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# A Retrospective Review of Shale Gas Development in the United States

*What Led to the Boom?*

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# **A Retrospective Review of Shale Gas Development in the United States: What Led to the Boom?**

Zhongmin Wang and Alan Krupnick

## **Abstract**

This is the first academic paper that reviews the economic, policy, and technology history of shale gas development in the United States. The primary objective of the paper is to answer the question of what led to the shale gas boom in the United States to help inform stakeholders in those countries that are attempting to develop their own shale gas resources. This paper is also a case study of the incentive, process, and impact of technology innovations and the role of government in promoting technology innovations in the energy industry. Our review finds that government policy, private entrepreneurship, technology innovations, private land and mineral rights ownership, high natural gas prices in the 2000s, and a number of other factors all made important contributions to the shale gas boom.

**Key Words:** shale gas, policy, research and development, technology, hydraulic fracturing, horizontal drilling

**JEL Classification Numbers:** Q4, O3, L71

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## Contents

<b>1. Introduction</b> .....	<b>1</b>
<b>2. Government Policies</b> .....	<b>6</b>
2.1 What Led to the Government Policies on Unconventional Natural Gas? .....	6
2.2 Incentive Pricing and Tax Credit .....	8
2.3 R&D Programs.....	9
<b>3. The Development History of the Barnett Shale Play</b> .....	<b>15</b>
3.1 Why Did Mitchell Energy Develop the Barnett Play?.....	16
3.2 How Did Technologies and Know-How Evolve at Mitchell Energy? .....	19
3.3 Did Environmental Issues Affect Mitchell Energy?.....	24
3.4 What External Help Did Mitchell Energy Obtain?.....	24
3.5 How Did the Mitchell–Devon Merger Accelerate Development? .....	27
<b>4. High Natural Gas Prices in the 2000s</b> .....	<b>28</b>
<b>5. Other Contributing Factors</b> .....	<b>29</b>
5.1. Geology.....	29
5.2. Land/Mineral Ownership.....	30
5.3 Market Structure .....	30
5.4 Water Availability.....	31
5.5. Natural Gas Pipeline Infrastructure .....	31
5.6 Capital Market .....	31
5.7 Other Factors.....	32
<b>6. Concluding Remarks</b> .....	<b>32</b>
<b>References</b> .....	<b>35</b>

# A Retrospective Review of Shale Gas Development in the United States: What Led to the Boom?\*

## 1. Introduction

Shale gas experienced an extraordinary boom in the United States in the past decade. Figure 1 shows the annual and projected production of natural gas, by type, in the United States from 1990 to 2020. Figure 2 shows the same thing for shale gas in the United States from 1979 to 2020. Shale gas accounted for only 1.6 percent of total US natural gas production in 2000, but this percentage had jumped to 4.1 percent by 2005 and to an astonishing 23.1 percent by 2010. This remarkable growth of shale gas production in the United States has spurred increasing interest in exploring shale resources in other areas of the world. A number of countries, including China,<sup>1</sup> Mexico,<sup>2</sup> Argentina,<sup>3</sup> Poland,<sup>4</sup> India,<sup>5</sup> and Australia<sup>6</sup> are considering or are in the process of developing their own shale gas resources.<sup>7</sup> Naturally, scholars, policymakers, and many other stakeholders who are interested in the development of shale gas outside of the United States are asking about the important factors for successfully developing shale gas resources. One way to shed light on this issue is to learn from the US experience. While it is difficult to know definitively the necessary or sufficient conditions for stoking a shale gas boom, a historical review of the US experience can at least inform the conditions that helped. In this paper, we

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<sup>1</sup> China has launched two rounds of shale gas block auctions, and the Chinese government issued, in March 2012, the *Shale Gas Development Plan 2011–2015*, which seeks to reach an annual shale gas production of 6.5 Bcm by 2015.

<sup>2</sup> According to International Energy Agency (IEA) (2012, p.111), Mexico is “keen to exploit shale gas resources to boost the country’s flagging output of unconventional oil and gas.”

<sup>3</sup> See Gonzalez and Orihuela (2012).

<sup>4</sup> See Kenarov (2012).

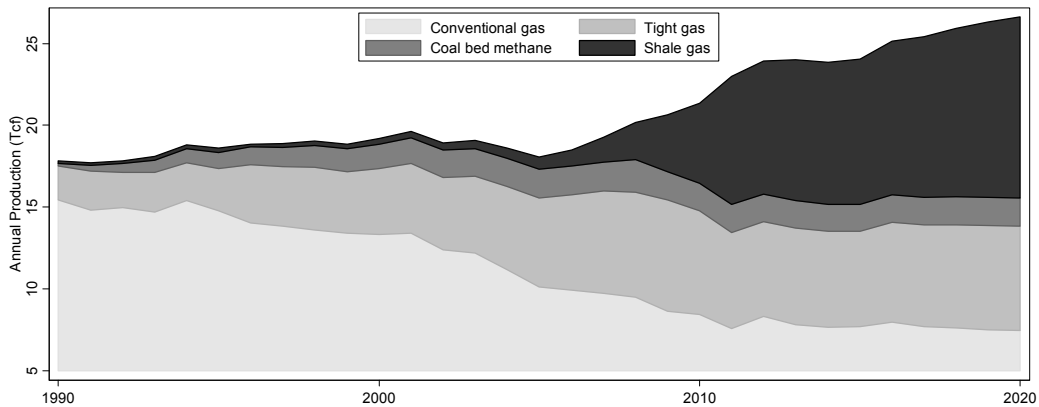
<sup>5</sup> See Stern (2012).

<sup>6</sup> See IEA (2012) for shale gas development in Australia, the sixth-largest shale gas resource country (Energy Information Administration 2011).

<sup>7</sup> Some other countries (e.g., France) have banned the use of hydraulic fracturing to drill shale gas.

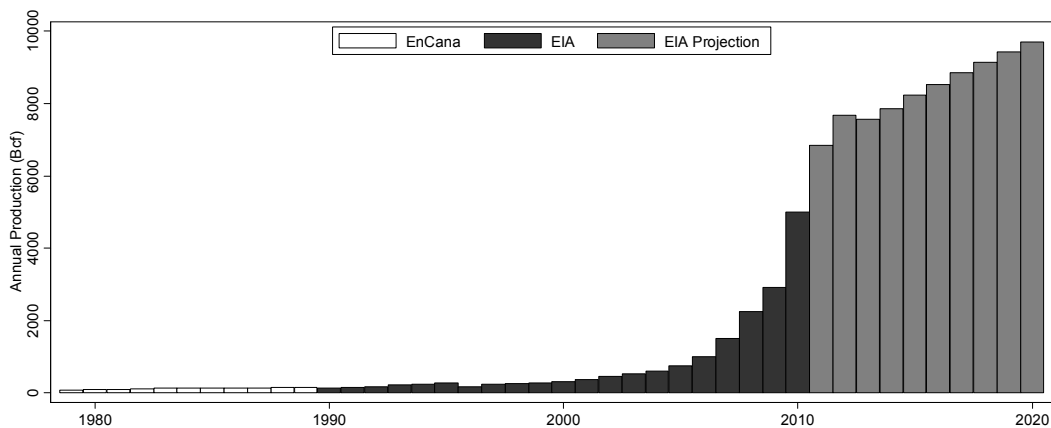
provide the first academic review of the economic, policy, and technology history of shale gas development to answer the question of what led to the shale gas boom in the United States.<sup>8</sup>

**Figure 1. Annual US Natural Gas Production and Projected Production by Gas Type, 1990–2020**



Source: Energy Information Administration 2013.

**Figure 2. Annual Shale Gas Production and Projected Production, 1979–2020**



Sources: Energy Information Administration 2013 and Curtis 2009.

<sup>8</sup> Some newspaper articles and consultancy reports, when discussing whether a country other than the US can develop shale gas successfully, often mention in passing what factors contributed to the shale gas boom in the US. The longest discussion of the history of shale gas development in the media is a report by the Breakthrough Institute (Trembath et al 2012), which focuses on “government’s role in the development of hydraulic fracturing in shale.”

For a real boom to occur in the private sector, high profitability, or at least the expectation of future high profitability, is a necessary ingredient. Our review suggests that a number of factors converged in the early 2000s to make it profitable for firms to produce large quantities of shale gas, but the most important factor was technology innovation, which took a long time to develop and ultimately made it cost-effective to produce shale gas. The main question we address in this paper is then, where did the technology innovations come from? Our review finds that some of the key technology innovations resulted from government research and development (R&D) programs and private entrepreneurship that aimed to develop unconventional natural gas (e.g., shale gas, coalbed methane, and tight gas), but some of the key technologies (e.g., horizontal drilling and three-dimensional [3-D] seismic imaging) were largely developed by the oil industry to explore and produce oil instead of unconventional natural gas.

The seed of the shale gas boom was planted in the late 1970s when the US government decided to fund R&D programs and provide tax credits (and incentive pricing) for developing unconventional natural gas in response to the severe natural gas shortage at the time. These policies were justified on the grounds that private firms did not have the incentive to make large and risky R&D investments to develop technologies necessary for extracting unconventional natural gas. The factors underpinning this view were summarized by the National Research Council (NRC 2001, p. 195) and Morgantown Energy Technology Center (1980, p. 3) as follows. First, it is difficult to keep new technologies proprietary in the oil and gas industry, and few technologies are patentable or licensable. Also, in the early years, unconventional gas sources could not compete with conventional oil or gas sources for investment dollars, and most US gas producers were small and did not have the incentive or capacity to do much R&D. Thus, it was government policies that stimulated the development of shale gas in the Appalachian and Michigan Basins and helped develop some key technologies, such as microseismic fracture (frac) mapping.

However, it was the private entrepreneurship from Mitchell Energy & Development (Mitchell Energy, hereafter) that played the primary role in developing the Barnett play in Texas, and it was the successful development of the Barnett play that jump-started the shale gas boom. Figure 3 shows the annual production of shale gas in the Appalachian, Michigan (Antrim), and Fort Worth (Barnett) Basins from 1979 to 2005. Government-sponsored R&D programs did not target the Barnett play, and tax credits had a rather limited impact on Mitchell Energy. Given that the argument for government interventions is that private firms lacked incentives, why did Mitchell Energy develop the Barnett play?

Mitchell Energy had the need and the financial capacity, both somewhat idiosyncratic, to develop the Barnett play and somewhat later was also motivated by the incentive to obtain large financial rewards from its innovations. It obtained large financial rewards by leasing large tracts of land and the associated mineral rights at low prices early on and later selling itself—the land it had leased, the innovations it had made, and the know-how it had accumulated—at a much higher price. This mechanism—leasing land at low prices early and selling at a higher price later—overcomes the difficulty of monetizing most technology innovations and know-how in the industry. This mechanism is made possible by the private land and mineral rights ownership system in the United States.

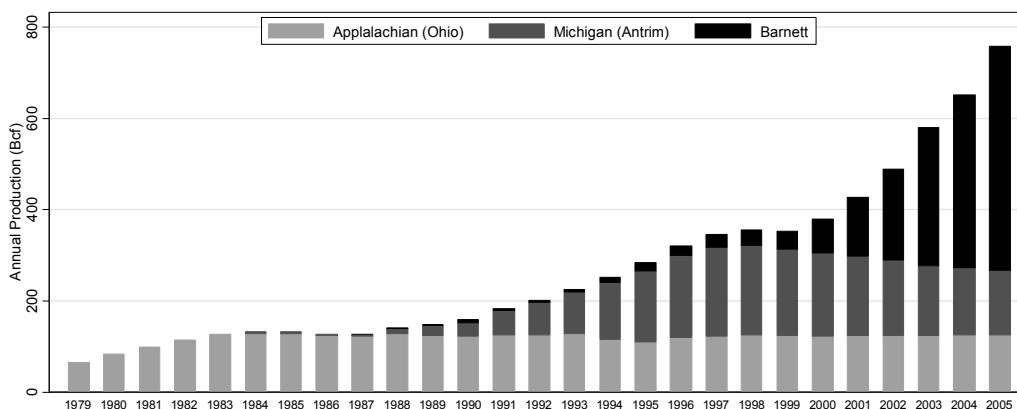
The high natural gas prices in the 2000s, which resulted from the declining production of conventional natural gas and other economic factors, also played an important role in making shale gas production profitable. Other contributing factors include favorable geology, private land and minerals ownership, market structure, water availability, natural gas pipeline infrastructure and the associated open-access policy. We do not attempt to quantify the effect of any of these individual contributing factors; rigorous identification of the impact of any particular factor requires counterfactuals that we cannot observe or estimate.

This paper is a case study of the incentive to innovate, the process of innovation, and the impact of technology innovations. As such, it contributes to the large literature that examines the processes and microeconomic effects of innovations. See Giovanni (1988) for an excellent review of this literature. We caution that one should not draw strong conclusions from a single case study like ours on the issue of what government R&D policies are appropriate in the energy sector. The appropriate role of government in promoting innovation in the energy system has been at the forefront of energy policy debates for many years.<sup>9</sup>

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<sup>9</sup> See Landsberg (1979) for an early elaboration of this issue. NRC (2001) offered a comprehensive review of many US Department of Energy (DOE) R&D programs from its inception to 1999 and provided policy recommendations on energy R&D programs. See Fri (2003) for a discussion of the NRC study in particular and technology innovations in the energy sector in general. See also the detailed case studies of DOE energy programs in the book edited by Cohen and Noll (1991).

**Figure 3. Annual Shale Gas Production by Play, 1979–2005**



Source: Curtis 2009.

The environmental impact of shale gas development has been a highly controversial subject, has raised difficult public policy issues, and has affected the pace of development in some areas. In this paper, we do not address the issue of sustainable shale gas development and environmental regulations largely because, first, the focus of our paper is on what led to the shale gas boom and, second, the environmental controversy did not arise until after the shale gas boom had arrived. Nonetheless, we shall discuss the significant effect of environmental lawsuits on Mitchell Energy and the implication that judicial enforcement of liability laws constrains firm behavior in the United States, even in the absence of environmental regulations specific to shale gas development.

The rest of the paper proceeds as follow. Section 2 focuses on government policy and the history of a few technologies thought to be important for shale gas development. We discuss the fiscal policies and the unconventional natural gas R&D programs sponsored by the federal government, NRC’s assessment of the R&D programs, and what led to the government policies. We review the technology history of horizontal drilling, 3-D seismic imaging, microseismic frac mapping, and massive hydraulic fracturing (MHF) to explain where these key technologies came from. Section 3 reviews Mitchell Energy’s development history of the Barnett play and addresses the following five questions: Why did Mitchell Energy develop the Barnett play? How did technology and know-how evolve at Mitchell Energy? How did environmental issues affect Mitchell Energy? What external help did Mitchell Energy obtain? How did Devon Energy’s acquisition of Mitchell Energy accelerate the development of the Barnett play? Section 3 also reviews the technology evolution of hydraulic fracturing fluids to illuminate Mitchell Energy’s



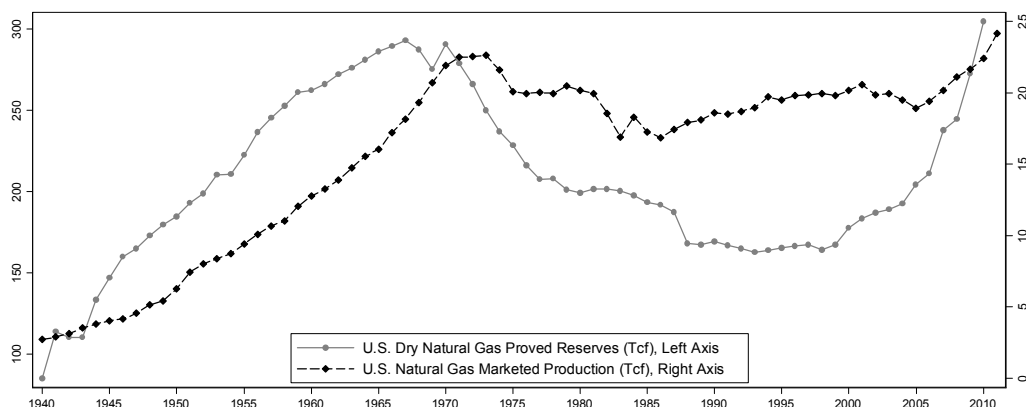
major contributions to slick water frac. Section 4 highlights the role of high natural gas prices in the 2000s, and section 5 briefly discusses other contributing factors. Section 6 concludes.

## 2. Government Policies

Starting in the late 1970s, the US government adopted a series of policies to promote the development of new sources of natural gas, including unconventional sources. These policies set the stage for the increased production of tight gas and coalbed methane and, later, the boom in shale gas. The major natural gas policies include incentive pricing, tax credits, and R&D programs for unconventional natural gas and policies promoting industry restructuring (e.g., gradual deregulation of wellhead natural gas prices and open access to interstate natural gas pipelines). The restructuring of the natural gas industry is well studied in the literature and will be briefly discussed in section 5.

### 2.1 What Led to the Government Policies on Unconventional Natural Gas?

The catalyst for the policies on unconventional natural gas was the severe natural gas shortage in the 1970s. It is well documented that the natural gas market in the 1960s and 1970s was characterized by price ceiling regulation that resulted in shortages in production and reserves (e.g., MacAvoy 1971; Breyer and MacAvoy 1973; MacAvoy 1983; Vietor 1984; Davis and Kilian 2011). Price ceilings on interstate natural gas were set at levels below the equilibrium prices that would arise in a competitive market, thus stimulating demand and discouraging supply. The shortage appeared first in natural gas reserves. Figure 4 shows the annual proved reserves and marketed production of all types of natural gas in the United States from 1940 to 2010. Proved natural gas reserve peaked in 1967 and experienced rapid declines in the 1970s. The ratio of reserves to production started to decrease much earlier; it was about 22 to 1 in 1959, 13 to 1 in 1969, and 9.8 to 1 in 1979. Shortages in production became evident in the middle 1970s. MacAvoy (1983, p.85), for example, writes that “forced curtailments of committed deliveries increased from 12 percent of total interstate demand in 1973 to 30 percent in 1975. Further curtailments caused the short deliveries to exceed 40 percent of the total in 1978.” Davis and Kilian (2011) report that the shortages started earlier and were even bigger, if shortage is properly defined as the difference between actual consumption and the amount of natural gas that would had been consumed by consumers not subject to any supply constraints. Note that the absolute level of production peaked in 1973 and exhibited a downward trend in the 1970s as well.

**Figure 4. US Natural Gas Proved Reserves and Marketed Production, 1940–2011**

Source: Energy Information Administration, natural gas data:  
<http://www.eia.gov/naturalgas/data.cfm>.

The severe natural gas shortage led to the passage of the Natural Gas Policy Act of 1978 (NGPA), which required phased removal of wellhead price controls and provided incentive pricing for developing new natural gas, including natural gas from unconventional sources. The natural gas shortage also led federal agencies to establish R&D programs on unconventional natural gas. Why unconventional natural gas? As early as 1968, when natural gas reserves began to decline, the National Energy Technology Laboratory (NETL 2007) notes, the US Bureau of Mines began to examine the issue of how to extract unconventional gas resources. Several major studies commissioned by the Federal Power Commission, the Energy Research and Development Administration (ERDA), and the US Department of Energy (DOE) in the 1970s suggested that the resource base of unconventional natural gas could be very large and that efforts to develop unconventional resources should be encouraged and subsidized. In the late 1970s, the annual production of unconventional natural gas was less than 5 percent of total annual gas production, but conventional natural gas production started to decline and was widely expected to continue to decline (Kuuskraa et al. 1978).

The broader context for the policies on unconventional natural gas is the energy crisis in the 1970s. The 1973 oil embargo stimulated the federal government to begin to adopt a series of policies to deal with the energy crisis, including the consolidation and expansion of energy-related R&D programs. A federal law in 1974 created ERDA by merging several separate research programs, including those of the technology research centers of the Bureau of Mines, the fossil energy R&D programs under the US Department of the Interior, and the system of

national laboratories under the Atomic Energy Commission (which was abolished at that time). In October 1977, DOE was created to consolidate in one agency the responsibilities for energy policy and R&D programs, including those of ERDA and the energy-related responsibilities of the US Departments of Agriculture, Commerce, Housing and Urban Development, and Transportation (Secretary of Energy Advisory Board 1995, p. 21). The budget for energy research, especially for fossil energy programs, significantly increased. NETL (2010, p. 255) notes that “between 1973 and 1976, total federal spending on energy research more than doubled, and the fossil-energy component increased more than tenfold from 1974 (\$143 million) to 1979 (\$1.41 billion).”

## ***2.2 Incentive Pricing and Tax Credit***

In this subsection, we describe the policies of incentive pricing and tax credits adopted by the US federal government to promote the development of unconventional natural gas.

Section 107 of NGPA provided for incentive pricing for “high-cost” natural gas from Devonian(-age) shale, coal seams, geopressured brines, and any other gas the Federal Energy Regulatory Commission (FERC) determined to incur high extraction costs. The wellhead prices for Devonian shale, coal seams, and geopressured brines were deregulated on November 1, 1979 (MacAvoy 1983, Table 15). This deregulation created a huge advantage for these fledgling gas resources. In the early 1980s, the deregulated high-cost natural gas was selling at more than twice the price of regulated natural gas (Tobin et al. 1989, p. 5). Though not originally listed as such, FERC later designated tight gas a high-cost gas. Its price, however, was not quickly deregulated. Instead, tight gas was eligible for the Section 107 price ceiling, which was the highest regulated price ceiling under NGPA (Kuuskraa and Guthrie 2002, p.78; Hass and Goulding 1992, p. 298). Interestingly, Mitchell Energy filed the Barnett shale as a tight gas formation probably because NGPA only mentioned Devonian shale and the Barnett shale was Mississippian-age.

The 1979 oil crisis led to the passage of the Crude Oil Windfall Profit Tax Act in 1980, part of which provides tax credits for producing unconventional fuels. This credit, which was implemented under Section 29 of the Internal Revenue Code, applied not only to unconventional gas from Devonian shale, coal seams, and tight gas, but also to biomass, geopressured brines, oil from shale or tar sands, synthetic fuels from coal, and some other fuels. Unconventional gas wells spudded between January 1, 1980, and December 31, 1992, were eligible for the tax credits, and production from eligible wells continued to receive credit until December 31, 2002. The size of the tax credits for Devonian shale (and coalbed methane) was determined by a

formula. Initially \$0.52/Mcf, it was increased to \$0.94/Mcf in 1992 (Hass and Goulding 1992, p.3). During much of this period, the national average wellhead natural price was between \$1.5/Mcf and \$2.5/Mcf. The formula accounted for inflation and contained a factor that would gradually phase out the effect of the tax credit when the price of oil was high, reflecting the consideration that the credits were to take effect when oil prices were so low as to limit the competitiveness of unconventional fuels (Soot 1991). The tax credit for tight gas was fixed at \$0.52/Mcf in the early 1980s, which was smaller than that for Devonian shale or coalbed methane. Tight gas began to “lose credit eligibility with partial price decontrol in 1985,” but regained it in 1991 (Hass and Goulding 1992, p. 299).

Gas producers had to select either NGPA incentive pricing or Section 29 tax credits. This requirement, however, did not affect Devonian shale or coalbed methane much since their prices were deregulated in late 1979 and producers naturally selected tax credits thereafter. As a result, Section 29 tax credit was far more important for the industry than incentive pricing.

No studies have rigorously examined the impact of these financial incentives on the development of unconventional natural gas. Trade publications (e.g., Soot 1991; Kuuskraa and Guthrie 2002; Hass and Goulding 1992; and Kuuskraa and Stevens 1995) discuss these policies in general terms and suggest that the Section 29 tax credit stimulated the development of unconventional natural gas. Hass and Goulding (1992, p. 300) write that even “critics [of the tax credit policy] agree that the credit has stimulated drilling and production.” Kuuskraa and Stevens (1995) suggest that Section 29 tax credit raised the financial returns and thus reduced the risk of investing in unconventional natural gas resources and, as a result, spurred investment in development activities and technology improvement. Nevertheless, as we will discuss in section 3, the impact of the tax credit or incentive pricing on Mitchell Energy was limited.

### **2.3 R&D Programs**

The unconventional natural gas research program was initiated by ERDA in the 1976 fiscal year and continued by DOE in 1978. This program had three components: the Eastern Gas Shales Program, the Western Gas Sands Program, and the Methane Recovery from Coalbeds Program. In this subsection, we focus on the Eastern Gas Shales Program, the most pertinent program, and we discuss the relevant contributions of other DOE R&D programs. In addition, we discuss briefly the role of the Gas Research Institute (GRI), which managed and funded R&D projects on natural gas. A report by NETL in 2007 documented the history of DOE’s unconventional gas R&D programs, and NRC, in 2001, assessed the benefits and costs of a large number of DOE R&D programs, including the three unconventional gas programs.

NRC assessed the most important energy technological innovations in the 1980s and the 1990s and the role of DOE in developing the technologies. Three technologies thought to be critical to shale gas development are among the most important technological innovations identified by NRC: horizontal drilling, 3-D seismic imaging, and fracturing technology. NRC (2001, p. 13) concluded that DOE's role in improving horizontal drilling and 3-D seismic imaging was "absent or minimal," but rated DOE's role in "fracture technology for tight gas" as "influential." Fracture technology for shale gas, which was greatly influenced by fracture technology for tight gas, was not considered by NRC, probably because the shale gas boom had not yet arrived at the time of the NRC report. Microseismic frac mapping, another technology thought to be critical to shale gas development, also was not yet fully developed or used at the time of the NRC report. As we discuss below, NETL (2007) and other trade publications suggest that DOE played a critical role in developing the technology of microseismic frac mapping.

### **2.3.1 Eastern Gas Shales Program**

NETL (2007, p. 19) summarizes that the DOE gas shales program "helped unlock a major new ... source of significant natural gas supply. It revitalized gas shales drilling and development in the Appalachian (Devonian) Basin, helped initiate development of other previously over-looked gas shale basins, and took the lead in demonstrating much more efficient and lower-cost gas shales production and recovery technology." Our review of the available evidence supports this conclusion.

Eastern gas shales refer to Devonian-age shales underlying vast areas of the eastern U.S., including the Appalachian, Michigan, and Illinois Basins. Devonian shales are shallow, easily accessible, and have been commercially exploited since the 1920s but were a minor source of US natural gas production at the start of the gas shales program. The technology used to extract shale gas was, notes NRC (2001, p. 201), "low cost but technically simple and ineffective." The industry had a poor understanding of the physical and chemical characteristics of Devonian shale, and the estimates of recoverable reserves were highly uncertain. Therefore, the purpose of the program, summarizes NRC (2001, p. 201), was "to assess the resource base, in terms of volume, distribution, and character and to introduce more sophisticated logging and completion technology to an industry made up mostly of small, independent producers. The goal was to substantially increase production from these basins at a time when increased national supply was critically important." DOE expenditures on this program, from 1978 through the termination of the program in 1992, were \$137 million (in 1999 dollars), about two-thirds of which was spent in the early years of the program (between 1978 and 1982). In addition to the DOE expenditures,

ERDA invested over \$20 million, GRI expended about \$30 million, and private industry spent \$35 million on eastern gas shales R&D. The R&D projects of the program were implemented by DOE's technology centers, national laboratories, universities, and private firms.

The realized benefit of the gas shales program came from the incremental gas production from shale formations that can be attributed to the program. The increase in shale gas production, since the program started, was large: the total annual shale gas production was 70 Bcf in 1978, 200 Bcf in 1992, and 380 Bcf in 1998. The production increase, however, was not due solely to the eastern gas shales program. Incentive pricing, tax credits, GRI's R&D program, and private firms all made contributions. NRC (2001, p. 201) credits the DOE gas shales program "with 50 percent of the incremental shale gas production from the Appalachian Basin (over industry's baseline) and 10 percent of the incremental gas production in the Michigan and Fort Worth Basins." The DOE program, NRC (2001) calculates, generated a revenue increase of \$705 million to the gas industry and over \$8 billion in savings to consumers as a result of lower gas prices. DOE's shale gas program appears to be highly successful in generating realized benefits.

We note that NRC attributes 10 percent of the incremental gas production in the Fort Worth Basin to the DOE shale gas program, even though this basin was not covered by the program and, prior to 2000, was developed primarily by Mitchell Energy. To have had an effect, some technologies, methods, or knowledge developed by the shale gas program must have been applied in the Fort Worth Basin. Unfortunately, the NRC report is silent about what such technologies or methods were. In section 3, we shall see that Mitchell Energy, in its early years of developing the Barnett shale, viewed the Devonian shale as an exploration and production analog, suggesting that the success of DOE's shale gas program likely played a significant role in motivating Mitchell Energy to initiate the development of the Barnett shale.

NRC (2001) and NETL (2007) offer only very brief discussions of the new technologies developed by the gas shales program or the technologies introduced by the program to eastern gas shales for the first time. We focus on a few that appear to be most important to shale gas development, and we review other sources to offer a brief history of the technologies.

*Horizontal Drilling.* To put DOE's contributions to horizontal drilling in perspective, we first note the history of horizontal drilling, which is documented by the Energy Information Administration (EIA 1993). Few practical applications of horizontal drilling took place until the early 1980s, when advancements in down-hole motors, down-hole telemetry, and other drilling equipment and technologies made the commercialization of horizontal drilling in oil wells within reach. Down-hole motors provide additional power to the drilling bit, thus increasing penetration

rates. Down-hole telemetry transmits down-hole information to the surface during drilling. EIA (1993, p. 7) writes that four horizontal wells drilled by the French oil company Elf Aquitaine from 1980 to 1983 “indicated that commercial horizontal drilling success could be achieved,” and horizontal drilling “was subsequently undertaken by British Petroleum in Alaska’s Prudhoe Bay Field, in a successful attempt to minimize unwanted water and gas intrusions ....” Encouraged by these early successes, horizontal drilling achieved commercial viability in the late 1980s. In 1990, over 99 percent of the horizontal wells drilled in the United States were completed to oil formations instead of natural gas formations (EIA 1993, p. 8) and, at the time of the EIA (1993) report, “the commercial viability of horizontal wells for production of natural gas [had] not been well demonstrated yet.” NRC’s assessment that DOE’s role in developing the technology of horizontal drilling was absent or minimal does not mean that DOE did not play a role in adapting the technology to gas shales. The gas shales program resulted in a number of industry “firsts” in horizontal drilling in Devonian shales. For example, in 1986, DOE and industry partners drilled the first air-drilled horizontal well in Devonian shales. NETL (2007, p. 4) notes that this well was “the first horizontal well where external casing packers ... were successfully installed and inflated in an air-filled wellbore, and the first horizontal well to complete seven individual hydraulically fractured intervals.” In 1989 and 1990, a DOE-industry partnership drilled three horizontal wells that “identified the technical barriers to widespread application of underbalanced horizontal drilling in the United States.”

*Massive Hydraulic Fracturing.* The gas shales program introduced large-scale MHF to eastern Devonian shales. The scale of MHF could refer to fracture half-length, which is the distance from the wellbore to the tip of the fracture, or to the quantity of fracture fluids and proppants. For example, Fast et al. (1977) define MHF as a frac treatment with a half-length of 1,500 feet, and Agarwal et al. (1979) define MHF by the quantity of fracture fluids and proppants. Neither NRC (2001) nor NETL (2007) mentions the specific scales of the MHF experiments conducted by the gas shales program. MHF was not used to stimulate shale wells before the gas shales program, but Agarwal et al. (1979, p. 172) note that MHF was already “a proven technique for developing commercial wells in low-permeability or ‘tight’ gas formations.” Mitchell Energy, with financial assistance from DOE, conducted in 1978 what was, at the time, the largest MHF in a tight gas formation. Mitchell Energy quickly applied MHF to the Barnett shale.

*Foam Fracture.* This technology was first used by the gas shales program, and more than 50 cost-shared demonstrations with industry were conducted in the first four years of the program. Prior to the program, Devonian shale wells were stimulated explosively in open-hole

well bore or by water fracs. Foam fracture, writes NETL (2007, p. 31), reduced “the volume of water used by 75 to 90 percent as compared to conventional water fracs. The incremental cost of foam fracs was offset by reduced well cleanup costs and improved productivity.” NETL (2007, p. 31) also states that “by 1979, foam fracturing was the preferred commercial method of stimulation for Devonian shale gas wells and commercial services were widely available to operators in the eastern United States.” In section 3, we document that Mitchell Energy used foam fracture in the first few years of its development of the Barnett shale because foam fracs were used in Devonian shales, but the firm abandoned foam fracs quickly. Interestingly, Mitchell Energy’s main technology breakthrough was to apply water fracs in the Barnett shale.

### **2.3.2 Related Technology Innovations and DOE Programs**

A few other DOE R&D programs helped develop technologies that have been important for shale gas development. These include not only the programs on tight gas and coalbed methane, but also the Seismic Technology Program and the Drilling, Completion, and Stimulation Program. See NRC (2001) for summaries and assessments of these programs. Here, we focus on two technologies that were targets of DOE R&D programs and have been important for shale gas development.

*3-D Seismic Imaging.* 3-D seismology has been a revolutionary technology for oil and gas exploration and development. By measuring acoustic reflections from an energy source, 3-D seismic imaging, writes Bohi (1999, p. 80), provides a better picture of the structure and properties of subsurface rocks than the earlier 2-D method and greatly improves “the ability to locate new hydrocarbon deposits, determine the characteristics of reservoirs for optimal development, and determine the best approach for producing a reservoir.” An enormous amount of data is required to form high-resolution 3-D images of the subsurface, and the processing of the data requires high-speed computing capability. Commercial application of 3-D seismic technology, notes Haar (1992, p. 8), began in the early 1980s on a limited basis. Bohi (1999, p. 82) writes that “once parallel computers arrived in 1985 to solve the process problem, it did not take long to develop improved sound receivers, data handling and transmission equipment, and analytical models to take advantage of the innovation [in computing capability].” DOE started its seismic technology program in 1988, and expended \$106 million (in 1999 dollars) from 1989 to 2000 on the program. NRC (2001, p. 208) notes that the “advances in seismic technology have been developed mostly by industry, although certain aspects of the DOE program have improved seismic technology.” NRC (2001, p. 210) also writes that “DOE estimates the overall benefit to industry of seismic technology to be \$6 billion per year. ... DOE calculates its contribution in the



range of 4 to 6 percent based on modeling analysis.” NRC (2001, p. 211) concludes its assessment of DOE’s seismic technology program by writing that the “principal lesson” from the program “is that even with a technology in which the private industry has invested massively, federal government funding geared to certain niche areas ... is a useful adjunct to a major private sector activity.” We shall see that 3-D seismic surveys contributed to Mitchell Energy’s development of the Barnett shale and became a widespread application in the Barnett shale in the early 2000s.

*Microseismic Fracturing Mapping.* Support from DOE and GRI played a critical role in developing microseismic frac monitoring. This technology has, since the early 2000s, been playing a key role in optimizing the way shale gas wells are hydraulically stimulated. Different from 3-D seismic imaging, microseismic frac monitoring is a passive method in that it listens for seismic energy occurring underground. By using sensors in a monitoring well to record the minor seismic events generated during the fracturing of a nearby well, microseismic fracturing mapping can reveal the height, length, orientation, and other attributes of induced fractures. The first systematic research into microseismic fracture mapping was a geothermal project funded by DOE and carried out by Los Alamos National Laboratory in the 1970s (NETL 2007, p.2; GasTips 2006, p. 2). Somewhat later, DOE funded Sandia National Laboratories to build and deploy receivers for testing similar frac mapping technology, and in the 1980s, this process was used at the DOE Multiwell Site experiment in Colorado to successfully monitor major fracture experiments (GasTips 2006, p. 2). The Multiwell Site experiment was part of the Western Gas Sands Program. From 1994 to 1996, DOE and GRI jointly funded a research project at the Multiwell experiment site, writes NETL (2007, p. 56), “to further develop and validate hydraulic fracture [mapping] technology, assess hydraulic fracturing mechanisms, and improve hydraulic fracturing stimulation models through a more complete physical understanding of the process.” GRI eventually partnered with Pinnacle Technologies, a private firm, to help commercialize microseismic frac mapping (GasTips 2006, p. 2).

### **2.3.3 Gas Research Institute**

GRI, a nonprofit organization established by the gas industry in 1976, began full operations in 1978, planning, managing, and financing R&D programs in all segments of the natural gas industry, including production, transmission, storage, and end-use. GRI was fully funded by a surcharge on interstate natural gas transactions until 1998, when phaseout of the mandatory surcharge began. The gas surcharge, approved by the Federal Power Commission (and later by FERC), was justified on the grounds that R&D expenditures by natural gas firms

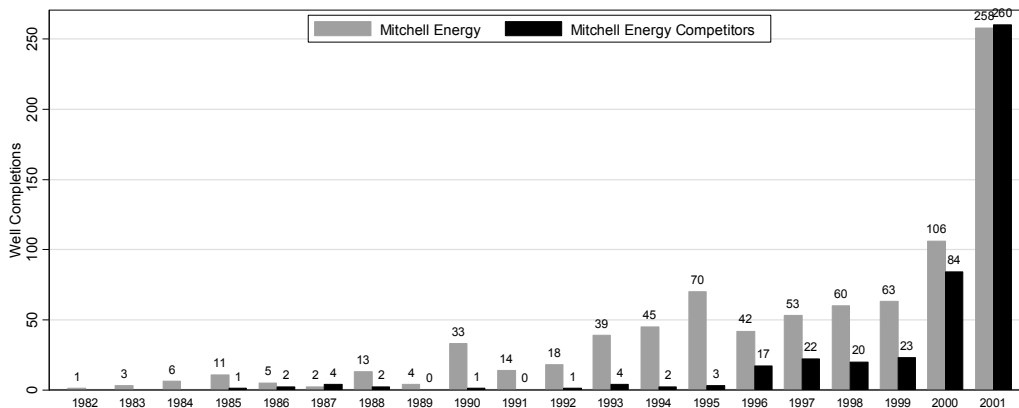
were too low to advance necessary technological improvements. NETL (2007, p. 14) notes that GRI's annual budget increased from about \$40 million in 1978 to about \$75 million in 1981, to an average of about \$120 million through the 1980s, and to an average of about \$200 million in the 1990s. GRI expended only a small percentage of its funding on natural gas exploration and production—about 15 percent in the 1990s. From its inception through early 1991, only 18 of the 170 products, processes, or techniques that resulted from GRI-sponsored R&D and were placed into commercial service were in the area of natural gas supply (Dombrowski et al. 1992).

GRI managed a Devonian-age Antrim shale R&D program in the Michigan Basin from 1989 to 1995 (Perry 2001; Reeves et al. 2007). GRI's gas shales program, according to Reeves et al. (2007), "accelerated" the development of the Antrim shale play in the Michigan Basin. GRI managed a coalbed methane R&D program from 1982 to 1996 after DOE's coalbed methane program was terminated in 1982 (Perry 2001). GRI was also involved in R&D on tight gas sands in east Texas (Hathaway and Salehi 1986) and, as mentioned above, at the Multiwell experiment site in Colorado. Details about these GRI programs on unconventional natural gas are scarce. NRC (1988, appendix A) reviewed the R&D activities of GRI, but not at the level of individual programs. NETL (2007, pp. 14–15) notes that "there was a significant degree of cooperation and coordination between the DOE and GRI research programs during much of their coexistence," and "the DOE program focused more on fundamental science and the GRI program focused on application and technology transfer."

### **3. The Development History of the Barnett Shale Play**

Mitchell Energy was the primary developer of the Barnett play until it was sold to Devon Energy in January 2002. This can be seen from Figure 5, which shows the number of well completions, by Mitchell Energy and its competitors, in the Barnett from 1982 through 2001. By 1995, Mitchell Energy completed 264 Barnett wells, but its competitors, eight operators in total, completed only 20. Therefore, the development history of the Barnett play is essentially a story of Mitchell Energy, which was documented in an excellent 2007 book written by Dan Steward, a geologist and former executive of Mitchell Energy, who "had been involved through the entire play" (p. 7). Our account of the Barnett development process is based on Steward's book and other trade publications that offer a discussion of the Barnett play.

**Figure 5. Number of Barnett Well Completions by Mitchell Energy and Its Competitors, 1982–2001**



Source: Steward 2007.

### 3.1 Why Did Mitchell Energy Develop the Barnett Play?

When Mitchell Energy drilled its first Barnett well in Wise County, Texas, little was known about the Barnett shale. Recall that the Eastern Gas Shales Program had started just a few years before. Barnett shale was not included in the major early studies that assessed the resource potential of unconventional natural gas (e.g., Kuuskraa et al. 1978; National Petroleum Council [NPC] 1980). The Barnett shale was not even included in NPC’s (1992, p. 119) assessment of natural gas potential in the United States due to “limited knowledge” of the play. Given the resource and technology uncertainties, why then did Mitchell Energy, a private firm, develop the Barnett play? According to Steward (2007, p. 122), Mitchell Energy invested about a quarter of a billion dollars in the Barnett play from 1981 through 1997, and “during [that period] had operated in the red, with cumulative revenues less than cumulative investment.” What sustained Mitchell Energy in its pursuit of the Barnett play? Mitchell Energy had an idiosyncratic need and the financial capacity, to some extent, to develop the Barnett play, and it was also motivated by the incentive to appropriate the potential benefits of innovations.

The initial incentive for Mitchell Energy to develop the Barnett play was its need to identify and develop a new source of natural gas to feed a large gas plant and a gas-gathering system and to fulfill its long-term contractual obligations to Natural Gas Pipeline Company of America (NGPL), an interstate gas pipeline company aiming to replace its natural gas production from shallower conventional formations that were expected to decline in a decade or so (Bowker 2003; Steward 2007). Mitchell Energy was in a financial position to undertake some risky investments. By the time Mitchell Energy drilled the first Barnett well in 1981, it was the largest

gas producer in North Texas and a diversified, publicly traded company whose business included not only the exploration, production, gathering, and processing of natural gas, but also drilling rigs and real estate operations. Steward (2007, p. 44) writes that Mitchell Energy was also “very fortunate” to have a long-term natural gas supply contract with NGPL, which guaranteed prices considerably higher than market prices. The financial advantage provided by this contract is emphasized repeatedly by Steward, in his 2007 book, as critical to the development of the Barnett. Steward emphasized this point again in December 2011: “Mitchell was selling his gas [for a] dollar and a quarter over the spot price. We would never have been able to do what we did in the Barnett without that. Mitchell had the money to invest in R&D.”<sup>10</sup>

Mitchell Energy was also able to minimize the financial losses from drilling Barnett wells in the early 1980s because those “exploratory” wells were not purely exploratory in nature. All the early Barnett wells were deepened to the Barnett formation from shallower gas-bearing formations, so Mitchell Energy had the option of completing the wells to, and thus producing gas from, the shallower formations. This overlapping of gas formations significantly reduced the risk and cost of drilling the early wells. In fact, says Steward (2007, p. 79), any early “well deepened to the Barnett had to justify its development cost, as well as associated deepening expenses, using expected reserves of the shallow objectives.” This is why only 20 of the 41 wells deepened by Mitchell Energy to the Barnett from 1981 to 1986 were completed as Barnett production wells. The 20 Barnett wells did incur financial losses, as only one of them was deemed “commercial” in 1987. Some of these wells were later re-fractured and became commercial. From 1987 to 1997, the financial returns of the Barnett wells gradually improved, offering incentives to continue with the development. During this period, Mitchell Energy completed 304 wells in two areas with favorable geology and 25 wells in four other areas with more challenging geological features. While the wells in the two favorable areas, on average, did not meet the firm’s rate-of-return criteria, says Steward (2007, p. 90), they were “very commercial” and “sufficient for proceeding with a Barnett development program.” The 25 wells in the more challenging areas were not commercial.

At some point, the possibility of reaping a large financial reward became a major consideration for Mitchell Energy to develop the Barnett play. Since few innovations are patentable and licensable and it is difficult to keep innovations proprietary, the best way to obtain

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<sup>10</sup> Steward said this during an interview with the Breakthrough Institute. Details of the interview can be found at [http://thebreakthrough.org/archive/interview\\_with\\_dan\\_steward\\_for](http://thebreakthrough.org/archive/interview_with_dan_steward_for).

financial reward from R&D investments in the natural gas industry is through leasing large tracts of land that can be sold at higher prices later. One indication of this incentive is George Mitchell's decision to delay his engineers' recommendation in late 1987 to involve GRI—which could provide financial and technology assistance at a time of budget cutbacks—in the Barnett. At the time, Mitchell Energy was in the process of acquiring leases on large tracts of land, so George Mitchell was, according to Steward (2007, p. 91), “concerned that any unnecessary publicity might adversely affect the growth of [the firm's] acreage position.” As a result, Mitchell Energy did not approach GRI until 1990 when its acreage position had much improved. In the late 1990s, two key technology events (which we discuss in detail later) and an improved natural gas price made the Barnett a marketable asset. Consequently, in the period of 2000 to 2001, writes Steward (2007, p.161), Mitchell Energy focused on “demonstrating the potential” and increasing the industry's awareness of the Barnett by leasing more lands, drilling more wells, and expanding the gathering and processing facilities. Mitchell Energy gained significant financial reward by selling itself in 2002 because it had leased large areas of land in the Barnett and its innovations and know-how proved that it can be profitable to drill wells in the Barnett.

Financial considerations did constrain Mitchell Energy's pace of drilling in the Barnett play. In 1986, when the oil price crash resulted in a decline in the natural gas price, writes Steward (2007, p. 74), “Mitchell management began to redirect capital expenditures ... away from higher-risk, long-term projects.” Consequently, “management directed that Barnett capital expenditures be minimized until further review.” In 1989, notes Steward (2007, p.84), the Barnett program “was constrained again” because the firm's gas wells in shallower formations were “providing sufficient gas for the contract requirements,” and such wells “had lower unit development cost and gas prices were down.” In July 1995, NGPL bought out its contract with Mitchell Energy. Afterward, says Steward (2007, p. 90), “the entire Barnett program became questionable” as the company had to sell its gas at lower spot prices. Even though returns were marginal at that time, Mitchell Energy had incentives to continue with its Barnett development program. Barnett shale, by 1994, became the primary source of new gas for Mitchell Energy in the North Texas area. Without drilling Barnett wells, Mitchell Energy's own drilling rigs would go idle and its gas processing plant would not have enough gas to process. Continued drilling allowed the firm to “keep the infrastructure intact while waiting for an industry upswing, technological breakthrough, or well cost reduction” (Steward 2007, p. 91).

### **3.2 How Did Technologies and Know-How Evolve at Mitchell Energy?**

In this subsection, we discuss the technology improvements or learning made by Mitchell Energy in the areas of hydraulic fracturing, geological knowledge, and drilling. In particular, we offer in-depth discussions of how Mitchell Energy lowered fracturing and drilling costs and achieved its major breakthrough in fracturing; the extent to which Mitchell Energy utilized 3-D seismic imaging, horizontal drilling, and microseismic frac mapping; the external help Mitchell Energy was able to obtain; how environmental issues affected Mitchell Energy; and how the Mitchell–Devon merger pushed the development of the Barnett shale forward.

#### **3.2.1 Hydraulic Fracturing**

Mitchell Energy stimulated the early Barnett exploratory wells with various types of foam fracs because foam fracs were used to stimulate Devonian shales in the Appalachians and because Devonian shale was viewed as an analog for the Barnett. The fracture half-length of the early Barnett wells varied between 500 and 1,500 feet. After some experimentation, Mitchell Energy started in 1984 to use nitrogen-assist, gelled water fracs.<sup>11</sup> In 1985 or 1986, Mitchell Energy started to use the 1,500-foot half-length gelled water design, commonly known as a massive hydraulic frac (Bowker 2003), for all Barnett stimulations. Mitchell Energy had previously acquired expertise in massive hydraulic frac in a tight gas formation in East Central Texas. As mentioned above, in 1978, Mitchell Energy, with financial assistance from DOE, conducted the largest MHF stimulation on record at the time. That stimulation was in the tight gas formation in East Central Texas.

From 1987 through 1993, Mitchell Energy “tweaked” the gelled frac method. In 1994, Mitchell engineers began looking aggressively to reduce the costs of fracturing without reducing well productivity. Nitrogen was completely eliminated from the frac design without causing any adverse effects. Cheaper, lower-quality sand was used to replace a more expensive type as the proppant in some areas of the Barnett with no adverse effects. Pre-frac acid treatment was also completely eliminated. The gel content of the frac fluid was slightly reduced. These incremental modifications allowed Mitchell Energy to reduce average frac costs by about 10 percent. Prior to these cost reduction measures, the stimulation cost of Barnett wells was about \$350,000 to

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<sup>11</sup> Gelled water refers to a mixture of water and cross-linked gel, and Nitrogen-assist refers to the fact that nitrogen is used to assist in carrying the proppant (i.e., sand) and fluids into the target formation and, after frac, in removing the fluid from the well.

\$450,000. Stimulation is a major cost component since the total cost of Barnett wells ranged from \$750,000 to \$950,000 at that time.

Mitchell engineers started to question the gelled water frac procedure after an experiment in 1996 in which only a small amount of gel was used to stimulate a Barnett well. The small amount of gel, writes Steward (2007, p. 113), was “entirely too low for adequate cross linking and carrying capacity. However, when the well was brought on production, it was an excellent performer.” In 1997, Mitchell engineers began to experiment with a “new” approach to fracturing. The new frac method was a slick water frac used and developed by Union Pacific Railroad Corporation (UPR) for use in the low-permeability Cotton Valley sandstone formation of East Texas. This new frac approach used a large amount of water as the frac fluid and a small amount of sand as the proppant. This procedure allowed UPR to achieve at least the same amount of gas production as before with a substantially reduced capital expenditure. Slick water frac was a radical concept at the time, according to Bowker (2003), “because the general consensus among completion engineers [at the time] was that as much proppant (sand) as economically possible had to be placed in the Barnett in order to maximize fluid conductivity to the wellbore. Gel can carry plenty of proppant, [but] un-gelled water can carry very little.”

Slick water frac was a major breakthrough as it reduced the cost of stimulation by about 50 percent while resulting in similar initial production rates and higher subsequent production rates (Steward 2008). Yet slick water frac was not a novel technology at all. It was previously used by another firm in a different formation. In fact, water-based frac was an old technology that had been widely used in earlier periods. Fisher (2012) emphasized that “in the 1950s, water-based fracs were utilized successfully in many areas.” Ely (2009, slide 7) wrote that “for more than 20 years, prior to the advent of the age of crosslinked gels, that a large majority of frac treatments were pumped using low viscosity fluids,” which included water. The age of crosslinked gels was started by SuperFrac, a fracturing technique an Exxon subsidiary introduced in the late 1960s that used high-viscosity fluids to stimulate oil and gas wells (Kiel 1970).

According to Ely (2009, slide 12), “the trend toward high viscosity fluids has been reversed and the majority of all fracturing fluids consist of water sometimes slightly viscosified.”<sup>12</sup>

Slick water frac is an innovation in only one aspect of good frac design. Frac efficiency requires the optimization of frac placement, size, orientation, pressure, and other attributes for a frac to stay in the target reservoir, create maximum contact with it, and achieve maximum flow of hydrocarbons and minimum flow of produced water (King 2012, p. 8). It is not surprising, then, that Mitchell Energy found that slick water frac was not effective in stimulating Barnett wells that were drilled in areas with weak frac containment barriers (e.g., the Viola limestone immediately below the Barnett shale). In areas with weak, thin, or no Viola limestone, fracs tend to extend out of the Barnett shale and into a water-saturated formation underlying the Barnett.

Mitchell Energy had very limited use of microseismic fracture mapping, which can be used to improve frac placement and direction. With assistance from Sandia National Laboratories and GRI, Mitchell Energy attempted to use microseismic fracture mapping in the Barnett in 1995 and again in 1997, but both tests failed. Around late 1999 and early 2000, the technology of microseismic frac mapping had substantially improved, and Mitchell Energy succeeded in using this technology in a number of infill wells (which are drilled to fill in the space between existing producing wells to increase production).

### 3.2.2 Geological Knowledge

Understanding the geology of the target reservoir is critical for deciding where to drill wells, how many wells to drill, and how to drill and stimulate wells. Thus, the accumulation of geological knowledge is an important part of the Barnett development story. In the early 1980s, Mitchell Energy focused on understanding the geology of the Barnett by drilling exploratory (deepening) wells and by acquiring and analyzing 2-D seismic data. Some properties of the Barnett were learned relatively quickly. For example, in the early 1980s, Mitchell geologists identified the two major fault systems in Wise County and learned about the need to drill wells away from faults. Some other properties of the Barnett were understood quite late. For example,

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<sup>12</sup> High-viscosity frac fluids were successful in many conventional reservoirs as viscous gels are good for carrying high concentrations of proppants into induced fractures. However, high-viscosity gel frac fluids harm well productivity if gel residues are not broken down and flown back during the fracture cleanup phase. Since water-based fluids can reach smaller fissures than gelled fluids, water fracs can create far more fracture surface area than gel fracs do. In the words of Fisher (2012), those large surface areas were only lightly propped, but “were connected just enough to the well bore to be able to access larger portions of the reservoir.”



Stewards (2007, p. 153) suggests that until 2000 or so, Mitchell Energy did not have a good “understanding of thermal maturation of the Barnett, and distribution of the dry, wet gas, and oil phases in the rock.”

The most important and dramatic geology story of the Barnett is the estimate of its gas-in-place. The gas-in-place of a reservoir is the volume of recoverable and unrecoverable gas in the reservoir. The gas-in-place estimate, for obvious reasons, had a significant impact on Mitchell’s development strategy of the Barnett. In 1991, Mitchell Energy and GRI conducted a joint project to estimate the gas-in-place of the Barnett by analyzing rock samples from a Barnett well. Unfortunately for Mitchell Energy, the gas-in-place estimate from the 1991 joint project was proved, by a new evaluation in 1999, to be low by a factor of 2.5 or 3, depending on whether the upper portion of the Barnett was taken into account. Barnett shale has two members, the lower Barnett and the upper Barnett, which are separated by a limestone formation. The upper Barnett is thinner than the lower Barnett, and it was considered by the 1999 evaluation but not by the 1991 evaluation. All of Mitchell Energy’s Barnett wells, prior to the 1999 reevaluation, were drilled and completed to the lower Barnett. The 1999 reevaluation changed the way Mitchell Energy developed the Barnett. First, it soon began to routinely frac the upper Barnett along with the lower Barnett, significantly improving the production rates of new wells. Second, it started to refrac existing wells and add in the upper Barnett during the refrac process. Third, it started to drill additional wells to fill in the space between existing wells to increase production. Fourth, Mitchell Energy started to explore more areas of the Barnett. The optimization of the slick water frac and improved gas prices also played a role in these new developments.

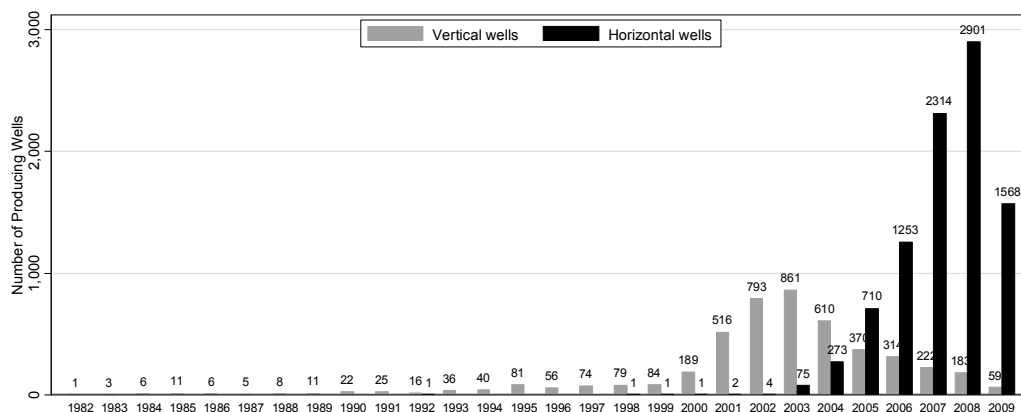
Mitchell Energy acquired its first 3-D seismic data set in North Texas in 1992, which was used to evaluate a formation shallower than the Barnett. It appears that Mitchell Energy first used 3-D seismic data to analyze the Barnett in 1994. The acquisition for this data set, covering a twenty square mile area, notes Steward (2007, p. 103), was justified “with possible fault/karst compartments” in a shallower formation, in addition to “detailed geophysical analysis of the Barnett.” Before its sale to Devon Energy, according to Steward (2007, p. 104), Mitchell Energy “acquired approximately 500 square miles of 3-D data in North Texas, 50 percent of which would eventually be used for the Barnett Shale play. In addition to the obvious structural value of the data we were able to perform detailed seismic attributes on many of the programs”

### 3.2.3 Drilling

Mitchell Energy drilled more than 800 vertical wells, but only attempted to drill four horizontal wells before its merger with Devon Energy. It is only after the merger that horizontal drilling took off in the Barnett play. See Figure 6, which shows the number of new vertical and horizontal wells in the Barnett from 1982 through 2009.

All of the drilling improvements that Mitchell Energy made were incremental in nature. From the early 1980s to the mid-1990s, Mitchell Energy reduced the average time of drilling (i.e., the spud-to-rig-release time) by nearly 50 percent, from 18–22 days to about 11 days, and the cost of drilling by about 15 percent. The incremental improvements in drilling efficiency were in the areas of drilling fluids (e.g., drilling mud), lost circulation control, and the use of down-hole drilling motors. Lost circulation occurs when drilling fluids flow into rock formations instead of returning up the well bore.

**Figure 6. Number of New Barnett Production Wells by Type, 1982–2009**



Source: Powell Barnett 2010.

Mitchell Energy drilled a horizontal well in 1991 with technical and financial assistance from GRI. It was not until 1998, however, that Mitchell Energy drilled its second and third horizontal wells, which were in an area where Mitchell Energy had failed to make vertical wells commercial. Both wells were mechanically successful, but neither met Mitchell Energy's minimum economic criteria. Considering this factor and the low natural gas price in late 1998 and early 1999, Mitchell Energy was reluctant to drill more horizontal wells. In late 2000, Mitchell Energy attempted to drill a horizontal well for the last time. That project was plagued with technical problems and was terminated after an expenditure of over half a million dollars.

Steward (2007, p. 161) recognizes that “[experiments] like this are necessary in technology plays, and are an important component of the learning process.”

### **3.3 Did Environmental Issues Affect Mitchell Energy?**

Environmental issues associated with natural gas drilling, not necessarily in shale formations, significantly affected Mitchell Energy. According to Kutchin (1998, p. 38), a number of lawsuits were filed by many plaintiff groups against Mitchell Energy in the 1990s, and these lawsuits claimed that the company’s natural gas drillings polluted landowners’ residential water. The most important case is the “Bartlett” case.

The environmental issues of the Bartlett case were similar to those that are being debated now. The plaintiffs in the Bartlett case were landowners in Wise County, and their residential water came from wells on their land. By the time of the lawsuit, Mitchell Energy had drilled over 3,500 wells in Wise County and neighboring counties since the 1950s. Most of these wells were drilled to a formation overlying the Barnett, with depths ranging from 5,000 to 7,000 feet. The plaintiffs’ wells drew water from an aquifer at a depth of 200 to 400 feet, and the plaintiffs contended that their water was polluted by 12 Mitchell Energy gas wells because the firm, in the words of the appeals court, “placed insufficient surface casing on the wells, failed to properly repair casing leaks in the wells, failed to place cement over potentially productive zones in the wells, failed to properly plug one of the wells, and failed to properly cement surface casing in one of the wells.”

A jury awarded the plaintiffs \$4 million in actual damages and \$200 million in punitive damages in March 1996. The appeals court, in November 1997, reversed the trial court’s judgment based on both procedural and substantive matters: most plaintiffs filed their cases after the statute of limitations had expired, and those who filed within the statute of limitations failed to prove that Mitchell Energy polluted their water. So the plaintiffs received nothing. Nevertheless, Mitchell Energy paid a high price. The litigation cost was over \$20 million and, more importantly, the large punitive damage awarded by the trial court, before it was overturned, Kutchin (1998, p. 38) writes, “was depressing to [Mitchell Energy], in everything from investor perceptions of the company’s future through employee morale to future planning.”

### **3.4 What External Help Did Mitchell Energy Obtain?**

Mitchell Energy did not operate in a vacuum. When developing the Barnett, Mitchell Energy, to various degrees, benefited from GRI, the federal government, academic publications, other operators, and service firms.

In the 1990s, Mitchell Energy cooperated with GRI on a number of research projects. Steward (2007, p. 94) writes that a project on fracture analysis “proved valuable,” as did a project “designed to evaluate the presence, importance, and relationship of natural fracture networks to induced fractures and subsequent drainage areas.” Down-hole motors were successfully used in drilling the 1991 horizontal wells, a cooperative venture, and this led Mitchell Energy to experiment with and regularly use down-hole motors afterward. Other projects did not work out. The gas-in-place evaluation in 1991, which was proved wrong by a factor of at least 2.5, probably hindered the pace of Barnett development. The joint attempts to use microseismic fracture mapping in 1995 and 1997 also failed. The 1991 project on horizontal drilling did not lead Mitchell Energy to drill horizontal wells on a regular basis, probably because horizontal drilling had not yet achieved commerciality in natural gas wells. GRI also assisted with reservoir and production modeling, reservoir characterization, and the refracs of Barnett wells, but it is not clear what impacts these projects had on Mitchell Energy.

DOE’s Eastern Gas Shale Program produced many reports and journal articles on Devonian shale but, unfortunately, it is not possible to evaluate the extent to which those publications helped Mitchell Energy develop the Barnett. At least one Mitchell engineer had some experience with the Devonian shale, but transferring the Devonian experience to help with the Barnett proved difficult in some areas. Using foam fracs in the Barnett after their success in the Devonian shale did not work well, and Mitchell Energy soon went to gel fracs. Mitchell engineers initially considered the Devonian shale as a production analog, but had to drop that idea because the initial production rates of and subsequent declines in Mitchell Energy’s Barnett wells were different from those of the Devonian shale.

Mitchell Energy benefited somewhat from the federal incentive pricing and/or tax credit policies for unconventional natural gas. Steward (2007, p. 50 and p. 54) writes that Mitchell Energy began to “file a new field discovery in the Barnett Shale” in 1982, and “due to possible tax advantages in the future, [several divisions of Mitchell Energy] were instructed to work on tight gas filings on the Barnett.” In July 1983, Mitchell Energy applied to the Texas Railroad Commission to designate “the Barnett Shale as a tight gas formation, under Section 107(b) of the Natural Gas Policy Act of 1978.” The designation was approved by FERC on December 31, 1985. It thus appears that the Barnett shale was filed under the NGPA category of tight gas instead of Devonian shale. Recall that tight gas enjoyed much smaller financial incentives than Devonian shale did. The Section 29 tax credit expired at the end of 1992, but this does not appear to have affected Mitchell Energy; the number of Barnett wells Mitchell Energy drilled per year more than doubled at that time. In comparison, the total number of unconventional gas wells

drilled per year in the United States declined significantly in 1993 and 1994 due to the expiration of the Section 29 tax credit (Kuuskraa and Stevens 1995).

Mitchell Energy benefited directly from its analysis of academic publications. For example, notes Steward (2007, p. 76), a Mitchell geologist “did a literature search in 1983 for any topics that might have applicability to the [Barnett] play. While many of these publications proved useful, one had particular merit.” The particularly useful publication was the master’s thesis of a graduate student at the University of Texas in Austin that identified a major fault in Wise County where Mitchell Energy drilled most of its wells. Another publication that had a big impact on Mitchell engineers was an article published by two University of Illinois, Urbana, geologists in the *Annual Review of Earth and Planetary Science* in 1990. This article helped Mitchell geologists, in the late 1990s, better understand the thermal history of the Barnett. Faults and thermal history are important geological features that firms must consider when deciding where to drill wells.

The company also benefited through hiring individuals and meeting with companies with expertise in the Barnett. The critical gas-in-place reevaluation in 1999 was initiated by a geologist who was hired in 1998 to “draw on his knowledge of Chevron’s Barnett science.” Chevron “acquired a significant amount of geological and reservoir data” from a Barnett wildcat well, but decided in late 1997 to sell its Barnett assets and withdraw from the Barnett play. The geologist, knowing that the gas-in-place estimate from the Chevron well was much higher, suspected that the 1991 gas-in-place estimate by Mitchell Energy and GRI was too low. In another important case, before experimenting with slick water fracs in the Barnett, a lead engineer with Mitchell Energy met with UPR personnel and reviewed UPR’s well and frac data. Recall that UPR used slick water frac to stimulate a tight gas formation.

Finally, Mitchell Energy benefited from the expertise of the service firms it employed.<sup>13</sup> Starting in the mid-1990s, Humble Geochemical performed all of Mitchell Energy’s thermal maturation analyses. Since 1995, Timeslice Technology oversaw Mitchell Energy’s seismic program. During the 1999 gas-in-place reevaluation, Mitchell Energy relied on several service

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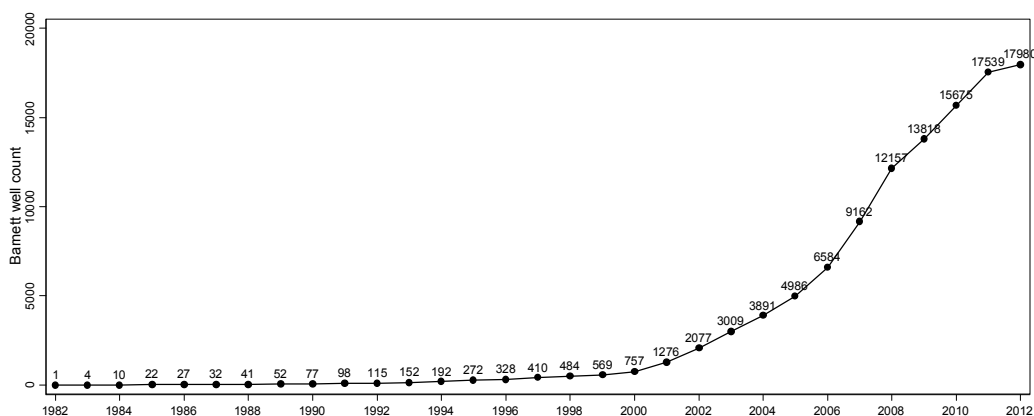
<sup>13</sup> Mitchell Energy seems to have done frac treatments largely on its own. Steward never mentions whether Mitchell Energy ever contracted for frac services. However, after Mitchell Energy was sold to Devon Energy, Steward mentions that Devon Energy and Republic Energy used Halliburton’s SurgiFrac technique, which can be used to “perform a large number of fracs, one at a time, along the lateral [of a horizontal well], to stimulate the reservoir.”

firms (e.g., Humble Geochemical and Core Lab) to perform many technical analyses, including geochemical analyses and rock properties analyses.

### 3.5 How Did the Mitchell–Devon Merger Accelerate Development?

The Mitchell–Devon merger greatly accelerated the development of the Barnett play. This can be seen from Figure 7, which shows the number of Barnett production wells from 1982 through 2012. The merger sent a strong signal to the industry that the Barnett play had great potential, but what turned the potential into a real boom was the widespread application of horizontal drilling, microseismic frac mapping, and 3-D seismic imaging, in addition to the slick water frac used extensively by Mitchell Energy.

**Figure 7. Number of Barnett Production Wells, 1982–2012**



Source: Powell Barnett 2010.

When it purchased Mitchell Energy for \$3.5 billion in January 2002, Devon Energy was one of the largest independent oil and gas operators in North America and, according to Devon Energy’s 2005 annual report, its total assets were \$13.2 billion in 2001. Shortly after the merger, Devon Energy, unlike Mitchell Energy in the past, started to drill horizontal wells in the Barnett. Five horizontal wells spudded in 2002, according to Steward (2007, p. 182), “out-perform[ed] anything previously seen in the Barnett.” Three of the five wells were in low-risk areas and two in high-risk areas a lower frac barrier that was either poor or nonexistent—the type of geological setting where Mitchell Energy had failed to produce commercial wells. The initial production rate of each of the three low-risk wells was over 3.5 times that of the average initial production rate of the vertical wells drilled by Mitchell Energy in 2000 and 2001; the initial production rate

of the two high-risk wells were 2.5 and 3.3 times Mitchell Energy's rate. As a result of these five wells, Devon Energy applied for permits to drill more than 80 horizontals in a five-county area in 2003. After the production rates of these five wells were filed with the Texas Railroad Commission and became public in July 2003, 25 other operators filed for more than 100 horizontal well permits over a seven-county area in 2003.

Horizontal wells, however, were not always successful for a number of reasons, the most important of which is, according to Steward (2007, p. 183), the "lack of understanding of the [geological setting] into which the lateral is being drilled." 3-D seismic data are needed to understand the geological setting. Devon Energy understood the importance of 3-D seismic data in drilling Barnett wells, but it kept this knowledge, acquired from Mitchell Energy, to itself. It is only after Republic Energy, another operator, used 3-D seismic data in 2003 to adjust the lateral placement of a horizontal well and shared this information with other operators that seismic activity in the Barnett exploded. Even with seismic control, notes Steward (2007, p. 186), "most horizontals still break out of zone to some extent and connect with Ellenburger water." Ellenburger is a water-saturated formation underlying the Barnett. Microseismic frac mapping is needed to optimize frac placement and height so as to minimize the connection with Ellenburger water. Devon Energy used microseismic frac mapping "wherever listening wells were available," and some operators even drilled vertical listening wells for the purpose of monitoring the stimulation process of nearby horizontal wells.

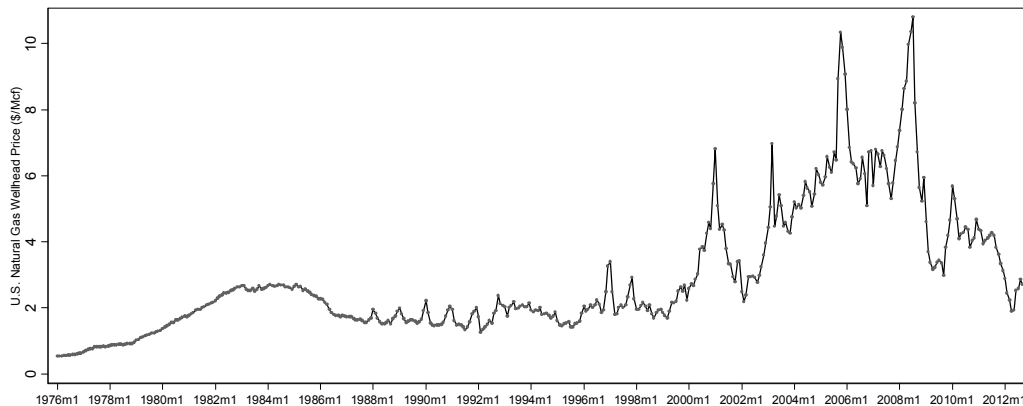
#### **4. High Natural Gas Prices in the 2000s**

In the previous section, we show that Mitchell Energy's pace of developing the Barnett shale was greatly influenced by the price of natural gas. This is not surprising, given that natural gas price has a direct and large impact on a gas firm's profitability. Mitchell Energy accelerated its development of the Barnett in 2000 and 2001 partly because natural gas prices increased significantly in those two years, from an average wellhead price of about \$2/Mcf in 1998–1999 to an average of \$3.85/Mcf in 2000–2001. Natural gas wellhead price decreased to an average of about \$3/Mcf in 2002 but remained higher than \$5/Mcf for most of the period from 2003 to 2008. This can be seen from Figure 8, which shows the monthly wellhead natural gas price in the United States from January 1976 through September 2012.

Given that drilling and fracturing technologies have achieved great successes, high natural gas prices imply that firms may realize significant profit margins from drilling shale gas wells. The prospect of high profit margins naturally attracts existing firms and new entrants to invest heavily into existing and new shale gas plays. This is an important reason for the rapid

development of shale gas in the 2000s. A major reason for the high natural gas prices between 2003 and 2008 was the declining production volume of conventional natural gas and a booming economy. The increased production of shale gas eventually drove down natural gas prices.

**Figure 8. Monthly US Wellhead Natural Gas Price, January 1976 to September 2012**



Source: Energy Information Administration, natural gas data:  
<http://www.eia.gov/naturalgas/data.cfm>.

## 5. Other Contributing Factors

In this section, we discuss briefly the roles of geology, land/mineral ownership, market structure, water availability, pipeline infrastructure, capital market, and a few other factors in shale gas development. These factors contributed to, or at least did not constrain, shale gas development in the US, but the same factors may be lacking in some countries that are attempting to develop their own shale gas resources.

### 5.1. Geology

Shale gas was developed later than tight gas or coalbed methane largely because of its difficult geological features. Shale gas, however, has become the most important unconventional gas because of its large recoverable reserves (as well as technology innovations). The area of the Barnett shale where Mitchell Energy concentrated its efforts, the Barnett core area, has two idiosyncratic geological features that helped Mitchell Energy jump start its shale gas development. First, that area is below shallower conventional formations where Mitchell Energy had been producing natural gas. Second, that area turns out to be one of the most geologically favorable shale formations. Shale gas plays may differ greatly in terms of geology and, consequently, profitability. According to an investment report by Tudor, Pickering, Holt & Co.



in 2012, the Barnett core area, among all dry shale gas formations in the US, ranks third in terms of profitability.<sup>14</sup> Natural gas only needs to be \$4/Mcf for the Barnett core area to achieve a 10 percent rate of return,<sup>15</sup> but it needs to be over \$7/Mcf for the Eagle Ford play to achieve the same rate of return.

## **5.2. Land/Mineral Ownership**

Shale gas development in the United States has essentially taken place in areas with private land and minerals ownership. Private land ownership contributed to the development of shale gas in that it offered entrepreneurial natural gas firms a method of obtaining reasonable returns from their early investments in technology innovations necessary for developing a new shale play. Early movers found that they could lease large tracts of land at low prices, and the leases became more valuable as the cost of extracting gas decreased. It is through land acquisition, not innovations per se, that early movers obtained their financial returns for their early investments. This mechanism is not perfect, though. One consequence of private land leasing is that well siting is not coordinated, and thus is probably not optimal. It also allows speculating firms to lease land without making substantial R&D investments, although firms need to drill something on the land within a few years to keep the lease. Indeed, more recently, this “use or lose” feature has contributed to the current glut of shale gas and low prices.

## **5.3 Market Structure**

In the economics literature, a long-running debate centers on whether large or small firms are more likely to innovate. The case of shale gas development in the United States does not fit in with this simple small–large dichotomy. Mitchell Energy was small when compared with the major international oil and gas companies, but large when compared with the typical natural gas firms.

Shale gas exploitation is one of the most capital-intensive industries, and Mitchell Energy’s development history in the Barnett play suggests strongly that small natural gas firms do not have the capacity, financial or technical, to make substantial risky investments in shale gas technology. Indeed, it was large independent natural gas firms (e.g., Mitchell Energy, Devon

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<sup>14</sup> The report is available at [http://tudor.na.bdvision.ipreo.com/NSightWeb\\_v2.00/Downloads/Files/6633134c-ed42-47a5-bbb4-261c333591ce.pdf](http://tudor.na.bdvision.ipreo.com/NSightWeb_v2.00/Downloads/Files/6633134c-ed42-47a5-bbb4-261c333591ce.pdf).

<sup>15</sup> The natural gas price can be even lower to profitably exploit so-called Tier 1 gas resources.

Energy, and Republic Energy) that made large amounts of investments in the early stage of shale gas development, and the United States has a considerable number of large independent natural gas firms. The major oil firms, which are much larger than any independent natural gas firm, had the capacity, but they did not invest in shale gas early. For large oil firms, shale gas was less attractive as an investment choice than conventional oil and gas. Oil and gas service companies helped Mitchell Energy with its development, though documenting the exact role of service companies in horizontal drilling and hydraulic fracturing after Mitchell Energy is beyond the scope of this paper.

#### ***5.4 Water Availability***

Slick water fracturing of shale gas wells requires a few million gallons of water per well. In the US, water needed for fracturing has generally been available, although in some areas shortages are a growing concern. For example, the 2011 drought in Texas, the worst in more than a century, forced natural gas companies, especially those in the Eagle Ford shale area, to “go farther afield to buy water from farmers, irrigation districts and municipalities,” and to recycle fracturing fluids (Carroll 2011). Shortages in northern Colorado in spring 2012 led to conflict between oil and gas companies and farmers, as the oil and gas companies could outbid farmers in auctions of surplus water (Healy 2012). Thus, while water availability has not yet been constraining to the shale gas boom, it may be constraining in the future.

#### ***5.5 Natural Gas Pipeline Infrastructure***

The United States already had an extensive network of pipelines to transport natural gas to market before shale gas became a major gas resource. Also important was the policy of open access to interstate natural gas pipelines (as well as natural gas storage facilities) as a result of a series of FERC orders in the 1980s and early 1990s. Interstate natural gas pipelines previously sold pipeline transportation and natural gas as a bundled product, but the open-access policy limited interstate pipelines to offer transportation services only, on a nondiscriminatory first come, first served basis. This open-access policy helped create a more competitive wholesale natural gas market. For more details, see Cuddington and Wang (2006) and the references cited therein.

#### ***5.6 Capital Market***

Some have claimed that the capital market has played a key role in the development of shale gas. After the shale gas boom took off, financial firms provided some natural gas firms

with large amounts of capital to drill, facilitated a considerable number of deals in which larger oil and gas firms bought out (relatively) smaller firms engaged in shale gas drilling, and may have contributed to the recent oversupply of shale gas.<sup>16</sup> Mitchell Energy also relied on the capital market (e.g., conventional bank loans, public stock offering, public bond offering, and private placement) to raise funds to drill for oil and gas and to develop real estate (Kutchin 1998, p. 35). However, Mitchell Energy raised those funds not because of but despite its shale gas development that lost money for many years. It is not clear whether the capital market has the incentive to invest in the type of long-term risky R&D activities that Mitchell Energy undertook.

### **5.7 Other Factors**

A number of other factors have also contributed to shale gas development in the United States. Road infrastructure is generally available; underground injection wells for waste water disposal have generally been available (with Pennsylvania as a prominent exception); topography of most shale basins is favorable; most shale gas plays are in areas with low population densities and a history of conventional oil and gas development, although in some places, like Pennsylvania, population densities are relatively high and large-scale development was only in the distant past; and oil and gas service companies

## **6. Concluding Remarks**

Our analysis of the economic, policy and technology history of shale gas development indicates that the shale gas boom resulted from factors that ultimately enabled firms to produce shale gas profitably. These factors include technology innovation, government policy, private entrepreneurship, private land and mineral rights ownership, high natural gas prices in the 2000s, market structure, favorable geology, water availability, natural gas pipeline infrastructure, and a number of other factors. Our review suggests that the key question for policymakers in countries attempting to develop own shale gas resources is how to generate a policy and market environment in which firms have the incentive to make investments and would eventually find it profitable to produce shale gas.

Countries new to shale gas enjoy a major advantage over the United States in that the state-of-the-art shale gas technologies are much more advanced than those that existed when the

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<sup>16</sup> Some of the financing contracts require continued drilling even when the natural gas price is low. See Krauss and Lipton (2012).

United States started to develop shale gas. The existing technologies may help jump start shale gas development in other countries. However, a great deal of innovations will be needed to adapt existing technologies and to develop new technologies to profitably exploit shale gas fields in any country where shale gas geology and/or water resources are significantly different from those in the United States. For example, the current cost of drilling a shale gas well in China is reported to be several times higher than that of a typical shale gas well in the United States. To substantially lower cost, technology experimentation, learning, and improvements are needed. Where will the technology innovations come from?

Our review suggests that small firms do not have the capability to make the necessary R&D investments, but large firms with the technical and financial capability may not have the incentive to do so. For example, we notice that China's major national oil firms, similar to the major international oil firms prior to the shale gas boom in the US, appear to be reluctant to make large R&D investments in domestic shale gas because of the alternative investment choices currently available to them. In the US, it was large natural gas firms such as Mitchell Energy that made significant amounts of early investments in shale gas development. Our review suggests that if a country is willing to use industrial policies to promote shale gas development, the issue of market structure may be an important component of such policies.

In the US, government-sponsored R&D programs helped with technology innovations, and fiscal policies, such as tax credits, offered firms some incentives to drill shale gas. More importantly, the ability to lease land and mineral rights across large areas early and at a low price was a powerful incentive to develop. Unfortunately, the situation in the United States is unusual. In most countries, such as China, below-ground mineral rights are owned by the state. Governments may use auctions to allocate shale gas blocks and impose the requirement that a certain amount of investments must be made to develop auctioned blocks in a certain period of time. This policy will force firms to drill, but it is not clear how large an incentive to innovate this mechanism provides, relative to those that come with the leasing of private property. A key issue is whether firms would be able to secure from auctions large enough acreage positions to potentially reap the benefits of their R&D investments.

In the US, deregulated natural gas prices provided a stimulus to exploit shale gas. Importantly, before the gradual deregulation of natural gas prices in the US, severe natural gas shortages occurred, reflecting firms' lack of incentives to explore and exploit new gas resources when the natural gas price set by the government was below market value. The price of natural gas is currently regulated in some of the countries with large shale gas reserves and is set at levels far below market value. Price regulation is a disincentive for firms to make substantial

investments in shale gas development, not only because of low price levels, but also because of the regulatory uncertainties created by price regulation. A related policy issue is open access to natural gas pipelines, which facilitates the marketing and transportation of natural gas.

Our review also raises the question of how a country's policy on shale gas should be coordinated with its policy on tight gas and coalbed methane. Government R&D programs and fiscal policies in the United States targeted all three types of unconventional natural gas. It is technically more challenging to exploit shale gas, so it is not surprising that Mitchell Energy gained substantial experience in drilling tight gas wells before drilling shale gas wells, and tight gas—and to a lesser degree, coalbed methane—experienced substantial production increases before the shale gas boom occurred (see Figure 1). A shale gas boom may occur in a country without much prior success in tight gas or coalbed methane, but our review suggests a need for a country to coordinate its policies on unconventional natural gas and oil resources.

Our review only touched on the issue of environmental risks, but the environmental lawsuits against Mitchell Energy do suggest that natural gas firms in the United States were constrained by law long before the environmental risks of shale gas development became controversial. In the absence of effective enforcement of laws and regulations, which may be the case in some developing countries, firms may not adopt enough measures (e.g., casing and cementing) to protect the environment; consequently, environmental risks may render a shale gas boom unsustainable. Sound environmental regulations are needed to make a shale gas boom sustainable.

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