EVALUATION AND PREDICTION OF UNCONVENTIONAL GAS RESOURCES IN UNDEREXPLORED BASINS WORLDWIDE

A Dissertation

by

KUN CHENG

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

May 2012

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Stephen A. Holditch
Committee Members,	Duane A. McVay
	Walter B. Ayers
	Yuefeng Sun
Head of Department,	Stephen A. Holditch

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ABSTRACT

Evaluation and Prediction of Unconventional Gas Resources in Underexplored Basins Worldwide.

(May 2012)

Kun Cheng, B.S.; M.S., Southwest Petroleum University, China

Chair of Advisory Committee: Dr. Stephen A. Holditch

As gas production from conventional gas reservoirs in the United States decreases, industry is turning more attention to the exploration and development of unconventional gas resources (UGR). This trend is expanding quickly worldwide. Unlike North America where development of UGRs and technology is now mature and routine, many countries are just beginning to develop unconventional gas resources. Previous research estimated that the unconventional gas in place, including coalbed methane, shale gas and tight-sand gas, exceeds 30,000 Tcf worldwide. As part of a research team, I helped to develop a software package called Unconventional Gas Resource Advisory (UGRA) System which includes the Formation Analog Selection Tool (FAST) and Basin Analog Investigations (BASIN) to objectively and rapidly identify and rank mature North American formations and basins that may be analogous to nascent international target basins. Based on BASIN and FAST results, the relationship between mature and underexplored basins is easily accessed.

To quantify the unconventional resource potential in typical gas basins, I revised and used a computer model called the Petroleum Resources Investigation Summary and Evaluation (PRISE). This research is based on the resource triangle concept, which implies that all natural resources, including oil and gas, are distributed log-normally. In

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this work, I described a methodology to estimate values of technically recoverable resources (TRR) for unconventional gas reservoirs by combining estimates of production, reserves, reserves growth, and undiscovered resources from a variety of sources into a logical distribution. I have also investigated mature North American unconventional gas resources, and predicted unconventional resources in underexplored basins worldwide for case study. Based on the results of testing BASIN and PRISE, we concluded that our evaluation of 24 North American basins supports the premise that basins analysis can be used to estimate UGRs.

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DEDICATION

I want to thank my wife for her selfless love and support. Without her support, this dissertation would not be completed; without her care, I would not have had the strength to preserve with my studies; without her faith, I would not have the mettle to face the future; without her view, I would not have the vision to explore the world.

I would also like to dedicate this dissertation to my parents. They continue to teach me and guide me on the path to rightness. Words cannot express my love for them.

Finally, I dedicate this to my brother who has the same goal and courage to realize his dreams.

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ACKNOWLEDGMENTS

I would like to express my earnest gratitude and appreciation to my advisor and committee chair, Dr. Stephen A. Holditch, for his help and invaluable guidance in every possible way. His constant encouragement and profound knowledge have always motivated me to achieve my research goals and to cultivate my abilities.

I would also like to thank Dr. Walter B. Ayers and Dr. Duane A. McVay for sharing philosophical thoughts, practical knowledge, detailed guidance, and support throughout my research progress.

I thank Dr. Yuefeng Sun for his valuable advice. His constructive discussions about my research have been very helpful throughout the whole dissertation.

Finally, I would like to thank the Crisman Institute in the Petroleum Engineering Department at Texas A&M University for sponsoring my research during my endeavor for a Ph.D. degree in petroleum engineering. Also I extend my gratitude to RPSEA/Schlumberger for providing me with financial assistance and generous scholarships.

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1 INTRODUCTION

1.1 Unconventional Gas Reservoirs

Conventional reservoirs are those that can be produced at economic flow rates and will recover economic volumes of oil or gas without large stimulation treatments or any special recovery process. A conventional gas reservoir is essentially a high- to medium-permeability gas reservoir in which one can drill a vertical well, perforate the pay interval, and then produce the well at commercial flow rates and recover economic volumes of gas (Holditch, 2003).

Holditch (2003) defined an *unconventional gas reservoir* as one that cannot be produced at economic flow rates or that does not produce economic volumes of gas without assistance from massive stimulation treatments or other advanced technologies, such as horizontal drilling. Typical unconventional gas reservoirs are tight sands, coal beds, and shales.

Before discussing the role of unconventional gas reservoirs in the future of the gas business, this dissertation needs to discuss the issue, "Why does the world need to develop unconventional gas resources?" To answer this question, it is necessary to conduct an overview of another competitive energy resource: oil. In *The Coming Oil Crisis*, Campbell (1997) determined that, through 1996, 784 billion STB of oil had been produced by the global oil and gas industry. After 1996, the worldwide oil production increased by about 25 to 27 billion STB of oil per year. With this trend, through year

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This dissertation follows the style of *SPE Journal*.

2009, world oil production since the first wells started to blow in the late 1800s has been estimated to total over 1,151 billion STB of oil. In 2010, the oil production rate was 29 billion STB (Holditch, 2011b).

Global conventional oil reserves in 2003 were a little more than 1 trillion STB, to which the Middle East contributes 70% (Fig. 1.1), North and South America offer 15%, and Africa, Eastern Europe and the Former Soviet Union, Asia Pacific, and Western Europe supply the remainder (OPEC, 2009). In 2009, the global oil reserves increased to 1,333 billion STB (BP, 2010a; BP, 2010b). The Organization of Petroleum Exporting Countries (OPEC) members have made significant additions to their oil reserves in recent years, and OPEC's proven oil reserves currently stand at well above 1,000 billion barrels (OPEC, 2010) (Fig. 1.2). The table on page 7 shows the oil reserves distribution worldwide (Holditch, 2011a). Virtually all of the production comes from conventional reservoirs. The 1,151 billion bbl of oil already produced and the 1,333 billion bbl of estimated reserves are located in conventional reservoirs. Fig. 1.3 illustrates the record of some 65 past estimates by major oil companies, other institutions, and the U.S. Geological Survey (USGS), which average 1.93 trillion bbl, mostly from conventional reservoirs.

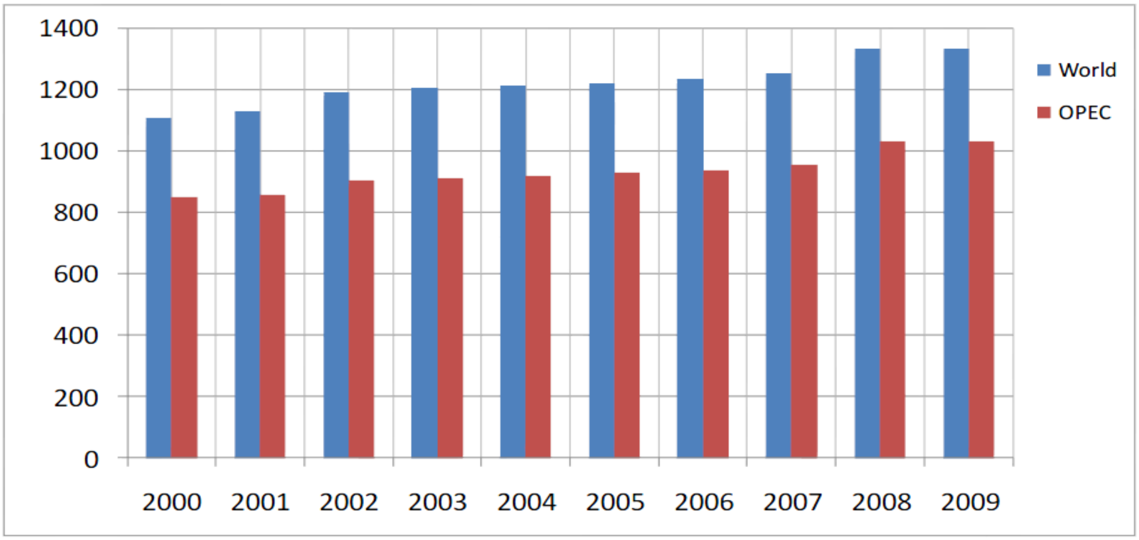

Fig. 1.1—World oil reserves (not including 150 billion barrels in Canadian oil sands) and Organization of the Petroleum Exporting Countries (OPEC) shares from 2000 to 2009 (Holditch, 2011b).

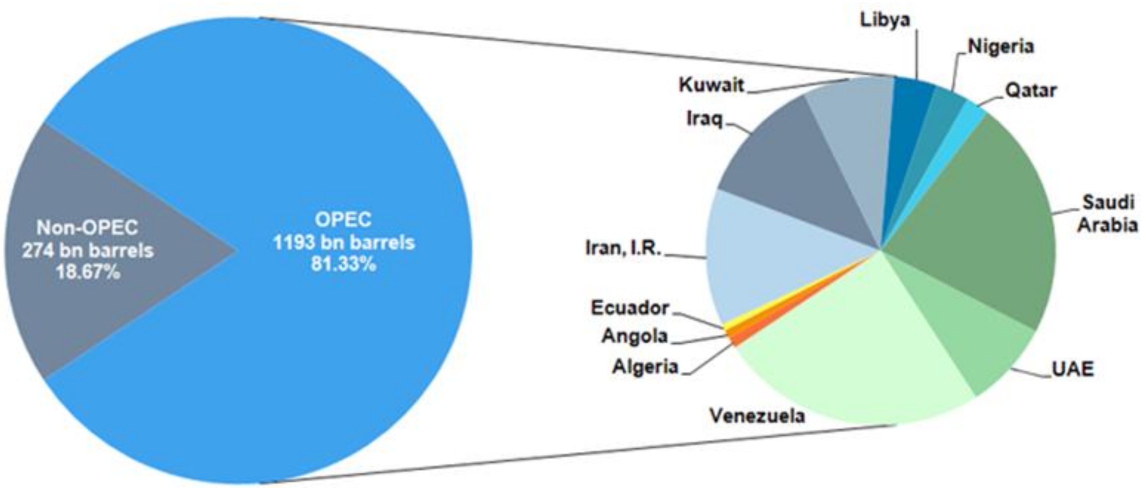

Fig. 1.2—OPEC share of world crude oil reserves 2009 (OPEC, 2010).

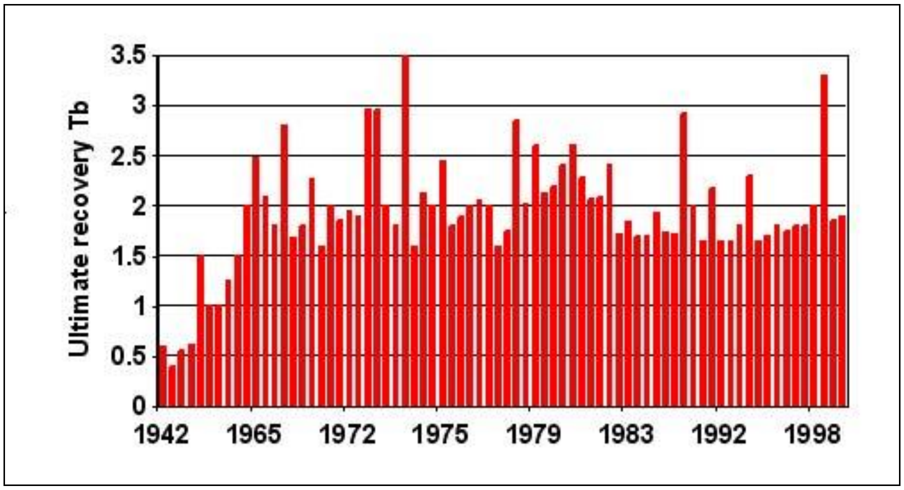

Fig. 1.3—Estimates of ultimate recovery per year from 1942 to 2003 by major oil companies, other institutions, and the USGS (Wood, 2003).

Based on the above estimates of oil potential, the remaining question is essentially "Can the remaining oil reserves satisfy the future needs of the global demand?" The Energy Information Administration (EIA) projects estimates for hydrocarbon liquids (including biofuels), coal, renewables (excluding biofuels), nuclear, and natural gas between 1980 and 2030 (Fig. 1.4). In the EIA (2009) International Energy Outlook (IEO) projections, the total world consumption of energy will increase by 44% from 2006 to 2030 (EIA, 2009). The IEO 2009 report projects that the world will need more oil, natural gas, and coal in the next 20 years. Natural-gas demand increases more rapidly than coal or oil, because most forecasts show that natural gas will be used to generate electric power in an ever-increasing proportion to coal and other fuels (Holditch, 2003). To meet the projected growth in demand for natural gas, the world's producers will need to increase annual production in 2030 to a level that is 49 Tcf higher than the 2006 total (Holditch, 2003).

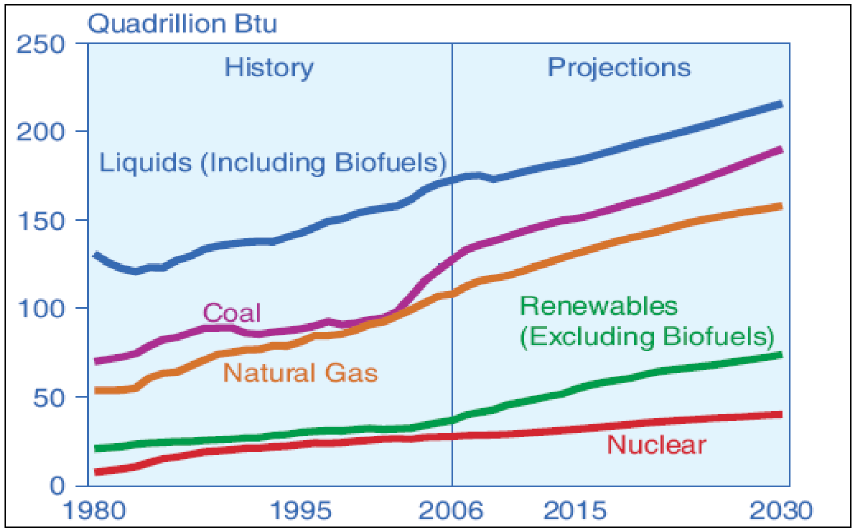

Fig. 1.4—World marketed energy use by fuel type, 1980-2030 (EIA, 2008).

For the projected oil production, MacKenzie (1996) tracked world oil production since 1950 and projected production through 2030, pointing to three possible future scenarios for global oil production from conventional reservoirs. The peak in global oil production is predicted to occur sometime between 2005 and 2020 for these three scenarios. Tien and McVay (2011) estimated that the ultimate recoverable resources (URR) of world conventional oil falls in a P10 to P90 range of 1.8 to 4.4 trillion bbl with a mean of 2.9 trillion bbl, not considering the impact of unconventional resources on future oil production. Whenever production from conventional reservoirs peaks, approximately 50% of ultimate world oil reserves from conventional reservoirs will have been produced. With the projected need for 225 quadrillion bbl, Fig. 1.5 suggests that as much as 700 billion bbl of oil needs to be discovered. Once world conventional oil production begins to decline, it will be very difficult to arrest that decline (Campbell, 1997). Even with higher oil prices and more rigs, most experts believe that the decline in world conventional oil, once it begins, will be permanent and continuous. For conventional oil production in the US, the trend toward decline started in the 1980s.

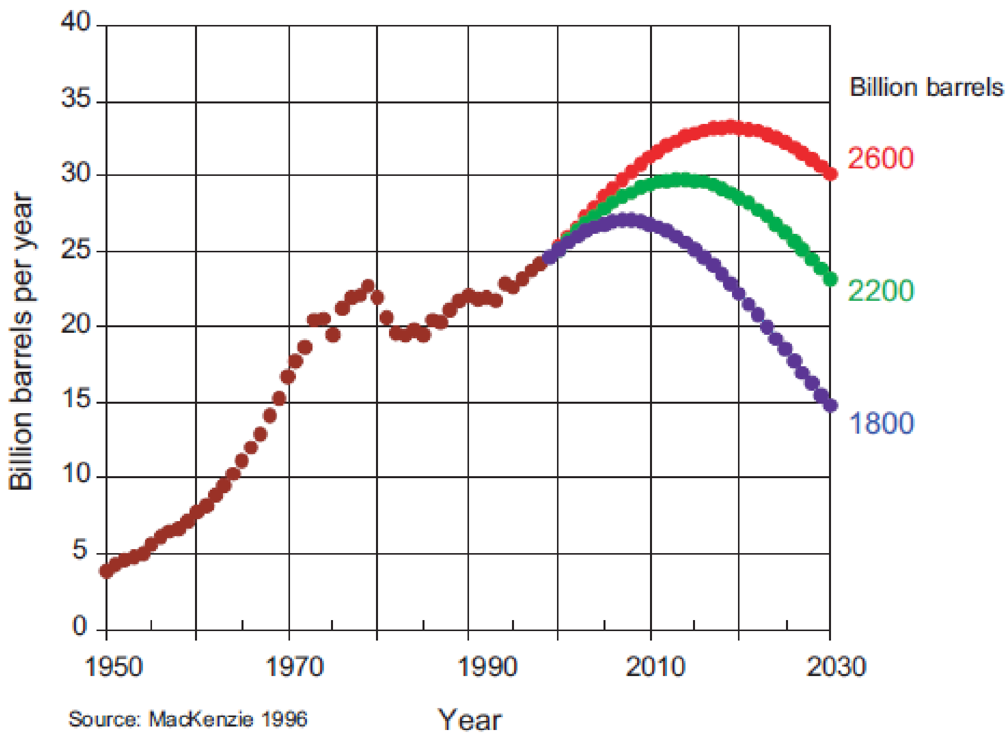

Fig. 1.5—Three scenarios for global oil production (MacKenzie, 1996).

Therefore, a gap between supply and demand will exist at some point in the future. Holditch (2001) asked the question "What can fill the gap?" He suggested several energy sources, including gas reservoirs around the world, unconventional reservoirs (heavy oil, tight gas sand, coalbed methane, and shale gas), and renewable resources. Natural gas reserves, shown in Table 1.1, total slightly more than 5,000 Tcf, and most reserves are mostly located outside the US. Onshore unconventional gas production is the only growing component of the US gas supply (Fig. 1.6).

Table 1.1—International Oil Reserves (EIA, 2009)

Rank	Country	Oil (million barrels) BP Statistical Review	World Oil
1	Saudi Arabia	264.209	264.825
2	Iran	138.400	137.000
3	Iraq	115.000	126.000
4	Kuwait	101.500	99.425
5	United Arab Emirates	97.800	68.105
6	Venezuela	87.035	81.000
7	Russia	79.432	76.000
8	Libya	41.464	36.500
9	Kazakhstan	39.828	Not Separately Reported
10	Nigeria	36.220	37.200
11	United States	30.460	21.317
12	Canada	27.664	25.157
13	Qatar	27.436	20.000
14	China	15.493	18.052
15	Brazil	12.624	12.539
16	Algeria	12.270	11.900
17	Mexico	12.187	11.061
18	Angola	9.035	9.500
19	Norway	8.172	6.693
20	Sudan	6.615	6.700
21	Oman	5.572	5.700
22	India	5.459	4.042
23	Malaysia	5.357	5.458
24	Indonesia	4.370	4.509
25	Ecuador	4.269	4.780
	Total 25 Total	1187.871	1,093.463
	OPEC Total	934.638	896.235
	World Total	1,238.892	1,184.208

Rogner (1997) estimated world unconventional gas resources (occurrences with less-certain geological assurance and/or with doubtful economic feasibility such as coalbed methane, shale gas, and tight gas sand) (Table 1.2). It is clear that unconventional gas reservoirs will be very important as we try to fill the gap (Fig. 1.7) between supply and demand in the coming decades.

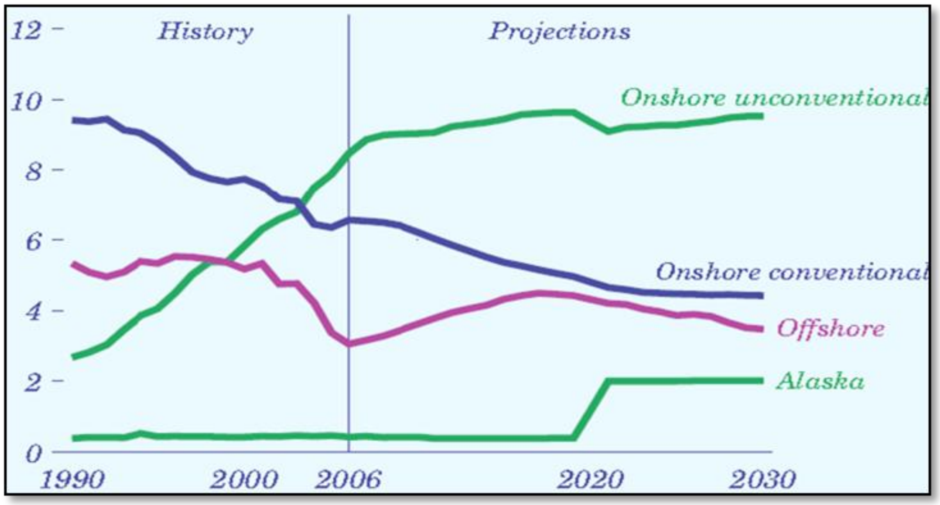

Fig. 1.6—UGRs account for more than 40% of US gas production (EIA, 2008).

Table 1.2—World Unconventional Gas Resources (after Rogner, 1997)

Region	Coalbed Methane (Tcf)	Shale Gas (Tcf)	Tight-Sand Gas (Tcf)	Total (Tcf)
Central and Eastern Europe	118	39	78	235
South Asia	39	0	196	235
Other Asia Pacific	0	314	549	862
Western Europe	157	510	353	1,019
Sub-Saharan Africa	39	274	784	1,097
Middle East and North Africa	0	2,548	823	3,370
Latin America	39	2,117	1,293	3,448
Pacific*	470	2,313	705	3,487
Centrally planned Asia and China	1,215	3,528	353	5,094
Former Soviet Union	3,957	627	901	5,485
North America	3,017	3,842	1,371	8,228
World	9,051	16,112	7,406	32,560

* Organization for Economic Cooperation and Development

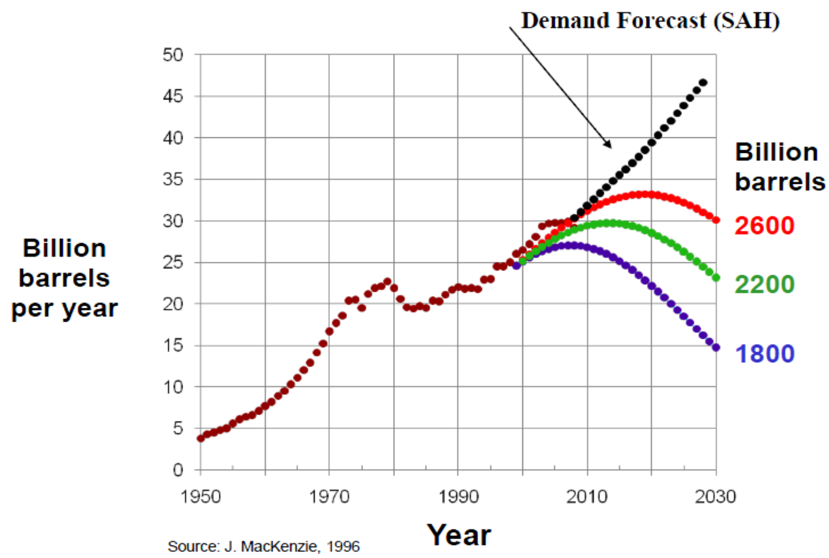

Fig. 1.7—World oil production and forecasts (MacKenzie, 1996; modified by Holditch, 2011b).

1.2 Resource Triangle

Masters (1979) and Gray (1977) presented their concept in terms of a resource triangle (modified by Holditch, 2004) that illustrates the increasing technological difficulty of producing hydrocarbons over time (Fig. 1.8). This theorized concept is that all natural resources are distributed log-normally in nature; once these resources are prospected, the best, highest-grade deposits are small and are easy to extract (Holditch, 2011b). The hard part is finding these pure veins of gold or high-permeability gas fields.

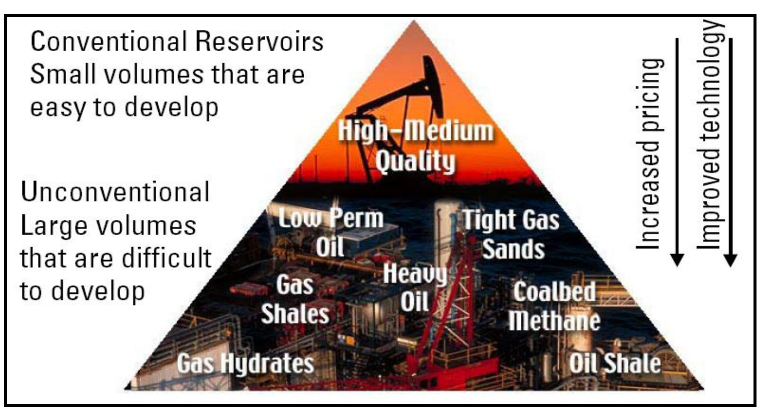

Fig. 1.8—Resource triangle (Holditch, 2004).

On this triangle, the apex represents relatively small volumes of conventional resources that are relatively easy and inexpensive to develop (Holditch, 2005). At the base of the triangle lie unconventional resources, such as tight gas sands, coalbed methane, shale gas, gas hydrates and heavy oil that require improved technology (Table 1.3) and better resource assessments to develop. Fig. 1.9 indicates the application of the resource triangle for TGS in the U.S.

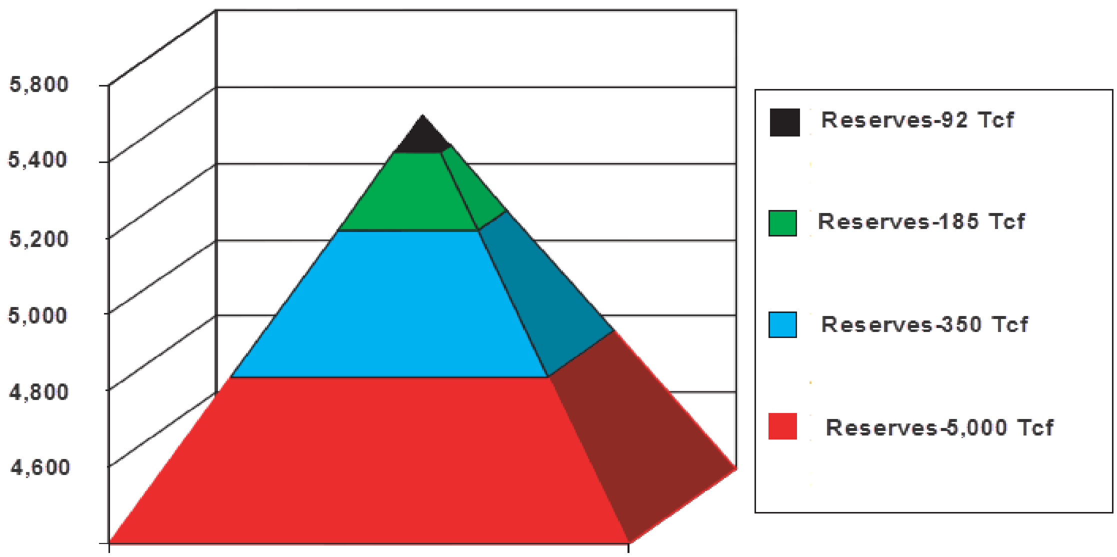

Fig. 1.9—Resource triangle for TGS in the U.S (Holditch, 2006).

Table 1.3—Critical Technology Needs and Applications for CBM and SG Reservoirs (Jenkins and Boyer, 2008)

Primary Technology Areas	Technology Needs	Technology Applications
Reservoir Characterization	Quantify fracture systems and variability; identify areas with high permeabilities	3D and 4D seismic Wellbore imaging tools Surface geochemistry
	Sorbed-gas content measurements	Downhole spectroscopic analysis Geochemical logging
	Permeability measurements	Pre- and post-closure minifrac analysis Wireline-conveyed isolation/injection systems
	Identification of behind-pipe reservoirs	Through-casing analysis Improved interpretive algorithms
Drilling Operations	Rapid, reduced-cost drilling	High-pressure, jet-assisted coiled-tubing systems Telemetric and composite drillpipe Nondamaging, environmentally benign fluids
	Reduced drilling “footprint”	Multilateral wells Below-reservoir extraction
	Horizontal-well stability	Combination drill and liner systems Mechanical liner systems
Completion Operations	Nondamaging cementing	Ultra lightweight cement
	Formation access	Jet-assisted hydrojetting High-energy laser perforating
	Increased hydraulic-fracturing effectiveness	Coiled-tubing-conveyed systems with horizontal-well application Fracture diagnostics, including micro seismic and tiltmeters Environmentally benign fluids Ultra lightweight proppants
Production Operations	Artificial lift/water disposal	Downhole gas/water separation and reinjection Improved filtration and/or sequestration of contaminants Surface-modification agents Smart-well and expert systems
	Enhanced production	Carbon dioxide or nitrogen injection Enhanced horizontal-wellbore configurations Microbial-enhanced gas generation

1.2.1 Coalbed Methane

Coalbed methane (CBM) is considered an unconventional gas resource. CBM contains mostly methane that is adsorbed to the surface of the coal (Ayers, 2002). CBM is often produced at shallow depths with large volumes of water of variable quality. CBM resource operations may contain large volumes of unconventional gas resources.

For North America, producing CBM can have a large impact on the regional gas market. Annual production from 11 coal basins in the US exceeds 1.5 Tcf, or 8 to 10% of the annual US gas production. About 18.6 Tcf of proven CBM reserves makes up 6.5% of US total gas reserves (EIA, 2009), and the total US CBM in place is estimated to be 749 Tcf (Leach, 2002). Significant reserves of coal underlie approximately 13% of the US. Of the coal regions shown in Fig. 1.10, several currently produce CBM, while exploration is active in other areas.

CBM production can be traced back to 1926 (Cardott, 1999) in Oklahoma. In the San Juan Basin, production from coal started in 1951 (Cardott, 1999). The greatest increase in development, however, began in approximately 1988 (Fig. 1.11), partly because Congress enacted tax incentives to boost domestic exploration into alternative sources for energy. CBM production continues to advance across North America as operators develop new techniques for drilling and producing coal seams of different rank and quality and the demand for natural gas continues to increase. Increased gas prices, the continued expansion of the natural gas transportation system, and recent advances in oilfield technologies have helped make CBM wells more profitable. Through the years, operators and service companies have gained valuable knowledge from mining research and practical experience from drilling activity induced by the US tax credits. Fig. 1.12 shows the significant CBM production growth, and Fig. 1.13 compares CBM production along with tight sands and shale gas. Because of decades of CBM development experience, CBM production potential from existing coal basins in the US serves as a qualitative analogy that can be used around the world (Fig. 1.14) to project growth in CBM gas production outside the US.

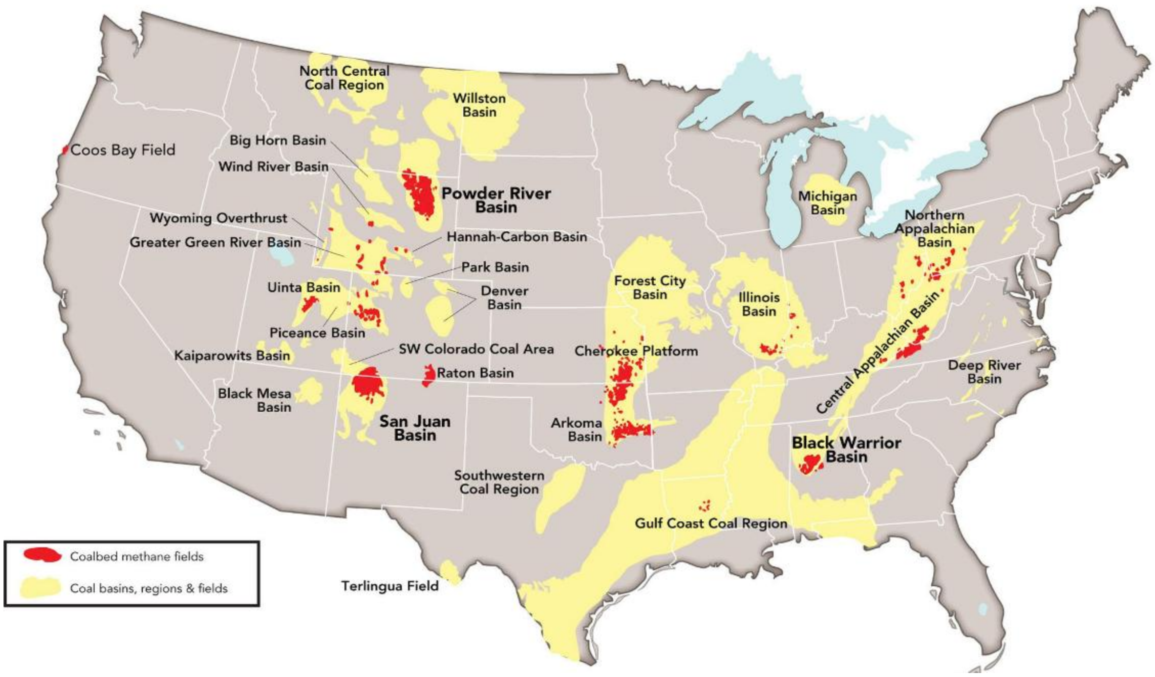

Fig. 1.10—CBM resource potential in the US (EIA, 2010).

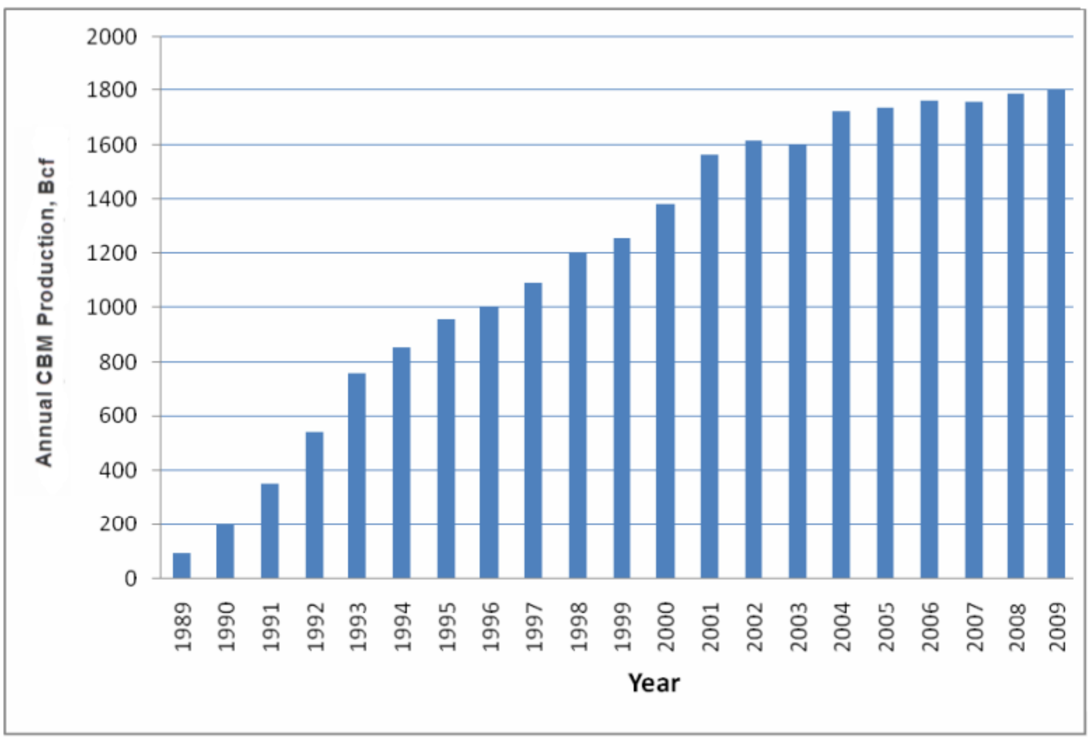

Fig. 1.11—US CBM production (EIA, 2009).

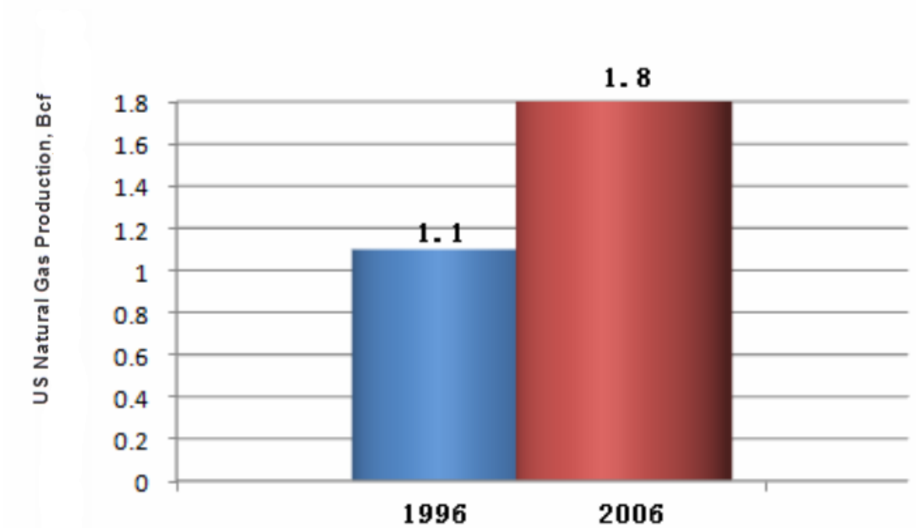

Fig. 1.12—CBM has seen production growth (modified from Kuuskraa, 2007).

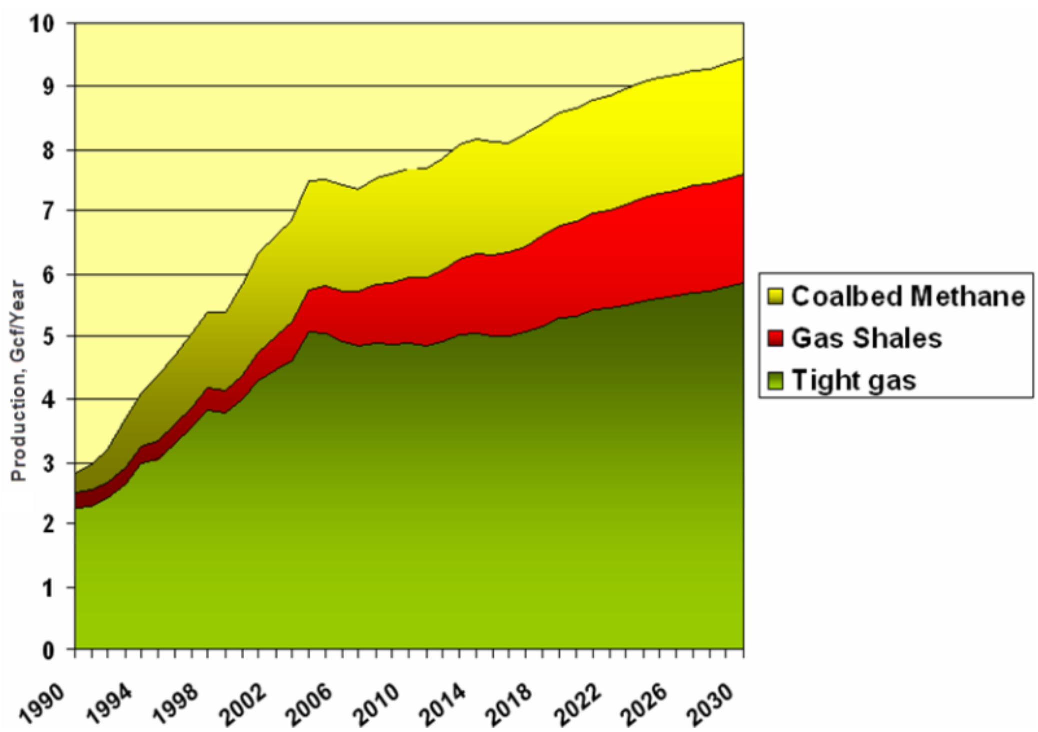

Fig. 1.13—EIA AEO 2005 with projections to 2025 (EIA, 2009).

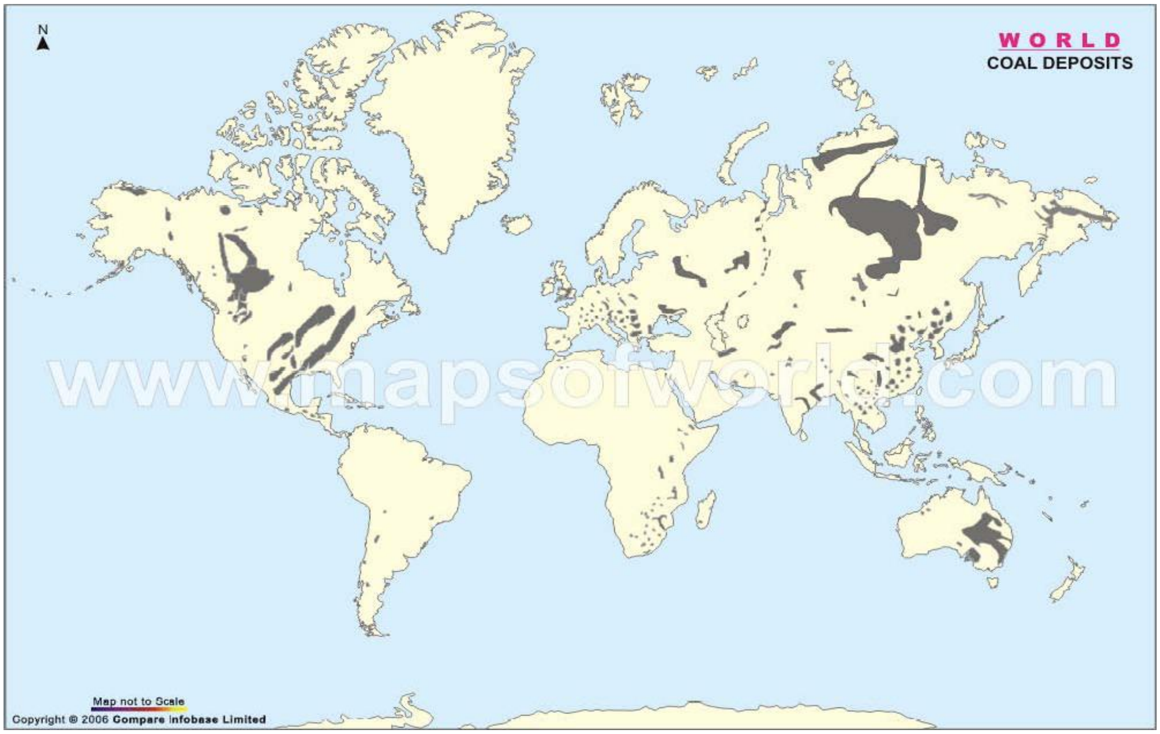

Fig. 1.14—World coal deposits (Maps of World, 2007).

The demand for energy worldwide is set to increase to 600 quadrillion BTU by the year 2020 from the current level of 400 quadrillion BTU. With this increase in demand for energy, the world is turning toward unconventional gas resources as conventional energy resources are depleting. Unconventional gas resources contribute a lot to meet US energy demand (Fig. 1.15). Development of CBM is one of the most successful examples of how technology opens new energy sources for production. By the year 2020, about 47.5% of the energy demand is expected to be fulfilled by natural gas resources. Significantly, about 20% of demand is expected to be fulfilled by CBM. Although this percentage is now very low, it is expected to increase in the future (Economides and Oligney, 2001) as shown in Fig. 1.16. Taking China for example, in the 7th Sino-American Oil & Gas Seminar, China United Coalbed Methane Co. Ltd. showed CBM importance using Table 1.4 and Fig. 1.17.

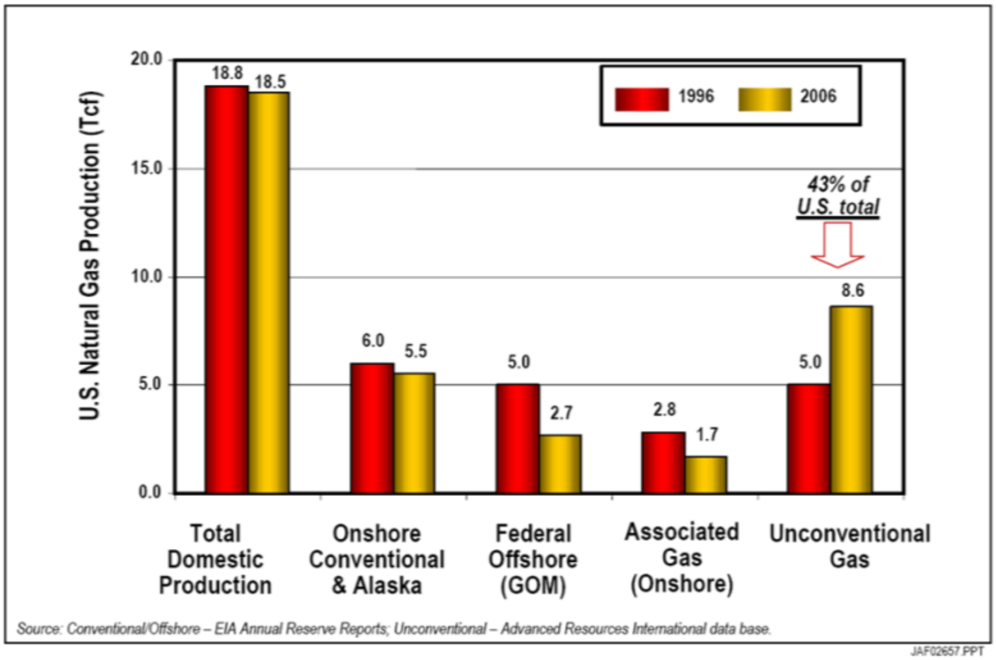

Fig. 1.15—Unconventional gas accounts for 43% of US natural gas production (Kuuskraa, 2007).

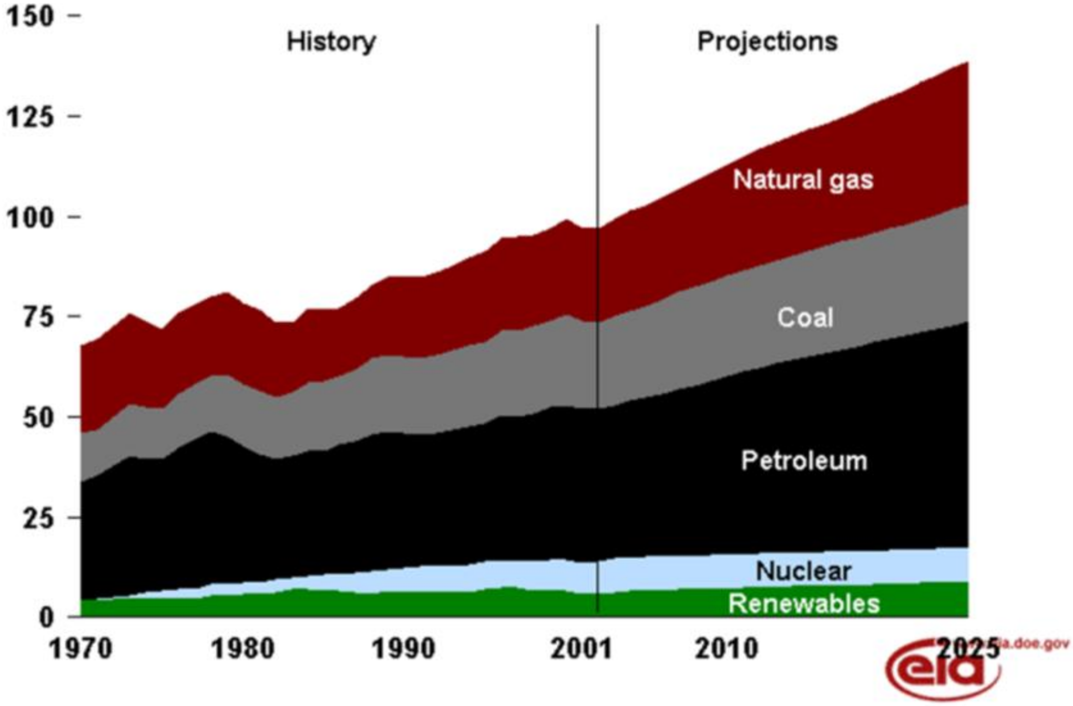

Fig. 1.16—US energy consumption by fuel (EIA, 2005).

Table 1.4— Proved CBM Reserves in China (Modified from Zhang, 2006)

Development Methods	Units	Proved Areas (km2)	Proved Reserves (Tcf)	Cumulative Production (Tcf)	Recovery (%)
Surface	CUCBM	164.20	1.4203	0.7712	54.3
Development	CNPC	182.22	1.2440	0.6220	50.0
Total		346.4	2.6643	1.3932	
Subsurface extraction	Tiefa Coal Mine	135.49	0.2723		
	Yangquan Coal Mine	94.04	0.6757	0.2651	39.2
Total		229.55	0.9487		
Grand		575.95	3.6130		

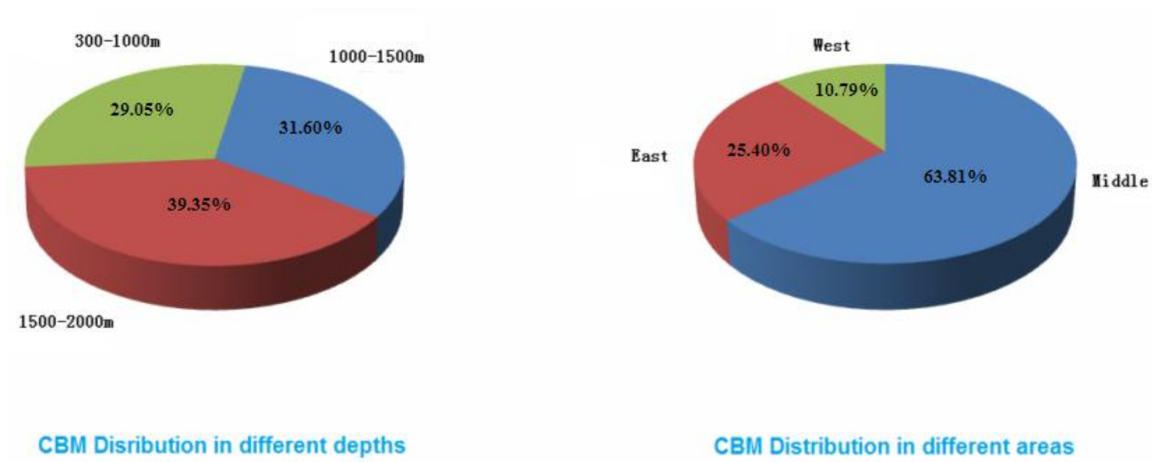

Fig. 1.17—CBM distribution in China (Zhang, 2006).

1.2.2 Shale Gas

Shale gas (SG) is defined as natural gas that is produced from a shale formation. The SG formations are commonly both the source rocks and the reservoirs for natural gas (Frantz et al., 2005; Frantz and Jochen, 2007). Because shales ordinarily have insufficient permeability to allow for economic gas flow to a vertical wellbore, the reservoir has to be stimulated. The low matrix permeability of shale formations requires hydraulic and/or natural fractures for a typical shale gas system to provide permeable pathways for flow of natural gas into the wellbore (Faraj et al., 2004). Natural gas is stored in the shale in three forms: free gas in rock pores, free gas in natural fractures, and adsorbed gas on organic matter and mineral surfaces. These different storage mechanisms affect the speed and efficiency of gas production.

Fig. 1.18 shows the major shale gas basins in the US commercial SG production in the United States is largely from the Appalachian, Michigan, Illinois, Fort Worth, San Juan, North Louisiana salt, and East Texas basins (EIA, 2010). Fig. 1.19 indicates production increased rapidly in the 2000s in the Barnett shale. In 2004, US shale gas production reached almost 700 Bcf/year, a fast increase compared to the 350 Bcf/year in 2000. Since the late 1990s, the largest producer of shale gas has been the Barnett shale in the Forth Worth basin (Fig. 1.19). Fig. 1.20 shows the significant SG production growth.

Fig. 1.18—Major shale gas basins in U.S (EIA, 2010).

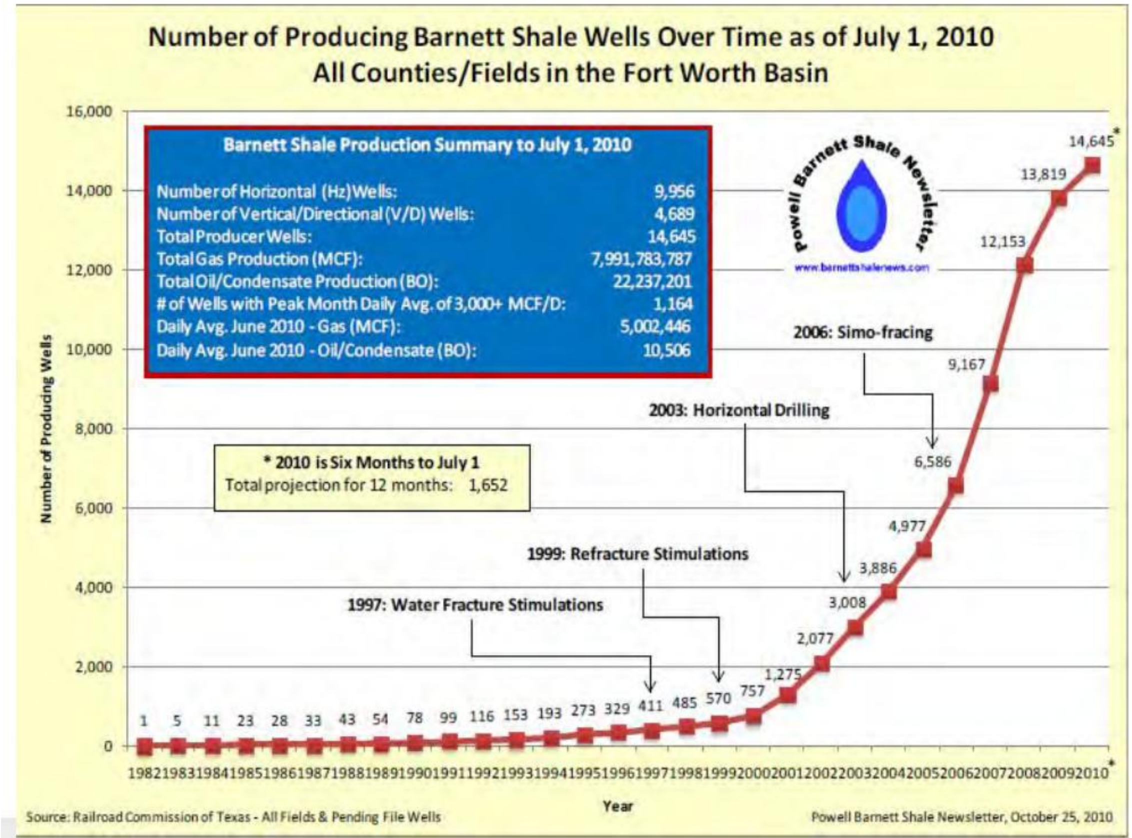

Fig. 1.19—Development history of Barnett Shale (Ireland, 2010).

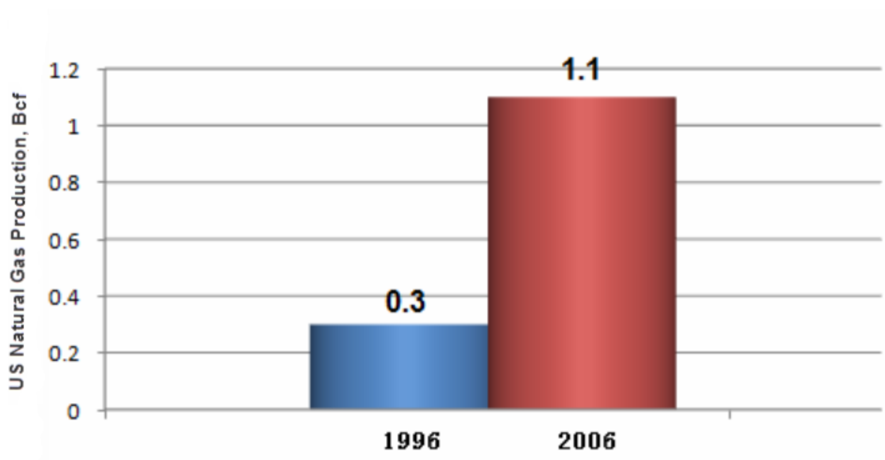

Fig. 1.20—SG has seen production growth (modified from Kuuskraa, 2007).

A global energy study in 1997 estimated that abundant shale gas resources are distributed mostly in North America, Latin America, and the Asia Pacific (Table 1.5).

Recent estimates suggest the resource ranges from 1,483 to 1,859 Tcf in the US, and 500 to 600 Tcf in Canada. In other regions of the world, this resource has been studied to only a limited extent (Holditch, 2007). Internationally, China is starting to develop shale gas (Fig. 1.21).

Table 1.5—Estimated Worldwide Shale Gas Resources (Rogner, 1997)

EEU-Eastern Europe	39
AFR-Africa	274
PAS-Other Asia Pacific	314
WEU-Western Europe	510
FSU-Former Soviet Union	627
LAM-Latin America	2,117
PAO-Asia and China	2,313
MEA-Middle East Asia	2,528
CPA-Central Pacific	3,528
NAM-North America	3,842
World	16,112

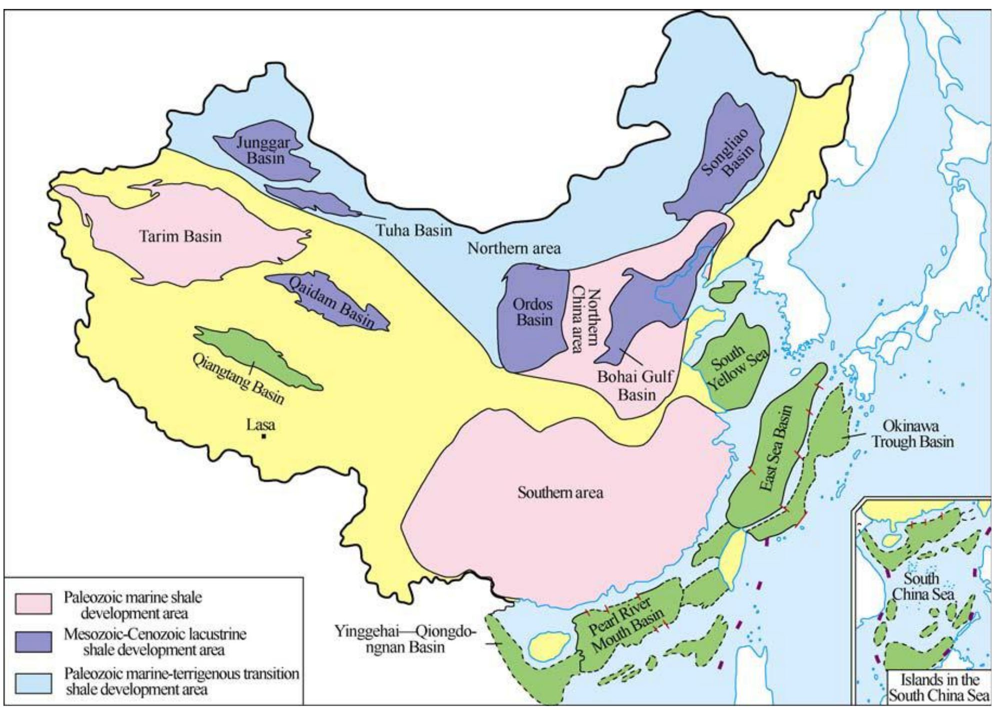

Fig. 1.21—Distribution of three major shale types in China (Zou et al., 2010).

1.2.3 Tight Gas Sand

Tight gas is the term commonly used to refer to low-permeability reservoirs that produce mainly dry natural gas. Demand for tight gas is expected to continue to rise steadily (Fig. 1.13). In the US, natural gas production is expected to rise from 19.5 Tcf/yr in 2004 to more than 25 Tcf/yr by 2020 to satisfy this demand (Fig. 1.16). Conventional gas sources will not be able to satisfy this demand and thus, unconventional gas sources (tight gas sand, shale gas, and coalbed methane), as shown in Fig. 1.16, Fig. 1.22, and Fig. 1.23, and are expected to be a major component of this production. Fig. 1.16, Fig. 1.22, and Fig. 1.23 illustrate that most of this unconventional gas supply will come from tight gas sands (TGS). Shanley et al. (2004) reported that 445 to 475 Tcf of Technically Recoverable Resource (TRR) would occur, and 315 to 340 Tcf are proposed for TGS resources. Fig. 1.24 indicates the US basins having significant TGS resources.

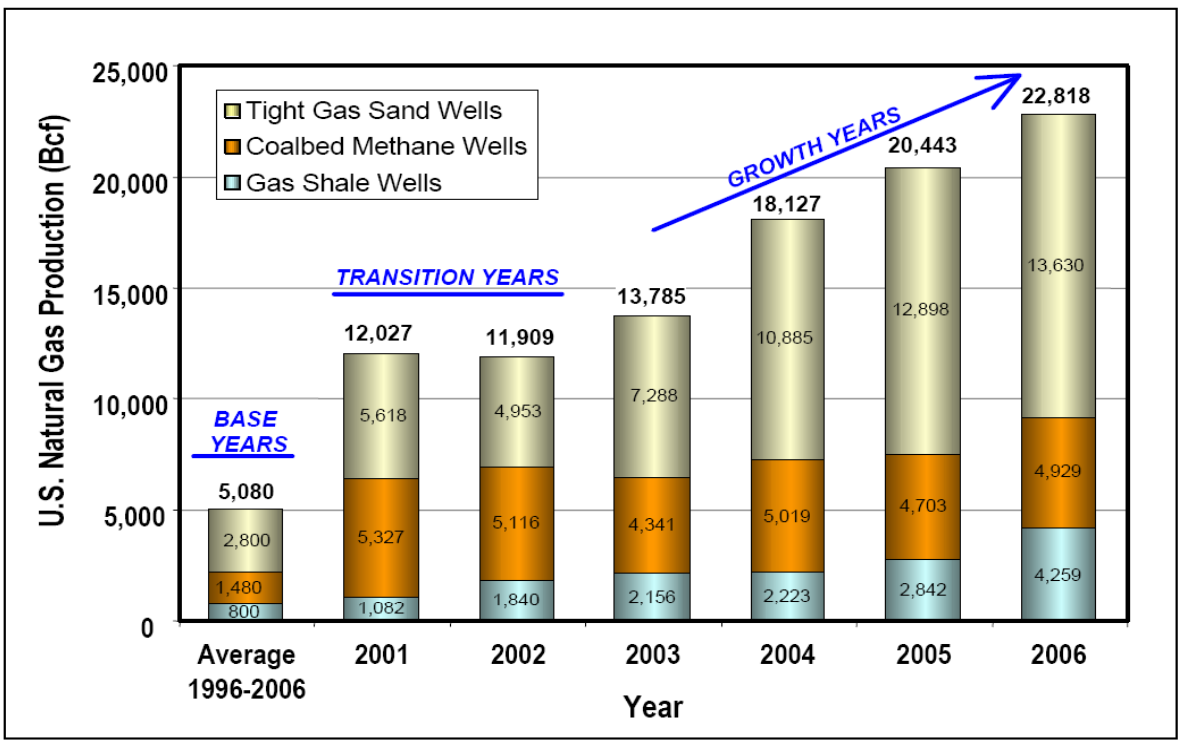

Fig. 1.22—New unconventional gas wells drilled and placed on production (Kuuskraa, 2007).

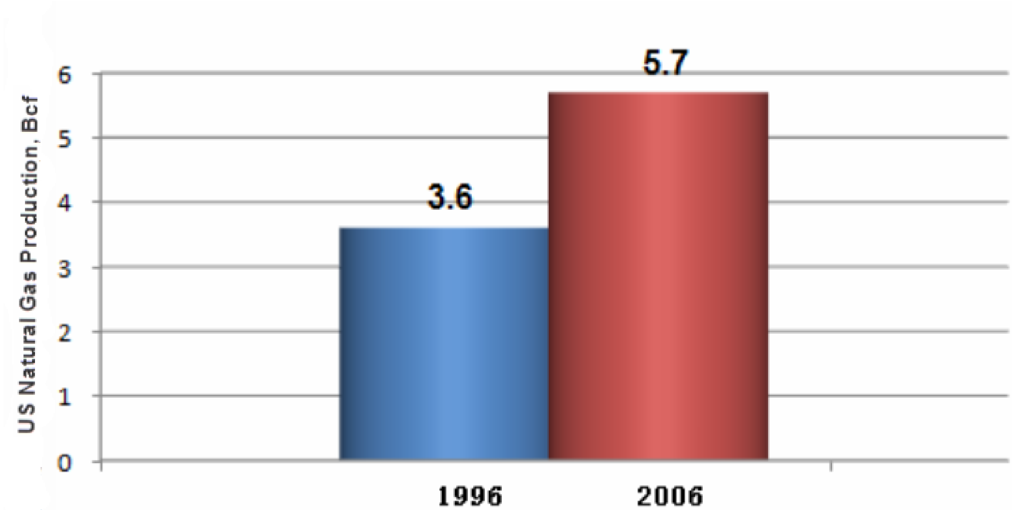

Fig. 1.23—TGS has seen production growth (modified from Kuuskraa, 2007).

The Section 29 tax credit for unconventional gas was created by the US Congress to address the need for increased natural gas production. The initial tax credit provided a tax credit of USD 0.50 per Mscf for gas produced from unconventional resources. Consequently, total unconventional gas production more than doubled from 2.0 Tcf in 1990 to 4.8 Tcf by 1999. Federal and state tight gas production incentives and investments in research have helped to increase TGS production. Hopwood (2009) forecasted an increase of TGS production in North America (Fig. 1.25).

The world distribution of TGS is shown in Fig. 1.26. Proportions of 45.5% of tight gas are shown for the Russian Confederation of States (GUS), 14.7% for the Middle East, 14.1% for North America, and 25.8% for the rest of the world including South and East Asia. Worldwide potential of TGS resources has been estimated to be about 7,406 Tcf (Rogner, 1997).

Fig. 1.24—US basins having TGS resources (EIA, 2010).

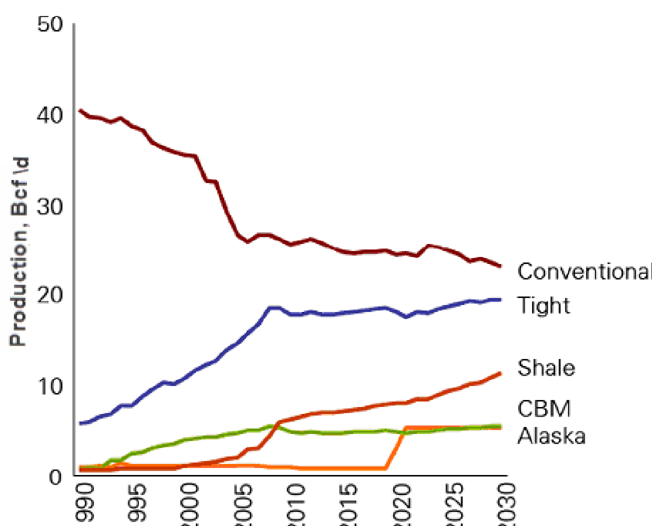

Fig. 1.25—Projections of unconventional natural gas production in North America (Hopwood, 2009).

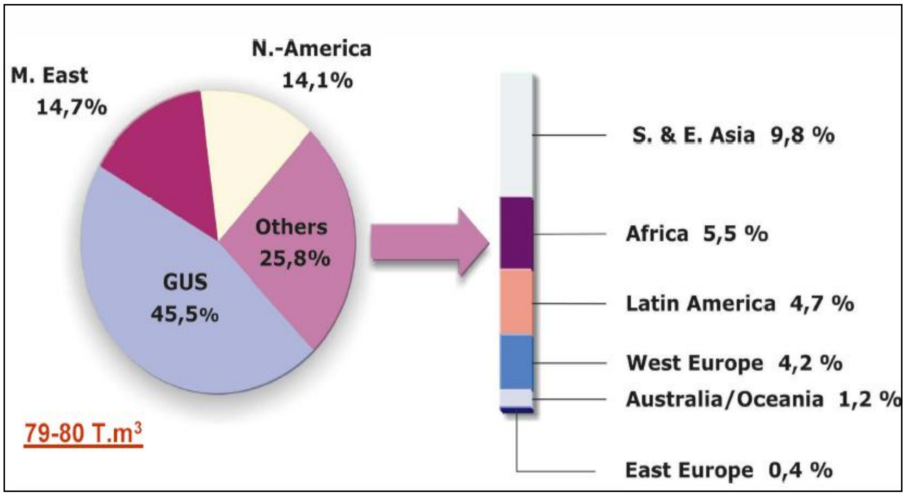

Fig. 1.26—Regional distribution of tight gas (Gerling, 2002).

TGS exploitation activities have not commenced in Russia although it has the largest share of TGS. This is probably because Russia, which has about one-third of the world conventional gas reserves, is largely dependent on its conventional gas supplies. Other countries in the world are also involved in some TGS exploitation.

1.3 Unconventional Gas Reservoir Advisory (UGRA) System

Producing natural gas from a UGR is currently very important to the energy mix in North America and will be of increasing importance to the global energy industry in the coming decades. At present, most of the expertise in UGR development resides in the US, but the need is urgent to develop the expertise and technology required for drilling, completion, and stimulation of developing UGRs more accessible to the engineers outside of North America. It is also important to use accessible, user-friendly systems for training young engineers (Wei, 2009). Therefore, a complex, multicomponent software package called the Unconventional Gas Reservoir Advisory (UGRA) system was designed to provide advice, recommendations, and/or best practices for a broad array of issues that describe a large and interconnected set of solutions required to develop a UGR.

For the complicated problems involved with drilling, completing, and stimulating wells to develop UGRs, it is not practical to assume that only one solution can solve any problem. There may be several answers for any one question. Therefore, different experts may have different solutions for any specific problem, even using the same dataset. For example, when designing a fracture treatment with the same dataset, experts in different teams may have different fracture treatment designs, and some of them could be very different. Any solution that results in a successfully stimulated well that reaches designed economic benchmarks can be considered an acceptable treatment design. Our concept of an advisory system has been to develop a software package with multiple components that can provide multiple reasonable solutions to any given problem for any given dataset (Wei, 2009).

Since the software includes multiple complex functions and components, it needs an integrated and user-friendly interface that is consistent and easy to use. Hence, I have developed a main user interface we call the UGRA System Express Panel, which integrates the links to all components with optimized functions (Fig. 1. 27 and Table 1.6). Through the UGRA System Express Panel, users can understand and implement the tasks of the UGRA system smoothly and efficiently.

Fig. 1.27—UGRA System Express Panel (Cheng et al., 2011b).

Table 1.6— UGRA System Express Panel (Cheng et al., 2011b)

Abbreviation	**Full Name**	**Function**
BASIN	Basin Analog Systems INvestigations	Identify analog basins.
FAST	Formation Analog Selection Tool	Identify and rank analog formations.
PRISE	Petroleum Resource Investigation Summary and Evaluation	1. Demonstrate the resource evaluation of 25 North American basins; 2. Perform the calculations to estimate the resource volume for frontier basins.
TGS	Tight Gas Sand Advisory System	Implement engineering computations to provide advice concerning drilling, completing, and stimulating unconventional gas reservoirs.
CBM	Coalbed Methane Advisory System	
SG	Shale Gas Advisory System	
OPTII	Fracture OPTimization II	Optimize hydraulic fracturing.
PMT	ProMAT™	A single phase, single well analytical production model.
RBK	eRedBook™	An essential information source for Halliburton services, products, and API standards.

Fig. 1.28 shows the UGRA system architecture. Imbedded connections among these components allow them to work seamlessly together. For example, to estimate and calculate resource volumes of underexplored basins using PRISE, the user should run BASIN first. Its analog results can then be applied to estimate UG resources for frontier basins worldwide.

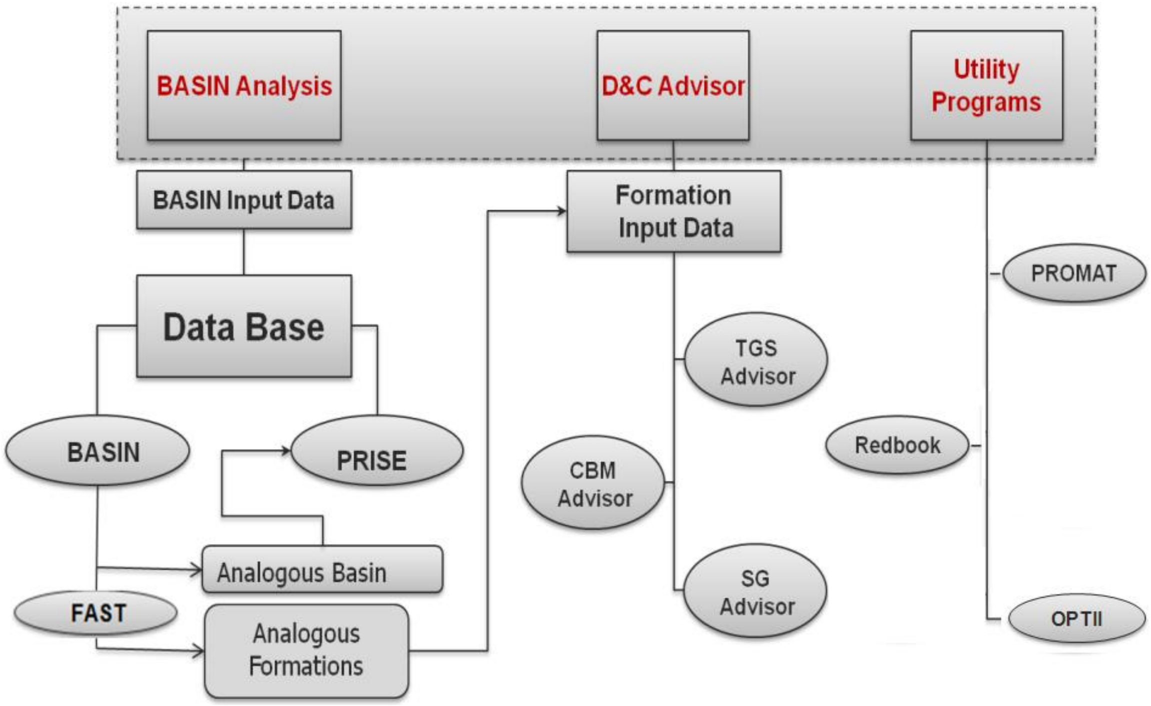

Fig. 1.28—UGRA system architecture (Cheng et al., 2010a).

1.4 Team Members and Contributions in Building UGRA System

The project of developing the UGRA system has been underway in the Crisman Institute at Texas A&M University for the past five years. The team to build different components of the program includes the principal investigator, eight MS degree students, one other PhD degree student, and me. The team members and their contributions are shown as follows.

1. Dr. Stephen A. Holditch (Department Head and Principal Investigator)

- Team leader, supervises the progress and performance of the whole project.

2. Dr. Walt B. Ayers (Visiting Professor and Investigator)

- Associate team leader, supervises the progress and performance of BASIN, FAST, and PRISE.

3. Dr. Duane A. McVay (Associate Professor and Investigator)

- Associate team leader, supervises the progress and performance of BASIN, FAST, and PRISE.

4. Kalwant Singh (MS student)

- Built and programmed BASIN as a stand-alone program using VB 6.0 language.

5. Sara Old (MS student)

- Built and programmed PRISE as a stand-alone program using Excel.
- Investigated 8 out of 25 North American basins.

6. Raj Malpani (2006) (MS student)

- Built and programmed a model to select fracture fluid in tight gas sand as a stand-alone program using Excel.

7. Kirill Bogatchev (2007) (MS student)

- Built and programmed the model for perforation design, including perforation phasing, perforation interval, and perforation shot density using Excel.

8. Obinna Ogueri (2007) (MS student)

- Built and programmed the diversion selection model using Excel.

- Built and programmed the injection method for fracturing treatment using Excel.

9. Nicolas Pilisi (2009) (MS student)

- Built and programmed the drilling module of D&C Advisor using Visual Basic (VB).

10. Wenyan Wu (2011) (MS student)

- Improved and redeveloped BASIN as a stand-alone program using VS .NET language.

11. Yunan Wei (2009) (PhD student)

- Designed, laid out, and programmed the D&C Advisor.
- Evaluated, tested, and programmed the models built by Malpani, Bogatchev, Ogueri, and Pilisi; transformmed the Excel model into VB form and then incorporated them into the UGRA umbrella; improved the models when necessary and incorporated all the models into the D&C Advisor.

12. Kun Cheng (PhD student)

- Improved BASIN from VB 6.0 to VS .NET.
- Improved PRISE form Excel to VS .NET.
- Developed FAST.
- Investigated 17 out of 25 North American basins.
- Developed the UGRA Express Panel.
- Generated the UGRA system software package.
- Finished the case study and validated BASIN, FAST, and PRISE.

The contributions by Singh and Old left some gaps in BASIN and PRISE. Therefore, I focused on improving these two components. During the research progress, I developed FAST to perform formation analog analysis.

1.5 Research Objectives

In the United States, the oil and gas industry has been developing unconventional gas reservoirs in 25 well documented basins since the 1970's. One objective of my research was to use the information from these 25 basins to develop a software solution that allows engineers and geoscientists to evaluate other basins (target basins) around the world. I did this by building a basin analogy software that can be used to compare target or frontier basins with the 25 North American basins that have substantial volumes of unconventional natural gas.

A second objective was to improve our methods for evaluating the quantity of unconventional gas in a target basin using, again, the information in the 25 North American basins. I used publically available data from several sources to quantify the distribution of both conventional and unconventional resources in the 25 North American basins.

A final objective was to build software to link a number of Unconventional Gas Reservoir (UGR) applications that have been developed by other graduate students who have previously worked in the unconventional reservoir evaluation group at Texas A&M University. To accomplish these 3 objectives, I completed the following tasks.

1) Improved the BASIN software.

2) Improved the PRISE software and increased the number of evaluated North American basins in the database from 8 to 25 by using data published by the United States Geological Survey (USGS).
3) Developed FAST which is a new formation analog identification program.
4) Linked BASIN, PRISE, and FAST to a common database.
5) Developed an interface to link all the components together.
6) Developed technologies and tools in advisory system to estimate UGR worldwide.

2 EVALUATION OF ANALOG RELATIONSHIPS BETWEEN MATURE AND UNDEREXPLORED BASINS*

The best way to reduce investment risk in oil and gas exploration is to ascertain the presence, types, and volumes of hydrocarbons in a prospective structure before drilling (Al-Hajeri et al., 2009). Investigations at the level of both sedimentary basins and petroleum systems are needed to better understand the genesis and habitat of hydrocarbons (Magoon and Dow, 1994) and to determine if historical conditions have been suitable for hydrocarbons to fill potential reservoirs and be preserved there. In the investigation of sedimentary basins and petroleum systems, we studied the essential elements needed for oil and gas accumulations to form and exist. Based on the analysis of basins and petroleum systems characteristics, I further improved the BASIN software that is used for comparing each of the mature basins with the underexplored basin, and developed the FAST software to identify analogs between a formation from any mature basin and a formation from an underexplored basin. Then, I improved the PRISE software that is used for estimating frontier basins' TRR volumes after running BASIN (Table 2.1).

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Table 2.1—Contribution to the Whole Project

Project	Contribution
BASIN	1) Improved BASIN from VB to VS .NET 2) Updated database structure 3) Work with Wu (2011) to develop new basin analog method 4) Developed method to validate BASIN with PRISE
PRISE	1) Extended investigation on North American basins from 8 to 25 2) Updated PRISE from VBA to VS .NET 3) Developed database for North American basins TRR information
FAST	1) Developed method and software for FAST 2) Connected FAST and BASIN database
UGRA	1) Connected BASIN, FAST, and PRISE with a common database 2) Developed UGRA Express Panel 3) Built software package for UGRA system

2.1 Basin Analog System Investigation (BASIN)

To meet the growing global demand in the coming decades, the energy industry needs creative thinking that can lead to new energy sources. Unconventional gas resources, especially those in underexplored basins, will play an important role in satisfying future world energy needs. Therefore, it is necessary to evaluate analog relationships between mature and underexplored basins worldwide.

2.1.1 North American Basin Selections

Singh (2006) developed the Basin Analog System (BAS) to identify analogies between 25 mature North American basins (Table 2.2 and Fig. 2.1) and given underexplored basins based on the similarities in geologic and petroleum system parameters.

Table 2.2—25 North American Basins Assessed (Cheng et al., 2010a)

Nomenclature	Full Name	Location
ADKB	Anadarko Basin	OK, TX, KS, CO
APPB	Appalachian Basin	PA, NY, WV, TN, VA, AL, OH, KT, GA
ARK	Arkoma Basin	AR, OK
BHB	Big Horn Basin	WY, MT
BWB	Black Warrior Basin	AL
CHK	Cherokee Basin	OK, KS,MO
DEN	Denver Basin	CO, WY, NE
ETX	East Texas Basin	TX
FCB	Forest City Basin	KS, MO, NE, IA
FWB	Fort Worth Basin	TX
GRB	Green River Basin	WY
IB	Illinois Basin	IL, IN, KT, TN
LAMS	Louisiana Mississippi Salt Basin	LA, MS, AL, FL
MICH	Michigan Basin	MI
PDX	Paradox Basin	UT, CO, AZ
PERM	Permian Basin	TX, NM
PWDR	Powder River Basin	WY, MT, SD
RAT	Raton Basin	NM, CO
SJB	San Juan Basin	NM, CO
TXGC	Texas Gulf Coast Basin	TX, LA
U-PB	Uinta-Piceance Basin	UT, CO
WCSB	Western Canada Sedimentary Basin	AB, SK, BC
WILL	Williston Basin	ND, SD, MT
WRB	Wind River Basin	WY
WTB	Wyoming Thrust Belt Basin	WY, UT, ID

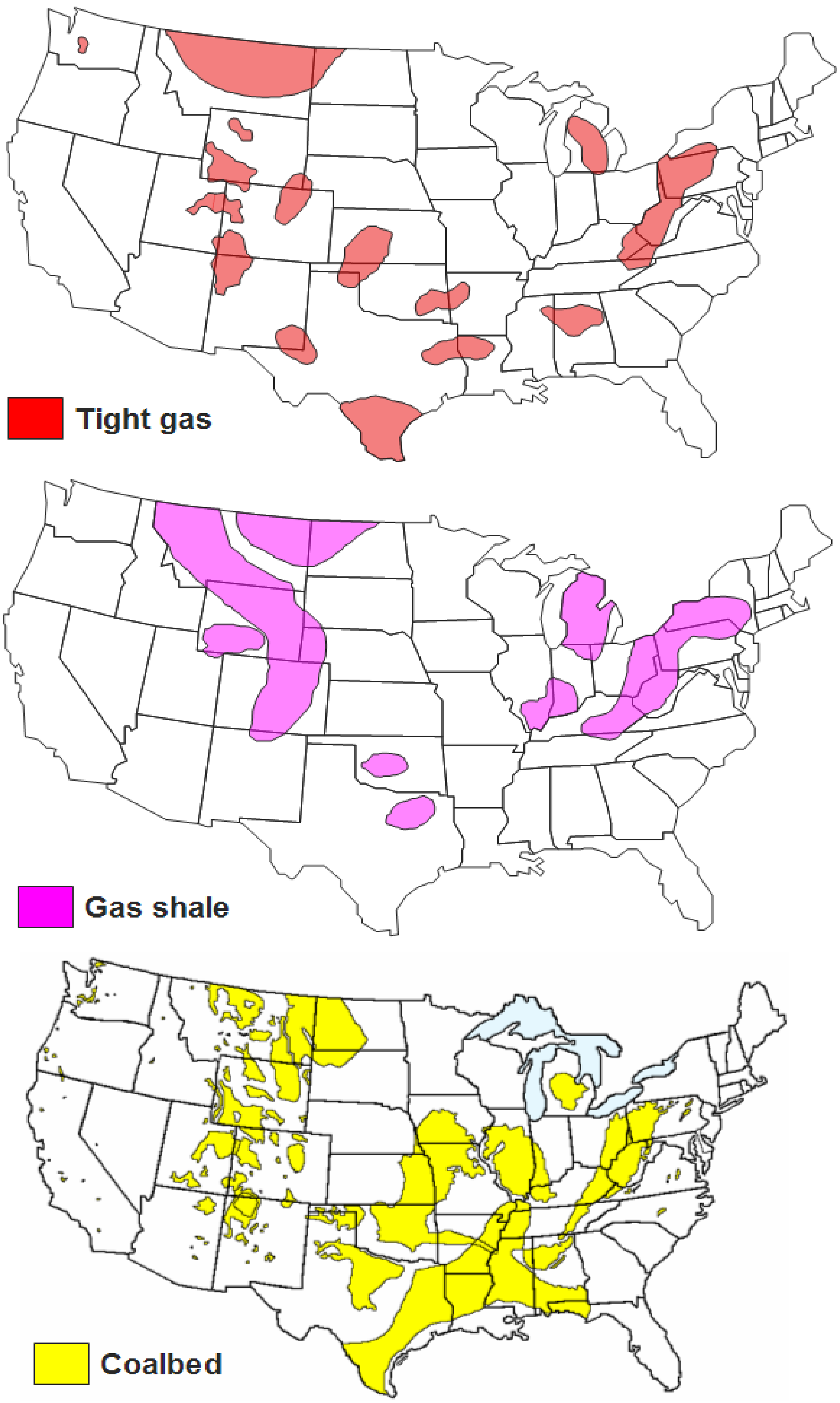


Fig. 2.1—25 selected North American basins (GRI/GTI, 2000).

2.1.2 BASIN Database

The original BASIN software contained a database and 54 related geologic and petroleum system parameters (Fig. 2.2) for 25 North American basins. The database includes geologic and petroleum system information for both conventional and unconventional hydrocarbon resources.

No.	Category / Parameter
	General Basin
1	Basin Type
2	Basin Area Min (mi2)
3	Basin Area Max (mi2)
4	Fill Thickness Min (ft)
5	Fill Thickness Max (ft)
6	Deforming Stress Type
7	Conventional Gas Cumulative Production (Tcf)
8	Conventional Oil Cumulative Production (Tcf)
	Source Rock
1	Rock Type
2	Age Min
3	Age Max
4	Depth Min (ft)
5	Depth Max (ft)
6	Thickness Min (ft)
7	Thickness Max (ft)
8	Kerogen Type
9	Vitrinite reflectance Min (%)
10	Vitrinite reflectance Max (%)
11	Total Organic Content Min (wt%)
12	Total Organic Content Max (wt%)

No.	Reservoir
1	Lithology
2	Age Min
3	Age Max
4	Depositional System
5	Present Depth Min (ft)
6	Present Depth Max (ft)
7	Gross Thickness Min (ft)
8	Gross Thickness Max (ft)
9	Net Thickness Min (ft)
10	Net Thickness Max (ft)
11	Pressure Min (psi)
12	Pressure Max (psi)
13	Pressure Regime (O,N,U)
14	Porosity Min (%)
15	Porosity Max (%)
16	Permeability Min (mD)
17	Permeability Max (mD)
18	Water Saturation Min (%)
19	Water Saturation Max (%)
20	Migration Distance Min (ft or mi)
21	Migration Distance Max (ft or mi)
22	Migration Direction (Vert., Hor.)
23	Seals
24	Traps Type
25	Fluid Type
26	Oil API Min (deg)
27	Oil API Max (deg)

No.	Reservoir (cont.)
28	Natural Fractures (Y,N)
29	Fracture type
30	Min Temperature (°F)
31	Max Temperature (°F)
32	Geothermal Gradient (°F/100ft)
33	Gas Gravity Min
34	Gas Gravity Max

Fig. 2.2—54 BASIN geologic and petroleum system parameters (Holditch, 2010).

2.1.2.1 Definition of BASIN Parameters

We classified 54 geologic and petroleum system parameters into 3 categories: basin information, source rock, and reservoir (Fig. 2.2).

We could not include all 54 Parameters in our improved BASIN, since many of the production values cannot be found in the literature. Also, the production and resource data are now included in PRISE. Therefore, we removed some of the 54 parameters from BASIN to make the software more accurate.

2.1.2.2 Database

BASIN, FAST, and PRISE share a common database. To improve the common database, I updated the database architecture and development environment. The updated database is built on Microsoft Access 2007, which is a pseudo-relational database management system from Microsoft that combines the relational Microsoft Jet Database Engine with a graphical user interface and software-development tools. Fig. 2.3 demonstrates the architecture of the common database.

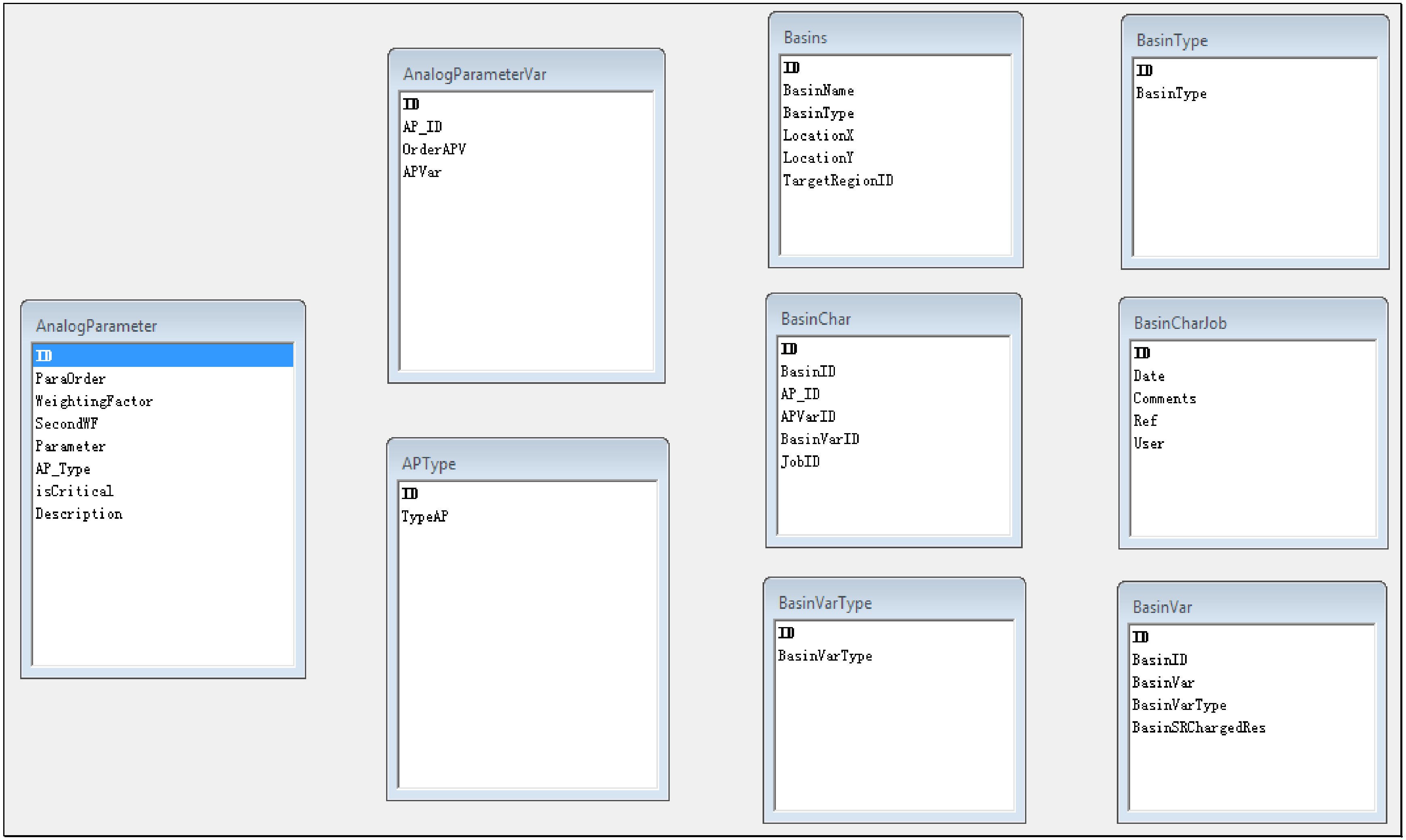


Fig. 2.3—Architecture of the common database

After building the database architecture, Wu (2011) and I developed an algorithm to load these data into the database populated by the UGRA development team. For the 25 North American mature basins, we searched the literature from sources such as the American Association of Petroleum Geologists (AAPG) and the US Geological Survey (USGS). Undergraduate student interns helped populate the database (Table 2.3).

Table 2.3—Student Interns and Their Responsibilities, Summer 2009

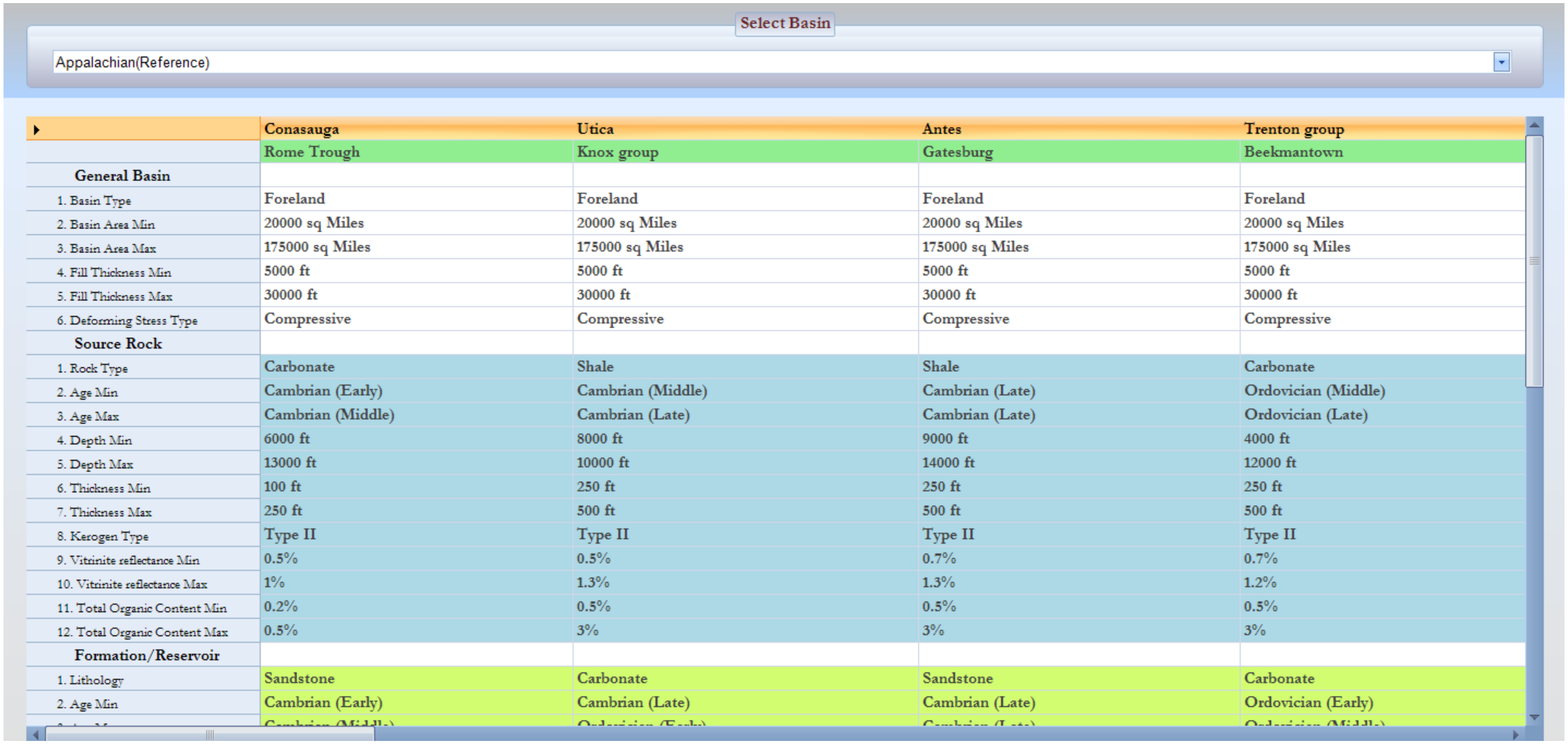
Student Interns – SUMMER 2009	
BASIN	**Student Worker**
Anadarko Basin	Complete
Appalachian Basin	Complete
Arkoma Basin	Complete
Big Horn Basin	Undergraduate
Black Warrior Basin	Complete
Cherokee Basin	Complete
Denver Basin	Complete
East Texas Basin	Undergraduate
Forest City Basin	Undergraduate
Fort Worth Basin	Undergraduate
Green River Basin	Undergraduate
Illinois Basin	Undergraduate
Louisiana Mississippi Salt Basin	Undergraduate
Michigan Basin	Undergraduate
Paradox Basin	Undergraduate
Permian Basin	Undergraduate
Powder River Basin	Undergraduate
Raton Basin	Undergraduate
San Juan Basin	Undergraduate
Texas Gulf Coast Basin	Undergraduate
Uinta-Piceance Basin	Undergraduate
Western Canada Sedimentary Basin	Undergraduate
Williston Basin	Undergraduate
Wind River Basin	Undergraduate
Wyoming Thrust Belt Basin	Undergraduate

The collected data were stored in spreadsheets (Fig. 2.4). Then data were transferred from spreadsheets to the Microsoft Access 2007 database by running BASIN (Fig. 2.5).

	A	B	D	G	H	I	J	K	L	M	N	O	P	Q	
1	Anadarko		Source Rock	Simpson gro	Arbuckle g	Simpson G	Morrow gro	Woodford	Cherokee group						
2		Parameters	Reservoir	Arbuckle gro	Simpson g	Viola	Hunton gro	Misener	Springer	Morrow	Atoka	St. Louis	Atester gro	Woodford	Cher
3		General Basin													
4	1	Basin Type													
5	2	Basin Area Min (mi2)													
6	3	Basin Area Max (mi2)													
7	4	Fill Thickness Min (ft)													
8	5	Fill Thickness Max (ft)													
9	6	Deforming Stress Type													
10		Source Rock													
11	1	Rock Type		Shale	Carbonate	Shale	Shale	Shale	Shale	Woodford Sh	Combination				
12	2	Age Min		Ordovician (E	Cambrian (	Pennsylvar	Pennsylvar	Pennsylvanian (Middle)			Pennsylvanian				
13	3	Age Max		Ordovician (M	Ordovician	Pennsylvar	Pennsylvar	Pennsylvanian (Middle)			Pennsylvanian				
14	4	Depth Min (ft)		3000 ft	15000 ft	7000 ft	7000 ft	> 13000 ft	> 13000 ft	4000 ft	> 13000 ft				
15	5	Depth Max (ft)		6000 ft	26000 ft	9000 ft	11000 ft		22000 ft	> 13000 ft					
16	6	Thickness Min (ft)		250 ft	750 ft	750 ft	100 ft	50 ft							
17	7	Thickness Max (ft)		1000 ft	1250 ft	1250 ft	1000 ft	750 ft			4642				
18	8	Kerogen Type		Type I	Type II	Type III	Type III	Type II, III	Type III	Type III	Type III				
19	9	Vitrinite reflectance Min (%)		0.50%	1.20%	0.60%	0.50%	0.50%	> 1.30%	> 1.30%	2.45				
20	10	Vitrinite reflectance Max (%)		1.50%	1.40%	1%	0.70%	1.30%			4.05				
21	11	Total Organic Content Min (wt%)		0.20%	1%	0.50%	17%	1%		2.70%	0.05%				
22	12	Total Organic Content Max (wt%)		8.50%	2%	8.50%	18%	14%		5.50%	1.30%				
23		Reservoir		918	**42.70%**										
24	1	Lithology		Carbonate	Sandstone	Carbonate	Carbonate	Sandstone	Sandstone	Sandstone	Sandstone	Carbonate	Carbonate	Shale	Tight
25	2	Age Min		Cambrian (La	Ordovician	Ordovician	Silurian (La	Devonian (	Pennsylvanian	Mississippian	Pennsylvania	Mississippi	Mississippi	Devonian (Late)	
26	3	Age Max		Ordovician (E	Ordovician	Ordovician	Devonian (	Mississipia	Pennsylvanian	Mississippian	Pennsylvania	Pennsylvar	Pennsylvar	Devonian (Late)	
27	4	Depositional System		Deltaic - Fluv	Fluvial	Submarine	Tidal	Fluvial	Fluvial	Fluvial	Deltaic	Tidal	Tidal	Deltaic	
28	5	Present Depth Min (ft)		15000 ft	3000 ft	4000 ft	15000 ft	4000 ft	4000 ft	6000 ft	14000 ft	5000 ft	6000 ft	14000 ft	
29	6	Present Depth Max (ft)		26000 ft	6000 ft	13000 ft	18000 ft	13000 ft	7000 ft	8000 ft	17000 ft	7000 ft	8000 ft	16000 ft	
30	7	Gross Thickness Min (ft)		2500 ft	250 ft	500 ft	100 ft	50 ft	1750 ft	1250 ft	250 ft	500 ft	250 ft	5 ft	

TargetBasin / ReferenceBasin

Fig. 2.4—Partial display of Anadarko basin data stored in spreadsheets file.



Select Basin

Appalachian(Reference)

	Conasauga	Utica	Antes	Trenton group
	Rome Trough	Knox group	Gatesburg	Beekmantown
General Basin				
1. Basin Type	Foreland	Foreland	Foreland	Foreland
2. Basin Area Min	20000 sq Miles	20000 sq Miles	20000 sq Miles	20000 sq Miles
3. Basin Area Max	175000 sq Miles	175000 sq Miles	175000 sq Miles	175000 sq Miles
4. Fill Thickness Min	5000 ft	5000 ft	5000 ft	5000 ft
5. Fill Thickness Max	30000 ft	30000 ft	30000 ft	30000 ft
6. Deforming Stress Type	Compressive	Compressive	Compressive	Compressive
Source Rock				
1. Rock Type	Carbonate	Shale	Shale	Carbonate
2. Age Min	Cambrian (Early)	Cambrian (Middle)	Cambrian (Late)	Ordovician (Middle)
3. Age Max	Cambrian (Middle)	Cambrian (Late)	Cambrian (Late)	Ordovician (Late)
4. Depth Min	6000 ft	8000 ft	9000 ft	4000 ft
5. Depth Max	13000 ft	10000 ft	14000 ft	12000 ft
6. Thickness Min	100 ft	250 ft	250 ft	250 ft
7. Thickness Max	250 ft	500 ft	500 ft	500 ft
8. Kerogen Type	Type II	Type II	Type II	Type II
9. Vitrinite reflectance Min	0.5%	0.5%	0.7%	0.7%
10. Vitrinite reflectance Max	1%	1.3%	1.3%	1.2%
11. Total Organic Content Min	0.2%	0.5%	0.5%	0.5%
12. Total Organic Content Max	0.5%	3%	3%	3%
Formation/Reservoir				
1. Lithology	Sandstone	Carbonate	Sandstone	Carbonate
2. Age Min	Cambrian (Early)	Cambrian (Late)	Cambrian (Late)	Ordovician (Early)
3. Age Max	Cambrian (Middle)	Ordovician (Early)	Cambrian (Late)	Ordovician (Middle)

Fig. 2.5—User can perform the function of transferring data from spreadsheets to the database.

2.1.3 BASIN Software Reengineering

The principle of software reengineering is to improve or transform existing software so that it can be understood and controlled. The need for BASIN software reengineering increased greatly as BASIN became obsolete in terms of its architecture, the platforms on which BASIN ran, and its suitability and stability to support changing needs. BASIN software reengineering was important for recovering and reusing existing software assets and establishing a base for the evolution of the BASIN analog approach.

2.1.3.1 The Definition of Reengineering

Reengineering is the examination, analysis, and alteration of an existing software system to reconstitute it in a new form, and the subsequent implementation of the new form. The process typically encompasses a combination of other processes such as reverse engineering, redocumentation, restructuring, translation, and forward engineering. The goal is to understand the existing software (specification, design, implementation) and then to reimplement it to improve the system's functionality, performance or implementation. The objective is to maintain the existing functionality and prepare for functionality to be updated later (Rosenberg, 2003).

The challenge in software reengineering is to take existing systems and instill good software development methods and properties, generating a new target system that maintains the required functionality while applying new technologies. The development process and general model for software reengineering can be demonstrated in Fig. 2.6 and Fig. 2.7. Four general reengineering goals are as follows (Rosenberg, 2003):

- Preparation for functional enhancement
- Improving maintainability

- Migration
- Improving reliability

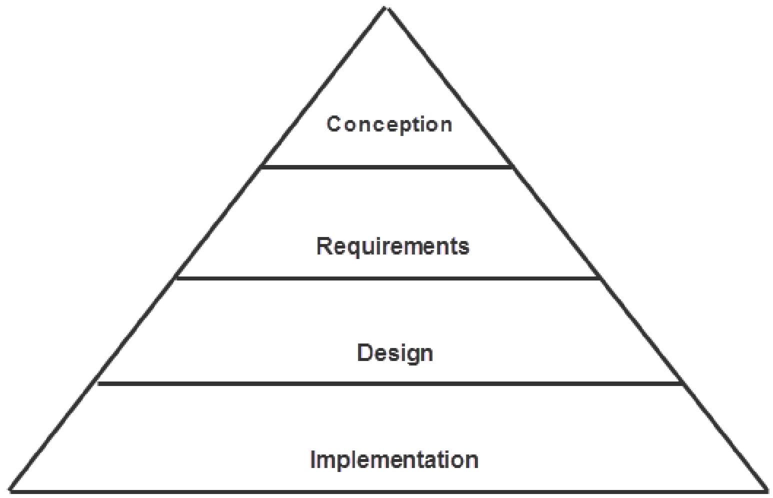


Fig. 2.6—Software reengineering development process (Rosenberg, 2003).

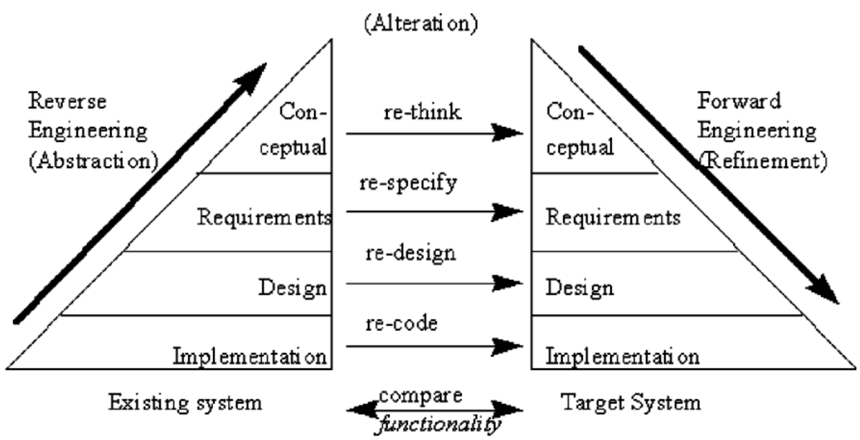


Fig. 2.7—Software reengineering general model (Rosenberg, 2003).

The software that I used to develop the improved BASIN software is Microsoft Visual Studio 2008, and the programming language is Visual Studio .NET (VS. NET). VS. NET which is implemented on the .NET Framework, can be viewed as an evolution of the classic Visual Basic (VB), which was used in the original BASIN software. VS.

NET has changed significantly in the semantics—from those of an object-based programming language running on a deterministic, reference-counted engine based on COM to a fully object-oriented language backed by the .NET framework, which consists of a combination of the Common Language Runtime (a virtual machine using generational garbage collection and a just-in-time compilation engine) and a far larger class library.

Fig. 2.8 and Fig. 2.9 demonstrate the graphical user interface (GUI) of BASIN after software reengineering.

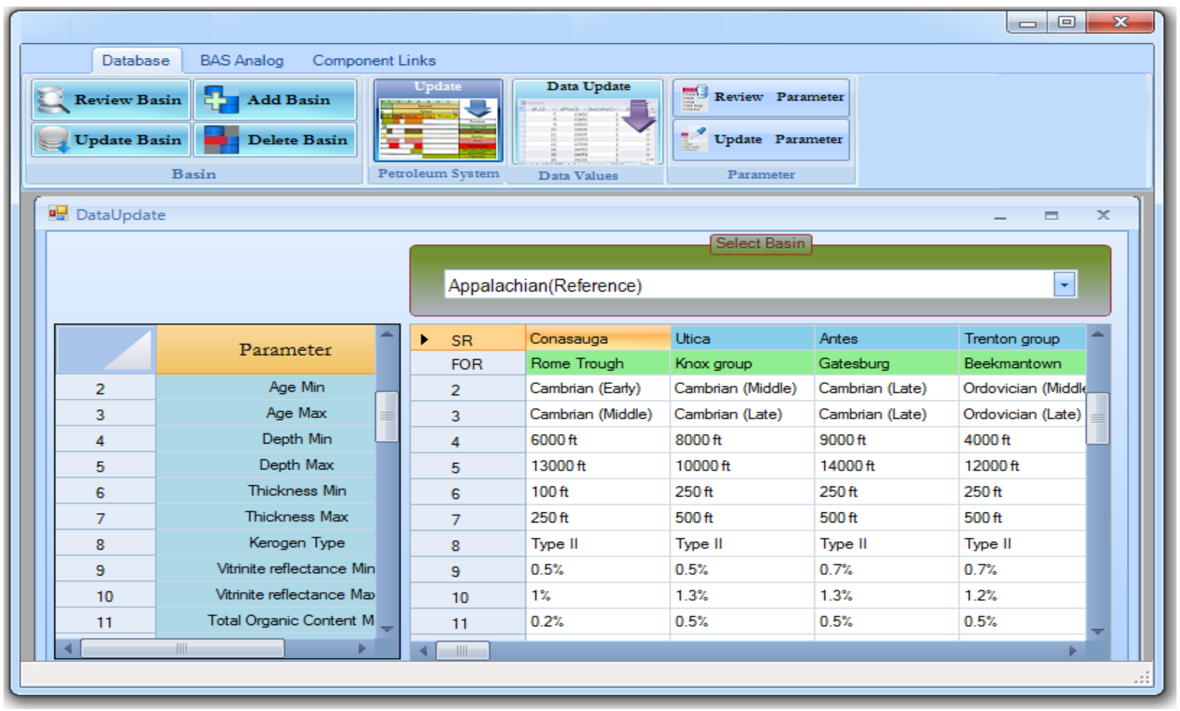


Fig. 2.8—BASIN GUI for database management after software reengineering (Cheng et al., 2011b).

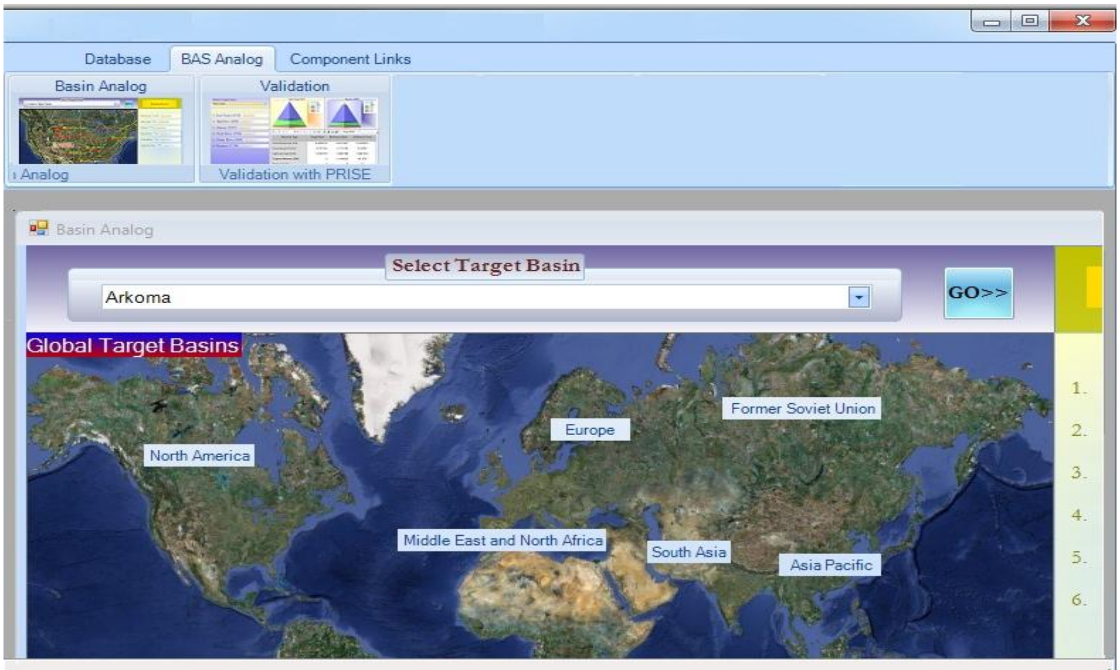


Fig. 2.9—BASIN GUI for basin analog after software reengineering (Cheng et al., 2011b).

2.2 Formation Analog Selection Tool (FAST)

Today, many countries are evaluating unconventional gas resources, which are estimated to exceed 30,000 Tcf of gas-in-place, worldwide.* Owing to declining conventional gas production, the US has led the world in development of unconventional gas resources (UGR) and technology over the past 3 decades. To facilitate transfer of unconventional gas technology and development internationally, we developed software called FAST (Formation Analog Selection Tool), as a tool to objectively and rapidly identify and rank analog formations. FAST software uses the existing UGRA database, BASIN, which contains geoscience and engineering parameters for approximately 240 formations in 25 North American basins that are mature for conventional and unconventional oil and gas production. We designed the FAST report module provides both general and detailed interpretation graphs and tables. FAST reports give an overview of analog results, and they allow insights into the quantitative details of reservoir parameter comparisons. Although the software needs further validation, preliminary testing shows consistent results. Planned and ongoing improvements to FAST include quality checking of formation parameters in the database, assessment of parameter weighting factors, validation of the analog selection performance against the literature and independent studies regarding analog formations, and linkage of FAST with the UGRA Drilling & Completion (D&C) Advisory System to identify the best engineering practices to be applied in early stages of testing analogous target formations.

2.2.1 FAST Methodology

To build a formation analog database, we first determined which geologic and engineering parameters should be used to quantify and rank analog formations. Then we began searching the literature and populating the database. Simultaneously, we developed the FAST software and began testing it to validate the software performance.

Many North American basins have produced oil and/or gas from both conventional and unconventional reservoirs for decades. Thus, we can quantify the oil/gas resources and reservoir properties and track the engineering practices used to extract hydrocarbons from these basins. We call the formations in these mature North American basins “reference” formations. Outside North America, in most basins of the world, unconventional resources have not been assessed or produced. The resource triangle concept indicates that many frontier basins having conventional oil and gas production should also contain unconventional resources. Potential hydrocarbon-bearing formations in these frontier basins are referred to as “target” formations. BAS (Singh, 2008) identifies analog basins, whereas FAST helps the user identify and rank reference formations analogous to target formations. Ultimately, we want to use knowledge of analog formations to infer potential unconventional hydrocarbons and to guide the exploration and development of target formations.

The shared BASIN/FAST database contains information for many conventional and unconventional reservoirs in 25 North American basins. These mature basins (GRI, 1999; GTI, 2001) have a history of producing significant volumes of unconventional resources (such as coalbed methane, tight sands gas, and shale gas), and significant data concerning unconventional gas resources and reservoir properties are available. Each of the selected basins contains multiple petroleum systems composed of source rocks and associated reservoirs. In FAST, we categorize the data by source rock (SR) and producing formation (For) (Fig. 2.10). The data that are stored for each formation are the properties of the reservoirs (or the reservoir-quality rock) in that formation. FAST software compares a target formation with all reference formations and ranks reference formations by similarity scores.

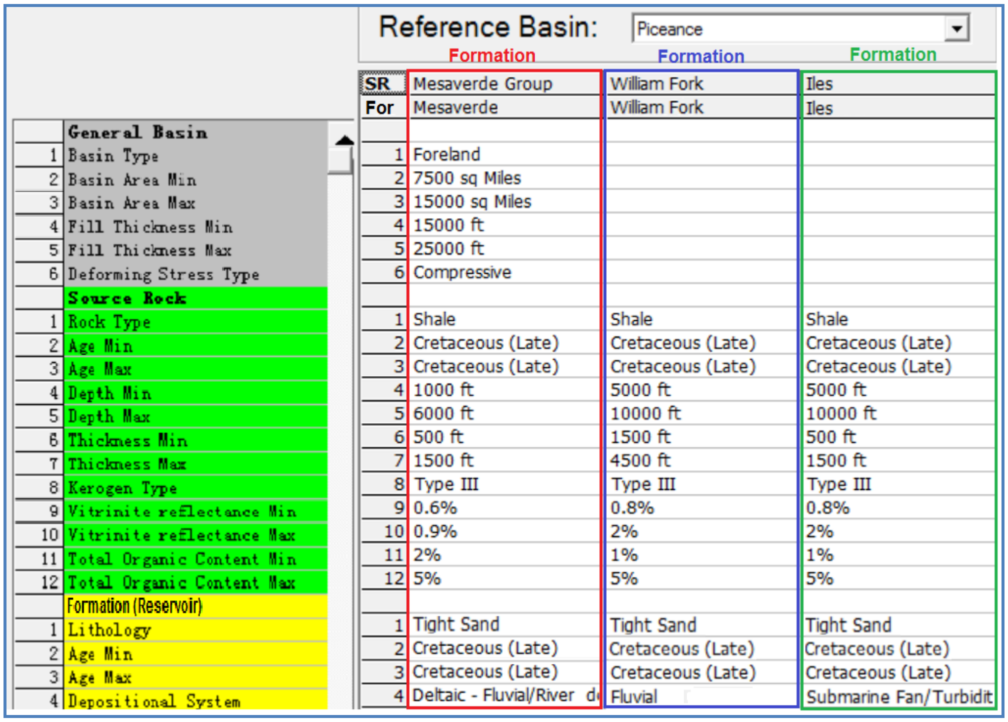


Fig. 2.10—Examples of formations in the FAST database (Cheng et al., 2010a).

In addition, to better reflect and explain the analog results, we designed graphical and digital reports that provide both general and detailed results for interpretation. These reports not only give a general overview of the results, but they also allow insights into the quantitative details of formation analog selection. We can use the FAST results in conjunction with other software to predict both the conventional and unconventional hydrocarbon resource potential of the target formation, to quantitatively assess the reservoir characteristics, and to make preliminary decisions concerning best engineering practices (such as drilling program, completion method, and stimulation method) to apply in initial development.

Some production of unconventional oil and gas has been assessed outside of North America, in areas such as the heavy oil fields in Venezuela, Canada, and Indonesia, some tight gas sands in Europe, South America, China, and Australia, and coalbed methane in Australia. Many areas of the world have abundant coal resources, and coalbed methane exploration and development are ongoing. In fact, much of the data from these international unconventional oil and gas projects may be used to help validate FAST methodology.

2.2.2 Formation Analog Parameters

From our review of literature from the American Association of Petroleum Geologists (AAPG) Datapages, the Society of Petroleum Engineers e-Library, the United States Geological Survey (USGS) 1995 National Assessment of US Oil and Gas Resources, the USGS website, Society of Exploration Geophysicists (SEG) publications, and the internet, we selected 54 formation characterization parameters, which are grouped into three categories: general basin, source rock, and reservoir (Fig. 2.10).

We applied adjustable primary weighting factors (WF), scaled from 0 to 100, to reflect the relative importance (Table 2.4). A secondary weighting factor was applied to some parameters that have quantitative (or numeric) classes (such as vitrinite reflectance or porosity) (Table 2.4) of each formation characteristic parameter. Primary and secondary weighting factors are further explained in the next section. We determined classes for each analog parameter. The term “classes” here means preassigned qualitative/descriptive or quantitative/numeric values for each parameter (Table 2.4). For example, the qualitative classes for “source rock type” are shale, carbonate, and coal, whereas “Vitrinite reflectance” has quantitative classes of 0.5%, 0.6%, 0.7%, ..., 3.4%, and 3.5% (Table 2.5).

Among the analog parameters, we consider three parameters to be critical parameters—lithology, fluid type, and kerogen type (Table 2.4). We picked these critical parameters based on our judgment that these parameters are the minimum parameters that must be common to the target and analog reference formations. The purpose for using critical parameters is to avoid obtaining false analogs. For example, a sandstone reservoir will not be analogous to a carbonate reservoir. Also, a formation containing oil reservoirs would not be analogous to a formation containing gas reservoirs. Thus, the analog model we developed first checks these critical parameters to ensure that they are common before reviewing other parameters.

Table 2.4—Partial Listing of Formation Characterization Parameters (Cheng et al., 2010a)

Category	Primary WF	Secondary WF	Parameter	Critical
Basin Information	30	FALSE	Basin Type	FALSE
	60	TRUE	Basin Area	FALSE
	50	TRUE	Fill Thickness	FALSE
	70	FALSE	Deforming Stress	FALSE
	30	TRUE	Cumulative Oil Produced	FALSE
	30	TRUE	Cumulative Gas Produced	FALSE
Source Rock	80	FALSE	Rock Type	FALSE
	50	FALSE	Age	FALSE
	60	TRUE	Depth	FALSE
	70	TRUE	Thickness	FALSE
	100	FALSE	Kerogen Type	TRUE
	100	TRUE	Vitrinite reflectance	FALSE
	80	TRUE	Total Organic Content	FALSE
Formation (Reservoir)	100	FALSE	Lithology	TRUE
	30	FALSE	Age	FALSE
	60	FALSE	Depositional System	FALSE
	50	TRUE	Depth	FALSE
	70	TRUE	Gross Thickness	FALSE
	70	TRUE	Net Thickness	FALSE
	80	TRUE	Pressure	FALSE
	80	FALSE	Pressure Regime	FALSE
	90	TRUE	Porosity	FALSE
	90	TRUE	Permeability	FALSE
	70	TRUE	Water Saturation	FALSE
	50	TRUE	Migration Distance	FALSE
	50	FALSE	Migration Direction	FALSE
	100	FALSE	Seals	FALSE

Table 2.5—Partial Listing of Formation Classes (Cheng et al., 2010a)

Parameter	Class No.	Classes
Basin Type	1	Foreland
	2	ForeArc
	3	BackArc
	4	Rift
	5	Srike-Slip
	6	IntraArc
Rock Type	1	Shale
	2	Carbonate
	3	Coal
Kerogen Type	1	Type I
	2	Type II
	3	Type III
Vitrinite Reflectance	1	0.5%
	2	0.6%
	3	0.7%
	4	0.8%
	5	0.9%
	6	1%
	7	1.1%
	8	1.2%
	…	…
	29	3.3%
	30	3.4%
	31	3.5%

2.2.3 Formation Analog Determination

We identify analog formations by comparing each available parameter in Table 2.3 of the target formation to the corresponding parameter in all reference formations. The comparison considers critical parameters before advancing to assessment of qualitative/descriptive and quantitative/numeric parameters. If critical parameters do not match, the match is flagged as “False” and comparison with that reference formation is terminated.

2.2.3.1 Qualitative/Descriptive Parameters

Qualitative/descriptive parameters are those parameters that can be observed but not measured, such as lithology. Because there is no secondary weighting applied to qualitative/descriptive parameters, they are assigned “False” for the “Secondary WF” (Table 2.4). To compare values of the qualitative/descriptive parameters between the target and reference formations, we check whether they are the same. If they do not match, we assign a value of 0 as the score of the reference formation for this parameter; otherwise, the value of 1 multiplied by the primary weighting factor is the reference score.

Fig. 2.11 shows a target formation and two reference formations. The weighting factor for the n^{th} parameter is indicated by "WF_n." For the first parameter, "Rock Type," which is a qualitative/descriptive parameter, the first reference formation matches the target formation (that is, both have the "Shale" rock type). Thus, the score of the first reference formation is 1 multiplied by the first parameter's primary weighting factor (WF_1), whereas the score of the second reference formation is 0, because this reference formation ("Carbonate") does not match the target formation ("Shale"). Following the same rule, for the eighth parameter, "Kerogen Type," which is also a qualitative/descriptive parameter, the scores of the first and second reference formations are both 0 in that neither of them (Type I and Type II) matches the target formation (Type III).

	Parameter	Target Formation	Reference formation 1	Reference formation 2
1	Rock Type	Shale	Shale	Carbonate
2	Age Min	Pennsylvanian (Late)	Ordovician (Middle)	Ordovician (Early)
3	Age Max	Mississippian (Early)	Ordovician (Early)	Cambrian (Late)
4	Depth Min	19000 ft	3000 ft	15000 ft
5	Depth Max	24000 ft	6000 ft	26000 ft
6	Thickness Min	1000 ft	250 ft	750 ft
7	Thickness Max	2000 ft	1000 ft	1250 ft
8	Kerogen Type	Type III	Type I	Type II
9	Vitrinite reflectance Min	1.3%	0.5%	1.2%
10	Vitrinite reflectance Max	1.6%	1.5%	1.4%
11	Total Organic Content Min	2%	0.2%	1%
12	Total Organic Content Max	5%	8.5%	2%
		1*WF_1	1*WF_1	0
		1*WF_8	0	0

Fig. 2.11—Example of qualitative/descriptive parameter comparison (Cheng et al., 2010a).

2.2.3.2 Quantitative/Numeric Parameters

For the quantitative/numeric parameters, which can be measured with numbers, the comparisons are more complex. Parameters of this type are indicated by the value of "True" for "Secondary WF" (e.g., Basin Area, Fill Thickness, and Vitrinite Reflectance) in Table 2.4. Commonly, the formation does not have a single value for a quantitative parameter, but instead, it has a range of values. In the database, the ranges are captured by fields "parameter Min" to "parameter Max." Therefore, the comparison of the quantitative/numeric parameters reflect a comparison of two ranges (Fig. 2.12). The quantitative parameter "Porosity" of the target formation has values ranging from 10% (Min) to 30% (Max), and the first and second reference formations have values ranging from 5% (Min) to 13% (Max) and from 10% (Min) to 20% (Max), respectively. If we were to use an absolute comparison criterion (as for qualitative/descriptive parameters), the scores for the two reference formations would be 0, because ranges of both reference basins differ from that of the target basin. This would be particularly troublesome for the second reference formation; its permeability range is considerably closer to the range of the target formation.

Therefore, for the quantitative/numeric parameters, we developed a more realistic method by addressing closeness to the minimum and maximum values of the range. For example, in Fig. 2.12, the target formation has a maximum porosity of 30% and reference formations 1 and 2 have maximum porosity of 13% and 20%, respectively. The two reference formation porosities are obviously not perfectly matched, but the porosity of reference formation 2 is closer to that of the target formation than is reference formation 1. We handle this issue by using classes and the secondary weighting factor. The classes for the quantitative/numeric parameters indicate the intervals to which the parameter values belong. For example, in Fig. 2.12, the maximum porosity of 30% for the target formation belongs to the class or interval 30% to 35%, and the maximum porosities 13% and 20% of reference formations 1 and 2, respectively, belong to the porosity classes 10% to 15% and 20% to 25%, respectively. The secondary weighting factor, which is introduced to reflect the degree of similarity between two numeric value classes (Cheng et al., 2010a), is defined as follows:

$$\text{Secondary WF} = 1 - \frac{\text{number of classes between the target value class and reference value class}}{\text{number of preassigned classes}}$$

If the target and reference formation values are the same, then the secondary weighting factor is 1. Because the target formation value of 30% belongs to the seventh class and the first reference formation value of 13% belongs to the third class, there are four classes between them. There are 10 pre-assigned porosity classes, so the secondary weight factor is 0.6 (Fig. 2.12). The secondary weight factor for the second reference formation is 0.8 since it is a closer match.

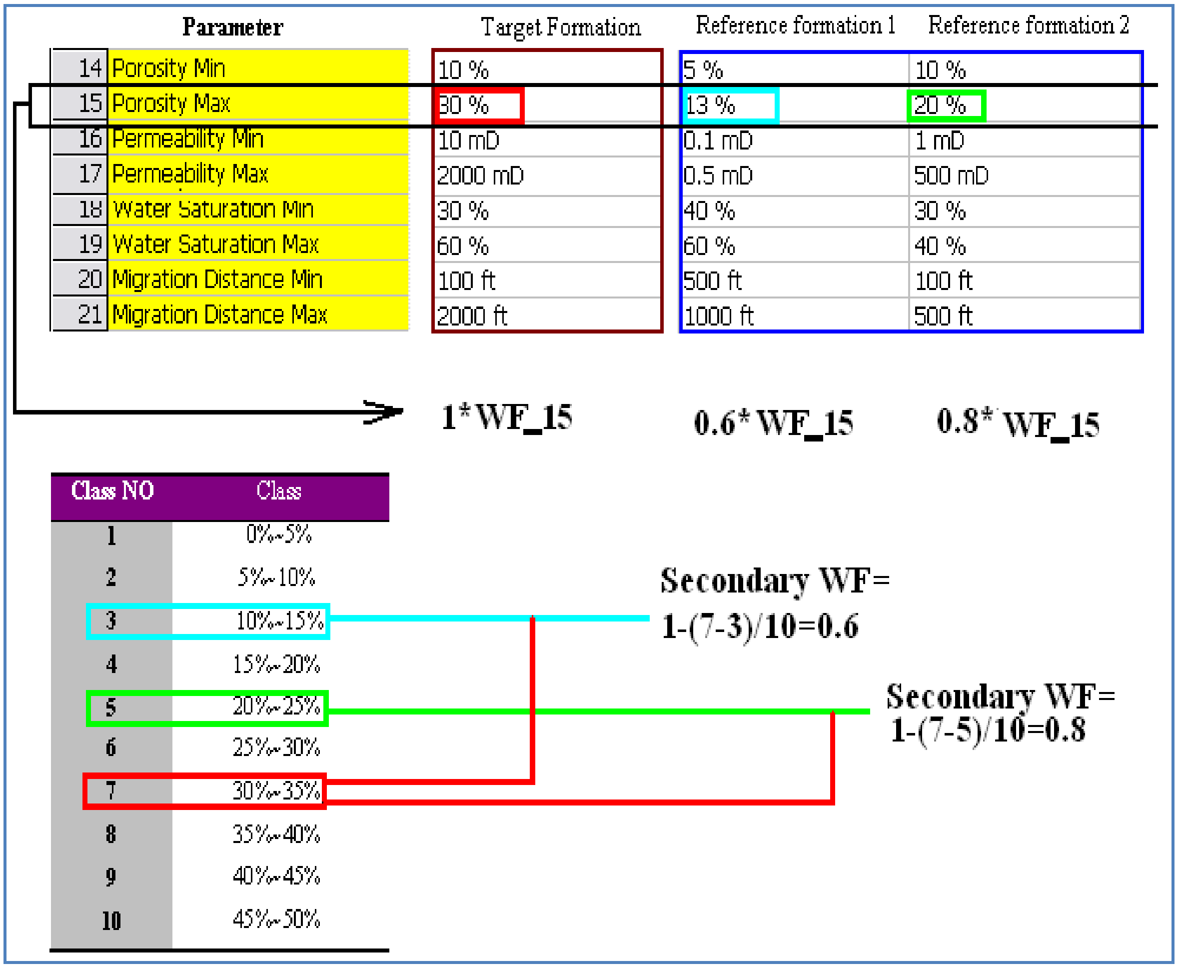


Fig. 2.12—Example of quantitative/numeric parameter comparison with secondary weighting (Cheng et al., 2010a).

2.2.4 Validation and Interpretation

2.2.4.1 Case One

To test the consistency and accuracy of FAST, we used the Mesaverde group in the Piceance basin as the "target formation" (Fig. 2.10), and compared it to the approximately 400 formations in the 25 North American basins, including the Mesaverde group itself. To run FAST software, we first chose the target basin where the target formation is located (Fig. 2.13). Then we selected the target formation and compared the target formation with all the North American formations by using the “Compare with all formations” option (Fig. 2.13). To test the software and methodology, the formation parameters in the Mesaverde target formation file were run with identical values as a reference formation; it was 100% analogous to itself. The second and fourth analogous formations, understandably, are the Iles and Williams Fork, which are formations (subsets) within the Mesaverde group. The Pictured Cliffs formation of the San Juan Basin was ranked third (Fig. 2.14).

Fig. 2.13—FAST example for "Mesaverde" formation (Cheng et al., 2010a).

To better communicate and explain results, we designed graphical and digital reports that provide both general and detailed interpretation windows for geoscientists and engineers. Fig. 2.14 shows the general report, which lists the reference formations ranked by analog scores from high to low and their host basins. The report can be exported as either a .pdf or an .xls file, allowing the user to analyze the results in both graphical and tabular formats (Fig. 2.15). For example, in the example test described, 71 reference formations were comparable (that is, the target formation and reference formations have the same values for the three critical parameters), and the analog scores ranged from 100 to 42. Other than itself, the petroleum system most analogous to the Mesaverde system was the Iles petroleum system (Fig. 2.15). The detailed report (Fig. 2.16) gives insights into the comparisons of parameters, and individual parameter scores are available in a window that compares the parameters of the reference formation to those of the target formation (Fig. 2.16). The choice of FAST weighting factors may result in less than ideal ranking. Having detailed printouts, the user may analyze the analog comparisons of each parameter to determine causes for analog rankings and to decide whether weighting factors of some parameters should be changed.

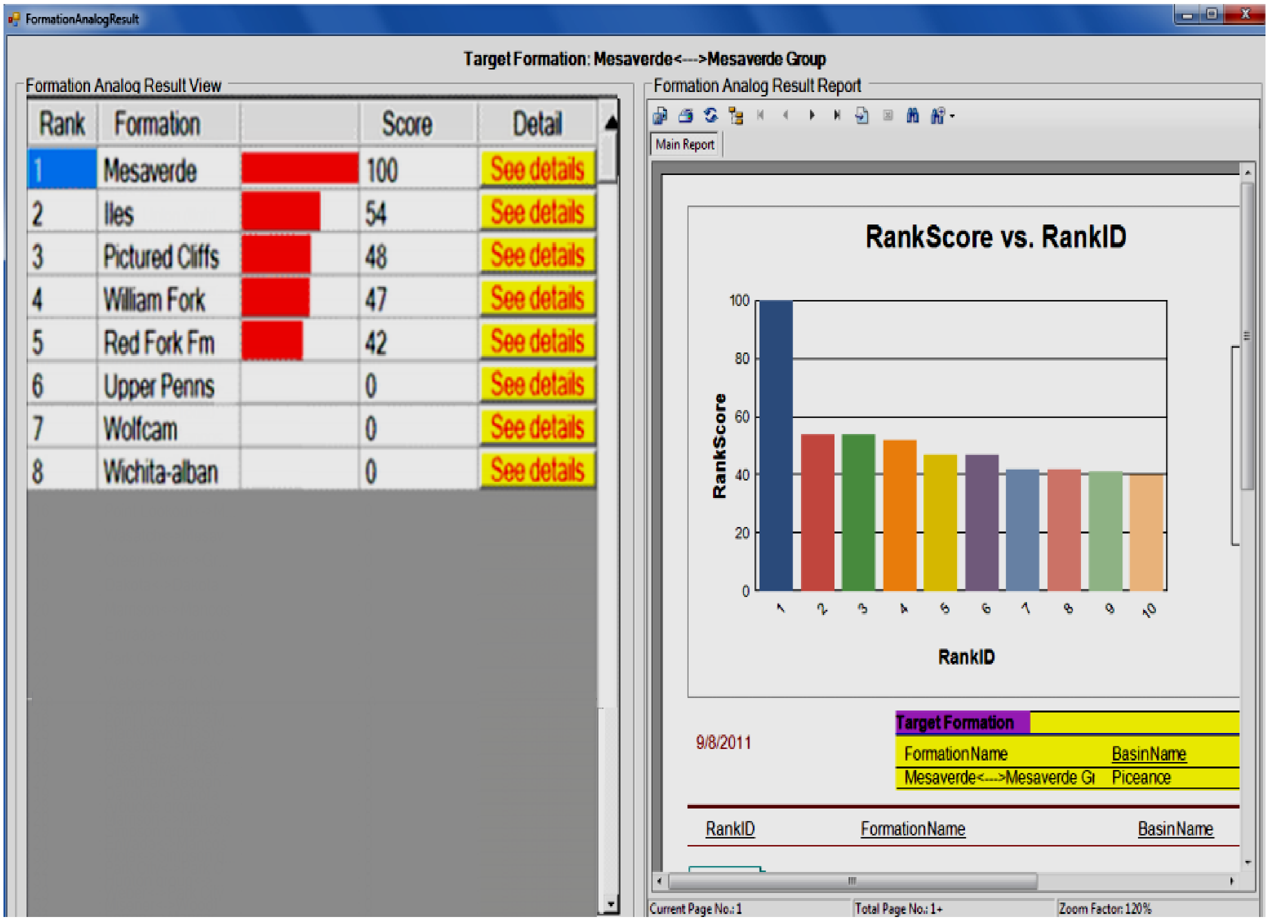
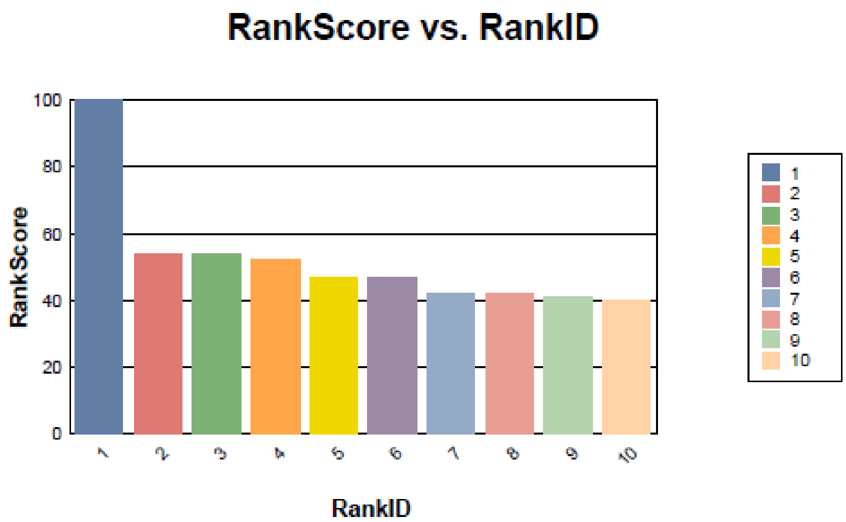


Fig. 2.14—Example results for the Mesaverde formation (Cheng et al., 2010a).



9/2/2011

Target Formation

FormationName	BasinName	SourceRockTypeName
Mesaverde<--->Mesaverde Grou	Piceance	Tight Sand

RankID	FormationName	BasinName	RankScore
1	Mesaverde<-->Mesaverde Group	Piceance	100
1 100.00			
2	Iles<-->Iles	Piceance	54
2 54.00			
3	Iles<-->Iles	Piceance Target	54
3 54.00			
4	Forth Union (tight sand)<-->Forth Union	Wind River	52

Fig. 2.15—Example of general report with rank results (Cheng et al., 2010a).

Target Formation

FormationName	BasinName	SourceRockTypeName
Mesaverde<--->Mesaverde Grou	Piceance	Tight Sand

Reference Formation

FormationName	BasinName
Iles<-->Iles	Piceance

General Rank Results

RankID	RankScore	Memo
2	54	Able to compare

Parameter	TargetValue	ReferenceValue	RelativeScore
Depositional System	Deltaic - Fluvial/River domin	Submarine Fan/Turbidite	0
Depth Min	1000 ft	5000 ft	0
Depth Max	6000 ft	10000 ft	0
Gross Thickness Min	100 ft	500 ft	81
Gross Thickness Max	500 ft	1500 ft	51
Net Thickness Min			0
Net Thickness Max			0
Pressure Min	100 psia	3500 psia	0
Pressure Max	2500 psia	6500 psia	0
Pressure Regime	Normal pressure	Over pressure	0
Porosity Min	10 %	5 %	72
Porosity Max	20 %	10 %	44
Permeability Min	0.5 mD	0.01 mD	41
Permeability Max	240 mD	5 mD	0
Water Saturation Min	30 %	20 %	72
Water Saturation Max	60 %	50 %	72
Migration Distance Min	500 ft	200 ft	0
Migration Distance Max	1000 ft	1000 ft	100
Migration Direction	Vertical	Vertical	100
Seals	Shale	Shale	100
Traps Type	Combination	Stratigraphic	0
Fluid Type	Gas	Gas	100
Oil API Min			0
Oil API Max			0
Sulfur content Min			0
Sulfur content Max			0
CO2 content Min			0
CO2 content Max			0
H2S content Min			0
H2S content Max			0

Fig. 2.16—Example of detailed report for each rank result (Cheng et al., 2010a).

FAST and the coupled BASIN database provide a method to characterize and evaluate the formations in frontier basins that have unconventional hydrocarbon resources but little reservoir characterization data. Identifying a reference formation that is analogous to a frontier formation allows preliminary insight into the likelihood that unconventional hydrocarbon resources are present, and suggests best practices for their recovery in the initial testing stage. Although our objective was to identify analogs for unconventional reservoirs, FAST may also be used to identify analogous formations for conventional reservoirs.

3 PETROLEUM RESOURCES INVESTIGATION SUMMARY AND EVALUATION (PRISE) OF MATURE NORTH AMERICAN BASINS*

3.1 Introduction

To better evaluate the unconventional gas reservoirs (UGRs) in North America, Martin (2010) developed the software system called Petroleum Resources Investigation Summary and Evaluation (PRISE). PRISE used data from 8 basins to assess TRR in UGRs (Martin, 2010). In this research, we extended the work of Martin (2010) to include data from 17 additional North American basins that contain significant volumes of gas in UGRs.

3.2 Data Sources for Investigating N.A. Basins

The resource information used in PRISE comes exclusively from published reports from several government and private industry agencies. The National Petroleum Council (NPC), Potential Gas Committee (PGC), Gas Technology Institute (GTI), Energy Information Administration (EIA), and US Geological Survey (USGS) routinely evaluate gas resources in North American basins. These organizations publish estimates of total recoverable resources (TRR) in most US basins. The resource estimates are often categorized as conventional or unconventional. Some resources are further classified as

*Reprinted with permission from “Assessment of the Distribution of Technically Recoverable Resources in North American Basins” by Cheng, K., Wu, W., Holditch, S. A., Ayers, W.B., and McVay, D.A., 2010. Paper SPE 137599 presented at the SPE Canadian Unconventional Resources & International Petroleum Conference, Copyright 2012 by Society of Petroleum Engineers, Inc.

tight gas, shale gas, and coalbed methane resources. Unfortunately, there is substantial variation among estimates from the organizations. The largest problem relates to differences in how the resources are defined and categorized. There are also differences in analytical approaches employed, and in the assumed economic conditions and technology levels under which the assessments were performed. To address these issues, and to maximize the use of multisourced data, Martin et al. (2010) mapped the data from different agencies to a unified system that generally conforms to standards of the Petroleum Resources Management System (PRMS) (SPE, 2007). PRMS definitions are those approved by the Society of Petroleum Engineers, the American Association of Petroleum Geologists, World Petroleum Council, and Society of Petroleum Evaluation Engineers.

NPC. The National Petroleum Council is the oil & natural gas advisory committee to the US secretary of energy that advises the Secretary on matters related to oil and natural gas. The Council membership of approximately 175 members are selected and appointed by the Secretary of Energy (DOE, 2010).

PGC. Potential Gas Committee provides estimates to assist in appraisal of the nation’s long-range gas supply (PGC, 2007). The PGC generates estimates based on three categories of resources (Fig. 3.1).

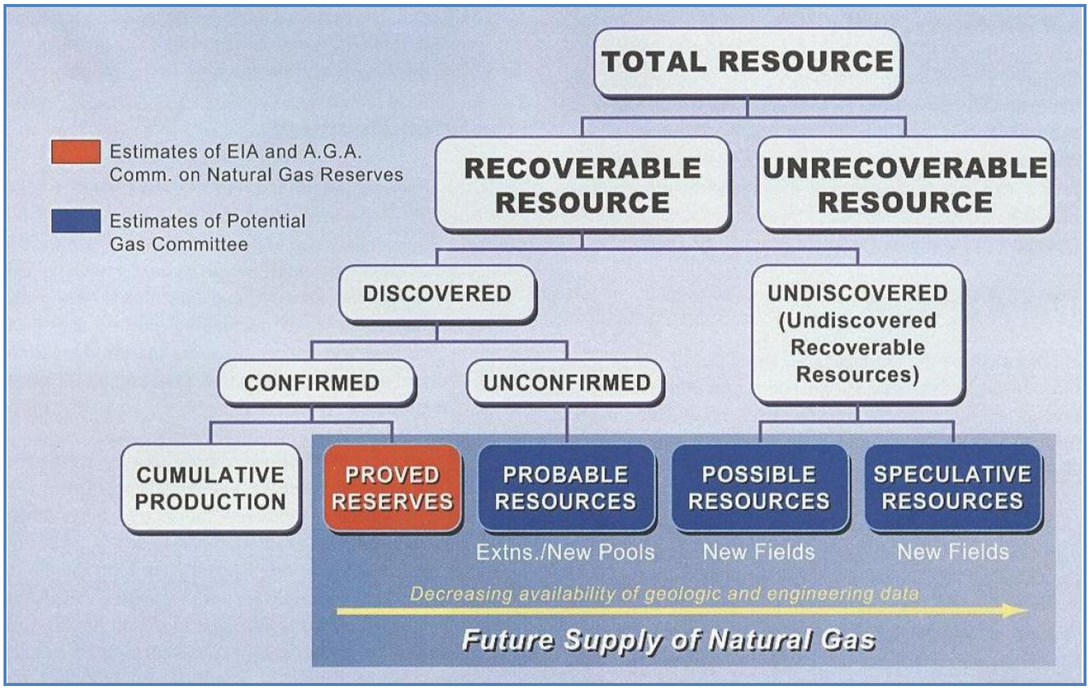


Fig. 3.1—PGC resource classification and organization (PGC, 2007).

GTI. GTI is a nonprofit research and development (R&D) organization (GTI, 2010).

EIA. The US Energy Information Administration collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment (EIA, 2010).

USGS. The USGS evaluates basins of great interest to the oil and gas industry to provide information in basins with active development (Old et al., 2008).

3.3 PRISE Methods

The aims of our research were to develop a systematic way of integrating and evaluating the data from North American conventional and unconventional resources reported by different agencies, and to quantify the resource distributions in terms of categories and certainties that are defined by the PRMS*. To accomplish these, we first identified the different resource types to be appraised in 25 North American basins. Then, keeping in mind the resource triangle concept, we used published resource information to quantify the distribution of recoverable resources in terms of these resource types.

3.3.1 Scope and Scale of Appraisals

The investigation and evaluation were conducted at the basin scale and included 25 North American basins. Each of the basins has significant conventional and unconventional resource development and production. In addition to the resource types, geologic and engineering conditions vary significantly among the basins.

3.3.2 Defining the Resource Triangle

To determine the categories to use in our software system, we compiled published information from the USGS, PGC, NPC, EIA, and GTI and compared differences in their purposes, data sources, resource estimates, and other considerations. On the basis of these understandings, we evaluated definitions of gas-resource categories and the methods different organizations used to estimate resource volumes. This way, we identified the appreciable variability in resource estimates and determined how the resource estimates from different agencies could be integrated into a common standard (Martin, 2010).

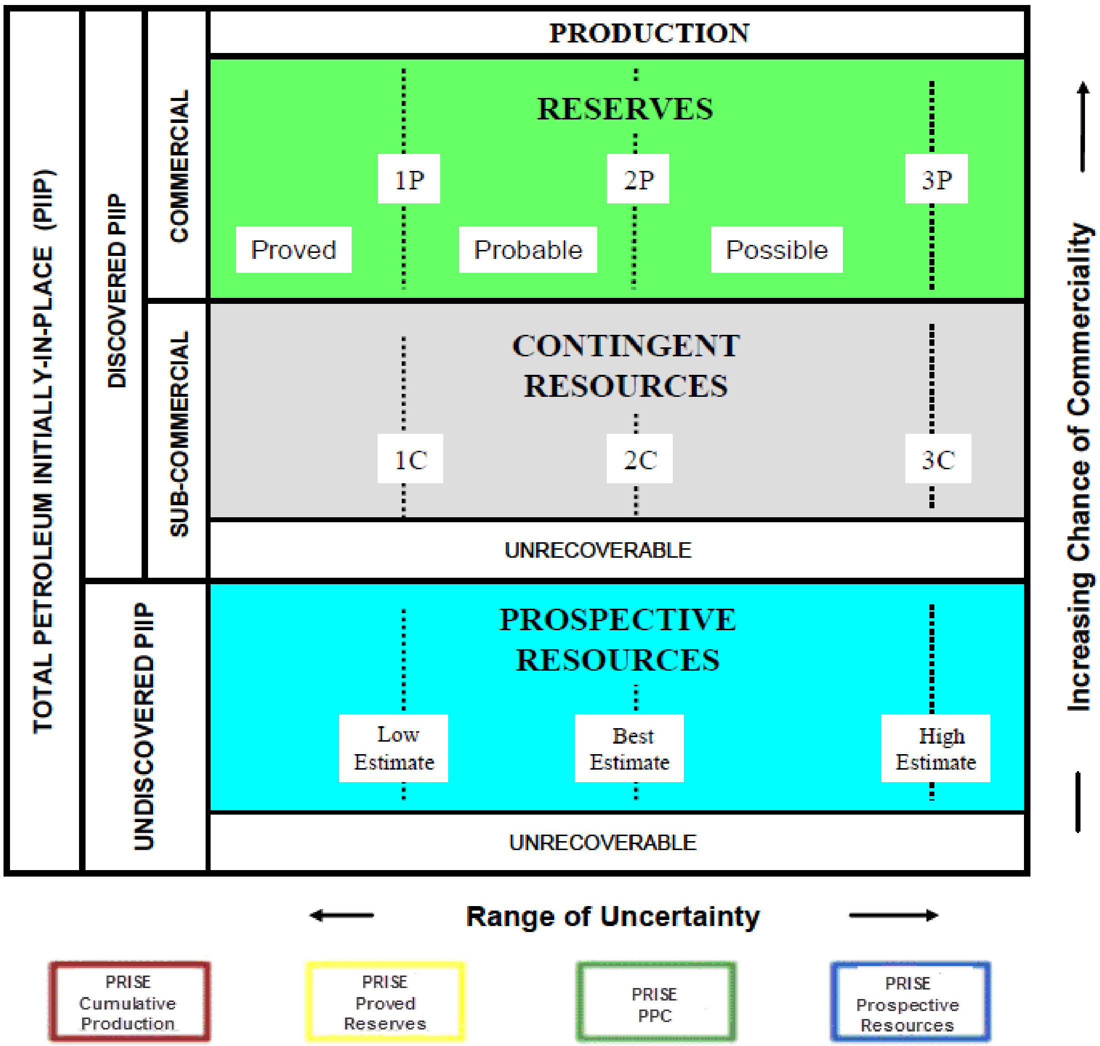


Fig. 3.2—PRISE categories mapped to PRMS categories (modified from SPE, 2007).

Martin et al. (2010) established four PRISE categories based upon the PRMS (Fig. 3.2). These categories are (1) cumulative production, (2) proved reserves, (3) probable plus possible reserves plus contingent resources (PPC), and (4) prospective resources. The system for mapping resource categories from various agencies into the PRISE categories is shown in Fig. 3.3. In the PRISE resource tree, each of the four resource categories is populated for each of the five resource types (conventional oil, conventional gas, tight-sands gas, coalbed methane, and shale gas) (Fig. 3.4).

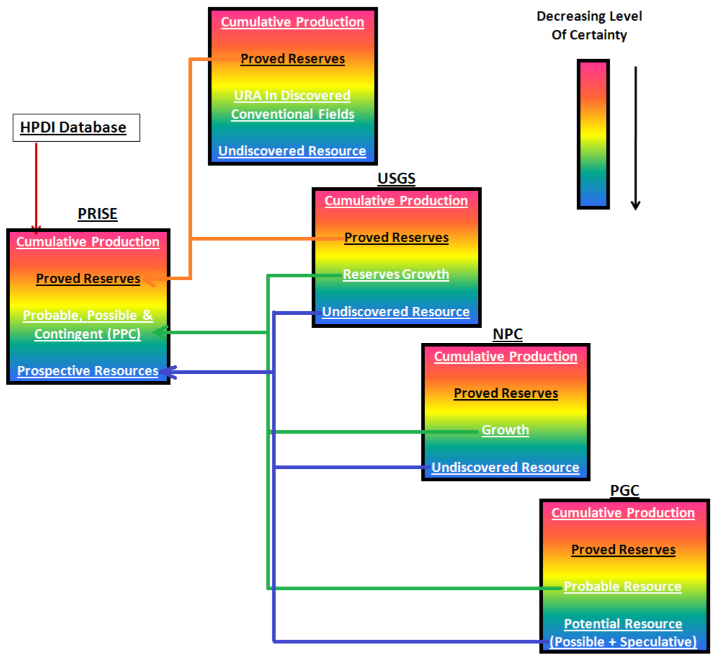


Fig. 3.3—Data sources used for PRISE resource quantification (Martin et al., 2010).

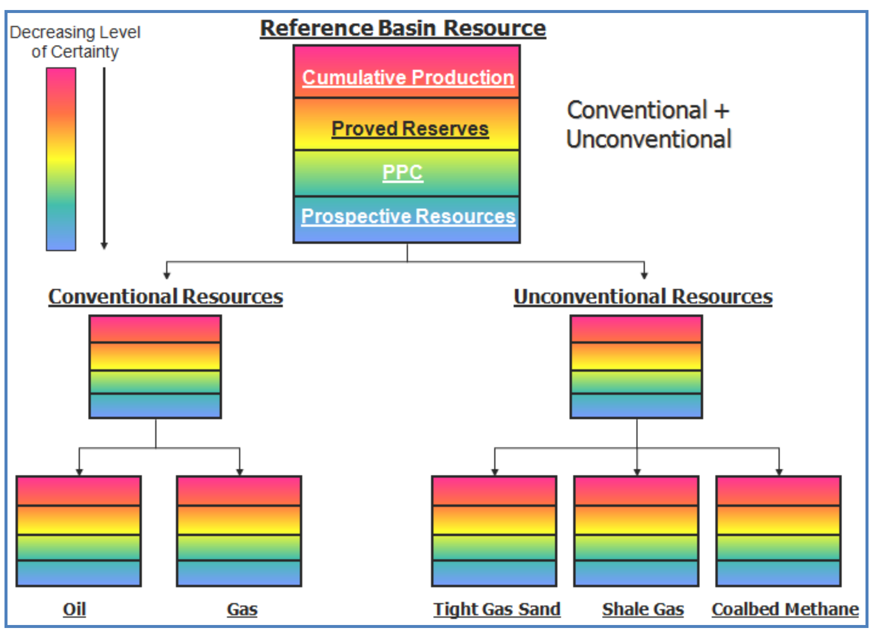


Fig. 3.4—PRISE resource tree with four resource categories and five resource types (Martin et al., 2010).

3.3.3 Quantification of the Resource Triangle

Although we integrated assessment data from various agencies, the HPDI (2009) database was our source for production data. The proved-reserves information was obtained from the EIA, USGS, and state agencies. For values of PPC and prospective resources, we used information from the USGS, PGC, and NPC. For these assessments, the agencies not only have particular definitions of resource categories but use different statistical terms within the categories. Table 3.1 (Martin et al., 2010) illustrates how different agencies classify their various resource estimates. Therefore, to maximize the use of data from various agencies, Martin et al. (2010) selected a quantification convention that is compatible with the resource categories and the statistical meanings of the agencies.

Table 3.1—Agency Statistical Reporting Terminology (Martin et al., 2010)

USGS (2006) - Reserves Growth / Undiscovered Resources		PGC (2007) – Probable Resource / Potential Resource		NPC (2003b) – Growth / Undiscovered Resource	
Statistical data Presentation	Description	Statistical data Presentation	Description	Statistical data Presentation	Description
F5	5% chance that at least that volume exists	P5	5% probability of occurrence	P10	10% chance that at least that volume exists
F50	50% chance that at least that volume exists	P50	50% probability of occurrence	P50	50% chance that at least that volume exists
F95	95% chance that at least that volume exists	P95	95% probability of occurrence	P95	90% chance that at least that volume exists

The quantification convention used in PRISE (Old et al., 2008; Martin et al., 2010) is an assigned a “confidence level” for each resource category. The confidence levels range from 100% to 10% for cumulative production, proved reserves, PPC, and prospective resources, in that order, and the sum of these four resource categories is the basin TRR. The PRISE confidence-level definitions are summarized in Table 3.2.

Table 3.2—PRISE Confidence Level Definitions (Old et al., 2008)

Naming Convention for Resource Quantification	Definition
C100	100% confidence that volume will be recovered. Cumulative Production.
C90	90% confidence that volume will be recovered. Cumulative Production + Proved Reserves = C100 + Proved Reserves.
C50	100% confidence that volume will be recovered. Cumulative Production + Proved Reserves + PPC = C90 + PPC.
C10	100% confidence that volume will be recovered. Cumulative Production + Proved Reserves + PPC + Prospective Resources = C50 + Prospective Resources = Total Recoverable Resources (TRR).

To integrate assessments from the various agencies for a particular resource category in the PRISE quantification convention, Martin et al. (2010) adopted an approximate method based on the concept of maximizing uncertainty, because uncertainty is usually underestimated when estimating unknown quantities (Capen, 1976). This method applies to situations when there are multiple assessments by different agencies for a particular resource category. We maximize uncertainty by selecting the widest possible range for the particular resource category, which will usually correspond to the largest possible maximum value (such as P5 or F5) for that resource category. Fig. 3.5 illustrates how the assessments from different agencies are integrated by the PRISE confidence levels and in this process it shows how the concept of maximizing uncertainty would be applied from the USGS and PGC to determine the full distribution of TRR for a particular resource category.

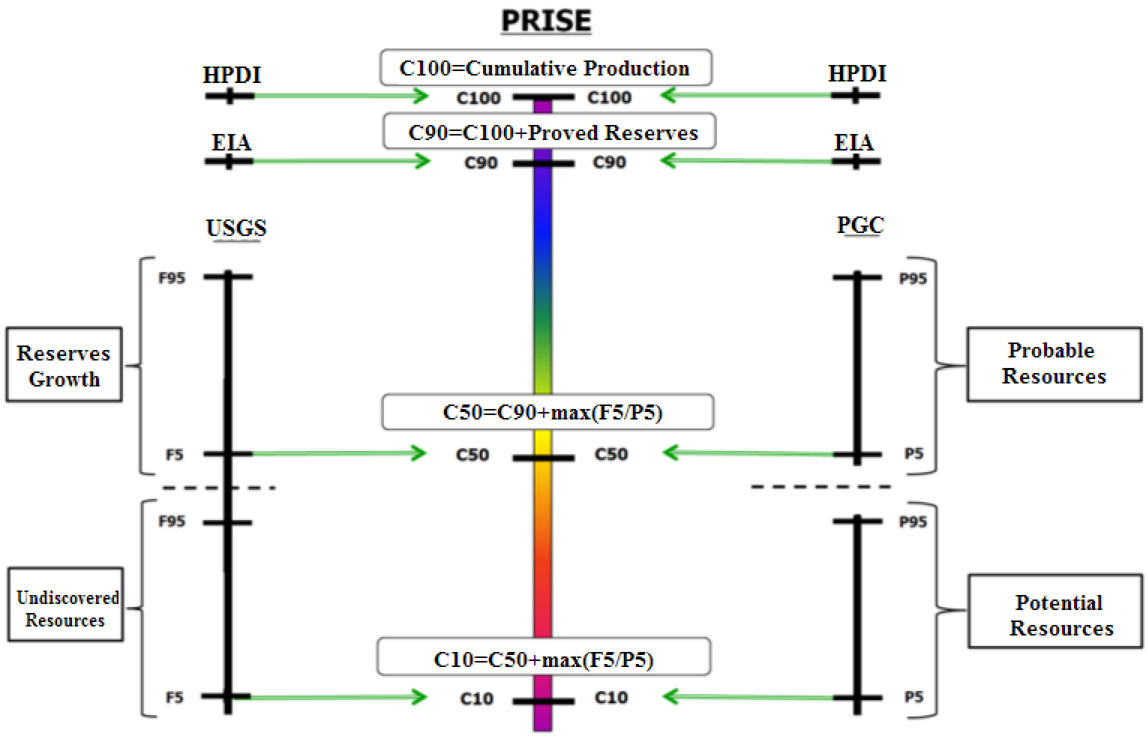


Fig. 3.5—Assessment integration by PRISE confidence levels with concept of maximizing uncertainty (Martin et al., 2010).

3.3.4 PRISE Quantification Results

The preliminary assessment (Martin et al., 2010) quantified the total recoverable resources of eight basins: the Appalachian, Black Warrior, Greater Green River, Illinois, San Juan, Uinta-Piceance, and Wind River basins (the Uinta and Piceance were combined). In this work, we updated the database to include information from a total of 25 North American basins. We completed the resource tree and determined TRR volumes for the five resource types: CBM, TSG, SG, CG (conventional gas), and CO (conventional oil). The CO resource value was converted to gas equivalent and added to CG to obtain combined conventional resources. CBM, TSG, and SG were summed to obtain combined unconventional resources. Conventional and unconventional resources were summed to obtain aggregate TRR in the basin.

Results of the analysis of TRR for the 25 basins are illustrated in Fig. 3.6 and Fig. 3.7. Fig. 3.6 shows the aggregate TRR for each of the 25 basins studied. Table 3.3 shows the values of conventional and unconventional resources for each basin. Table 3.4 indicates that most of data are collected from USGS. Fig. 3.7 presents the numbers in terms of percentages, which shows the relationship of TRR of both oil and gas that will be produced from conventional reservoirs in a basin to the TRR from unconventional gas reservoirs in the same basin. In the Fort Worth basin, the large majority of the TRR is from unconventional gas reservoirs (97%, a ratio of about 32 to 1). On the other end of the spectrum, the Wyoming Thrust Belt has an unconventional gas percentage of only 62% (ratio of about 1.6 to 1). The overall ratio of unconventional to conventional resources for all 25 basins is about 4 to 1. We theorize that as more data are collected on shale gas reservoirs in some of the basins to the right in Fig. 3.7, the ratio of unconventional to conventional resources will increase significantly.

Figs. 3.34 through 3.36 show distributions of TRR by resource types in the various basins. Each figure shows the basins dominated by a different unconventional resource type – CBM in Fig. 3.8, TGS in Fig. 3.9, and SG in Fig. 3.10.

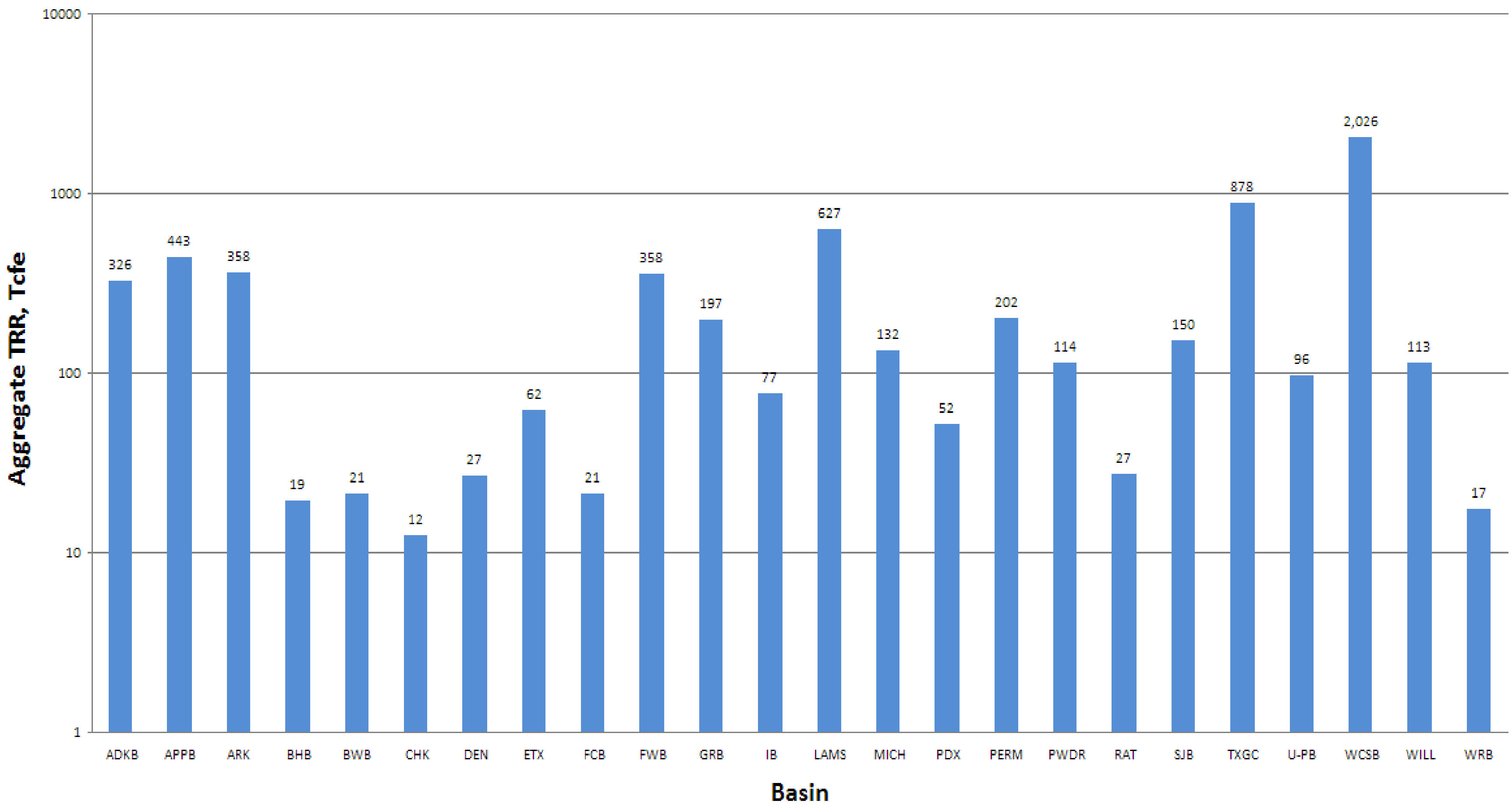


Fig. 3.6—Aggregate TRR volumes in the 25 reference basins studied (Cheng et al., 2010b).

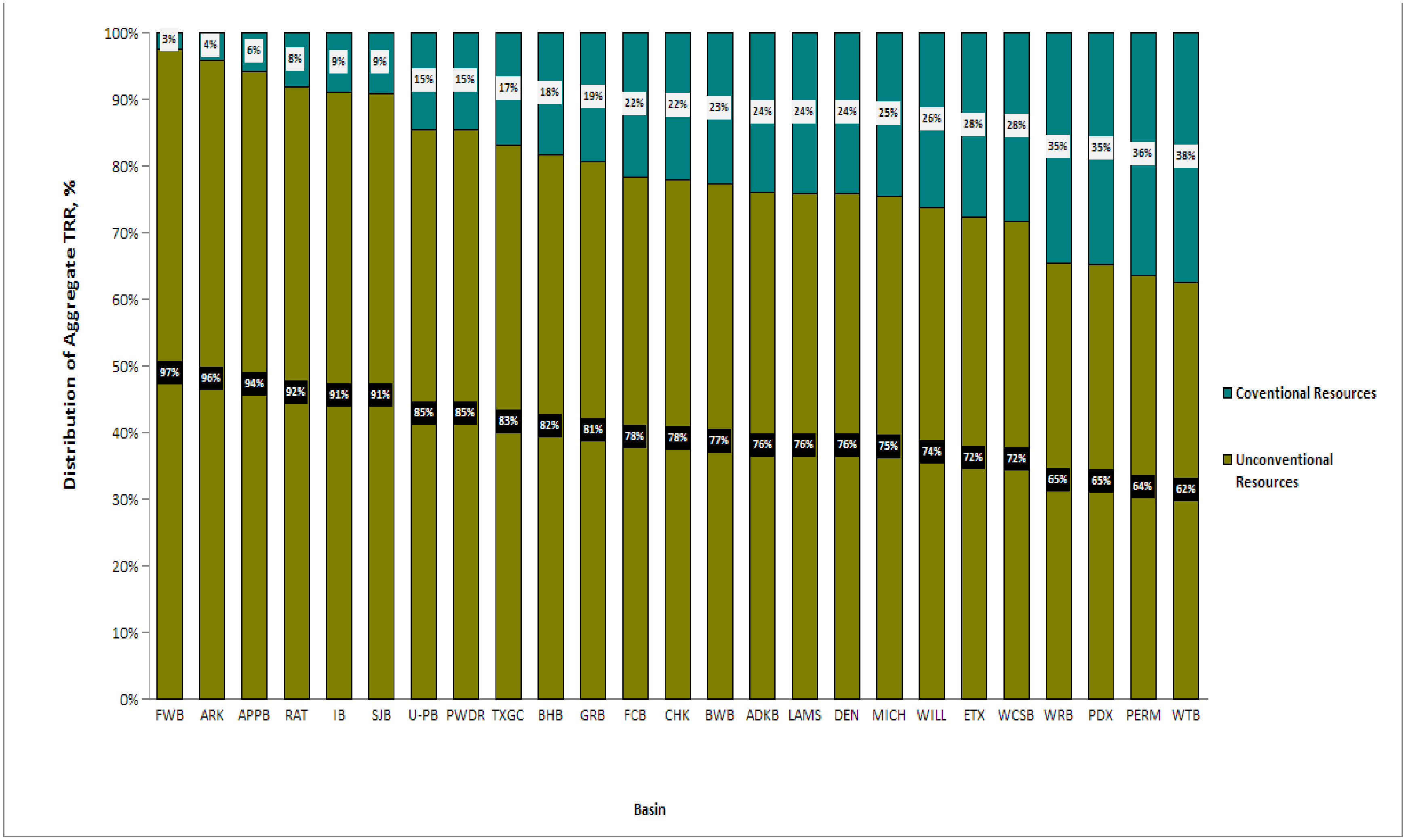


Fig. 3.7—The distribution of conventional and unconventional resources for the 25 reference basins studied (Cheng et al., 2010b).

Table 3.3—Aggregate TRR Volumes in the 25 Reference Basins (Cheng et al., 2010b)

Abbreviation	**Name**	**TRR Conventional Resources (Tcfe)**	**TRR Unconventional Resources (Tcfe)**	**Aggregate TRR Resources (Tcfe)**
ADKB	Anadarko Basin	79	247	326
APPB	Appalachian	26	417	443
ARK	Arkoma Basin	15	343	358
BHB	Big Horn Basin	3	16	19
BWB	Black Warrior	5	16	21
CHK	Cherokee Basin	2	10	12
DEN	Denver Basin	6	21	27
ETX	East Texas Basin	17	45	62
FCB	Forest City Basin	4	17	21
FWB	Fort Worth	9	349	358
GRB	Green River Basin	38	159	197
IB	Illinois Basin	7	70	77
LAMS	Louisiana Mississippi Salt Basin	151	476	627
MICH	Michigan Basin	32	100	132
PDX	Paradox Basin	18	34	52
PERM	Permian Basin	73	129	202
PWDR	Powder River	17	97	114
RAT	Raton Basin	2	25	27
SJB	San Juan Basin	14	136	150
TXGC	Texas Gulf Coast Basin	148	730	878
U-PB	Uinta-Piceance Basin	14	82	96
WCSB	Western Canada Sedimentary Basin	575	1451	2026
WILL	Williston Basin	30	83	113
WRB	Wind River	6	11	17
WTB	Wyoming Thrust Belt Basin	12	21	33

Table 3.4—Aggregate TRR Volumes Data Collection

Basin Name	Data from USGS (Tcfe)	Data Kun (2010) Used from DOE or Other Souces (Tcfe)	Total (Tcfe)
Anadarko Basin	326	0	326
Appalachian Basin	322	121	443
Arkoma Basin	351	7	358
Big Horn Basin	16.5	2.5	19
Black Warrior	21	0	21
Cherokee Basin	2.4	9.6	12
Denver Basin	27	0	27
East Texas Basin	45.4	16.6	62
Forest City Basin	6	15	21
Fort Worth Basin	58	300	358
Green River Basin	38	159	197
Illinois Basin	19	58	77
Louisiana Mississippi Salt Basin	627	0	627
Michigan Basin	43	89	132
Paradox Basin	52	0	52
Permian Basin	202	0	202
Powder River Basin	23	91	114
Raton Basin	7	20	27
San Juan Basin	138	12	150
Texas Gulf Coast Basin	878	0	878
Uinta-Piceance Basin	51	45	96
Western Canada Sedimentary Basin	0	2026	2026
Williston Basin	111.5	1.5	113
Wind River Basin	9	8	17
Wyoming Thrust Belt Basin	12.4	20.6	33

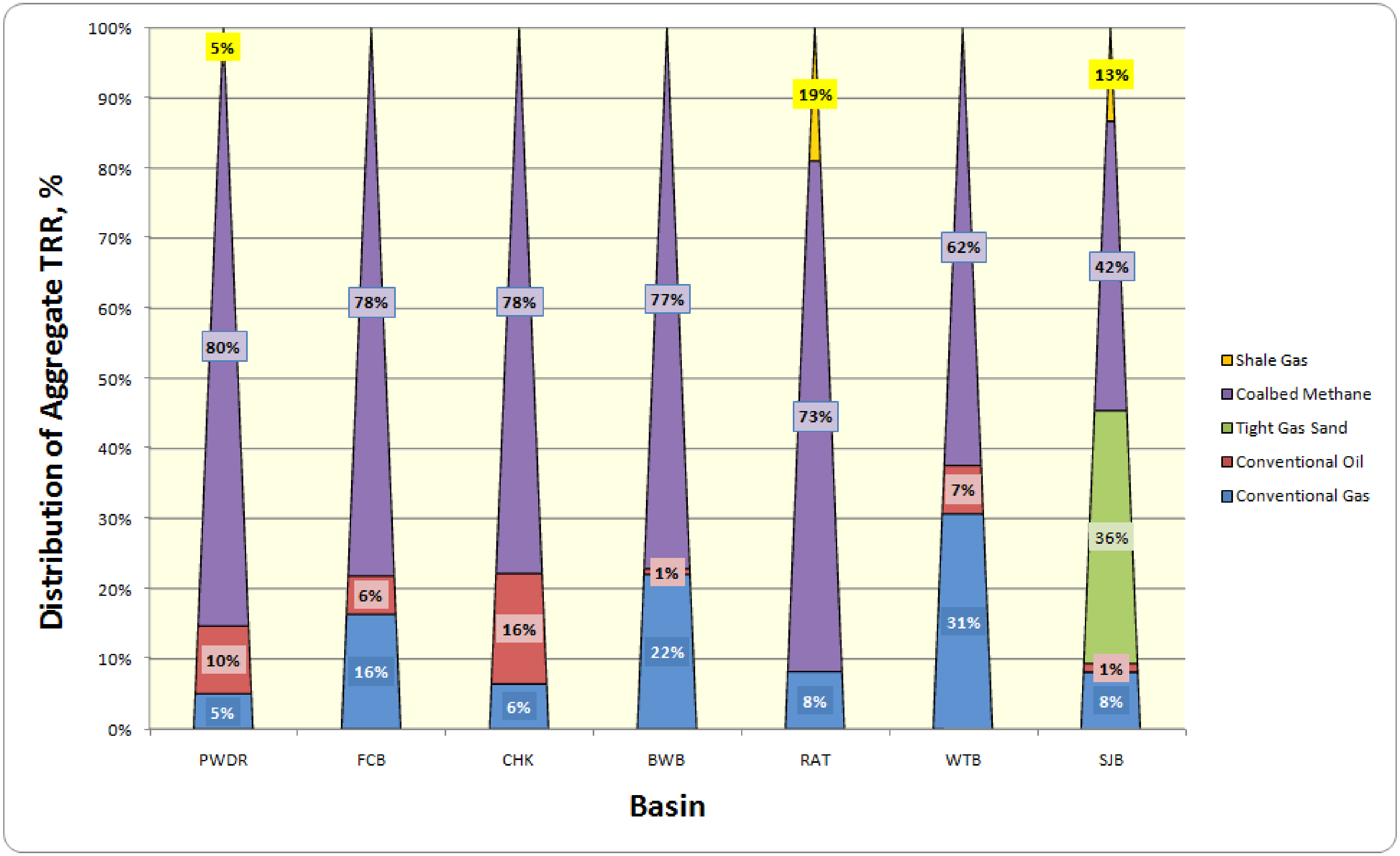


Fig. 3.8—Distribution of the five resource types in seven basins dominated by CBM (Cheng et al., 2010b).

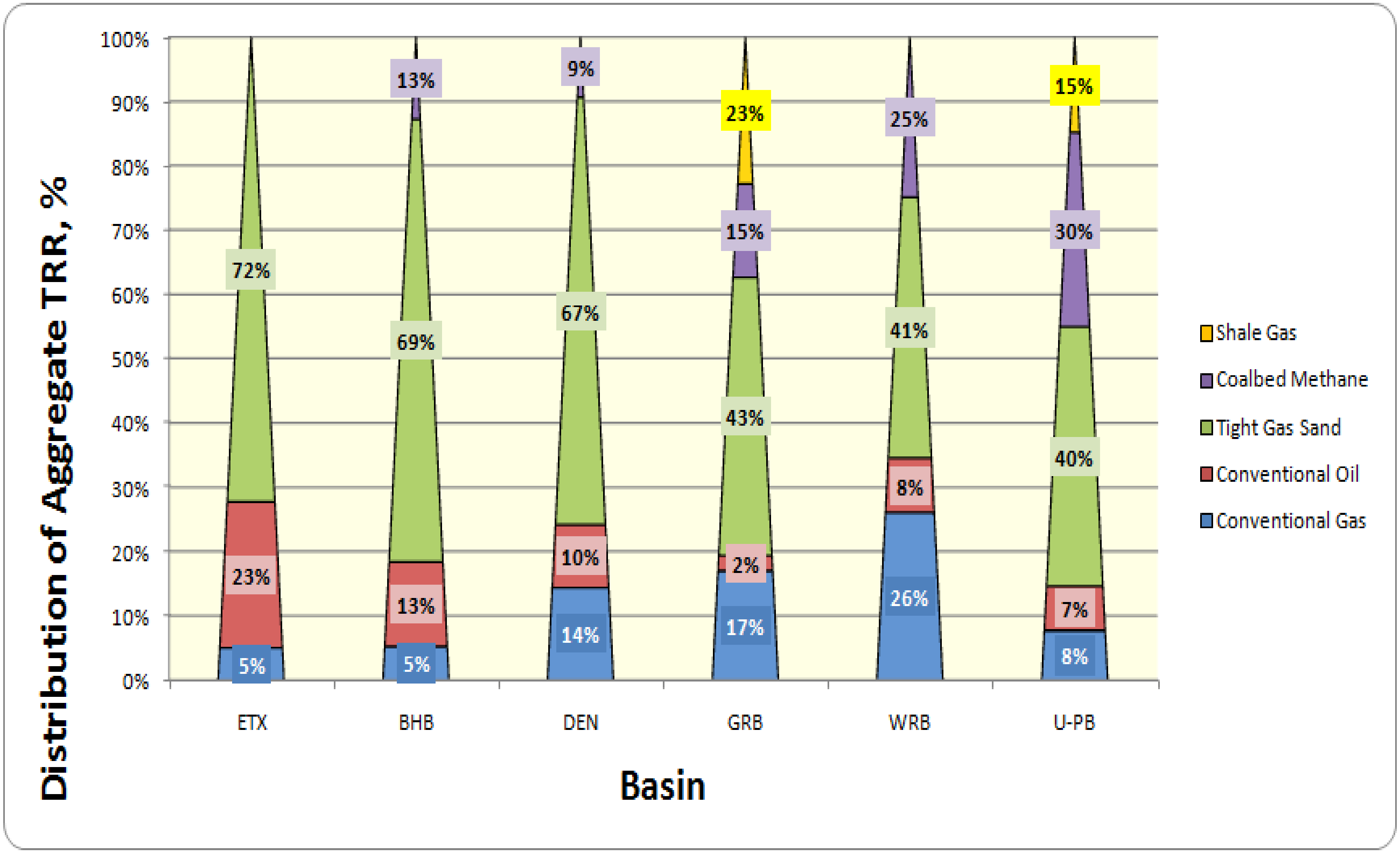


Fig. 3.9—Distribution of the five resource types in six basins dominated by TGS (Cheng et al., 2010b).

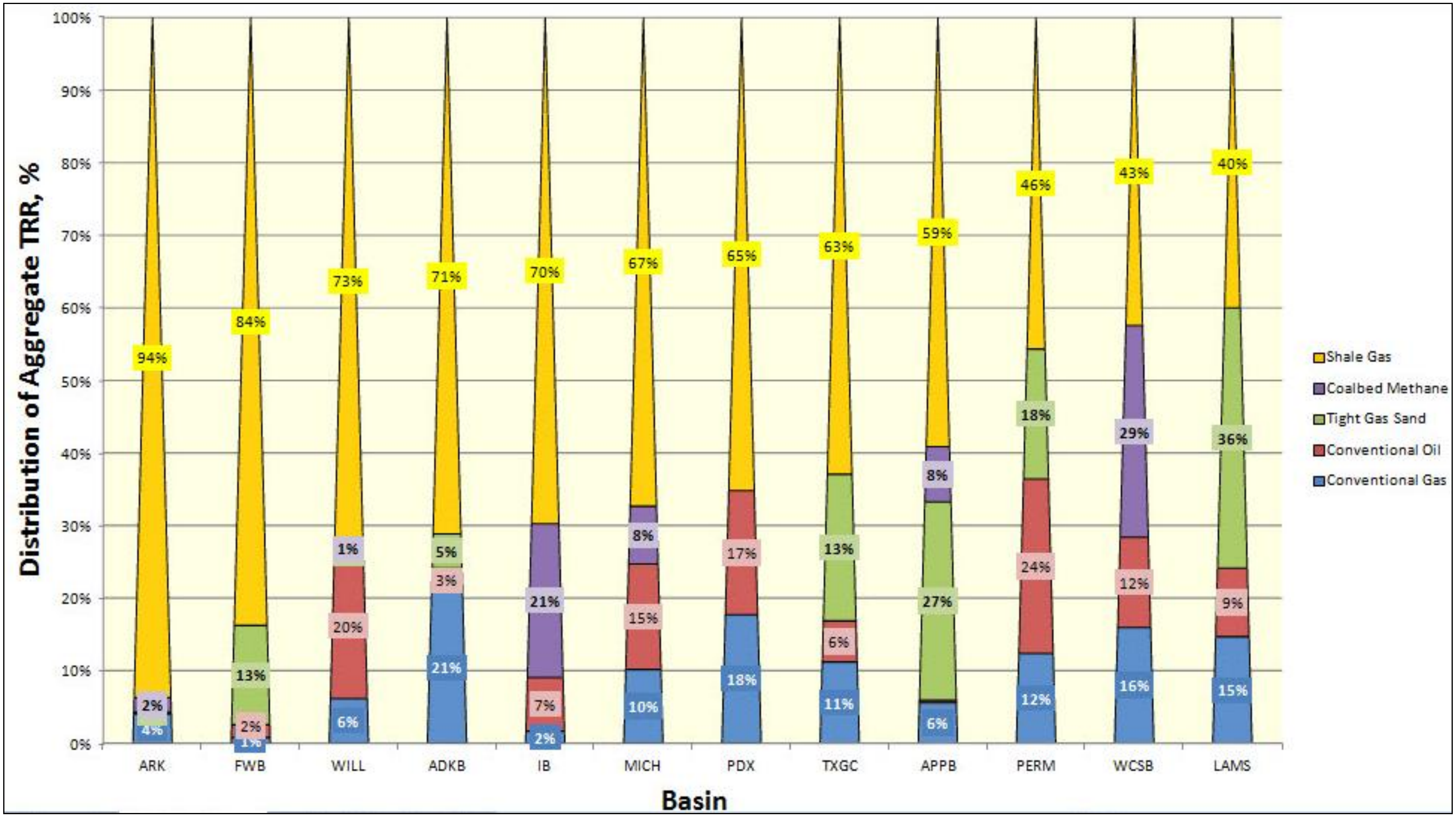


Fig. 3.10—Distribution of the five resource types in twelve basins dominated by SG (Cheng et al., 2010b).

3.3.5 Discussion of PRISE Quantification Results

Based on the results above, we conclude that (1) there is a relatively consistent distribution between recoverable conventional and unconventional resources; (2) the overall ratio of TRR from conventional reservoirs to TRR gas from unconventional resources in the 25 basins is approximately 1 to 4; and (3) the resource triangle concept is valid for the 25 North American basins. The distribution of resource volumes under different confidence levels can serve as an important indicator of the development level of North American basins, which can aid in business strategic planning. In addition, these observations can help companies assess potential unconventional resources in frontier basins worldwide. As an initial approximation, we would estimate that the TRR from unconventional gas reservoirs in a target frontier basin is 4 to 8 times greater than known recoverable conventional volumes. Such estimates can be further refined by combining the PRISE methodology with the BASIN system (described earlier in this paper from Singh et al., 2008), since the database for the 25 North American reference basins is shared by PRISE and BASIN. That is, we could determine reference North American basin(s) that provide the best analog to the target frontier basin, then use the distribution of resources in the reference basin to better estimate the distribution of resources in the target basin. We will explore this application of BASIN and PRISE in the next section.

We note that these results are not final. The data change annually as the various agencies update their estimates, and these ratios will change with time as more data are published and more shale gas reservoirs are developed. Future work will include further review and updating of data from these basins, addition of more basins, and improvement of the methodology for combining assessments for different resource categories and from different agencies.

4 PREDICTION OF UNCONVENTIONAL GAS RESOURCES IN UNDEREXPLORED BASINS*

4.1 Introduction

As unconventional gas resources become increasingly significant in meeting the world's great energy demands, it is increasingly important to quantify their volumes, especially for frontier basins where little exploration of unconventional resources has been undertaken.* Following our work in standardized investigation and quantified evaluation of recoverable resources in 25 mature North American basins, I further employed two methodologies to evaluate technically recoverable resources (TRR) for unconventional gas in frontier basins: source rock (SR) and conventional TRR input (CTRRI).

The source rock methodology derives from the fact that source rock potential is the mechanism for generating hydrocarbons. Thus, using the relationships between TRR and source rock factors, SR can adequately capture TRR from an indirect source rock evaluation. Combined with the ratio of unconventional and conventional hydrocarbons from our prior investigations, the methodology can further deduce conventional and

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unconventional resource volumes. Different from CTRRI methodology, SR provides an independent measure of TRR which requires known recoverable conventional resources for frontier basins.

Our objective was to calculate TRR volumes in frontier basins that have been recently discovered or not yet exploited because of the complexities of producing unconventional reserves. To calculate TRR for these basins, we divided their recoverable conventional volume by the fraction of conventional resources in a similar reference basin from Basin Analog System INvestigation (BASIN) analysis. BASIN contains a large database of information on 25 North American basins that can be compared by analogy with frontier basins. All of the quantifications are regulated by unified definitions from Petroleum Resource Investigation Summary and Evaluation (PRISE) software, another tool in the same family as BASIN. Although the SR and CTRRI methodologies estimate TRR for frontier basins in different conditions, the initial tests on three basins show that estimates by CTRRI are in accordance with those by SR. The results can be further evaluated by more complete estimation of NA basin resources and international UGRs. They also validate the resource triangle concept: acknowledging that all natural resources are distributed log-normally in nature, once these resources are prospected, the best highest-grade deposits are small and are easy to extract (Holditch, 2011b) (Fig. 4.1).

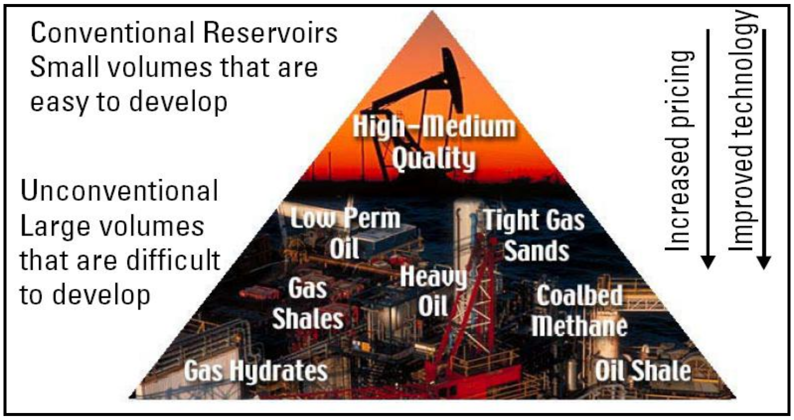


Fig.4.1—Resource triangle (Holditch, 2004).

4.2 Traditional Resource Estimation Methodologies

Currently, an enormous volume of oil and gas resides in unconventional reservoirs, and these resources in tight reservoirs, coal seams, and shales are expected to be significant in fulfilling the global energy demand, just as they have already played a major role in the US gas supply in recent years (Martin et al., 2010). To evaluate the feasibility of developing these resources, it is important to estimate the volume of TRR.

TRRs are producible using current recovery technology if we ignore economic profitability (Schmoker, 2005), and estimates can be combined with other key values (such as gas in place and economically recoverable resources) to determine how to proceed with investment and development. In particular, the preliminary estimates of technically recoverable unconventional resources are important for planning economic and development strategy in frontier basins worldwide, where little unconventional resource exploration has been undertaken and thus knowledge and experience are very limited. Three basic methods have been proposed for TRR estimation: volumetric, performance, and analog.

4.2.1 Volumetric-Based Method

Since TRR represents the subset of the assessed petroleum in place (or simply resources) that is thought to be technically recoverable, the volumetric method produces its estimate of TRR volume by applying a recovery factor to its estimate of the total petroleum resources in place. Although the total oil- or gas-in-place of a continuous accumulation can be quantitatively appraised from geologic considerations, the estimation of an overall recovery factor must sometimes be quite qualitative (Schmoker, 2005). A uniform recovery factor can greatly influence the results because it is a direct multiplier in converting petroleum in place to TRR; more accurate assessments would evaluate each play, or even subplay, according to its own characteristics. However, that approach may be impractical at the basin level, where the characteristics can vary considerably with lithology, depth, tectonic setting, and available drilling technology, and the specific recovery factors can also be subjective.

4.2.2 Performance-Based Method

The performance-based method was employed by USGS for its 1995 national oil and gas resource assessment, which is based on the production performance of continuous petroleum reservoirs, as empirically shown by wells. Thus, production data are the foundation for forecasts of potential additions to reserves within a given time span. Production schedules are created for the statistical 95% probability, mean, and 5% probability of recovering the volumes. Production is scheduled for different development rates for each of the three probability estimates. The annual development rate is not associated with field size but is an amount attributed to the wells drilled each year. Then the lowest and highest value in the entire range of potential serve as the TRR with the 95% and 5% probability, respectively, and the mid-case for the TRR is based on the statistical mean of the estimates. Such reservoir-performance assessment models are particularly well suited to continuous accumulations that are already partially developed. The wells themselves serve as comprehensive analog computers that evaluate and weight all relevant reservoir parameters. A similar methodology was also adopted in mature areas with significant amounts of data including the Gulf of Mexico and southern California (Lore, 2006), where plays were analyzed on a basis of statistical parameters of discovered pools and historical trends.

If assessors lack sufficient drilling and production data, they must draw upon information from analog accumulations. The assessment model for continuous accumulations used in the USGS 1995 National Assessment (Gautier et al., 1995; Schmoker, 1994) and the revised USGS model (FORSPAN) discussed here are both reservoir-performance models. The use of reservoir-performance models for domestic assessments takes full advantage of the development activity that is occurring in many US continuous accumulations. Examples of previous assessments of continuous accumulations based on reservoir-performance methods can be found in NPC, 1992; Gautier et al., 1995; Schmoker, 1994; and Kuuskraa, 1998.

4.2.3 Analog-Based Method

The analog-based method for estimating TRR has been mentioned in literature (Schmoker, 2005; Lore, 2006), although no detailed information has been given. In general, this methodology has unique advantages in conditions lacking sufficient drilling and production data, where the assessor must draw upon information from analog accumulations. Such conditions are typical for frontier basins because they are usually in the underexplored status and only have sparse data. For many plays in Alaska and the Atlantic and some in the Pacific, analogs have been assessed this way.

For plays in frontier areas with sparse data, analogs have been developed using subjective probabilities to cover the range of uncertainties.

4.3 Principle of Estimating Resources

4.3.1 Application of the BASIN

The BASIN software is based on the concept that analogous basins have similar distribution in the resource triangle. The resource triangle (Fig. 4.1) suggests the distributions of hydrocarbon resources in nature: the base of the triangle represents large volumes of unconventional, low-quality hydrocarbon resources, in contrast to the apex of the triangle, which indicates the small volumes of conventional, high-quality resources.

To support this concept, we compared the results of BASIN software with the analog results based on the related PRISE software (Cheng et al., 2010b): the BASIN software uses the basin analog approach to identify analogous basins for the target basin, and the PRISE software has detailed information on resource distributions (CG-conventional gas, CO-conventional oil, SG-shale gas, CBM-coalbed methane, and TGS-tight gas sand) of 25 North American basins. In each of the comparisons, we selected one of the 25 North American basins as the target basin in the BASIN software that provides the analog results, and then for the same North American basin, its analogous North American basins are also identified according to the similarity of their resource distributions from PRISE. Fig. 4.2 to Fig. 4.4 show the comparison results for the San Juan, Williston, and Green River target basins, respectively. The matching basins between BASIN and PRISE are connected by a red line in these figures, which show that the BASIN results are closely consistent with the PRISE results. These verifications lead to an important conclusion: analogous basins should have similar resource distributions.

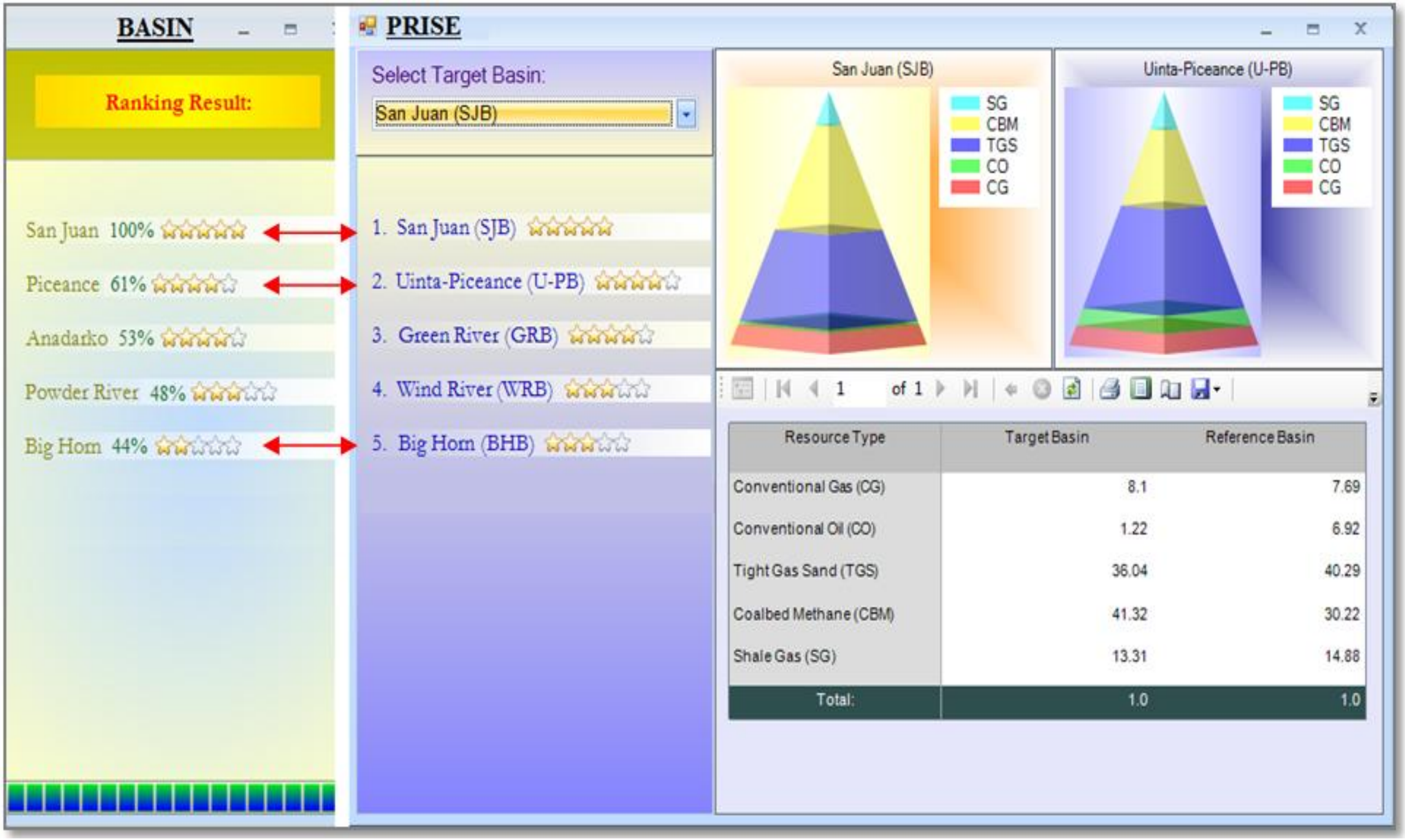


Fig. 4.2—Comparison of BASIN and PRISE for the San Juan target basin (Cheng et al., 2011c).

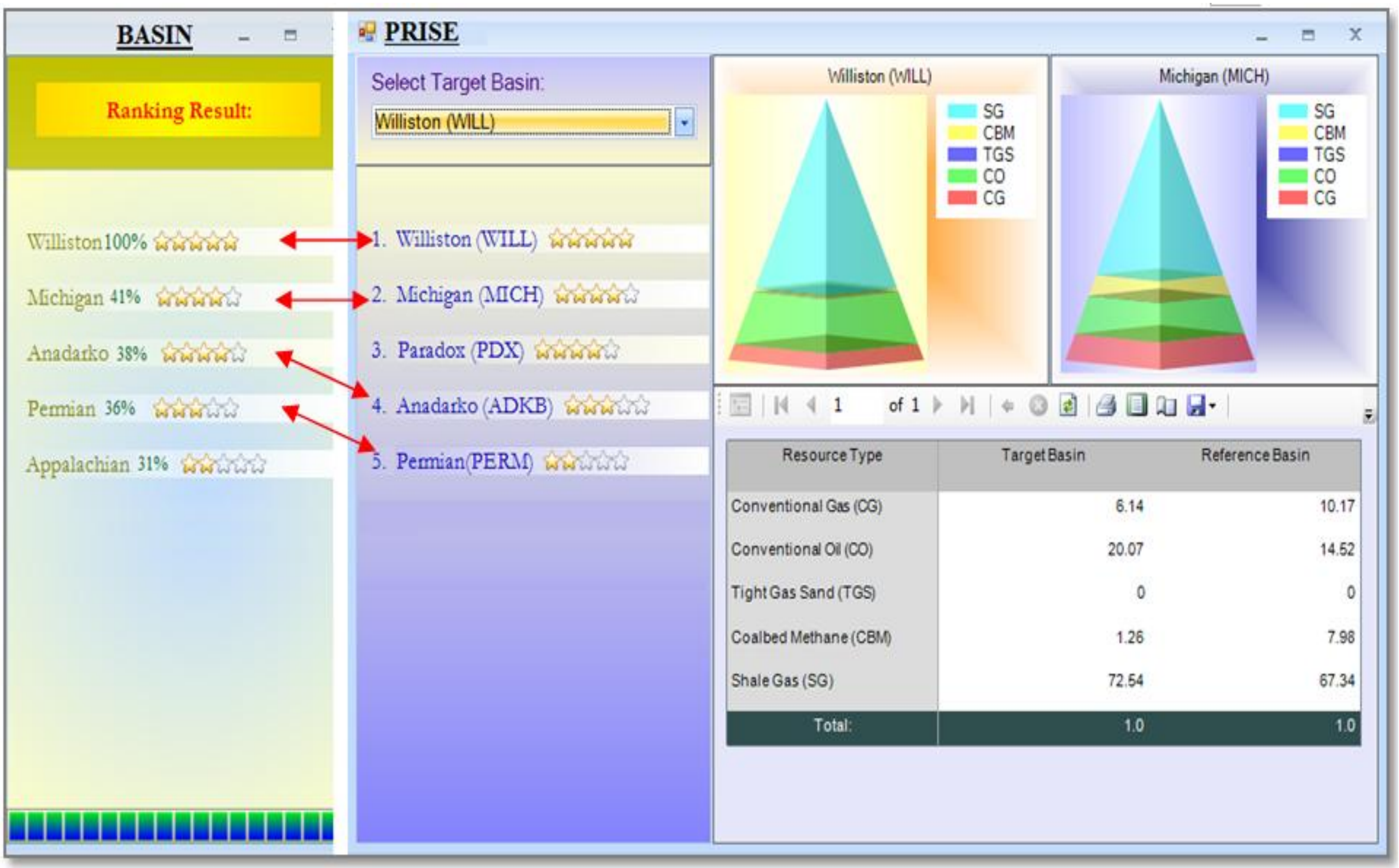


Fig. 4.3—Comparison of BASIN and PRISE for the Williston target basin (Cheng et al., 2011c).

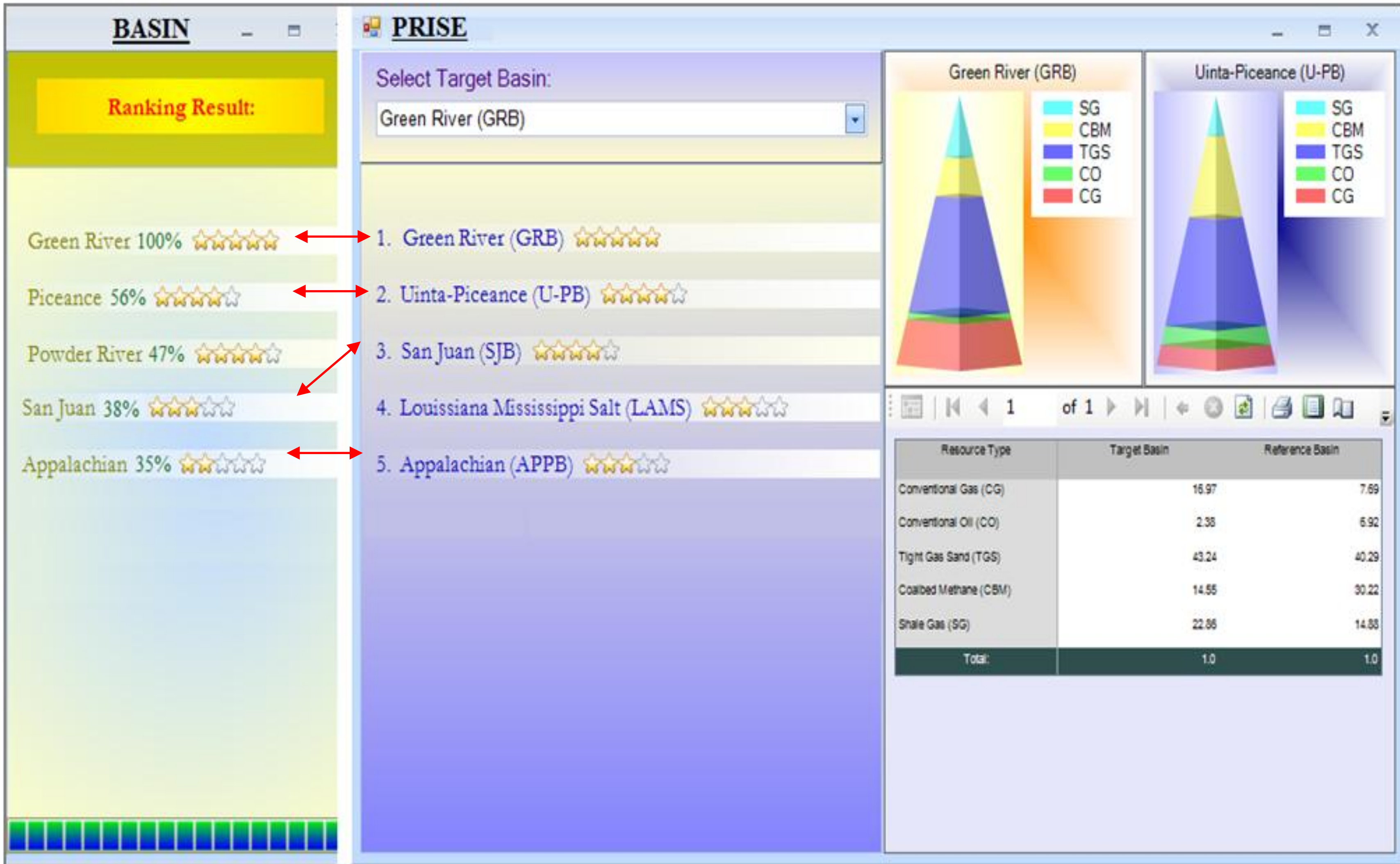


Fig. 4.4—Comparison of BASIN and PRISE for the Green River target basin (Cheng et al., 2011c).

Based on the above observation, we can use the well-characterized resource distributions of the analogous North American basins to infer the resource distribution on the frontier basin and further estimate the volumes for different types of resources. For example, we can use the ratio of conventional TRR volume to unconventional TRR volume in the most analogous North American basin and the conventional TRR volume in the frontier basin (if known) to predict the unconventional TRR volume in the frontier basin. Detailed methods for using BASIN and PRISE to estimate the resource volumes in frontier basins are described by Cheng et al. (2011c).

4.3.2 Application of Basin Analog Approach in Estimating Unconventional Gas Resources

The methods we used for estimating the TRR in frontier basins are in accordance with the available data and methodologies from our work on the updated BASIN and PRISE (Martin et al., 2010; Cheng et al., 2010b; Cheng et al., 2011a) in 25 North American basins, where significant unconventional gas resource development has been undertaken. Then, with the geologic and engineering data for petroleum system characterization, and the comprehensive resource investigation and evaluation in the mature North American basins, we applied two methods to the TRR estimates in frontier basins. The TRR estimates in the target Basin were conducted in three-tiers:

- Tier 1 - Total TRR
- Tier 2 - Conventional and Unconventional TRR
- Tier 3 - Five Resource Types of TRR (CO, CG, CBM, SG, and TSG)

The BASIN software was initially developed to identify analog basins for a target basin, and the BASIN database contained 72 geologic and engineering parameters for some petroleum systems in the 25 North American reference basins (Singh et al., 2008). Currently, its method and database have been updated, and the estimation methods in this paper employ the results from the updated BASIN. To quantitatively determine the analog basins for the target basin, the user enters the available parameters for the target basin, which are then compared to the corresponding parameters for the 25 North American reference basins. BASIN algorithms are used to evaluate and rank the 25 reference basins in the order of their similarity to the target basin, respectively. The analog results are further combined with PRISE to estimate resources.

Based on the published reports from several government and private industry agencies, such as the NPC, PGC, GTI, EIA, and the USGS, PRISE includes evaluations of both conventional resources (conventional oil and conventional gas) and unconventional resources (shale gas, coalbed methane, and tight sand gas) in the 25 North American basins, and is designed to assess the volume of gas in frontier basins. Once the analogous basins are determined by BASIN, PRISE uses the resource distribution of the analogous North American basins to infer the resource distribution of the frontier basin.

Fig. 4.5 shows the functions and relationships of BASIN and PRISE in estimating TRR for the target basin (or frontier basin): once the geologic and engineering data for the target basin is input into the BASIN software, BASIN generates the list of reference basins ranked by their analog to the target basin. Then, PRISE provides TRR distribution information of the top analog basins in the list. This list of TRR distributions of the analog basins, combined with other input information (which will be discussed later for the specific estimation method), provides the necessary data used by the TRR estimation methods to output different types of TRR for the target basin in the result.

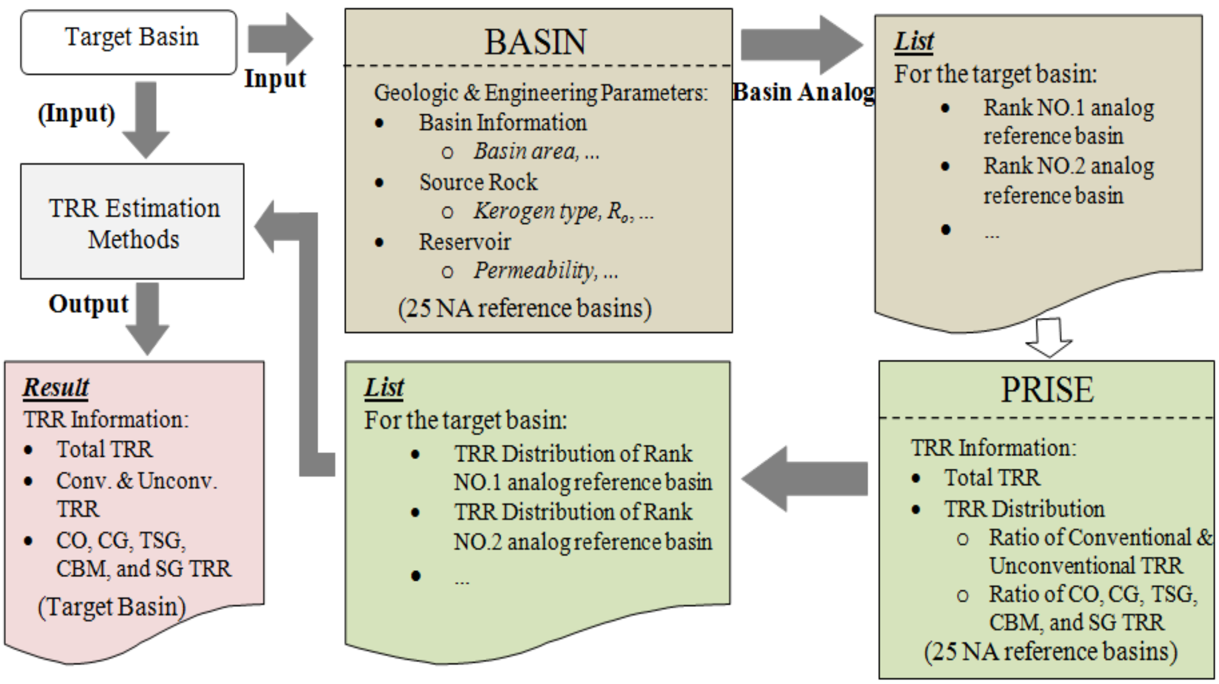


Fig. 4.5—Workflow of BASIN and PRISE in estimating TRR for the target basin (Cheng et al., 2011c).

4.3.3 SR Method for Estimating TRR in Target Basins

Outlined by Old in her thesis (2008), the SR method is used to estimate the TRR in target basins, including both conventional and unconventional TRRs. As an indirect approach of estimating TRR from source rock data, we analyze the method in the following two parts.

4.3.3.1 Part I - Evaluation on Generative Capacity of the Source Rocks in The Basin

The main reasons for taking the source rock generative capacity as the starting point of TRR estimation are two facts: first, source rock potential is the fundamental mechanism for generating hydrocarbons. In other words, without source rock potential there is no ground for estimating in-place or recoverable hydrocarbon resources. Second, many source rocks are self-sourced unconventional reservoirs that contribute greatly to the TRR. Although conventionally trapped hydrocarbon resources are not directly used in the SR methods, they may account for less than 15% of the TRR volume (Martin et al., 2010; Cheng et al., 2010b). Another reason that we adopt the SR method rather than the volumetric-based and performance-based methods is the disadvantages or limitations of the more traditional methods: for example, as analyzed in the previous section, those methods depend on reservoir properties, impact of technology on the recovery factor, or production data; instead, the SR method can be applied even if the basin is underexplored or the conventional resources are poorly known.

To quantify the generative capacity of the source rocks in the basin, Schmoker (1994) developed a method for calculating the mass of generated hydrocarbons using only five parameters: source rock volume, total organic content (TOC) in weight percent, formation density, original hydrogen index, and present hydrogen index. As shown in Fig. 4.6, the procedure was performed for each source rock, and, therefore, we consider the variations in rock characteristics in this method.

In BASIN, the available source rock data that can be relevant to the above five parameters are (1) rock type, (2) kerogen type, (3) minimum and maximum source rock thickness, (4) minimum and maximum vitrinite reflectance, and (5) minimum and maximum total organic content. While the kerogen type is an indicator of present day hydrogen index (HI), we lack data concerning the original HI. Although Waples (2000) proposed that the value of the source rock's HI at initial or original conditions can be calculated from the current HI, the saturation threshold and the transformation ratio used in the calculation are still unavailable. Because it is difficult to directly calculate the generated hydrocarbon mass using Schmoker's method and the ultimate goal is to quantify recoverable resource volumes, the SR method is designed for an indirect evaluation of quantified source rock potential to be able to determine a relationship between source rock potential and TRR for the North American basins.

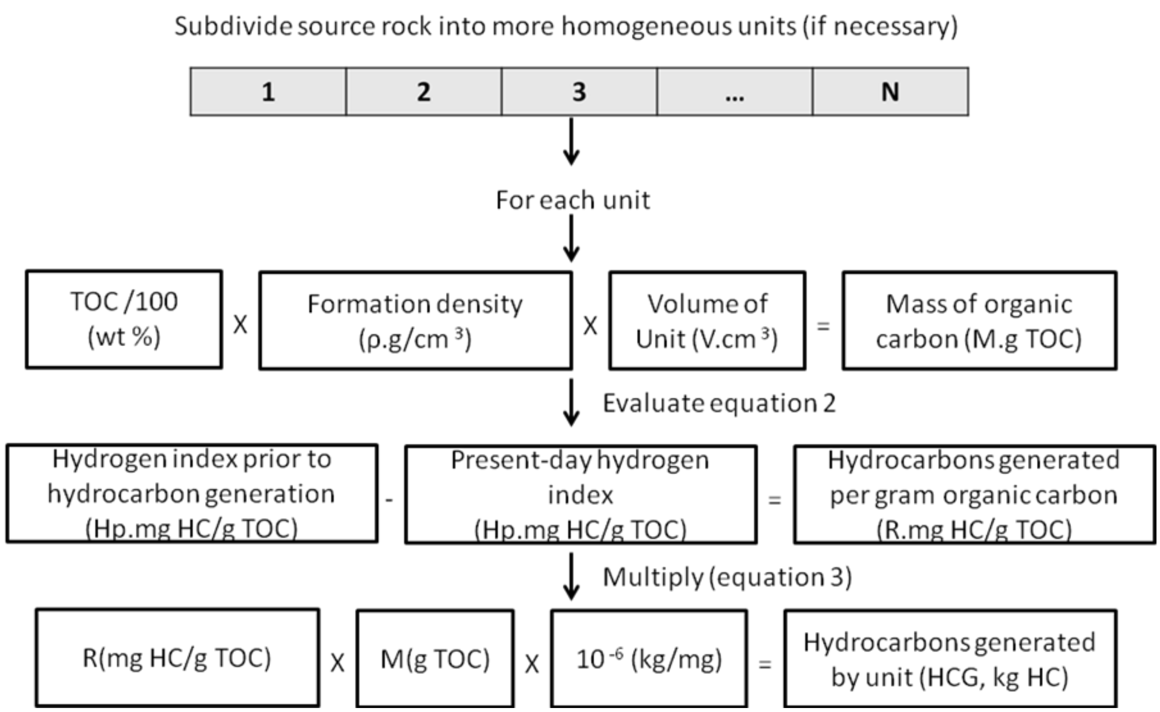
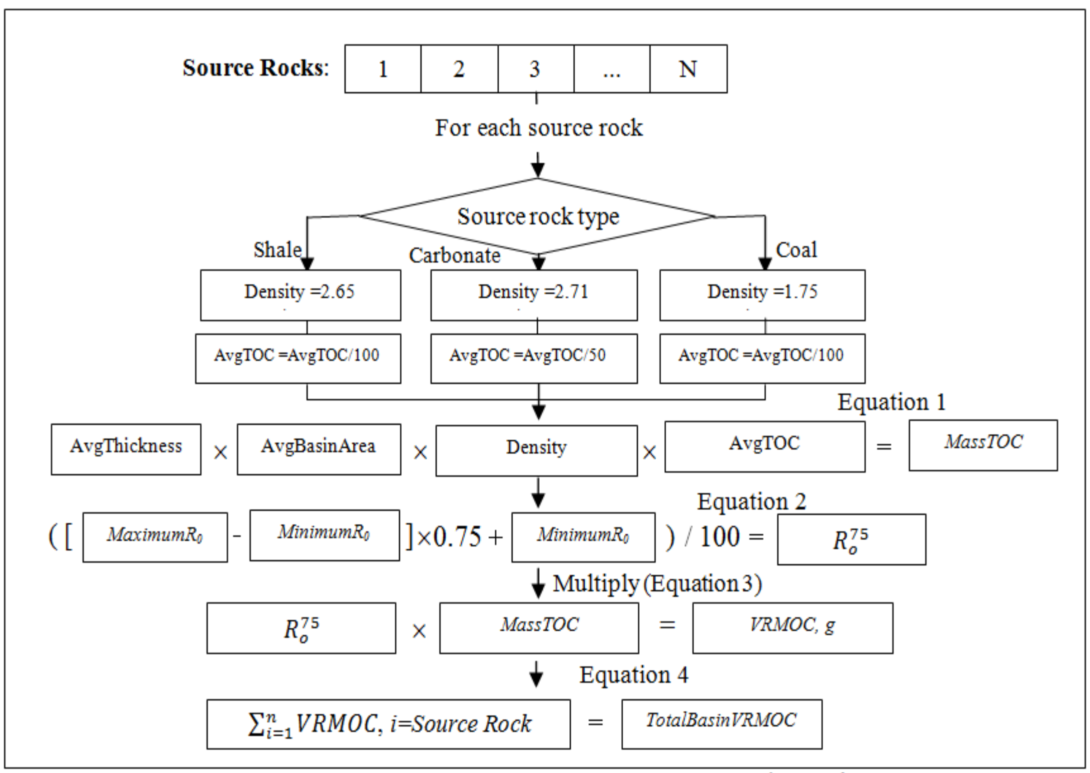


Fig. 4.6—Flow diagram of method for approximate calculation of mass of hydrocarbons generated (Cheng et al., 2011c).

The quantified source rock potential evaluation in the SR method is performed through the steps in Fig. 4.7. Eq. 1 calculates mass TOC, in grams, for each source rock. Notice that carbonate source rocks require approximately half the weight percent TOC of shale and coal to have equivalent generative capacity. Eq. 2 chooses the 75th percentile value of the range of Ro values as the thermal maturity indicator, because it would better represent the overall thermal maturation of the source as a function of depth and burial, whereas an average value might be too low. In Eq. 3, vitrinite reflectance measured organic content (VRMOC) is defined as the mass TOC multiplied by the 75th percentile of the Ro range for an indirect evaluation. Finally, VRMOC for each source rock is summed to generate a total VRMOC for the target basin.



Note: *the units for the parameters Density, AvgThickness, AvgBasinArea, and AvgTOC are g/cm³, cm, cm², and %, respectively.*

Fig. 4.7—Flow diagram of SR method for quantified source rock potential evaluation (Old, 2008; modified by Cheng et al., 2011c).

4.3.3.2 Part II - Characterization of the Relationship between the Quantified Source Rock Potential and TRR in the Basin

To indicate that the TRR volume can be determined from the quantified source rock potential, we employed the regression model to characterize the numeric relationship between the VRMOC and the estimated recoverable resources. Fig. 4.8 shows the results for the tests where VRMOC was used as the controlling parameter for TRR in the total 24 North American basins, which suggested a power function trend with regression value of 0.93. The high regression value is an indicator that the indirect source rock evaluation is a good way to determine TRR values.

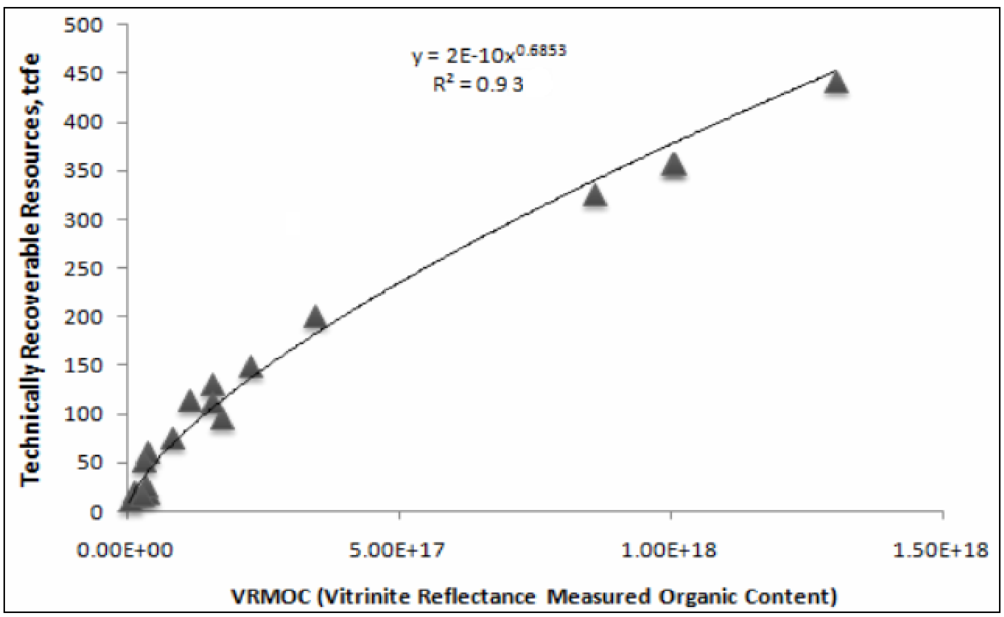


Fig. 4.8—Relationship between VRMOC and TRR volumes (Cheng et al., 2011c).

Based on the above indirect evaluation of quantified source rock potential and regression analysis for the relationship between VRMOC and TRR, we used the SR method for estimating the TRR in the target basin as follows:

Step 1: Input geologic and engineering data into BASIN.

Step 2: Run BASIN, which identifies the top three analog reference basins.

Step 3: Run PRISE, where the three-tiered estimates of TRR in the target basin are calculated; the Tier 1 calculation for the total TRR is based on VRMOC evaluation (Fig. 3) and the regression relationship between the TRR and VRMOC (Fig. 4), and Tiers 2 and 3 for the specific TRR estimates are determined from the resource distribution of the top-ranked analog reference basin (Old, 2008).

Tier 1: Total TRR in the target basin

$$\text{TargetBasin\_TRR}=(2\times10^{-10})\text{TargetBasin\_TRR}\times\text{AnalogReferBasin}^{0.6853}$$

Tier 2: Conventional and Unconventional TRR in the target basin

$$\text{TargetBasin\_Conv\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_Conv\_TRR\%}$$

$$\text{TargetBasin\_Unconv\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_Unconv\_TRR\%}$$

Tier 3: TRR of CO, CG, CBM, TSG, and SG in the target basin

$$\text{TargetBasin\_CO\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_CO\_TRR\%}$$

$$\text{TargetBasin\_CG\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_CG\_TRR\%}$$

$$\text{TargetBasin\_CBM\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_CBM\_TRR\%}$$

$$\text{TargetBasin\_TSG\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_TSG\_TRR\%}$$

$$\text{TargetBasin\_SG\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_SG\_TRR\%}$$

4.3.4 CTRRI Method for Estimating TRR in Target Basins

Different from the SR method, the CTRRI method requires additional estimation of conventional TRRs in the target basin. Traditionally, the CTRRI only uses the resource distribution in the analog reference basins to directly calculate the unknown TRR in the target basin, whereas the SR method also employs the relation between VRMOC and TRR that is an indirect source rock evaluation to determine TRR.

Steps of estimating the TRR in target basins by the CTRRI method are:

Step 1: Input geologic and engineering data into BASIN.

Step 2: Run BASIN, which identifies the top three analog reference basins.

Step 3: Input Conventional TRR data of the target basin (Target Basin_Conv_TRR) into PRISE.

Step 4: Run PRISE, where the three-tiered estimates of TRR in the target basin are calculated from the resource distribution of the top-ranked analog reference basin.

Tier 1: total TRR in the target basin

$$\text{TargetBasin\_TRR}=\text{TargetBasin\_Conv\_TRR}/\text{AnalogReferBasin\_Conv\_TRR\%}$$

Tier 2: Conventional and Unconventional TRR in the target basin

$$\text{TargetBasin\_Unconv\_TRR}=\text{TargetBasin\_TRR}\times\text{AnalogReferBasin\_Unconv\_TRR\%}$$

Tier 3: TRR of CO, CG, CBM, TSG, and SG in the target basin

Both of the methods require BASIN to identify the analog reference basin and further use PRISE to determine the resource distribution.

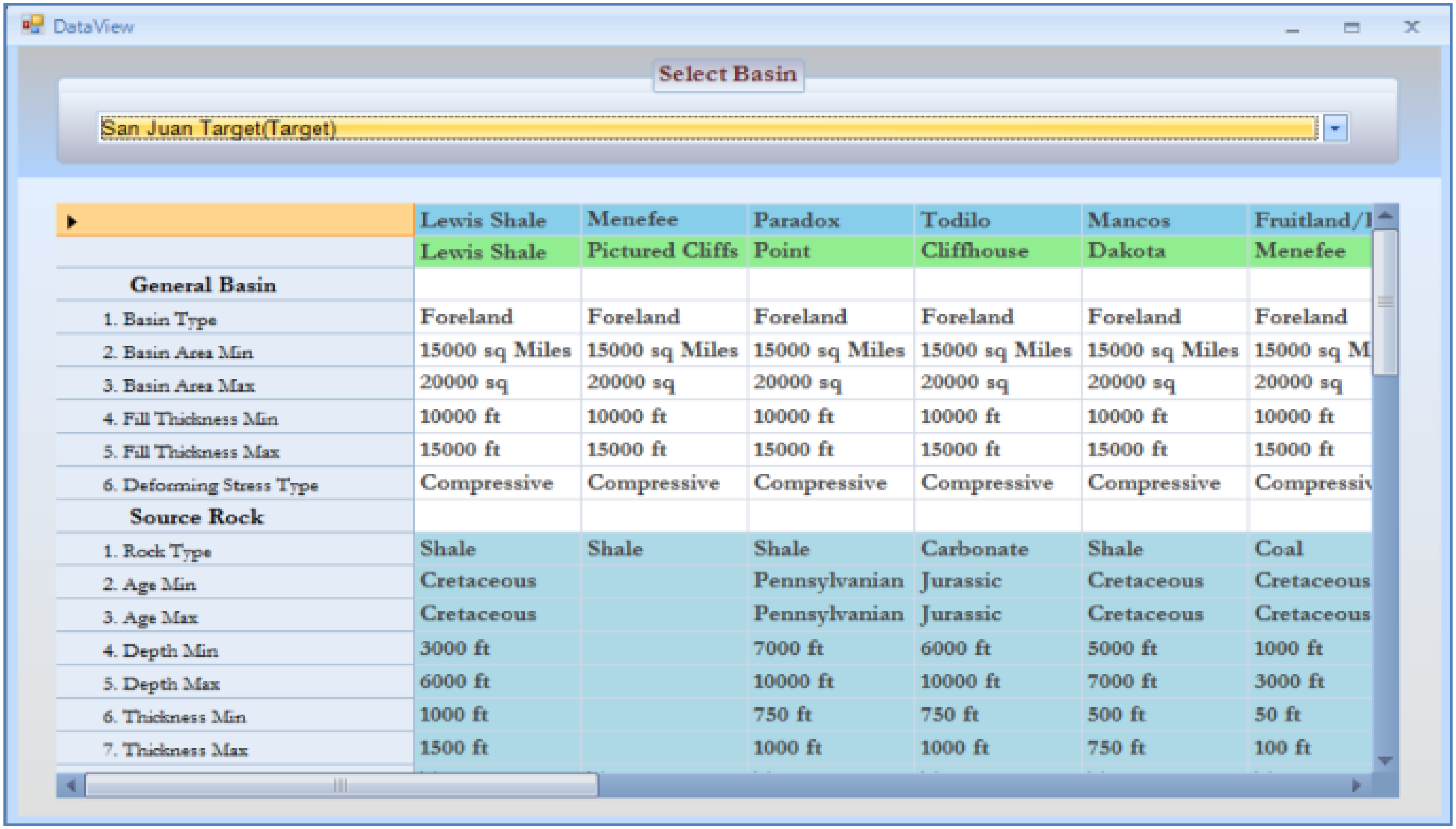
4.3.5 Tests of Estimating TRR in Target Basins

To specifically explain the SR method and CTRRI method of TRR estimation in target basins, we evaluated the San Juan basin as an example the “target” basin in a series of tests. We also performed the tests on other North American basins, and the results demonstrate the effectiveness of the TRR estimation methods.

4.3.5.1 Example of Estimating TRR in San Juan Target Basin

In our running example, the target basin is the San Juan basin. We developed a San Juan "target" basin by modifying a small portion of the reservoir data in the San Juan target data set from the San Juan reference basin data set, but source rock data were kept the same so that the VRMOC calculation remained valid to test the SR method. We input the San Juan target basin data into BASIN (Fig. 4.9) and ran the program, which identified the top 3 analog reference basins as the San Juan, Piceance, and Anadarko basins (Fig. 4.10). Next, we entered the actual conventional TRR volume of 14.1 Tcfe for the San Juan basin into the PRISE analysis that was used for the CTRRI method (Fig. 4.11).

Fig. 4.11 shows the TRR volumes in the San Juan target basin estimated by PRISE: SR-Estimate 1 and CTRRI-Estimate 1 are based on the distribution of the quantified PRISE San Juan reference basin and use the SR and CTRRI methods, respectively; SR-Estimate 2 and CTRRI-Estimate 2 are based on the resource distribution of the quantified PRISE Piceance reference basin and use the SR and CTRRI methods, respectively. The comparison of SR-Estimate 1 with CTRRI-Estimate 1 and the comparison of SR-Estimate 2 with CTRRI-Estimate 2 shows that the estimated TRR volumes (whether they are total, conventional, unconventional, TGS, CBM, SG, CG, or CO TRR volumes) by the two methods complement each other.



	Lewis Shale	Menefee	Paradox	Todilo	Mancos	Fruitland/I
	Lewis Shale	Pictured Cliffs	Point	Cliffhouse	Dakota	Menefee
General Basin						
1. Basin Type	Foreland	Foreland	Foreland	Foreland	Foreland	Foreland
2. Basin Area Min	15000 sq Miles	15000 sq Miles	15000 sq Miles	15000 sq Miles	15000 sq Miles	15000 sq M
3. Basin Area Max	20000 sq	20000 sq	20000 sq	20000 sq	20000 sq	20000 sq
4. Fill Thickness Min	10000 ft	10000 ft	10000 ft	10000 ft	10000 ft	10000 ft
5. Fill Thickness Max	15000 ft	15000 ft	15000 ft	15000 ft	15000 ft	15000 ft
6. Deforming Stress Type	Compressive	Compressive	Compressive	Compressive	Compressive	Compressiv
Source Rock						
1. Rock Type	Shale	Shale	Shale	Carbonate	Shale	Coal
2. Age Min	Cretaceous		Pennsylvanian	Jurassic	Cretaceous	Cretaceous
3. Age Max	Cretaceous		Pennsylvanian	Jurassic	Cretaceous	Cretaceous
4. Depth Min	3000 ft		7000 ft	6000 ft	5000 ft	1000 ft
5. Depth Max	6000 ft		10000 ft	10000 ft	7000 ft	3000 ft
6. Thickness Min	1000 ft		750 ft	750 ft	500 ft	50 ft
7. Thickness Max	1500 ft		1000 ft	1000 ft	750 ft	100 ft

Fig. 4.9—Target basin input of BASIN (Cheng et al., 2011c).

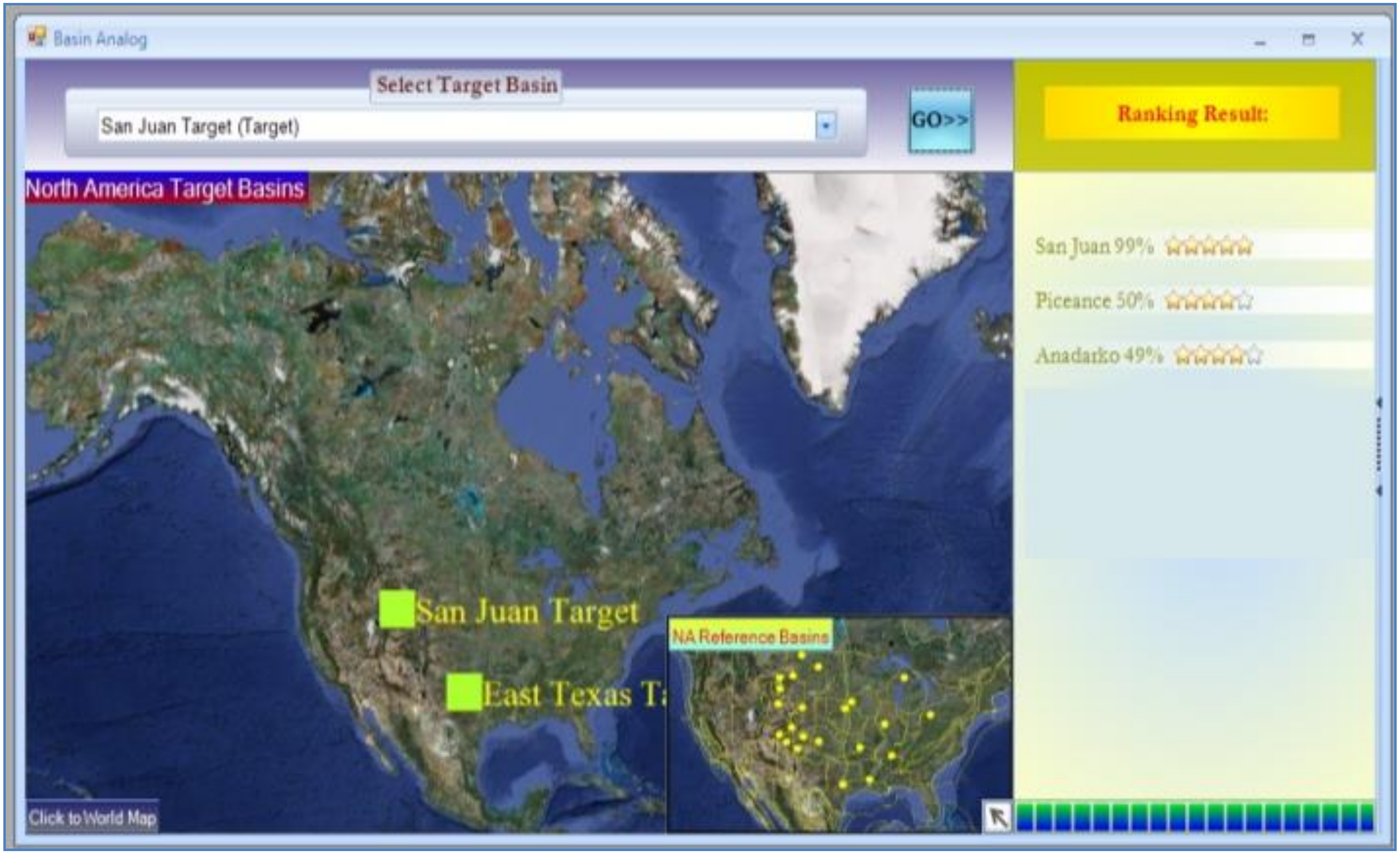


Fig. 4.10—Running results of BASIN (Cheng et al., 2011c).

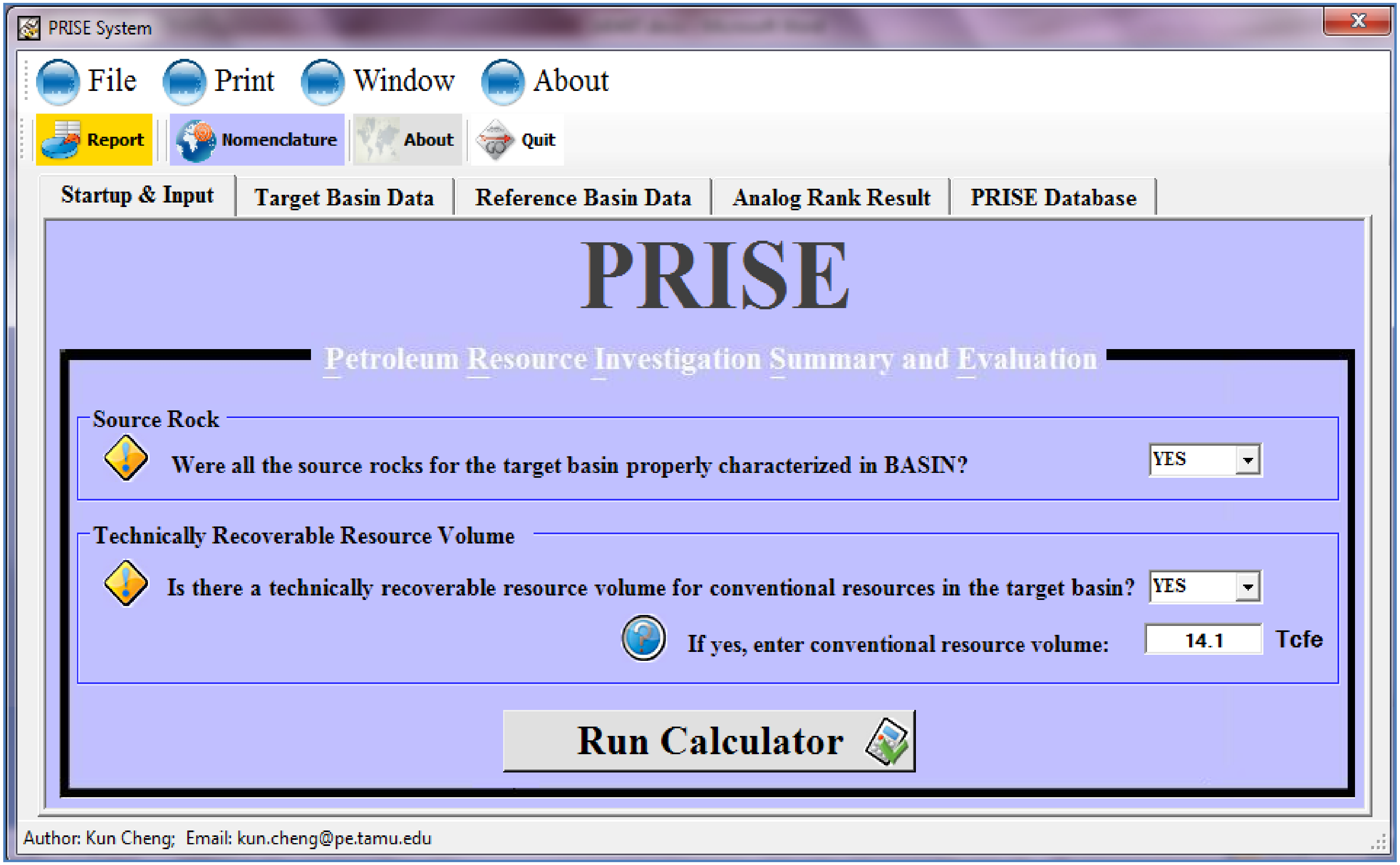


Fig. 4.11—Input interface of PRISE (Cheng et al., 2011c).

Report Page1 | Report Page2 | Report Page3 | Report Page4 | Report Page5 | Report Page6 | Report Page7 | Report Page8 | Results

San Juan Target

Technically Recoverable Resources

	SR-Estimate 1, Tcfe	SR-Estimate 2, Tcfe	CTRRI-Estimate 4, Tcfe	CTRRI-Estimate 5, Tcfe
Total	153.6	153.6	151.3	133.1
Conv.	14.32	16.26	14.1	14.1
Unconv.	139.25	137.24	137.15	118.99
TGS	55.3	61.9	54.5	53.6
CBM	63.5	52.5	62.5	45.5
SG	20.4	22.8	20.1	19.8
CG	12.4	11.8	12.3	10.2
CO	0.31	0.74	0.31	0.64

Fig. 4.12—PRISE estimates of TRR volumes in target basin (Cheng et al., 2011c).

To further validate the SR and CTRRI methods, we compared the estimated results with the PRISE-quantified San Juan basin resources volume in Fig. 4.12. The estimated volumes (the SR-Estimate 1, SR-Estimate 2, CTRRI-Estimate 1, or CTRRI-Estimate 2) are close to the PRISE-quantified San Juan basin resources volume for the corresponding TRR (the total, conv., unconv., TGS, CBM, SG, CG, or CO TRR).

4.3.5.2 Tests on East Texas Basin and Michigan Basin

For more validation, we used the exact East Texas basin and Michigan basin as target basins to test the SR and CTRRI methods. We also compared estimated results with the PRISE-quantified resources volume for the corresponding target basins (Fig. 4.13 and Fig. 4.14). In both of the tests, the SR-Estimate 1 and CTRRI-Estimate 1 approximately match each other, and are in accordance with the PRISE-quantified resources volume; the differences among the SR-Estimate 2, CTRRI-Estimate 2, and the PRISE quantified resources volume reflect the differences in the resource distribution of the less analogous reference basin.

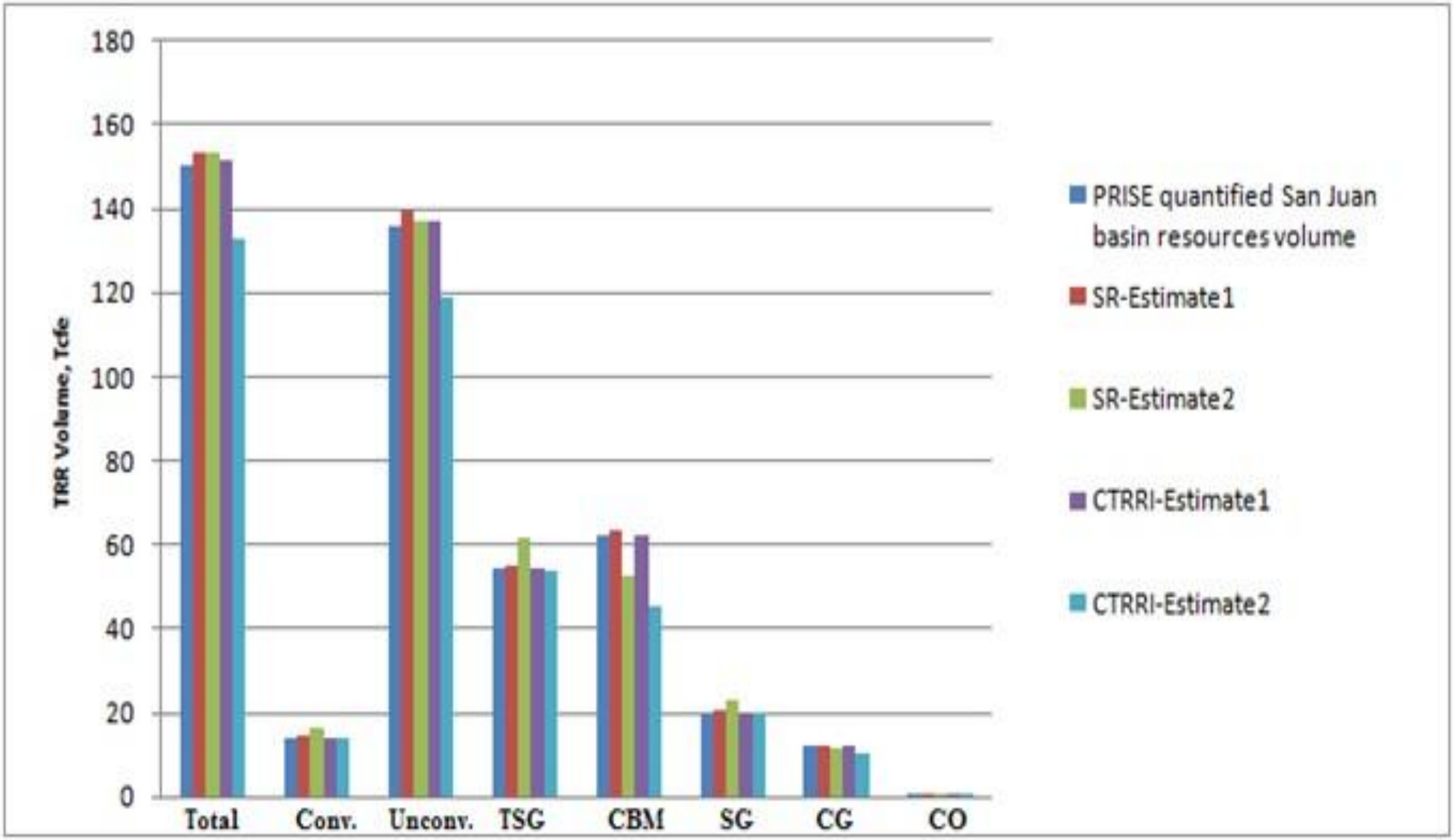


Fig. 4.13—Comparison of PRISE estimated results and PRISE quantified resources volume for San Juan basin (Cheng et al., 2011c)

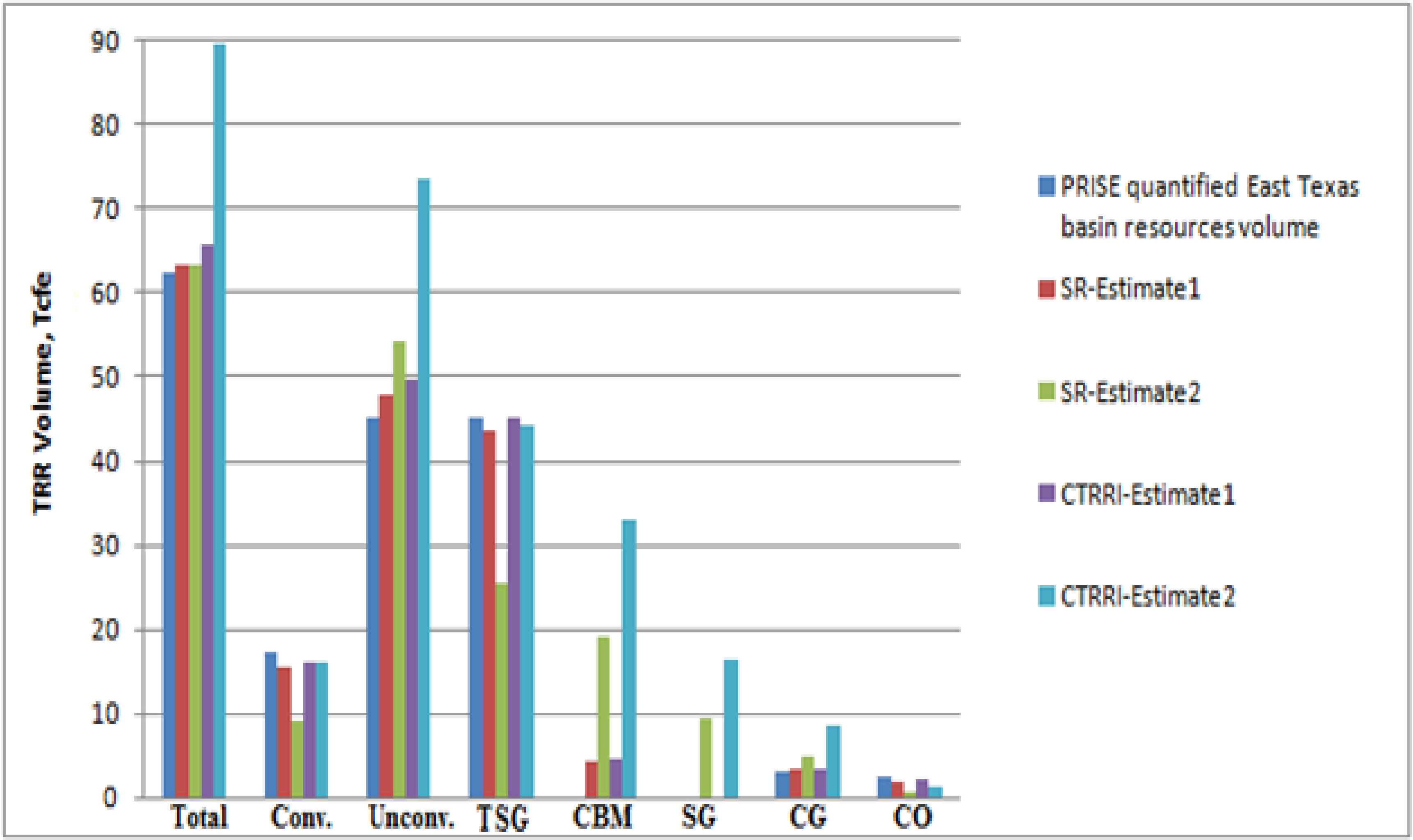


Fig. 4.14—Comparison of PRISE-estimated results and PRISE-quantified resources volumes for East Texas basin (Cheng et al., 2011c).

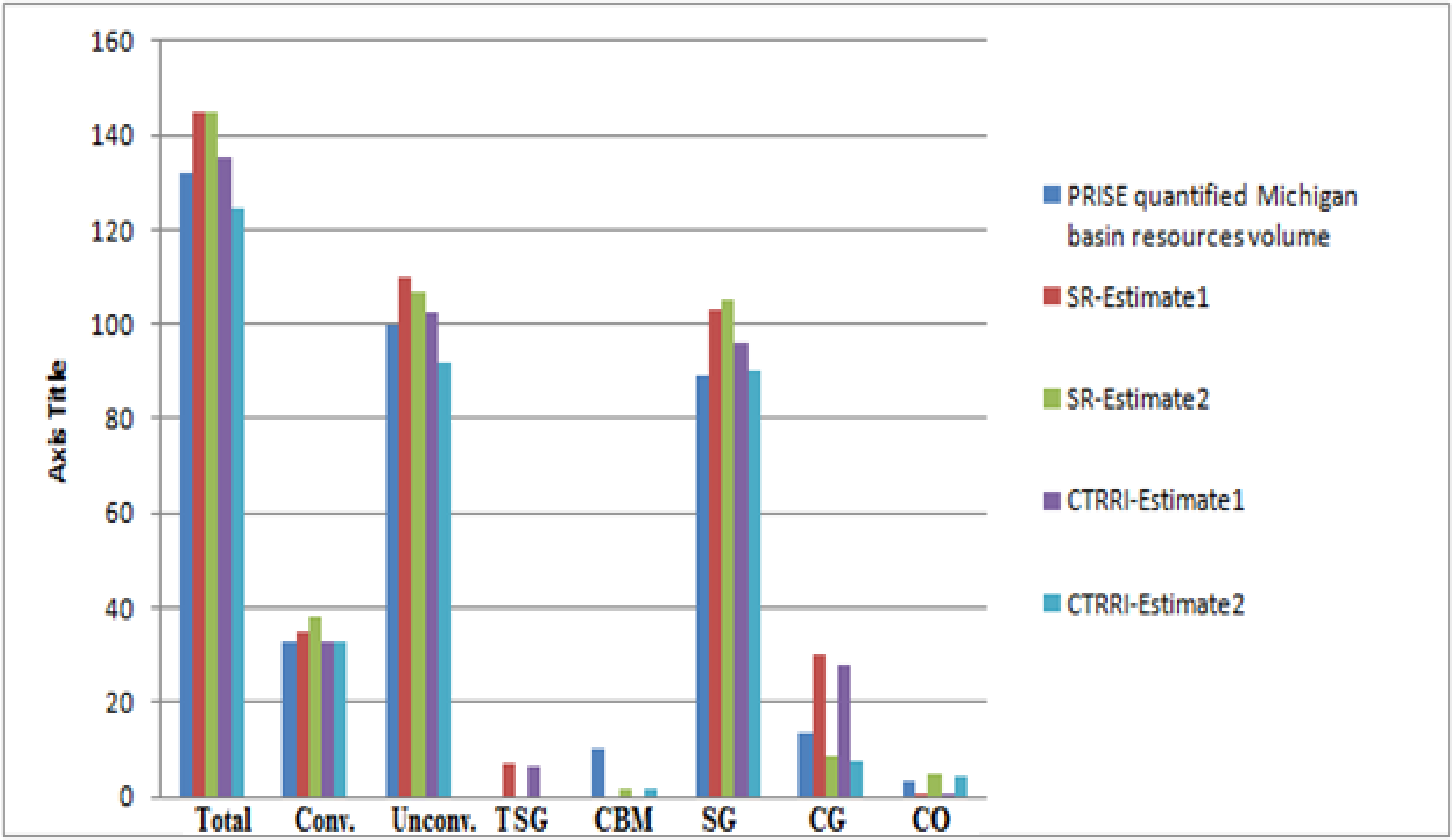


Fig. 4.15—Comparison of PRISE-estimated results and PRISE-quantified resources volumes for Michigan basin (Cheng et al., 2011c)

4.4 Case Study

As gas production from conventional gas reservoirs in the United States decreases, the industry is turning more attention to the exploration and development of UGRs.[*] This trend is expanding quickly worldwide. However, unlike in many mature North American basins where significant development of UGRs is now routine, many countries are just turning to UGR exploration. Therefore, insightful resource assessment is important for tapping UGR in the frontier basins.

To evaluate the UGRs in frontier basins that are underexplored, basin analysis was used to address the evaluation of 1) basin characterization; 2) basin analogy between frontier basins and mature North American basins; 3) conventional and unconventional resources in mature North American basins; and 4) methods to quantitatively predict UGRs in frontier basins by using information from analogous North American basins. This comprehensive basin analysis study not only validates the resource triangle, which is characterized by a large ratio of unconventional TRR (technically recoverable resources) to conventional TRR, but also makes it possible to quantitatively assess unconventional resources in under-explored basins, worldwide.

To demonstrate use of basin analysis in evaluating the UGRs of frontier basins, two world hotspots for UGR exploration were selected as the target basins: Neuquén basin in South America and Berkine basin in North Africa. Recent assessment reports and exploration activities indicate that the two basins have substantial unconventional gas resources. As a case study, basin analysis was used to identify North American reference basins that are analogous to the Neuquén and Berkine basins, and to characterize their distributions of UGRs. Furthermore, the quantitatively estimated unconventional

TRR were compared with those from EIA (Energy Information Administration) and companies to support the effectiveness of basin analysis results.

4.4.1 Premise of Basin Analysis

As an analog method, basin analysis is based on the premise that analogous basins have similar resource distributions. Although previous research indicated that the undiscovered petroleum potential of a target basin could be predicated by finding a geological analog that has been sufficiently explored and fully realized for its resource potential (Morton, 1998; Abangan, 2003; USGS Bighorn Basin Province Assessment Team, 2010; CNPC, 2011), solid support for such a concept was missing. Therefore, we tested the premise of basin analysis by comparing the analog results from BASIN software with the analog results from PRISE software (Cheng et al., 2010; Cheng et al., 2011a). BASIN software identified the analogous NA reference basins for the target basin based on the geologic and petroleum systems characteristics, and the PRISE software was used to assess resources (CG, CO, SG, CBM, and TGS) for each of the 24 NA reference basins. In each comparison, one of the 24 NA basins was selected as the target basin and compared to every other basin in each of the two programs (PRISE and BASIN).

For each of the 24 North American basins as the target basin, we calculated and plotted the similarity for each pair of the target and reference basin in both BASIN and PRISE, producing a data point on the BASIN similarity/PRISE similarity plane, and evaluated the trend for the 24 data points by checking the R^2 value (Fig. 4.16). The R^2 for the 24 basins is 0.52, which indicates that, while basin similarity and resource distribution similarity are correlated, there will be uncertainty in using BASIN/PRISE for estimating resources in new basins. The uncertainty results from the data used in both BASIN and PRISE, which are based on published literature (which may not be complete, consistent or current), and/or from the methods used in BASIN and PRISE, which are deterministic and approximate.

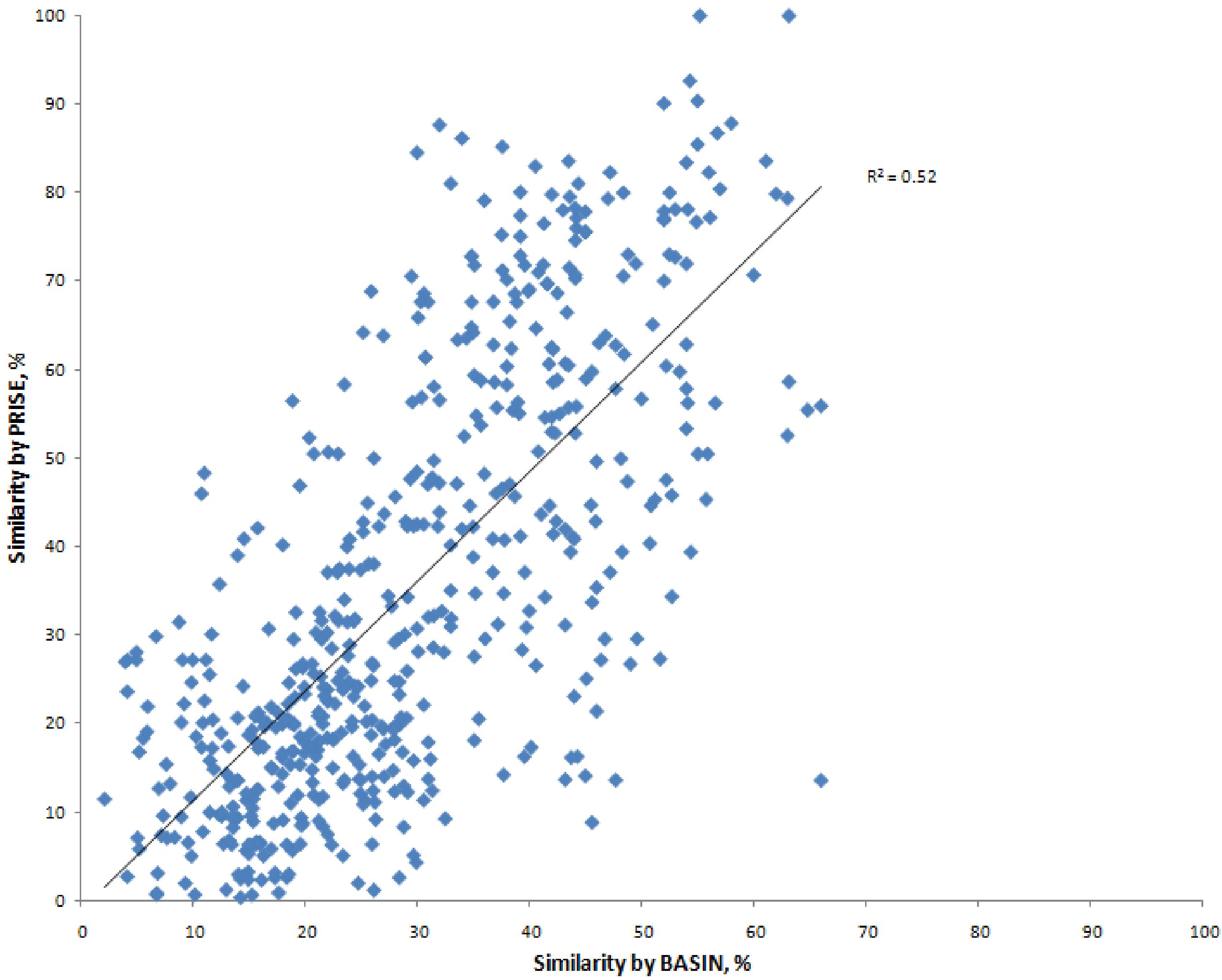


Fig. 4.16—Similarity crossplot of BASIN and PRISE (Cheng et al., 2011d).

4.4.2 Case Study of Using Basin Analysis to Evaluate UGRs in Frontier Basins

To test the use of basin analysis in evaluating the UGRs of frontier basins, two basins, located in Argentina and Algeria, were selected as the target basins: the Neuquén and Berkine basin, respectively. Then, as introduced in the previous section we followed the workflow of using BASIN and PRISE to estimate UGRs. Recent assessment reports and exploration activities indicated that the two basins have potentially vast unconventional gas resources. In the case studies, the basin analysis applications were used to identify the analogous North American reference basins for the Neuquén and Berkine basins and to characterize the distribution of UGRs in the target basins. Then, the quantitatively estimated unconventional TRR were compared with those from EIA and other organizations to support the effectiveness of the basin analysis results.

4.4.2.1 Case Study I—Neuquén Basin

Among the petroleum basins of Argentina, the Neuquén Basin is the leading producer of hydrocarbons. The basin holds 35% of the country's oil reserves and 47% of its gas reserves (Eurasia Review, 2011). The 137,000 km² basin, situated entirely onshore, is part of the Sub-Andean trend which extends the entire length of South America.

4.4.2.1.1 Geology and Petroleum System Characteristics

The Neuquén basin contains a near-continuous Late Triassic–Early Cenozoic succession deposited on the eastern side of the evolving Andean mountain chain. Its formation is characterized by three main stages of evolution: initial rift stage; subduction-related thermal sag; and foreland stage (Howell et al., 2005). The source rocks of the Neuquén basin mainly include mudstones of the Lower Jurassic Los Molles Formation, Upper Jurassic-Lower Cretaceous Vaca Muerta Formation, and Lower Cretaceous Agrio Formation (Fig. 4.17) (Spalletti and Vergani, 2007). The hydrocarbons migrated laterally and vertically along carrier beds and faults from the deep basin to the basin margin and platform areas (USGS, 2000).

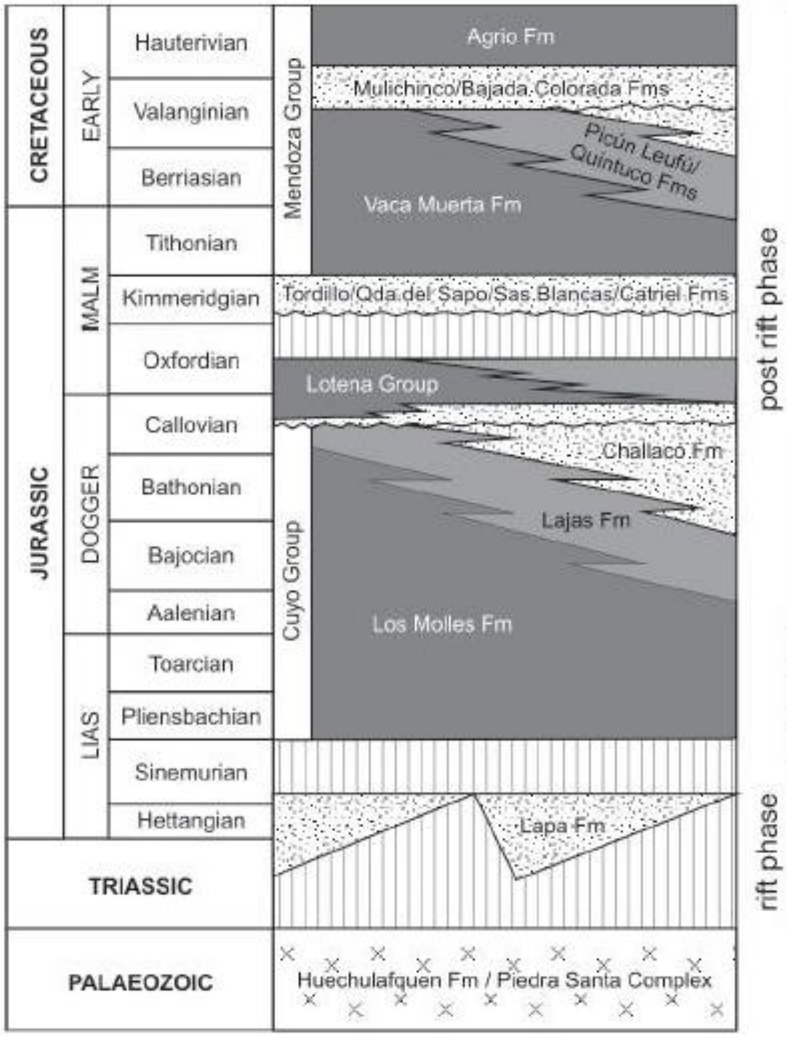


Fig. 4.17—Lithostratigraphy of Neuquén Basin (Spalletti and Vergani, 2007).

4.4.2.1.2 Analogous Basins

After entering the geologic and engineering petroleum systems data of the Neuquén basin in the BASIN database, we selected the Neuquén basin as the target basin and ran BASIN software. The analog results (Fig. 4.18) indicate that the Arkoma basin is the most analogous basin for the Neuquén Basin with a 62% match. The Big Horn basin is the second-most analogous basin for the Neuquén Basin with a 55% match.

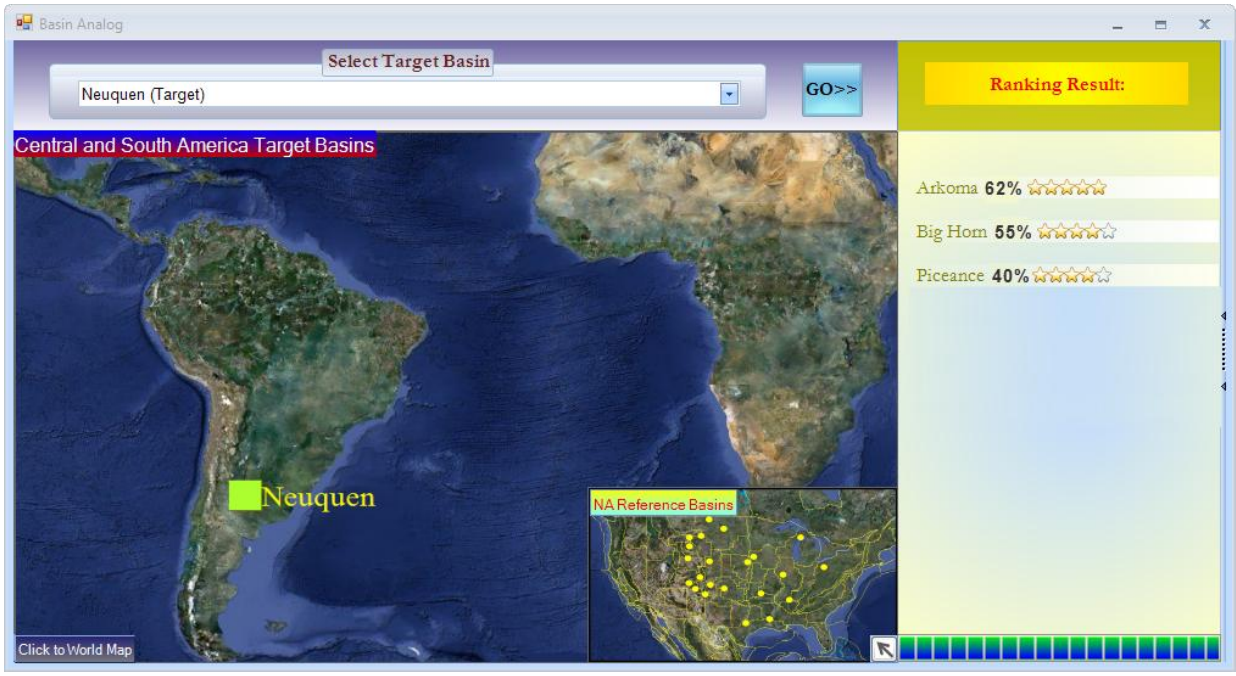


Fig. 4.18—BASIN Analog results for target Neuquén Basin (Cheng et al., 2011d).

4.4.2.1.3 TRR Distribution and Quantification

For the TRR quantification, we used Tankard's (1995) estimate that recoverable and probable conventional hydrocarbon reserves in Neuquén Basin are approximately 2.3 billion bbl of oil equivalent. Thus, we input 13.8 Tcfe (one barrel of oil equivalent is roughly equivalent to 6 Mscf of typical natural gas) for the conventional resources in PRISE software. Based on the TRR distribution in Arkoma basin (Fig. 4.19), the PRISE software calculated that the volume of unconventional TRR in the Neuquén basin is 331.2 Tcfe, including 321.2 Tcfe technically recoverable shale gas resources. Based on the TRR distribution in Big Horn basin (Fig. 4.20), the PRISE software indicated that the volume of unconventional TRR in the Neuquén basin is 62.8 Tcfe, including 59.2 Tcfe technically recoverable tight gas sand resources (Table 4.1). Both of the estimates based on the Arkoma basin and Big Horn basin are possible, because there are different types of unconventional resources in the Neuquén Basin.

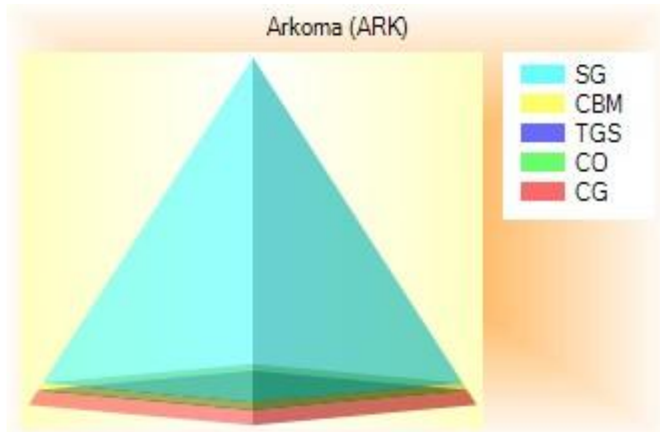


Fig. 4.19—TRR distribution of the Arkoma basin (Cheng et al., 2011d).

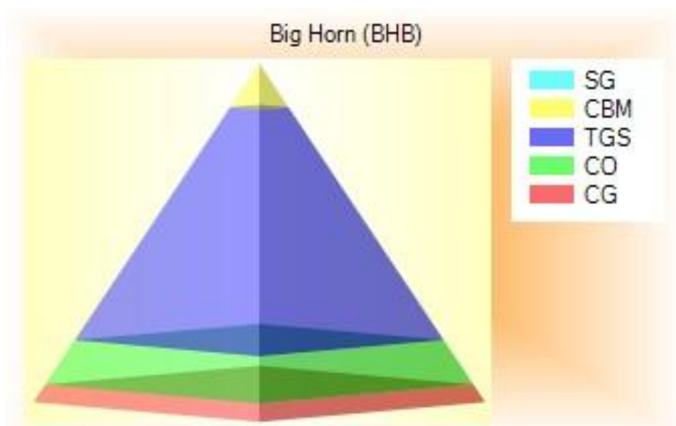


Fig. 4.20—TRR distribution of the Big Horn basin (Cheng et al., 2011d).

Table 4.1—Neuquén Basin TRR Estimation Based on TRR Distribution in Analogous Basins

Rank	Basin	TGS (tcfe)	SG (tcfe)	CBM (tcfe)	Total Unconventional Gas (tcfe)
1	Arkoma	0	321.2	10	331.2
2	Big Horn	59.2	0	3.6	62.8

Argentina's Neuquén Basin is fast becoming a world hotspot for shale exploration, and it is already well known as an area that is rich in tight-gas potential (Unconventional Oil & Gas Center, 2011). EIA (2011b) estimates that the volume of technically recoverable shale gas resources in Argentina is 774 Tcf. The Neuquén Basin contains more than half of the country's technically recoverable shale gas resources (Eurasia Review, 2011). Thus, technically recoverable shale gas resources in the Neuquén Basin estimated from the most analogous reference basin (Arkoma basin) as approximately 321.2 Tcf is quite close to the published estimates. For tight gas sand, exploration activities in the Neuquén basin have been widely reported (Coppoli et al., 2007; Moreyra and García, 2007; Naides, 2010).

Table 4.2—Major Petroleum Companies' Activities in Neuquén Basin on Shale Gas (Cheng et al., 2011d)

Date	Events	Sources
Aug-11	"Americas Petrogas Inc. (TSX: BOE) has initiated the drilling of the first deep shale gas well on the Huacalera block in the Neuquén Basin of Argentina."	Unconventional Oil & Gas Center, 2011
July-11	"Baker Hughes has completed its first unconventional hydrocarbon shale hydraulic fracturing and stimulation project in Argentina for YPF in the Neuquén basin."	Petroleum Economist, 2011
Jan-11	"Total announces that it has acquired interests in four exploration licenses in Argentina in partnership with YPF in order to appraise their shale gas potential. Located in the Neuquén Basin, the licenses were awarded by the provincial authorities for a six-year period."	TOTAL, 2011
Jan-11	"ExxonMobil plans to explore for shale gas in Argentina following the award of two blocks in the western Neuquén province. ExxonMobil spokesman Patrick McGinn told Dow Jones news service that the exploration agreements were signed in December 2010."	World Oil, 2011
Dec-10	"YPF announced the discovery of 4.5 Tcf of proven shale gas reserves in the Patagonia area of the Neuquén Basin."	World Oil, 2010

4.4.2.2 Case Study II — Berkine Basin

The Berkine (Ghadames) Basin with an area of 120,000 km^2 is a subcircular, intracratonic, extensional basin that is situated in eastern Algeria and extends into Tunisia and Libya. This basin is separated from the Hoggar crystalline basement to the south by the Illizi basin. The western edge of the basin is defined by the El Biod-Hassi Messaoud structural axis and is bounded to the north by the Daharridge (Yahi et al., 2001).

4.4.2.2.1 Geology and Petroleum System Characteristics

The Berkine basin contains a thick section of Paleozoic and Mesozoic-Cenozoic sediments. The first hydrocarbon source rock in the basin corresponds to the Lower Silurian bituminous and micaceous mudstones. Upper Devonian shales are considered as the secondary hydrocarbon source rocks in the basin (Schlumberger, 2007). There are several significant reservoirs in Berkine Basin; these include the Upper Triassic clay sandstone, the Triassic limestone–Intermediate Triassic, and the Lower Triassic clay sandstone (Fig. 4.21).

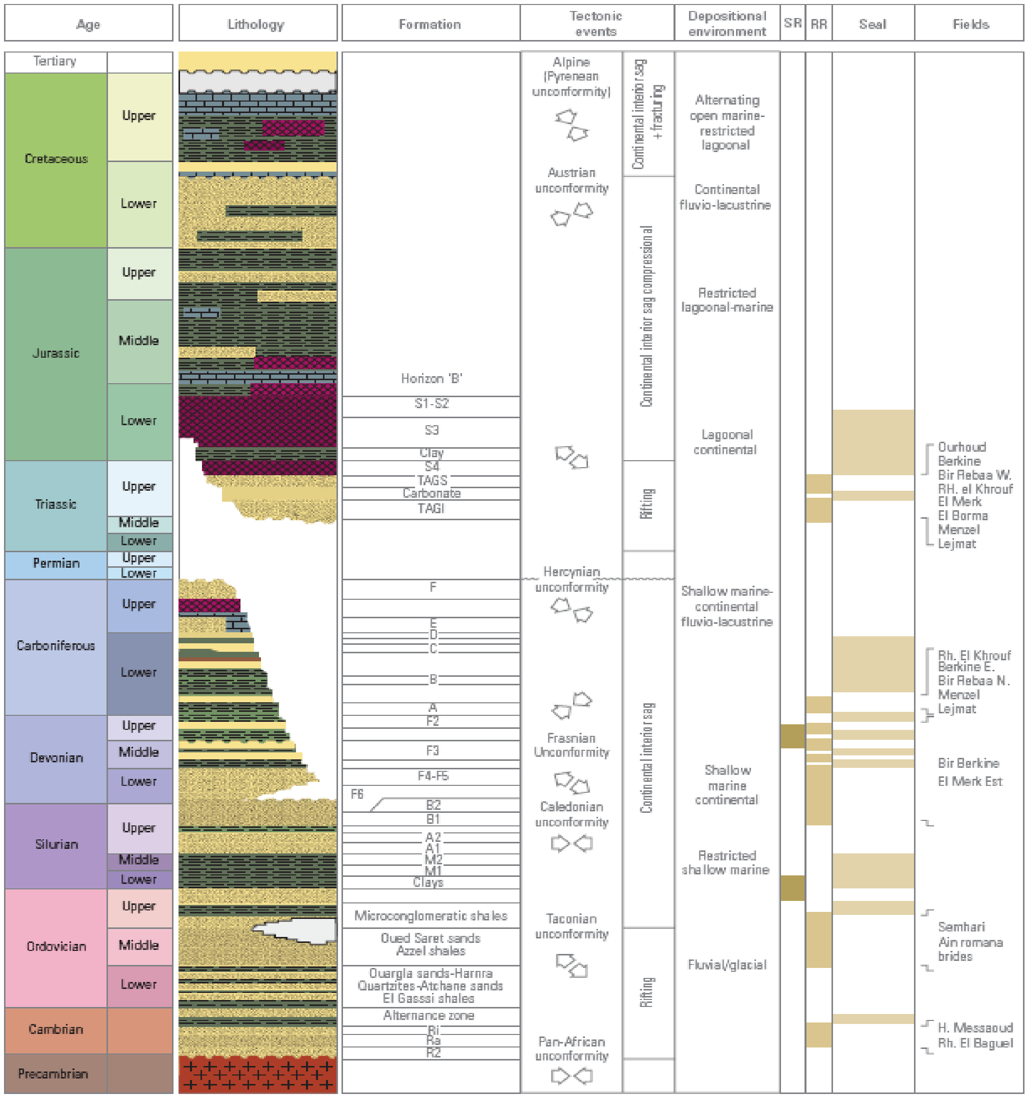


Fig. 4.21—Stratigraphic column of the Berkine basin (Schlumberger, 2007).

4.4.2.2.2 Analogous Basins

After inputting the geology and petroleum systems data of the Berkine basin into the BASIN database, we selected the basin as the target basin and ran BASIN software. The analog result (Fig. 4.22) indicates that the Michigan basin is the most analogous basin for the Berkine Basin with a 51% match, closely followed by the Williston basin as the second-most analogous basin with a 49% match.

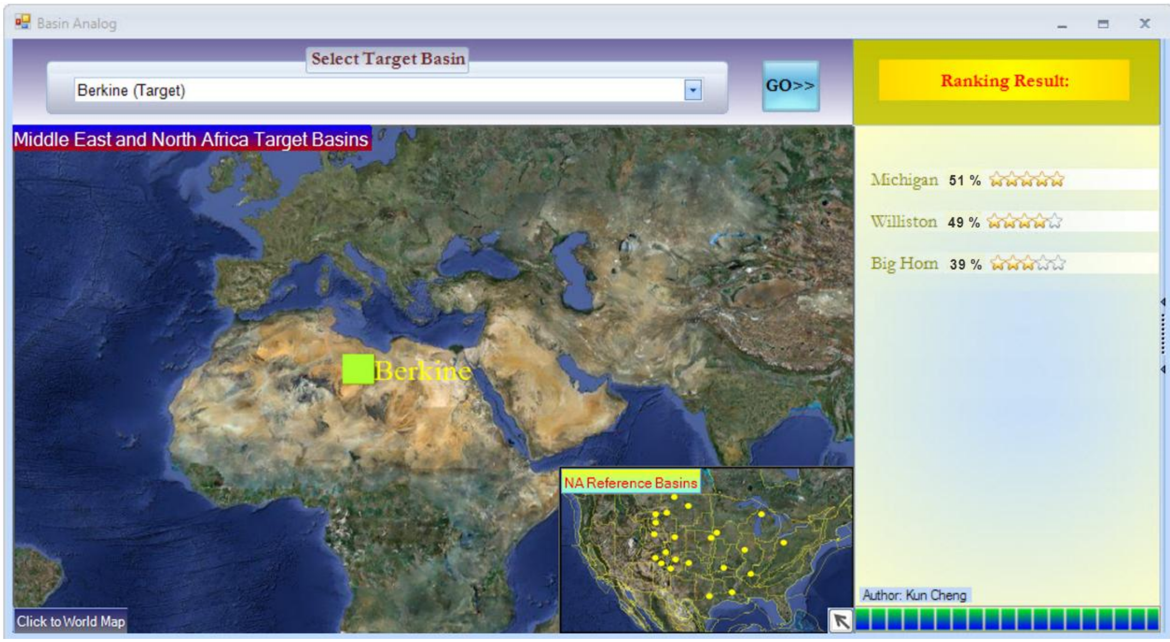


Fig. 4.22—The analog results after running BASIN for Berkine Basin (Cheng et al., 2011d).

4.4.2.2.3 TRR Distribution and Quantification

For the TRR quantification, the recoverable oil discovered to date is in excess of 3.5 billion bbl (Underdown et al., 2007) and the conventional recoverable gas is at least 2.2 Tcf (First Calgary Petroleums Ltd, 2005) in the Berkine basin. Thus, after converting barrels to Tcfe, we input 23.2 Tcfe for the conventional resources in PRISE software. Based on the TRR distribution in Michigan basin (Fig. 4.23), the PRISE software estimates that the volume of unconventional TRR in the Berkine basin is 73.5 Tcfe, including 66.2 Tcfe technically recoverable shale gas resources. Estimates of TRR distribution in Williston (Fig. 4.24) basin are very similar to those of the Michigan basin. Based on the Williston basin, the volume of unconventional TRR in the Berkine basin is 66.0 Tcfe, including 65.1 Tcfe technically recoverable shale gas resources (Table 4.3).

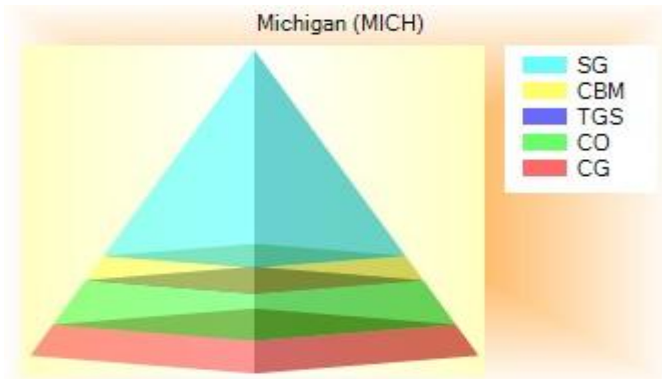


Fig. 4.23—TRR distribution of the Michigan basin (Cheng et al., 2011d).

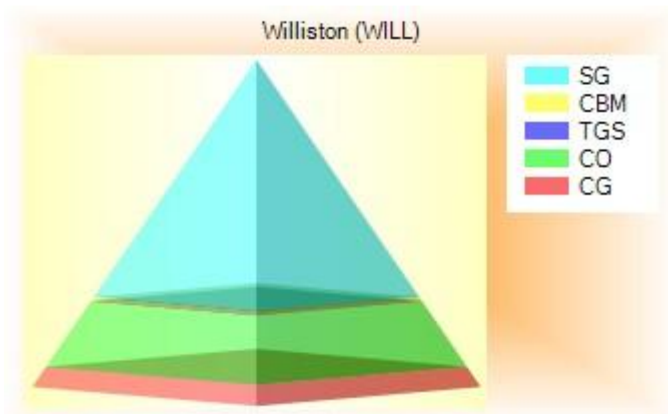


Fig. 4.24—TRR distribution of the Williston basin (Cheng et al., 2011d).

Table 4.3—Berkine Basin TRR Estimation Based on TRR Distribution in Analogous Basins

Rank	Basin	TGS (tcfe)	SG (tcfe)	CBM (tcfe)	Total Unconventional Gas (tcfe)
1	Michigan	0	66.2	7.3	73.5
2	Williston	0	65.1	0.9	66

EIA (2011b) estimates about 231 Tcf shale gas are technically recoverable in Algeria, with the Berkine and Illiz basins having the most prospective shale gas potential (Hill and Whiteley, 2010). It should be pointed that our basin analysis investigation does not include Bakken shale oil resources in the Williston basin evaluation. Development of unconventional gas resources in Berkine basin is at the early stage, and we have yet to find any news about developing unconventional gas reservoirs in this basin.

5 CONCLUSION

5.1 Conclusion

On the basis of the work accomplished during the research, I have drawn the following conclusions.

1. The data from the 25 North American basins that are included in the UGR Advisory system provide the information required to identify and rank analogous basins.
2. The BASIN software provides a consistent method for comparing one basin with another using data describing basin characteristics, source rocks, and reservoir rocks.
3. There are sufficient data in the public domain from the USGS, EIA, and other organizations to quantify the volumes of gas in place in unconventional reservoirs in the 25 basins that I studied.
4. When I compared basins using the BASIN analogy software with PRISE, the results could be correlated. The correlation may improve in the future as more data are added to BASIN and PRISE.
5. As more unconventional gas reservoirs are developed in North America, the geological data, reservoir data, and other technical data should be used to improve the UGR Advisory system so it can be used to more accurately evaluate target basins outside of North America.

GLOSSARY

AAPG	American Association of Petroleum Geologists
AASG	Association of American State Geologists
ADKB	Anadarko basin
AI	artificial intelligence
API	Application Programming Interface
APPB	Appalachian basin
ARK	Arkoma basin
AU	assessment unit
BAS	Basin Analog System
BASIN	Basin Analog System Investigation
bbl	barrels of oil
Bcf	billion cubic feet
BHB	Big Horn basin
BOE	barrel of oil equivalent
BP	British Petroleum
BTU	British thermal unit
BWB	Black Warrior Basin
C10	10% confidence resource volume will be recovered
C100	100% confidence resource volume will be recovered
C50	50% confidence resource volume will be recovered
C90	90% confidence resource volume will be recovered
CBM	coalbed methane

CGPC	Canadian Gas Potential Committee
CHK	Cherokee basin
CNPC	China National Petroleum Corporation
COM	Component Object Model
Conv	conventional resources
ConvGas	conventional gas
ConvOil	conventional oil
CSD	Committee on Statistics and Drilling
CSM	Colorado School of Mines
CTRRI	Conventional TRR Input
CUCBM	China United Coalbed Methane Co Ltd
D&C	drilling & completion
DEN	Denver basin
DOE	Department of Energy
DOI	Department of the Interior
EIA	Energy Information Administration
ETX	East Texas basin
F5	5% chance the resource volume exists
F50	50% chance the resource volume exists
F95	95% chance the resource volume exists
FAST	Formation Analog Selection Tool
FCB	Forest City basin
FWB	Fort Worth basin

GNC	Geologic Names Committee
GRB	Green River basin
GRI	Gas Research Institute
GTI	Gas Technology Institute
GUI	graphical user interface
HC	hydrocarbons
HI	Hydrogen Index
IB	Illinois basin
IDE	Integrated Development Environment
IEO	International Energy Outlook
km^2	square kilometer
LAMS	Louisiana Mississippi Salt basin
MICH	Michigan basin
MMS	Mineral Management Service
NA	North American
NPC	National Petroleum Council
NRC	National Research Council
OGRC	Society of Petroleum Engineers Oil and Gas Reserves Committee
OPEC	Organization of Petroleum Exporting Countries
P10	10% probability of resource occurrence
P30	30% probability of resource occurrence
P5	5% probability of resource occurrence
P50	50% probability of resource occurrence

P70	70% probability of resource occurrence
P90	90% probability of resource occurrence
P95	95% probability of resource occurrence
PDX	Paradox basin
PERM	Permian basin
PGC	Potential Gas Committee
PRISE	Petroleum Resource Investigation System and Evaluation
PRMS	Petroleum Resources Management System
PWDR	Powder River basin
RAT	Raton basin
SEG	Society of Exploration Geophysicists
SG	Shale Gas
SJB	San Juan basin
SPE	Society of Petroleum Engineers
SR	source rock
STB	stock tank barrel
Tcfe	trillion cubic feet equivalent
TGS	tight gas sand
TOC	total organic content
TPS	total petroleum system
TRR	total recoverable resource
TXGC	Texas Gulf Coast basin
UG	unconventional gas

UGA	Unconventional Gas Advisor
UGR	Unconventional Gas Resource
UGRA	Unconventional Gas Reservoir Advisory
UPB	Uinta-Piceance basin
URA	ultimate reserves appreciation
USGS	United States Geological Survey
VBA	Visual Basic Application
VRMOC	vitrinite reflectance measured organic content
WCSB	Western Canada Sedimentary basin
WF	Weighting Factor
WILL	Williston basin
WRB	Wind River basin
WTB	Wyoming Thrust Belt basin

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APPENDIX

OVERVIEW OF SELECTED 25 N.A. BASINS

The total petroleum system (TPS) compares the essential elements (source rock, reservoir rock, seal rock, and overburden rock) and processes (generation-migration-accumulation and trap formation) with all genetically related petroleum that occurs in seeps, shows, and accumulations, both discovered and undiscovered, whose provenance is a pod or closely related pods of active source rock (USGS, 2000).

We have included 25 basins in our work. The following section briefly discusses these 25 basins.

Anadarko Basin: USGS (2010) reported that “The Anadarko Basin Province is in a mature state of exploration and development for conventional resources. Much of the production is reported as being commingled from numerous formations that were deposited over broad age ranges; this commingling influenced grouping of formations into the assessment units (AUs). The Woodford Composite and Pennsylvanian Composite TPSs represent source rock input from numerous Ordovician through Pennsylvanian formations. The Woodford Composite TPS source rocks primarily contribute to Cambrian through Mississippian reservoirs, and those of the Pennsylvanian Composite TPS to Pennsylvanian and Permian reservoirs. Migration and accumulation of hydrocarbons from variable sources can occur along fault systems and updip from the extent of the Woodford Shale and other source rocks. Biogenic gas from the Cretaceous Niobrara Formation is produced from western Kansas and eastern Colorado; however, that resource was evaluated in the Denver Basin Province assessment” (Fig. A.1).

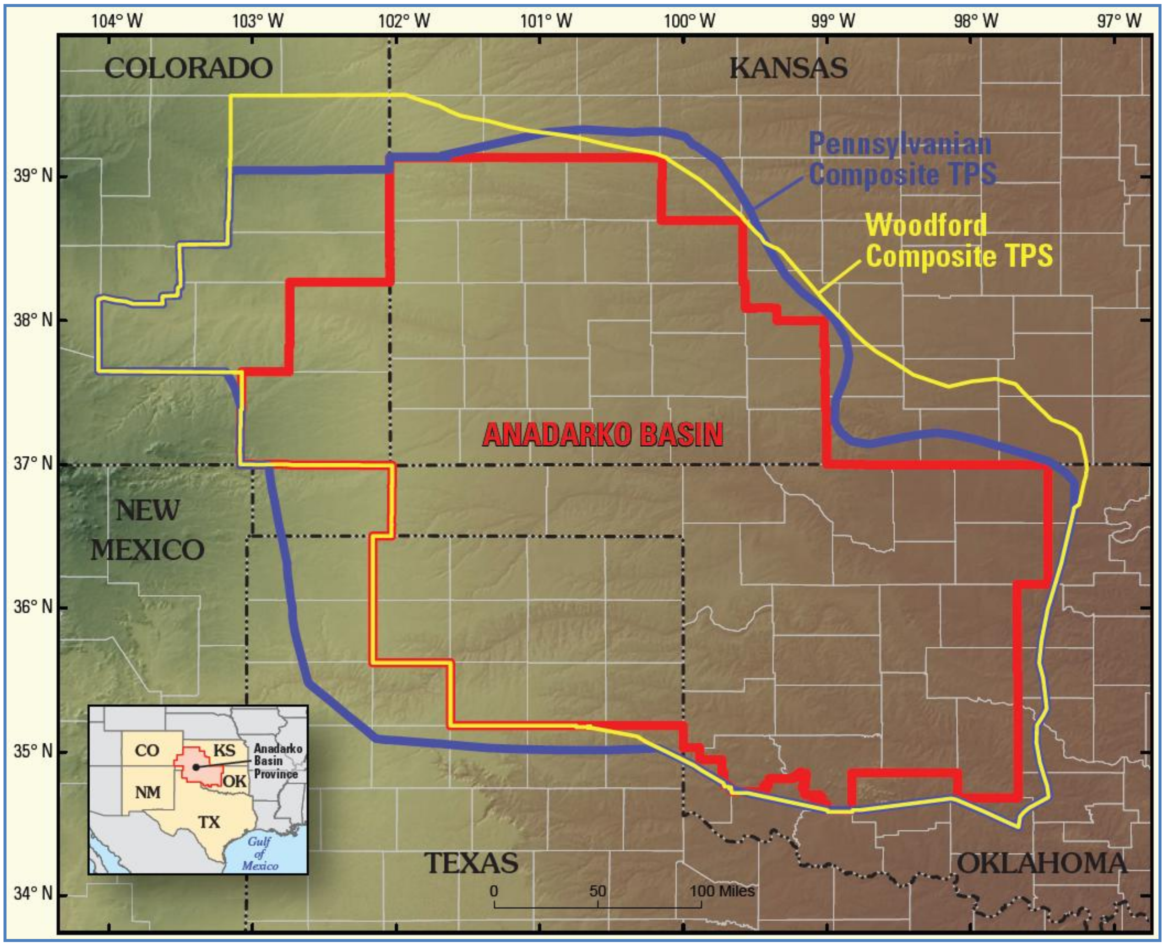

Fig. A.1—Map showing boundaries of the Anadarko Basin Province (red line), the Woodford Composite total petroleum system (TPS), and the Pennsylvanian Composite TPS (USGS 2010).

Appalachian Basin: USGS (2003) reported that "The USGS Appalachian Basin Province for this assessment includes parts of New York, Pennsylvania, Ohio, Maryland, West Virginia, Virginia, Kentucky, Tennessee, Georgia, and Alabama. The assessment of the Appalachian Basin Province is based on the geologic elements of each TPS defined in the province, including hydrocarbon source rocks (source rock maturation, and hydrocarbon generation and migration), reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing). Using this geologic framework, the USGS defined 6 TPS and 26 AU) within these TPS, and quantitatively estimated the undiscovered oil and gas resources within 21 of the 26 AU" (Fig. A.2).

Fig. A.2—Appalachian basin province (USGS, 2003).

Arkoma Basin: USGS (2010) reported that "USGS in 2010 completed an assessment of the undiscovered, technically recoverable petroleum resources of the Arkoma Basin Province, which includes the Arkoma Basin and Ouachita Thrust Belt, and two adjacent areas. The principle focus of this assessment is the Arkoma Basin of central Arkansas and east-central Oklahoma and the Ouachita Thrust Belt of southeast Oklahoma, south-central Arkansas, and west-central Mississippi. Other areas assessed include (1) the Post-Ouachita Successor Basin of northeast Texas, south Arkansas, and north and northwest Louisiana; and (2) part of the Reelfoot Rift in northeast Arkansas and southeast Missouri" (Fig. A.3).

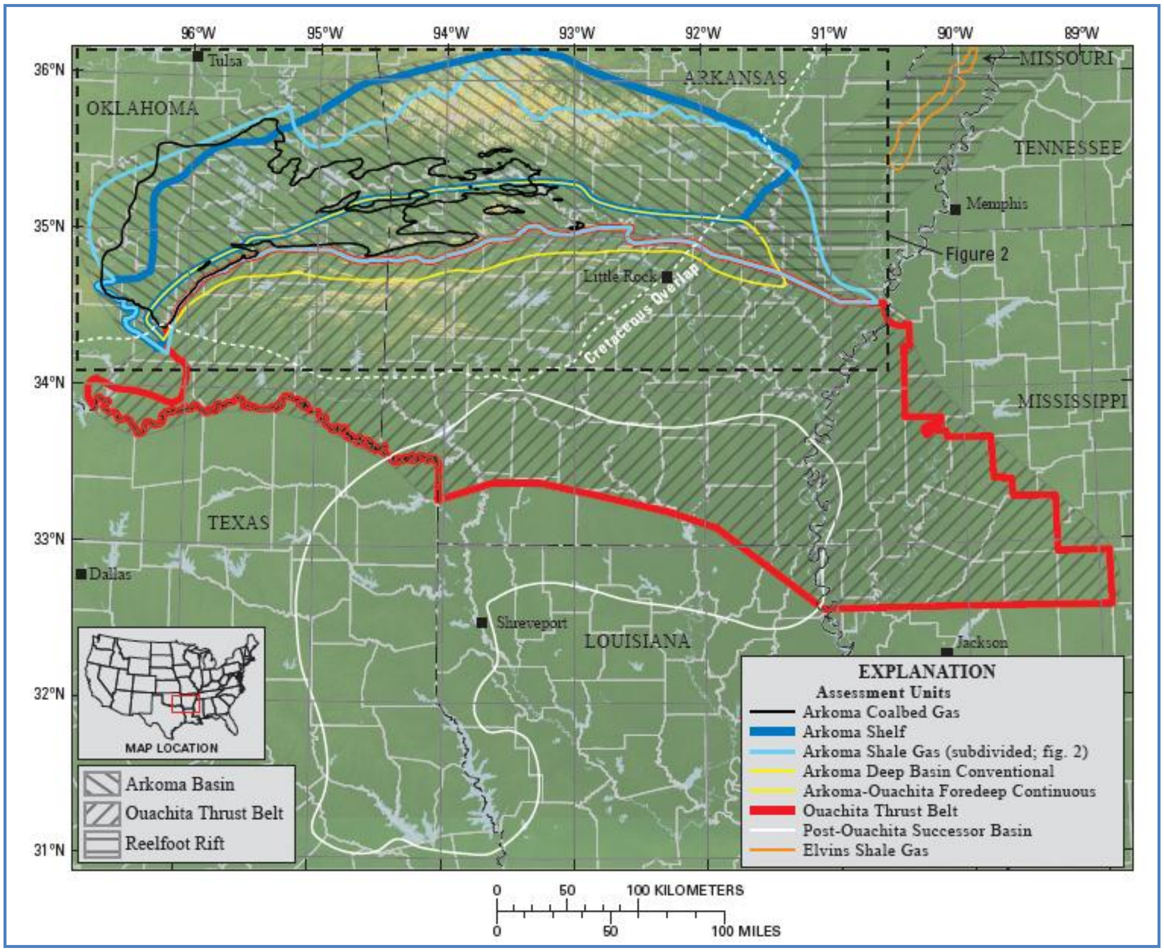

Fig. A.3—Arkoma Basin Province showing AU boundaries as well as generalized areas of Arkoma Basin, Ouachita Thrust Belt, and Reelfoot Rift. The area identified as "Arkoma Shale Gas" includes six AUs, which are delineated in Fig. A.4 (USGS, 2010).

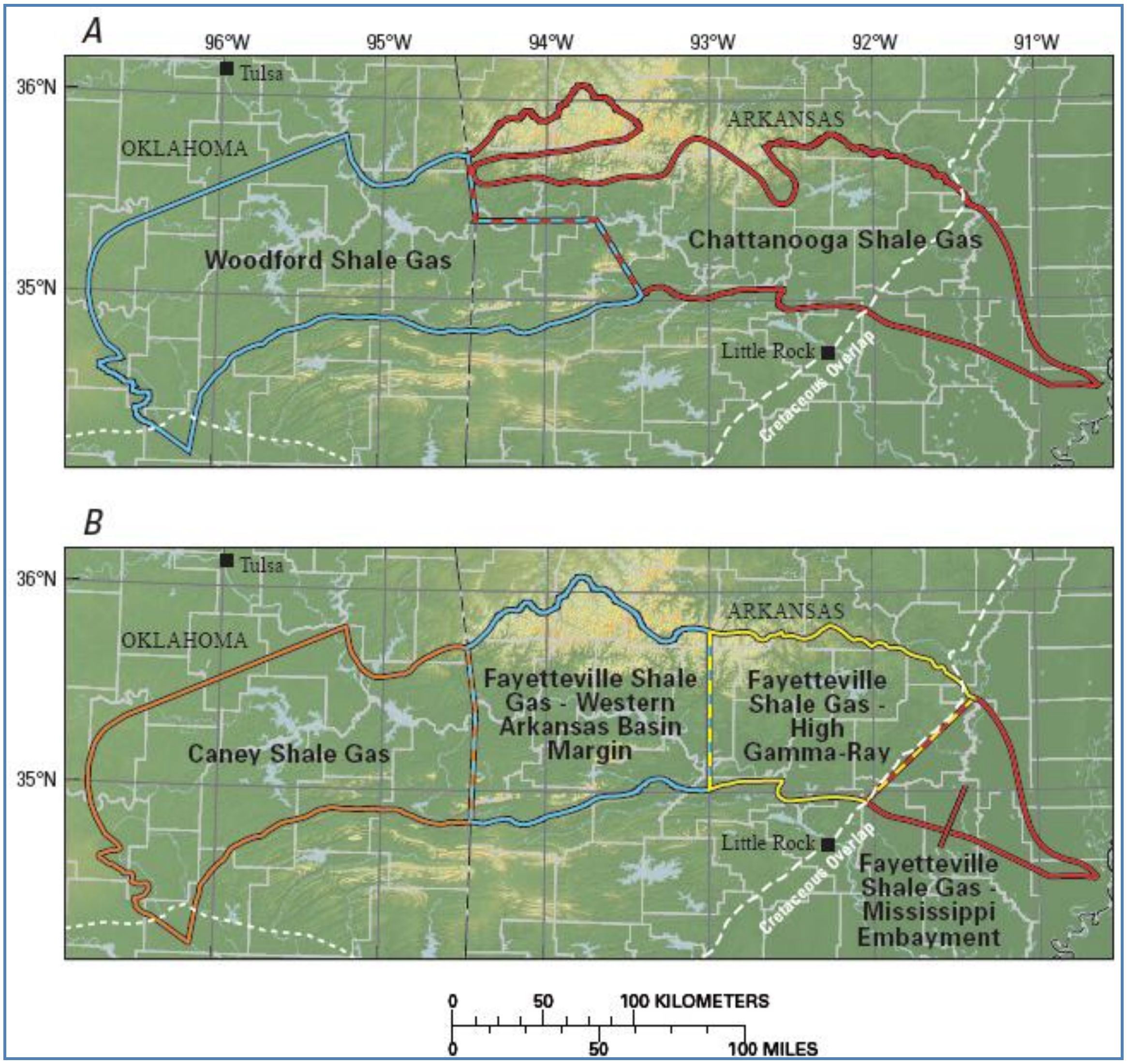

Fig. A.4—Specific boundaries for Arkoma Shale Gas AU. (A) Two AUs in the Woodford and Chattanooga Shales, defined based on maps of high gamma-ray response in wireline logs. (B) Four AUs in the Fayetteville and Caney Shales, defined based on maps of high gamma-ray response in wireline logs and of thermal maturity. Area of map shown by dashed, black rectangle in Fig. A.3 (USGS, 2010).

Bighorn Basin: USGS (2008) reported that "Two petroleum systems were defined in the Bighorn Basin based on geochemical analyses of oil types. Two oil families were defined: one with low API gravity and low to moderate sulfur interpreted to be from a Permian Phosphoria Formation source, and the other showing higher API gravities and low to absent sulfur content interpreted to be from several stratigraphic units in the Cretaceous and Tertiary. The geochemical data indicate that there has been little mixing of the two oils in the basin, as the two oil families are effectively sealed by thick mudstone units in the Triassic Chugwater Formation and a thick anhydrite bed in the Jurassic Gypsum Springs Formation. The Phosphoria-derived oils largely migrated into the Bighorn Basin from the west and have partly cracked to gas with increasing thermal maturity. The Cretaceous and Tertiary oils were generated in the basin largely from the Mowry Shale, and little of the oil is interpreted to have cracked to gas. The Cretaceous and Tertiary petroleum source rocks are combined into one composite petroleum system because there are insufficient data to differentiate gas types from the various potential source rocks. Most of the conventional petroleum traps in the Bighorn Basin are anticlinal traps and few of these structures remain untested by drilling. New conventional resource potential is interpreted to be from stratigraphic traps mainly in carbonate mounds in the Permian Park City Formation and in sandstone stratigraphic pinch-out traps in the Upper Cretaceous Frontier Formation and Cody Shale. Six continuous type accumulations—three basin-centered gas, one oil, and two coalbed gas—are interpreted to be present in the basin. These AUs, as defined by their limits, have little or no drill-stem tests and little production data, so geologic analogs from similar AUs in the Wind River Basin and Southwestern Wyoming Provinces were used to infer production potentials. The potential for undiscovered gas is relatively low in the Bighorn Basin compared to these analog basins because of having: (1) overall less coal-bearing source rocks compared to the analog basins, (2) lower thermal maturity, (3) less volume of sandstone (reservoirs), and (4) fewer fractured structures in the central part of the basin. The Mowry Formation fractured oil accumulation in the Bighorn Basin is hypothetical, and the Mowry Formation in the Powder River Basin was used as a geologic and production analog" (Fig. A.5).

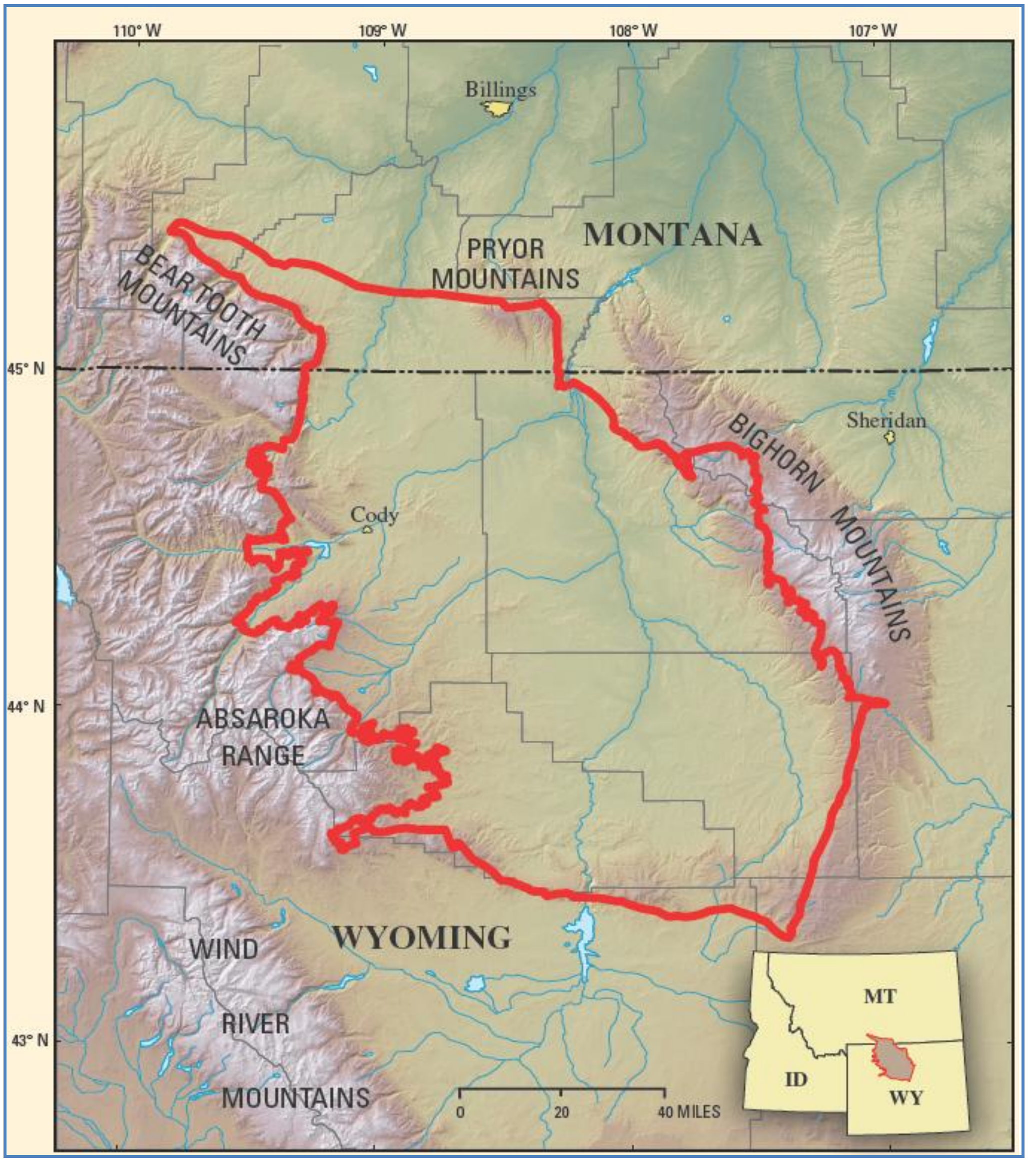

Fig. A.5—Bighorn basin in north-central Wyoming and southern Montana (USGS, 2008).

Black Warrior Basin: USGS (2003) reported that "The total petroleum systems within the Black Warrior Basin Province are the Pottsville Coal TPS and the Chattanooga Shale/Floyd Shale-Paleozoic TPS. The Black Warrior Basin AU of the Pottsville Coal

TPS defines potential coal-bed gas found primarily in the Alabama portion of the basin. The Carboniferous Sandstones AU of the Chattanooga Shale/Floyd Shale-Paleozoic TPS is defined by gas and oil trapped in Upper Mississippian deltaic and shallow-marine sandstone reservoirs by a variety of basement-involved fault blocks, combination traps, and stratigraphic traps. The Pre-Mississippian Carbonates AU of the Chattanooga Shale/Floyd Shale-Paleozoic TPS is defined by gas trapped primarily in Cambrian and Ordovician platform-carbonate reservoirs by basement-controlled fault blocks" (Fig. A.6).

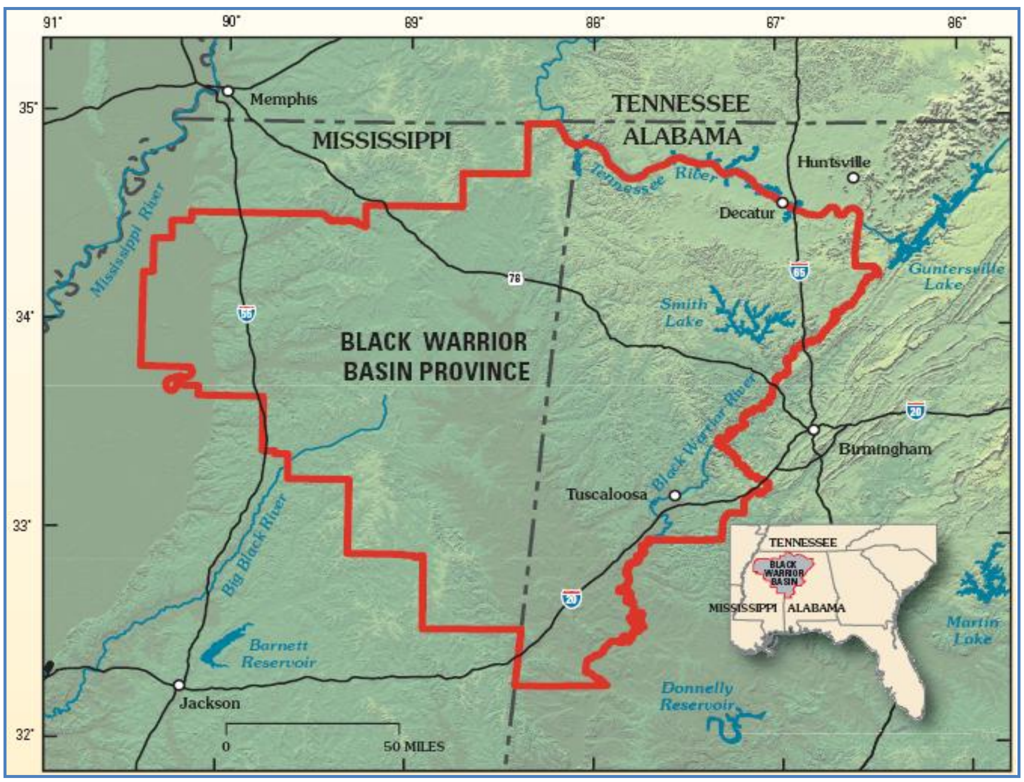

Fig. A.6—Location of the Black Warrior basin (USGS, 2003).

Cherokee Basin: USGS (2010) reported that "The Cherokee Basin extends from southeastern Kansas and part of southwestern Missouri to northeastern Oklahoma. It consists of 37 counties; all boundaries of this province follow county boundaries. The province is 235 miles long (north-south) by 210 miles wide (east-west) and has an area of 26,500 sq mi" (Fig. A.7).

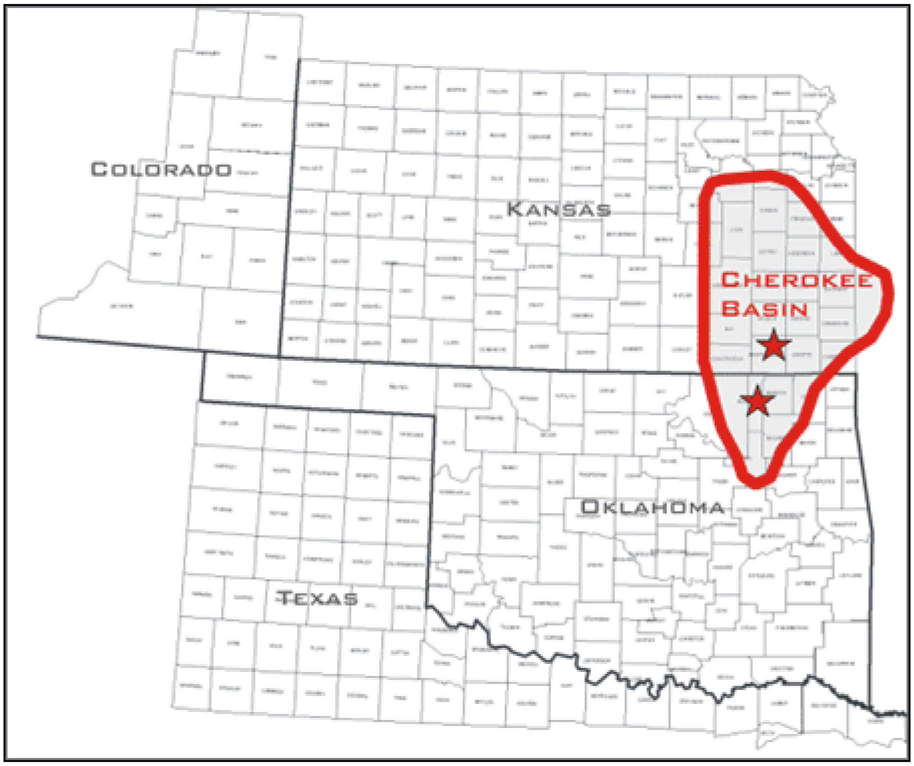

Fig. A.7—Location of the Cherokee basin (Presco Inc., 2010).

Denver Basin: The Denver basin covers parts of Colorado, Wyoming, South Dakota, Nebraska and Kansas. The basin is predominantly of Cretaceous age but also sediments range from Cambrian to Recent, and its maximum thickness reaches 15000 feet. Structural arches of the Front Ranges of the Rocky Mountains to the west, the Hartville uplift to the northwest, the Black Hills uplift and Chadron arch to the north and northeast, the Las Animas arch to the south, and Wet Mountain or Apishapa uplift to the southwest define the boundaries of the Denver basin (McGinnis, 1958). USGS (2003) reported that "using a total petroleum system method of analysis, the USGS defined seven TPS and12 AU in the province. TPS and AU are defined in Magoon and Dow (1994) and Klett and others (2000)." (Fig. A.8).

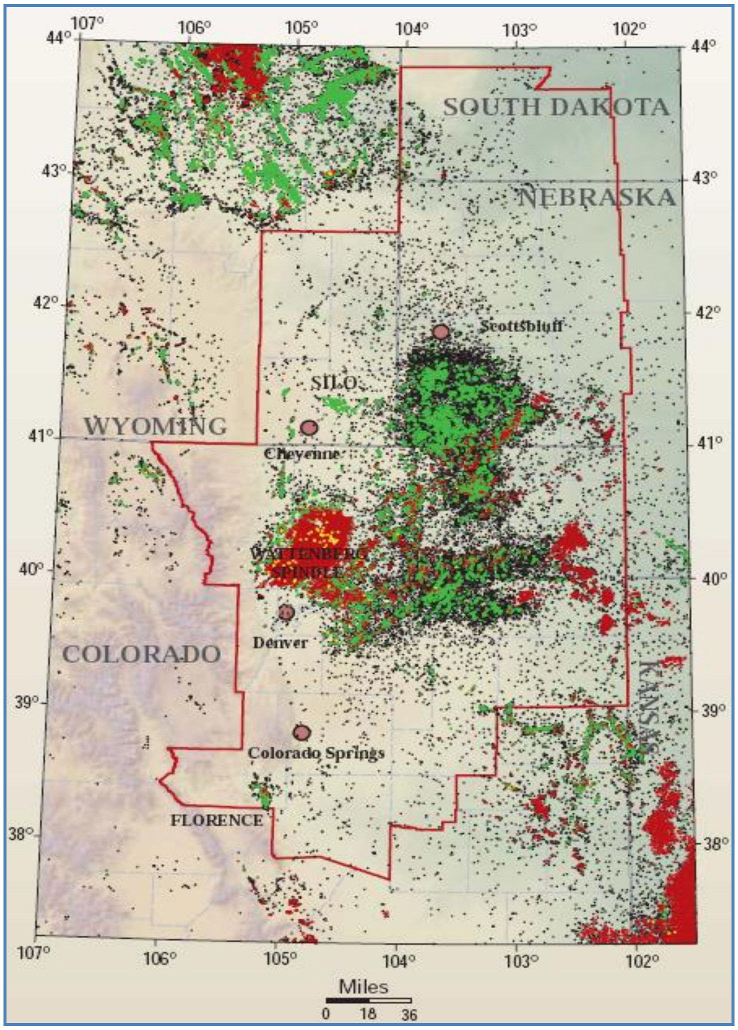

Fig. A.8—The Denver Basin (red line) of Colorado, Kansas, Nebraska, South Dakota, and Wyoming. Shown are oil (green), gas (red), oil and gas (yellow) and nonproductive (black) wells (USGS, 2003).

East Texas Basin: The East Texas Basin formed in the Late Triassic as a failed rift, and was subsequently flooded by the proto-Gulf of Mexico in the Middle Jurassic due to subsidence. The Luann Salt was formed during this time period as a result of evaporation of highly saline water in this restricted marine environment. By the Late

Jurassic, the basin had subsided enough to allow circulation of marine sediments, thus forming the Smackover and Cotton Valley formations. USGS (2003) reported that "East Texas basin encompasses the area commonly referred to as East Texas, which is the area of eastern Texas north of the Angelina Flexure, and east of the Ouachita Fold Belt" (Fig. A.9).

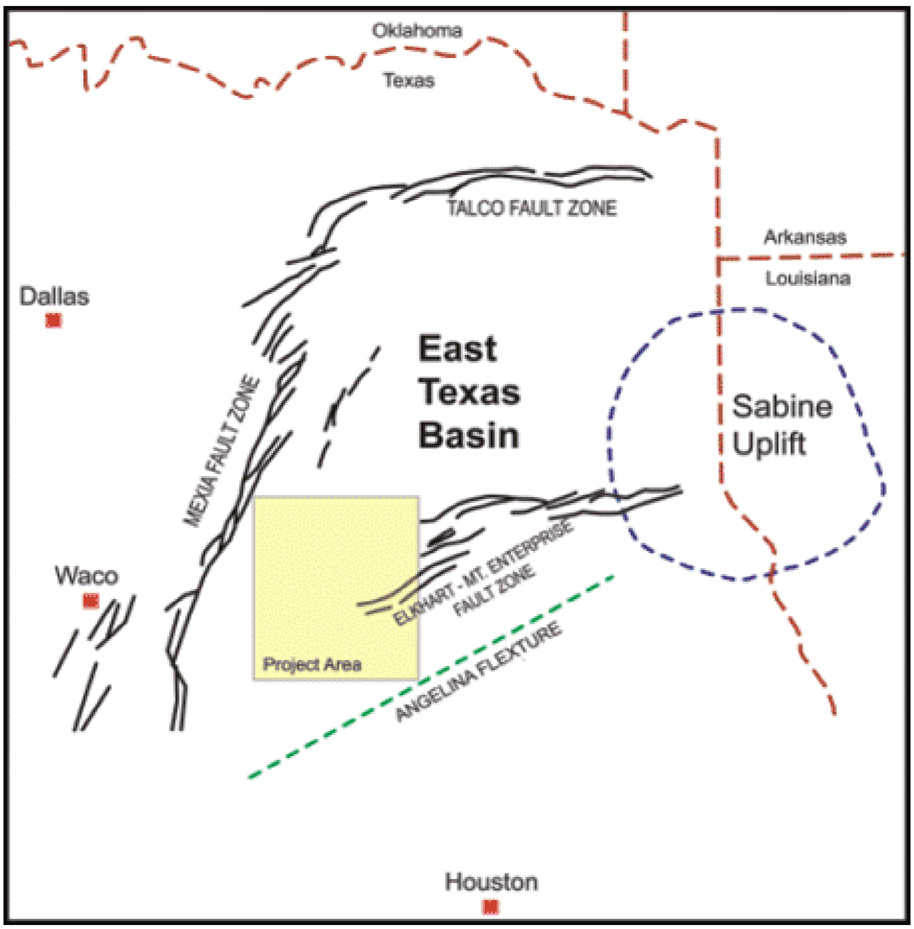

Fig. A.9—Location of the East Texas basin (Presco Inc., 2010).

Forest City Basin: USGS (2003) reported that "The Forest City Basin extends from southwestern Iowa and northeastern Kansas to central Missouri. It consists of 58 counties; the boundaries of this province all follow county boundaries. The basin is 240 mi long (north-south) by 195 mi wide (east-west) and has an area of 32,000 sq mi" (Fig. A.10).

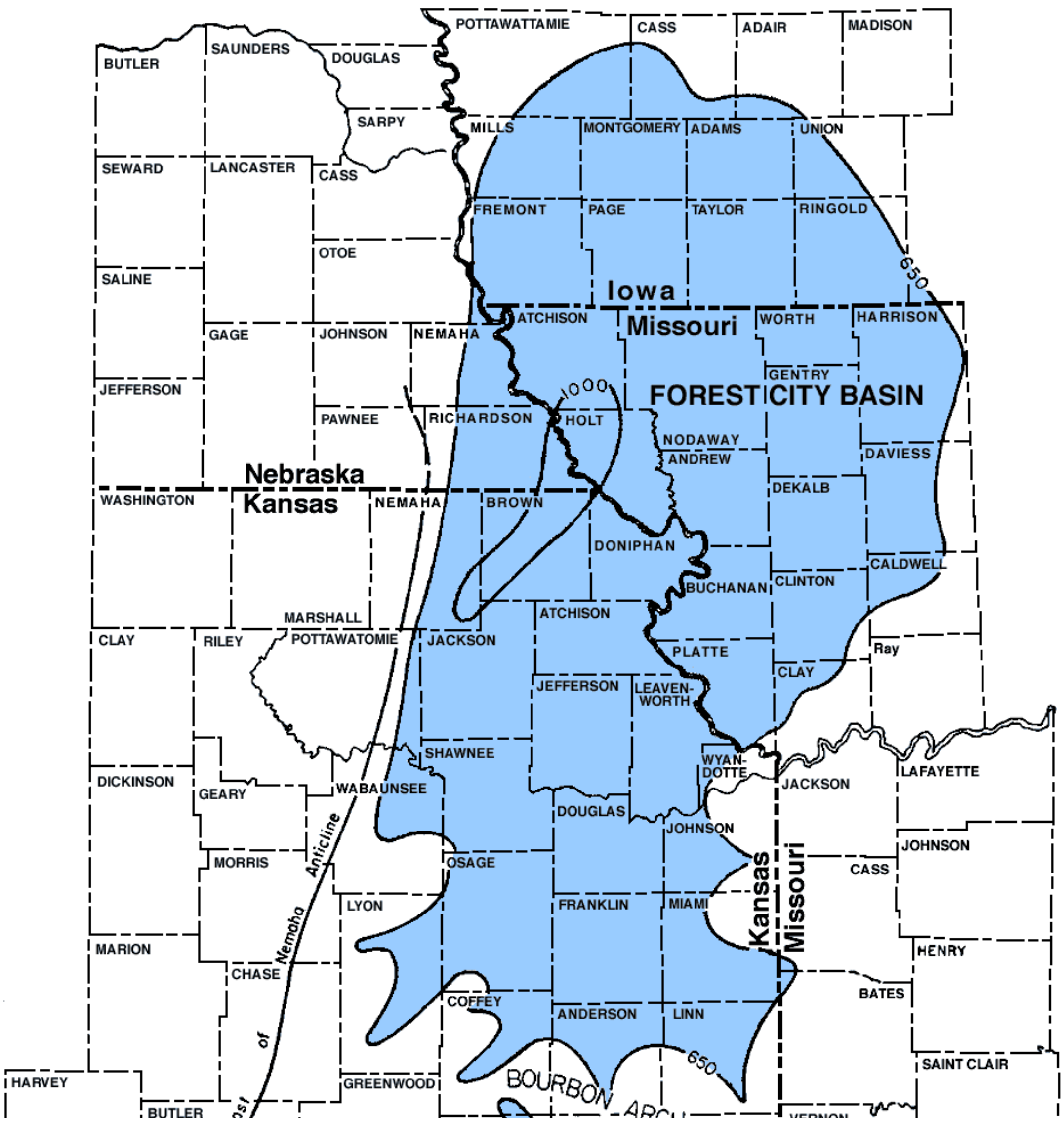

Fig. A.10—Location of the Forest City basin (Kansas Geological Survey, 2005).

Fort Worth Basin: The Fort Worth basin is an asymmetric wedge-shaped regional feature having a length of approximately 200 mi and width ranging from only a few miles at its southern end to about 100 mi at the latitude of Fort Worth in Tarrant

County. A maximum thickness of approximately 12,000 ft of strata is preserved in the deepest part of the basin, adjacent to the Ouachita fold belt (Branson, 1962). USGS (2004) reported that “based on geologic elements of each TPS defined in the Fort Worth basin, including characterization of hydrocarbon source rocks (source-rock maturation, hydrocarbon generation, and migration), reservoir rocks (sequences tratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing). By using these criteria, the USGS defined 4 TPSs and 11 AUs within them and quantitatively estimated the undiscovered oil and gas resources within 8 of the 11 AUs, which represented 3 of the 4 TPSs. The TPSs cover a geographic area that includes the bounding structural elements of the Bend arch and Fort Worth Basin: Ouachita thrust front, the Hardeman Basin, Wichita uplift, Llano uplift, Muenster and Red River arches, Broken Bone graben, and easternmost part of the Eastern shelf of the Permian Basin” (Fig. A.11).

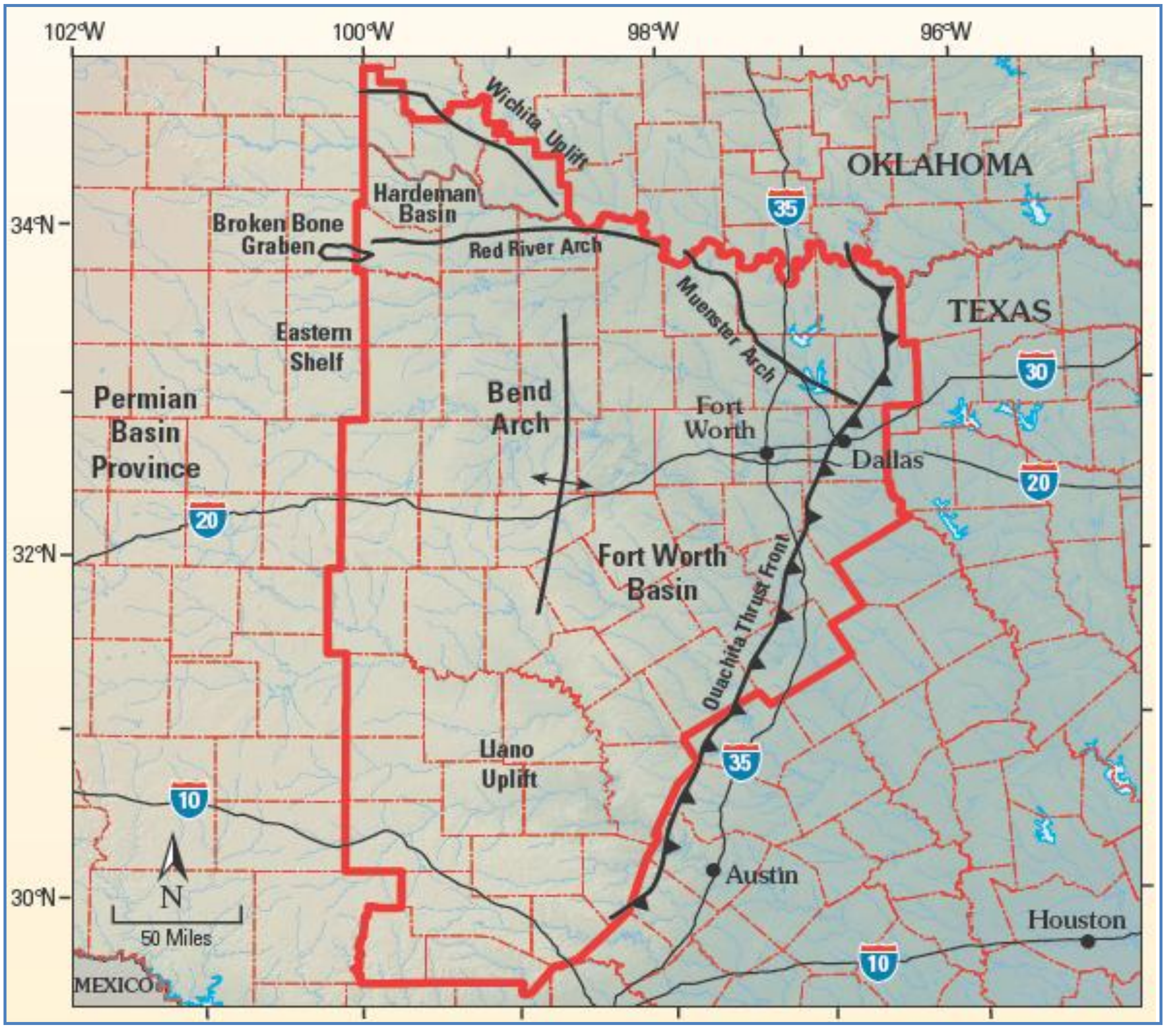

Fig. A.11—Bend arch-Fort Worth basin within the boundary outlined in red and primary structural elements of north-central Texas and the southwestern corner of Oklahoma (USGS, 2004).

Green River Basin: USGS (2002) reported that "The Greater Green River Basin is a large Laramide (Late Cretaceous through Eocene) structural and sedimentary basin that encompasses about 25,000 square miles in southwestern Wyoming, northwestern Colorado, and northeastern Utah. Important conventional oil and gas resources have been discovered and produced from reservoirs ranging in age from Cambrian through Tertiary (Law, 1996). In addition, an extensive over pressured basin - centered gas accumulation has also been identified in Cretaceous and Tertiary reservoirs by numerous researchers including Law (1984a, 1996), Law and others (1980, 1989), McPeek (1981), and Spencer (1987)" (Fig. A.12).

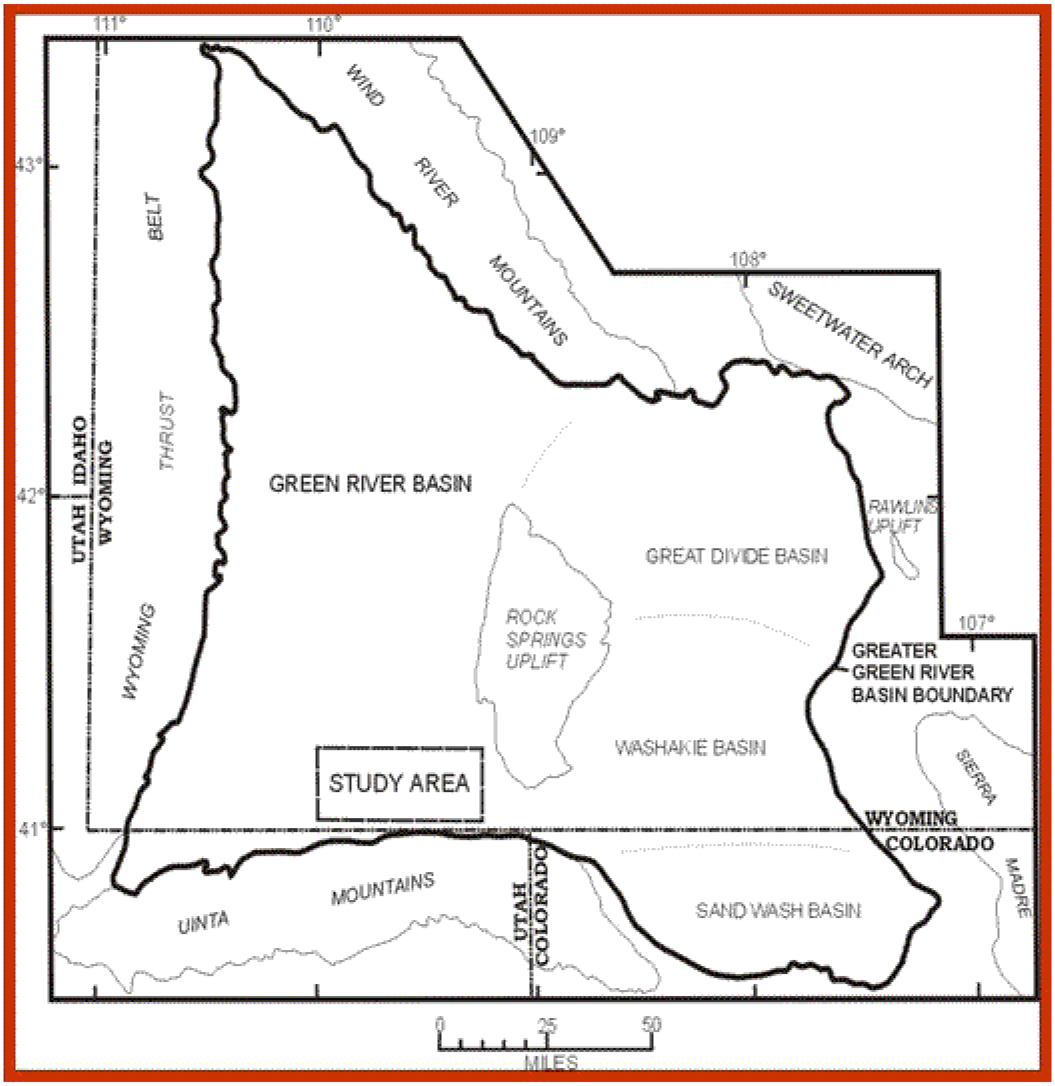

Fig. A.12—Location of the Green River basin (USGS, 2003).

Illinois Basin: USGS (2007) reported that "The four total petroleum systems identified in the Illinois Basin are the (1) Precambrian to Cambrian TPS, (2) Ordovician Ancell / Maquoketa TPS, (3) Devonian to Mississippian New Albany TPS, and (4)

Pennsylvanian Coal and Shale TPS. Each TPS is named according to the petroleum source rock(s) of that system. For most of the systems, each TPS is associated with only one source rock. The Precambrian to Cambrian TPS, however, encompasses both source rocks in the Cambrian Eau Claire Formation and older, hypothetical source rocks in the deeper parts of the basin. Sixteen of the AUs are characterized as conventional oil and gas accumulations, and three of the AUs are characterized as continuous accumulations. The 16 conventional AUs are the (1) Precambrian to Cambrian Rift-Fill AU, (2) Cambrian Mount Simon to Eau Claire AU, (3) Cambrian to Ordovician Knox Group AU, (4) Cambrian to Ordovician Carbonates Cumberland Saddle AU, (5) Ordovician St. Peter/Everton AU, (6) Ordovician Dutch town to Galena AU, (7) Lower Silurian Carbonates AU, (8) Upper Silurian Calcareous Siltstones AU, (9) Upper Silurian Carbonates(Reef) AU, (10) Lower Devonian Carbonates AU, (11) Middle Devonian Dutch Creek Sandstone AU, (12) Middle Devonian Carbonates AU, (13)Lower Mississippian Borden AU, (14) Lower Mississippian Carbonates AU,(15) Upper Mississippian Sandstones AU, and (16) Pennsylvanian Sandstones AU. All of these conventional AUs were assessed quantitatively, except for the Precambrian to Cambrian Rift-Fill AU, the Cambrian Mount Simon to Eau Claire AU, the Cambrian to Ordovician Knox Group AU, and the Ordovician St. Peter/Everton AU. The three continuous AUs are the (1) Ordovician Maquoketa Continuous AU, (2) Devonian to Mississippian New Albany Continuous AU, and (3) Pennsylvanian Coalbed Gas AU. All of these continuous AUs were assessed quantitatively, except for the Ordovician Maquoketa Continuous AU." (Fig. A.13).

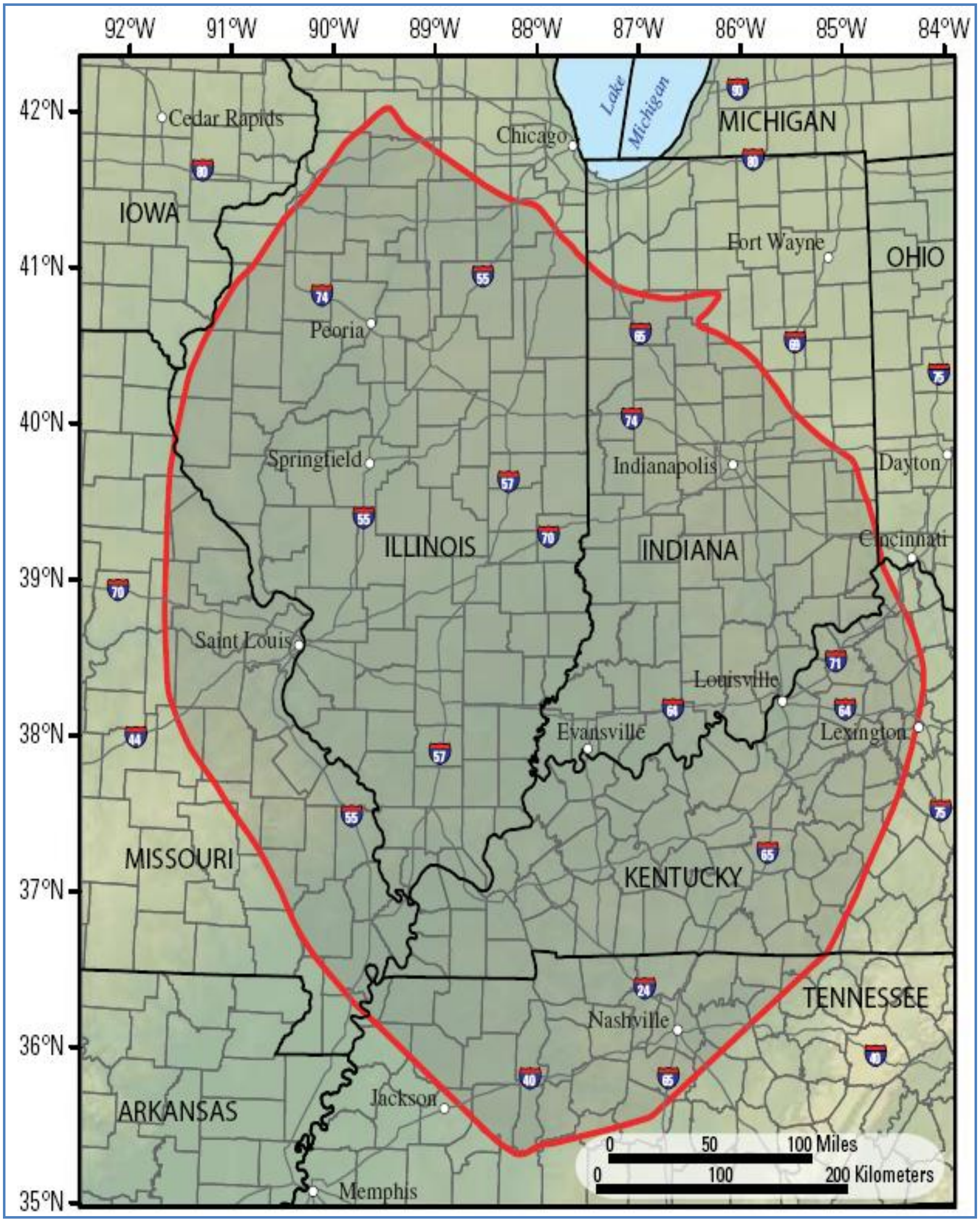

Fig. A.13—Location of the Illinois basin (USGS, 2007).

Louisiana-Mississippi Salt Basin: USGS (2007) reported that "USGS completed an assessment of the undiscovered oil and gas potential of the Jurassic-Cretaceous Cotton

Valley Group in the Louisiana-Mississippi Salt basin of the northern Gulf Coast Region as part of a national oil and gas assessment effort. The assessment of the petroleum potential of the Cotton Valley Group was based on the general geologic elements used to define a TPS, which include hydrocarbon source rocks (source rock maturation, hydrocarbon generation and migration), reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing). Using this geologic framework, the USGS defined four AU that are included in one TPS, the Jurassic Smackover Interior Salt Basins TPS: Cotton Valley Blanket Sandstone Gas AU, Cotton Valley Massive Sandstone Gas AU, Cotton Valley Updip Oil and Gas AU, and Cotton Valley Hypothetical Updip Oil AU" (Fig. A.14).

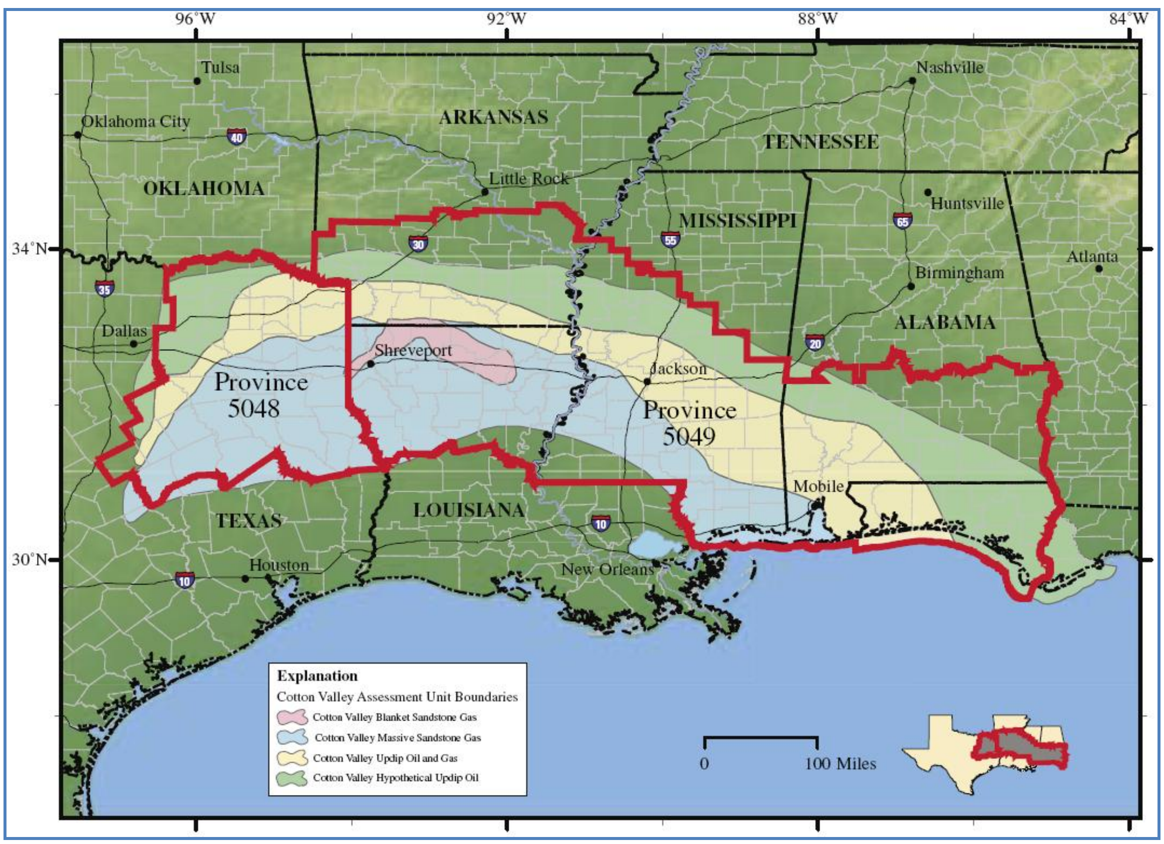

Fig. A.14—Location of the Louisiana-Mississippi Salt basin (USGS, 2007).

Michigan Basin: USGS (2005) reported that “The six total petroleum systems identified in the U.S. portion of the Michigan Basin are the (1) Precambrian Nonesuch TPS, (2) Ordovician Foster TPS, (3) Ordovician to Devonian Composite TPS, (4) Silurian Niagara/Salina TPS, (5) Devonian Antrim TPS, and (6) Pennsylvanian Saginaw TPS. Each TPS is named according to the petroleum source rock(s) of that system. For most of the systems, each TPS is associated with only one source rock. The Ordovician to Devonian Composite TPS, however, is a composite petroleum system having contributions from one or more of the following different source rocks: Ordovician Collingwood Shale, Devonian Detroit River Group, and the Devonian Antrim Shale. Nine of the AUs are characterized as conventional oil and gas accumulations, and four of the AUs are characterized as continuous accumulations. The nine conventional AUs are the (1) Precambrian Nonesuch AU; (2) Ordovician Sandstones and Carbonates AU, which includes the Prairie du Chien Group, St. Peter Sandstone, Glenwood Formation, and equivalent stratigraphic units within the basin; (3) Ordovician Trenton/Black River AU; (4) Silurian Burnt Bluff AU; (5) Silurian Niagara AU; (6) Silurian A-1 Carbonate AU; (7) Devonian Sylvania Sandstone AU; (8) Middle Devonian Carbonates AU, which includes the Detroit River Group, Dundee Limestone, and Traverse Group; and (9) Devonian to Mississippian Berea/Michigan Sandstones AU. All of these conventional AUs were assessed quantitatively, except for the Precambrian Nonesuch AU. The four continuous AUs are the (1) Ordovician Collingwood Shale Gas AU, (2) Devonian Antrim Continuous Oil AU, (3) Devonian Antrim Continuous Gas AU, and (4) Pennsylvanian Saginaw Coalbed Gas AU. All of these four continuous AUs, only the Devonian Antrim Continuous Gas AU was assessed quantitatively” (Fig. A.15).

Fig. A.15—Location of the Michigan basin (USGS, 2005).

Paradox Basin: The Paradox basin covers an area of 33000 sq miles. This foreland basin has a sedimentary fill thickness of 5000 to 15000 ft. Source rocks for the basin come mainly from the organic-rich shales of the Hermosa Group. During the Pennsylvanian time period the Paradox basin went under cyclic marine conditions resulting in depositions of carbonate, shale, and salt. After burial, the shale matured and became the source rock, the carbonates housed the hydrocarbons and the salt sealed the hydrocarbons in (USGS, 2009). USGS (2010) reported that “The Paradox Basin Province is in southeastern and south-central Utah and southwestern Colorado and encompasses much of the area from latitude 37°to 40 °N. and from longitude 108 °to 114 °W. It includes almost all of the Paradox Basin, the Uncompahgre and San Juan uplifts, the San Rafael, Circle Cliffs, and Monument uplifts, the Kaiparowits and Henry Mountains basins, and the Wasatch and Pausaugunt Plateaus. Maximum dimensions of the province area are approximately 280 mi long and 200 mi wide. It covers an area of about 33,000 sq mi. The maximum thickness of Phanerozoic sedimentary rocks ranges from 5,000-8,000 ft in the central part of the province to more than 15,000 ft in the Paradox Basin, Kaiparowits basin, and Wasatch Plateau” (Fig. A.16).

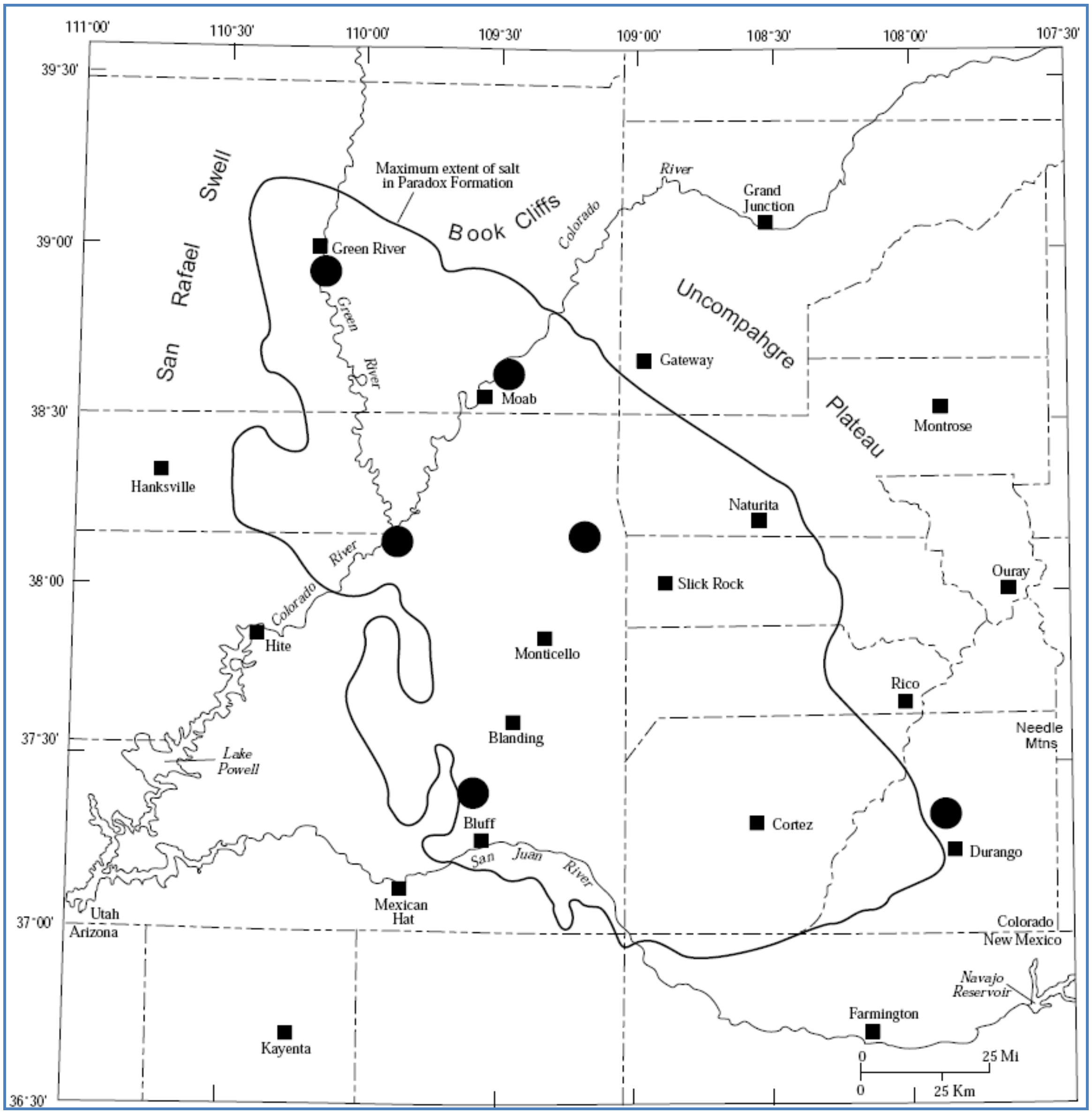

Fig. A.16—Location of the Paradox Basin. Large dots indicate areas where burial, thermal, and petroleum-generation histories were reconstructed (USGS ,2000).

Permian Basin: USGS (2008) reported that "USGS defined a Paleozoic Composite TPS and 31 AU within the system, and it quantitatively estimated the undiscovered oil and gas resources within 30 of the AUs" (Fig.3.17).

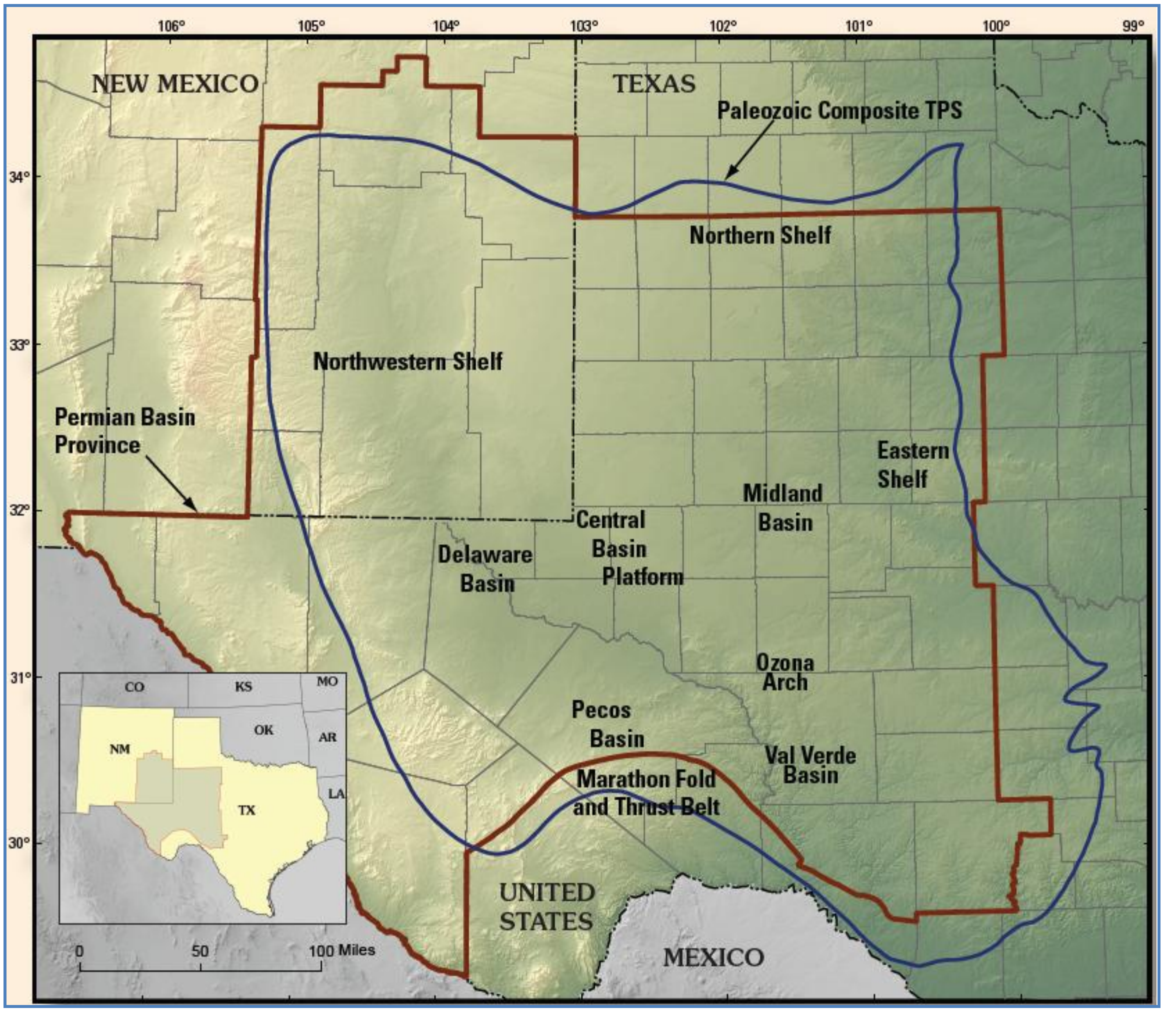

Fig. A.17—Permian basin in west Texas and southeastern New Mexico (USGS, 2008).

Powder River Basin: The Powder River basin is a Laramide foreland basin. The basin filled with combination of fluvial, deltaic, paludal, and lacustrine sediments (Ayers, 1986). USGS (2006) reported that “The current assessment of conventional oil and gas resources, based on geologic elements such as hydrocarbon source rocks (source rock maturation and hydrocarbon generation and migration), reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing), includes five TPS identified in the province by the USGS; 8 AUs were defined within the TPSs” (Fig. A.18).

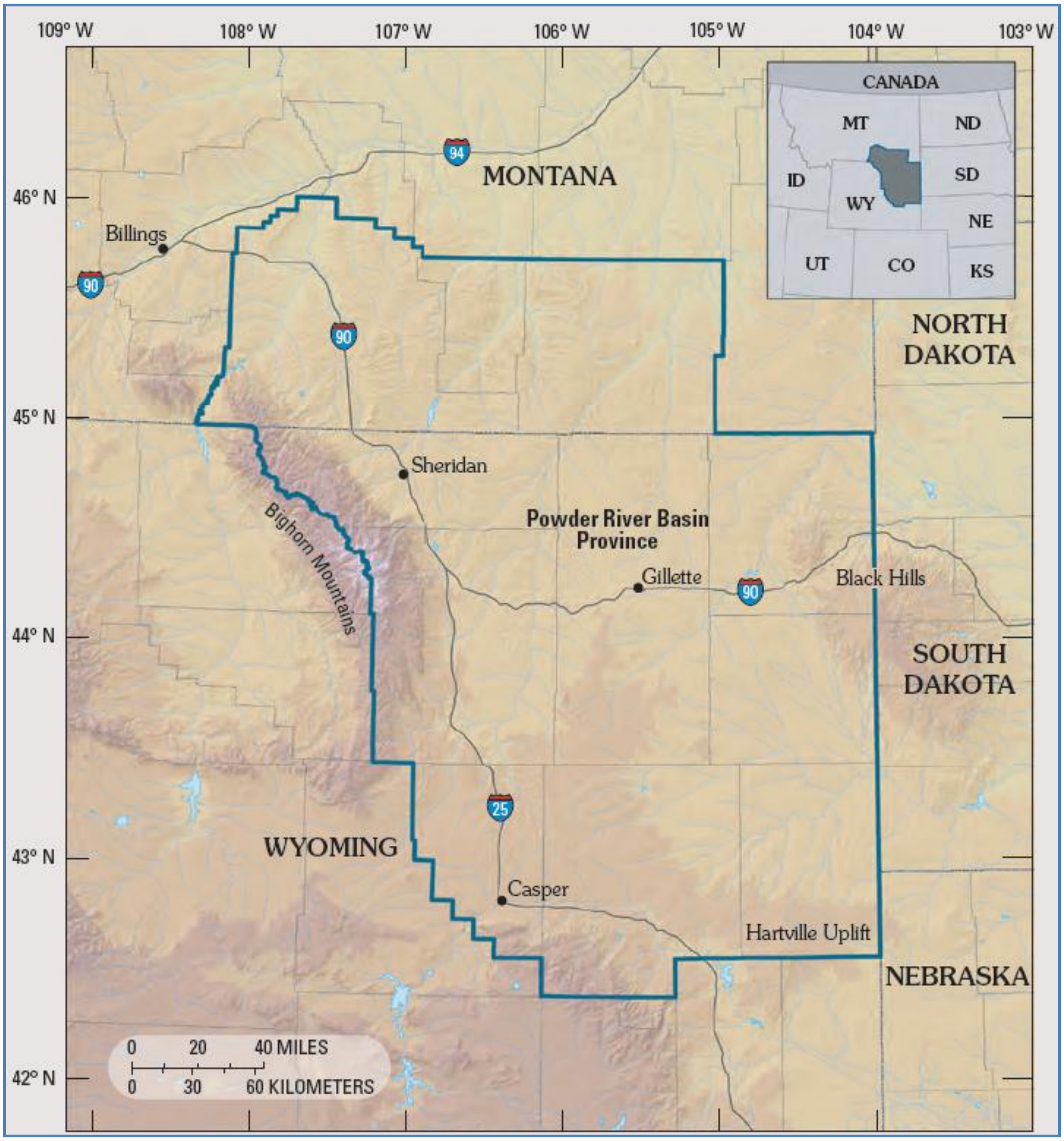

Fig. A.18—Powder River basin of northeastern Wyoming and southeastern Montana (USGS, 2006).

Raton Basin: USGS (2005) reported that "USGS defined (1) the Upper Cretaceous–Tertiary Coalbed Gas TPS containing one conventional oil and gas AU (Upper Cretaceous–Tertiary Sandstones AU) and two continuous oil and gas assessment units (RatonCoalbed Gas AU and Vermejo Coalbed Gas AU), and (2) the Jurassic-

Cretaceous Composite TPS containing two conventional oil and gas assessment units (Fractured Reservoirs AU and Jurassic-Cretaceous Reservoirs AU). Undiscovered oil, gas, and natural gas liquids resources were quantitatively estimated within the 5 AUs" (Fig. A.19).

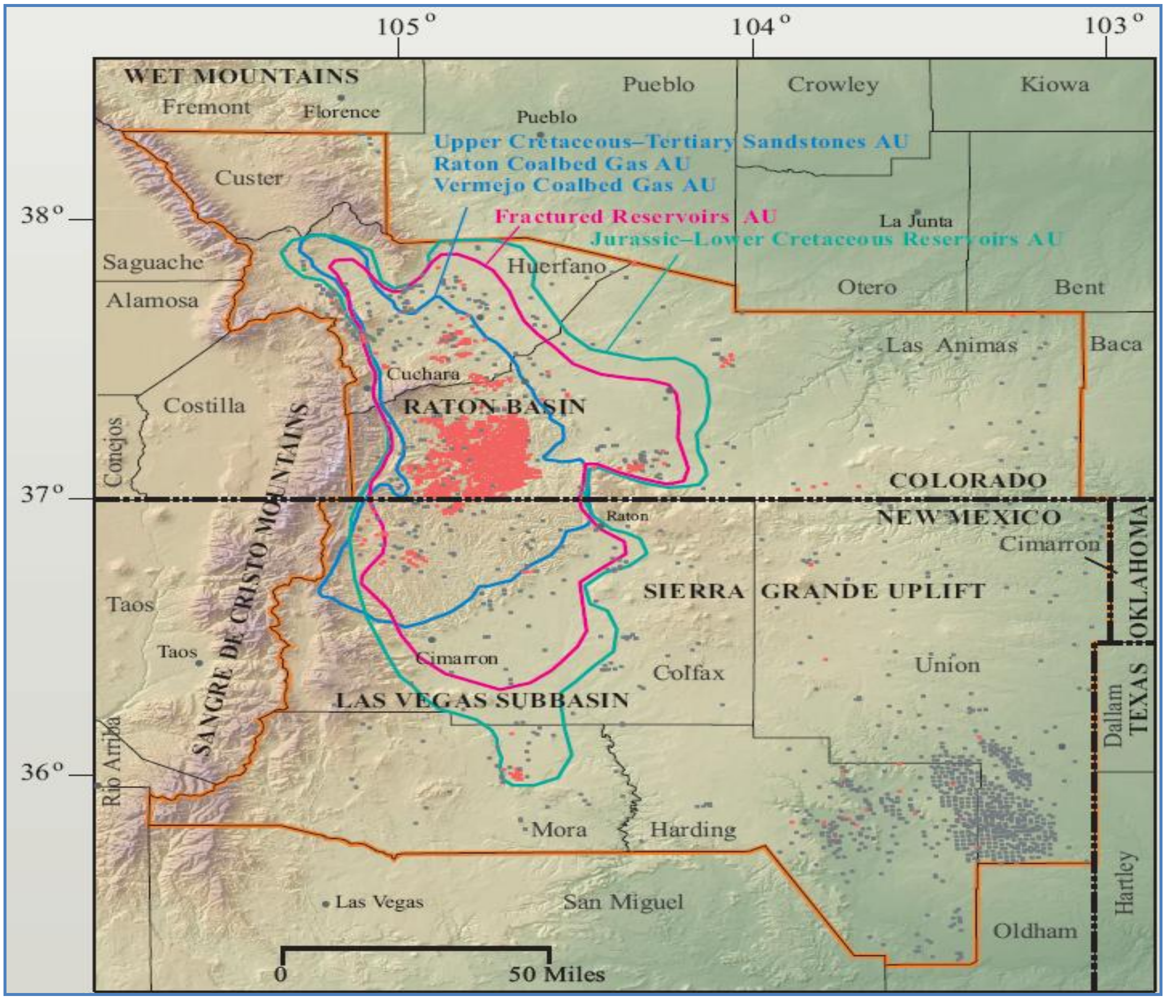

Fig. A.19—Location of Raton basin (USGS, 2005).

San Juan Basin: USGS (2002) reported that "The assessment of the San Juan Basin Province is based on the geologic elements of each Total Petroleum System defined in the province, including hydrocarbon source rocks (source-rock maturation, hydrocarbon generation and migration),reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing). Using this geologic framework, the USGS defined four Total Petroleum Systems and 14 AUs within these Total Petroleum Systems and quantitatively estimated the undiscovered oil and gas resources within the 14 AUs" (Fig. A.20).

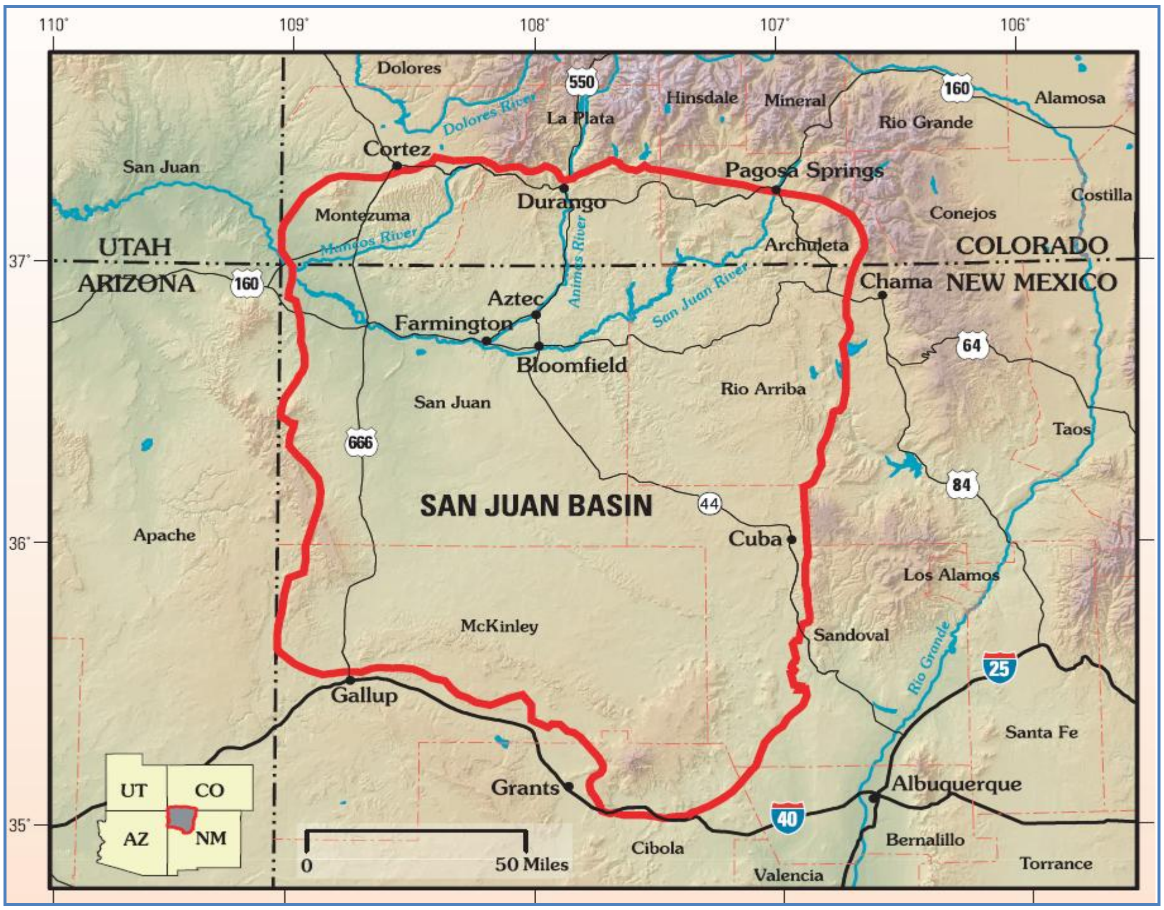

Fig. A.20—San Juan Basin of northwestern New Mexico and southwestern Colorado (USGS, 2002).

Texas Gulf Coast Basin: PGC (2006) reported that "The Texas Gulf Coast basin occupies 67 counties in southern and southeastern Texas. It encompasses parts of the Mississippi and Rio Grande Embayments. The Balcones fault zone and Ouachita tectonic belt bound the basin on the north and west. This is one of the major hydrocarbon regions of the United States. Much of the production comes from Cenozoic reservoirs" (Fig. A.21).

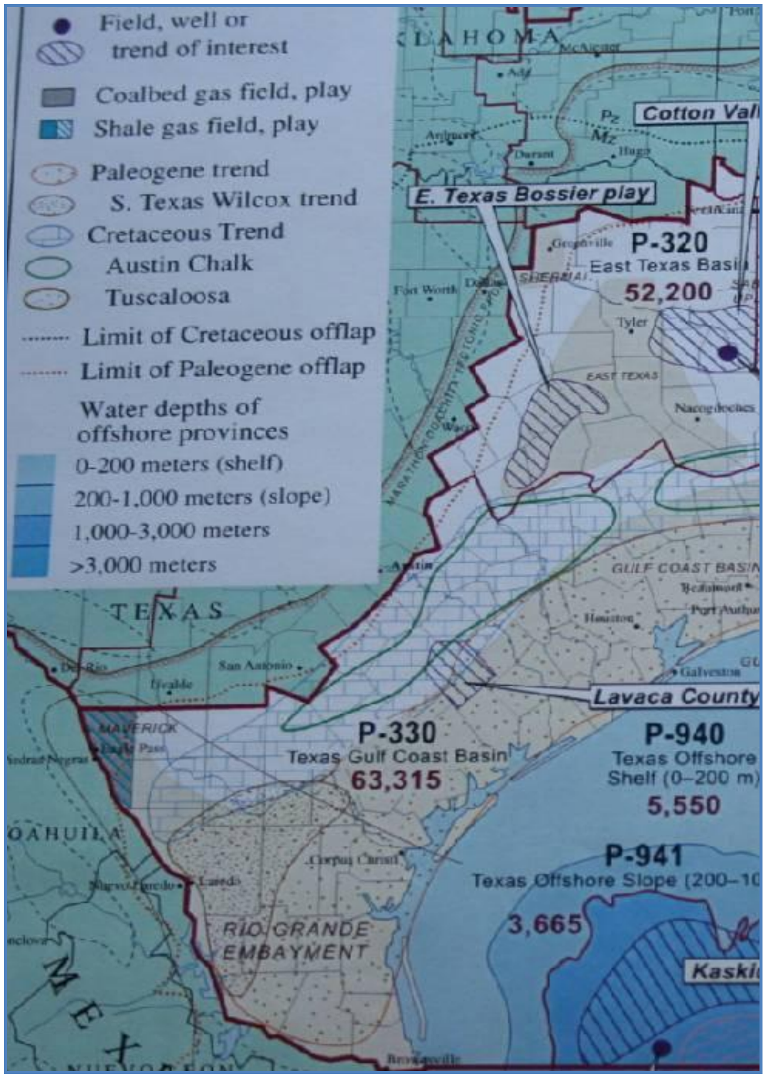

Fig. A.21—Location of Texas Gulf Coast Basin (PGC, 2006).

Uinta-Piceance Basin: USGS (2002) reported that "the USGS defined 5 Total Petroleum Systems and 20 AUs within these Total Petroleum Systems, and quantitatively estimated the undiscovered oil and gas resources within each AU" (Fig. A.22).

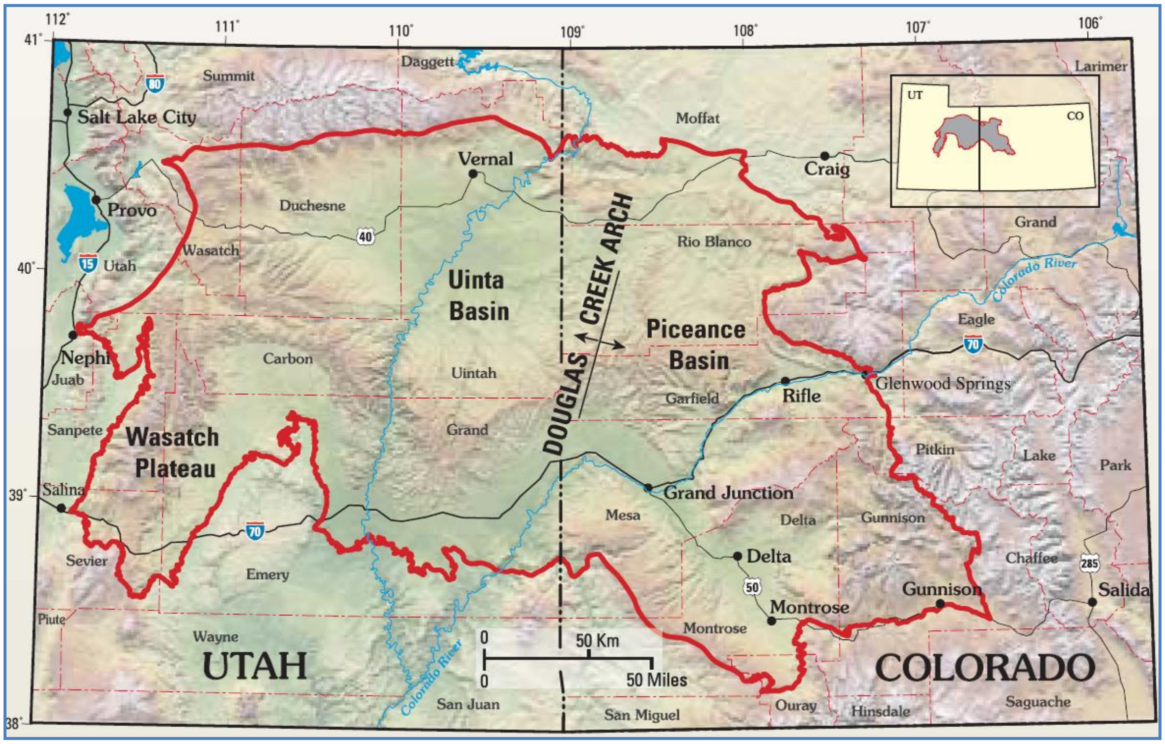

Fig. A.22—Uinta-Piceance basin located in northwestern Colorado and northeastern Utah. The Douglas Creek arch separates Piceance basin from Uinta basin. The Wasatch Plateau is included in this basin (USGS, 2002).

Western Canada Sedimentary Basin: The Western Canada Sedimentary Basin comprises the eastern portion of the Canadian Cordillera, or the Canadian portion of the Western Cordillera (which covers an extensive area of mountain ranges, basins, and plateaus in Western North America), and two major sedimentary basins. The first basin being a northwest-trending trough in front of the Cordilleran Fold and Thrust Belt and extending eastward is called the Alberta Basin. The second is the cratonic Williston Basin which is centered in North Dakota and extends upward in to southern Saskatchewan and southwest Manitoba (Canadian Society of Petroleum Geologists, 2008) (Fig. A.23).

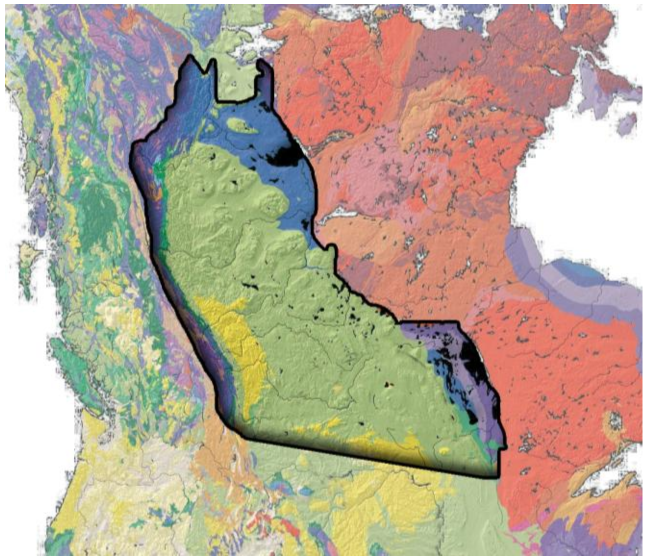

Fig. A.23—Location of Western Canada Sedimentary Basin (USGS, 2008).

Williston Basin: USGS (2006) reported that “The Upper Devonian–Lower Mississippian Bakken Formation is a thin but widespread unit within the central and deeper portions of the Williston Basin in Montana, North Dakota, and the Canadian Provinces of Saskatchewan and Manitoba. The formation consists of three members: (1) lower shale member, (2) middle sandstone member, and (3) upper shale member. Each succeeding member is of greater geographic extent than the underlying member. Both the upper and lower shale members are organic-rich marine shale of fairly consistent lithology; they are the petroleum source rocks and part of the continuous reservoir for hydrocarbons produced from the Bakken Formation. The middle sandstone member varies in thickness, lithology, and petrophysical properties, and local development of matrix porosity enhances oil production in both continuous and conventional Bakken reservoirs. Within the Bakken-Lodgepole TPS, the upper and lower shale members of the Bakken Formation are also the source for oil produced from reservoirs of the Mississippian Lodgepole Formation. The geologic model used to define AUs and to assess the Bakken Formation resources generally involves thermal maturity of the Bakken shale source rocks, petrophysical character of the middle sandstone member, and structural complexity of the basin. Most important to the Bakken-Lodgepole TPS and the continuous AUs within it are (1) the geographic extent of the Bakken Formation oil generation window (fig. 2), (2) the occurrence and distribution of vertical and horizontal fractures, and (3) the matrix porosity within the middle sandstone member. The area of the oil generation window for the Bakken continuous reservoir was determined by contouring both hydrogen index and well-log resistivity values of the upper shale member, which is youngest and of greatest areal extent. The area of the oil generation window for the Bakken Formation was divided into five continuous AUs: (1) Elm Coulee–Billings Nose AU, (2) Central Basin–Poplar Dome AU, (3) Nesson–Little Knife Structural AU, (4) Eastern Expulsion Threshold AU, and (5) Northwest Expulsion Threshold AU. A sixth hypothetical conventional AU, a Middle Sandstone Member AU, was defined external to the area of oil generation" (Fig. A.24).

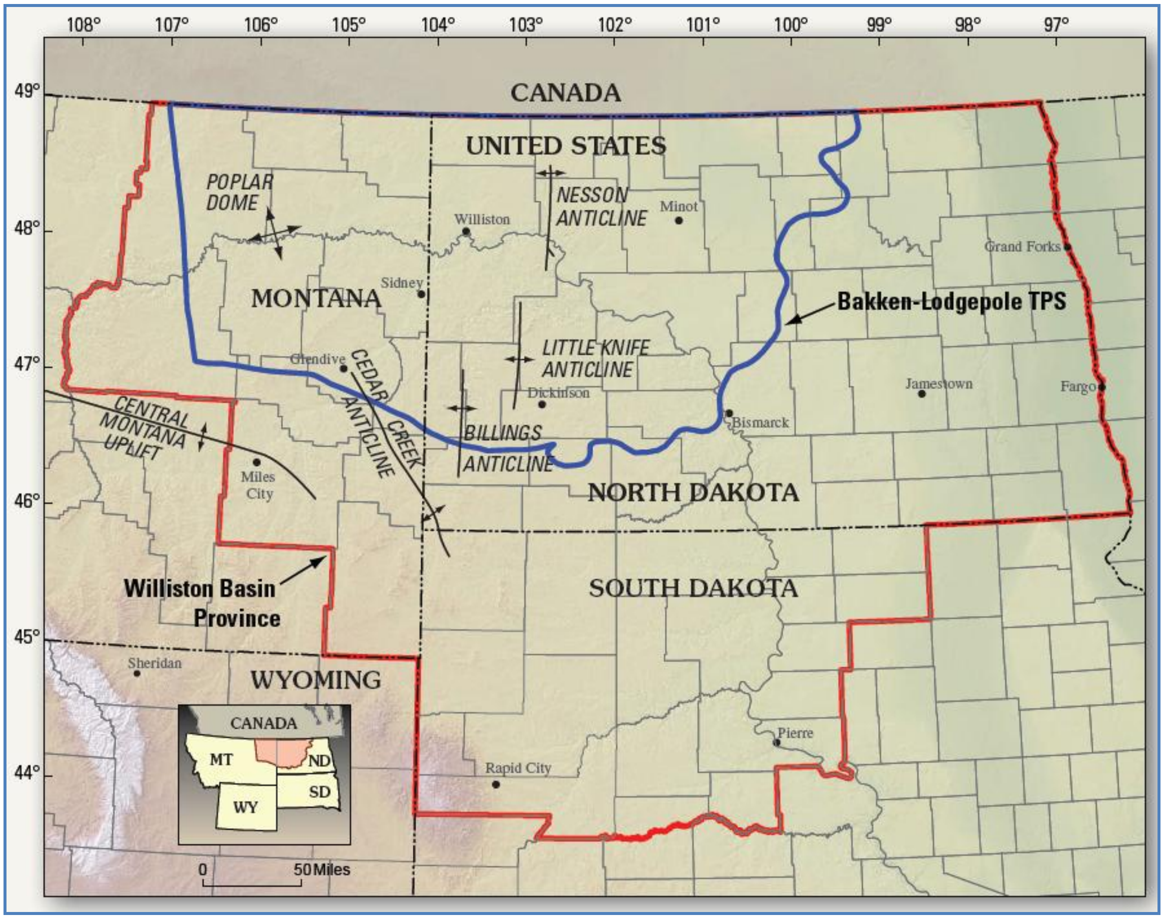

Fig. A.24—Map showing Williston basin boundary (in red), Bakken-Lodgepole TPS (in blue), and major structural features in Montana, North Dakota, and South Dakota (USGS, 2006).

Wind River Basin: USGS (2005) reported that “Wind River basin encompasses about 4.7 million acres in central Wyoming. The assessment is based on the geologic elements of each TPS defined in the province, including hydrocarbon source rocks (source-rock maturation, hydrocarbon generation, and migration), reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing). Using this geologic framework, the USGS defined three TPSs: (1) Phosphoria TPS, (2) Cretaceous-Tertiary TPS, and (3) Waltman TPS. Within these systems, 12 AU were defined and undiscovered oil and gas resources were quantitatively estimated within 10of the 12 AUs" (Fig. A.25).

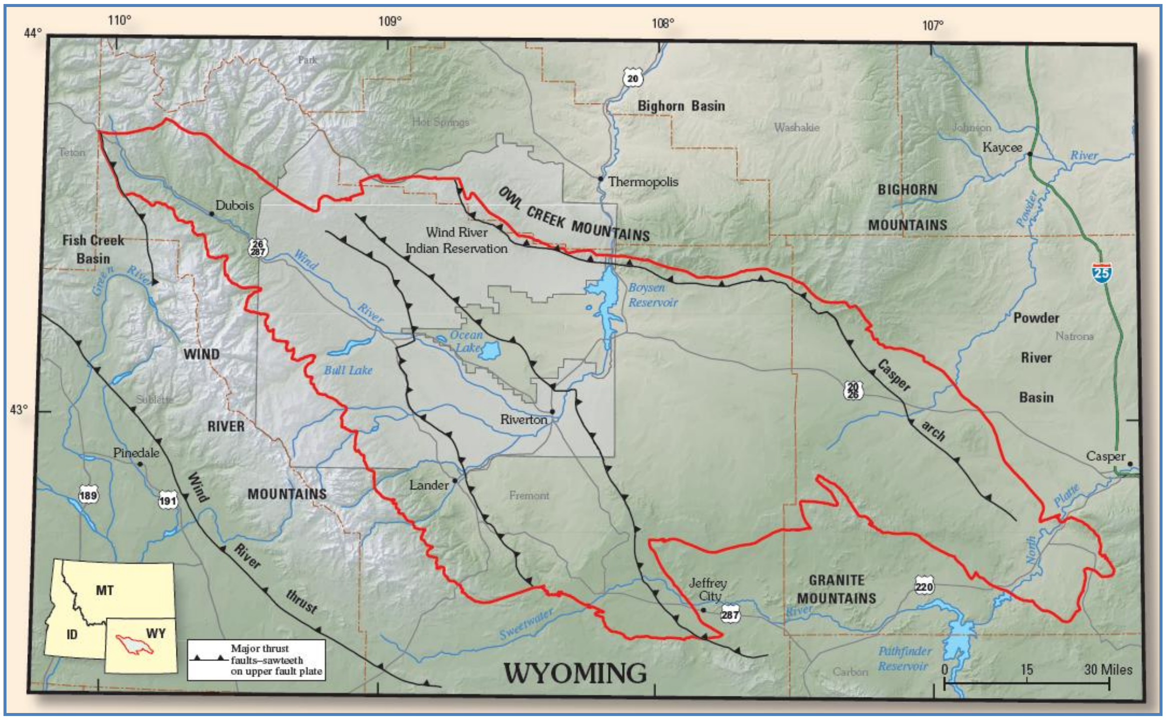

Fig. A.25—Wind River Basin located in central Wyoming (USGS, 2005).

Wyoming Thrust Belt: USGS (2004) reported that "Wyoming Thrust Belt includes all the major thrusts faults within those parts of Idaho, Utah, and Wyoming bounded on the northwest by the Snake River Plain, on the east by the Greater Green River Basin, on the south by the Uinta Mountains and associated structures, and on the west by the easternmost major extensional fault of the Basin and Range Province. The assessment is based on the identification and integration of geologic elements, including hydrocarbon source rocks (source-rock maturation, hydrocarbon generation, and migration), reservoir rocks (sequences tratigraphy and petrophysical properties), and hydrocarbon traps (trap formation and timing). By using this geologic framework, the

USGS defined two TPS, each containing one AU, as follows: (1): Mowry Composite TPS and Thrust Belt Conventional AU; and (2) Frontier-Adaville-Evanton Coalbed Gas TPS and Frontier-Adaville-Evanton Coalbed Gas AU" (Fig. A.26).

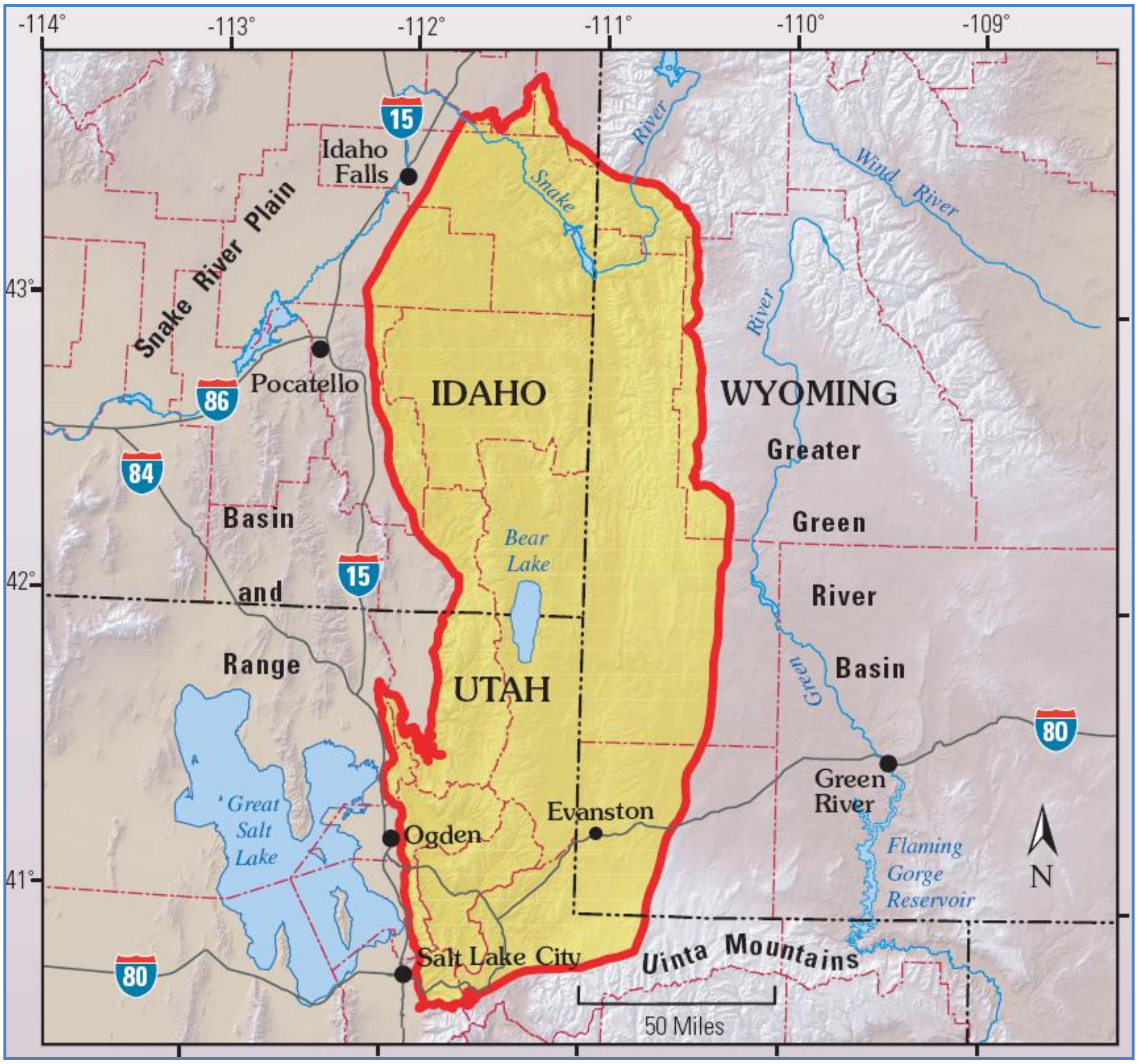

Fig. A.26—Wyoming Thrust Belt Province of southeastern Idaho, northwestern Utah, and western Wyoming (USGS, 2004).

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