to invest more capital until stability returns. Its ability to act as a price support when wellhead prices are low is one of the main reasons cited by operators and investors for the current success of the Section 29 credit.

The Section 29 credit mechanism is effective in stimulating gas development, but factors unrelated to the credit itself limit its effectiveness. Due to the tax circumstances of many independent operators (who drill 85% of all wells and produce about 90% of all unconventional gas), many cannot use all of the credit. One operator reported being eligible for about \$6 million in credits but could not take them due to tax circumstances. An operator who is in a net operating loss position has no regular tax liability, thus is ineligible for the credit. Section 29 regulations do not allow for any carryover in this case, so the credit is lost. As of 1989, about 10% of independents were in a net operating loss position. Due to their downstream and foreign operations, no integrated companies had a net operating loss.

For some companies, it is possible to structure a partnership to pass off the credit to investors in return for capital to drill unconventional gas wells. These deals are exceedingly difficult to structure for large drilling partnerships and generally have been restricted to smaller financing packages. Although not envisioned as a stimulant for third party investment, the Section 29 credit mechanism restores a vehicle for investment in drilling partnerships that was curtailed by the 1986 Tax Reform Act.

Because each company differs in its project financing, no valid estimates could be made of additional capital generated from the availability of Section 29 credits. A different measure for impact of Section 29, however, was estimated using ICF Resources' capital and drilling model. The model balances oil and gas demand with required reserve additions as a function of drilling costs, wellhead prices and capital availability. Keeping capital availability constant, increased revenues of \$7.1 billion would be required (through higher wellhead prices) to add production equal to a two-year extension of Section 29. Average wellhead prices would have to increase \$0.24/Mcf in 1991 and \$0.17/Mcf in 1992 to stimulate the same increase in production described below.

D. Impact on Drilling and Reserve Additions

For the historically dominant unconventional gas producing regions, we tabulated wells drilled over the past five years, and estimated drilling both without the credit and with a two-year extension (see Table V-3 and Figure II-2, above). These estimates are the most sensitive to assumptions about company capacity to develop new prospects, project financing, company planning, and lease availability. Estimates of drilling with and without the credit were based on extensive interviews with the most active operators in the current unconventional gas plays.

All figures reported beyond this point are based on the net wells drilled as a result of the credit. An estimated 6,600 well completions can be attributed to a two year extension of the credit beyond what would be drilled if the credit expires as scheduled. This estimate is higher than previously thought.

The impact of the credit is different for coalbed and Devonian shale than for tight sands, since tight sands currently is not eligible for the credit. First, for coalbed and Antrim shales, the dramatic increase in drilling this year has left companies with a need to complete and put on line all these wells in the first part of 1991. This leaves little capacity, even with the credit extension, to drill as many wells next year as in 1990. Therefore, coalbed development will decrease from 1990 levels with or without the credit, but only more so without the credit. Also, the potential for additional development in the recently tested portions of active basins is still limited by geologic and market risks. Without the Section 29 credit, development in new basins will slow considerably.

For tight sands, the reinstatement of eligibility can be expected to increase drilling, especially in the Appalachian basin. Much of the current western tight gas activity is infill wells. For example, Cotton Valley formation (a tight sandstone) infill development made Panola County, Texas the 7th most actively drilled county in the country in 1989. This increased infill activity was primarily due to remaining eligibility for Section 29 credits scheduled to expire in 1990. Therefore, there should be a smaller increase in drilling resulting from tight gas reinstatement in western basins than in the East.

Table V-3

Expected Drilling and Reserve Additions from Section 29 Extension
(Wells and Bcf Reserves)

	COALBED			DEVONIAN			TIGHT SAND		Total
	Warrior	San Juan	Other	Appalachian	Antrim	Appalachian	Eastern	Western	
1985	75	29	0	0	15	1093	5053	1263	7528
1986	73	48	0	0	32	738	3570	893	5354
1987	129	43	0	0	91	615	2371	593	3842
1988	479	255	0	2	230	494	1680	520	3640
1989	1079	462	45	9	553	863	1250	600	5211
1990	1800	900	270	25	900	900	1100	700	6795
Anticipated Successful Wells Without Credit Extension									
1991	200	300	100	10	200	300	1000	500	2610
1992	200	300	100	10	200	300	1000	500	2610
Anticipated Successful Wells With Credit Extension									
1991	800	500	300	100	800	800	1500	700	5500
1992	800	500	400	210	1000	800	1700	900	6310
Net Effect of Credit									
1991	600	200	200	90	600	500	500	200	2890
1992	600	200	300	200	800	500	700	400	3700
	1200	400	500	290	1400	1000	1200	600	6590
Avg. Reserves/Well	0.4	2.0	0.4	0.3	0.7	0.3	0.3	1.5	

Table V-3 (Continued)

Expected Drilling and Reserve Additions from Section 29 Extension
(Wells and Bcf Reserves)

	COALBED			DEVONIAN				TIGHT SAND		Total
	Warrior	San Juan	Other	Appalachian	Antrim	Appalachian	Eastern	Western		
Total Unconventional Gas Reserve Additions (Bcf)										
1988	192	510	0	1	161	148	504	750		2266
1989	432	924	18	3	387	259	480	900		3403
1990	720	1800	108	8	630	270	390	1050		4976
Estimated Incremental Reserve Additions Due to 2-Year Section 29 Extension (Bcf)										
1991	240	400	80	27	420	150	150	300		1767
1992	240	400	120	60	560	150	210	600		2340
2-Year Total	480	800	200	87	980	300	360	900		4107

Sources: FERC 121 well filings, state regulatory agencies, DOE/EIA, GRI, ICF Resources.

Finally, the existence of Section 29 eligible gas in many of the most actively drilled counties and fields in 1989 shows the impact the credit has already had. In 1989, the top ten drilled (oil and gas) counties in the U.S. contained five that produce predominantly unconventional gas. In 1985, only one of these counties (Weld, Colorado) made the top ten, and it had significant tight sands production at this time. The top 15 drilled fields in 1989 include 8 that produce mostly unconventional gas. In 1985, only two of these fields made the top 15 (Wattenburg, Colorado and Basin, New Mexico), both among the earliest tight gas plays in the U.S. Thus, the credit is clearly adding reserves that otherwise would not have been developed.

At the average reserves per well shown in the Table V-3, 4.1 Tcf would be added in the next two years from these incremental wells. This is equal to more than 10% of the total expected gas reserve additions for those years from conventional sources.

E. Impact on Gas Production

For each resource/play combination a typical well production profile was selected to estimate incremental production during the next 10 years. Figure V-5 and Table V-4 shows the average daily production rates for these wells, and the total annual production from incremental wells drilled in 1991-1992 as a result of the tax credit.

An additional 104 Bcf of production would be added in 1991, increasing to 266 Bcf in 1992. Due to the late peaking of coalbed wells, this production volume could be maintained for several years, until when it would start to decline at about 6% per year. Over a five year period, 1.1 Tcf could be produced, and 2.2 Tcf would be produced over a 10 year period.

F. Impact on Regional Economies

While this production increment is large, it is concentrated in a few regions of the country, specifically Alabama, New Mexico, the Appalachian states and Michigan. These areas generally have suffered the worst from recent economic downturns in the petroleum industry. The combination of technology improvements and economic incentives has had a substantial impact on the local economies and the continuation or expiration of the credit is of real concern to local officials.

Figure V-5
Unconventional Gas Resources
Typical Well Production Profiles

SOURCE: ICF RESOURCES INC.

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ICF Resources Incorporated

Table V-4

**Expected Per Well and Total Production
From Section 29 Extension (Mcf/d)**

	Warrior	COALBED		DEVONIAN			TIGHT SAND	
		San Juan	Other	Appalachian	Antrim	Appalachian	Eastern	Western
1	37	85	37	58	77	93	93	465
2	113	210	113	66	77	61	61	307
3	164	203	164	74	77	54	54	272
4	122	246	122	72	77	49	49	246
5	96	285	96	66	77	46	46	229
6	84	304	84	60	73	42	42	211
7	73	323	73	55	69	39	39	193
8	61	342	61	49	66	36	36	180
9	49	361	49	44	62	34	34	168
10	37	380	37	38	59	31	31	155
Estimated Total Production for Incremental (1991-1992) Section 29 Wells (Bcf/Year)								
1991	8	6	3	2	17	17	17	34
1992	33	22	12	6	39	28	35	90
1993	61	30	24	7	39	21	26	65
1994	63	33	27	8	39	19	23	58
1995	48	39	20	7	39	17	21	53
1996	40	43	17	7	38	16	19	49
1997	34	46	15	6	36	15	18	45
1998	29	49	12	6	35	14	16	41
1999	24	51	10	5	33	13	15	39
2000	19	54	8	4	31	12	14	36
Total	358	372	149	59	347	171	205	509
								2170
								Annual
								Cumulative
								104
								369
								643
								911
								1156
								1384
								1599
								1801
								1991
								2170

Source: ICF Resources Analyses (1990).

The lower quality unconventional gas resources are more likely to be found on federal, state or Indian lands than on fee lands, thus more likely to provide a source of public sector royalty income. Except for Appalachian, Warrior, and Michigan basins, a substantial amount of the potential reserves in the western or southwestern U.S. lie under federal lands. Although not estimated explicitly, at least 15% of the resource could be produced from federal lands, more in some cases. For example, the San Juan basin is about 40% federal lands, 42% tribal lands, 16% fee lands and 2% state lands. Royalty payments of 1/6 to 1/8 would be paid directly to the Treasury to partially offset the cost of the credit and provide needed revenues to state and Indian communities. On average, this would provide about \$10,000 per well per year direct royalty payment to the state starting immediately.

The evaluation of impacts of federal policies on state and federal revenues are often ignored in the assumption that revenues from alternative incentives are equivalent in their effect on local economies. While this may be true for income taxes generated by other economic activities, petroleum ad valorem and severance taxes are an important source of revenue to state treasuries. An estimated additional \$336 million in production and severance taxes will be paid to the states for the wells drilled because of the two-year Section 29 extension. An additional \$168 million in state income taxes would be generated over the same period.

G. Impact on Federal and State Revenues

Given the need to minimize costs to the U.S. Treasury of tax incentives, the cost of the Section 29 credit is a major concern. We analyzed the cost to the Treasury as a function of how much credit could be generated if all producers were eligible and the expected percentage usage of the credit (based on tax circumstances of the companies or drilling partnerships).

Detailed information on the usage of the Section 29 credit is only available in aggregate from the IRS for corporate returns. It is reported for partnership and individual returns aggregated with "Other Credits." It is expected that integrated producers, who are most likely to be able to make direct use of the credit, will have reported it on their corporate returns. Independents, who are much less able to take the credit would report it on their corporate returns. Thus, while it is unknown how

much credit is being used by individuals or partnerships, the small number of drilling partnerships active recently indicates that this number is likely to be small.

As for proportion of credit ultimately paid, operators in a net operating loss are not eligible for the credits, while those who have the credit reduced by AMT can carry over only that portion of the credit lost because of AMT. With low taxable income from low wellhead prices, operators now in AMT are likely to stay there for several years. Increased drilling would incur more intangible drilling costs, thus making AMT even more likely. Thus, the usage of the credit may not change much from historical levels.

As of 1987, the latest year for which statistics have been compiled by the IRS, about 10% of independents were in a net operating loss position, making them ineligible for credits. Of the remainder who weren't, about 75% were under Alternative Minimum Tax rules, also effectively restricting their use of the credit. For integrated producers, about 35% were under AMT rules. Since being under AMT probably only reduces the eligibility to receive the credit and not eliminates it, we assume that the incentive still has some value, although less than intended.

In 1986 and 1987, the latest years for which data are available, Section 29 claims on corporate returns were \$64 million and \$53 million, respectively. Large corporations receive most of the corporate credits, with over 80% of claims made by corporations with over \$250 million in assets, and only about 2% with assets under \$10 million. Of the \$64 million total claims made in 1986, \$50 million were made by companies classified as oil, gas or coal related.

Based on eligible 1986 Devonian and coalbed production of about 90 Bcf and a credit amount of \$0.74/Mcf, a maximum of \$67 million potentially could have been paid out for unconventional gas production, assuming no tight sands production recovered the credit. This suggests that only about 75% of potential credits were paid (\$50 million/\$67 million). Given that these returns are weighted toward larger companies that are less likely to lose eligibility because of net operating losses or AMT, this 75% estimated credit usage is probably optimistic. Therefore, an estimated two-thirds of the maximum payable credit would be actually paid by the Treasury.

The five year undiscounted (1990 dollars) maximum cost of the credit to the U.S. Treasury for incremental wells only is \$848 million (Table V-5). The ten year cost is \$1,601 million. Given 4.1 Tcf reserve additions, this is equivalent to a total undiscounted incentive of \$0.39/Mcf (or \$2.26/BOE). Likely costs, due to restrictions on eligibility to claim the full credit, are about one-third lower. Because there is no risk to the Treasury for unsuccessful wells (the credit is only paid on production), this is the full cost of the incentive, paid out over ten years, for incremental wells. This amounts to \$1.50/BOE, compared to other proposed incentives ranging to more than \$10/BOE.

This is not, however, the full cost of a two-year extension of Section 29. As currently proposed, the credit would be paid on all eligible unconventional gas production, not just for wells stimulated by the credit. An estimated 5,220 unconventional gas wells would be drilled in 1991-1992 even without the credit. This is fewer than the more than 12,000 unconventional gas wells drilled in 1989-1990. This decrease is both because many 1991-1992 prospects were accelerated into 1990 to beat the current Section 29 expiration date, as well as the effect of project economics with the loss of the credit.

The estimated total wells drilled for 1991-1992 with the credit extension is 11,810. Reserves added by these wells would be 8.1 Tcf, 1991-2000 production would be 4.3 Tcf, and maximum Section 29 credits paid over the 1991-2000 period would be \$2,955 million. Because only 4.1 Tcf of incremental reserves are added, however, the maximum cost of these reserves is therefore \$0.72/Mcf or (\$4.17/BOE). Presuming one-third of this would not be paid, the likely undiscounted loss of Treasury receipts of a two-year extension of Section 29 would be \$1,970 over 10 years or \$0.48/Mcf (\$2.78/BOE). The breakdown by resource type is shown in Figure V-6.

This is the gross loss in U.S. Treasury receipts of adding 4.1 Tcf of gas reserves. It does not include the estimated \$336 million in new production and severance taxes to states and localities, \$150 million in royalty payments for production on federal lands, or the \$1,345 million in net increased state and federal income taxes paid. Increased energy security, decreased environmental costs, and increase economic activity in local economies and tribal communities are not included in these estimates. Thus, the undiscounted net public costs of the Section 29 extension are \$139 million, or \$0.03/Mcf (\$0.20/BOE).

Table V-5

Maximum and Most Likely Section 29 Credits Paid by Treasury
(Millions of 1990 Dollars)

	Incremental Wells		Total	Total Wells		Total
	Coalbed	Devonian		Coalbed	Devonian	
1991	17	30	72	29	44	158
1992	65	60	185	109	85	349
1993	109	54	204	177	75	362
1994	116	52	203	188	72	354
1995	102	50	183	175	70	327
1996	94	48	171	170	67	310
1997	90	46	160	167	63	294
1998	85	43	150	163	60	280
1999	81	41	141	160	56	267
2000	76	38	132	157	52	255
1991-1995	409	246	848	678	345	1,549
1991-2000	835	462	1,601	1,495	642	2,955
Incr. Resv (Bcf)	1,567	1,280	4,107	1,567	1,280	4,107
Cost/Mcf	\$0.53	\$0.36	\$0.39	\$0.95	\$0.50	\$0.72
Cost/BOE	\$3.09	\$2.09	\$2.26	\$5.53	\$2.91	\$4.17
Likely Utilization (2/3 of maximum possible claims) paid resulting from partial ineligibility due to corporate tax circumstances						
1991-2000	\$557	\$308	\$1,068	\$997	\$428	\$1,970
Cost/Mcf	\$0.36	\$0.24	\$0.26	\$0.64	\$0.33	\$0.48
Cost/BOE	\$2.06	\$1.39	\$1.51	\$3.69	\$1.94	\$2.78

Note: Incremental wells are the 6,590 wells stimulated by the 2-year extension. Total wells includes those wells that would have been drilled even without the credit extension (11,810 total).

Figure V-6

Estimated Section 29 Credits Paid on Unconventional Gas

SOURCE: ICF RESOURCES INC.

NOTE: DOES NOT INCLUDE RECEIPTS OF PRODUCTION AND SEVERENCE TAXES, STATE AND FEDERAL INCOME TAXES, OR ROYALTIES ON FEDERAL LANDS

On a discounted basis, however these unit costs increase dramatically. The timing of outlays, which occur early, and receipts, which occur over the life of the project, weighing the costs and diminish the revenues. The total streams of credits paid and revenues collected (severance, state income and federal income taxes), discounted at 10%, add up to \$1,032 million. This is equal to, for the 4.1 Tcf incremental reserves, a final cost to the public sector of \$0.25/Mcf (\$1.46/BOE).

VI. Alternative Section 29 Reformulations

The effectiveness and cost of the Section 29 incentive are the two most critical questions addressed by this report. Direct U.S. Treasury payments for the proposed two-year extension of the credit in its current configuration are estimated at \$1,970 million over 1991-2000 (excluding incremental public sector revenues generated by the credit). This cost is a function of both the level of incentive (cost per BOE) and the production for which it is eligible. The large number of wells that would receive credits that would have been drilled without the credit extension indicates that a more targeted incentive could be formulated.

The analysis reported above looked at only the current formulation of the credit, which is the most likely one proposed by Congress for extension. Two types of alternatives could be offered -- ones that expand the incentive to stimulate more production, and ones that restrict the incentive to reduce overall costs.

A. Expand Incentive

The current credit mechanism has shown itself to be quite powerful in its ability to add reserves and production. This is shown by the dramatic decrease in tight sands production after its eligibility was all but ended starting in 1985 and the coincident increase in coalbed and Devonian drilling as new technologies and incentives combined to make them attractive prospects. Although estimates of the effect on drilling and production of alternative formulations of the credit are beyond the scope of work, we discuss below three ways to expand the incentive:

- Provide an inflation adjustment for tight sands. Currently all fuels except tight sands under the Section 29 regulation are provided with an annual adjustment to the \$3.00/BOE credit amount to account for inflation. Extending this provision to tight sands would increase the amount of the credit from the current \$0.52/Mcf to \$0.89/Mcf, or the equivalent of adding another \$0.62/Mcf to the wellhead price. Based on the small net increase in tight gas wells due to restoration of eligibility of the credit, this would only have a modest incremental impact on reserve additions and be quite costly since it would be paid on all tight gas produced from new wells.

- Remove restrictions on tight formation eligibility requirements. Section 29 provides for only those formations designated by FERC as tight to be eligible for the credit. As incentive pricing became ineffective and decontrol was determined by the Martin decision, designations of new tight formations ceased. Development of several tight formations is proceeding only slowly because they aren't designated eligible for the incentive. Provision of alternative mechanisms for formation designation or eligibility for tight sands would expand the credit's effectiveness. This would be an efficient use of the credit because the additional credits paid would only be for incremental wells.
- Extend the placed in service eligibility period. The recent one-year extension and the proposed two-year extension makes planning difficult and cause severe distortions in the drilling activity of companies using the credit. Extending the period during which well drilling would be eligible for the credit would minimize this distortion. This could be done in concert with modifications to the credit to reduce its cost per Mcf, thereby keeping the total cost of the credit the same.

The overall impact of these modifications has not been assessed, although the latter two would be the most cost efficient.

B. Restrict Incentive

The Section 29 credit has been criticized by some, especially those preferring a market approach to energy, as overly generous. The most commonly cited methods to reduce the cost of the credit are limit eligibility by a rate or production cap, to limit eligibility until payback, or reduce the amount of the credit paid per Mcf.

We examined the project economics for typical wells of each of these formulations to see the impact on economic attractiveness. Sensitivity analyses were conducted on selected typical wells used in the main analysis. Both net present value (NPV) and internal rate of return (IRR) were calculated for formulations. Each of the 2 wells had an NPV of \$0 and an IRR of 10% at approximately \$2.00/Mcf wellhead price without the credit. Four cases are presented for both the current amount of the credit (\$3.00/BOE) and a reduced amount (\$1.50/BOE).

- Current formulation of the credit
- Credit only until project payback.
- Cap eligible production to 100 Mcfd.
- Cap eligible production at 100 Mcfd until payback.

The results are tabulated in Table VI-1 and are after tax values. The full tax credit under current formulation increases IRR from 10% to about 25% in all cases. The differing NPV's reflect the different amount of investments required to drill these wells (see Table V-2 for relative drilling and completion costs of these same typical wells).

Case 2, credit until payback, reduces IRR to between 16.9% and 19.6%, still above the minimum 15% after tax return required by most companies. This is an efficient formulation that provides for Congressional intent to support the prices paid for these new sources of gas, but eliminates that support when the operator is making a profit. For an unusually high productivity well that pays out in a year, no credit is paid past the point of profitability. For wells that don't produce well, some incentive is provided to partially offset the risks, the intent of the legislation. This is more efficient than the current time cap (until 2000). Since prudent investments optimally pay out within a few years, providing a credit past the point of profitability, could more efficiently be used to drill additional wells.

Case 3, a rate cap of 100 Mcfd, would provide full incentive for those wells that are poor producers and reduced incentives (relative to the current formulation) for high productivity wells. Some tight gas and coalbed wells produce more than 1 MMcfd, equivalent to a good conventional well that does not receive an incentive.

There are three parameters that need to be clearly addressed in a rate cap formulation: rate of eligible production, unit of time, and unit of production. The rate would be set at a level that would provide an effective incentive that would exclude production levels that would allow a well to pay back its costs in a normal period of time. The 100 Mcfd level was selected because the majority of unconventional wells would be fully eligible, but high productivity wells (those that are not high cost relative to their revenues) would receive a reduced incentive.

The unit of time to which the rate cap applies should address differences in producing characteristics between resources. Due to curtailment of production, a daily rate may be inappropriate. A monthly or yearly rate might minimize changes in producing practices merely to maximize the credit while still providing a generous incentive.

Table VI-1 **Section 29 Tax Credit Sensitivity Analysis**

Cases analyzed:

1. Full tax credit
2. Credit until payout
3. 100 Mcfd cap
4. 100 Mcfd cap until payout
5. All of above at \$1.50/BOE credit

\$3.00/BOE Credit

\$1.50/BOE credit

Tight Sands (Cotton Valley Well - minimum gas price \$1.99)

Case	\$MM NPV	IRR	Case	\$MM NPV	IRR
1	0.53	24.5%	1	0.26	16.8%
2	0.28	18.5%	2	0.17	14.5%
3	0.21	15.0%	3	0.10	12.5%
4	0.13	13.2%	4	0.07	11.8%

Coalbed Methane (Warrior Basin Well - minimum gas price \$2.15)

Case	\$MM NPV	IRR	Case	\$MM NPV	IRR
1	0.23	25.9%	1	0.11	18.2%
2	0.08	16.9%	2	0.06	14.6%
3	0.16	22.8%	3	0.09	16.7%
4	0.08	16.7%	4	0.04	13.4%

Devonian shale (Appalachian Devonian Shale Well - minimum price \$1.97)

Case	\$MM NPV	IRR	Case	\$MM NPV	IRR
1	0.17	27.3%	1	0.09	18.3%
2	0.08	19.6%	2	0.05	15.5%
3	0.16	26.1%	3	0.08	17.8%
4	0.08	19.0%	4	0.05	15.0%

Finally, the unit of production (e.g., well, lease, field) should be addressed. This is particularly true for coalbed, where the nature of the pressure distribution in a group of wells is such that some wells produce better than others. In these cases, production could be on an the basis of average production for a pattern or lease rather than for a well.

Table VI-1 shows differential responses to a 100 Mcfd per well cap by resource type. The low productivity Devonian well receives minimal reduction in incentives relative to the current formulation, while the higher productivity tight sands well has IRR reduced from 24.5% under the current formulation to 15% under a 100 Mcfd rate cap. The average Black Warrior coalbed well also receives a minimal reduction in incentive.

This does not, however, account for the fact that high productivity wells often cost more to develop. To provide incentives more equally across resource types, a combined rate cap until payout was analyzed (Case 4). This limits incentives for high productivity wells but retains the treatment of the high cost nature of all wells, whether they are good or poor producers. The poorest well, the Devonian shale well would have an IRR of 19%, while the tight sands well would have an IRR of 13.2%. The tight sand well would be marginally economic under these circumstances but this formulation would halve the difference in IRR between tight sands and the other resource types, compared to Case 3.

A final analysis looked at the project economics of each of these four cases with a credit that is reduced from the \$3.00/BOE to one half that amount. When the original law was passed, oil prices were approximately twice the level they are today. Therefore, the equilibrium price of oil the law was trying to tie the incentive to be reflected in the amount of the incentive. The results are similar to the \$3.00/BOE formulation except that the most equitable alternative formulation analyzed, credit until payback with rate cap (Case 4), makes all wells marginally economic, which would start to dramatically reduce the number of new wells drilled.

The impact on number of wells stimulated by these alternative formulations was not estimated in this study. There are, however, even more suggested methods to reduce the cost of the credit, although these may have a proportional reduction in production stimulated, thus costing the same amount per BOE:

- Limit the time of eligibility to less than the current ten years (e.g., if credit until payout is administratively burdensome, limit the credit to five years from spud date).
- Reduce the trigger price at which the credit begins to phase out (e.g., from \$23.50/BOE in 1979 dollars to \$18/BOE in 1990 dollars).
- Cap ultimate production eligible for the credit (e.g., 20 MMcf per well).

These alternatives should be investigated further. The structure of gas markets, the relationship of oil to gas prices, and the efficiency of tax incentives to stimulate production have all changed substantially since the original legislation was passed. This analysis shows the credit could be made more efficient.

VII. Summary and Conclusions

The Section 29 incentives have been unequivocally effective in stimulating drilling for unconventional sources of gas over the past ten years. The proposed extension of the credit will have a similar effect on drilling, allowing the nation to maintain, possibly increase, gas development to meet increasing demand.

The cost of the credit, appropriately including all public sector payments and revenues and discounted to current dollars, is \$1,032 million. This is equal to \$0.25/Mcf, or less than \$1.50/BOE. This is about 20% of the current \$1.35/Mcf U.S. average finding cost of gas, and an appropriate level for an incentive. This level is also one of the lowest of alternative petroleum incentives proposed in the current federal budget negotiations.

The proposed two-year extension of the placed in service date for new unconventional gas wells and reinstatement of eligibility for tight sands would add nearly 6,600 incremental wells and 4.1 Tcf of reserves during 1991-1992. Production would increase by between 200 and 300 Bcf per year over the next five years.

The credit cost-efficiently stimulates production because it is paid only for successful wells. The operator bears all the risk -- if no gas is found, no credit is paid. Average wellhead prices for all domestic gas would have to increase \$0.24/Mcf in 1991, \$0.17/Mcf in 1992 and \$0.03/Mcf in 1993 to stimulate an equivalent increase in production from the current resource base. This would cost consumers \$7.1 billion in higher wellhead prices.

Interpretation of the results of this study should not be considered merely as possible added reserves and production, but as the net effect of the extension of the credit. Because the credit has become structurally embedded in national gas completion trends over the past few years, gas well completions from conventional sources can be expected to decrease further. Since 1980, total gas completions have declined 60%, during a time when unconventional gas activity (including tight

sands) increased dramatically to more than half of all gas completions. Without continued aggressive development of these resources, gas completions can be expected to fall further.

Even though the efficiency of the Section 29 credit, whereby it only pays for results (production) rather than for just attempts (investment), is quite high, it could be made more efficient. A large number of wells will receive the credit even though they would have been drilled even without the credit. One of the benefits of the credits has been the support of technology improvements. Although most unconventional wells remain geologically, technologically and economically risky, improved technology has made some wells near-conventional that remain eligible for the credit. Several options, including rate, time or volume caps on eligible production, and reduction of the amount of the credit, should be investigated further.

Finally, modification of the eligibility window to a longer period or, at least, with more advanced notification, could reduce market distortions in drilling activity. The dramatic increase of activity in 1989 and 1990 is at least partially due to operators who are trying to "beat the window" of eligibility for the credit. A phased out credit is more appropriate than a specific date of eligibility.

Overall, the proposed two-year Section 29 production tax credit extension for unconventional gas is an appropriate and cost-effective mechanism to add gas reserves. It is one of the least expensive incentives under consideration and provides targets for the extraction of one of the largest new gas resources known.

Appendix A

The Unconventional Gas Resource

Unconventional gas resources (UGR) refer to natural gas produced from so-called high cost/high risk wells. These wells are defined in Section 107 of the Natural Gas Policy Act of 1978 (NGPA). The NGPA defined high-cost gas as gas produced from: (1) wells completed at a depth of more than 15,000 feet (provided surface drilling was begun on or after February 19, 1977), (2) geopressured brine, (3) coal seams, and (4) Devonian Shale. In addition to these four types of high cost gas, the law provided for FERC to determine other types of gas produced under conditions presenting extraordinary risks or costs. FERC used this authority to define two additional types of high cost gas -- that from tight formations (drilling begun on or after 16 July, 1979) and from production enhancement processes.

This report refers specifically to two types of gas defined in Section 107: gas from coal seams, and gas from wells drilled in Devonian age shale formations, as well as gas from tight formations which designated by FERC in Order 99 as being a "high cost/high risk" natural gas, and therefore eligible for price ceilings under Title I, NGPA.

Tight Sands

Introduction

Gas-bearing tight sandstone formations are currently the largest and most widely recognized of the unconventional natural gas resources. In 1988 they accounted for over 90% of all unconventional gas produced in the United States. The dominant characteristic of tight gas is its low *in situ* flow capacity. Formations are called tight when their *in situ* permeability is less than 0.1 millidarcy. In addition, such reservoirs often contain discontinuous (lenticular) pay zones and other heterogeneous geological properties. Because of these geological complexities, characterization of tight sands remains a major technical challenge.

Resource Base

The most comprehensive estimate to date of the U.S. tight gas resource base is in the U.S. National Petroleum Council's 1980 study of unconventional gas. This study appraised twelve tight gas basins leading to an estimate of 430 Tcf of natural gas in place. Based on an extrapolation from these appraised basins, the NPC speculated that an additional 510 Tcf existed in 101 other basins and regions. Thus the overall tight gas resource, as set forth by the NPC study is 940 Tcf.

Technology for Recovering Tight Gas

While the tight gas resource base is unarguably massive, the key issue is how much of this gas is economically recoverable. In turn, how much tight gas is recoverable when, and at what costs depends on how rapidly and how successfully advanced gas extraction technology can mature from research to field use. While numerous technical challenges exist, two are currently viewed as most critical:

- On the geologic front, there is need for improved diagnostic capacity to identify the higher grade tight gas deposits and, in particular, to define the continuity of the thick, complex sequence of reservoir sands. Engineering rules of thumb, adequate for conventional settings, are often misleading for tight settings.
- On the engineering front, the challenge centers on improved reservoir stimulation (fracturing). Once productive zones have been located and characterized, effective design and control of stimulation treatments determine economic recovery of gas from tight formations.

Development Activity

Tight gas already makes an important contribution to U.S. supplies of natural gas:

- Tight gas provides approximately 1.4 to 1.7 Tcf per year to U.S. supplies and accounts for a major share of the gas production in Colorado, New Mexico, and Wyoming. While some of the tight gas production is a residual of incentive prices during the early 1980s, and improvements in technology have helped maintain the momentum, substantial further technology advances are needed to increase the market share of tight gas.

- Drilling in tight formations has continued through the recent period of low gas prices. Over 5,000 designated tight wells have been drilled annually since 1981, with a peak of 10,000 drilled in 1982. Approximately three-fourths of these wells have been drilled in the tight gas formations of the Appalachian basin. The decline in gas prices since 1984 has reduced drilling to less than 6,500 wells per year.

Coalbed Methane

Introduction

Coalbed methane production is a relatively new industry. Less than twenty years ago there were only a few research and demonstration wells; in 1989 there was a commercial production of over 80 Bcf (up from 35 Bcf in 1988). While this production took place primarily in Alabama (Warrior Basin), Colorado (Piceance Basin), and New Mexico (San Juan Basin), coalbed methane operations are under development in seven other states: Pennsylvania, West Virginia, Virginia, Wyoming, Mississippi, Oklahoma, and Utah.

By early 1991, it is estimated that the San Juan Basin will be producing 600 million cubic feet per day of coalbed methane, the Warrior Basin will be at 200 million cubic feet per day, and other basins, such as the Raton, Piceance and Appalachia, may add another 200 million cubic feet per day.

Significant expansions of gas processing, field gathering and pipeline systems have been announced for bringing these new supplies to market. For example, El Paso Natural Gas is planning to add 26 miles of large diameter pipe and install 3,600 hp of compression to its San Juan Triangle System to carry 500 MMcfd of mainly San Juan Basin coalbed methane. Also, Northwest Pipeline is looking to lay 154 miles of 30 inch pipe to link 500 million cubic feet per day of coalbed methane and shut-in conventional gas at the Ignacio gas plant at Durango, Colorado with the Transwestern Pipeline system serving California.

Resource Base

The amount of gas in coal seams depends upon factors such as maturity of the coal, geothermal history and depth. Bituminous and sub-bituminous coals not only are great generators

of gas (at temperatures greater than 176 °F (80 °C)), but are likely to contain the most amount of methane at a given depth. Generally, the deeper the coal seam, the more gas per unit volume it will have; coal seams typically contain 200 to 600 cubic feet/ton. This means that a 20 foot coal seam can contain 5 to 14 Bcf per square mile.

In a literal sense, any basin that contains coal, contains natural gas. However, the bulk of the U.S. coalbed methane resource is in 13 large basins. Recently, ICF Resources, conducting research for the Gas Research Institute, completed five basin-level resource studies of the Warrior, Piceance, Northern Appalachian, Central Appalachian, and San Juan Basins. These studies show that about 250 Tcf of natural gas is in place in these five basins. These and other resource studies have begun to identify the favorable reservoir settings and areas of higher gas concentrations in the U.S. coal basins. An additional 150 Tcf of gas in place is speculated to exist in the eight other U.S. coal basins, however, current data are insufficient for making reliable estimates of their in place resources or recoverable reserves.

Technology for Recovering Coalbed Methane

The process of gas desorption within the coal matrix necessitates a unique approach to well completion, stimulation, and dewatering of the coal seam. Furthermore, stratigraphically, coal is often distributed in relatively thin seams over large intervals. This means that for economic recovery, special production practices and multiple completions from the same wellbore will be required. Finally, the mechanical properties of coal, different from reservoir rocks typically encountered by the oil and gas industry imply that specialized stimulation technologies are required to convert this resource into a low-cost reserve.

The important question is, how much can be recovered under present or foreseeable economic conditions? It is commonly accepted that recoverable gas is less than 10% of gas in place with today's economics and technology. With the increasing amount of effort being focused on extraction of methane from coal, particularly in the U.S., we would expect this recovery efficiency to improve in the future.

Development Activity

Coalbed methane represents the fastest growing and potentially the economically most attractive of the low permeability gas sources. From a base of a few research and demonstration wells in the 1970s, there are currently over 2500 wells producing natural gas from coal seams. The greatest drilling activity is in the Warrior Basin, which has over 2000 producing wells. The greatest production is from the San Juan Basin, where 450 wells produced over 50 Bcf in 1989. Activity is also underway in the coals of the Appalachian, Arkoma, Piceance, and Raton basins.

Devonian Shale

Introduction

The fractured, organically rich devonian age shales of the Appalachian, Illinois, and Michigan basins contain a huge concentration of organically rich carbon and gas in place. Unlike coalbed methane and tight gas, which both are relatively new sources of natural gas, production from Devonian shales dates back to the turn of the century.

Resource Base

The bulk of devonian shale gas production to date has been from the tectonically altered areas of the appalachian Basin where natural fractures and other permeability channels provide paths of flow. The resource includes free gas in the natural fracture and porosity system as well as adsorbed gas on the surface of the organic kerogen. While the gas resource per-unit rock is lean this is counter-balanced by the thick shale column and numerous producing horizons contacted by a single well.

Where these shales are naturally fractured, there is the potential for commercial production. One of the earliest uses of natural gas in North America was to provide fuel from the Devonian shales for a lighthouse built in 1821 at Barcelona, New York. Since then about 10,000 wells have been drilled to the Devonian shale. Completion methods have varied from inexpensive stimulation by detonation of gelled nitroglycerine to the most expensive massive hydraulic foam fractures.

Although these wells are generally low productivity (typically less than 200 Mcf/day), they are capable of producing for many decades.

The total gas in place in Devonian age shales may be extremely large. It is only the gas in permeability contact with a wellbore, however, that can be produced. The producing gas in place for the Devonian age shales has recently been estimate by ICF Resources for he U.S. Department of Energy and GRI. These studies estimated 266 Tcf of gas in place in the three states of Kentucky, Ohio, and West Virginia.^{1,2,3} Resource studies by the U.S. Geological Survey and others have speculated that another Tcf of gas in place may exist in the remainder of the Appalachian Basin.

Technology for Recovering Gas from Devonian Shales

As for the other low permeability gas sources, the three key challenges to technology are to establish:

- here to drill. Which areas have sufficient gas in place and permeability?
- Where to complete. Which zones in the massive shale sequence contain natural fractures, silts, or bedding planes?
- How to stimulate. How can long effectively propped fractures be contained in unbounded shales?

Development Activity

To date, over 10,000 wells have drilled into the Devonian Shale of the Appalachian Basin. The vast majority of the wells are concentrated in the Big Sandy field in Eastern Kentucky and West

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¹ Kuuskraa, V.A., et al, "Technically Recoverable Devonian Shale Gas in Kentucky," DOE/MC/19239-1834, 1985.

² Kuuskraa, V.A., et al, "Technically Recoverable Devonian Shale Gas in Ohio," DOE/MC/19239-1525.

³ Kuuskraa, V.A., et al, "Technically Recoverable Devonian Shale Gas in West Virginia," DOE/MC/19239-1750, 1984.

Virginia. In 1988, as has been the recent history, the majority of the Shale wells drilled in the basin were development wells.

There were, however, a number of deep and shallow pool tests and wildcats. Some of these exploratory wells came in with high initial potentials, indicating that there are still undeveloped productive shale areas in the basin.

Estimates of Future Supplies and Reserves

Estimating Tight Sands Supplies and Reserves

The most important reservoir parameter to consider in terms of a resource assessment of tight sands is the permeability. Permeability is a measure of the interconnectedness of the pores of the reservoir rock and thus represents the availability of channels through which gas can move through the rock to the well bore.

Other important considerations are the lateral continuity and geometry of the gas producing sandstone beds, both of which tend to vary considerably, depending on environment of deposition. Nearshore and marine sandstones form areally extensive deposits which are generally referred to as blanket formations. In contrast, river bed deposits form laterally discontinuous lenticular bodies occurring interbedded with shale beds. Their size, orientation, and geometry are difficult to predict. The lenticular formations frequently are found stacked in thick sequences, whereas the blanket formations usually consist of thinner beds.

Estimating Coalbed Methane Supplies and Reserves

Establishing reserves for coalbed methane involves three stages -- estimating the gas in place, calculating methane recovery, and performing an economic analysis. The first step, estimating the gas in place, is relatively straightforward. The volume of coal can generally be well defined and the gas content of the coal can be accurately measured. Given reliable estimates of gas and water recovery and their flow rates, the economic analysis is also straightforward, although special attention

needs to be given to properly accounting for the tax credit. The second step, calculating gas recovery, represents a major challenge. Here, the traditional methods of using analogy, decline curves, and material balance calculation are not applicable. Neither is using volumetric calculation with an assumed recovery factor. The only reliable method currently available for estimating coalbed methane reserves is reservoir simulation.

The reasons coalbed methane reserves are more difficult to evaluate than conventional gas reserves are that coalbed methane wells pass through three distinct stages of production. During the first stage, as the coal reservoir dewateres, methane production increases (the "negative decline curve"). Changes in relative gas-water permeability and the relationship of the coal and reservoir desorption pressures will govern production during this initial stage. The first stage ends as the pressure level reaches the reservoir boundary. During the second stage of stable gas production, improving relative gas-water permeability and desorption are counterbalanced by loss of permeability due to formation compaction. The third stage mirrors conventional gas production as the driving pressure in the reservoir declines.

Estimating Devonian Shale Supplies and Reserves

The difficulty in accurately estimating Devonian Shale supplies and reserves stems from the generally poor understanding of the natural fracture system in shales, and the effects the natural fractures have on the results of wellbore stimulation. The heterogeneity of natural fracturing in shale formations creates situations where alternatively sized fracture treatments have shown little or no discernible difference in gas production. Therefore, the reserves which lie outside a proven area cannot be accurately inferred from historical production from known areas. No acceptable model for Devonian shale reservoir behavior yet exists.

Appendix B

Unconventional Gas Development Activity

The U.S. Department of Energy's Energy Information Administration (EIA) has conducted thorough analysis of unconventional gas activity over the life of the NGPA (1978 - 1988). Based on NGPA Section 107 well filings and commercially available production data, EIA has estimated unconventional gas production for this period. The data generally reflect the trends which ICF Resources is tracking in its ongoing analysis of unconventional gas. The recent (1989 and later) drilling and production data compiled by the EIA seem to be less than expected when compared to state data. This is mostly due to delays in reporting by states of new wells. Except where noted, the comments below are based upon EIA analysis only.

Unconventional Activity by State

Unconventional exploration and development activity has varied greatly in different states. Some, e.g. New Mexico and Alabama, have seen a virtual boom in activity due to unconventional resources. Other state, e.g. Ohio, have not shown an increase in activity, but, rather, have production trends that have remained flat or even declined. The following section describe state by state the trends in unconventional gas activity. At the end of the section is a table which shows state by state the trends in numbers of producing unconventional wells, the amount of unconventional gas produced from 1984 to 1988, and current incentives for production.

Alabama

Coalbed methane activity has increase dramatically in Alabama over the last five years, both in relative and absolute terms. Coalbed methane production has more than tripled over the last five years, as has the number of producing wells. Coalbed methane now accounts for over 12% of all gas production, up from 5% in 1984. It is the most active coal basin in the country in terms of coalbed methane wells drilled. The drilling activity is best characterized as "frenzied." The number of wells

has increased from 374 in 1987 to 2,068 in 1989. Estimates of coalbed methane reserves for the state run as high as 10 Tcf.¹

Colorado

Colorado is the fifth largest producer of unconventional gas. Portions of four major coalbed methane-producing basins (Uinta, Raton, Mesa, San Juan, and Greater Green River) lie within the state, as well as the entirety of the Piceance Basin. These basins contain both tight sand formations as well as coal beds suitable for coalbed methane production. Although gas from tight sand formations still account for about 90% of all unconventional gas production. The number of tight sand wells and production has remained relatively flat during the last five years. Coalbed methane activity, on the other hand, has more than doubled (from 48 wells in 1984 to 134 in 1988, and from 1.1 Bcf production in 1984 to 4.5 Bcf in 1988).

Kentucky

Kentucky's unconventional gas production accounts for 41% of its total gas production. This percentage has remained relatively constant over the last five years. Devonian shale gas wells produce 94% of the unconventional gas. The number of Devonian wells and production has not grown much over the last five years, both have grown by less than 1% on a compounded annual basis.

Louisiana

Louisiana's unconventional gas resources comprise part of the same basins that supply East Texas: the Anadarko and Cotton Valley. Louisiana's unconventional gas production comes from tight sands formations only. The number of producing wells nearly doubled between 1984 and 1988, from 605 to 1,149, but the production declined slightly, from 33.6 Bcf in 1984 to 31.6 Bcf in 1988.

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¹ Estimate based upon GRI estimate of total resource GIP and the percentage of the areal extent of the basin which lies within the state.

Michigan

Based on EIA data, the scale of Michigan's unconventional gas production has not changed over the last five years. The total overall number of wells has increased slightly from 156 to 158, but production has dropped from 2.7 Bcf to 2.4 Bcf per year. All of Michigan's unconventional gas is Devonian (Antrim) shale. However, based on data compiled by ICF Resources from operators in the state, drilling has increased dramatically (Table 3 in the main body of this report) to an expected 400 wells in 1990.

Mississippi

Mississippi has both tight sand and coalbed methane unconventional gas resources. To date, only the tight sands formations have produced much gas, and this tight sand gas represents only around 1% of overall gas production. The coalbed methane resource, though, holds much promise. Approximately, one-half of the Warrior Basin lies in Mississippi, and the state is very eager to develop this resource. The state legislature recently dropped its severance tax to 3.5% for the first five years of production (.5% less than neighboring Alabama) and has spent money to help develop geologic data on its coalbed methane resources. To date, however, no coalbed activity of any scale or scope has occurred.

New Mexico

New Mexico is the largest producer of coalbed methane. Production topped 8 Bcf in 1988 and 50 Bcf in 1989. Estimates of gas in place run as high as 84 Tcf in the San Juan Basin, and 18 Tcf in Raton Mesa. (About one-half of Raton lies in New Mexico.) Like Alabama, the state is currently enjoying a boom in drilling activity as producers race to spud as many wells as possible before the current expiration date of the Section 29 Tax Credit. There were approximately 450 producing wells at the end of 85 and by mid-1990 over 550.

New York

New York's unconventional gas resource are Appalachian Devonian shale and tight sand. Production and total number of producing wells has remained flat for the past few years.

Ohio

Like New York, Ohio has both Devonian shale and tight sands formations. The number of Devonian shale producing wells and production has remained constant, however, the tight sand activity has steadily increased year by year by approximately 78%. They have more unconventional gas wells than any other state, and behind Texas, are the largest producer of unconventional gas. Unconventional gas production accounted for 82% of all gas production, up from 54% in 1984. This increase in production by Section 107 wells occurred as conventional and overall gas production dropped.

Oklahoma

Oklahoma contains resource of both tight sand and coalbed methane. Production, though has been restricted to tight sands only. The coalbed methane potential of the Arkoma Basin is not thought to be as high as in other areas. Unconventional gas production has doubled over the last five years, but still remains insignificant compared to production from conventional resources.

Pennsylvania

Pennsylvania is one of the four states which has coalbed methane, Devonian shale, and tight sands resources. Tight sands resources, however, dwarfs the other two. Between 1984 and 1989, tight sands production grew at an annualized rate of 12% per year. In 1988, Pennsylvania was the nation's third largest producer of unconventional gas. There are no commercial coalbed methane wells, and many of the "Devonian wells" only became classified under section 107 after the 1988 redefinition of what "Devonian Shale" means.

Tennessee

Tennessee has both Devonian aged shale formations and tight sands. Activity however, is only nominal; production from these unconventional resources was less than .1 Bcf during the period of 1984 to 1988. This production represented only 1% to 2% of all gas production in the state.

Texas

Texas is by far the largest producer of unconventional gas in the country. It has numerous basins which contain gas-bearing tight sands formations. During the period 1984 to 1988, Texas' production accounted for 61% of the country's tight sand production, or 57% of the country's unconventional gas production overall. Production grew from 590 Bcf in 1984 to 740 Bcf in 1988.

Utah

Utah has coalbed methane and tight sands unconventional gas resources. Although the Uinta Basin is estimated to have as much as 5 Tcf, production is currently confined to tight sands. Unlike most other states, unconventional gas production dropped in the period of 1984 to 1988. In absolute terms, annual production dropped from 16.0 Bcf to 10.5 Bcf, and as a percentage of overall state gas production, unconventional gas dropped from 9% to 6%.

Virginia

Like Pennsylvania, Virginia contains unconventional gas resources in Devonian shale, tight sands, and coal basins. To date, however, activity has concentrated in tight sands. The number of producing wells and production from tight sands more than tripled between 1984 to 1988. Coalbed methane production is set to take off as the Governor of Virginia recently signed into law a measure which cleared up ownership rights of gas in coal seams.

West Virginia

West Virginia's unconventional gas production comes from Devonian shale and tight sands. In 1988, Devonian production represented two-thirds of the total unconventional gas production. Tight sands production, however, has grown 50% faster during the period of 1984 to 1988. There is research and exploratory activity for coalbed methane in West Virginia coal fields, however, no commercial production is underway. Production has been hindered by existing laws which essentially ban most coalbed methane wells. These laws are currently under debate in the West Virginia legislature and may change in the near future.

Wyoming

Like Utah and Colorado, Wyoming contains extensive coalbed methane resources, but produce most unconventional gas from tight sands formations. Wyoming's gas production from tight sands remained constant during the period of 1985 to 1988 at about 75 Bcf per year production. Relatively speaking, this meant about 15% of Wyoming's total gas production came from unconventional sources. Recently, there has been increasing interest in its coalbed methane resources, as pilot programs have been initiated in the Powder River, Wind River, and Green River Basins.

Other States

Coalbed methane plays are being developed in southeastern Kansas, western Washington, and other states.

DOE/EIA Unconventional Gas Database (1987-1987)

State	Resource	Drilling (Wells Producing)					Production (Mcf)			Incentives/Taxation
		84	85	86	87	88	84	85	86	
Alabama	Warrior Basin	185	247	446	374	501	6.4	8.7	13.0	4% severance tax for 1st 5 years of coalbed methane production (versus 8-10% normal severance tax)
	Coalbed Tight Sands	0	0	1	1	7	0.0	0.0	0.1	
Colorado	Raton Mesa San Juan Basin Piceance Basin	48 2,715	49 2,399	54 2,612	105 2,682	134 2,744	1.1 54.6	0.5 57.1	0.4 53.2	2.5% severance tax (depending on sales)
	Coalbed Tight Sands									
Kentucky	Appalachian Basin	2,666	2,696	2,741	2,779	2,786	27.2	26.7	26.8	4.5% gross production tax
	Devonian Tight Sands	35	49	56	73	72	1.0	1.3	1.5	
	Tight Sands	609	751	894	1,042	1,149	33.2	30.5	31.2	\$0.03/Mcf severance tax
Louisiana	Cotton Valley Basin Anadarko Basin									5% severance tax
	Devonian Tight Sands	156	156	158	162	158	2.7	2.5	2.4	
Michigan	Antrim Shale									3.5% severance tax for 1st 5 years of coalbed methane produced vs. 6% round severance tax
Mississippi	Warrior Basin	9	9	8	8	8	1.7	1.2	1.5	
	Coalbed Tight Sands	16	17	20	23	25	1.4	1.2	2.6	3.75% severance tax
	Devonian Tight Sands	886	930	940	1,032	1,109	63.8	54.1	44.9	
New Mexico	San Juan Basin Permian Basin Raton Mesa									No state tax
	Devonian Tight Sands	14	14	14	14	14	0.1	0.1	0.1	
	Devonian Tight Sands	2,011	2,383	2,647	2,831	2,741	13.1	15.2	16.5	\$0.025/Mcf
New York	Appalachian Basin	2,268	2,525	2,552	2,571	2,571	11.8	11.9	11.4	Production tax 7% Conservation \$0.07/Mcf less 7% of gross value
Ohio	Appalachian Basin	13,151	16,293	18,145	19,488	19,078	89.8	109.7	119.3	
	Devonian Tight Sands									
Oklahoma	Arkoma Basin	46	52	47	50	48	3.3	5.3	6.1	
	Tight Sands									

DOE/EIA Unconventional Gas Database (1987-1987) (Continued)

State	Reservoir	Drilling (Wells Producing)					Production (Bcf)					Incentives/Taxation
		84	85	86	87	88	84	85	86	87	88	
Pennsylvania	Appalachian Basin	0	0	1	2	1	0.0	0.0	<0.1	<0.1	<0.1	No state tax
		17	28	38	43	43	0.1	0.3	0.4	0.4	0.4	
		3,745	5,119	6,144	7,016	6,777	46.0	61.6	73.0	84.7	81.2	
Tennessee	Appalachian Basin	3	5	8	8	8	<0.1	<0.1	<0.1	<0.1	<0.1	3% severance tax
		22	23	24	26	24	<0.1	<0.1	<0.1	<0.1	<0.1	
Texas	Anadarko Basin	5,177	5,782	5,843	6,032	6,180	590.2	693.8	764.4	763.1	740.3	No severance tax
Utah	Uinta Basin	198	201	204	207	207	16.0	12.9	11.5	9.7	10.5	4% occupation tax
Virginia	Appalachian Basin	32	34	34	35	34	0.4	0.4	0.4	0.4	0.4	
		75	127	238	365	256	2.3	4.0	7.4	11.0	7.8	
West Virginia	Appalachian Basin	3,459	4,184	4,621	4,931	4,955	24.8	29.9	32.8	35.3	34.9	Severance tax:
		706	1,014	1,208	1,469	1,338	7.5	10.5	11.9	14.9	12.9	1989 5.5%
												1990 5.0%
												1991 4.5%
												1992 4.0%
Wyoming	Power River Basin	1	1	1	1	0	<0.1	<0.1	<0.1	<0.1	<0.1	6% severance tax
		594	621	616	630	592	74.2	77.4	65.8	73.1	77.7	
	Wind River Basin											
	Greater Green River Basin											
	Powder River Basin											
	TOTALS											
	Coalbed						9.0	10.3	16.1	22.8	32.6	
	Devonian						67.1	71.7	74.3	78.3	77.6	
	Tight Sands						996.8	1,130.0	1,120.0	1,250.0	1,220.0	

Appendix B

Technical Issues

Tight Sands¹

While the tight gas resource base is unarguably massive, the key issue is how much of this gas is economically recoverable. In turn, how much tight gas is recoverable when, and at what costs depends on how rapidly and how successfully advanced gas extraction technology can mature from research to field use. While numerous technical challenges exist, two are currently viewed as most critical:

- On the geologic front, there is need for improved diagnostic capacity to identify the higher grade tight gas deposits and, in particular, to define the continuity of the thick, complex sequence of reservoir sands. Engineering rules of thumb, adequate for conventional settings, are often misleading for tight settings.
- On the engineering front, the challenge centers on improved reservoir stimulation (fracturing). Once productive zones have been located and characterized, effective design and control of stimulation treatments determine economic recovery of gas from tight formations. Among the variety of R&D programs supported by GRI, two research concepts show particular promise:

Integrated Log Analysis System. The interpretation of wireline logs in low porosity and permeability tight gas sands, such as those found in East Texas and Western U.S. Basins, is complicated by time-dependent resistivity changes due to filtrate invasion. To solve this problem, the Gas Research Institute has sponsored the development of an integrated log analysis system for tight sands that offers improved formation evaluation capability.

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¹ Adapted from "Natural Gas From Low Permeability Formations," SPE 17746, by Kuuskraa, V.A., and Haas, M.R., 1988.

Cooperating with industry, GRI used the integrated log analysis system on several wells in the Travis Peak (Texas) and Corcoran-Cozzette (Colorado) sandstones. The integrated data suite from cores, wireline logs and completion tests led to improved pay zone selection and fracture placement.

The integrated log analysis system correctly identifies drilling fluid invaded intervals that have high gas saturation, which traditional wireline log interpretations would read as "wet." Moreover, this system yields more accurate predictions of irreducible water saturation and permeability calculations, two of the key mechanisms that govern gas production rates. Integrated log analysis, when combined with the cased hole logging suite, will also be valuable for identifying economically attractive bypassed and "behind-the-pipe" gas zones in already drilled and logged wells.

Real Time Monitoring, Analysis, and Control System for Hydraulic Stimulation. In low permeability, "tight" formations and complex reservoir settings, such as layered gas and water zones, large treatment volumes and properly placed and controlled fractures are essential for achieving economically attractive rates of gas production. Yet, propagating such large, effective hydraulic fractures is often hindered by undesirable vertical fracture growth and inefficient proppant transport.

The control levers available today -- the use of surface recorded pressure and the modifications of pumping rates, fluid volumes and sand concentrations - are inadequate. The delays in detection of downhole pressure change and the difficulties obtaining accurate fluid rheology measurements make real-time treatment response difficult.

To achieve the goal of improved hydraulic fracturing, GRI and many companies have developed a mobile, computer-based, real-time fracture monitoring, analysis and control center that can be transported to and installed at a well site. Combined with the knowledge gained from rheology research, real-time data collection and fracture modeling, the it integrates the formation evaluation and stimulation design and monitoring knowledge to deliver the optimum fracture treatment.

Coalbed Methane

A number of special engineering and testing steps are required to properly measure the unique properties inherent to coalbed methane:

- *Gas Content.* While initial values for gas content may be estimated from coal rank and depth relationships, controlled desorption of coal cores are required for accurate data.
- *Net Coal Thickness.* High resolution logs are needed to identify the thinner coal seams, and laboratory analysis of ash content are important to establish the true net or clean coal thickness.
- *Desorption Isotherm.* Each type of coal has its own isotherm that governs the release of the adsorbed gas; importantly, it is essential to establish whether the gas content in the coal is "on the isotherm" and thus readily releasable or whether the coal is undersaturated and requires significant depressuring before methane is released.
- *Diffusion Properties.* While recent work indicates that the diffusion properties of U.S. coals are favorable, diffusion times of 300 or more days have been reported for some coals; controlled methane desorption and readsorption of coal cores can provide this important data.
- *Absolute and Relative Permeability.* Because it is a fractured medium, the permeability of a coal seam is almost impossible to measure in a laboratory. Short term slug tests and longer term water injection tests can provide the initial estimates. Ultimately, simulator based history matching will be required to establish reliable values for permeability, including the relative permeabilities of gas and water.

Other coal reservoir and rock properties are important to gather, such as porosity, pressure, temperature, and gas composition. However, while important, these measures can be obtained through traditional reservoir testing and engineering methods.

Reservoir Engineering. A reservoir engineer, one well experienced in coal properties, its storage/release mechanisms, and its special production practices, is invaluable to a successful coalbed methane project. The role of the reservoir engineer is to assemble and integrate the basic data, to estimate the production and reserves of methane, and to recommend the best well drilling, completion, stimulation and spacing strategies. This is particularly critical as conventional "rules of

thumb" about well spacing and stimulation design rarely hold. For example, closer well spacing often provides higher early time production rates and better economics due to the positive effects of well interference in a two phase gas-water system. Also, much higher proppant concentrations are important to extend a low pressure sink far into a coal reservoir to enhance efficient desorption.

Drilling, Completion and Production

Coals present a special challenge to the driller and reservoir engineer, because coals are easily damaged, difficult to stimulate, and a challenge to produce for methane. How best to drill, complete and produce coalbed methane wells is still being learned, however, some insights have been gained from the experiences to date.

- **Drilling.** The first question faced by the driller is choosing the proper drilling fluid, one that will maintain well control yet prevent formation damage. The second question is whether to case across the coal face and risk further damage and cement invasion or to leave the coal interval (or intervals) as an open hole. While the early preference was for open hole completion (in the Warrior Basin) and while high gas production has been achieved with cavity-type open hole completions (in the overpressured settings of the San Juan Basin), the industry trend is toward cased wells with perforations. The economic attractiveness of multiple seam completions and the need for greater control over the hydraulic stimulation are responsible for this change in the choice for well completions.
- **Stimulation.** Except in areas of high natural permeability, coalbed methane wells need to be artificially stimulated to achieve commercial rates of gas flow. Because coal is a naturally fractured, a somewhat plastic, and a readily crushable material, its stimulation has proven to be particularly challenging. High treatment pressures, limited proppant penetration, and complex fractures are common to coalbed methane stimulation. More rigorous definitions of reservoir and bounding layer stresses, higher proppant concentration carrying fluids, and improved fracture diagnostics and control are all required for effective stimulation of coalbeds.
- **Production.** The production challenges are many, but generally solvable. Dewatering and pump selection, produced water disposal, well and surface equipment workover, and gas treatment and compression all need to be thoroughly addressed for a smoothly operating coalbed methane field.

Devonian Shale

As for the other low permeability gas sources, the key challenges to technology are to develop:

Shale Specific Logging System. Research to date has begun to provide logging and interpretive tools to isolate the productive zones seen by a wellbore. One problem with traditional interpretation is distinguishing between apparent and effective porosity. A formation evaluation log, tailored specifically for Devonian shales, is now able to do this by identifying four individual porosity "elements," as seen by logs.

Low Liquid Volume Stimulations. To propagate fractures deep into the formation requires large fracture treatments which maximize proppant and minimize liquid volumes. Recent analytical studies on massive hydraulic fractures treatments identified liquid cleanup as specific detriment to increased gas production in these low pressure formations. Improved quality control during treatment and careful formulation of breaker mixtures are currently under investigation to address this problem.

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Appendix C

Legislative and Regulatory Overview

Legal History

From 1938 to 1978, the Federal Government regulated only the interstate natural gas market. By the 1970's, however, shortages in the interstate market developed because gas producers could get higher prices in unregulated intrastate markets. In 1977, two conflicting legislative solutions were developed: the Senate passed a bill deregulating interstate gas; the House passed a bill extending Federal regulation to intrastate gas. The Conference Committee struck a compromise. The result was the Natural Gas Policy Act of 1978 (NGPA).

The availability of tax credits due to the production of fuel from nonconventional sources originated in the Crude Oil Windfall Profit Tax of 1980. With the enactment of the Tax Reform Act of 1984, the tax credit provisions were reclassified to their current status under Section 29 of the Internal Revenue Code. The fundamental provisions of the tax credit and its computation have remained intact since passage of the original legislation, even though functional modifications have been required due to changes in the regulatory and energy environment, such as natural gas deregulation.

Between the NGPA, which established price controls for natural gas, and the Windfall Profits Tax Act, which created the production tax credit, the producers had two sources of government price assistance. The first was a price ceiling 50% - 100% higher than other price ceilings, the other worked a price floor which was \$0.52 (1979 dollars) higher than the prevailing market price. The Economic Recovery Tax Act of 1981 prevented producers from receiving both at the same time.

In December 1984 FERC issued Order 406 which focused on the regulation of natural gas which qualified under more than one section of the NGPA. FERC's order on so-called "dually qualified" gas issue created significant controversy as it stated that gas which qualified under more than one section of Title I of the NGPA, e.g. both as a Section 102 or Section 103 "new" gas, and

as a Section 107 unconventional gas, would be considered deregulated when deregulation was phased in 1985 and 1987 per the NGPA. Gas considered deregulated would no longer qualify for price supports or tax credits.

Order 406 was immediately appealed by numerous producers to the U.S. Court of Appeals. This court overturned Order 406 and ruled in favor of the producers, i.e. the court rejected the argument that dually qualified gas would be deregulated in 1985 and 1987. The legal controversy caused by this order was not solved until 1988, when the Supreme Court issued the so-called Martin Decision. In the Martin decision, the Supreme Court overturned the appellate decision and upheld FERC Order 406.

Passage of the Natural Gas Wellhead Decontrol Act of 1989 also supports termination of the incentive ceiling prices for new supplies of gas. In this Act, Congress amended the NGPA and mandated that all wellhead price controls be phased out in the next several years. On January 1, 1993, Title I of the NGPA, which contains all the wellhead pricing provisions (including the authorization for the incentive price rule), will be repealed.¹

The phased decontrol of wellhead pricing under the Act works as follows. Effective on the Act's date of enactment, there were no more wellhead price controls for any natural gas whose pre-existing first sales contract expires or is terminated, for any natural gas sold under certain renegotiated contracts, and for any natural gas not subject to a first sale contract as of that date.² Wellhead sales of natural gas from wells spudded after 26 July, 1989, subject to contracts on 26 July, 1989, will no longer be subject to price controls as of 15 May, 1991.³ And all wellhead sales of natural gas, including sales of old gas that would have remained indefinitely under price controls under the NGPA as it was originally enacted, will be free from price controls as of 1 January, 1993.⁴

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¹ Excerpted from FERC Order 519.

² NGPA section 121(f)(1)-(3), 15 U.S.C. Section 3331.

³ NGPA section 121(f) (4).

⁴ Well Decontrol Act, section 2 (b).

As the legislative history of the Wellhead Decontrol Act makes clear, Congress recognized that continuing the elaborate system of vintages and categories of wellhead price controls in the NGPA was not in the public interest. Congress in 1978 had been intent on ending the natural gas shortages of the 1970's by giving incentives to new and high-cost gas production. But the regulatory pricing scheme distorted the marketplace, by encouraging the development of higher cost sources of production than may have developed in a free market. Congress felt that consumer interests were not fostered by the remaining price controls, since they affected only a small and declining portion of the market and certain gas could receive above-market prices as new and decontrolled gas.⁵ In this competitive market environment, the escalating price ceilings of the NGPA have become increasingly irrelevant.

Congress therefore concluded that it was in the national interest to move away from the partly regulated environment of the NGPA to a wellhead market for natural gas that is completely free from price controls. In this market, all gas will compete free from price controls. In this market, all gas will compete on the basis of its own value, and supply and demand will play a greater role in determining whether producers develop whatever gas will be the least expensive in cost to produce and the most valuable to sell, but only that gas that the market needs.⁶ As the phased decontrol of the Act takes effect, therefore, all natural gas will increasingly have to compete without the benefits (or burdens) of price controls.

In this transition period until the repeal of all wellhead price controls, FERC felt it was no longer necessary to maintain the incentive prices for new supplies of section 107 (c) (5) gas. Given the long lead times to develop and produce this gas and the current state of the gas markets, as discussed above, it is not in the public interest for any producer to make new investments in producing high cost gas in reliance on the incentive price rule.

Roughly the same time that wellhead decontrol was being debated the Section 29 tax credit was extended by the Technical Corrections Act of 1988. Significant lobbying efforts by producers

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⁵ The EIA estimated that only about 8% of the nation's total supply of natural gas consists of old gas, and most gas still subject to price ceilings sells at far less than the applicable ceilings due to competitive market conditions. H.R. Rep. No. 29 at 3-4.

⁶ H.R. Rep. No. 29 at 6-7, S. Rep. No. 38 at 10-11.

succeeded in extending the tax credit eligibility date one year. In order to claim the tax credit on unconventional gas production, the producer can now spud a well as late as 31 December, 1990.

The most recent development concerning the Section 29 Tax Credit is FERC Order 519, which was issued in February 1990. This order, in essence, moved the eligibility date for the few remaining tight sands wells which still qualified for the credit from 31 December, 1990, the date specified in the Technical Corrections Act up to 12 May, 1990.

Current Legislative Initiatives

There are a number of bills in congress which attempt to extend the Section 29 tax credit. Two of the bills deal specifically with the extension of the credit and the reinstatement of the credit for tight sands, another treats the extensions as one of many incentives for the energy industry. The two bills which treat the extension as a separate issue were introduced by Senator Domenici and Congressman Andrews. They are cited as the Unconventional Fuel Production Incentives Act of 1990 and Unconventional Fuel Production Extension Act of 1990, respectively.

The two Section 29 specific bills both attempt to extend the application of credits for qualified fuels two years to 1993, reinstate the credit for tight formations, and index the credit for tight sands to inflation in the same manner as is done for other unconventional fuels. The main differences in the two bills is that Domenici ties the reinstatement of credit for tight sands to the date that FERC Order 519 took effect, while the Andrews bill attempts to bypass all previous regulation/deregulation legislation and offer the credit independent previous eligibility requirements that existed under NGPA and the Windfall Profits Tax.

The other piece of legislation which contains an extension to the Section 29 tax credit is the Domestic Energy Security Act of 1989, the so-called Archer-Andrews-Boren Bill. At the writing of this report the legislation was still active in the House Ways and Means Committee. The Domestic Energy Security Act is a "catch all" bill for the petroleum industry. It advances all of the major incentives sought by various industry segments. Its provisions are as follows.

Section 101. Exploration and Development Tax Credit. This provision provides a 20% tax credit for exploration and development expenditures which applies toward both regular and alternative minimum tax liability.

Section 102. Production Credit for Maintaining Economically Marginal Wells. This section allows a 20% tax credit which applies to stripper wells, heavy oil, tertiary oil recovery, and oil produced in "harsh environments" (north of 49th parallel or in water deeper than 400 feet).

Section 201. This section permits the immediate expensing of geological, geophysical, and unrecoverable surface casing costs.

Section 202. This section essentially repeals the transfer rule. It permits new owners to claim percentage depletion on proven properties purchased from other producers.

Section 203. This section removes the 50% net income limitation on percentage depletion.

Section 204. Here the taxable income limitation of 65% on sustained depletion is repealed.

Section 205. This section contains the seven year extension of the Section 29 tax credit for unconventional gas. The spud date is moved to 1 January, 1998. The tax credit for tight sands is also reinstated at the same rates as for Devonian shale or coal seam methane, i.e. the tax credit escalates with inflation.

Section 301. This section removes percentage depletion and intangible drilling costs from the alternative minimum tax.

Section 401. This is a repeal of Revenue Ruling 77-176 which relates to "deemed" income resulting from certain farmout agreements where acreage is earned outside of the drill site.

Section 402. Allows for the accrual of costs to dismantle offshore production facilities.

Section 403. This section exempts oil and gas exploration activities from the uniform capitalization rules. Currently, only intangible drilling costs are exempted.

Appendix D

The Credit Mechanism

The credit mechanism is based upon the change in crude oil prices (and inflation). The general tax credit formula is:

$$\text{Tax Credit} = (\text{Tax Credit Allowance} * I_f) - \text{Phase out Factor.}$$

where Phase out Factor =

$$(R_p - ((B_p * I_f)/(C_f * I_f \text{ inflation factor})) * (\text{Tax Credit Allowance} * I_f)$$

Tax Credit Allowance = \$3.00 per barrel of oil equivalent (1979 real dollars).

I_f = Inflation Adjustment Factor. The factor is the GNP deflator using the year 1979 as the base (1979 = 1.0).

R_p = Reference Price. Estimate average domestic crude oil wellhead price furnished by the Department of Treasury for the year of the credit.

B_p = Base Price = \$23.50 (1979 real dollars).

C_f = Support Ceiling factor = \$6.00 (1979 real dollars).

To translate the tax credit from dollars per barrels of oil equivalent into dollars per Mcf, the tax credit allowance and Base Price must be divided by 5.8. The value 5.8 is used since a barrel of oil contains approximately 5.8 MMBTUs (million BTUs) of energy, and an Mcf of natural gas contains on average one MMBTU of energy. The phase out factor is only used if the reference price rises above the base price, adjusted for inflation. For example, in 1979, the phase out factor would

begin to decrease the tax credit if the reference crude price were \$23.50 and completely nullify the tax credit if the reference crude oil price were above \$29.50/bbl:

$$\text{Tax Credit} = \$3.00 - ((\$29.50 - \$23.50) / \$6.00) * \$3.00$$

In 1989, producers received a tax credit worth approximately \$0.86/Mcf. (\$4.99 per barrel of oil equivalent, in nominal terms):

$$\text{Tax Credit} = \$0.86/\text{Mcf} = (\$4.99/\text{bbl}) / (5.8 \text{ Mcf/bbl}) = \$3.00/\text{bbl} * 1.66 \text{ inflation factor.}$$

At this amount of tax credit, the base price above which the reference price of crude oil must rise to start the phase out of the tax credit is \$39.00/bbl, with full phase out of the tax credit occurring at \$45.00/bbl. Unlike the tax credit for Devonian Shale and Coalbed Methane wells, that for tight formation gas is not adjusted for inflation. Its tax credit is still \$3.00 per barrel of oil equivalent, or \$0.52 per Mcf.

The theory of this price support mechanism is that producers of high cost/high risk gas should be guaranteed a minimum price above the market rates because the wells that they are drilling are generally more expensive and have lower flow rates than conventional gas wells. The rates originally established by Congress were based upon the then existing costs of unconventional gas development and market price of oil and gas. The phase out factor was included because the lawmakers agreed that above certain market prices, any well would be economical, and therefore would not require government subsidy. In other words, a prices support while market prices were low was a necessary incentive to encourage development of important national resources, but at high market prices, the prices support turns into excessive government benevolence.

The Section 29 tax credit is a production credit and not a exploration and development credit (such as in Section 101 of the Archer-Andrews-Boren bill). The producer, consequently, bears all the risk for his exploration and development activity. He only receives the credit when he produces gas. The producer looking for this credit will probably be less risky than one who receives an

exploration and development tax credit. That person gets "rewarded" for drilling activity, and not production, *per se*.

To be eligible for the tax credit, the owner of the well must first file for and receive a well determination from FERC. In addition to complying with Title I requirements of the NGPA, the following information must be forwarded to FERC along with a FERC form 121:

Coalbed Methane. Evidence to establish the productive interval is a coal seam and a radioactive or other log or detailed lithological description of the producing interval.

Tight Formation. Proof that (A) the estimated *in situ* permeability, throughout the pay section, is expected to be 0.1 millidarcy or less and (B) the stabilized production rate, against atmospheric pressure, of wells completed for production in the formation, without stimulation, is not expected to exceed a certain maximum specified in FERC's guidelines. The maximum flow rate ranges from 44 Mcfd at 1000 feet or less of depth up to 2,557 Mcfd for wells up to 15,000 feet deep.

Devonian Shale. Evidence that the gas produced is from fractures, micropores, and bedding planes of shales deposited during the Paleozoic Devonian period. Furthermore, 95% of the gross Devonian age stratigraphic interval encountered by the wellbore must have a gamma ray index of 0.7 or greater (the five percent test). This five percent test was designed to exclude excessive gas production from "stringers"¹ within the Devonian shale formation from qualifying as NGPA section 107 (c)(4) high-cost gas. In Order 501, issued in July, 1988, FERC provided an alternative method from which to measure Devonian Shale within the Devonian age stratigraphic interval. This alternative permits producers to select a continuous Devonian shale interval for which the five percent test will be applied. If the Devonian shale interval selected under the alternative method of

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¹ "Stringers" are potentially gas bearing rock within the Devonian shale strata which because of their sand content do not qualify as shale. Most Devonian age intervals are not 100% shale and contain, varying amounts of sand stringers. In order not to disqualify all Devonian shale intervals with sand stringer, the rule permits a Devonian shale interval to qualify as Devonian shale if the interval does not contain more than five percent nonshale rock.

measurement is more than 200 feet thick, the bottom and top 100 foot portions must meet the five percentage test independently.²

Carryover Considerations

A significant underlying issue about the Section 29 tax credit is that, unlike other standard tax credits, under current tax law there are only limited provisions for carryover. For tax years beginning after December 31, 1986, the tax credit allowed may not exceed the excess of the regular tax (as reduced by certain other credits), over the tentative minimum tax (found as part of the new alternative minimum tax computation).³ The credit for prior year minimum tax liability is increased by the amount of nonconventional fuels credit that was disallowed for the tax year solely because of the limitation based on the taxpayer's tentative minimum tax.⁴ This has the effect of allowing taxpayers to carry forward that portion of the credit that is disallowed because of the alternative minimum tax. Otherwise there is no provision to allow any portion of the unused credit to carryover or carryback to other tax years. In other words, if the producer is not profitable, i.e. does not have a tax liability above and beyond the alternative minimum tax, he cannot use the tax credit, now or carried forward into the future.

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² FERC estimated that Devonian filings would increase from 1200 annually to 2200 annually following this Order.

³ IRC, Section 29(b)(5), as amended by the Tax Reform Act of 1986, Section 701(c)(3).

⁴ IRC, Section 53(d)(1)(B)(iii), as added by the Technical and Miscellaneous Revenue Act of 1988, Section 6304.

Appendix E

Comparative Analysis

The WEFA Group prepared a comprehensive analysis for the Independent Petroleum Association of America in November, 1985, which look at both the future of the U.S. Oil and Gas industry and the possible effects of the Domestic Energy Security Act of 1989, the Archer-Andrews-Boren bill. The analysis included both cumulative effects, i.e., if the bill were passed intact, as well as marginal effects of each section.

WEFA Methodology

WEFA used different techniques to model different sections of the bill. These sections relevant to natural gas production are explained below.

Section 101: 20% exploration and development tax credit. The WEFA model assumes that the tax credit can be used in its entirety, i.e., the firms always have a sufficiently large tax liability that the credit can be used immediately, and not carried forward. Accordingly, WEFA models the tax credit as a net 20% reduction in the cost of drilling. Drilling activity, however, will of course not rise by 20% because, as drilling activity increases, average drilling costs do rise.

Section 201: Intangible drilling costs include geological, geophysical, and surface casing costs. Unlike Section 101, which is a tax credit, this provision is merely an additional tax deduction, and therefore has a much smaller effect than a tax credit. Data from API indicates that geological, geophysical, and unrecoverable surface casing costs amounts to about 2.5% of total exploration and development expenditures. Using an average effective tax rate of 20%, this translates to a net revenue rate of .5%. The WEFA model than uses this dollar value of additional revenue to generate higher drilling activity.

Section 202: Percentage depletion permitted after transfer of proven property. This provision is modeled by reducing the stripper well abandonment rate by 50%.

Section 203: Net income limitation on percentage depletion not to apply to oil and gas wells.

Section 204: Credit for producing fuel from non-conventional sources (extension of Section 29 credit).

Section 203: Exemption of oil and gas activities from the uniform capitalization rules. These three sections are all modeled based upon the revenue loss estimated by the JCT. These annual revenue losses by the government become annual revenue "gains" by industry. Depending on the appropriate reinvestment rate for oil and gas producers, these "gains" correspond to an increase in drilling activity, production, etc.

Section 301: Removal of percentage depletion and intangible drilling costs from the Alternative Minimum Tax. A review of API's "Survey on Oil and Gas Expenditures" suggests that 75% of exploration and development costs on oil and natural gas wells and 100% of exploration and development costs of dry wells could be considered IDC. Additionally, 75% of development work in progress could be considered IDCs. Together, these IDCs accounted for 23% of total expenditures being applied to the alternative minimum tax. Eliminating 23% of the independent producers budget as a preference item leads to an overall tax savings of 4.6% (preference items taxed at effective rate of 20%). This 4.6% increase in revenue is then used in the WEFA model to stimulate additional drilling activity.

Results

When taken as a whole, the Archer-Andrews-Boren bill seems to have significant effect. Gas production is up 11.4% over base case projections, while gas wells drilled and gas reserves are up 22.86% and 9.74%, respectively. Taken separately, each provision has only a nominal effect, with two exceptions: the 20% exploration tax credits, and the change to the AMT. These two provisions would provide about 5% increase base projections in gas production and reserves, and about a 10% increase in drilling activity.

Other analysis also indicates that these are the two most sought after provisions, in general, by the oil and gas industry. Randall Neil of David P. Cook & Associates, a Dallas consultant found

in a comparison of legislative initiatives that the Section 101 20% ITC effects on project value far exceed any other provision. They did not, however, include Section 301, the change to the AMT in their calculations. Our own informal survey of industry showed that among respondents, the change to the AMT was the most valuable legislative initiative to them, apart from the Section 29 extension.

Caveat

The WEFA model indicates that the extension of the Section 29 tax credit had little effect, <1% income in production and reserves through the year 2000. Their model, however, does not model directly tight sand, coalbed methane, or Devonian shale wells. It merely uses revenue estimates from the JCT. As explained in the section on methodology, WEFA calculated the effects of the tax credit extension by using the net revenue "loss" to the Treasury as a "gain" to industry which would be reinvested, thereby increasing exploration and drilling, etc. This approach neglects every issue specific to unconventional gas production, e.g. the financial incentive of the tax credit itself, or the increase in activity during the last 10 years that could be directly attributed to the credit, and treats the natural gas industry uniformly across all regional and resource boundaries.

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