U.S. Energy Information Administration

World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States

APRIL 2011

Independent Statistics & Analysis

www.eia.gov

U.S. Department of Energy
Washington, DC 20585

The information presented in this overview is based on the report "World Shale Gas Resources: An Initial Assessment," which was prepared by Advanced Resources International (ARI) for the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. The full report is attached. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Background

The use of horizontal drilling in conjunction with hydraulic fracturing has greatly expanded the ability of producers to profitably produce natural gas from low permeability geologic formations, particularly shale formations. Application of fracturing techniques to stimulate oil and gas production began to grow rapidly in the 1950s, although experimentation dates back to the 19th century. Starting in the mid-1970s, a partnership of private operators, the U.S. Department of Energy (DOE) and the Gas Research Institute (GRI) endeavored to develop technologies for the commercial production of natural gas from the relatively shallow Devonian (Huron) shale in the Eastern United States. This partnership helped foster technologies that eventually became crucial to producing natural gas from shale rock, including horizontal wells, multi-stage fracturing, and slick-water fracturing.[1] Practical application of horizontal drilling to oil production began in the early 1980s, by which time the advent of improved downhole drilling motors and the invention of other necessary supporting equipment, materials, and technologies, particularly downhole telemetry equipment, had brought some applications within the realm of commercial viability.[2]

The advent of large-scale shale gas production did not occur until Mitchell Energy and Development Corporation experimented during the 1980s and 1990s to make deep shale gas production a commercial reality in the Barnett Shale in North-Central Texas. As the success of Mitchell Energy and Development became apparent, other companies aggressively entered this play so that by 2005, the Barnett Shale alone was producing almost half a trillion cubic feet per year of natural gas. As natural gas producers gained confidence in the ability to profitably produce natural gas in the Barnett Shale and confirmation of this ability was provided by the results from the Fayetteville Shale in North Arkansas, they began pursuing other shale formations, including the Haynesville, Marcellus, Woodford, Eagle Ford and other shales.

The development of shale gas plays has become a “game changer” for the U.S. natural gas market. The proliferation of activity into new shale plays has increased shale gas production in the United States from 0.39 trillion cubic feet in 2000 to 4.87 trillion cubic feet in 2010, or 23 percent of U.S. dry gas production. Shale gas reserves have increased to about 60.6 trillion cubic feet by year-end 2009, when they comprised about 21 percent of overall U.S. natural gas reserves, now at the highest level since 1971.[3]

The growing importance of U.S. shale gas resources is also reflected in EIA’s *Annual Energy Outlook 2011* (*AEO2011*) energy projections, with technically recoverable U.S. shale gas resources now estimated at 862 trillion cubic feet. Given a total natural gas resource base of 2,543 trillion cubic feet in the *AEO2011* Reference case, shale gas resources constitute 34 percent of the domestic natural gas resource base represented in the *AEO2011* projections and 50 percent of lower 48 onshore resources. As a result, shale gas is the largest contributor to the projected growth in production, and by 2035 shale gas production accounts for 46 percent of U.S. natural gas production.

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[1] G.E. King, Apache Corporation, “Thirty Years of Gas Shale Fracturing: What Have We Learned?”, prepared for the SPE Annual Technical Conference and Exhibition (SPE 133456), Florence, Italy, (September 2010); and U.S. Department of Energy, *DOE's Early Investment in Shale Gas Technology Producing Results Today*, (February 2011), web site http://www.netl.doe.gov/publications/press/2011/11008-DOE_Shale_Gas_Research_Producing_R.html

[2] See: U.S. Energy Information Administration, “*Drilling Sideways: A Review of Horizontal Well Technology and Its Domestic Application”*, DOE/EIA-TR-0565 (April 1993).

[3] http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html

The successful investment of capital and diffusion of shale gas technologies has continued into Canadian shales as well. In response, several other countries have expressed interest in developing their own nascent shale gas resource base, which has lead to questions regarding the broader implications of shale gas for international natural gas markets. The U.S. Energy Information Administration (EIA) has received and responded to numerous requests over the past three years for information and analysis regarding domestic and international shale gas. EIA's previous work on the topic has begun to identify the importance of shale gas on the outlook for natural gas.[4] It appears evident from the significant investments in preliminary leasing activity in many parts of the world that there is significant international potential for shale gas that could play an increasingly important role in global natural gas markets.

To gain a better understanding of the potential of international shale gas resources, EIA commissioned an external consultant, Advanced Resources International, Inc. (ARI), to develop an initial set of shale gas resource assessments. This paper briefly describes key results, the report scope and methodology and discusses the key assumptions that underlie the results. The full consultant report prepared for EIA is in Attachment A. EIA anticipates using this work to inform other analysis and projections, and to provide a starting point for additional work on this and related topics.

Scope and Results

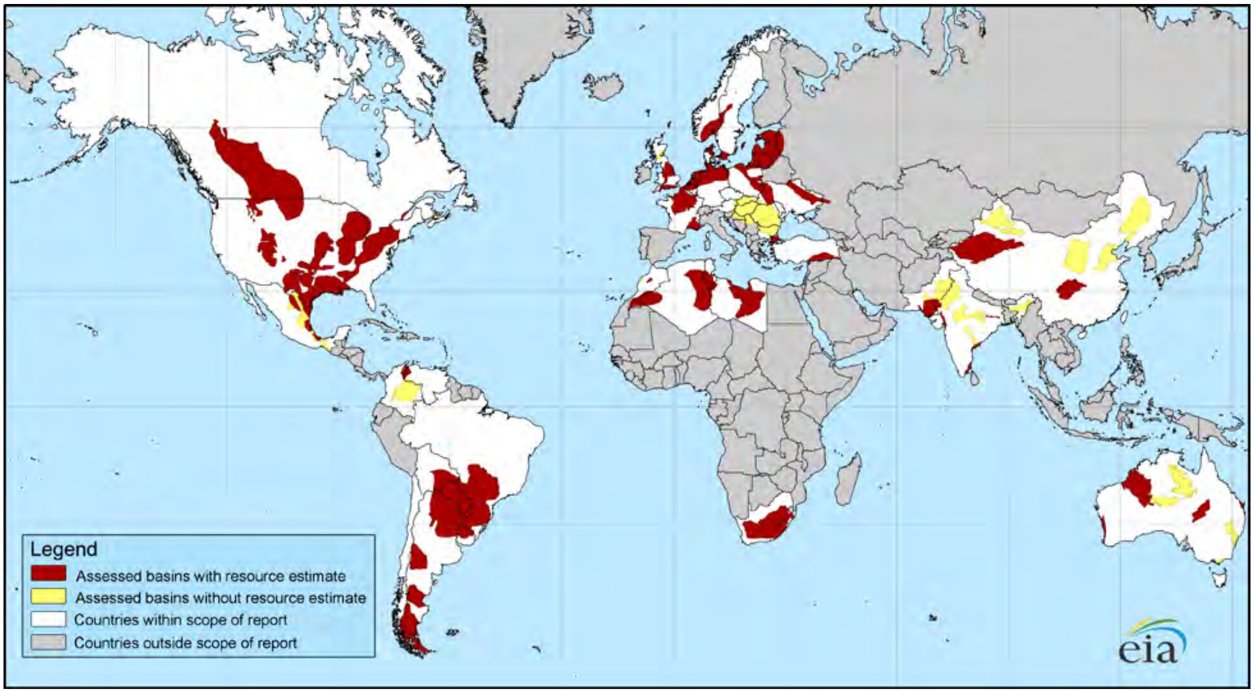
In total, the report assessed 48 shale gas basins in 32 countries, containing almost 70 shale gas formations. These assessments cover the most prospective shale gas resources in a select group of countries that demonstrate some level of relatively near-term promise and for basins that have a sufficient amount of geologic data for resource analysis. Figure 1 shows the location of these basins and the regions analyzed. The map legend indicates four different colors on the world map that correspond to the geographic scope of this initial assessment:

- Red colored areas represent the location of assessed shale gas basins for which estimates of the 'risked' gas-in-place and technically recoverable resources were provided.
- Yellow colored area represents the location of shale gas basins that were reviewed, but for which estimates were not provided, mainly due to the lack of data necessary to conduct the assessment.
- White colored countries are those for which at least one shale gas basin was considered for this report.
- Gray colored countries are those for which no shale gas basins were considered for this report.

Although the shale gas resource estimates will likely change over time as additional information becomes available, the report shows that the international shale gas resource base is vast. The initial estimate of technically recoverable shale gas resources in the 32 countries examined is 5,760 trillion

[4] Examples of EIA work that has spurred or resulted from interest in this topic includes: U.S. Energy Information Administration, *AEO2011 Early Release Overview* (Dec 2010); R. Newell, U.S. Energy Information Administration, "Shale Gas, A Game Changer for U.S. and Global Gas Markets?", presented at the *Flame – European Gas Conference*, Amsterdam, Netherlands (March 2, 2010); H. Gruenspecht, U.S. Energy Information Administration, "International Energy Outlook 2010 With Projections to 2035", presented at Center for Strategic and International Studies, Washington, D.C. (May 25, 2010); and R. Newell, U.S. Energy Information Administration, "The Long-term Outlook for Natural Gas", presented to the Saudi Arabia - United States Energy Consultations, Washington, D.C. (February 2, 2011).

Figure 1. Map of 48 major shale gas basins in 32 countries



cubic feet, as shown in Table 1. Adding the U.S. estimate of the shale gas technically recoverable resources of 862 trillion cubic feet results in a total shale resource base estimate of 6,622 trillion cubic feet for the United States and the other 32 countries assessed. To put this shale gas resource estimate in some perspective, world proven reserves[5] of natural gas as of January 1, 2010 are about 6,609 trillion cubic feet,[6] and world technically recoverable gas resources are roughly 16,000 trillion cubic feet,[7] largely excluding shale gas. Thus, adding the identified shale gas resources to other gas resources increases total world technically recoverable gas resources by over 40 percent to 22,600 trillion cubic feet.

The estimates of technically recoverable shale gas resources for the 32 countries outside of the United States represents a moderately conservative 'risked' resource for the basins reviewed. These estimates are uncertain given the relatively sparse data that currently exist and the approach the consultant has employed would likely result in a higher estimate once better information is available. The methodology is outlined below and described in more detail within the attached report, and is not directly comparable to more detailed resource assessments that result in a probabilistic range of the technically

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[5] Reserves refer to gas that is known to exist and is readily producible, which is a subset of the technically recoverable resource base estimate for that source of supply. Those estimates encompass both reserves and that natural gas which is inferred to exist, as well as undiscovered, and can technically be produced using existing technology. For example, EIA's estimate of all forms of technically recoverable natural gas resources in the U.S. for the *Annual Energy Outlook 2011* is 2,552 trillion cubic feet, of which 827 trillion cubic feet consists of unproved shale gas resources and 245 trillion cubic feet are proved reserves which consist of all forms of readily producible natural gas including 34 trillion cubic feet of shale gas.

[6] "Total reserves, production climb on mixed results," *Oil and Gas Journal* (December 6, 2010), pp. 46-49.

[7] Includes 6,609 trillion cubic feet of world proven gas reserves (*Oil and Gas Journal 2010*); 3,305 trillion cubic feet of world mean estimates of inferred gas reserves, excluding the Unites States (USGS, *World Petroleum Assessment 2000*); 4,669 trillion cubic feet of world mean estimates of undiscovered natural gas, excluding the United States (USGS, *World Petroleum Assessment 2000*); and U.S. inferred reserves and undiscovered gas resources of 2,307 trillion cubic feet in the United States, including 827 trillion cubic feet of unproved shale gas (EIA, *AEO2011*).

Table 1. Estimated shale gas technically recoverable resources for select basins in 32 countries, compared to existing reported reserves, production and consumption during 2009

	2009 Natural Gas Market[1] (trillion cubic feet, dry basis)			Proved Natural Gas Reserves[2] (trillion cubic feet)	Technically Recoverable Shale Gas Resources (trillion cubic feet)
	Production	Consumption	Imports (Exports)		
Europe					
France	0.03	1.73	98%	0.2	180
Germany	0.51	3.27	84%	6.2	8
Netherlands	2.79	1.72	(62%)	49.0	17
Norway	3.65	0.16	(2,156%)	72.0	83
U.K.	2.09	3.11	33%	9.0	20
Denmark	0.30	0.16	(91%)	2.1	23
Sweden	-	0.04	100%		41
Poland	0.21	0.58	64%	5.8	187
Turkey	0.03	1.24	98%	0.2	15
Ukraine	0.72	1.56	54%	39.0	42
Lithuania	-	0.10	100%		4
Others[3]	0.48	0.95	50%	2.71	19
North America					
United States[4]	20.6	22.8	10%	272.5	862
Canada	5.63	3.01	(87%)	62.0	388
Mexico	1.77	2.15	18%	12.0	681
Asia					
China	2.93	3.08	5%	107.0	1,275
India	1.43	1.87	24%	37.9	63
Pakistan	1.36	1.36	-	29.7	51
Australia	1.67	1.09	(52%)	110.0	396
Africa					
South Africa	0.07	0.19	63%	-	485
Libya	0.56	0.21	(165%)	54.7	290
Tunisia	0.13	0.17	26%	2.3	18
Algeria	2.88	1.02	(183%)	159.0	231
Morocco	0.00	0.02	90%	0.1	11
Western Sahara	-	-		-	7
Mauritania	-	-		1.0	0
South America					
Venezuela	0.65	0.71	9%	178.9	11
Colombia	0.37	0.31	(21%)	4.0	19
Argentina	1.46	1.52	4%	13.4	774
Brazil	0.36	0.66	45%	12.9	226
Chile	0.05	0.10	52%	3.5	64
Uruguay	-	0.00	100%		21
Paraguay	-	-			62
Bolivia	0.45	0.10	(346%)	26.5	48
Total of above areas	**53.1**	**55.0**	**(3%)**	**1,001**	**6,622**
Total world	**106.5**	**106.7**	**0%**	**6,609**	

Sources:
[1]Dry production and consumption: EIA, International Energy Statistics, as of March 8, 2011.
[2] Proved gas reserves: *Oil and Gas Journal*, Dec., 6, 2010, P. 46-49.
[3]Romania, Hungary, Bulgaria.
[4] U.S. data are from various EIA sources.

recoverable resource. At the current time, there are efforts underway to develop more detailed shale gas resource assessments by the countries themselves, with many of these assessments being assisted by a number of U.S. federal agencies under the auspices of the Global Shale Gas Initiative (GSGI) which was launched in April 2010.[8]

Delving deeper into the results at a country level, there are two country groupings that emerge where shale gas development may appear most attractive. The first group consists of countries that are currently highly dependent upon natural gas imports, have at least some gas production infrastructure, and their estimated shale gas resources are substantial relative to their current gas consumption. For these countries, shale gas development could significantly alter their future gas balance, which may motivate development. Examples of countries in this group include France, Poland, Turkey, Ukraine, South Africa, Morocco, and Chile. In addition, South Africa's shale gas resource endowment is interesting as it may be attractive for use of that natural gas as a feedstock to their existing gas-to-liquids (GTL) and coal-to-liquids (CTL) plants.

The second group consists of those countries where the shale gas resource estimate is large (e.g., above 200 trillion cubic feet) and there already exists a significant natural gas production infrastructure for internal use or for export. In addition to the United States, notable examples of this group include Canada, Mexico, China, Australia, Libya, Algeria, Argentina, and Brazil. Existing infrastructure would aide in the timely conversion of the resource into production, but could also lead to competition with other natural gas supply sources. For an individual country the situation could be more complex.

Methodology

This report represents EIA's initial effort to produce a systematic assessment of the international shale gas resource base and contains chapters on the 14 priority regions identified by EIA for initial study, including 32 countries. These priority regions were selected for a combination of factors that included potential availability of data, country-level natural gas import dependence, observed large shale basins, and observations of activities by companies and governments directed at shale gas development.

The 14 regions and 32 countries covered in the report are:

- Canada
- Mexico
- Northern South America (Columbia, Venezuela)
- Southern South America (Argentina, Chile, Uruguay, Paraguay, Bolivia, Brazil)
- Central North Africa (Algeria, Tunisia, Libya)
- Western North Africa (Morocco, Mauritania, Western Sahara)
- Southern Africa (South Africa)
- Western Europe (including, France, Germany, Netherlands, Norway, Denmark, Sweden, United Kingdom)
- Poland
- Ukraine, Lithuania and other Eastern Europe countries

[8] The Department of State is the lead agency for the GSGI, and the other U.S. government agencies that also participate include: the U.S. Agency for International Development (USAID); the Department of Interior's U.S. Geological Survey (USGS); Department of Interior's Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE); the Department of Commerce's Commercial Law Development Program (CLDP); the Environmental Protection Agency (EPA), and the Department of Energy's Office of Fossil Energy (DOE/FE). See http://www.state.gov/s/ciea/gsgi/index.htm for more information.

- China
- India and Pakistan
- Turkey
- Australia

Russia and Central Asia, Middle East, South East Asia, and Central Africa were not addressed by the current report. This was primarily because there was either significant quantities of conventional natural gas reserves noted to be in place (i.e., Russia and the Middle East), or because of a general lack of information to carry out even an initial assessment. In addition, certain limitations in scope reflected funding constraints.

The consultant's approach relied upon publically available data from technical literature and studies on each of the selected international shale gas basins to first provide an estimate of the 'risked gas in-place,' and then to estimate the technically recoverable resource for that region. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

Risked Gas In-Place

The risked gas in-place estimate is derived by first estimating the amount of 'gas in-place' resource for a prospective area within the basin, and then de-rating that gas in-place by factors that, in the consultant's expert judgment, account for the current level of knowledge of the resource and the capability of the technology to eventually tap into the resource. The resulting estimate is referred to as the risked gas in-place.

Determining the risked gas in-place consists of the following specific steps:

1. Conduct a preliminary review of the basin and select the shale gas formations to be assessed.
2. Determine the areal extent of the shale gas formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the 'prospective area' deemed likely to be suitable for development based on a number of criteria and application of expert judgment.
4. Estimate the gas in-place as a combination of 'free gas'[9] and 'adsorbed gas'[10] that is contained within the prospective area.
5. Establish and apply a composite 'success factor' made up of two parts. The first part is a 'play success probability factor' which takes into account the results from current shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a 'prospective area success factor', which takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the 'prospective area' from development.

Technically Recoverable Resource

The estimated technically recoverable resource base is one of the basic metrics for quantifying the total resource base that analysts would use to estimate future natural gas production. The technically

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[9] 'Free gas' is gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

[10] 'Adsorbed gas' is gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

recoverable resource estimate for shale gas in this report is established by multiplying the risked gas-in-place by a shale gas recovery factor, which incorporates a number of geological inputs and analogs that are appropriate to each shale gas basin and formation.

The basic recovery factors used in this report generally ranged from 20 percent to 30 percent, with some outliers of 15 percent and 35 percent being applied in exceptional cases. The consultant selected the recovery factor based on prior experience in how production occurs, on average, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology.

Key Exclusions

The information contained within this report represents an initial assessment of the shale gas resource base in 14 regions outside the United States. As such, there are a number of additional factors outside of the scope of this report that must be considered when attempting to incorporate the information into a forecast of future shale gas production. In addition, several other exclusions were made for this report to simplify how the assessments were made and to keep the work to a level consistent with the available resources.

Some of the key exclusions for this report include the following:

- **Assessed basins without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional basins would, on average, likely result in an increase in the estimated resource base.
- **Countries outside the scope of the report,** the inclusion of which would also likely add to the estimated resource base – particularly since it is acknowledged that potentially productive shales exist in Russia and most of the countries in the Middle East. While expanding the scope would likely result in an increase in the estimated shale gas technically recoverable resources, this initial assessment did not focus on those regions due to their substantial conventional gas resources. In other cases, the infrastructure or markets that would be a necessary precondition for gas production may not be built within a meaningful time frame.
- **Offshore portions** of assessed shale gas basins were excluded, as well as shale gas basins that exist entirely offshore.
- **Coalbed methane, tight gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
- **Shale oil** was excluded from the assessment, although the contractor noted for several basins that the limits of the assessed shale gas area were defined by the transition from higher maturity gas prone areas to the lower maturity 'oil window'.
- **Production costs** were not estimated for any of the basins. The costs of production could be greatly impacted by a number of factors including the availability of existing infrastructure, availability and cost of adequately trained labor, availability and cost of equipment such as rigs and pumping equipment, the geologic features of the fields within the play such as depth and thickness, and a number of other factors that affect the direct costs of production. Estimated production costs for each of the basins would also need to be considered in order to estimate the potential future production of shale gas given a future price.
- **Above ground issues** were not considered, such as access to the resource, can greatly affect production costs and the timing of production.

Attachment A

WORLD SHALE GAS RESOURCES: AN INITIAL ASSESSMENT OF 14 REGIONS OUTSIDE THE UNITED STATES

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1. EXECUTIVE SUMMARY AND STUDY RESULTS

INTRODUCTORY REMARKS

The “World Shale Gas Resources: An Initial Assessment”, conducted by Advanced Resources International, Inc. (ARI) for the U.S. DOE’s Energy Information Administration (EIA), evaluates the shale gas resource in 14 regions containing 32 countries, Table 1-1.

The information provided in the 14 regional reports (selected for assessment by EIA) should be viewed as initial steps toward future, more comprehensive assessments of shale gas resources. The study investigators would have, if allowed, devoted the entire study budget to just one of the 14 regions and would have judged this more in-depth time and budget investment “well spent”. Alas, that was not possible. As such, this shale gas resource assessment captures our “first-order” view of the gas in-place and technically recoverable resource for the 48 shale gas basins and 69 shale gas formations addressed by the study. As additional exploration data are gathered, evaluated and incorporated, the assessment of shale gas resources will become more rigorous.

Table 1-1. The Scope of the "World Shale Gas Resources: An Initial Assessment"

Continent	Region/Country	Number of Countries	Number of Basins	Number of Gas Shale Formations
North America	I. Canada	1	7	9
	II. Mexico	1	5	8
	Subtotal	2	12	17
South America	III. Northern South America	2	2	3
	IV. Southern South America	6	4	7
	Subtotal	8	6	10
Europe	V. Poland	1	3	3
	VI. Eastern Europe	3	3	3
	VII. Western Europe	7	6	9
	Subtotal	11	12	15
Africa	VIII. Central North Africa	3	2	4
	IX. Morocco	3	2	2
	X. South Africa	1	1	3
	Subtotal	7	5	9
Asia	XI. China	1	2	4
	XII. India/Pakistan	2	5	6
	XIII. Turkey	1	2	3
	Subtotal	4	9	13
Australia	XIV. Australia	1	4	5
Total		**32**	**48**	**69**

Two points are important to keep in mind when viewing the individual shale gas basin- and formation-level shale gas resource assessments:

- First, the resource assessments provided in the individual regional reports are only for the higher quality, "prospective areas" of each shale gas basin and formation. The lower quality and less defined shale gas resource areas in these basins, that may hold additional shale gas resources, are not included in the quantitatively assessed and reported values.

- Second, the in-place and recoverable resource values for each shale gas basin and formation have been risked to incorporate: (1) the probability that the shale gas formation will (or will not) have sufficiently attractive gas flow rates to become developed; and (2) an expectation of how much of the prospective area set forth for each shale gas basin and formation will be developed in the foreseeable future.

No doubt, future exploration drilling will lead to adjustments in these two risk factors and thus the ultimate size of the developable international shale gas resource. We would urge the U.S. Energy Information Administration, who commissioned this valuable, “cutting edge” shale gas resource assessment, to capture and incorporate the significant volume of shale gas exploration and resource information that will become available during the next several years, helping keep this shale gas resource assessment “evergreen”.

SUMMARY OF STUDY FINDINGS

Although the exact resource numbers will change with time, our work shows that the international shale gas resource is vast.

- Overall, we have identified and assessed a shale gas resource equal to 22,016 Tcf of risked gas in-place, not including U.S. shale gas resources.

- Applying appropriate recovery factors, we estimate a technically recoverable shale gas resource of 5,760 Tcf.

Importantly, much of this shale gas resource exists in countries with limited conventional gas supplies or where the conventional gas resource has largely been depleted, such as in China, South Africa and Europe.

The regional level tabulations of the risked in-place and technically recoverable shale gas resource are provided in Table 1-2.

Table 1-2. Risked Gas In-Place and Technically Recoverable Shale Gas Resources: Six Continents

Continent	Risked Gas In-Place (Tcf)	Risked Technically Recoverable (Tcf)
North America	3,856	1,069
South America	4,569	1,225
Europe	2,587	624
Africa	3,962	1,042
Asia	5,661	1,404
Australia	1,381	396
Total	**22,016**	**5,760**

A more detailed tabulation of shale gas resources (risked gas in-place and risked technically recoverable), at the country-level, is provided in Table 1-3.

Additional information on the size of the shale gas resource, at a detailed basin- and formation-level, is provided in Appendix A.

Significant additional shale gas resources exist in the Middle East, in Russia, in Indonesia, and numerous other regions and countries not yet included in our study. Hopefully, future editions of this report will more fully incorporate these other important shale gas areas.

Table 1-3. Risked Gas In-Place and Technically Recoverable Shale Gas Resources: 32 Countries

Continent	Region	Country	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
North America	I. Canada		1,490	388
	II. Mexico		2,366	681
	Total		**3,856**	**1,069**
South America	III. Northern South America	Columbia	78	19
		Venezuela	42	11
		Subtotal	*120*	*30*
	IV. Southern South America	Argentina	2,732	774
		Bolivia	192	48
		Brazil	906	226
		Chile	287	64
		Paraguay	249	62
		Uruguay	83	21
		Subtotal	*4,449*	*1,195*
	Total		**4,569**	**1,225**
Europe	VI. Eastern Europe	Poland	792	187
		Lithuania	17	4
		Kaliningrad	76	19
		Ukraine	197	42
			1,082	*252*
	VII. Western Europe	France	720	180
		Germany	33	8
		Netherlands	66	17
		Sweden	164	41
		Norway	333	83
		Denmark	92	23
		U.K.	97	20
		Subtotal	*1,505*	*372*
	Total		**2,587**	**624**
Africa	VIII. Central North Africa	Algeria	812	230
		Libya	1,147	290
		Tunisia	61	18
		Morroco*	108	18
		Subtotal	*2,128*	*557*
	X. South Africa		1,834	485
	Total		**3,962**	**1,042**
Asia	XI. China		5,101	1,275
	XII. India/Pakistan	India	290	63
		Pakistan	206	51
	XIII. Turkey		64	15
	Total		**5,661**	**1,404**
Australia	XIV. Australia		**1,381**	**396**
Grand Total			**22,016**	**5,760**

* Includes Western Sahara & Mauritania

Advanced Resources International, Inc.

COMPARISON OF STUDY FINDINGS

Prior to this study - - "World Shale Gas Resources: An Initial Assessment" - - only one other study is publically available that addresses the overall size of the shale gas resource. This is the valuable work by H-H. Rogner.[1]

Our detailed basin-by-basin assessments of the shale gas resource, show that the shale gas resource in-place is larger than estimated by Rogner, even accounting for the fact that a number of the large shale gas resource areas (such as Russia and the Middle East) have not yet been included in our study (but are included in Rogner's shale gas resource numbers).

- Overall, our gas study established a risked shale gas in-place of 25,300 Tcf (when we include our shale gas estimate for the U.S. of 3,284 Tcf) compared to Rogner's estimate of 13,897 Tcf of shale gas in-place when we exclude the areas of the world not included in this study. (Rogner's total shale gas in-place is 16,112 Tcf.)
- The largest and most notable areas of difference in the shale gas resource assessments are for Europe, Africa and North America, Table 1-4.

Table 1-4. Comparison of Rogner's and This Study Estimates of Shale Gas Resources In-Place

Continent	H-H Rogner (Tcf)	EIA/ARI (Tcf)
1. North America*	3,842	7,140
2. South America	2,117	4,569
3. Europe	549	2,587
4. Africa**	1,548	3,962
5. Asia	3,528	5,661
6. Australia	2,313	1,381
7. Other***	2,215	n/a
Total	16,112	25,300

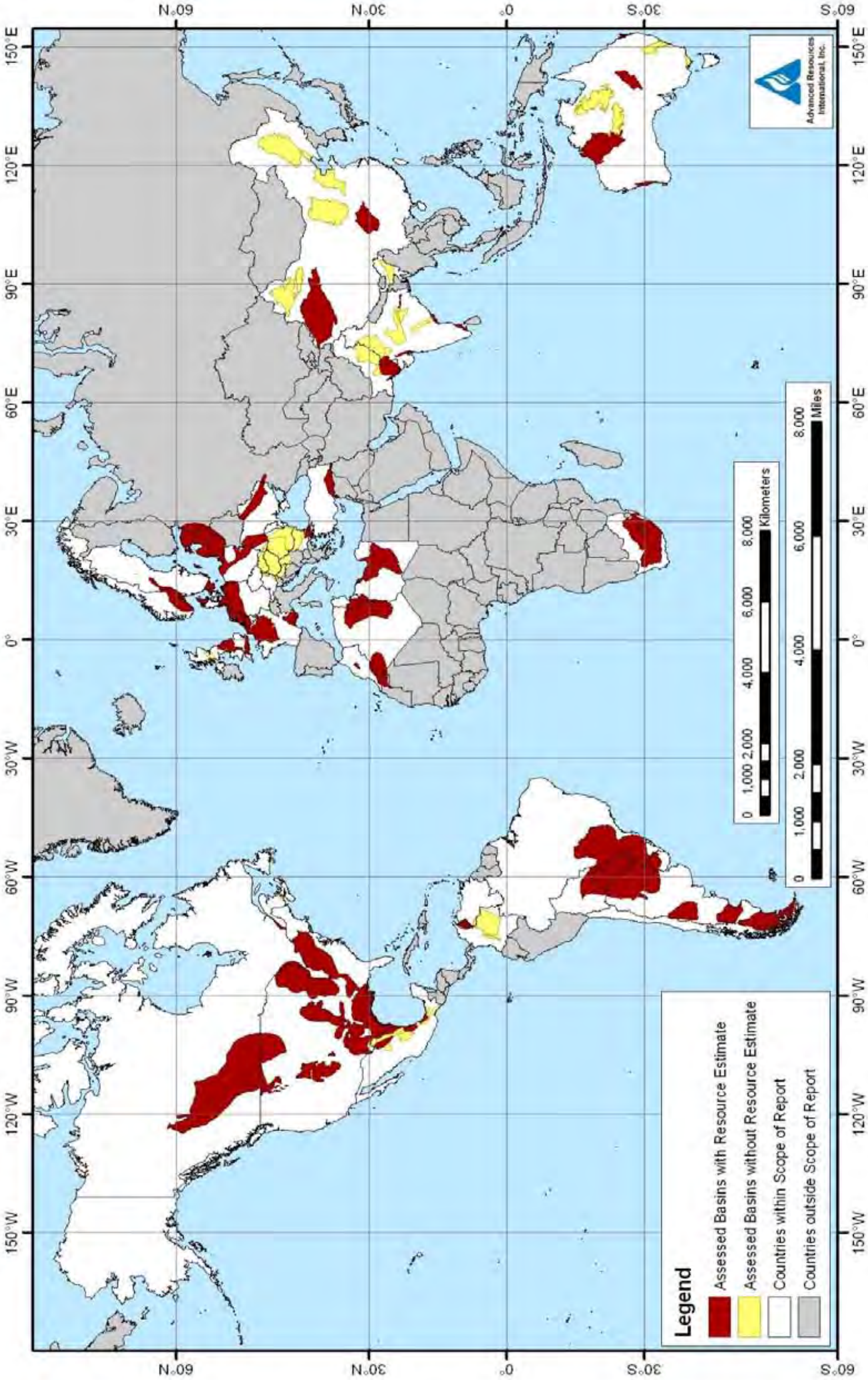
* Includes U.S. shale gas in-place of 3,.824 Tcf, based on estimated (ARI) 820 Tcf of technically recoverable shale gas resources and a 25% recovery efficiency of shale gas in-place.

** Rogner estimate includes one-half of Middle East and North Africa (1,274) and Sub-Saharan Africa (274 Tcf).

*** Includes FSU (627 Tcf), Other Asia Pacific (314 Tcf) and one-half of Middle East/North Africa (1,274) Tcf.

[1] Rogner, H-H., "An Assessment of World Hydrocarbon Resources", Annu. Rev. Energy Environ. 1997, 22:217-62.

Figure 1-1 Map of 48 Major Shale Basins in 32 Countries



2. SHALE GAS RESOURCE ASSESSMENT METHODOLOGY

INTRODUCTION

This Chapter sets forth our methodology for assessing the in-place and recoverable shale gas resources for the 14 regions (encompassing 32 countries) addressed by this study. The methodology relies on extensive geological information and reservoir properties assembled from the technical literature and data from publically available company reports and presentations. This publically available information has been augmented by internal (non-confidential) prior work on U.S. and international shale gas by Advanced Resources International.

The regional reports should be viewed as initial steps toward future, more comprehensive assessments of shale gas resources. As additional exploration data are gathered, evaluated and incorporated, these regional assessments of shale gas resources will become more rigorous.

RESOURCE ASSESSMENT METHODOLOGY

The methodology for conducting the basin- and formation-level assessments of shale gas resources includes the following five topics:

1. Conducting preliminary geologic and reservoir characterization of shale basins and formation(s).
2. Establishing the areal extent of the major shale gas formations.
3. Defining the prospective area for each shale gas formation.
4. Estimating the risked shale gas in-place.
5. Calculating the technically recoverable shale gas resource.

Each of these five shale gas resource assessment steps is further discussed below. The shale gas resource assessment for Central North Africa and particularly the Ghadames Basin is used to illustrate certain of these resource assessment steps.

2.1. Conducting Preliminary Geologic and Reservoir Characterization of Shale Basins and Formation(s).

The resource assessment begins with the compilation of data from multiple public and private sources to define the shale gas basins and to select the major shale gas formations to be assessed. The stratigraphic columns and well logs, showing the geologic age, the source rocks and other data, are used to select the major shale formations for further study, as illustrated in Figure 2.1 for the Ghadames Basin of southern Tunisia.

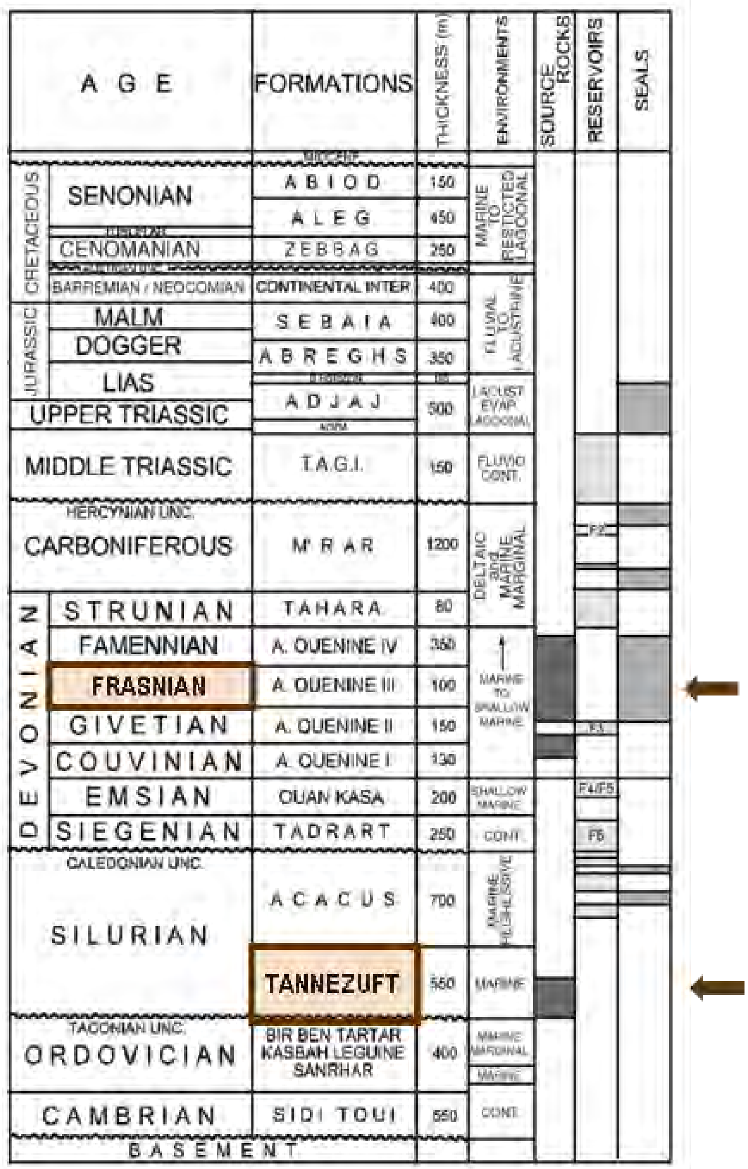
Preliminary geological and reservoir data are assembled for each major shale formation, including the following key items:

- Depositional environnent of shale (marine vs non-marine)
- Depth (to top and base of shale interval)
- Structure, including major faults
- Gross shale interval
- Organically-rich gross and net shale thickness
- Total organic content (TOC, by wt.)
- Thermal maturity (Ro)

These geologic and reservoir properties are used to provide a first order overview of the geologic characteristics of the major shale gas formations and to help select the shale gas formations deemed worthy of more intensive assessment.

Figure 2-1: Southern Tunisia, Ghadames Basin Stratigraphic Column[i]

(The two major shale gas formations, the Silurian Tannezuft and the Devonian Frasnian, are highlighted.)



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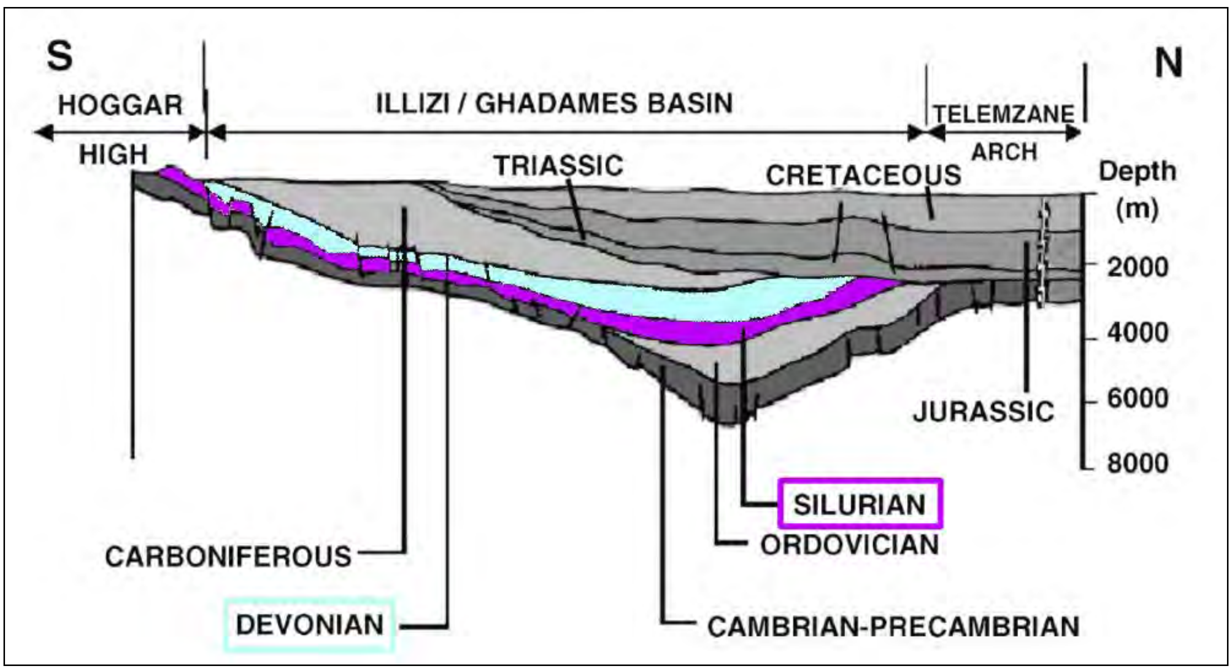
2.2. Establishing the Areal Extent of Major Shale Gas Formations.

Having identified the major shale gas formations, the next step is to undertake more intensive study to define the areal extent for each of these formations. For this, the study team searches the technical literature for regional as well as detailed, local cross-sections identifying the shale gas formations of interest, as illustrated by Figure 2.2 for the Silurian and Devonian shale gas formations in the Ghadames Basin. In addition, the study team draws on internal cross-sections previously prepared by Advanced Resources and, where necessary, assembles well data to construct new cross-sections.

The regional cross-sections are used to define the lateral extent of the shale formation in the basin and/or to identify the regional depth and gross interval of the shale formation.

Figure 2.2 : Ghadames Basin Structure Depth Map and Cross Section [i]

(The geological ages containing the two major shale gas formations, the Devonian and the Silurian, are highlighted.)



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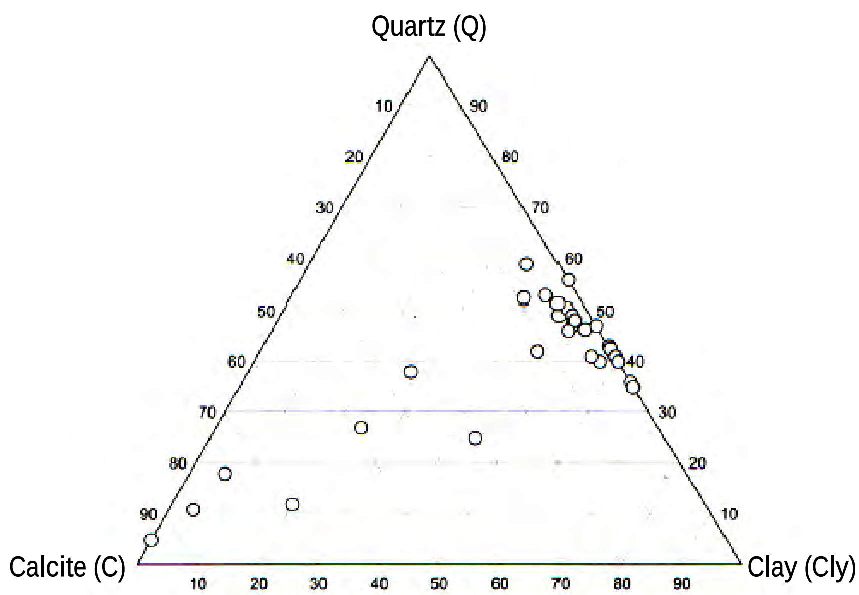
3. Defining the Prospective Area for Each Shale Gas Formation.

An important and challenging resource assessment step is to establish the portions of the basin that, in our view, are deemed to be prospective for development of shale gas. The criteria used for establishing the prospective area include:

- Depositional Environment. An important criterion is the depositional environment of the shale, particularly whether it is marine or non-marine. Marine-deposited shales tend to have lower clay content and tend to be high in brittle minerals such as quartz, feldspar and carbonates. Brittle shales respond favorably to hydraulic stimulation. Shales deposited in non-marine settings (lacustrine, fluvial) tend to be higher in clay, more ductile and less responsive to hydraulic stimulation.

  Figure 2.3 provides a ternary diagram useful for classifying the mineral content of the shale for the Marcellus Shale in Lincoln Co., West Virginia. Figure 2.4 illustrates the relationship between shale formation mineralogy, shale brittleness and shale response to hydraulic fracturing.

Figure 2.3. Ternary Diagram of Shale Mineralogy (Marcellus Shale).



Source: Modified from AAPG Bull. 4/2007, p. 494 & 495

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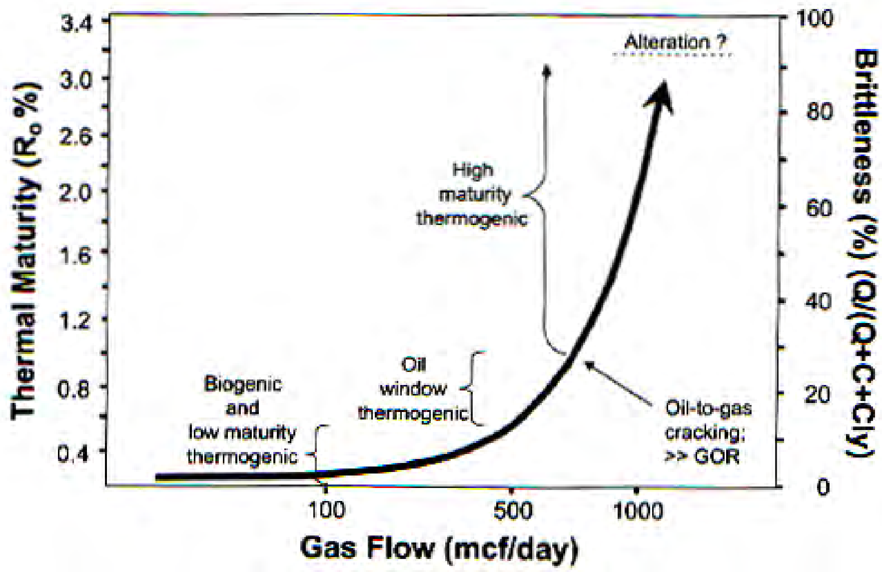
Figure 2.4. Relationship of Shale Mineralogy (Q, C and Cly) and Thermal Maturity to Gas Flow



Source: Modified from AAPG Bull. 4/2007, p. 494 & 495

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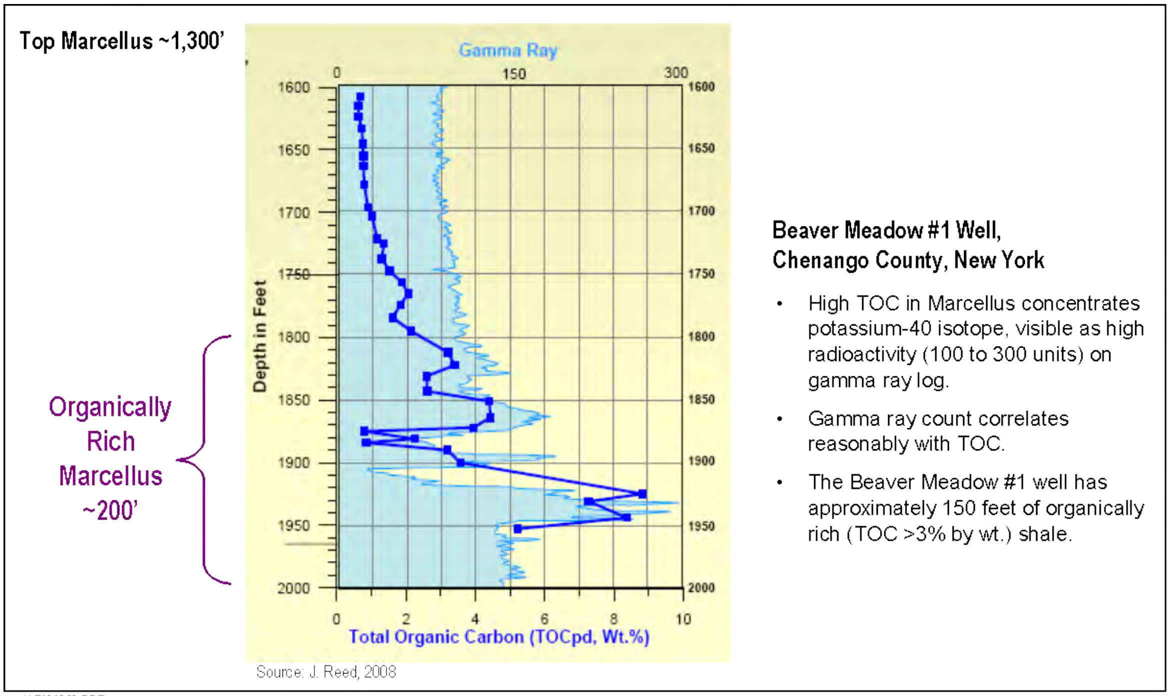
- Depth. The depth criterion for the prospective area is greater than 1,000 meters, but less than 5,000 meters (3,300 feet to 16,500 feet). Areas shallower than 1,000 meters have lower pressure and a lower gas concentration. In addition, shallow shale gas formations have risks of higher water content in their natural fracture systems. Areas deeper than 5,000 m have risks of reduced permeability and much higher drilling and development costs.

- Total Organic Content (TOC). In general, the TOC of prospective area needs to be equal to or greater than 2%. Figure 2.5 provides an example of using a gamma ray log to identify the TOC content for the Marcellus Shale in the New York (Chenango Co.) portion of the Appalachian Basin.

  Organic materials such as microorganism fossils and plant matter provide the requisite carbon, oxygen and hydrogen atoms needed to create natural gas and oil. As such TOC is an important measure of the gas generation potential of a shale formation.

Figure 2.5. Relationship of Gamma Ray and Total Organic Carbon



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- Thermal Maturity. Thermal maturity measures the degree to which a formation has been exposed to high heat needed to break down organic matter into hydrocarbons. The reflectance of certain types of minerals (Ro%) is used as an indication of Thermal Maturity, Figure 2.6.

  The thermal maturity of the prospective area needs to have a Ro greater than 1.0%, with a second higher quality prospective area defined as having a Ro greater than 1.3%. Higher thermal maturity settings also lead to the presence of nanopores which contribute to additional porosity in the shale matrix. Figure 2.7 provides an illustration of the relationship between thermal maturity and the development of nanopores in the shale matrix.

- Geographic Location. The prospective area is limited to the onshore portion of the shale gas basin.

Figure 2-6. Thermal Maturation Scale

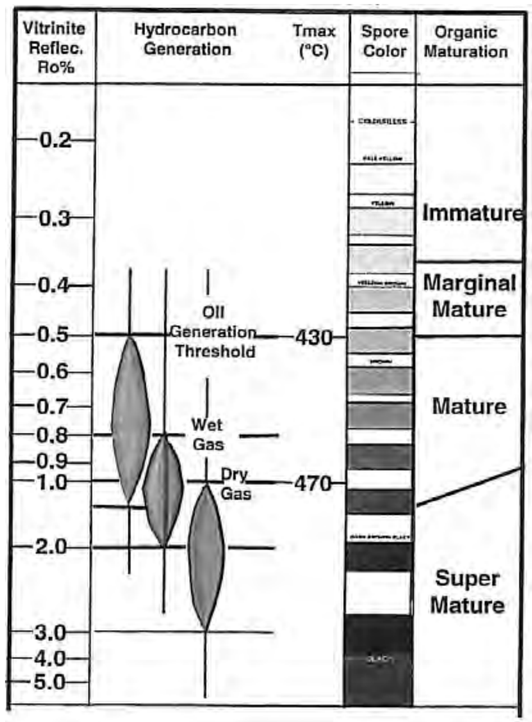
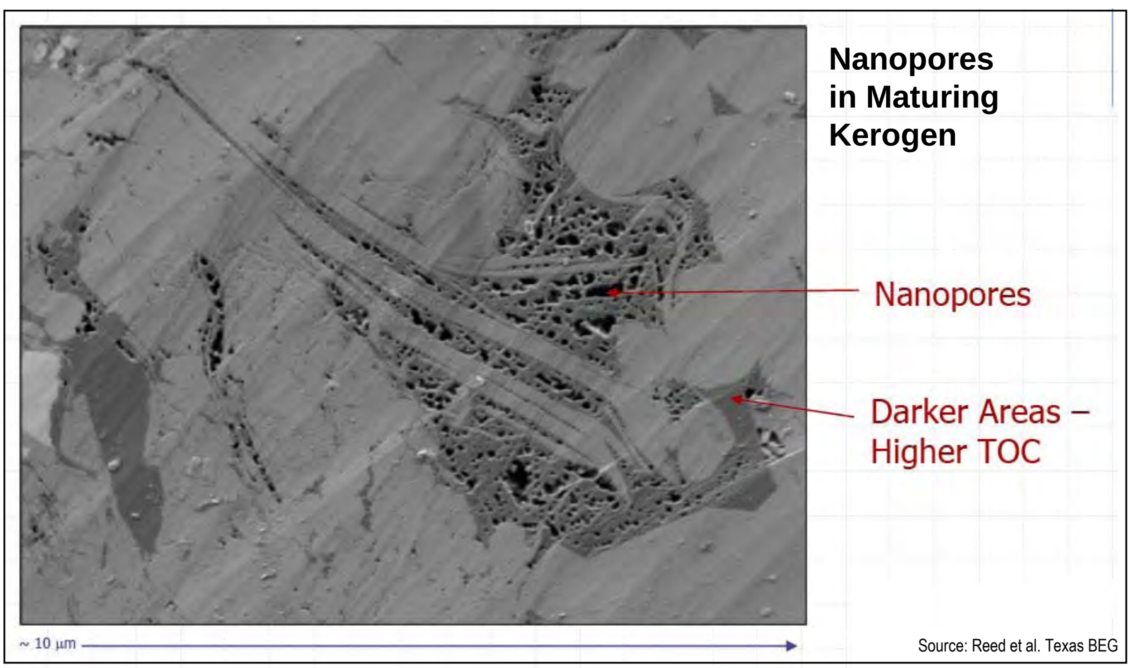


Figure 2-7. Thermal Maturity and Gas Storage Capacity



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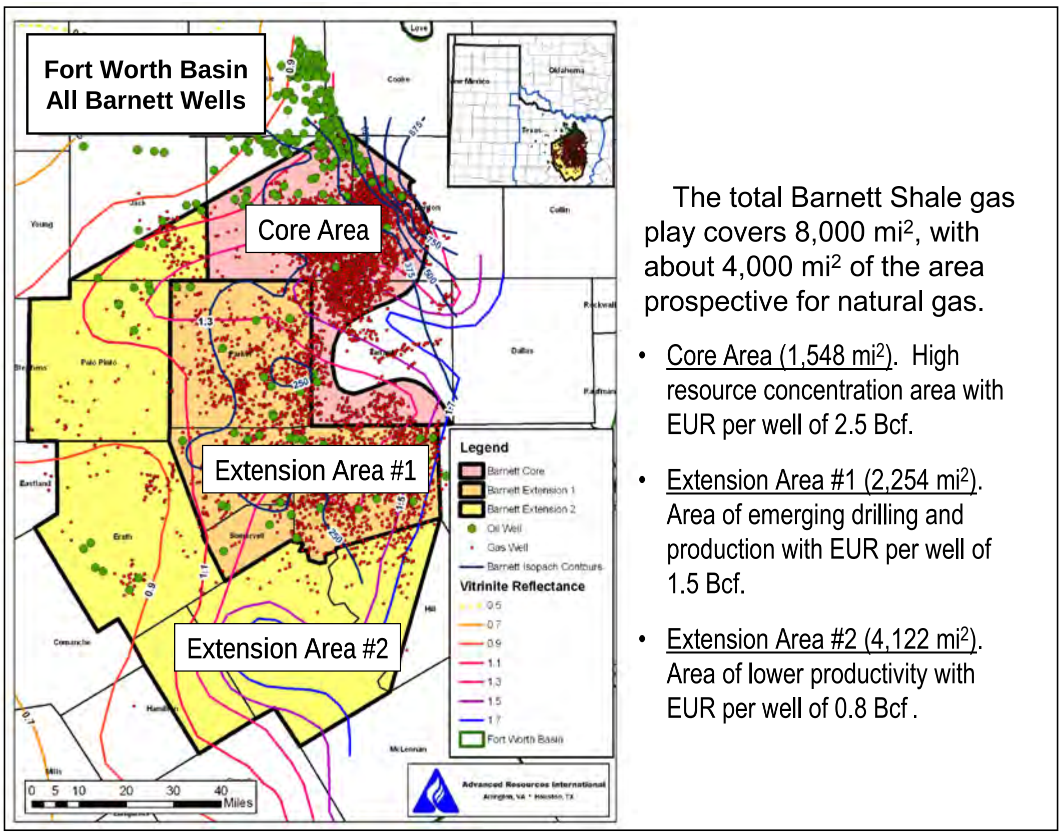
The prospective area contains the higher quality portion of the shale gas resource and, in general, covers less than half of the overall basin area. The prospective area will contain a series of shale gas quality areas, typically including a geologically favorable, high resource concentration "core area" and a series of lower quality and lower resource concentration extension areas. However, the further delineation of the prospective area was beyond the scope of this initial resource assessment study.

The U.S. Barnett Shale illustrates the presence of a high quality "core area", two extension areas (called Extension Area #l and Extension Area #2) and a lower thermally less mature (combination of oil, condensate and natural gas) play along the northern edge of the basin, Figure 2.8.

Figure 2-8. Barnett Shale Resource and Play Areas



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A more detailed resource assessment, including in-depth appraisal of newly drilled exploration wells, with modern logs and rigorous core analyses, will be required to define these next levels of resource quality and concentration for the major international shale gas plays.

4. Estimating the Risked Gas In-Place (GIP).

Detailed geologic and reservoir data are assembled to establish the free as well as the adsorbed gas in-place (GIP) for the prospective area. Adsorbed gas can be the dominant in-place resource for shallow and highly organically rich shales. Free gas becomes the dominant in-place resource for deeper, higher clastic content shales.

a. Free Gas In-Place. The calculation of free gas in-place for a given areal extent (acre, square mile) is governed, to a large extent, by four characteristics of the shale formation - - pressure, temperature, gas-filled porosity and net organically-rich shale thickness.

- Pressure. The study methodology places particular emphasis on identifying areas with overpressure, which enables a higher concentration of gas to be contained within a fixed reservoir volume. A normal hydrostatic gradient of 0.433 psi per foot of depth is used when actual pressure data is unavailable.

- Temperature. The study assembles data on the temperature of the shale formation, giving particular emphasis on identifying areas with higher than average temperature gradients and surface temperatures. A normal temperature gradient of 1° F per foot of depth plus a surface temperature of 60° F are used when actual temperature data is unavailable.

- Gas-Filled Porosity. The study assembles the porosity data from core or log analyses available in the public literature. When porosity data are not available, emphasis is placed on identifying the mineralogy of the shale and its maturity for estimating porosity values from analogous U.S shale basins. Unless other evidence is available, the study assumes the pores are filled with gas and residual water.

- Net Organically-Rich Shale Thickness. The overall shale interval is obtained from prior stratigraphic studies of the formations in the basin being appraised. The organically-rich thickness of the shale interval is established from log data and cross sections, where available. A net to gross ratio is used to estimate the net thickness of the shale from the gross organically-rich shale interval.

The above data are combined using established PVT reservoir engineering equations and conversion factors to calculate free GIP per square mile. The calculation of free GIP uses the following standard reservoir engineering equation:

$$\text{GIP} = \frac{43{,}560 * A\, h\Phi(1 - S_w)}{B_g}$$

$$\text{Where: } B_g = \frac{0.02829zT}{P}$$

A is area, in acres (with the conversion factors of 43,560 square feet per acre and 640 acres per square mile).

h is net shale thickness, in feet (a minimum TOC criterion of 2% (by wt.) is used to define the net organically-rich pay from the larger shale interval and the gross organically-rich shale thickness.)

ϕ is porosity, a dimensionless fraction (the values for porosity are obtained from log or core information published in the technical literature or assigned by analogy from U.S. shale gas basins; the thermal maturity of the shale and its depth of burial can influence the porosity value used for the shale).

$(1\text{-}S_W)$ is the fraction of the porosity filled by gas (S_g) instead of water (S_W), a dimensionless fraction (the established value for porosity (ϕ) is multiplied by the term $(1\text{-}S_W)$ to establish gas-filled porosity; the value Sw defines the fraction of the pore space that is filled with water, often the residual or irreducible reservoir water saturation in the natural fracture and matrix porosity of the shale; liquids-rich shales may also contain condensate and/or oil (So) in the pore space, further reducing gas-filled porosity.

P is pressure, in psi (pressure data is obtained from well test information published in the literature, inferred from mud weights used to drill through the shale sequence, or assigned by analog from U.S. shale gas basins; basins with normal reservoir pressure are assigned a gradient of 0.433 psi per foot of depth; basins with indicated overpressure are assigned pressure gradients of 0.5 to 0.6 psi per foot of depth; basins with indicated underpressure are assigned pressure gradients of 0.3 to 0.4 psi per foot of depth).

T is temperature, in degrees Rankin (temperature data is obtained from well test information published in the literature or from regional temperature versus depth gradients; the factor 460 ^{o}F is added to the reservoir temperature (in ^{o}F) to provide the input value for the gas volume factor (B_g) equation).

B_g is the gas volume factor, in cubic feet per standard cubic feet and includes the gas deviation factor (z), a dimensionless fraction. (The gas deviation factor (z) adjusts the ideal compressibility (PVT) factor to account for non-ideal PVT behavior of the gas; gas deviation factors, complex functions of pressure, temperature and gas composition, are published in standard reservoir engineering text.)

b. Adsorbed Gas In-Place. In addition to free gas, shales can hold significant quantities of gas adsorbed on the surface of the organics (and clays) in the shale formation.

A Langmuir isotherm is established for the prospective area of the basin using available data on TOC and on thermal maturity to establish the Langmuir volume (V_L) and the Langmuir pressure (P_L).

Adsorbed gas in-place is then calculated using the formula below (where P is original reservoir pressure).

$$G_C = (V_L * P) / (P_L + P)$$

The above gas content (G_C) (typically measured as cubic feet of gas per ton of net shale) is converted to gas concentration (adsorbed GIP per square mile) using actual or typical values for shale density. (Density values for shale are typically in the range of 2.65 to 2.8 gm/cc and depend on the mineralogy and organic content of the shale.)

The estimates of the Langmuir value (V_L) and pressure (P_L) for adsorbed gas in-place calculations are based on either publically available data in the technical literature or internal (proprietary) data developed by Advanced Resources from prior work on various U.S. and international shale basins.

In general, the Langmuir volume (V_L) is a function of the organic richness and thermal maturity of the shale, as illustrated in Figure 2.9. The Langmuir pressure (P_L) is a function of how readily the adsorbed gas on the organics in the shale matrix is released as a function of a finite decrease in pressure.

The free gas in-place (GIP) and adsorbed GIP are combined to estimate the resource concentration (Bcf/mi^2) for the prospective area of the shale gas basin. Figure 2.10 illustrates the relative contributions of free (porosity) gas and adsorbed (sorbed) gas to total gas in-place, as a function of pressure.

Figure 2-9. Marcellus Shale Adsorbed Gas Content

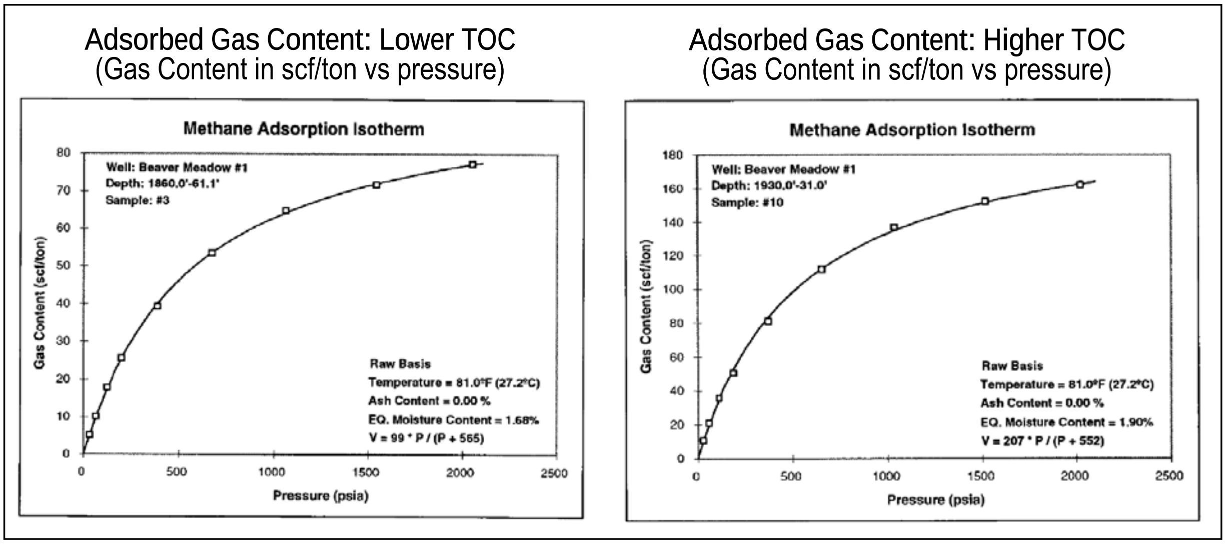

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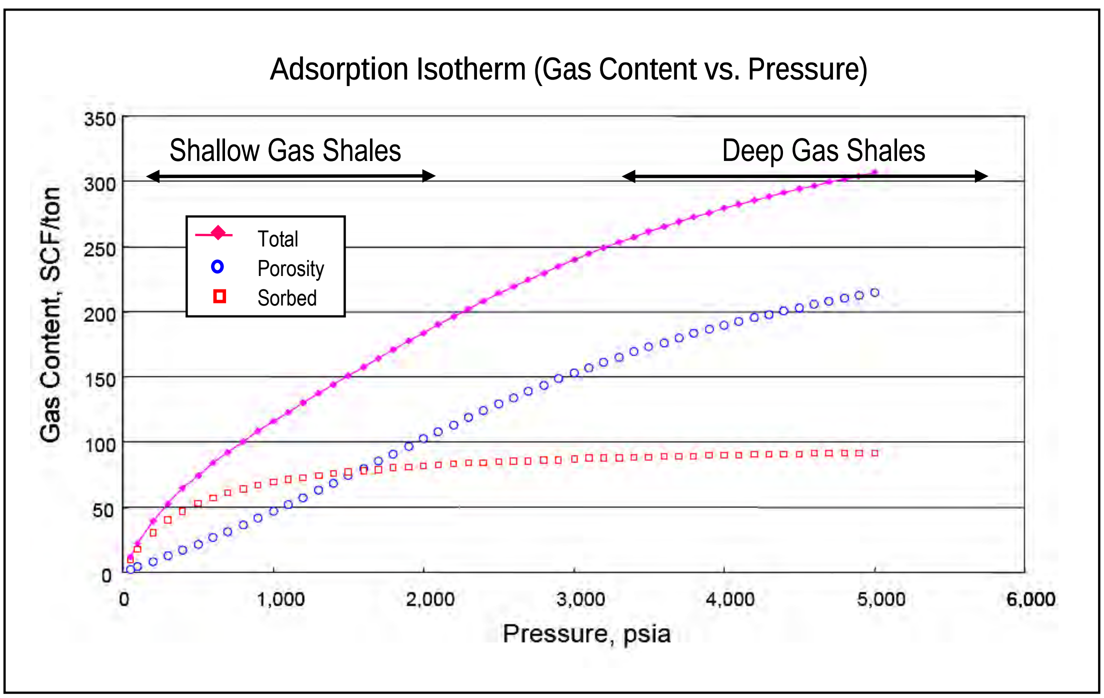
Figure 2-10. Combining Free and Adsorbed Gas for Total Gas In-Place



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c. Establishing the Success/Risk Factors. Two specific judgmentally established success/risk factors are used to estimate risked GIP within the prospective area of the shale gas formation. These two factors, are as follows:

- Play Success Probability Factor. The shale gas play success probability factor captures the likelihood that at least some significant portion of the shale gas formation will provide gas at attractive flow rates and become developed. Certain shale gas formations, such as the Muskwa Shale/Otter Park in the Horn River Basin are already under development and thus would have a play probability factor of 100%. More speculative shale gas formations with limited geologic and reservoir data, may only have a play success probability factor of 30% to 40%.

  As exploration wells are drilled, tested and produced and information on the viability of the shale gas play is established, the play success probability factor will change.

- Prospective Area Success (Risk) Factor: The prospective area success (risk) factor combines a series of concerns that could relegate a portion of the prospective area to be unsuccessful or unproductive for gas production. These concerns include areas with high structural complexity (e.g., deep faults, upthrust fault blocks); areas with lower thermal maturity (Ro between 1.0 and 1.2); the outer edge areas of the prospective area with lower net organic thickness; and other information appropriate to include in the success (risk) factor.

  The prospective area success (risk) factor also captures the amount of available geologic/reservoir data and the extent of exploration that has occurred in the prospective area of the basin to determine what portion of the prospective area has been sufficiently "de-risked". As exploration and delineation proceed, providing a more rigorous definition of the prospective area, the prospective area success (risk) factor will change.

These two success/risk factors are combined to derive a single composite success factor with which to risk the GIP for the prospective area. Appendix B provides a tabulation of the play success probability and prospective area success factors assigned to each of the major shale gas basins included in this resource assessment.

As introduced above, the history of shale gas exploration has shown that the success/risk factors, particularly the prospective area success/risk factor, change over time. As exploration wells are drilled and the favorable shale gas reservoir settings and prospective areas are more fully established, it is likely that larger assessments of the gas in-place will emerge.

6. Estimating the Technically Recoverable Resource.

The technically recoverable resource is established by multiplying the risked GIP by a shale gas recovery factor, which incorporates a number of geological inputs and analogs appropriate to each shale gas basin and formation. The recovery factor uses information on the mineralogy of the shale to determine its favorability for applying hydraulic fracturing to "shatter" the shale matrix. The recovery factor also considers other information that would impact gas well productivity, such as: presence of favorable micro-scale natural fractures; the absence of unfavorable deep cutting faults; the state of stress (compressibility) for the shale formations in the prospective area; the relative volumes of free and adsorbed gas concentrations; and the reservoir pressure in the prospective area.

Three basic gas recovery factors, incorporating shale mineralogy, reservoir properties and geologic complexity, are used in the resource assessment.

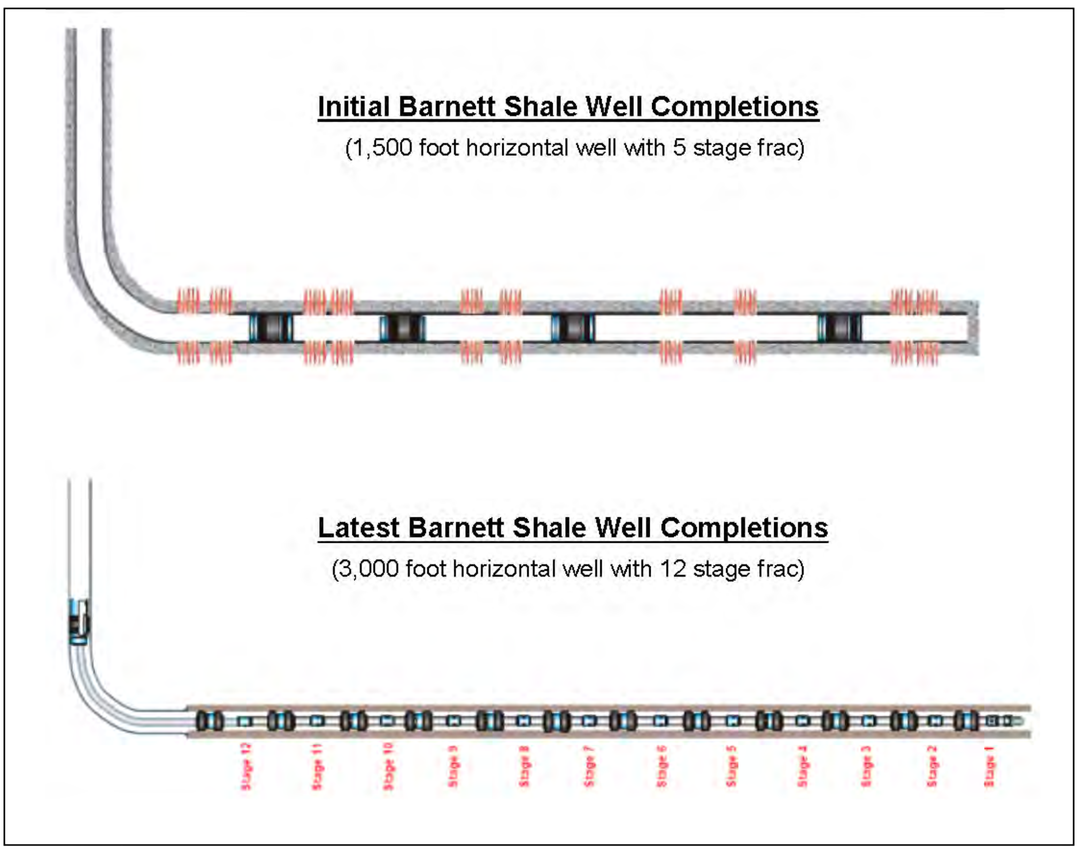
- Favorable Gas Recovery. A 30% recovery factor of the gas in-place is used for shale gas basins and formations that have low clay content, low to moderate geologic complexity and favorable reservoir properties such as an overpressured shale formation and high gas-filled porosity.
- Average Gas Recovery. A 25% recovery factor of the gas in-place is used for shale gas basins and formations that have a medium clay content, moderate geologic complexity and average reservoir pressure and properties.
- Less Favorable Gas Recovery. A 20% recovery factor of the gas in-place is used for shale gas basins and formations that have medium to high clay content, moderate to high geologic complexity and below average reservoir properties.

A recovery factor of 35% is applied in a few exceptional cases with established high rates of well performance. A recovery factor of 15% is applied in exceptional cases of severe under-pressure and reservoir complexity.

Finally, shale gas basins and formations that have very high clay content (e.g., non-marine shales) and/or have very high geologic complexity (e.g., thrusted and high stress) are categorized as non-prospective and excluded from this shale gas resource assessment. Subsequent, more intensive and smaller-scale (rather than regional-scale) resource assessments may identify the more favorable areas of a basin, enabling portions of the basin currently deemed non-prospective to be added to the shale gas resource assessment. Similarly, advances in well completion practices may enable more of the very high clay content shale formations to be efficiently stimulated, also enabling these basins and formations to be added to the resource assessment.

a. Two Key Gas Recovery Technologies. Because the native permeability of the shale gas reservoir is extremely low, on the order of a few hundred nano-darcies (0.0001 md to 0.001 md), efficient recovery of the gas held in the shale matrix requires two key well drilling and completion techniques, as illustrate by Figure 2.11:

Figure 2-11. Lower Damage, More Effective Horizontal Well Completions Provide Higher Reserves Per Well



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- Long Horizontal Wells. Long horizontal wells (laterals) are designed to place the gas production well in contact with as much of the shale matrix as technically and economically feasible.

- Intensive Well Stimulation. Large volume hydraulic stimulations, conducted in multiple, closely spaced stages (up to 20), are used to "shatter" the shale matrix and create a permeable reservoir. This intensive set of induced and propped hydraulic fractures provided the critical flow paths from the shale matrix to the horizontal well. Existing, small scale natural fractures (micro-fractures) will, if open, contribute additional flow paths from the shale matrix to the wellbore.

The efficiency of the hydraulic well stimulation depends greatly on the mineralogy of the shale, as further discussed below.

b. Importance of Mineralogy on Recoverable Resources. The mineralogy of the shale, particularly its relative quartz, carbonate and clay content, significantly determines how efficiently the induced hydraulic fracture stimulates the shale, as illustrated by Figure 2.12:

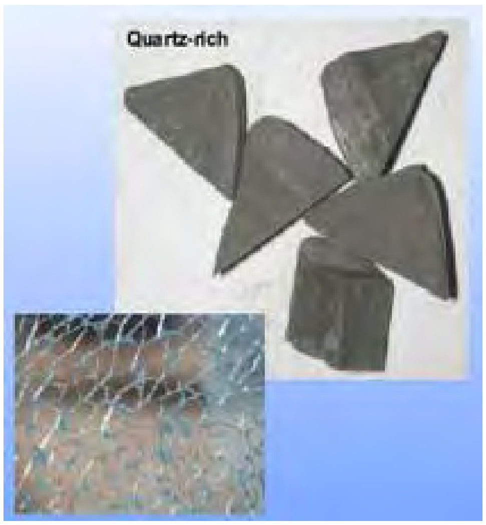
- Shales with a high percentage of quartz and carbonate tend to be brittle and will "shatter", leading to a vast array of small-scale induced fractures providing numerous flow paths from the matrix to the wellbore, when hydraulic pressure and energy are injected into the shale matrix, Figure 2.12A.

- Shales with a high clay content tend to be ductile and to deform instead of shattering, leading to relatively few induced fractures (providing only limited flow paths from the matrix to the well) when hydraulic pressure and energy are injected into the shale matrix, Figure 2.12B.

Figure 2-12. The Properties of the Reservoir Rock Greatly Influence the Effectiveness of Hydraulic Stimulations.

High clastic content shales are brittle and shatter, providing multiple dentrict fracture swarms. High clay content shales are plastic and absorb energy, providing single-planar fracs.

12A. Quartz-Rich (Brittle)



Barnett Shale

12B. Clay-Rich (Ductile)

Cretaceous Shale

Source: CSUG, 2008

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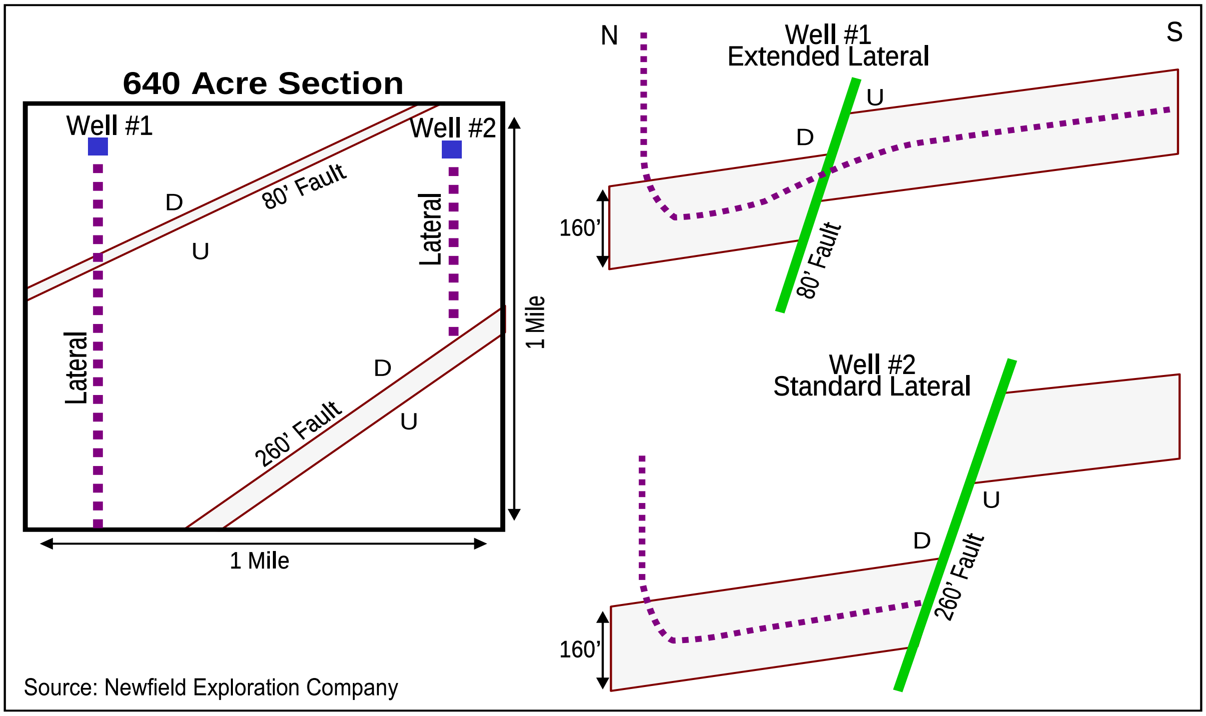
c. Significance of Geologic Complexity. A variety of complex geologic features can reduce the gas recovery efficiency from a shale gas basin and formation:

- Extensive Fault Systems. Areas with extensive faults can hinder gas recovery by limiting the productive length of the horizontal well, as illustrated by Figure 2.13.

- Deep Seated Fault System. Vertically extensive faults that cut through organically rich shale intervals can introduce water into the shale matrix, reducing relative permeability and gas flow capacity.

- Thrust Faults and Other High Stress Geological Features. Compressional tectonic features, such as thrust faults and up thrusted fault blocks, are an indication of basin areas with high lateral reservoir stress, reducing the permeability of the shale matrix and its gas flow capacity.

Figure 2-13. 3D Seismic Helps Design Extended vs. Limited Length Lateral Wells



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SUMMARY

The step-by-step application of the above discussed shale gas resource assessment methodology leads to three key assessment values for each major shale gas formation:

- Gas In-place Concentration, reported in terms of Bcf per square mile. This key resource assessment value defines the richness of the shale gas resource and its relative attractiveness compared to other gas development options.
- Risked Gas In-Place, reported in Tcf for each major shale gas formation.
- Risked Recoverable Gas, reported in Tcf for each major shale gas formation.

The risked gas in-place and recoverable gas provide the two "bottom line" values that help the reader understand how large is the prospective shale gas resource and what impact this resource may have on the energy, particularly the natural gas supply, options available in each region and country.

Table 2-1, constructed for two major shale gas basins and four shale gas formations, provide a concise summary of the resource assessment conducted for Central North Africa. Additional detail is provided in each of the 14 regional shale gas resource assessment reports.

These individual reports also allocate the risked shale gas in-place and recoverable shale gas resource to the various countries holding the assessed shale gas basins. For example, the assessment report for Central North Africa further details the shale gas resource (reported at the basin- and formation-level in Table 2-1) to the three countries holding these resources - - Algeria, Libya and Tunisia.

Table 2-1: Reservoir Properties and Resources of Central North Africa

Basic Data	Basin/Gross Area		Ghadames Basin (121,000 mi^2)		Sirt Basin (177,000 mi^2)	
	Shale Formation		Tannezuft	Frasnian	Sirt-Rachmat	Etel
	Geologic Age		Silurian	Middle Devonian	Upper Cretaceous	Upper Cretaceous
Physical Extent	Prospective Area (mi^2)		39,700	12,900	70,800	70,800
	Thickness (ft)	Interval	1,000 - 1,800	200 - 500	1,000 - 3,000	200 - 1,000
		Organically Rich	115	197	2,000	600
		Net	104	177	200	120
	Depth (ft)	Interval	9,000 - 16,500	8,200 - 10,500	9,000 - 11,000	11,000 - 13,000
		Average	12,900	9,350	10,000	12,000
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Normal	Normal
	Average TOC (wt. %)		5.7%	4.2%	2.8%	3.6%
	Thermal Maturity (%Ro)		1.15%	1.15%	1.10%	1.10%
	Clay Content		Medium	Medium	Medium/High	Medium/High
Resource	GIP Concentration (Bcf/mi^2)		44	65	61	42
	Risked GIP (Tcf)		520	251	647	443
	Risked Recoverable (Tcf)		156	75	162	111

REFERENCES

[i] Acheche, et al., 2001.

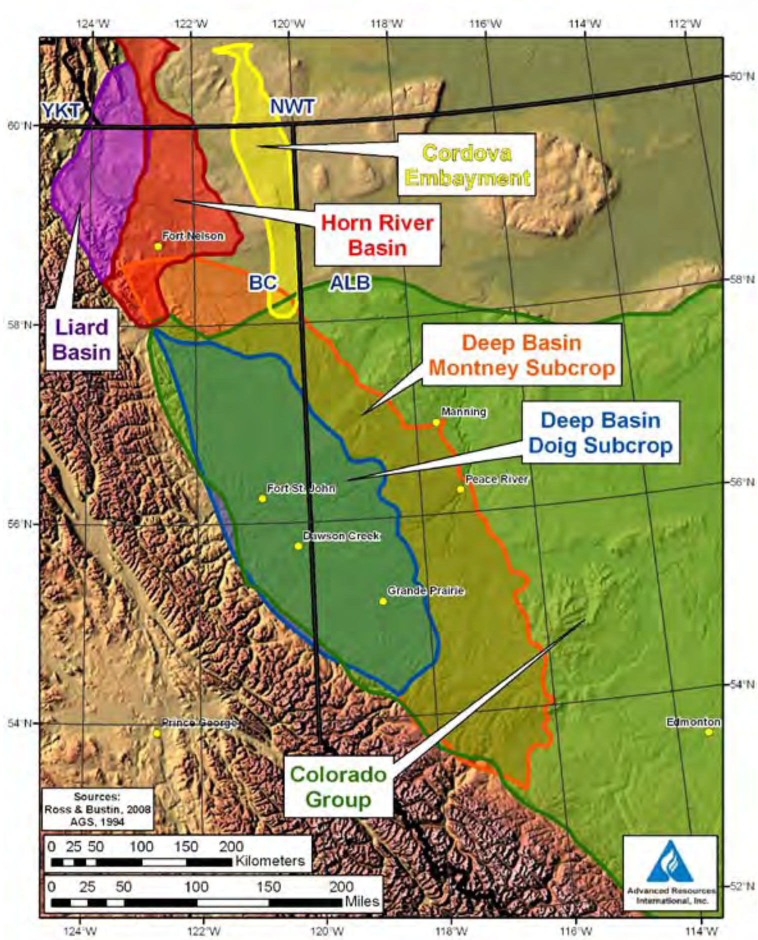
I. CANADA

The gas-bearing shales of Canada are concentrated in Alberta and British Columbia of Western Canada and in Quebec, Nova Scotia and New Brunswick of Eastern Canada.

WESTERN CANADA

Western Canada has five large sedimentary basins that contain thick, organic-rich shales - - the Horn River, Cordova Embayment and Liard in northern British Columbia; the Deep Basin/Montney in central Alberta and British Columbia; and the Colorado Group in central and southern Alberta, Figure I-1.

Figure I-1. Shale Gas Basins of Western Canada



The five large Western Canada shale gas basins contain a total of 1,326 Tcf of risked gas in-place. (This assessment is consistent with the British Columbia Ministry of Energy, Mines and Petroleum Resources estimates of 500 Tcf of gas in-place for the Horn River Shale, 200 Tcf of gas in-place for the Cordova Embayment Shale and 35 to 250 Tcf of gas in-place for the Montney Resource Play, a combined shale gas and tight gas sand play.)[1]

The risked, technically recoverable shale gas resource for these five Western Canada basins is estimated at 355 Tcf, as shown on Table I-1.

Table I-1. Shale Gas Reservoir Properties and Resources of Western Canada

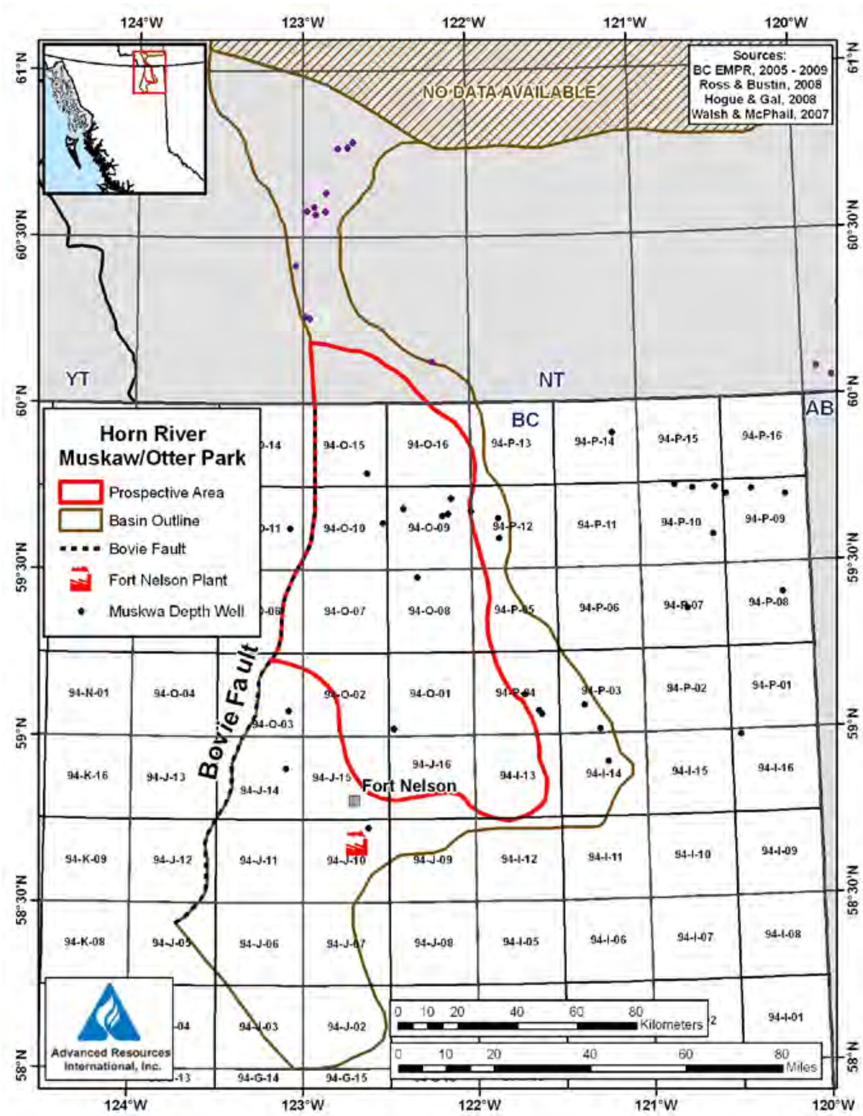
Basic Data	Basin/Gross Area		**Horn River (8,100 mi^2)**		Cordova (4,290 mi^2)	**Liard (4,300 mi^2)**
	Shale Formation		Muskwa/Otter Park	Evie/Klua	Muskwa/Otter Park	Lower Besa River
	Geologic Age		Devonian	Devonian	Devonian	Devonian
Physical Extent	Prospective Area (mi^2)		3,320	3,320	2,850	1,940
	Thickness (ft)	Interval	250 - 730	110 - 205	150 - 350	490 - 1,100
		Organically Rich	420	160	230	630
		Net	380	144	207	441
	Depth (ft)	Interval	6,300 - 10,200	6,800 - 10,700	5,500 - 6,200	6,600 - 12,300
		Average	8,000	8,500	6,000	9,000
Reservoir Properties	Reservoir Pressure		Moderately Overpressured	Moderately Overpressured	Normal	Moderately Overpressured
	Average TOC (wt. %)		3.5%	3.5%	2.0%	3.5%
	Thermal Maturity (%Ro)		3.80%	3.80%	2.50%	3.80%
	Clay Content		Low	Low	Low	Low
Resource	GIP Concentration (Bcf/mi^2)		152	55	61	161
	Risked GIP (Tcf)		378	110	83	125
	Risked Recoverable (Tcf)		132	33	29	31

	Basin/Gross Area		Deep Basin (2,650 mi²)		Colorado Group (124,000 mi²)
Basic Data	Shale Formation		Montney Shale	Doig Phosphate	2WS & Fish Scales
	Geologic Age		Triassic	Triassic	Cretaceous
Physical Extent	Prospective Area (mi^2)		1,900	3,000	48,750
	Thickness (ft)	Interval	200 - 1,100	70 - 220	300 - 2,000
		Organically Rich	400	165	523
		Net	240	150	105
	Depth (ft)	Interval	3,000 - 9,000	6,800 - 10,900	5,000 - 10,000
		Average	6,000	9,250	6,900
Reservoir Properties	Reservoir Pressure		Overpressured	Moderately Overpressured	Underpressured
	Average TOC (wt. %)		3.0%	5.0%	2.4%
	Thermal Maturity (%Ro)		1.50%	1.10%	0.61%
	Clay Content		Low	Low	Low
Resource	GIP Concentration (Bcf/mi^2)		99	67	21
	Risked GIP (Tcf)		141	81	408
	Risked Recoverable (Tcf)		49	20	61

Horn River Basin

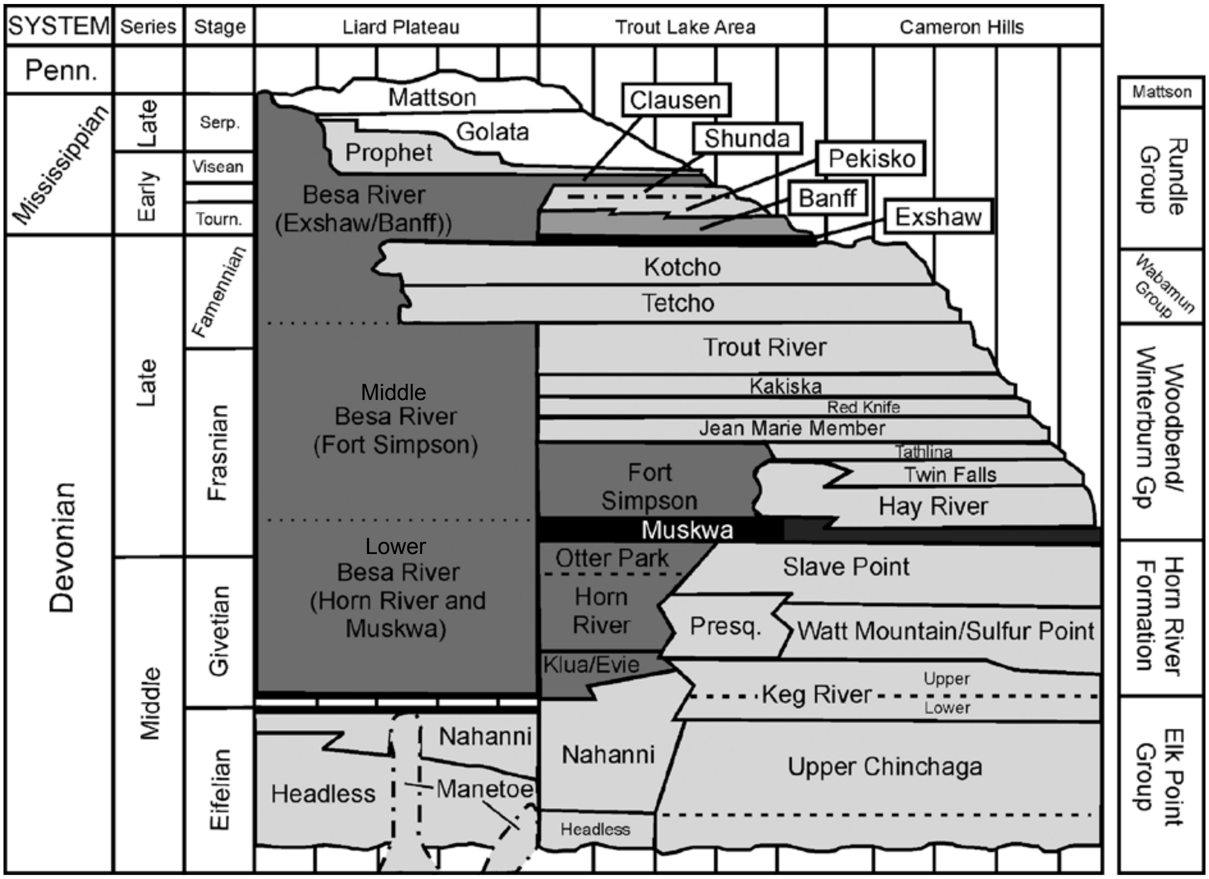
Geologic Characterization. The Horn River Basin covers an area of 8,100 mi^2 in northern British Columbia and the Northwest Territory. Its western border is defined by the regionally significant Bovie Fault, which separates the Horn River Basin from the Liard Basin. Its northern border, in Northwest Territory, is defined by the thinning of the shale section and by lack of data. Its southern border is defined by the shallowing and pinch-out of the shale. Its eastern border is defined by Slave Point/Keg River Uplift and thinning of the shale. The prospective area for Muskwa/Otter Park Shale covers a 3,320 mi^2 area along the western portion of the basin, Figure I-2.

Figure I-2. Horn River (Muskwa/Otter Park Shale) Basin and Prospective Area



The Horn River, as well as the other two north British Columbia shale gas basins (Cordova Embayment and Liard Basin), contains a stack of organic shales, with the Middle Devonian-age Muskwa/Otter Park and Evie/Klua most prominent, Figure I-3. These two shale units were mapped in the Horn River Basin to establish the prospective area with sufficient thickness and resource concentration favorable for shale gas development. Other shales in this basin include the high organic content but lower thermal maturity Mississippian Exshaw/Banff Shale and the thick but low organic content Late Devonian Fort Simpson Shale.

Figure I-3. NE British Columbia, Devonian and Mississippian Stratigraphy



Source: D. J. K. Ross and R. M. Bustin, AAPG Bulletin, v. 92, no. 1 (January 2008), pp. 87–125 JAF21300.AI

Reservoir Properties (Prospective Area)

Muskwa/Otter Park (Middle Devonian). The Middle Devonian Muskwa/Otter Park black shale, the upper shale interval within the Horn River Group, is the main shale gas target in the Horn River Basin. Drilling depth to the top of the Muskwa Shale ranges from 6,300 to 10,200 feet, averaging 8,000 feet for the prospective area. The Muskwa/Otter Park shale is moderately over-pressured in the center of the basin. The organically-rich gross thickness of 420 feet covers much of the overall Muskwa/Otter Park interval of 500 feet, with a net thickness of 380 feet. Total organic content (TOC) in the prospective area averages 3.5% (by wt.) for the net shale thickness investigated. Thermal maturity (R_o) is high, averaging about 3.8%, placing this shale gas in the dry gas window. Because of the high thermal maturity (high R_o) in the prospective area, the gas has a CO_2 content of 10%. The Muskwa/Otter Park Shale has a high quartz/low clay content, favorable for hydraulic stimulation.

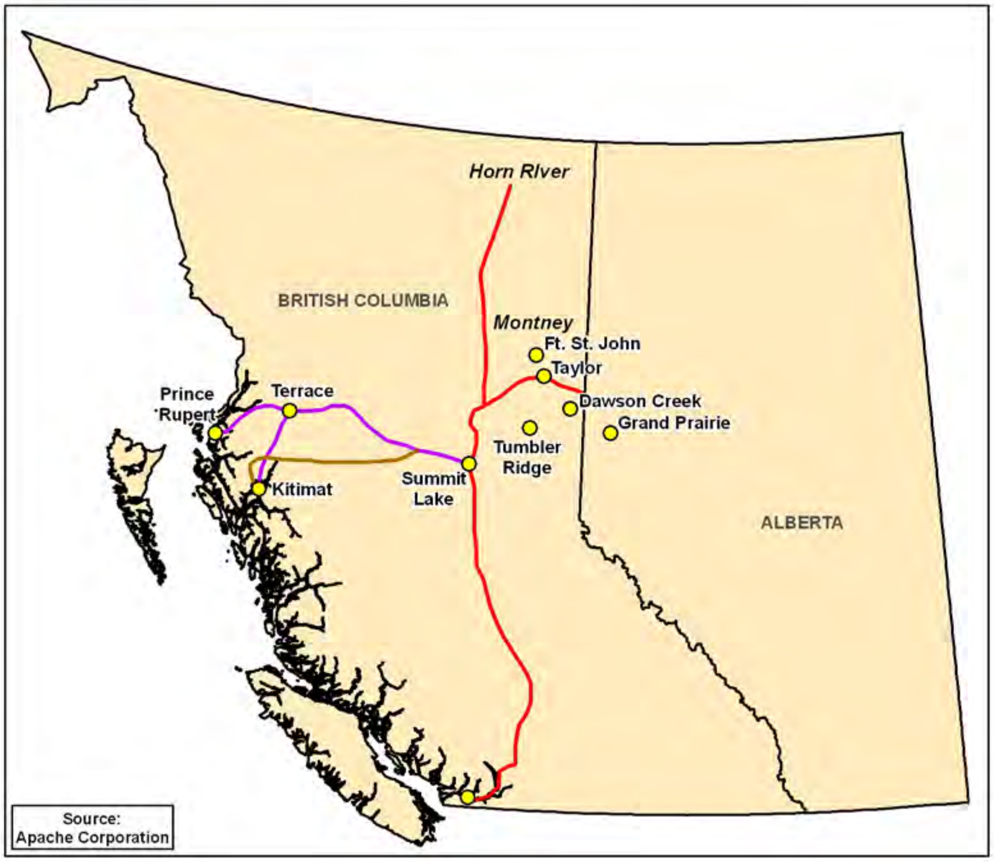
Evie/Klua (Middle Devonian). The Middle Devonian Evie/Klua black shale, the lower shale interval within the Horn River Group, provides a secondary shale gas target in the Horn River Basin. The top of the Evie/Klua shale is approximately 500 feet below the top of the Muskwa/Otter Park Shale, separated by an organically lean rock interval. The organically-rich Evie/Klua shale thickness, with an average TOC of 3.5%, is about 160 feet (gross) and 144 feet (net). Thermal maturity (R_o) is high, at about 3.8%, placing this shale gas in the dry gas window, with potential for the presence of CO_2. The Evie/Klua Shale has a low clay content.

<u>Other Shales</u>. The Horn River Basin also contains two shallower shales - - the Upper Devonian/Lower Mississippian Exshaw Shale and the Late Devonian Fort Simpson Shale. The Exshaw Shale, while rich in TOC (5%) is relatively thin (10 to 30 feet). The shallower portions of the Exshaw Shale appear to be in the gas condensate window. The massively thick Fort Simpson shale, with an interval of 2,000 to 3,000 feet, is organically lean (TOC <1%). Because of less favorable reservoir properties and limitations of data, these two shale units have not been included in the assessment.

Resources. The prospective area for both the Horn River Muskwa/Otter Park and Evie/Klua shales is approximately 3,320 mi^2. Within this prospective area, the Horn River Muskwa/Otter Park shales have a rich resource concentration of about 152 Bcf/mi^2. As such, the risked gas in-place is 378 Tcf. Based on favorable reservoir mineralogy and other properties, we estimate a risked technically recoverable shale gas resource of 132 Tcf in the Muskwa/Otter Park Shale. The thinner Evie/Klua Shale has a resource concentration of 55 Bcf/mi^2, and 110 Tcf of risked gas in-place with 33 Tcf as risked technically recoverable, Table I-1.

Activity. The gas processing capacity in the Horn River Basin is being expanded to provide improved market access to shale gas production from this basin. For example, the Cabin Gas Plant, with 800 MMcfd of capacity, is due on stream in Q3 of 2012 and the Fort Nelson Gas Plant is being expanded to 1 Bcfd. Pipeline infrastructure is also being expanded to bring the gas south to the Deep Basin and then to the Kitimat LNG export plant on the Pacific coast of British Columbia, due on line in 2014. A 287-mile Pacific Trail Pipeline would connect the Kitimat LNG export plant with Spectra Energy's West Coast Pipeline System, Figure I-4. The Kitimat LNG terminal has an announced send-out capacity of 5 million tons of LNG per year.

Figure I-4. Horn River LNG Export Pipeline and Infrastructure



A number of major and independent companies are active in the Horn River Shale Play. For example, EnCana plans to drill 41 long horizontal wells as part of their 2010 joint program with Apache to achieve a year-end exit rate of 100 MMcfd, net to EnCana. Devon is in the early stages of de-risking its 170,000 net acre lease position, projected to hold nearly 10 Tcfe of net risked resource. The company plans to drill 7 horizontal wells in 2010. EOG has acquired a 157,000 net acre lease position, with potential recoverable resources of 9 Tcf. Its two significant pilot/development areas have booked 850 Bcf of proved reserves, as of the end of 2009. Quicksilver has a 130,000 net acre lease position with a projected recoverable resource potential of over 10 Tcf. Nexen has drilled 18 horizontal wells, establishing production capacity of 100 MMcfd.

Cordova Embayment

Geologic Characterization. The Cordova Embayment covers an area of 4,290 mi^2 in the extreme northeastern corner of British Columbia, extending into the Northwest Territory. It is separated from the Horn River Basin on the west by the Slave Point Platform. Its northern and southern boundaries are defined by a thinning of the shale. Its eastern boundary is a facies change along the British Columbia and Alberta borders. The dominant shale gas formation, the Muskwa/Otter Park Shale was mapped to establish the 2,850 mi^2 prospective area with minimum thickness for favorable shale gas development, Figure I-5.

Reservoir Properties (Prospective Area)

Muskwa/Otter Park. The Middle Devonian Muskwa/Otter Park Shale is the main shale gas target in the Cordova Embayment. The drilling depth to the top of the Muskwa Shale in this basin ranges from 5,500 to 6,200 feet, averaging 6,000 feet in the prospective area. The reservoir pressure is normal. The organically-rich gross thickness is 230 feet, with a net thickness of 207 feet. Total organic content (TOC) in the prospective area is 2.5% for the net shale thickness investigated. Thermal maturity averages 2.0% R_o, placing the shale in the dry gas window. The Muskwa/Otter Park Shale has a moderately high quartz content, favorable for hydraulic stimulation.

Other Shales. The deeper, relatively thin Evie/Klua Shale is separated from the overlying Muskwa/Otter Park by the Slave Point and Sulfur Point Formations, Figure I-6. The overlying Exshaw and Fort Simpson shales are shallower, thin or low in organics. These shales have not been included in the assessment.

Resources. The prospective area of the Cordova Embayment Muskwa/Otter Park Shale is approximately 2,850 mi^2. Within this prospective area, the shale has a moderate resource concentration of 61 Bcf/mi^2. As such, the shale gas in-place is 83 Tcf risked. Based on favorable reservoir mineralogy and other properties, we estimate a risked technically recoverable shale gas resource of 29 Tcf for the Cordova Embayment, Table I-1.

Activity. Nexen has acquired a 38,000-acre lease position in the Cordova Embayment and has drilled one new exploration well. Penn West Energy Trust and Mitsubishi have formed a joint venture to develop the estimated 5 to 7 Tcf of recoverable shale gas resources on their 120,000-acre (gross) lease area, planning to drill 5 wells in 2010.

Figure I-5. Cordova Embayment (Muskwa/Otter Park Shale) Outline and Prospective Area

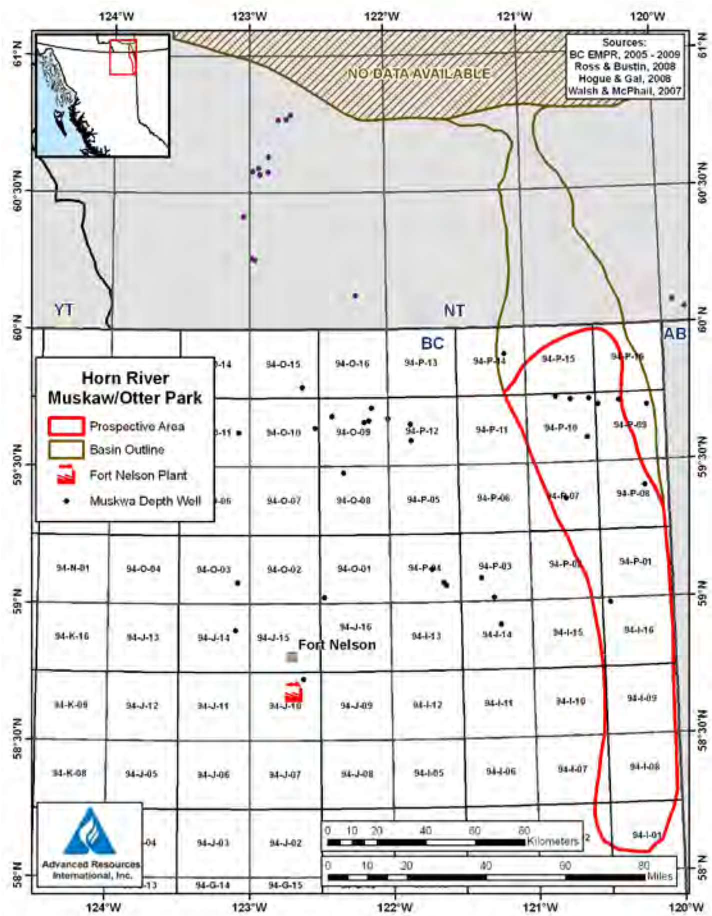
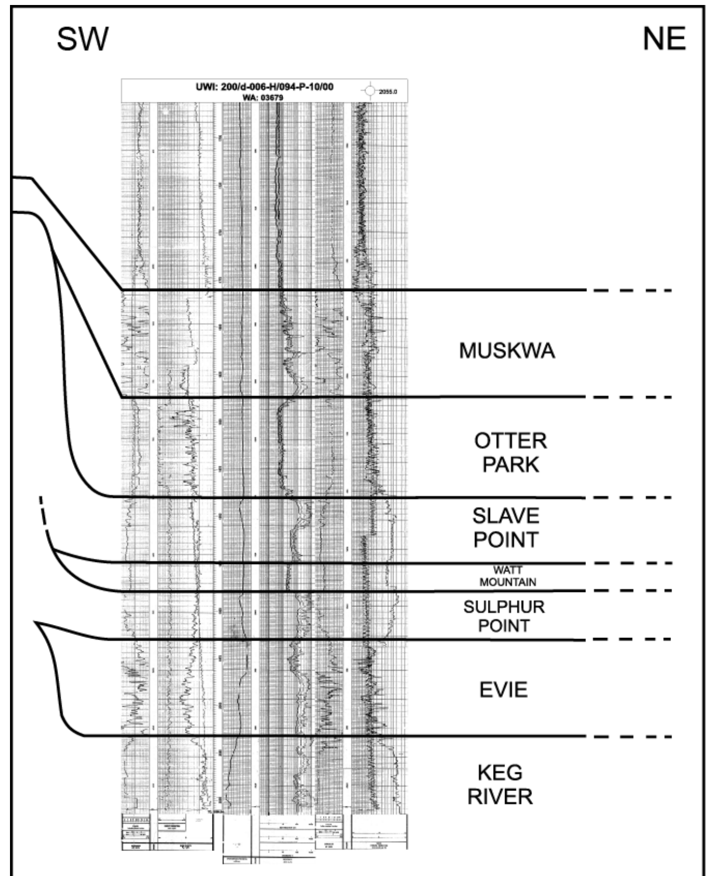


Figure I-6. Cordova Embayment Stratigraphic Column



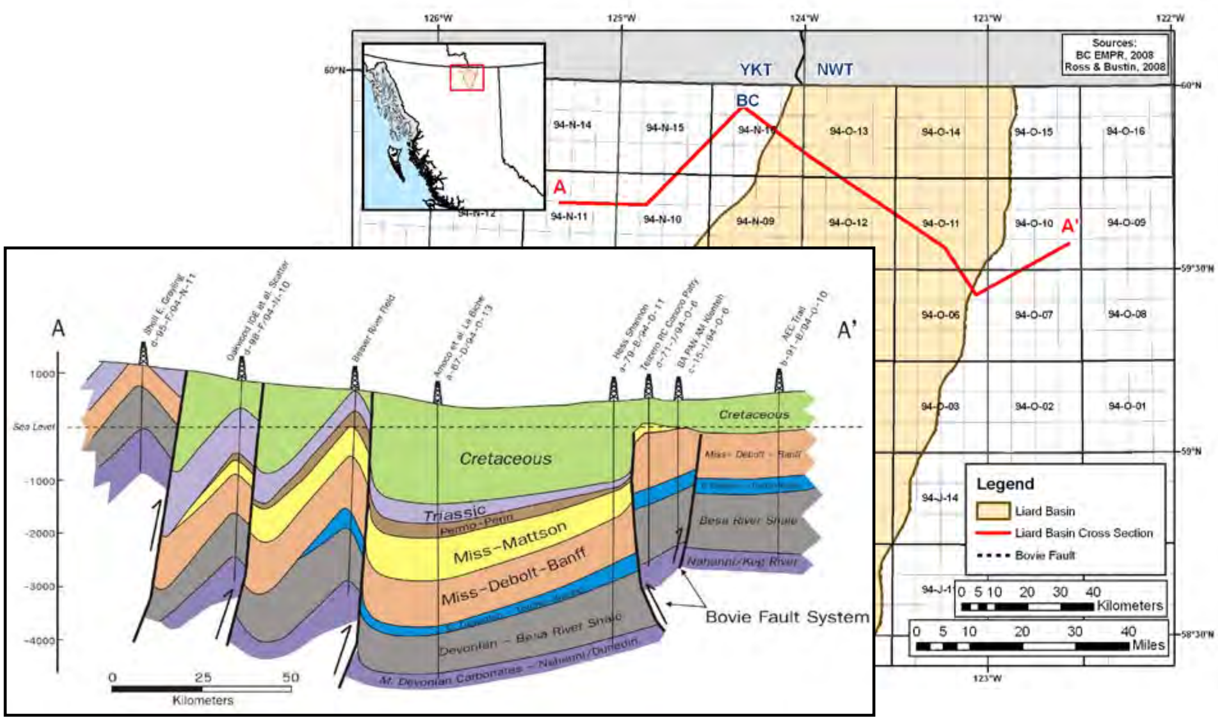
Source: British Columbia Government

JAF21311.AI

Liard Basin

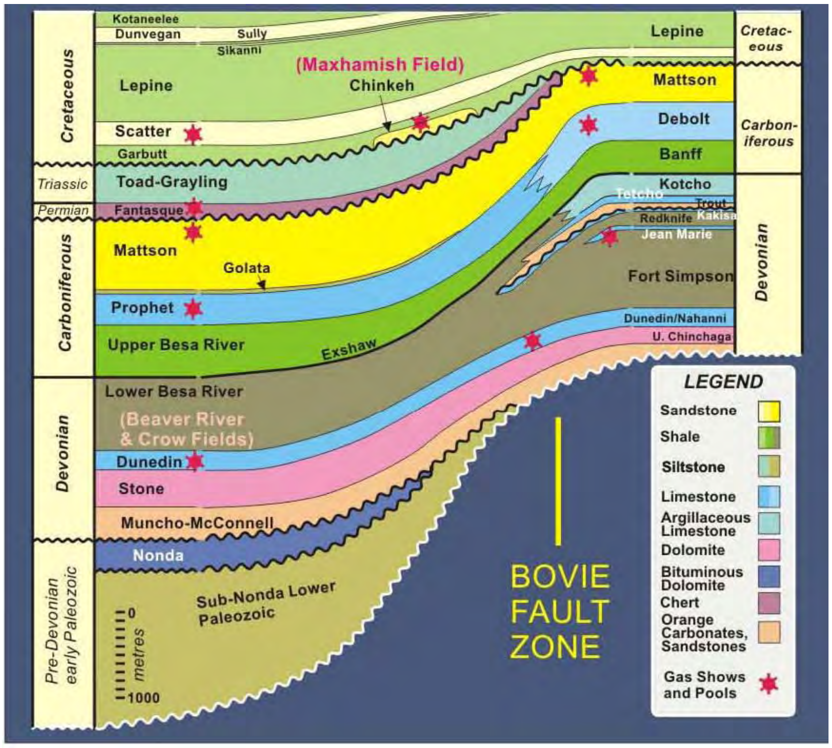
Geologic Characterization. The Liard Basin covers and area of 4,300 mi^2 in northern British Columbia. Its eastern border is defined by the Bovie Fault, which separates the Liard Basin from the Horn River Basin, Figure I-7. Its northern boundary is currently defined by the British Columbia and the Yukon/Northwest Territories border. Its western and southern boundaries are defined by structural folding.

Figure I-7. Liard Basin Location, Cross Section and Prospective Area



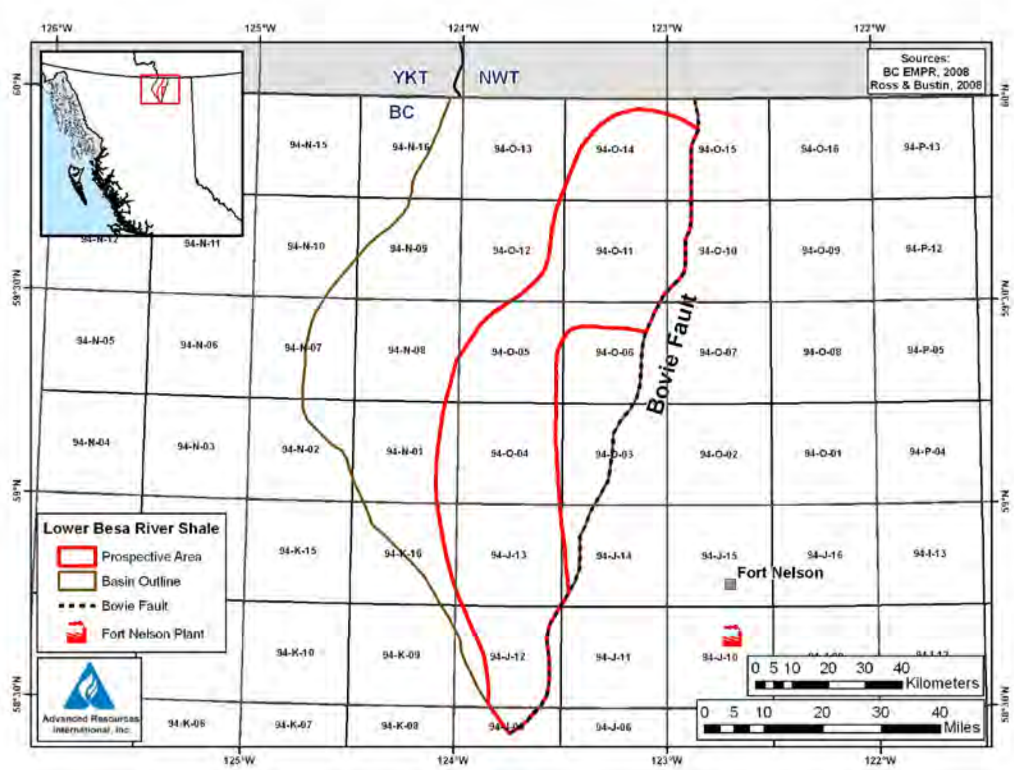
The dominant shale gas formation in the Liard Basin is the Middle Devonian-age Lower Besa River Shale, equivalent to the Muskwa/Otter Park and Evie/Klua shales in the Horn River Basin. Additional, less organically-rich and less prospective shales exist in the basin's Upper Devonian- and Mississippian-age shales, such as the Middle Besa River Shale (Fort Simpson equivalent) and the Upper Besa River Shale (Exshaw/Banff equivalent), see Figures I-3 and I-8. The prospective area for the Lower Besa River Shale covers a 1,940 mi^2 area along the eastern portion of the basin, Figure I-9.

Figure I-8. Liard Basin Stratigraphic Cross Section



Source: D. W. Morrow and R. Shinduke, "Liard Basin, Northeast British Columbia: An Exploration Frontier", Geological Survey of Canada (Calgary), Natural Resources Canada

Figure I-9. Liard Basin and Prospective Area (Lower Besa River Shale)



Reservoir Properties (Prospective Area)

Middle Devonian (Lower Besa River). The Lower Besa River organically-rich shale is the main shale gas target in the Liard Basin. Drilling depths to the top of the formation in the prospective area range from 6,600 to 12,300 feet, averaging about 9,000 feet. The organically-rich Lower Besa River section has a gross thickness of 630 feet and a net thickness of 441 feet. Total organic content (TOC) in the prospective area can reach as high as 5%, averaging 3.5% for the net shale interval investigated. The thermal maturity of the prospective area is high, with an average R_o of 3.8%. The geology of the Besa River Shale is complex, with numerous faults and thrusts. The Lower Besa River Shale is quartz-rich (40% to >80%), with episodic intervals of dolomite and more pervasive intervals of clay.

Resources. The Liard Basin's Lower Besa River Shale has a high resource concentration of 161 Bcf/mi^2. Given a prospective area of 1,940 mi^2, the risked shale gas in-place is approximately 125 Tcf. Based on relatively favorable reservoir mineralogy but significant structural complexity, we estimate a risked technically recoverable shale gas resource of 31 Tcf for the Liard Basin, Table I-1.

Exploration Activity. Transeuro Energy Corp. and Questerre Energy Corp., two small Canadian operators. have drilled and completed three exploration wells producing from the Besa River and Mattson shale/siltstone intervals at the Beaver River Field. The gas is being sold into the existing gas gathering and pipeline system, initially built for the conventional gas play in this area. In addition, Nexen has recently acquired a large 170,000-acre lease position in this basin.

Deep Basin

Geologic Characterization. The Deep Basin of Alberta and British Columbia covers a massive area of over 54,000 mi^2 along the border of Alberta and British Columbia, Figure I-10. The basin contains the Montney and Doig Phosphate Resource plays, two large, multi-depositional Triassic-age hydrocarbon resource accumulations containing over 1,000 Tcf of gas in-place in conventional gas formations, tight gas sands and shale gas. (Separately, for a private study, Advanced Resources previously assessed the Montney tight gas sand resource in-place at over 500 Tcf).

A critical step for assessing the Montney Resource Play is establishing where to draw the demarcation line between the shale gas and the tight gas resource areas. For this study, we have designated the areas west of the Deformation Front as “shale gas dominant” and the areas east of the Deformation Front as “tight gas dominant”, Figure I-11.

The Montney Resource Play is overlain by the Middle Triassic-age Doig Formation, incorporating the Diog Phosphate shale gas play, which reaches prospective thickness in the western portion of the Deep Basin.

Reservoir Properties (Prospective Area)

Montney Shale (Lower Triassic). The Lower Triassic Montney Shale covers a prospective area of approximately 1,900 mi^2 on the northwestern edge of the Deep Basin, Figure I-12. Drilling depth to the top of the Upper Montney Shale ranges from 3,000 to 9,000 feet, averaging 6,000 feet for the prospective area. The interval from the top of the Upper Montney to the base of the Lower Montney encompasses up to 1,000 feet, with an extensive 100- to 500-foot interval separating the two units, Figure I-13. The organically-rich gross thickness for the Montney Shale averages 400 feet, with a net thickness of 240 feet. The total organic content in the prospective area averages 3% for the net shale thickness. The thermal maturity (R_o) ranges from about 1.3% on the eastern edge of the shale play to 2.0% on the western edge, placing the shale into the dry gas window. The Montney Shale has a favorable quartz to clay ratio, making the formation attractive for hydraulic fracturing.

Figure I -10. Deep Basin, Montney Resource Play, Base Map

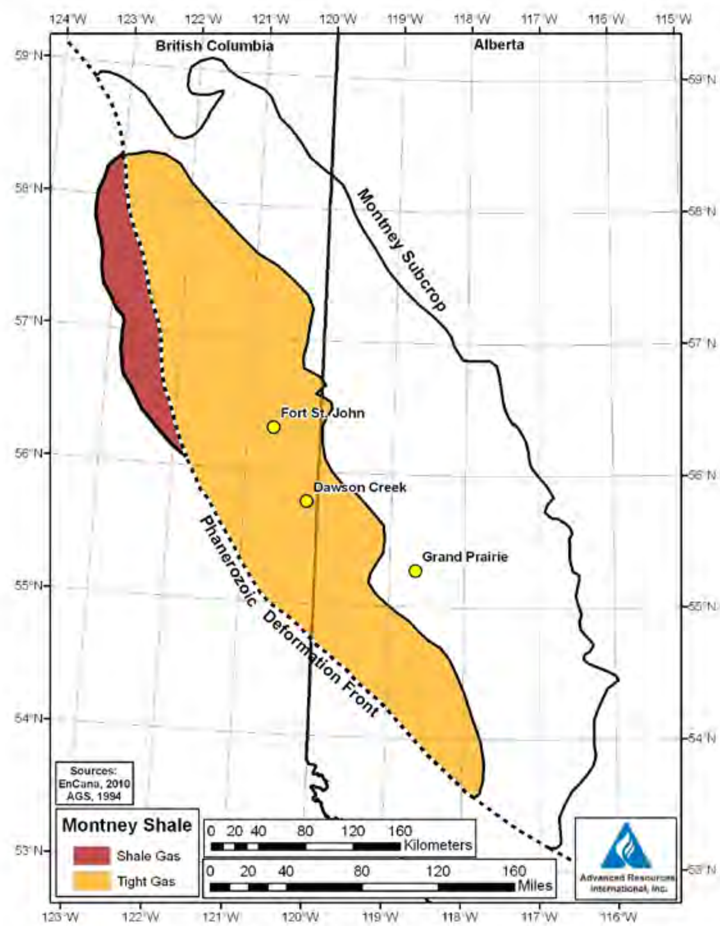


Figure I -11. Montney and Doig Resource Plays, Stratigraphy

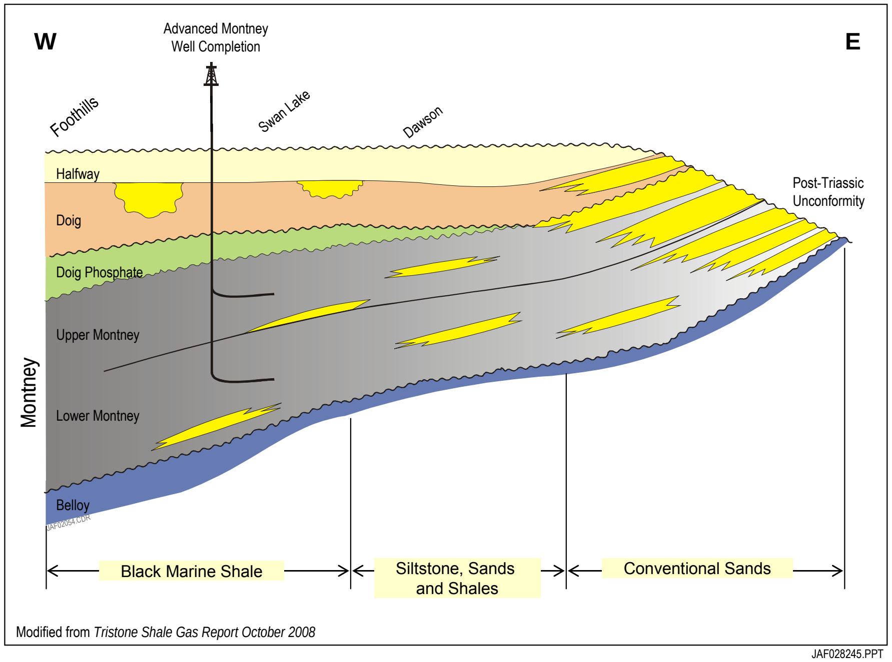


Figure I -12. Deep Basin, Montney Shale Prospective Area

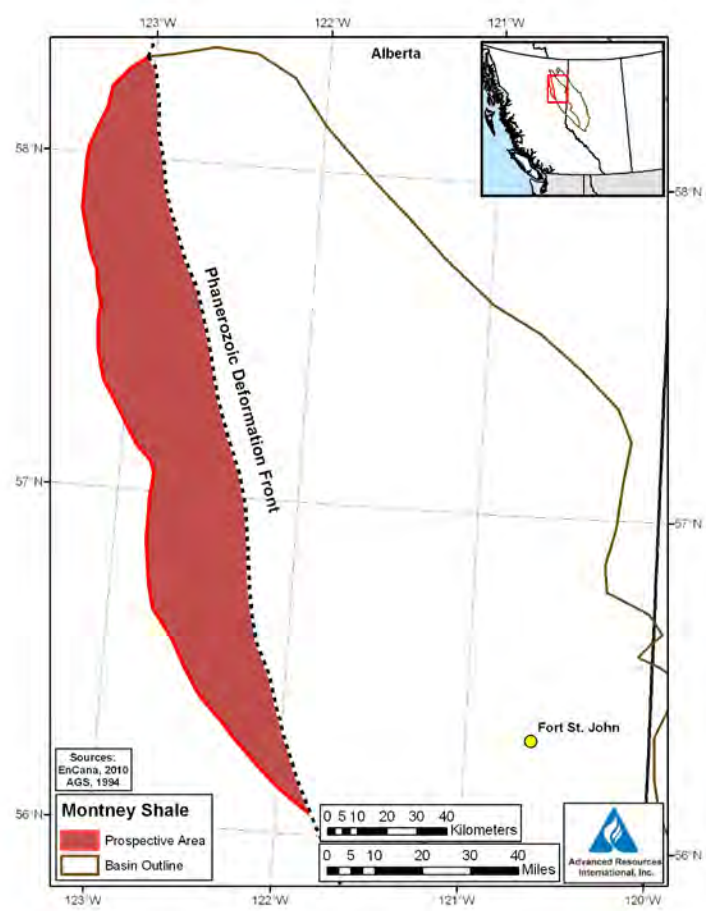
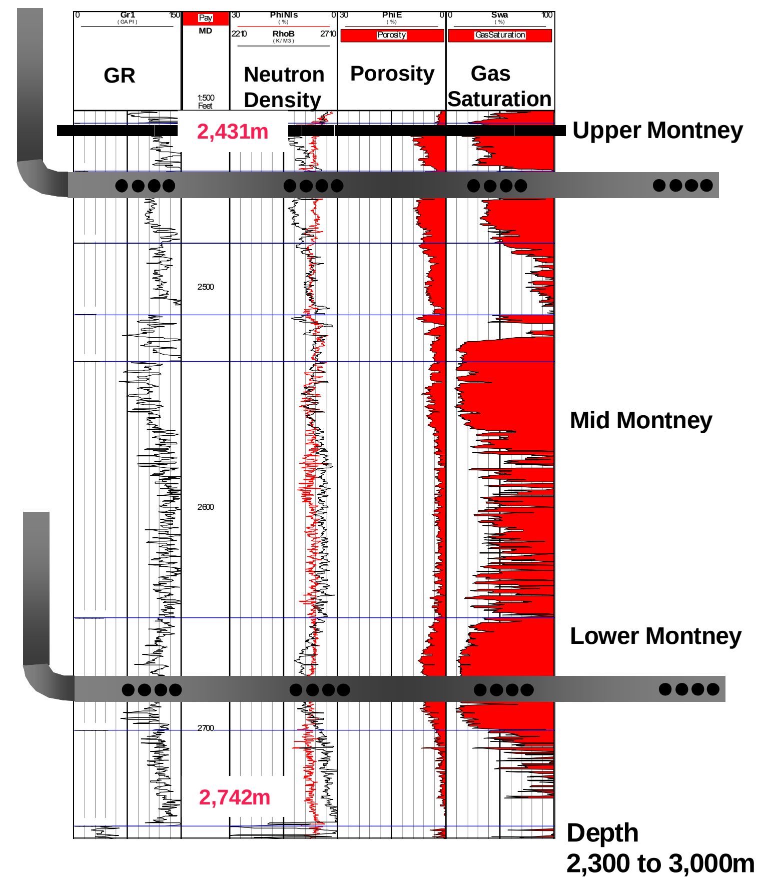


Figure I-13. Cutback Ridge – Montney Type Log

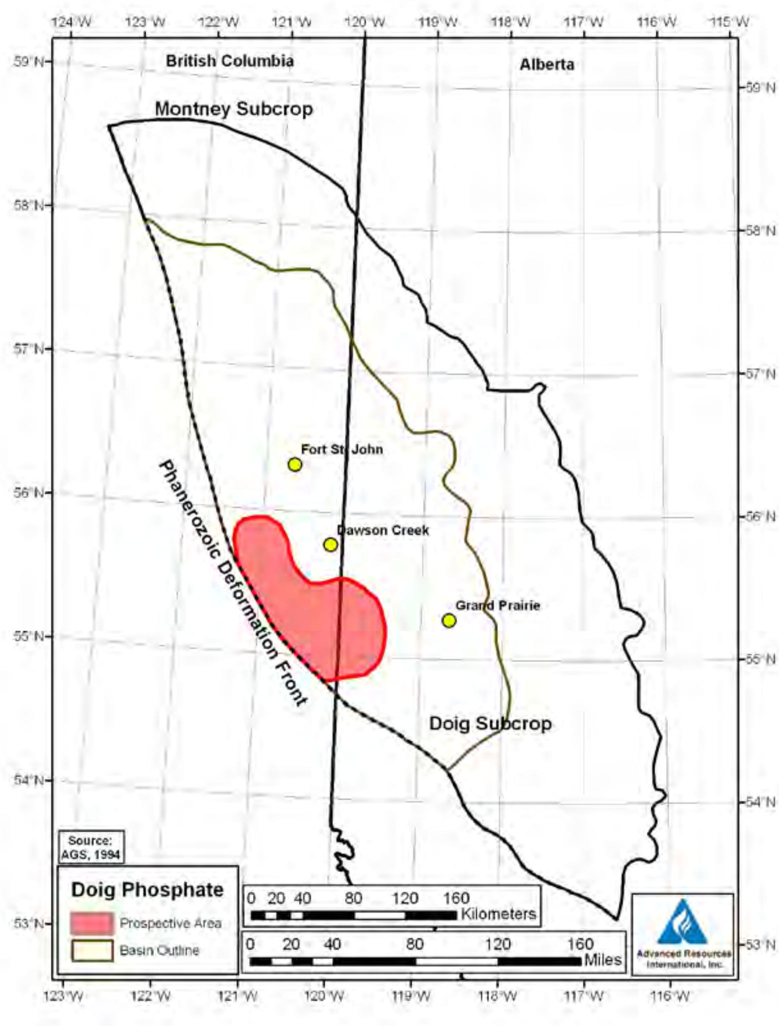


Source: EnCana Corporation (2009)

JAF21312.AI

Doig Phosphate Shales (Middle Traissic). The Middle Triassic Doig Phophate play has a thick section of organically rich shale along the western edge of the Deep Basin that forms the prospective area, Figure I-14. Drilling depth to the top of the Doig Phosphate Shale averages 9,250 feet. The organic-rich Doig Phosphate ranges from 130 to 200 feet thick with a net thickness of 150 feet in the western prospective area. The thermal maturity (R_o 1.1%) places the shale in the wet gas window. The total organic contact is moderate to high, averaging 5% within the Doig Phosphate Shale. X-ray diffraction of cores taken from the Doig Phosphate Formation show significant levels of quartz with minor to moderate illite clay and trace to minor amounts of pyrite and dolomite, making the formation favorable for hydraulic fracturing.

Figure I-14. Doig Resource Play, Doig Phosphate Prospective Area



Resources. The prospective area for the Montney Shale is estimated at 1,900 mi^2 and the prospective area of the Doig Phosphate Shale is estimated at 3,000 mi^2. Within these prospective areas, the shales have moderately-rich resource concentrations of about 100 Bcf/mi^2 for the Montney Shale and 67 Bcf mi^2 for the Doig Phosphate Shale. As such, the risked shale gas in-place is 141 Tcf for the Montney Shale and 81 Tcf for the Doig Phosphate Shale. Based on favorable mineralogy and a compact package of shale, we estimate a risked technically recoverable shale gas resource of 49 Tcf for the Montney Shale and 20 Tcf for the Doig Phosphate Shale.

Exploration Activity. A significant number of wells have been drilled into the Montney and Doig Resource plays. The bulk of the wells have targeted the clastic- and siltstone-rich tight gas intervals sourced by the organically-rich shales. An extensive system of existing gas pipelines link the Deep Basin to Canadian and U.S. natural gas markets.

Colorado Group

Geologic Characterization. The Colorado Group Shales cover a massive, 124,000 mi^2 square mile area in southern Alberta and southeastern Saskatchewan. The western boundary of the Colorado Group is the Canadian Rockies Overthrust. The northern and eastern boundaries are defined by shallow shale depth and loss of net pay. The southern boundary is the U.S./Canada border. The Colorado Group encompasses a thick, Cretaceous-age sequence of sands, mudstones and shales. Within this sequence are two shale formations of interest for natural gas development - - the Fish Scale Shale Formation in the Lower Colorado Group and the Second White Speckled Shale Formation in the Upper Colorado Group, Figure I-15. We selected the 5,000 to 10,000 foot depth contours for defining the prospective area, to capture the potential for both thermogenic as well as biogenic gas generation, Figure I-16.

Reservoir Properties (Prospective Area). In the prospective area, the depth to the Second White Speckled (2WS) and the Fish Scale shales ranges from 5,000 feet near Medicine Hat (on the east) to over 10,000 feet in the west. The Fish Scale Shale is generally about 200 feet deeper than the 2WS. The interval from the top of the 2WS to the base of the Fish Scales Shale ranges from 300 feet in the east to over 1,000 feet in the west, with an organically-rich gross pay of 523 feet. We assume a conservative net to gross ratio of 20%. Much of the Colorado Group Shale appears to be underpressured at about 0.25 to 0.3 psi/ft. The total organic carbon content of the shale ranges from 2% to 3%. In the prospective area, the thermal maturity of the shale is low (R_o of 0.4% to 0.8%). However, the presence of biogenic gas plus some low-temperature cracking of kerogen appear to have provided adequate volumes of gas generation in the deeper portions of the basin. The rock mineralogy appears to be low to moderate in clay (ductile clays and other materials of 31%) and thus favorable for hydraulic fracturing.

Resources. The potentially prospective area of the Colorado Group shale is 48,750 mi^2, covering much of southwestern Alberta. Within this prospective area, the shale has a relatively low gas concentration of 21 Bcf/mi^2. The shale gas in-place is 408 Tcf risked. Based on potentially favorable shale mineralogy, but other less favorable reservoir properties such as lower pressure and an uncertain gas charge, we estimate a risked technically recoverable shale gas resource of 61 Tcf for the Colorado Group, Table I-1.

Exploration Activity. To date, the Colorado Group Shales have seen only limited exploration and development, primarily in the shallower eastern portion of the play area.

Figure I-15. Colorado Group Stratigraphic Column

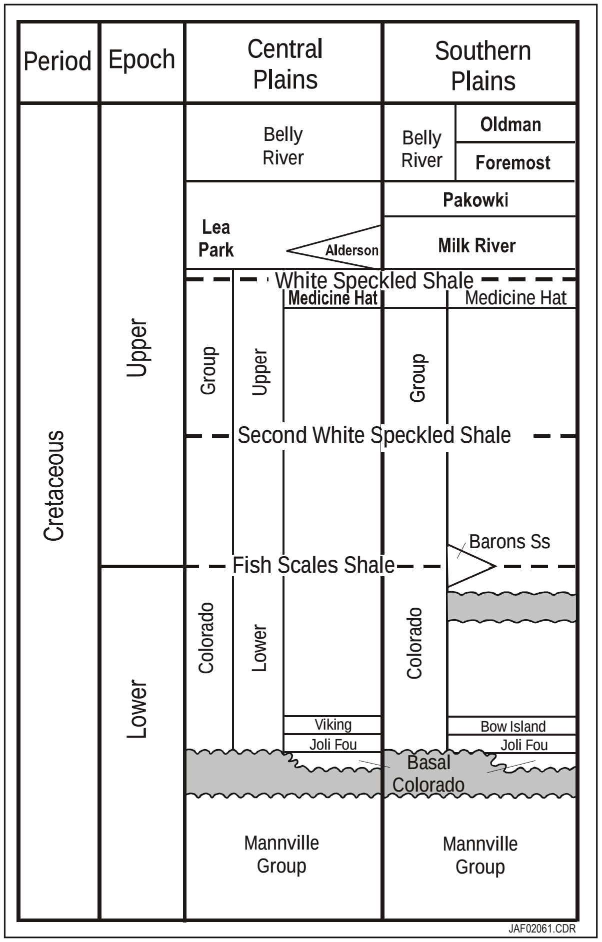
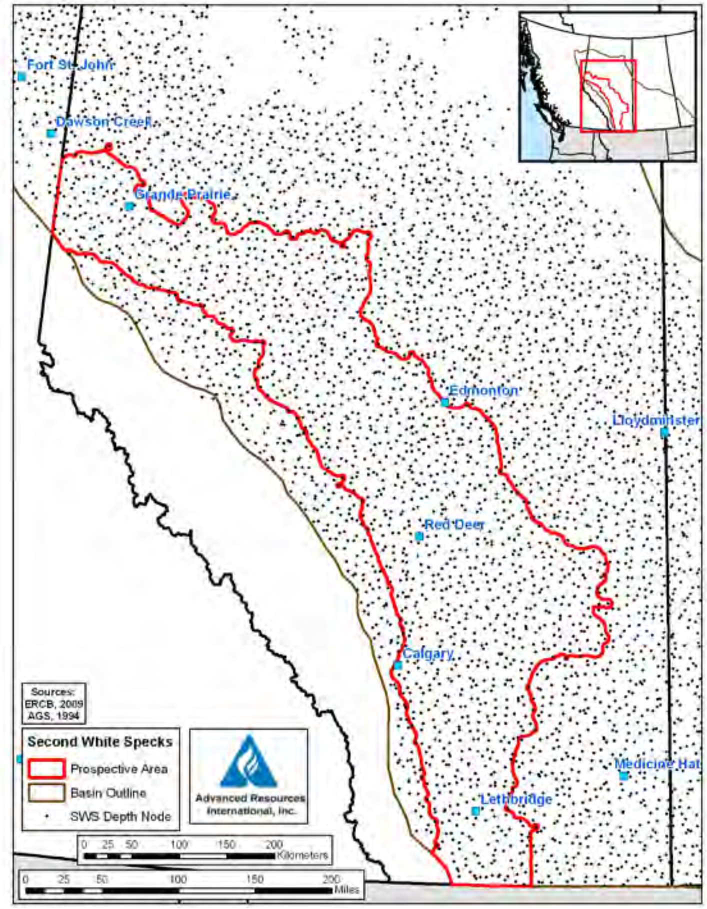


Figure I-16. Colorado Group, Prospective Area



EASTERN CANADA

Eastern Canada has four potential shale gas plays, namely - - the Utica and Lorraine shales in the St. Lawrence Lowlands of the Appalachian Fold Belt of Quebec, the Horton Bluff Shale in the Windsor Basin of northern Nova Scotia, and the Frederick Brook Shale in the Moncton Sub-Basin of the Maritimes Basin in New Brunswick. These three shale gas basins are in an early exploration stage. Therefore, only preliminary shale gas resource assessments are offered for the Utica and Horton Bluff shales. Insufficient information exists for assessing the Lorraine and Frederick Brook shales.

The two assessed Eastern Canada shale gas basins contain 164 Tcf of risked gas in-place. (The Canadian Society for Unconventional Gas (CSUG) cites an OGIP for unconventional gas of 181 Tcf (unrisked) for the Utica Shale.[2]) The risked, technically recoverable resources for these two basins are estimated at 33 Tcf, Table I-2.

Table I-2. Gas Shale Reservoir Properties and Resources of Eastern Canada

				Appalachian Fold Belt (3,500 mi²)	Windsor Basin (650 mi²)
Basic Data	Basin/Gross Area			Appalachian Fold Belt (3,500 mi²)	Windsor Basin (650 mi²)
	Shale Formation			Utica	Horton Bluff
	Geologic Age			Ordovician	Mississippian
Physical Extent	Prospective Area (mi^2)			2,900	524
	Thickness (ft)	Interval		1,000 - 3,000	500 - 1,000
		Organically Rich		1,000	500
		Net		400	300
	Depth (ft)	Interval		4,000 - 11,000	3,000 - 5,000
		Average		8,000	4,000
Reservoir Properties	Reservoir Pressure			Slightly Overpressured	Normal
	Average TOC (wt. %)			2.0%	5.0%
	Thermal Maturity (%Ro)			2.00%	2.00%
	Clay Content			Low	Unknown
Resource	GIP Concentration (Bcf/mi^2)			134	82
	Risked GIP (Tcf)			155	9
	Risked Recoverable (Tcf)			31	2

St. Lawrence Lowlands Basin (Quebec)/Utica Shale

Geologic Characterization. The Utica Shale is located within the St. Lawrence Lowlands and Gaspe Peninsula of the Appalachian Fold Belt in Quebec, Canada, Figure I-17. The Utica is an Upper Ordovician-age shale, located above the conventional Trenton-Black River Formation, Figure I-18. A second, less defined, thicker but lower TOC Lorraine Shale overlies the Utica. Because of limited data, the Lorraine Shale play is not included in this assessment.

Figure I-17. Utica Shale Outline and Prospective Area

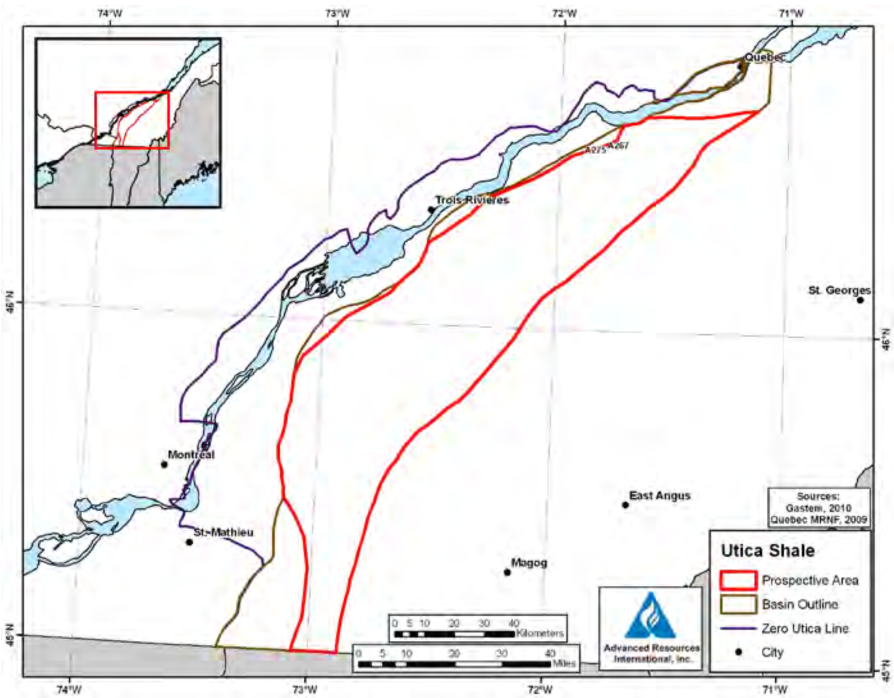
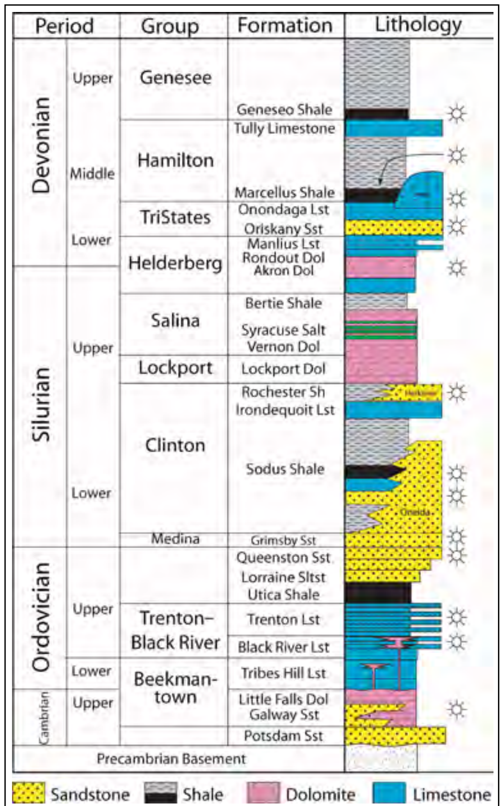


Figure I-18. Utica Shale Stratigraphy



Source: L. Smith AAPG, AAPG Bulletin, v. 90, no. 11 (November 2006), pp. 1691–1718

Reservoir Properties (Prospective Area). The Utica Shale in Quebec is structurally much more complex than the Utica Shale in the Appalachian Basin of New York. Three major faults - - Yamaska, Tracy Brook and Logan's Line - - form structural boundaries and partitions for the Utica Shale play in Quebec. The extensive faulting and thrusting in the shale introduces considerable exploration and completion risk. The depth to the top of the shale in the prospective area ranges from 3,000 to over 11,000 feet, shallower along the southwestern and northwestern boundaries and deeper along the eastern boundary. The thickness of the Utica Shale interval ranges from 1,000 feet to over 3,000 feet, with an organically rich gross interval of 1,000 feet. With a net-to-gross ratio of 40%, the net organic-rich shale is estimated at 400 feet. The total organic content (TOC) ranges from 1% to 3%, with the higher TOC values concentrated in the Upper Utica Shale. The thermal maturity is high, ranging from R_o of 1.1% to 4% and averaging 2%, placing the shale mostly in the dry gas window. Data on quartz and clay contents are not publicly available.

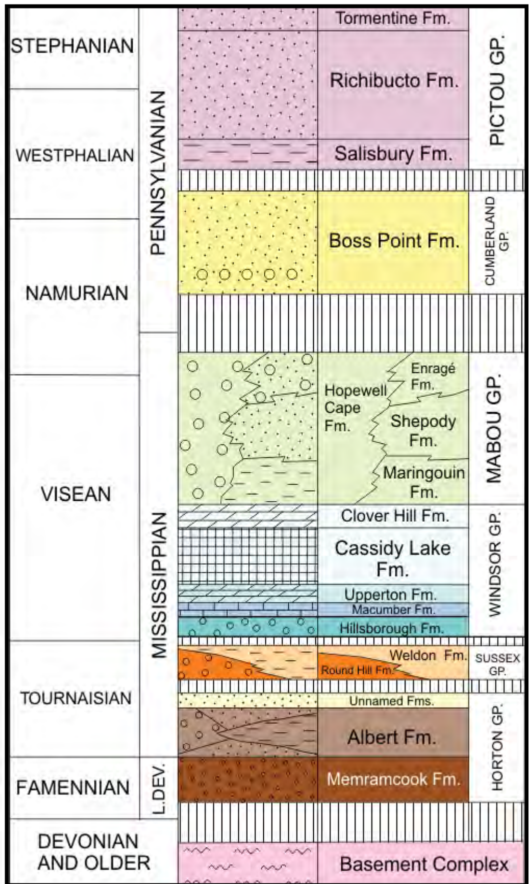
Resources. The prospective area of the Utica Shale in Quebec is estimated at 2,900 mi^2. Within this prospective area, the shale has a rich gas concentration of 134 Bcf/mi^2. As such, the risked shale gas in-place is 155 Tcf. With moderate clay content, but severe geologic complexity within the prospective area, we estimate a risked technically recoverable shale gas resource of 31 Tcf for the Utica Shale.

Exploration Activity. Two significant size operators, Talisman and Forest Oil, plus numerous smaller companies such as Questerre, Junex, Gastem and Molopo, hold leases in the Utica Shales of Quebec. Approximately 25 exploration wells have been drilled with moderate results. Market access is provided by the Maritimes and Northeastern pipeline as well as the TransCanada Pipeline to markets in Quebec City and Montreal.

Windsor basin (Nova Scotia)/Horton Bluff Shale

Geologic Characterization. The Horton Bluff Shale is located in north-central Nova Scotia. It is an Early Mississippian Shale within the Horton Group, Figure I-19. Because the Horton Bluff Shale rests directly on the pre-Carboniferous, igneous and metamorphic basement, it has experienced high heat flow and has a high thermal maturity (R_o of 1.5% to 2.5%) in northern Nova Scotia. The Horton Bluff Shale geology is complex and faulted.

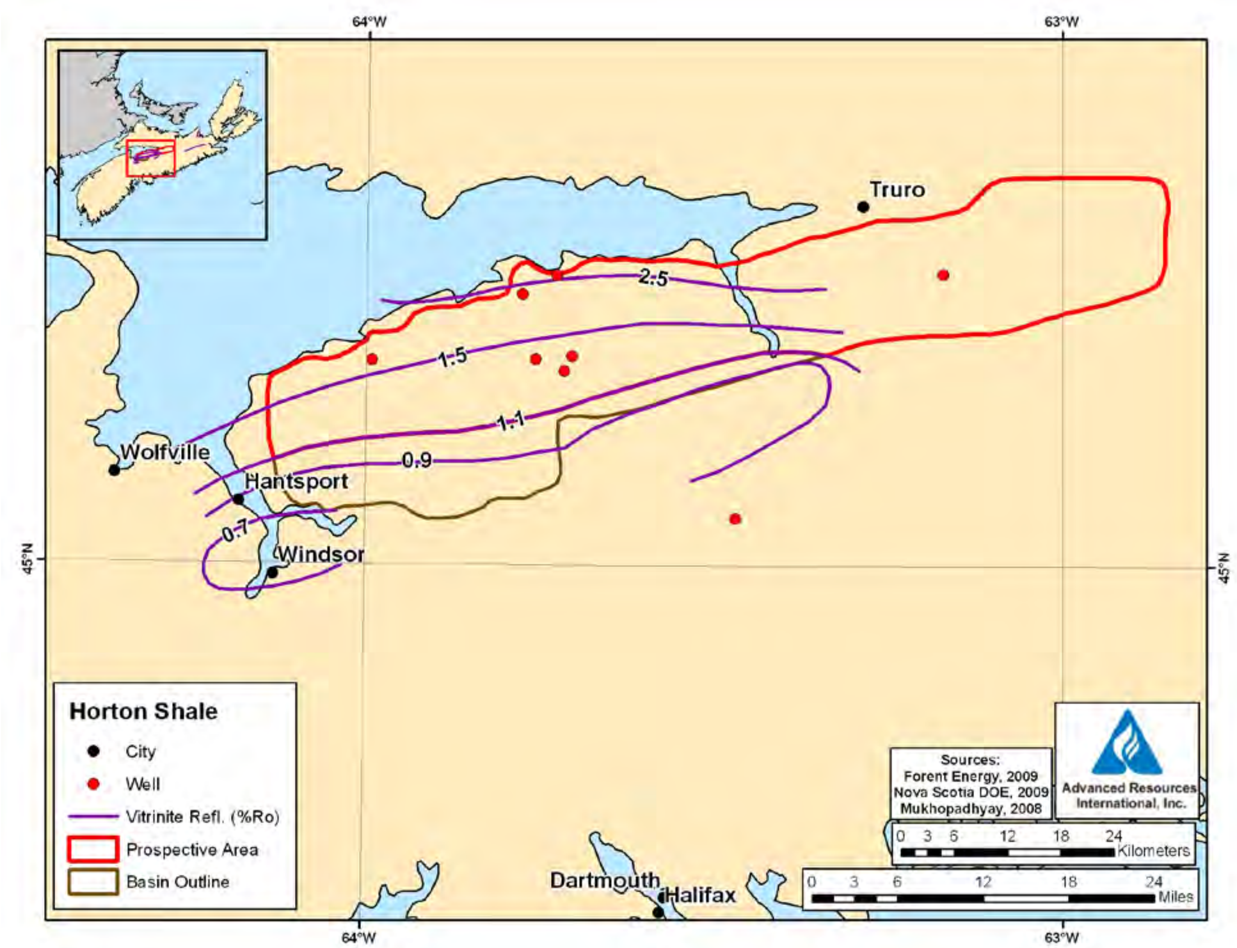
Figure I-19. Horton and Frederick Brook Shale (Horton Group) Stratigraphy



Source: Mukhopadhyay, 2009

Reservoir Properties (Prospective Area). The regional extent of the Horton Shale play is only partly defined as the basin and prospective area boundaries are highly uncertain. A preliminary outline and prospective area of 524 mi^2 for the Horton Bluff Shale play is provided in Figure I-20. The depth of the prospective area ranges from 3,000 to 5,000 feet. The shale interval is on the order of 500 to 1,000 feet thick with 500 feet of organic-rich gross pay and 300 feet of net pay. The TOC is 4% to 5% (locally higher). The thermal maturity of the prospective shale area ranges from an R_o of 1.1% in the south to an R_o of over 2.5% in the northeastern portion of the area, placing the bulk of the Horton Bluff Shale in the dry gas window. Data from the Kennetcook #1, drilled to test the Horton Bluff shale in the Windsor Basin provided a portion of the data on reservoir properties.

Figure I-20. Preliminary Outline and Prospective Area for Horton Bluff Shale (Nova Scotia)



Resource. The potentially prospective area of the Horton Bluff Shale in Nova Scotia is 524 mi^2, covering the northern and eastern portions of the play area. Within this prospective area, the shale has a resource concentration of 82 Bcf/mi^2. As such, our preliminary estimate is 9 Tcf of risked shale gas in-place. Given the geologic complexity in the prospective area, we estimate a risked technically recoverable shale gas resource of 2 Tcf for the Horton Bluff Shale.

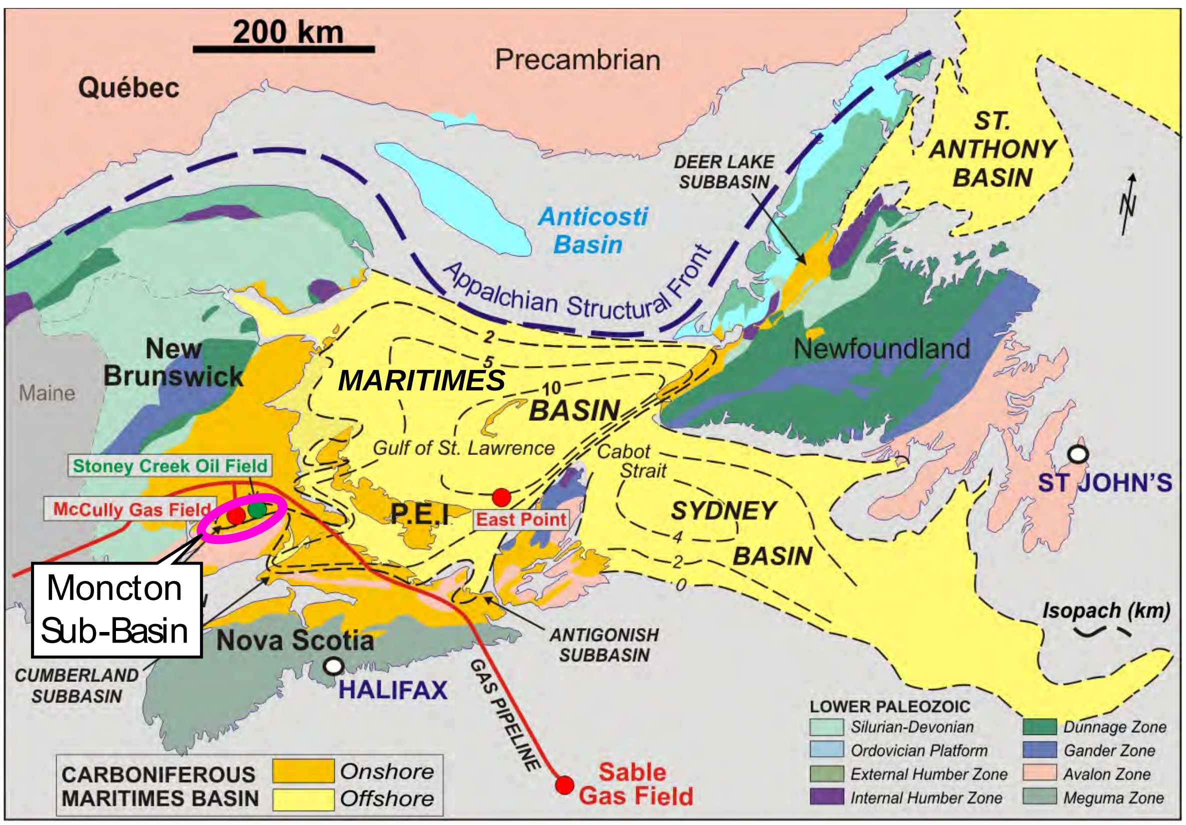
Exploration Activity. Two small operators, Triangle Petroleum and Forent Energy, have acquired leases and have begun to explore the Horton Bluff Shale.

Moncton Sub-Basin (New Brunswick)/Frederick Brook Shale

The Frederick Brook Shale is located in the Moncton Sub-Basin of the larger Maritimes Basin of New Brunswick, Figure I-21. This Mississippian-age shale is correlative with the Horton Group in Nova Scotia, Figure I-19. The Moncton Sub-Basin is bounded on the east by the Caledonia Uplift, on the west by the Kingston Uplift and on the north by the Westmoreland Uplift, Figure I-22. Because of limited data, the definition of the prospective area of the Frederick Brook Shale has not yet been established.

The Frederick Brook Shale is structurally complex, with extensive faulting and deformation. Its depth ranges from about 3,000 feet along the basin's eastern edges to 15,000 feet in the north. The total organic content of the shale ranges widely, from 1% to 10% and typically from 3% to 5%. No data are available on the mineralogy of the shale. The shales thermal maturity ranges from immature R_o < 1% in the shallower portions of the basin to highly mature (R_o > 2%) in the deeper western and southern areas.

Figure I-21. Location of the Moncton Sub-Basin

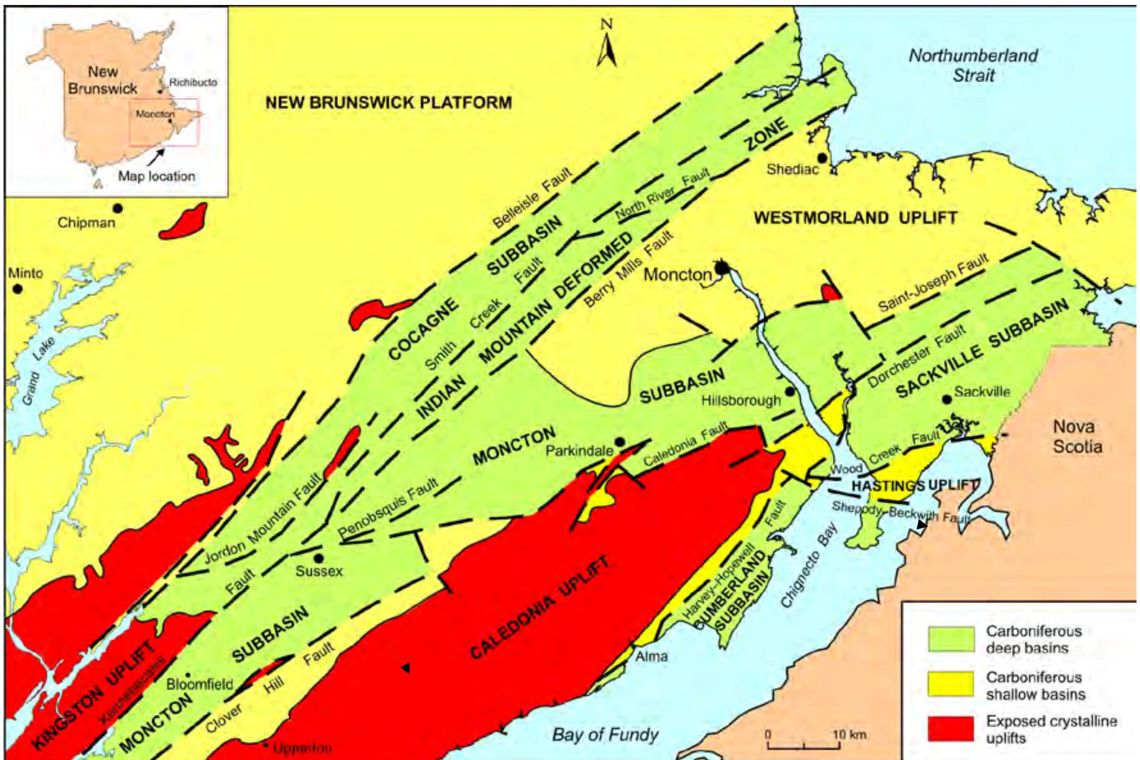


Source: Geological Survey of Canada, 2009 CSPG CSEG CWLS Convention, Canada

JAF21297.AI

Much of the data for this preliminary assessment of the Frederick Brook Shale is from the McCully gas field along the southwestern edge of the Moncton Sub-Basin and from a handful of vertical exploration wells. Other area, such as the Cocagne Sub-Basin, Figure I-22, may also be prospective for the Frederick Brook Shale but have yet to be explored or assessed.

Figure I-22. Structural Controls for Moncton Sub-Basin (New Brunswick) Canada



Source: P.K. Mukhopadhyay, Search and Discovery Article #10167 (2008)

Natural Gas Profile

Canada is a major producer and a net exporter of natural gas. In 2009, Canada produced 5,697 Bcf of natural gas, making it the world's third largest producer of this resource. Canada consumed 3,342 Bcf and exported 2,758 Bcf to the U.S. in 2009.

Overall natural gas production in 2009 declined by nearly 6% from 2008, with gas exports to the U.S. dropping below 3 Tcf for the first time in this decade. Much of Canada's natural gas production is concentrated in the Western Canada Sedimentary Basin, particularly in the province of Alberta. Conventional natural gas production in Canada has been steadily declining, with coalbed methane, tight gas and more recently shale gas production helping stem the decline.

Canada's proved reserves of natural gas, which had been declining steadily, stabilized at 58 Tcf in 2009.

Canada's natural gas pipeline system is highly interconnected with the U.S. Within Canada, TransCanada Pipeline operates a 25,600-mile network including the 13,900-mile, 10.6 Bcfd Alberta System and the 8,900-mile, 7.2 Bcfd Canadian Mainline. Spectra Energy operates a 3,540-mile, 2.2 Bcfd pipeline system connecting western Canada gas supply regions with markets in the U.S. and Canada. Spectra Energy also operates the Maritimes and Northeast Pipeline linking eastern Canada gas supply with markets in the eastern U.S.

REFERENCES

[1] Adams, C., "British Columbia, A Leading Canadian Oil and Gas Province, New Shale Gas Opportunities in the Horn River Basin, Montney and Other Basins", British Columbia Ministry of Energy, Mines and Petroleum Resources, presented at NAPE 2010, February 20, 2010, Houston, Texas.

[2] Dawson, F.M., "Unconventional Gas in Canada, Opportunities and Challenges", Canadian Society for Unconventional Gas, Service Sector Workshop, June 22, 2010.

II. MEXICO

INTRODUCTION

Thick, organic-rich and thermally mature source rock shales of Jurassic- and Cretaceous-age occur in northeast and east-central Mexico, along the country's onshore portion of the Gulf of Mexico Basin, Figure II-1. These shales are time-correlative with gas productive shales in the United States, including Eagle Ford, Haynesville, Bossier and Pearsall shales. [1]

However, compared with the shale belts of Texas and Louisiana, Mexico's coastal shale zone is narrower, less continuous and structurally much more complex. Regional compression and thrust faulting related to formation of the Sierra Madre Ranges has narrowed Mexico's coastal plain, creating a series of partly prospective, discontinuous sub-basins.[2] Many of Mexico's largest conventional oil and gas fields have been discovered here, both onshore and offshore. Conventional gas is produced mainly from sandstone reservoirs of Miocene and Pliocene age sourced by deep, organic-rich and thermally mature Jurassic (Tithonian) and Cretaceous-age shales. These deep source rocks are the principal targets for shale gas exploration in Mexico.

Based on regional mapping and source rock characterization, Advanced Resources (ARI) estimates that the five Mexico onshore basins assessed in this study contain approximately 2,366 Tcf of geologically risked shale gas in-place, Table II-1. An estimated 681 Tcf (risked) is judged to be technically recoverable. Structural complexity (faulting and folding), excessive depth (>5,000 m), and locally thin or absent shale on paleo highs constrain the resource assessment. No shale gas leasing or exploration activity has been reported to have occurred in these five basins.

Figure II-1. Onshore Shale Gas Basins of Eastern Mexico's Gulf of Mexico Basin.

Cross-section locations are noted

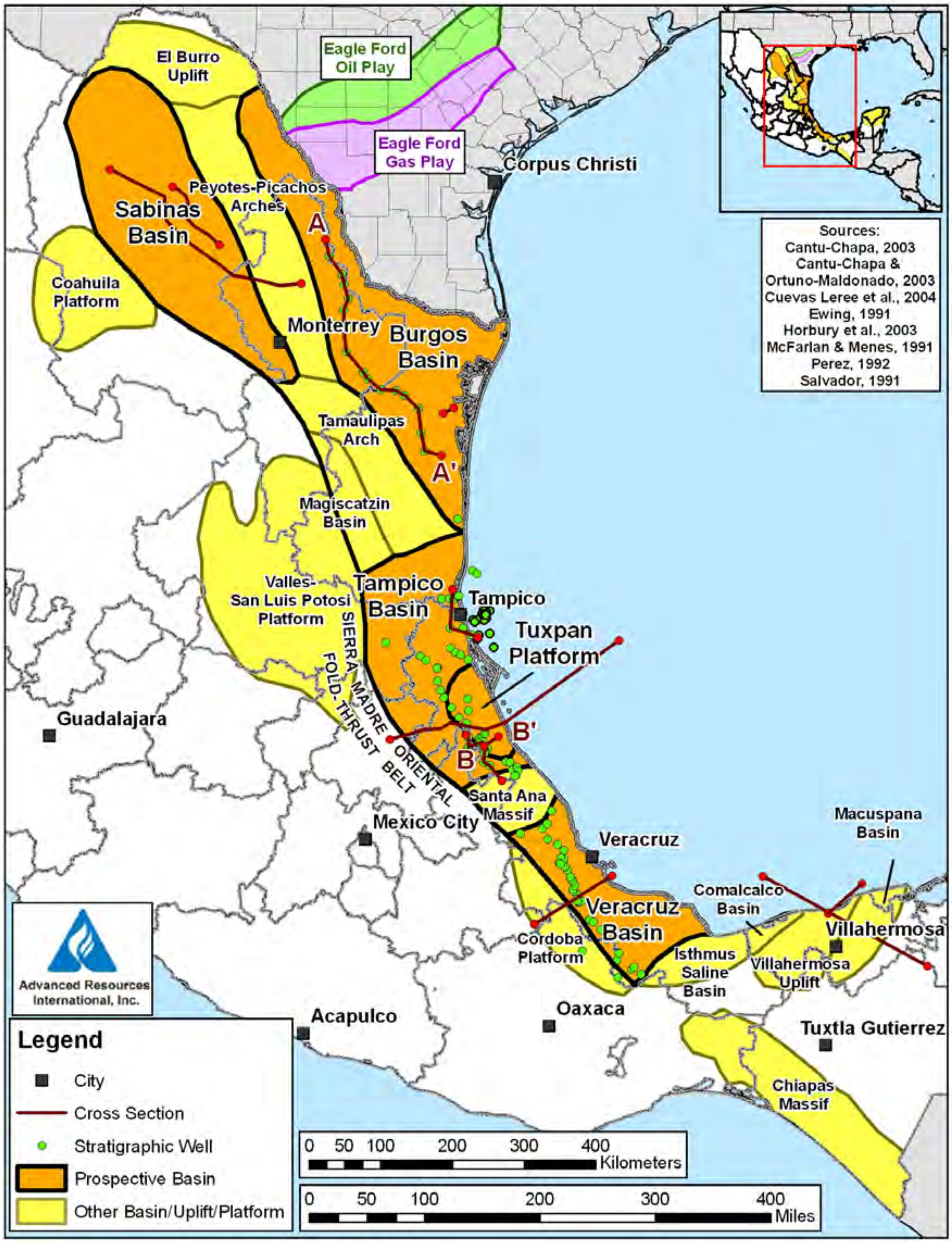


Table II-1. Shale Gas Reservoir Properties and Resources of Mexico

				Burgos Basin (24,200 mi²)		Sabinas Basin (23,900 mi²)	
Basic Data	Basin/Gross Area			Burgos Basin (24,200 mi²)		Sabinas Basin (23,900 mi²)	
	Shale Formation			Eagle Ford Shale	Tithonian Shales	Eagle Ford Shale	Tithonian La Casita
	Geologic Age			L-M Cretaceous	Upper Jurassic	L-M Cretaceous	Late Jurassic
Physical Extent	Prospective Area (mi^2)			18,100	14,520	12,000	12,000
	Thickness (ft)	Interval		300 - 1,000	100 - 1,400	300 - 1,000	200 - 2,600
		Organically Rich		600	500	500	800
		Net		400	200	400	240
	Depth (ft)	Interval		3,390 - 16,400	5,000 - 16,400	5,000 - 12,500	9,800 - 13,100
		Average		10,380	12,000	9,000	11,500
Reservoir Properties	Reservoir Pressure			Normal	Normal	Underpressured	Underpressured
	Average TOC (wt. %)			5.0%	3.0%	4.0%	2.0%
	Thermal Maturity (%Ro)			1.30%	1.30%	1.30%	2.50%
	Clay Content			Low	Low	Low	Low
Resource	GIP Concentration (Bcf/mi^2)			209	75	113	58
	Risked GIP (Tcf)			1,514	272	218	56
	Risked Recoverable (Tcf)			454	82	44	11

			Tampico Basin (15,000 mi²)	Tuxpan Platform (2,810 mi²)		Veracruz Basin (9,030 mi²)
Basic Data	Basin/Gross Area		Tampico Basin (15,000 mi²)	Tuxpan Platform (2,810 mi²)		Veracruz Basin (9,030 mi²)
	Shale Formation		Pimienta	Tamaulipas	Pimienta	Maltrata
	Geologic Age		Jurassic	L-M Cretaceous	Jurassic	Upper Cretaceous
Physical Extent	Prospective Area (mi^2)		14,240	1,950	1,950	8,150
	Thickness (ft)	Interval	16 - 650	50 - 500	400 - 1,000	0 - 600
		Organically Rich	490	300	490	300
		Net	245	225	245	120
	Depth (ft)	Interval	3,300 - 10,700	6,000 - 10,100	6,600 - 10,700	9,850 - 12,000
		Average	6,200	7,900	8,500	11,200
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%	3.0%	2.0%
	Thermal Maturity (%Ro)		1.30%	1.25%	1.30%	1.50%
	Clay Content		Low	Low	Low	Low/Medium
Resource	GIP Concentration (Bcf/mi^2)		63	65	72	29
	Risked GIP (Tcf)		215	25	28	38
	Risked Recoverable (Tcf)		65	8	8	9

In April 2010 PEMEX announced plans to drill Mexico's first shale gas test well in Coahuila state sometime during this year, while in August 2010 Pemex Director General Juan Jose Suarez listed shale gas among Mexico's "great future" untapped opportunities.

GEOLOGIC CHARACTERIZATION

Regional Geology

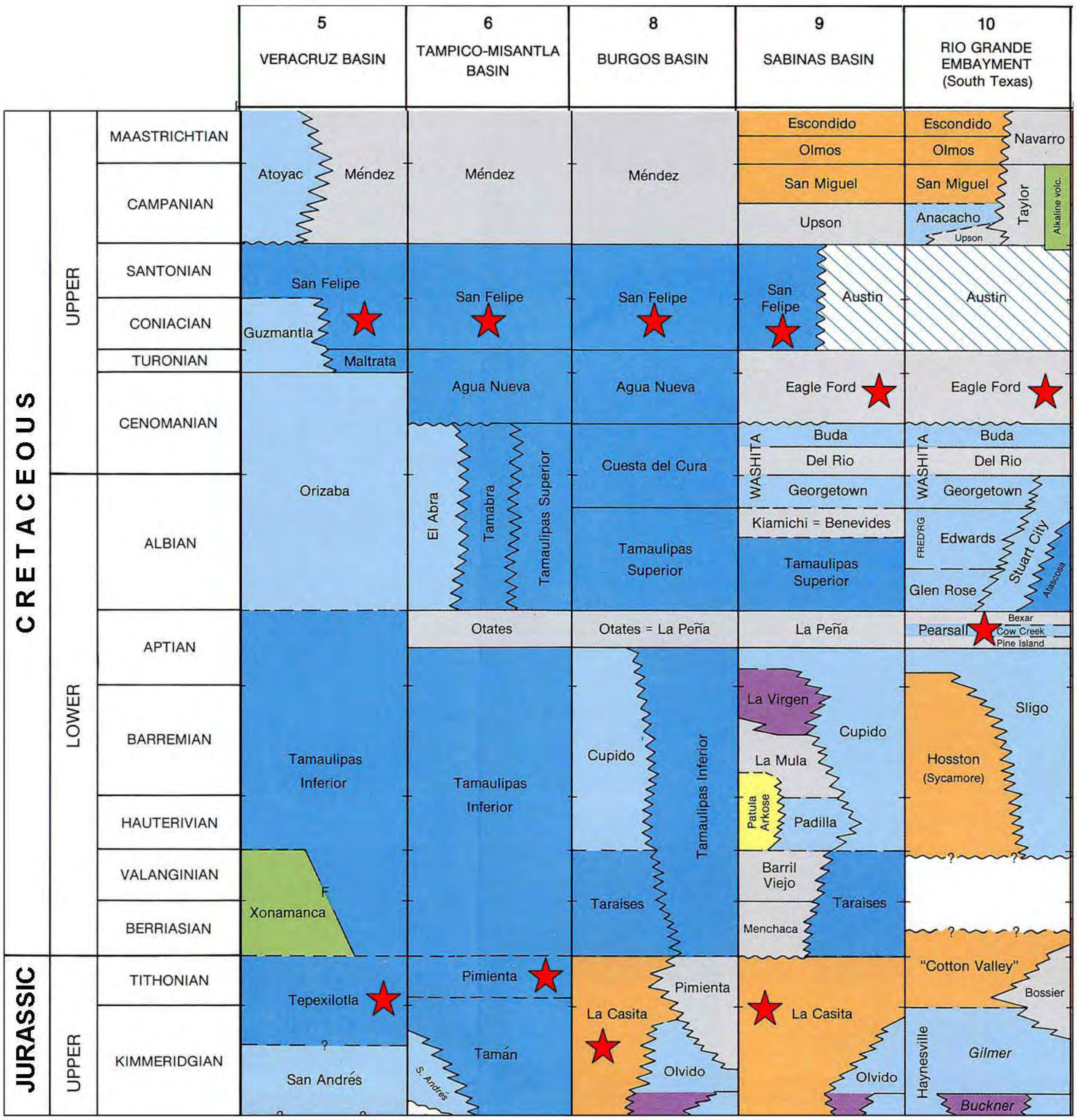
Onshore eastern Mexico contains a series of medium-sized basins and structural highs (platforms) within the larger western Gulf of Mexico Basin.[3] These structural features contain organic-rich marine shales of Jurassic and Cretaceous age that may be prospective for shale gas development. The accurate coastal shale belt includes the Burgos, Sabinas, Tampico, Tuxpan Platform, and Veracruz basins and uplifts. While detailed geologic maps of these areas generally are not publicly available, ARI constructed a general pattern of shale depth and thickness from a wide range of published local-scale maps and cross sections.

Many of Mexico's shale basins are too deep in their center for shale gas development (>5 km), while their western portions tend to be overthrusted and structurally complex. However, the less deformed eastern portions of these basins and adjacent shallower platforms are structurally more simple. Here, the most prospective areas for shale gas development are buried at suitable depths of 1 km to 5 km over large areas.

Pyrolysis geochemistry, carbon isotopic and biomarker analysis of oil and gas fields identify three major Mesozoic hydrocarbon source rocks in Mexico's Gulf Coast Basin: the Upper Cretaceous (Turonian to Santorian), Lower-Mid Cretaceous (Albian-Cenomanian), and -- most importantly – Upper Jurassic (Tithonian), the latter having sourced an estimated 80% of the conventional oil and gas discovered in this region.[4] These targets, particularly the Tithonian, also appear to have the greatest potential for shale gas development, Figure II-2.

This section discusses the shale gas geology of the individual sub-basins and platforms along eastern Mexico's onshore Gulf of Mexico Basin. The basins discussed start in northern Mexico near Texas moving to the south and southeastern regions close to the Yucatan Peninsula.

Figure II-2. Stratigraphy of Jurassic and Cretaceous rocks in the Gulf of Mexico Basin, Mexico and USA. Shale gas targets are highlighted.



Modified from Salvador, A. and Quezada-Muneton, J.M., 1989

Burgos Basin

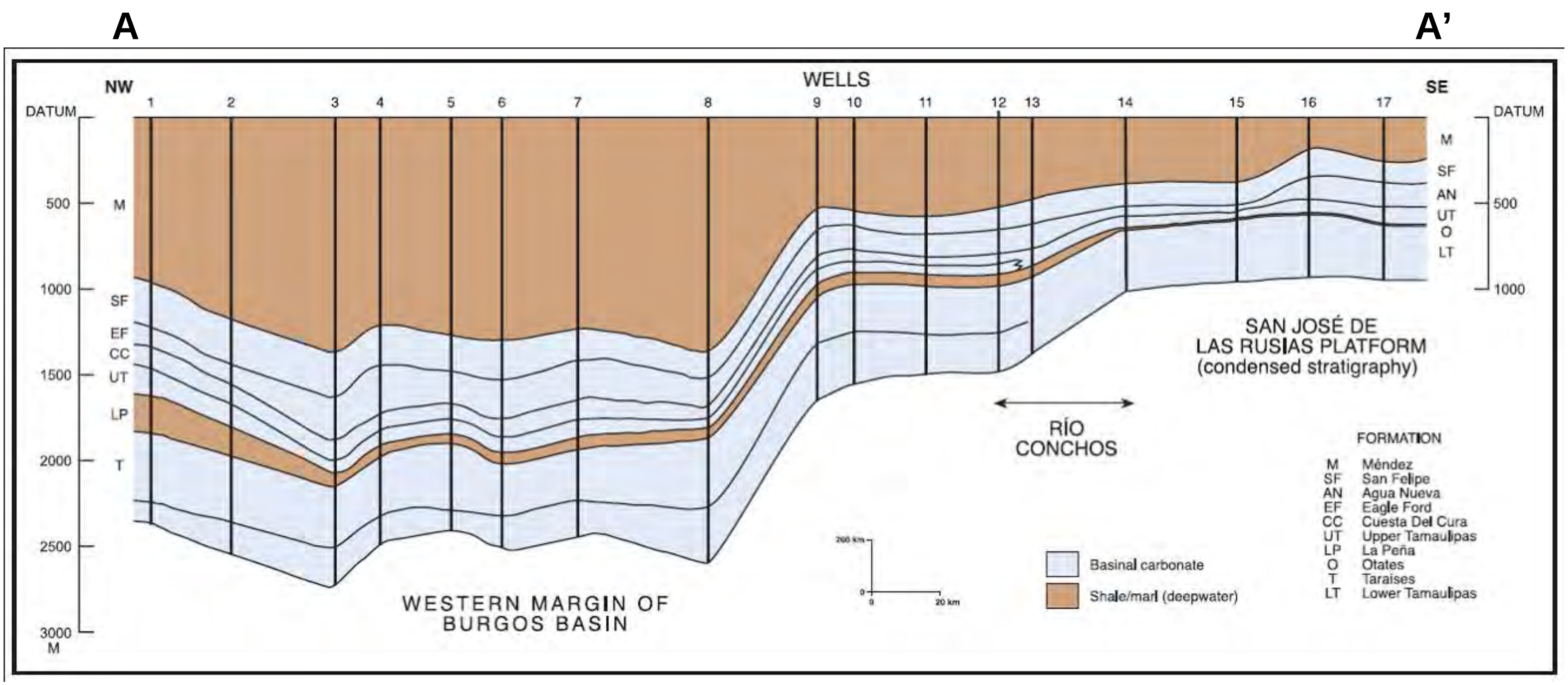
Overview. Located in northeast-most Mexico's Coahuila state, directly south of the Rio Grande River, the Burgos Basin is the southern extension of the Maverick Basin in Texas, the latter hosting the highly productive Eagle Ford and Pearsall shale plays. The Burgos Basin covers a total area of approximately 24,200 mi^2.

Reservoir Properties (Eagle Ford Shale). Based on an analog with the Eagle Ford Shale in Texas, ARI considers the Eagle Ford Shale in the Burgos Basin to be Mexico's top-ranked shale prospect. In the western margin of the Burgos Basin the Eagle Ford Shale gross pay ranges from 100 to 300 m thick (average 200 m), Figure II-3.[5] Recognizing the sparse regional depth and thickness control on the Eagle Ford Shale in the Burgos Basin[6], we estimate a prospective area of 18,100 mi^2 within the 1 km to 5 km depth window, Figure II-4, with a net organically-rich shale thickness of 400 feet. The eastern section of the basin is excluded as the shale is deeper than 5 km. Total organic content (TOC) is estimated at 5% (average) with a mean vitrinite reflectance of 1.3% R_o. Because reservoir pressure data were lacking; a hydrostatic pressure gradient (0.43 psi/ft) was assumed. The surface temperature in this region averages approximately 20°C, while the geothermal gradient typically is 23°C/km.

Resources (Eagle Ford Shale). Within its 18,100 mi^2 prospective area, the Eagle Ford Shale exhibits a high resource concentration of 210 Bcfmi^2. Risked shale gas in-place is 1,514 Tcf with a risked technically recoverable resource of 454 Tcf.

Figure II-3. Stratigraphic Cross-Section Along the Western Margin of the Burgos Basin.

Section is flattened on top Cretaceous. The Eagle Ford Shale (EF) here ranges from about 100 to 300 m thick (average 200 m).



Modified from Horbury et al., 2003

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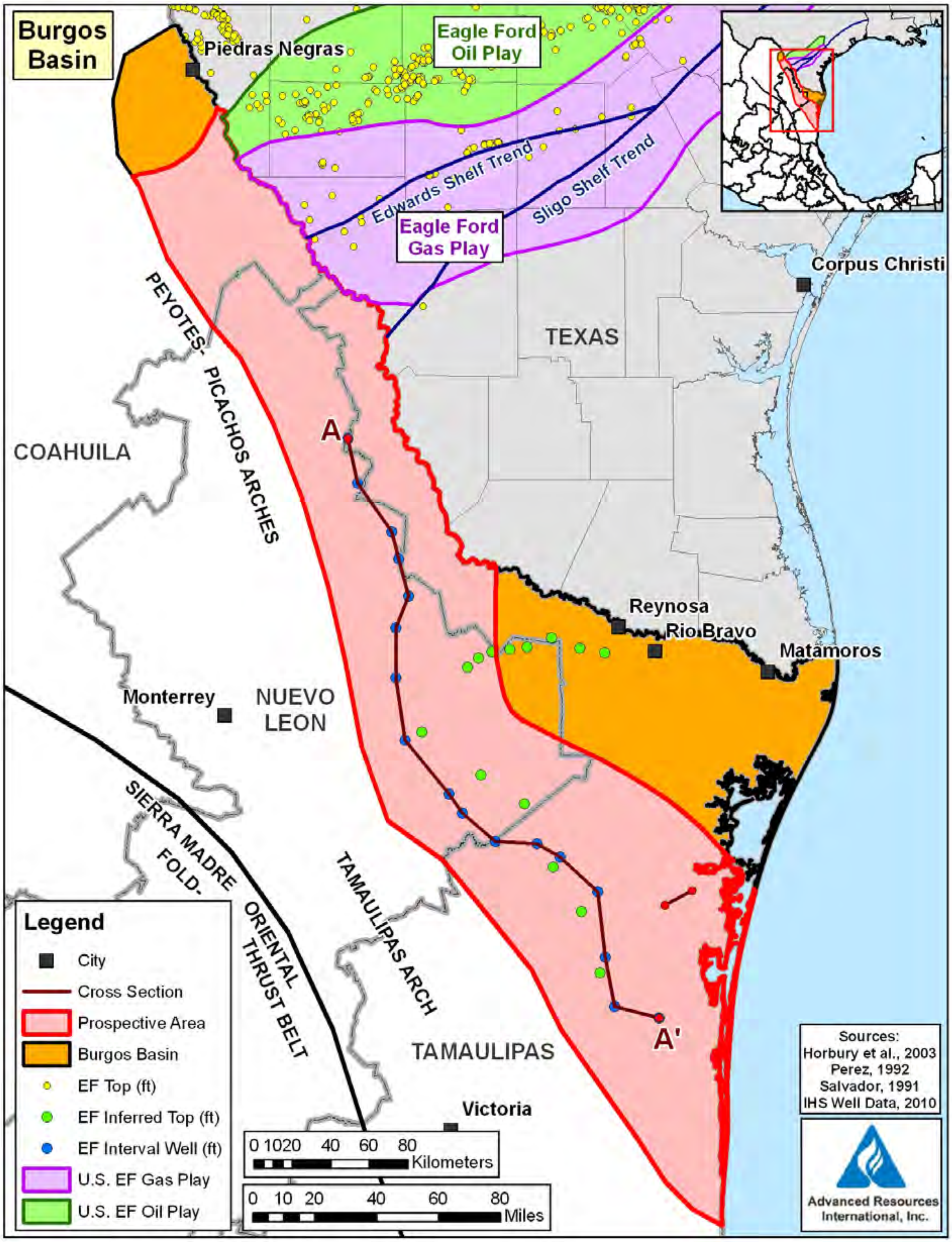
Figure II-4. Burgos Basin Outline and Shale Gas Prospective Area.



Reservoir Properties (Tithonian Shale). The Upper Jurassic Tithonian Shale is the other important petroleum source rock in the Burgos Basin. Extrapolating from the structure of the younger Eagle Ford, the average depth of the Tithonian Shale is 12,000 feet, with a prospective range of 5,000 to 16,400 feet. Gross thicknesses can be up to 1,400 feet, with an organically-rich net pay of 200 feet. A moderate TOC of 3.0% and thermal maturity of 1.30% R_o are estimated for the Tithonian Shale.

Resources (Tithonian Shales). With a prospective area of 14,520 mi^2, the Tithonian Shale of the Burgos Basin has an average resource concentration of 75 Bcf/mi^2. The risked shale gas in-place is 272 Tcf with a risked technically recoverable resource of 82 Tcf.

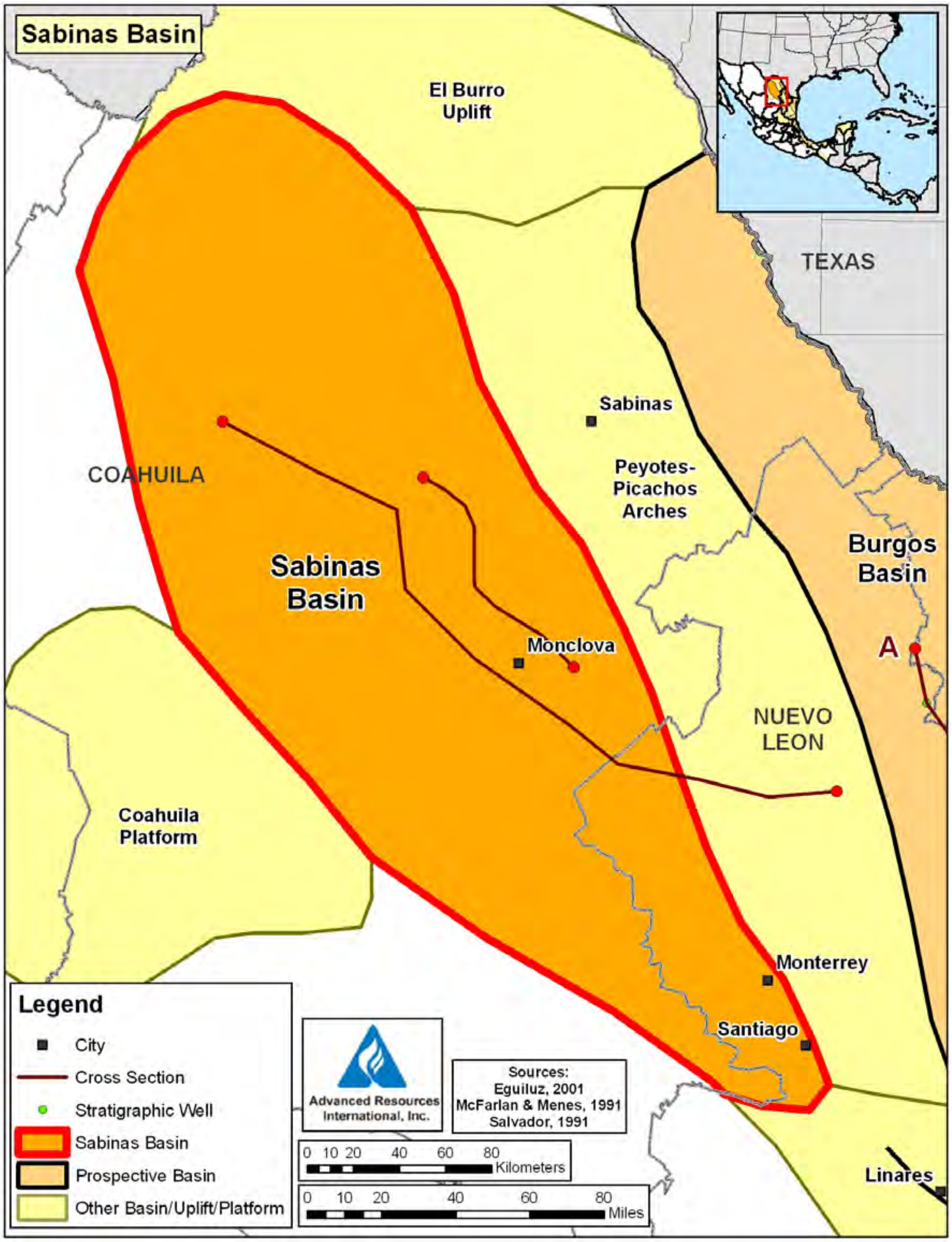
Sabinas Basin

Overview. The Sabinas is one of Mexico's largest onshore marine shale sub-basins, extending over a total area of 23,900 mi^2 in the northeast part of the country, Figure II-5. The Sabinas Basin is structurally quite complex, having been deformed into a series of tight, NW-SE trending, evaporate-cored folds of Laramide origin called the Sabinas foldbelt. In addition, withdrawal of Lower Jurassic salt during early Tertiary time induced an overprint of complex salt-withdrawal tectonics.[7]

Much of the basin is probably too structurally deformed for shale gas development, although a small area on the northeast side of the basin is more gently folded and may be prospective. The Eagle Ford (Turonian) and the Late Jurassic La Casita Fm (Tithonian)[8] in this basin appear to be the most prospective for shale gas development (The deltaic to continental Cretaceous Olmos Shale appears to be rich in terrigenous clay and coals).

Reservoir Properties (Eagle Ford Shale). The Eagle Ford Shale (Turonian) is distributed across the NW, NE, and central portions of the Sabinas Basin. It consists of a 300-m thick sequence of black shales rhythmically interbedded with sandy limestone and carbonate-cemented sandstone. We assume an organically-rich interval of 500 feet with 400 feet of net pay. We have used the Eagle Ford Shale in the Maverick Basin of South Texas as the analog for reservoir properties, using a TOC of 4%, a thermal maturity of 1.30% (R_o) and moderate to low gas-filled porosity. By extension of Burgos Basin data to the east, the average depth for the prospective Eagle Ford is 9,000 feet. Based on reported data, we use an underpressured gradient of 0.28 psi/ft for the Sabinas Basin.

Figure II-5. Sabinas Basin Outline and Shale Gas Prospective Area.

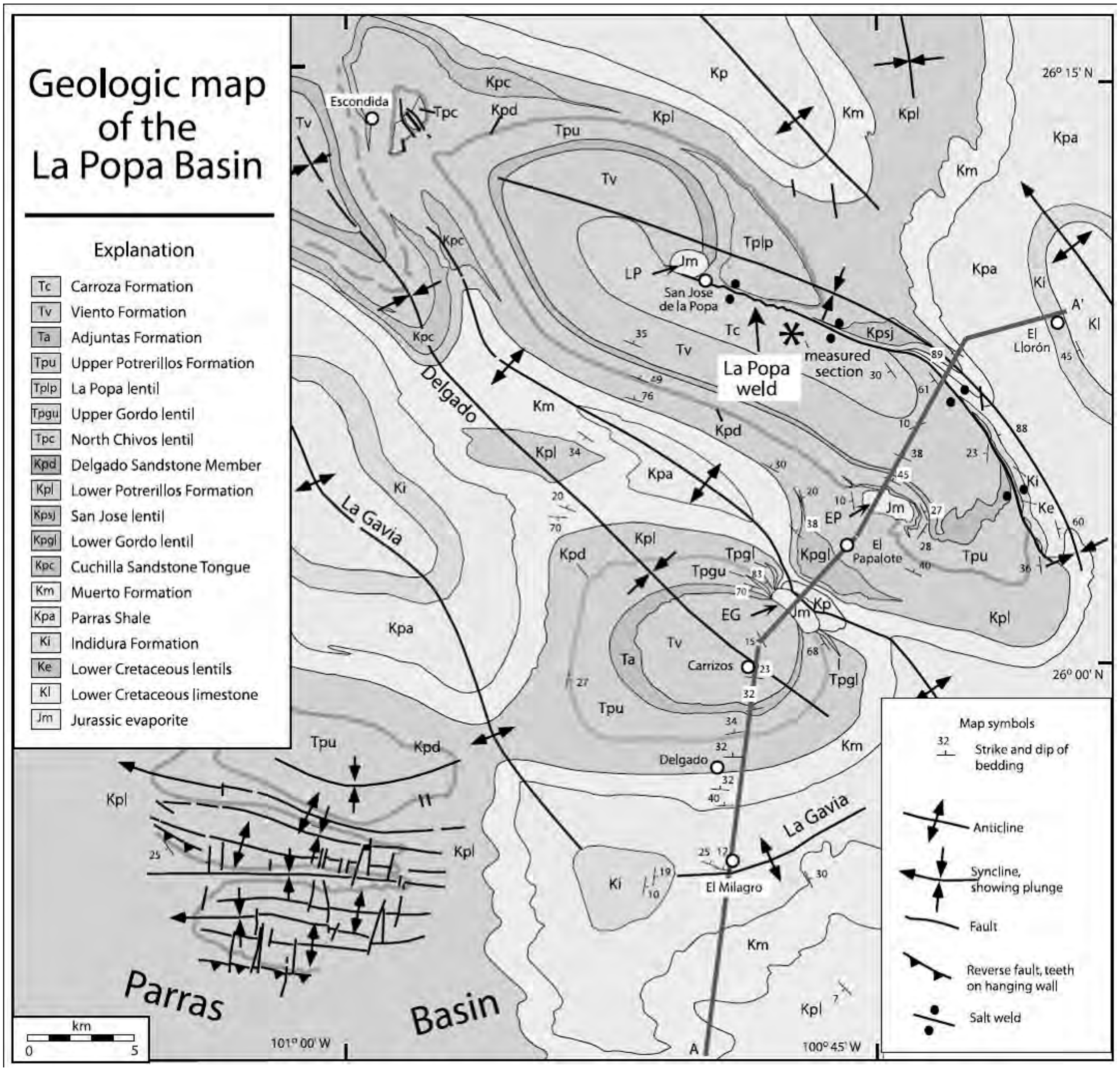


Resources (Eagle Ford Shale). Within a prospective area of 12,000 mi^2, the Eagle Ford Shale of the Sabinas Basin has a resource concentration of 113 Bcf/mi^2. The risked shale gas in-place is estimated at 218 Tcf, with a risked technically recoverable resource of 44 Tcf.

Reservoir Properties (La Casita Fm). The underlying La Casita Fm (Tithonian) is regarded as the primary hydrocarbon source rock in the Sabinas Basin, consists of organic-rich shales deposited in a deepwater marine environment. The La Popa sub-basin is one of numerous sub-basins within the Sabinas Basin, Figure II-6.[9] The La Popa is a rifted pull-apart basin that contains thick source rock shales. Up to 370 m of black carbonaceous limestone is present in the Upper Jurassic La Casita Fm (Tithonian), overlying several km of evaporitic gypsum and halite. Total shale thickness in the La Casita ranges from 60 m to 800 m. Thick (300 m), prospective La Casita Fm shales have been mapped at depths of 2,000 to 3,000 m in the central Sabinas Basin. Nearby, a thicker sequence (400-700 m) was mapped at greater depth (3,000 to 4,000 m). We assume an organically-rich interval of 800 feet with 240 feet of net pay. TOC ranges from 1.0% to 3.0%, and thermally the shale is well into the dry gas window (R_o = 2 to 3%).

Resources (La Casita Fm). Uncertainty of reliable formation depths along the edges of the Sabinas limited our estimate of the prospective area to 12,000 mi^2 for the La Casita Fm. With gas in-place concentrations for the La Casita Fm at 58 Bcf/mi^2, the risked shale gas in-place is 56 Tcf, with a risked technically recoverable resource of 11 Tcf.

Figure II-6. Geologic Map of the La Popa Sub-Basin, Southeastern Portion of the Sabinas Basin. Note the numerous detachment and salt-controlled folds.



Source: Hudson and Hanson, 2010.

Tampico Basin

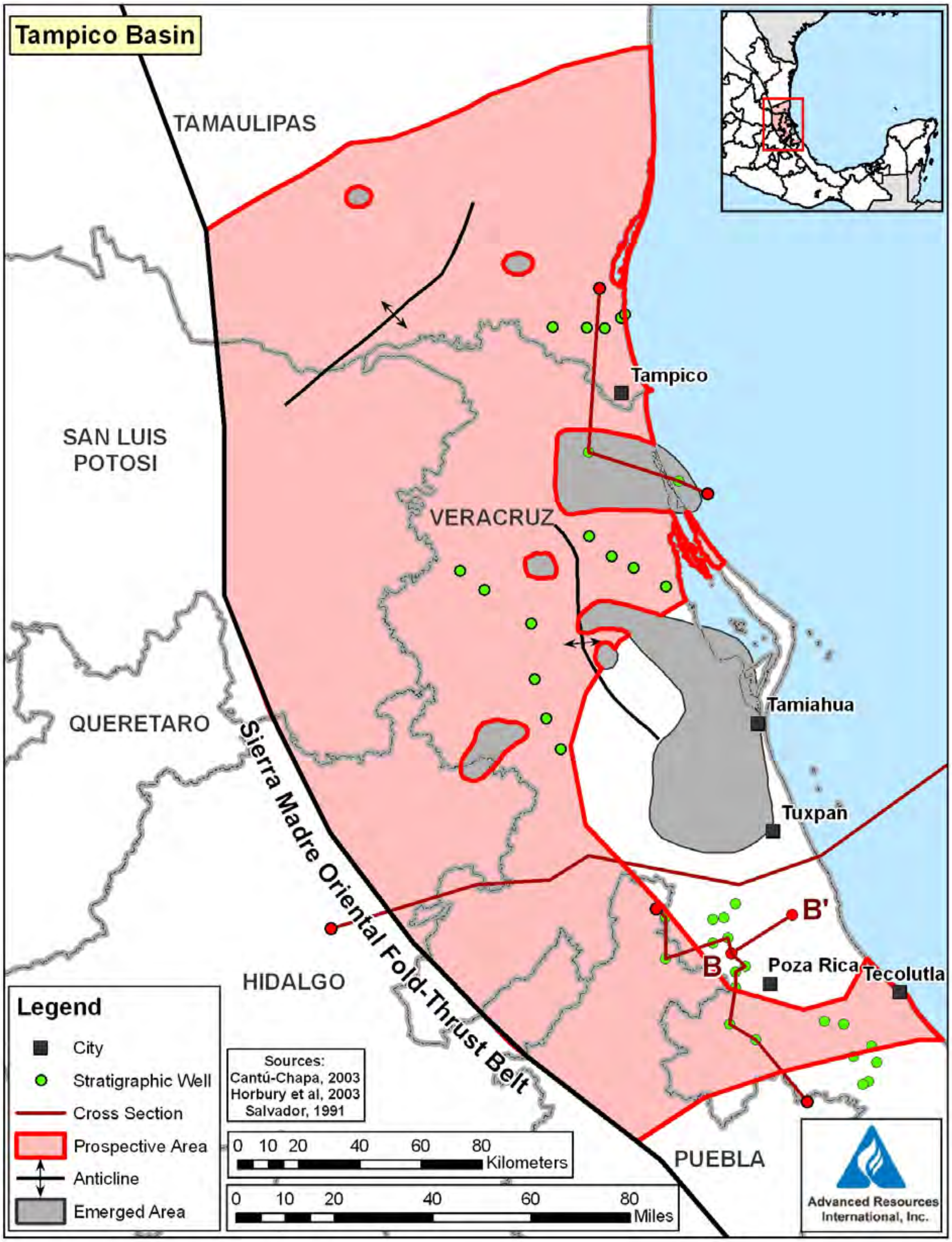
Overview. Bounded on the west by the fold-and-thrust belt of the Sierra Madre Oriental (Laramide) and on the east by the Tuxpan platform, the Tampico-Mizatlan Basin extends north from the Santa Ana uplift to the Tamaulipas arch north of Tampico. At the northern margin of the basin is an arch, limited by a series of faults extending south from the Tamaulipas arch.

In the southern Tampico Basin, the Pimienta Shale is at a prospective depth of 1,400 to 3,000 m. Three structures dominate this area. The NE-SW trending Piedra de Cal anticline in southwest Bejuco area is about 40 km long with a Pimienta Shale cresting at 1,600-m depth. The SW-NE trending Jabonera syncline in southeast Bejuco is about 20 km long, with a maximum shale depth of 3,000 m in the east and a minimum of about 2,400 m in the west. A system of faults defines the Bejuco field in the center of the area. Two large areas (Llano de Bustos and La Aguada) remained emergent and lack upper Tithonian shale deposits.

Reservoir Properties (Pimienta Fm). Near the city of Tampico, some 50 conventional wells have penetrated organic-rich Upper Jurassic (Tithonian) Pimienta Fm shales at depths of about 1,000 to 3,000 m, Figure II-7. Detailed shale thickness data are not available, but the Pimienta Fm here generally ranges from 200 m thick to as little as 10 m thick on paleo highs. We estimate an average net shale thickness of 245 feet for the prospective area. Average net shale TOC is estimated at 3%, with a thermal maturity of 1.3% Ro.

Resources (Pimienta Fm). Excluding the paleo highs, the prospective area of the Pimienta Shale is 14,240 mi^2 in the Tampico Basin. The resource concentration averages 63 Bcf/mi^2. We estimate a risked shale gas in-place of 215 Tcf, with a risked technically recoverable resource of 65 Tcf.

Figure II-7. Potentially Prospective Pimienta Formation (Tithonian) Shale, Tampico Basin.



Tuxpan Platform

Overview. This feature southeast of the Tampico Basin is a subtle basement high capped with a well-developed Early Cretaceous carbonate platform.[10] A particularly prospective and relatively well defined shale gas deposit is located in the southern Tuxpan Platform. Approximately 50 km south of the city of Tuxpan, near Poza Rica, a dozen or so conventional petroleum development wells in the La Mesa Syncline area penetrated thick organic-rich shales of the Pimienta (Tithonian) and Tamaulipus (Lower Cretaceous) Formations.[11] A detailed cross-section of the Tuxpan Platform shows thick. Lower Cretaceous and Upper Jurassic source rocks dipping into the Gulf of Mexico Basin, Figure II-8. These source rocks reach prospective depths of 2,500 m.

Reservoir Properties (Tamaulipas Fm). The Lower Cretaceous Tamaulipas Fm spans a depth range of 6,000 to 10,100, averaging 7,900 feet. The gross interval averages 500 feet while the net organically-rich pay is 225 feet. TOC in the Tamaulipas Fm is estimated at 3.0%. The thermal maturity is slightly lower than for the deeper Pimienta, at 1.25% R_o.

Resources (Tamaulipas Fm). Given limited data on the younger Tamaulipas Fm, the prospective area of the Pimienta Shale was used, limiting the area to 1,950 mi^2, Figure II-9. The shallower Tamaulipas Shale is estimated to hold about 65 Bcf/mi^2 with a risked shale gas in-place of 25 Tcf. The Tamaulipas Fm has a risked technically recoverable resource of 8 Tcf.

Reservoir Properties (Pimienta Fm). The Pimienta Shales range from 140 to 350 m thick, is 2,400 to 3,300 m deep, and is prospective for shale gas development across a nearly 80-km long trend. However, southeast of Poza Rica some areas have thin to absent shale, probably due to submarine erosion or lack of deposition. The gamma ray log response in the organic-rich Pimienta shale indicates high TOC.

Resources (Pimienta Fm). In the Tuxpan Platform, the prospective area of the Pimienta Fm shale is 1,950 mi^2. Greater depth pushes the resource concentration to 72 Bcf/mi^2 and the risked shale gas in-place to 28 Tcf. The risked technically recoverable of the Pimienta Shale equals 8 Tcf.

Figure II-8. Detailed Cross-Section of the Tuxpan Platform in East-Central Mexico Showing Thick Lower Cretaceous and Upper Jurassic Source Rocks Dipping into the Gulf of Mexico Basin.

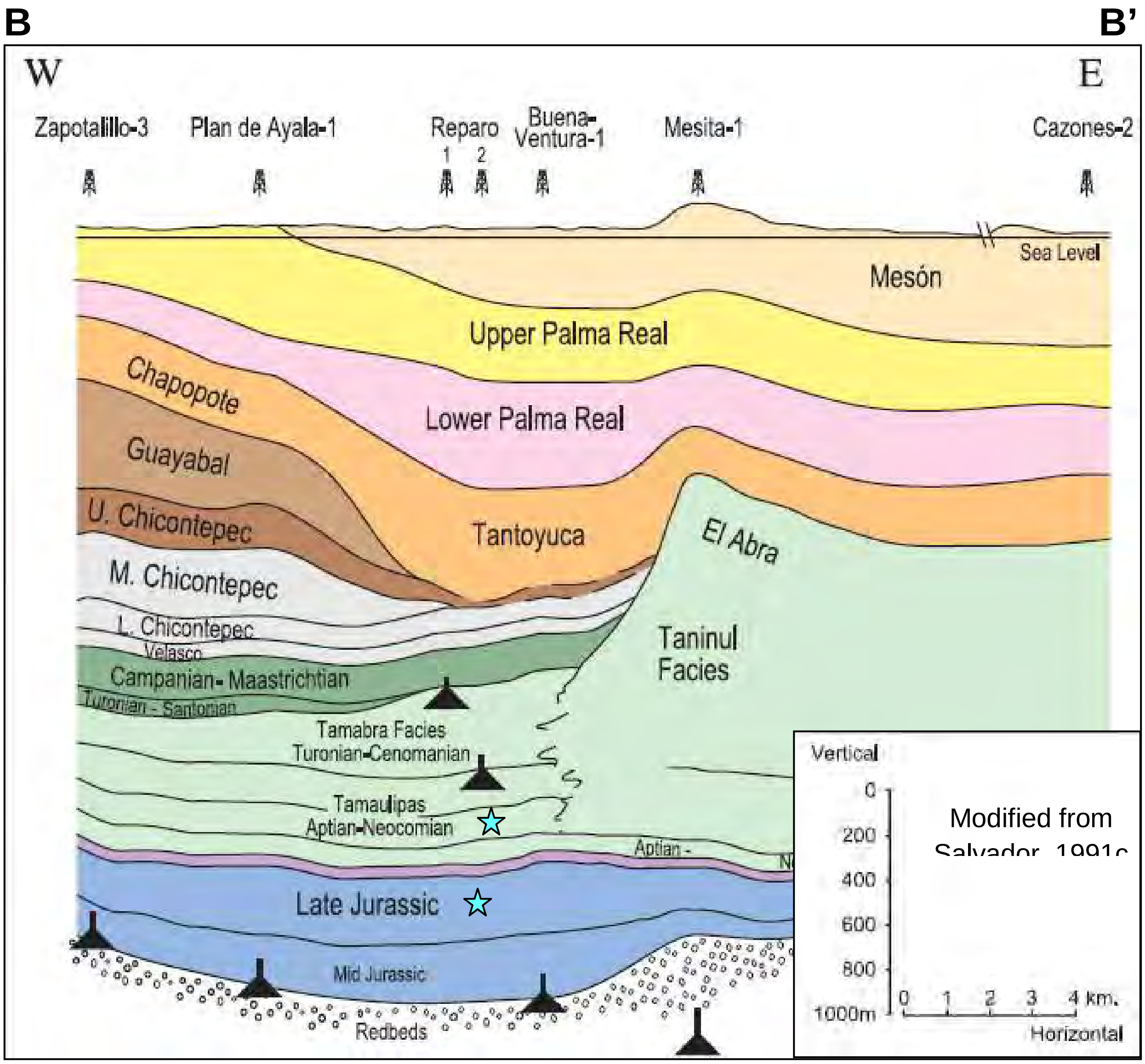


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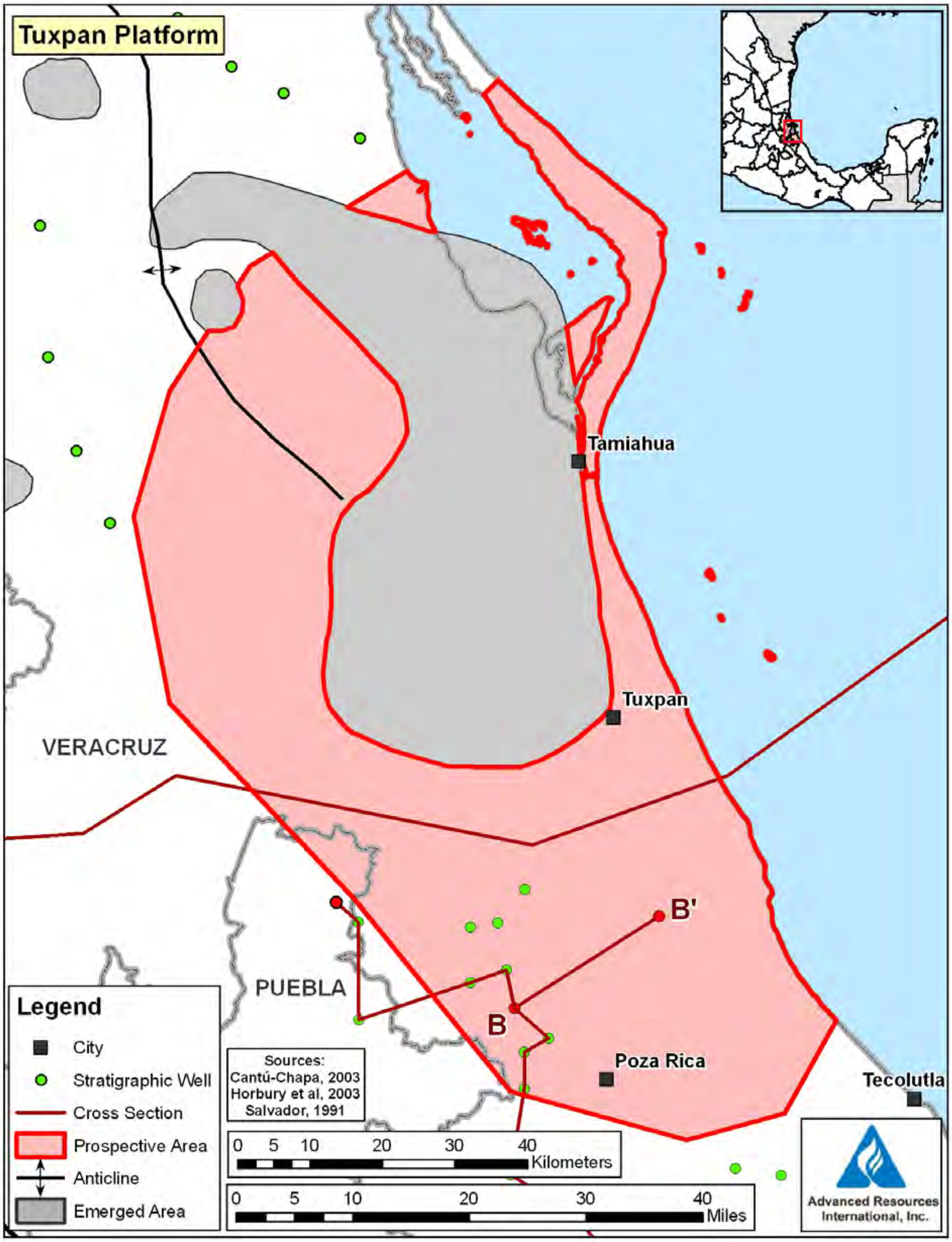
Figure II-9. Potentially Prospective Shale Gas Area of the Tuxpan Platform.



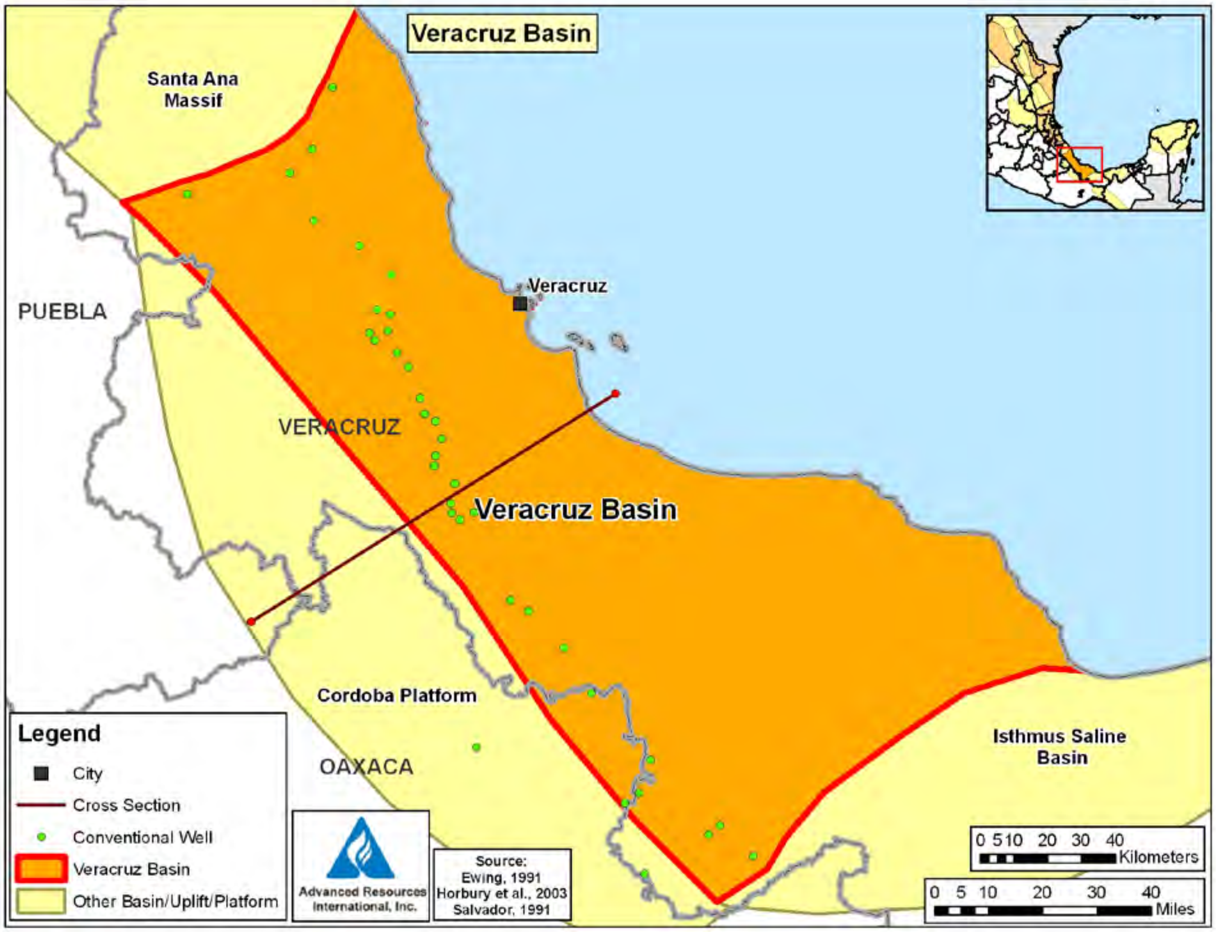
Veracruz Basin

Overview. The Veracruz Basin extends over a total area of about 9,030 mi^2 onshore near its namesake city. The basin's western margin is defined by thrusted Mesozoic carbonates (early Tertiary Laramide Orogeny) of the Cordoba Platform and Sierra Madre Oriental, Figure II-10. The basin is asymmetric in cross section, with gravity showing the deepest part along the western margin. The basin comprises several major structural elements, from west to east: the Buried Tectonic Front, Homoclinal Trend, Loma Bonita Anticline, Tlacotalpan Syncline, Anton Lizardo Trend, and the highly deformed Coatzacoalcos Reentrant in the south.[12]

Reservoir Properties (Upper Cretaceous Maltrata Fm). The Upper Cretaceous (Turonian) Maltrata Formation is a significant source rocks in the Veracruz Basin, with up to 80 m of shaly marine limestones and TOC exceeding 2%. Currently the Maltrata is in the late oil-to-gas preservation window, with R_o of 1.0% to 1.3%.

Resources (Upper Cretaceous Maltrata Fm). Assuming that 90% of the Veracruz Basin is in a favorable depth range, the prospective area of the Upper Cretaceous Maltrata Fm of the Veracruz Basin is 8,150 mi^2. ARI estimates a relatively low resource concentration of 29 Bcf/mi^2, resulting in a risked shale gas in-place of 38 Tcf. The risked technically recoverable resource is estimated at 9 Tcf.

Figure II-10. Veracruz Basin Outline and Shale Gas Prospective Area.



NATURAL GAS PROFILE

Mexico produced 1.84 Tcf of natural gas in 2008 and consumed 2.36 Tcf,[13] Mexico's Gulf of Mexico Basin is the country's main petroleum producing area, with approximately 12.7 Tcf of proved natural gas reserves as of 2010. The Southern Region of Mexico includes the majority of the reserves though the Northern Region is expected to grow as unconventional prospects are explored. With an estimated total 681 Tcf of technically recoverable resources, shale gas could greatly expand Mexico's existing natural gas reserves.

State-owned Pemex operates more than 5,700 miles of natural gas pipelines across Mexico as well as much of the distribution network. There are currently ten active import connections with the United States, which saw 338 Bcf of U.S. imports to Mexico and 28.3 Bcf of Mexico's gas exports to the U.S. in 2009.

EXPLORATION ACTIVITY

Despite the close proximity of successful shale gas plays in the USA, such as the Eagle Ford Shale in South Texas, no shale gas exploration drilling has yet occurred in Mexico. The national oil company PEMEX plans to drill the country's first shale gas test well sometime later this year, very likely targeting the Eagle Ford Shale in Coahuila state.

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III. NORTHERN SOUTH AMERICA

INTRODUCTION

A series of Late Cretaceous-age organic-rich shales exist in northern South America. These shales have sourced the vast majority of the conventional oil and gas produced from Venezuela and Colombia, in particular from the Maracaibo Basin and its inclusive Catatumbo Sub-basin, Figure III-1.[1] These organic-rich shale source rocks in these basins are age-equivalent to the prolific South Texas Eagle Ford Shale in the United States.

Based on regional mapping and analysis of available geologic data, the Maracaibo and Catatumbo onshore basins in Venezuela contain the most prospective shale gas plays in northern South America, holding an estimated 120 Tcf of risked shale gas in-place, Table III-1. Technically recoverable shale gas resources are estimated at approximately 30 Tcf. While a high proportion of these two basins contain shale source rocks, significant areas are immature for gas generation and/or are excessively deep for exploration and production (over 5,000 meters).

In addition, the Upper Magdalena Valley and Llanos basins in west-central and eastern Colombia were analyzed for shale gas potential. While thick sequences of Late Cretaceous black shales are also present here, low thermal maturities[2] (~0.5% Ro) persist across the region and the shale gas formations appear to be immature for gas generation. Further limiting the prospectivity of the Columbian shales are the complex Andean tectonics which include numerous thrust and extensional faults, particularly in the Llanos Foothills.[3]

Figure III-1. Gas Shale Basins of Northern South America.

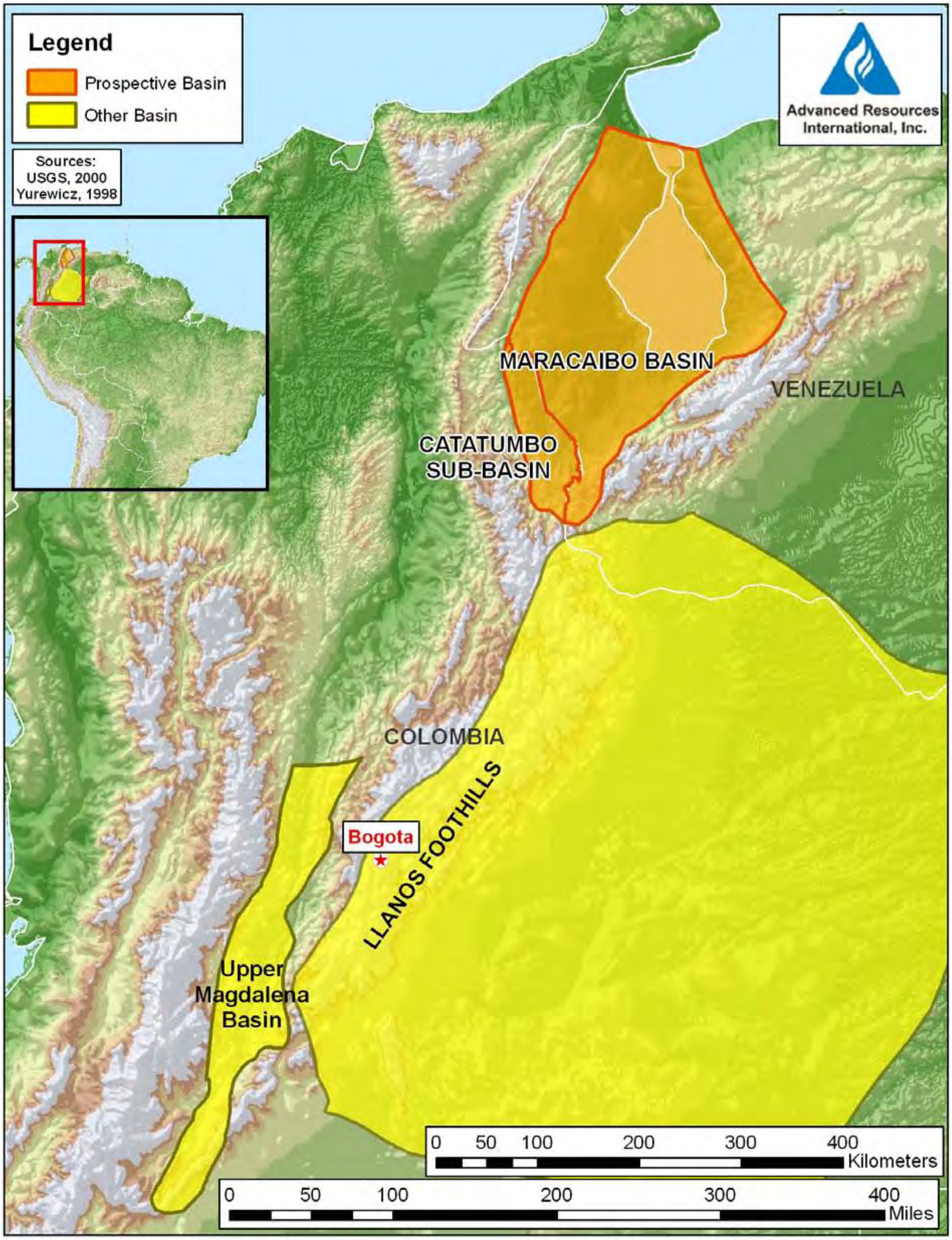


Table III-1. Gas Shale Reservoir Properties and Resources of Northern South America.

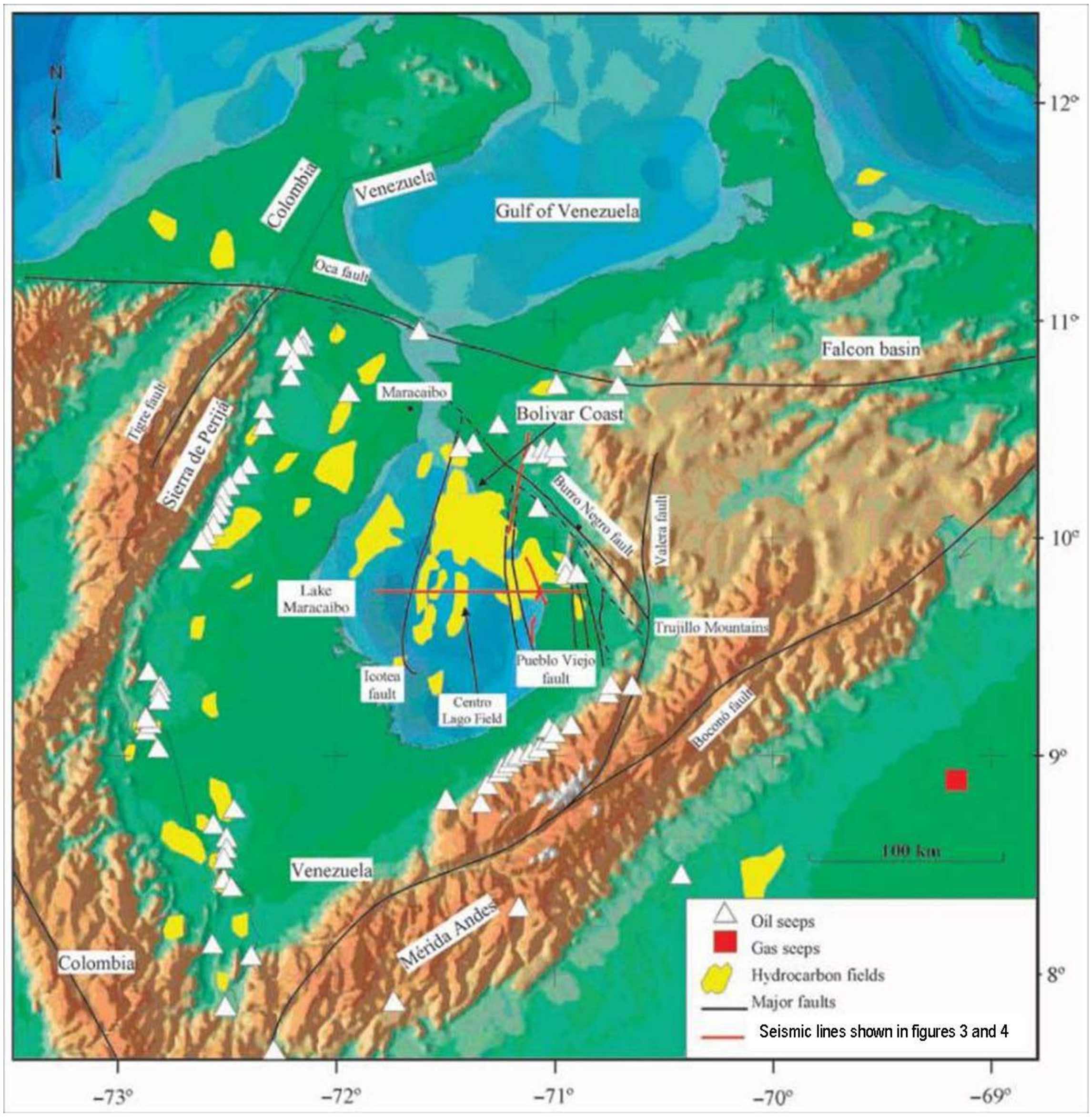
Basic Data	Basin/Gross Area		Maracaibo Basin (20,420 mi²)	Catatumbo Sub-Basin (2,380 mi²)	
	Shale Formation		La Luna Fm	La Luna Fm	Capacho Fm
	Geologic Age		Late Cretaceous	Late Cretaceous	Late Cretaceous
Physical Extent	Prospective Area (mi^2)		1,800	1,310	1,550
	Thickness (ft)	Interval	100 - 400	100 - 300	590 - 1,400
		Organically Rich	200	200	800
		Net	180	180	320
	Depth (ft)	Interval	12,500 - 15,000	6,000 - 7,200	6,500 - 8,500
		Average	13,500	6,600	7,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		5.6%	4.5%	1.3%
	Thermal Maturity (%Ro)		1.25%	1.05%	1.10%
	Clay Content		Low/Medium	Low/Medium	Low/Medium
Resource	GIP Concentration (Bcf/mi^2)		93	74	106
	Risked GIP (Tcf)		42	29	49
	Risked Recoverable (Tcf)		11	7	12

MARACAIBO BASIN (VENEZUELA)

Geologic Characterization. The Maracaibo Basin in northeastern Venezuela is situated in a triangular intermontane depression.[4] The western edge of the basin is bounded by the Sierra de Perija mountain range. The Merida Andes define the southern limit and the Trujillo Mountains the eastern extent of this basin, Figure III-2. Beginning in the Late Jurassic, sediments were deposited in depressions defined by north-northeast trending normal faults.[5] Throughout the Cretaceous and Paleocene, clastic and carbonate material along with marine shales were laid down across the passive margin, eventually becoming the main source rocks of the Maracaibo Basin.

By the end of the Paleocene, when the Caribbean plate began to collide with northwestern South America, the main sedimentary depocenter shifted from northwest to southeast. The convergence resulted in subsidence and a 3-mile thick Eocene foreland wedge of clastic sediments that accumulated across much of the present-day Maracaibo Basin. The area was then affected by regional uplift across the central and northeastern portions during the Oligocene, which brought about erosion and an Eocene unconformity. The uplift of the surrounding mountain ranges resulted in Miocene-Holocene subsidence of the basin.

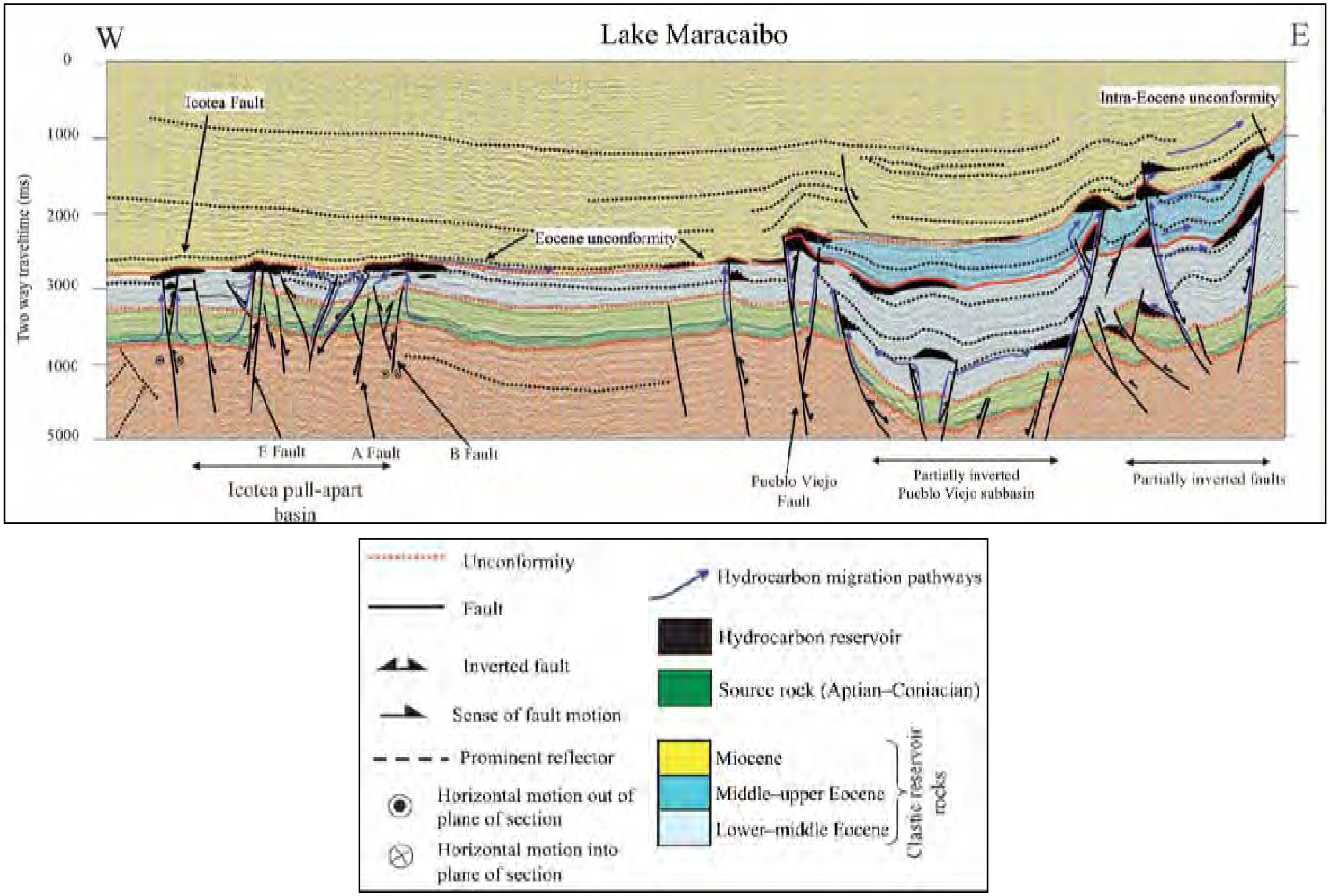
Figure III-2. Regional Outline of the Maracaibo Basin.



Modified from Escalona, A. and Mann, P., 2006

Major structural features present within the Maracaibo Basin include the Icotea and Pueblo Viejo faults which run north-south through central Lake Maracaibo and its eastern flank. The Burro Negro Fault stretches northwest-southeast in the northeastern portion of the basin. The Valera Fault runs north-south along the eastern portion of the basin. These structural elements are mapped in Figure III-2 and shown in the corresponding seismic cross-sections of Figures III-3 and III-4. To the east of the Icotea Fault, numerous minor faults make up a small pull-apart basin, extending up to the Eocene unconformity. The seismic profiles also show most of the hydrocarbon reservoirs present reside below this erosional surface.

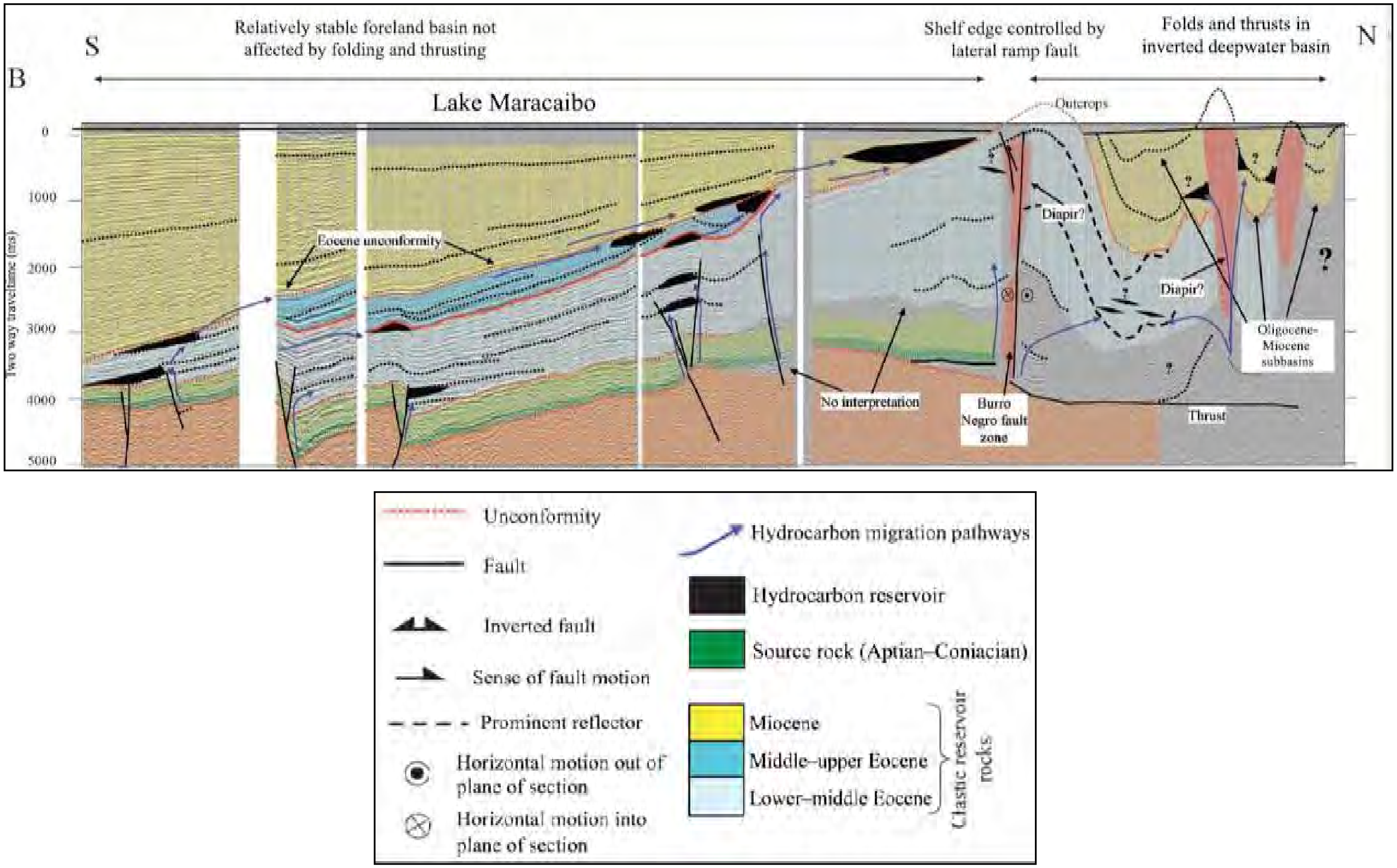
Figure III-3. Seismic Profiles, Maracaibo Basin.



Modified from Escalona, A. and Mann, P., 2006

Advanced Resources International, Inc.

Figure III-4. Seismic Profiles, Maracaibo Basin.

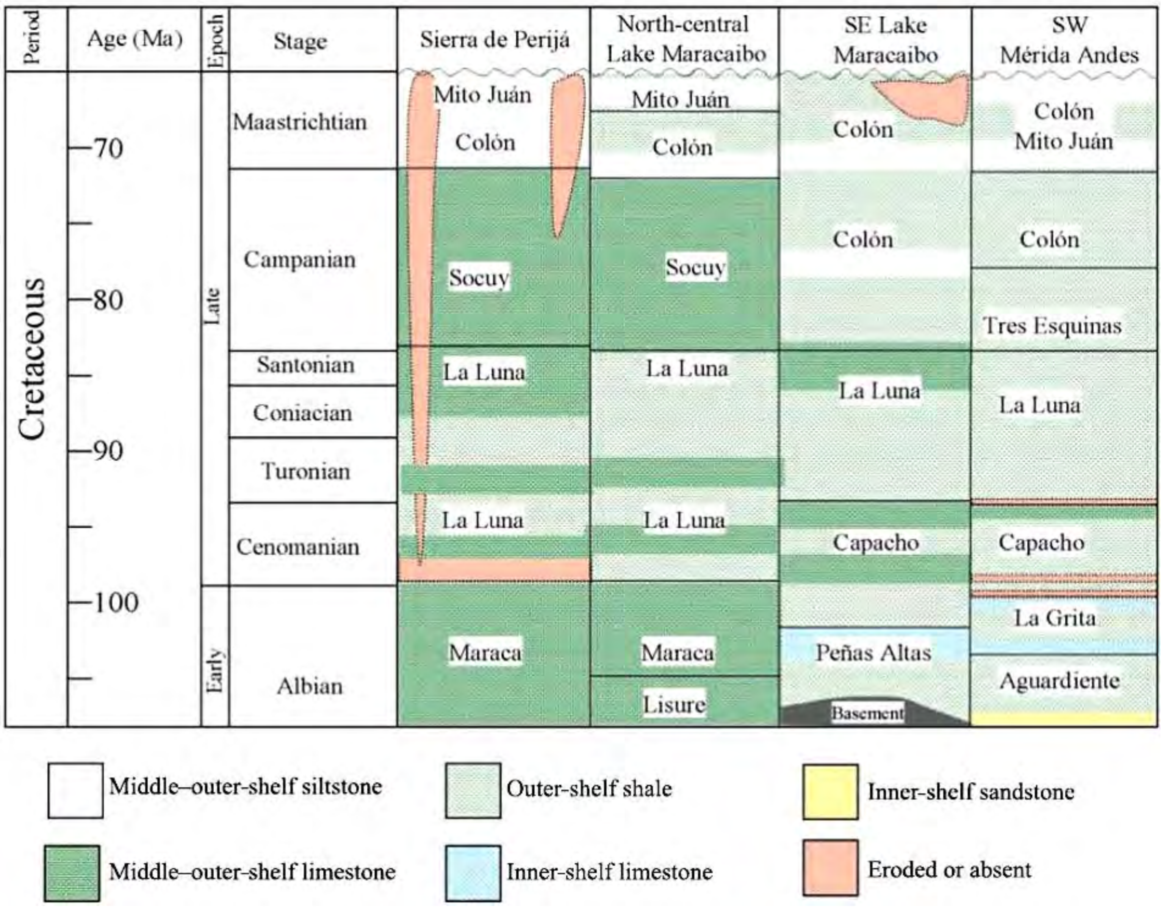


Modified from Escalona, A. and Mann, P., 2006

Advanced Resources International, Inc.

Despite these and other geologic complexities, the Maracaibo Basin is home to some of the world's richest source rocks and conventional oil and gas reservoirs. In particular, the Late Cretaceous shales of the La Luna Formation are a highly prospective target for shale gas exploration, Figure III-5.

Figure III-5. Maracaibo Basin Stratigraphy.

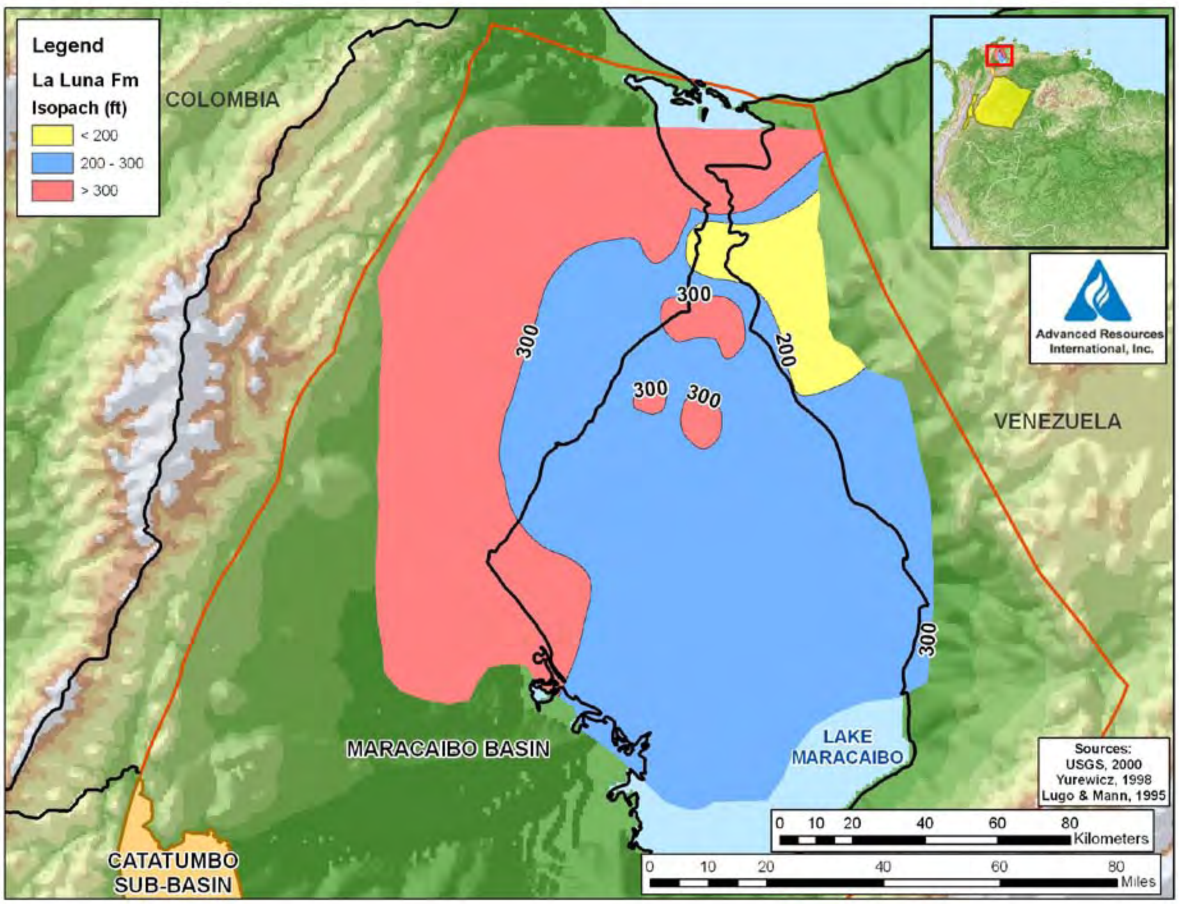


Source: Escalona, A. and Mann, P., 2006

Reservoir Properties (La Luna Shale). The Cretaceous (Cenomanian-Santonian) La Luna Formation, deposited under anoxic conditions, has long been a focus of study for conventional onshore oil production as it is the primary source rock for the hydrocarbons in the Maracaibo Basin.[6] Limestone intervals within the La Luna Fm can be excellent oil reservoirs, sourced by hydrocarbons of the adjoining deep shales. The outer-shelf shales of the overlying Colon Fm act as effective petroleum seals across the region, with most oil seepage only occurring via fault pathways.

Distributed across much of the Maracaibo Basin, the black calcareous La Luna Shale ranges from 100 to over 400 feet thick,[7] thinning towards the south and east,[8] Figure III-6. Maximum thickness of nearly 500 feet occurs in the extreme northern part of the basin. To the south and along Lake Maracaibo's eastern flank, the La Luna averages about 200 feet thick. ARI estimates that between one- and two-thirds of the gross thickness is net source rock pay. While it is widely accepted that the formation was deposited in an anaerobic setting, paleowater depth estimates range from over 3,000 feet[9] to only 160 feet.[10] The deeper environment is based on faunal assemblages, whereas the shallow deposition theory argues for upwelling of deep water onto a shallow platform.

Figure III-6. La Luna Fm Isopach, Maracaibo Basin.



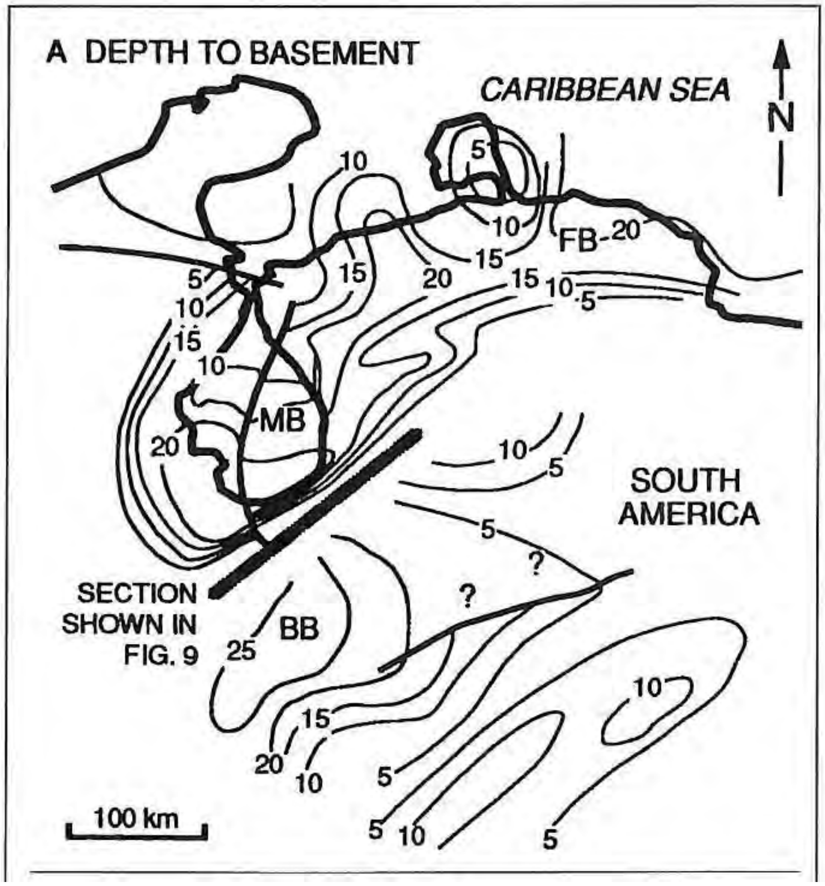
Depth to the Precambrian-Jurassic basement in the Maracaibo Basin reaches over 20,000 feet in southern Lake Maracaibo and its onshore eastern edge, Figure III-7. Much shallower depths occur towards the west, where the basement depth quickly rises to 5,000 feet. Depth to the La Luna Fm ranges from less than 5,000 to over 15,000 feet, generally deepening from northeast to southwest, Figure III-8. ARI's mapping indicates that the best shale gas potential exists at depths of 12,500 to 15,000 feet, the interval where the La Luna becomes thermally mature and gas prone.

Thermal maturity of the La Luna Fm increases from west to east across the Maracaibo Basin, from less than 0.7% R_o to over 1.7% R_o east of Lake Maracaibo, Figure III-9.[11] Vitrinite reflectance data indicate the unit is mainly in the oil generation window, with only a narrow area of the eastern basin prospective for shale gas. This gas prone area covers approximately 1,800 mi^2 and establishes the prospective area for this basin. The western boundary is defined by the 1.0% R_o contour. The eastern edge is limited by maximum 15,000-ft depth, inferred from the structure of the Late Jurassic basement.[12] To date, no significant free gas accumulations have been discovered in the Maracaibo Basin; all natural gas production has been associated gas.

Total organic carbon (TOC) varies across the basin, with values ranging from 3.7% to 5.7% in the northwest to 1.7% to 2% in the south and east. Maximum TOC values can reach 16.7%. ARI estimates the average TOC across the entire Maracaibo Basin is approximately 5.6%. A large portion of this shale-gas-prospective area includes part of Lake Maracaibo itself. ARI chose to include this submerged area because water depths are shallow (less than 100 feet) and there are numerous conventional production platforms that could provide access to shale drilling and development.

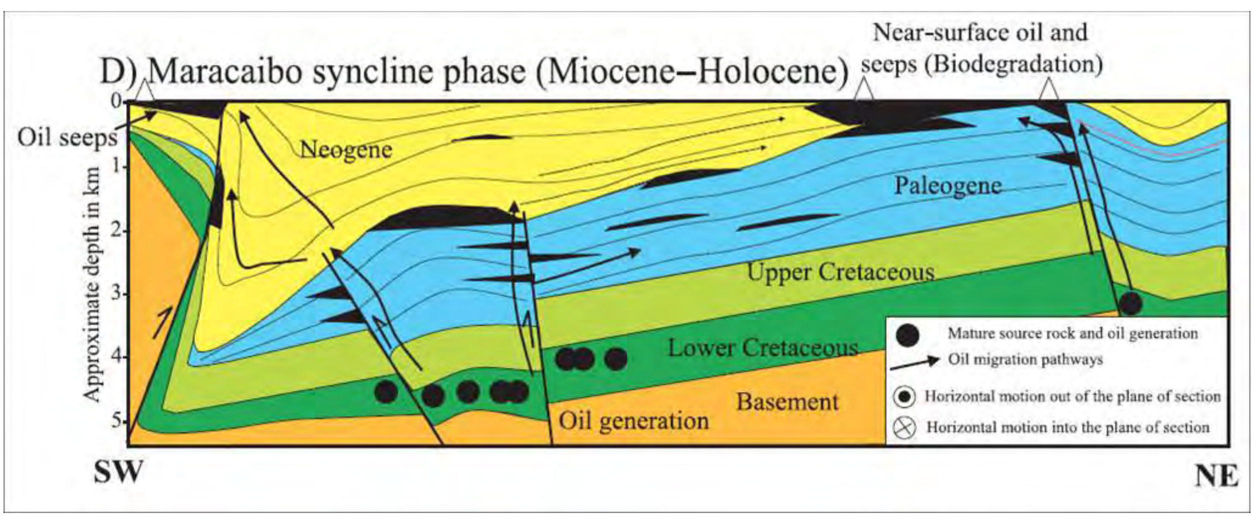
The underlying Capacho Formation, which is defined as a separate unit in the southern and eastern regions, contains black limestone and overlying micaceous-argillaceous shale with gross thicknesses of over 500 feet in the Maracaibo Basin. However, the Capacho Fm was determined to be mostly located in areas that exceeded the prospective depth threshold and/or where gas maturity was not reached, thus its shale gas potential was not assessed.

Figure III-7. Maracaibo Basin Depth to Basement.



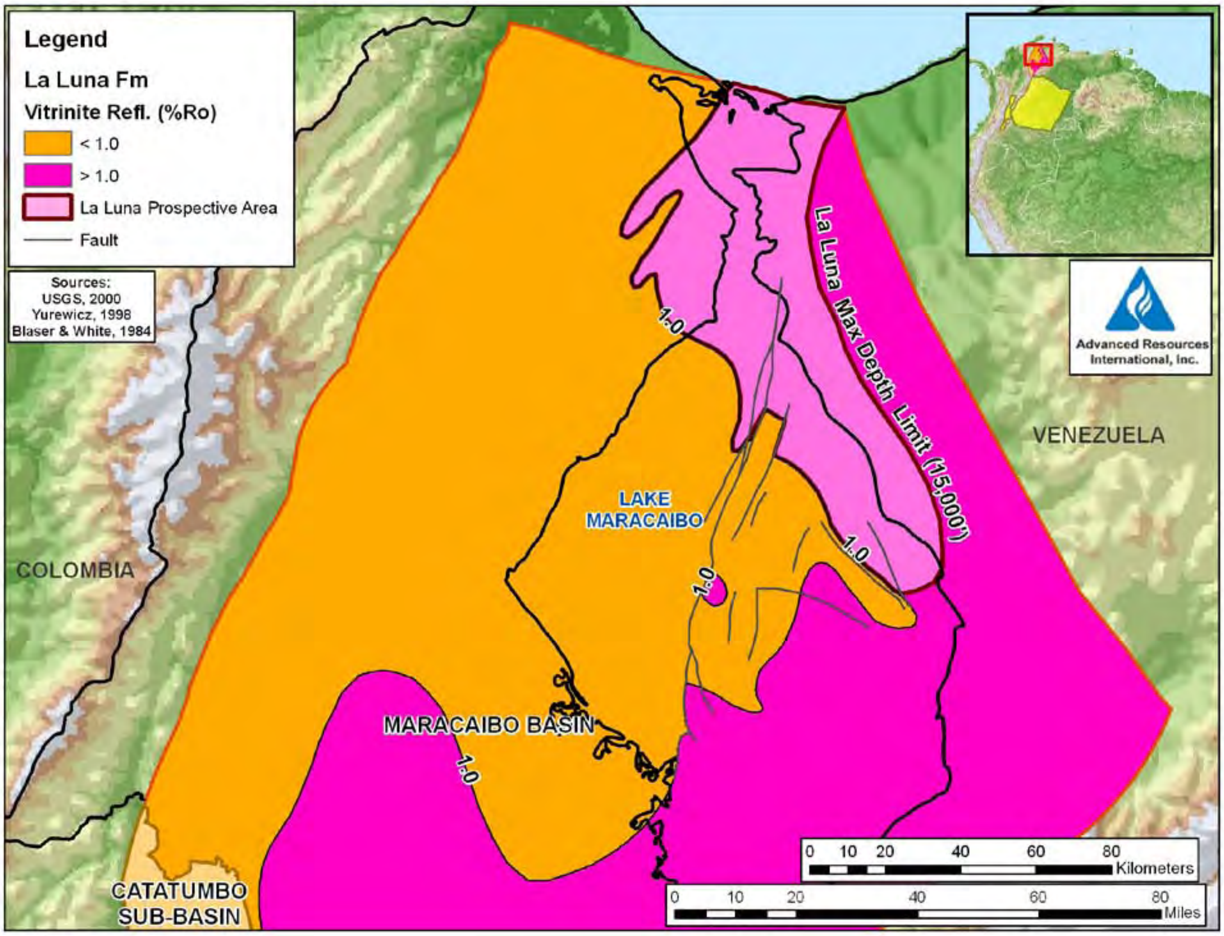
Modified from Lugo, J. and Mann, P., 1995

Figure III-8. Maracaibo Basin Cross Section.



Source: Escalona, A. and Mann, P., 2006

Figure III-9. Maracaibo Basin, La Luna Shale Prospective Area.



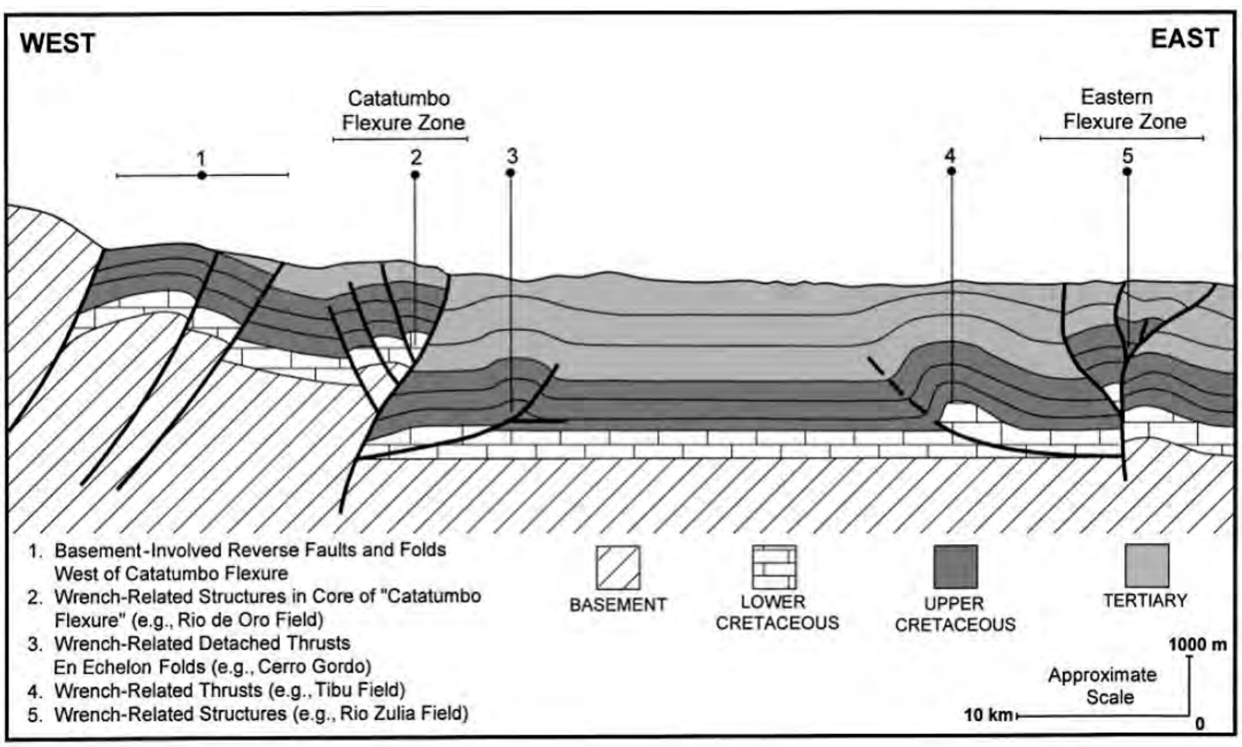
Resources (La Luna Shale). The La Luna Formation shales of the Maracaibo Basin have an estimated resource concentration of approximately 93 Bcf/mi^2, a level which is prospective and compares favorably with that of the Marcellus Shale. With an estimated 1,800-mi^2 prospective area as well as significant geologic complexity in the region, the risked gas-in-place is approximately 42 Tcf. Risked recoverable resources for the La Luna Shale is estimated at about 11 Tcf, **Table III-1**.

CATATUMBO SUB-BASIN (COLOMBIA)

Geologic Characterization. The southwestern Catatumbo Sub-basin extension in eastern Colombia also shows La Luna and Capacho shale potential. The Santander Massif forms the western boundary of this geologic province, the Merida Andes limit its southern and southeastern extent, and the Colombia-Venezuela border defines its eastern edge. The western and eastern areas of the sub-basin are characterized by folds, reverse faults and thrust faults, Figure III-10. Much like in the northern Maracaibo Basin, the Catatumbo Sub-basin has numerous conventional oil fields across its 2,380-mi^2 areal extent.

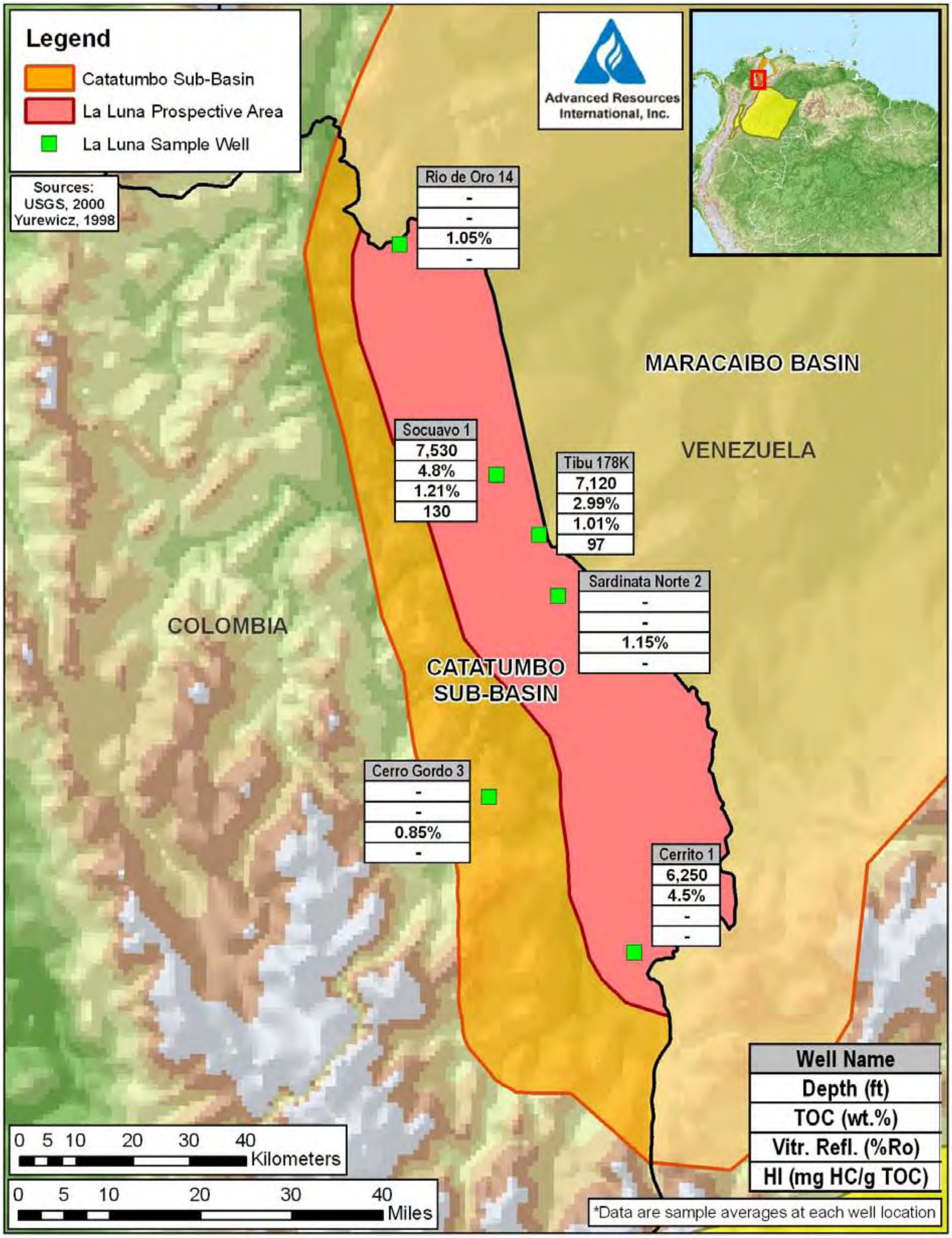
Reservoir Properties (La Luna Shale). The La Luna Formation is at relatively shallow depth in the Catatumbo Sub-basin, ranging from 6,000 to 7,600 feet.[13] Limited available well samples mapped in Figure III-11 show the average depths (along with other geologic properties), range from 7,120 feet in the extreme eastern Tibu 178K well to the slightly deeper 7,530 feet in the Socuavo 1 well, fifteen miles to the northwest. The unit consists of limey mudstones, wackestones, and minor shales ranging in gross thickness from 100 to 300 feet, averaging nearly 200 feet. Based on available vitrinite samples, thermal maturity ranges from 0.85 to 1.21% R_o, with generally higher reflectance in the central and northern areas of the basin. Samples from the Cerro Gordo 3 well in the southeast portion of the Catatumbo Sub-basin averaged 0.85% R_o, indicating that this area is oil prone.

Figure III-10. Catatumbo Sub-basin Cross-Section.



Source: Yurewicz, D.A., Advocate, D.M., Lo, H.B., and Hernández, E.A., 1998.

Figure III-11. La Luna Fm Basemap and Geologic Properties, Catatumbo Sub-basin.

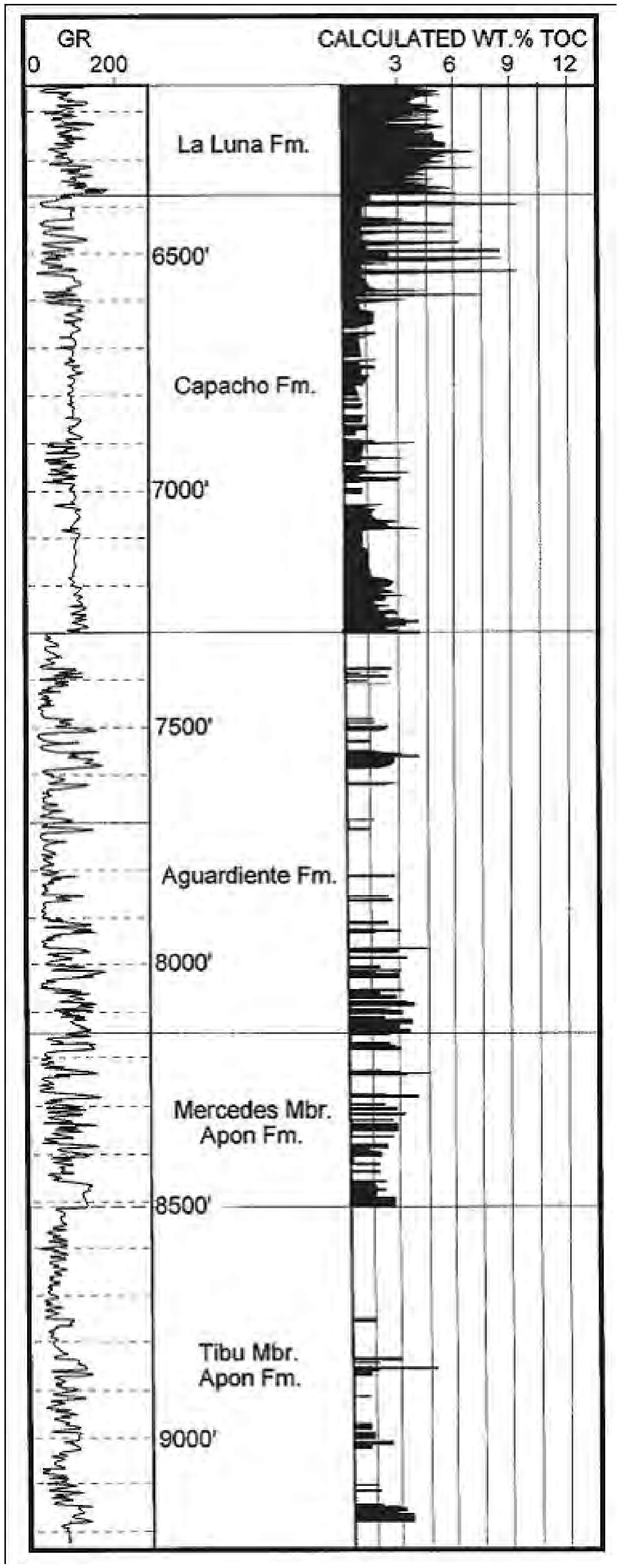


Total organic carbon in core samples reaches a maximum of 11.2% in the La Luna, but more typically averages a still rich 4 to 5% TOC. Figure III-12 shows a slight increase in TOC concentration towards the base of the La Luna Fm in the Cerrito 1 well, southeastern Catatumbo Sub-basin. In the eastern Catatumbo, the La Luna Fm shows lower TOC of 2.99% in the Tibu 178K well. Based on pyrolysis and maturity data, organics are mainly type II kerogen, with original hydrogen indices (HI) ranging from 200 to 500 mg/g C. Rock-Eval analyses show lower rock extract HI values, approximately 97 to 130 mg/g C, in the eastern to northeast region of the basin. ARI estimates the total prospective area for shale gas development to be about 1,310 mi^2, based on thermal maturity distribution and depth cut-off. Additionally, basin modeling shows that the present-day temperature gradient in the area ranges from 1.7 and 2.0 degrees F per 100 feet of depth.

Resources (La Luna Shale). ARI estimates a moderately high average 74 Bcf/mi^2 resource concentration for the La Luna Shale in the Catatumbo Sub-basin. Covering a prospective area of approximately 1,310 mi^2 (Figure III-10), the risked shale gas in-place totals an estimated 29 Tcf. Risked technically recoverable resources for the La Luna Shale amount to about 7 Tcf, considerably less than in the Maracaibo Basin due to shallower burial and a smaller prospective area.

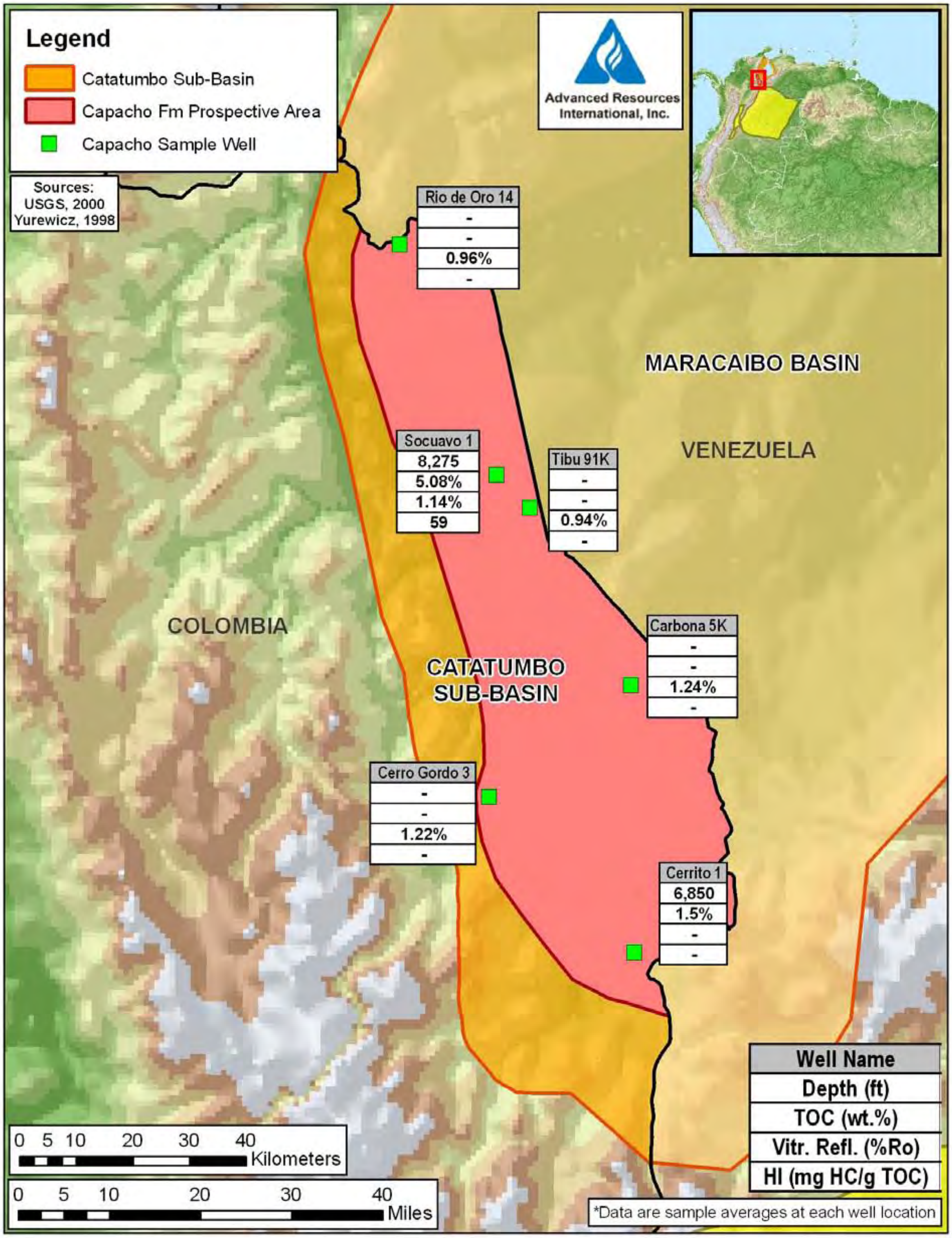
Reservoir Properties (Capacho Formation). The Capacho Formation (Cenomanian-Coniacian) is a distinct unit from the overlying La Luna Formation in the Catatumbo Sub-basin, whereas the two units are merged in most of the Maracaibo Basin. The Capacho Fm consists of dark-gray to black shales and limestones and is much thicker than the La Luna, ranging from 590 to nearly 1,400 feet in total thickness. Depth to the Capacho ranges from 6,500 feet to 8,500 feet in the Catatumbo Sub-basin, with greater measured depth in the north and east at 8,275 feet in the Socuavo 1 well, Figure III-13. Vitrinite reflectance ranges from 0.96% R_o in the northern Rio de Oro 14 well to 1.22-1.24% R_o in southeastern well samples. Based on the above properties, the prospective area for the Capacho Formation shales is about 1,550 mi^2, larger than the prospective area for the La Luna shale primarily due to higher thermal maturity in the south.

Figure III-12. Calculated TOC (wt/%) Well Log from Cerrito 1 Well, South-Central Catatumbo Sub-basin.



Source: Yurewicz, D.A., Advocate, D.M., Lo, H.B., and Hernández, E.A., 1998.

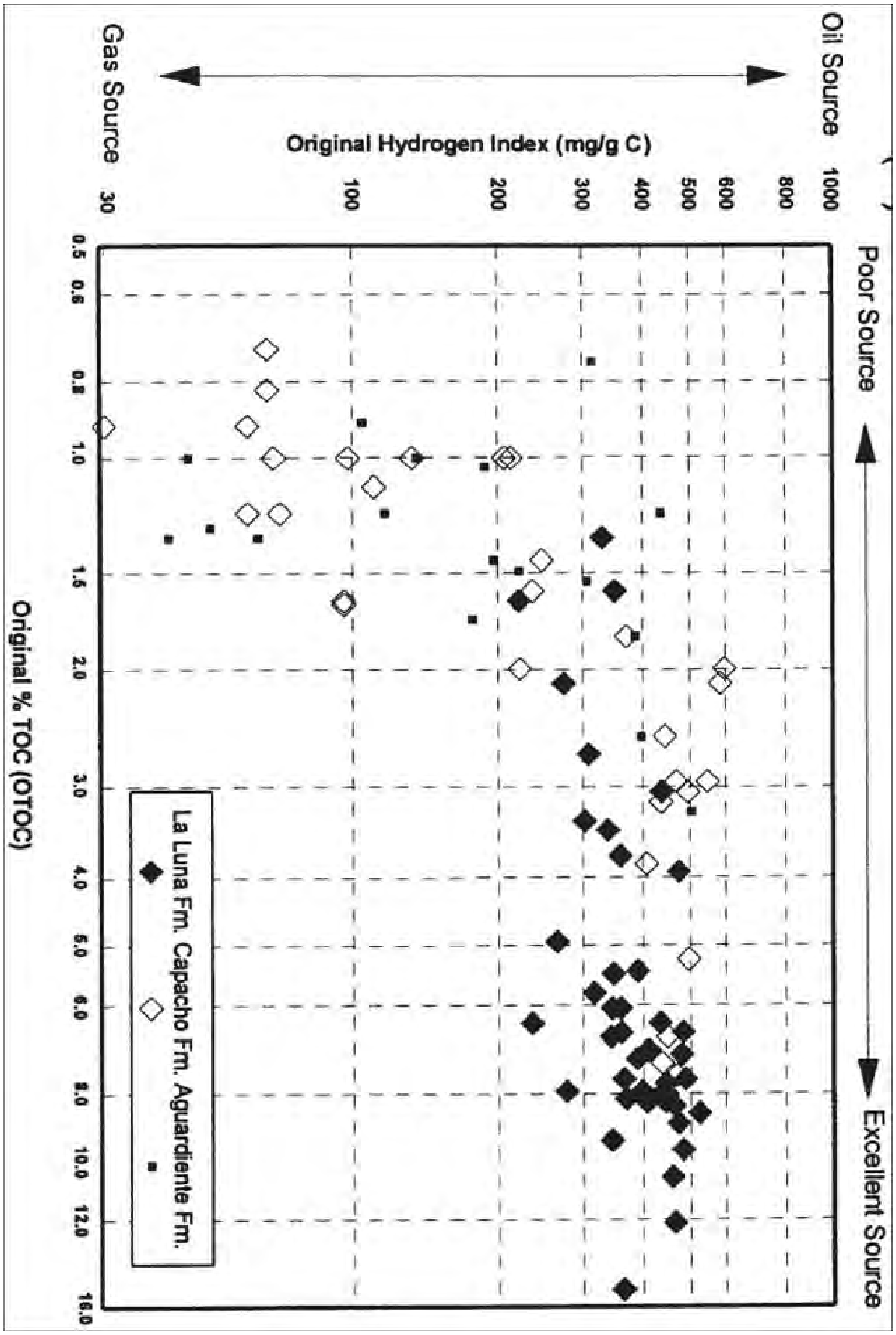
Figure III-13. Capacho Fm Basemap and Geologic Properties, Catatumbo Sub-basin.



Maximum measured total organic carbon reaches 5% in the Capacho Formation, as shown in the Socuavo 1 well in the northeastern Catatumbo Sub-basin. However, more typically, the TOC is lower, with a mean value of about 1.3 to 1.5%, shown in Figure III-12 in the Cerrito 1 well. The lowermost segment of the Capacho Fm, shown in the Cerrito 1 well, is believed to have been deposited during a transgressive period dominated by slow sedimentation and more anoxic conditions yielding better preservation of organic matter. Figure III-14 plots original HI versus original TOC of samples from the Capacho and La Luna formations, indicating the Capacho Formation ranges from a good oil to poor gas source. The underlying Aguardiente Fm is also plotted in the chart but was not assessed due to unpromising TOC and HI levels. Pyrolysis data shows kerogen within the Capacho Fm to be a mixture of Types II and III.

Resources (Capacho Formation). Within the Catatumbo Sub-basin, the Capacho Formation has an estimated 106 Bcf/mi^2 resource concentration. The prospective area of 1,550 mi^2 yields a risked gas in-place of about 49 Tcf, with a risked technically recoverable resource of approximately 12 Tcf.

Figure III-14. Source-Rating Chart Plotting Original HI and TOC Among Formations in the Catatumbo Sub-basin.



Source: Yurewicz, D.A., Advocate, D.M., Lo, H.B., and Hernández, E.A., 1998.

VENEZUELA

Venezuela produced 848 Bcf of natural gas in 2008 and consumed 901 Bcf, importing a small volume from neighboring Colombia.[14] Proven natural gas reserves were estimated at 176 trillion cubic feet in 2010 by the *Oil & Gas Journal* (OGJ), of which 90% is associated with oil reserves. The government regulatory agency Enagas reports that 70% of natural gas production is not marketed but rather re-injected for enhanced crude oil extraction. Recent upgrades to Venezuela's natural gas pipeline network include the Interconnection Centro Occidente (ICO), with ultimate capacity of 520 MMcf/d, connecting the central and western parts of the country.

ARI estimates a risked shale gas in-place of 42 Tcf for Venezuela, all coming from the La Luna Formation of the Maracaibo Basin. The risked recoverable resource here is approximately 11 Tcf.

COLOMBIA

Colombia produced 318 billion cubic feet of natural gas in 2008 and consumed 265 Bcf. OGJ reported Colombia's proven natural gas reserves were 3.96 Tcf in 2010, mostly located in the Llanos Basin. Re-injection for enhanced oil recovery consumed 43% of gas production in 2008. Approximately 2,000 miles of natural gas pipeline stretch across Colombia. In early 2008 the new Antonio Ricuarte pipeline linked the country with Venezuela. Initially, gas is being exported to aid oil production in western Venezuela, though current plans call for flow reversal beginning in 2012.

Colombia's cumulative shale gas resource (risked) totals 79 Tcf, combining the gas in-place of the Catatumbo Sub-Basin's La Luna and Capacho formations. Ultimately, 19 Tcf is determined to be technically recoverable.

Exploration Activity

As previously mentioned, much of the current oil production in the Maracaibo Basin and Catatumbo Sub-basin is from conventional stratigraphic traps. A recent well drilled by Ecopetrol -- apparently the first test of the La Luna Formation in the Catatumbo – reportedly showed good gas potential, albeit from conventional targets. Junior Canadian E&P Alange Energy Corporation is evaluating the prospectivity of the eastern area of the basin. However, this exploration activity also appears to be focused on conventional reservoirs within the La Luna Shale interval.

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IV. SOUTHERN SOUTH AMERICA

INTRODUCTION

The "Southern Cone" region of South America has world-class shale gas potential that is just beginning to be tested. **Figure IV-1** shows the principal shale gas basins of South America.

Figure IV-1. Shale Gas Basins of Southern South America

Argentina's Neuquen Basin appears the most prospective. Also in Argentina, the Cretaceous shales in the Golfo San Jorge and Austral-Magallanes basins have good potential, although higher clay content may be a risk in these lacustrine-formed deposits. Additional shale gas potential exists in the frontier Parana-Chaco Basin complex of Brazil and Paraguay in Devonian Los Monos Formation shales.

The Neuquen, Golfo San Jorge, and Austral basins in Argentina, the Magallanes Basin in Chile, the Chaco Basin in Paraguay, Argentina, and Bolivia, and the Parana Basin in Brazil and Uruguay contain an estimated 4,449 Tcf of risked shale gas in-place with 1,195 Tcf of technically recoverable resources, **Table IV-1**. Smaller Tertiary rift basins also are present in coastal southeastern Brazil,[1] but were not assessed.

Table IV-1. Reservoir Properties and Resources of Southern South America

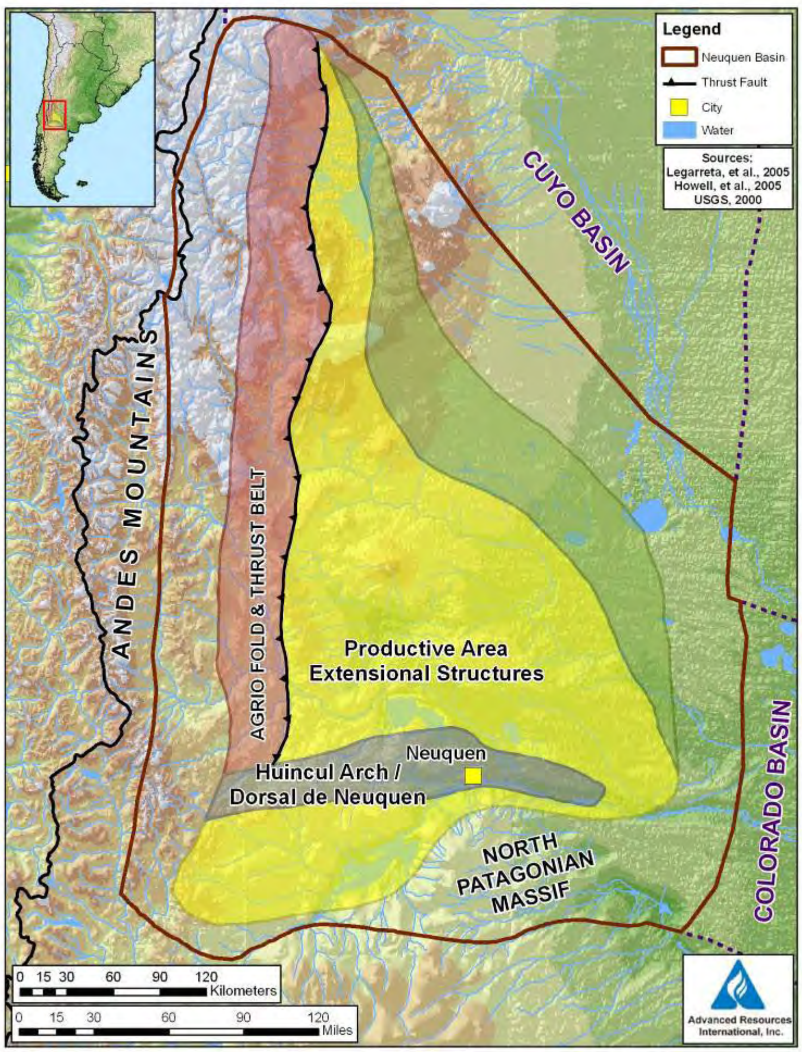
			Neuquen Basin (66,900 mi²)		San Jorge Basin (46,000 mi²)	
Basic Data	Basin/Gross Area		Neuquen Basin (66,900 mi²)		San Jorge Basin (46,000 mi²)	
	Shale Formation		Los Molles Fm	Vaca Muerta Fm	Aguada Bandera Fm	Pozo D-129 Fm
	Geologic Age		Middle Jurassic	Jurassic-Early Cretac	Late Jurassic-Early Cretaceous	Early Cretaceous
Physical Extent	Prospective Area (mi^2)		9,730	8,540	8,380	4,990
	Thickness (ft)	Interval	0 - 3,300	100 - 750	0 - 15,000	800 - 4,500
		Organically Rich	800	500	1,600	1,200
		Net	300	325	400	420
	Depth (ft)	Interval	6,500 - 15,000	5,500 - 10,000	6,500 - 16,000	6,600 - 15,800
		Average	12,500	8,000	12,000	10,500
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Normal	Normal
	Average TOC (wt. %)		1.1%	4.0%	2.2%	1.5%
	Thermal Maturity (%Ro)		1.50%	1.25%	2.00%	1.50%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	GIP Concentration (Bcf/mi^2)		123	168	149	151
	Risked GIP (Tcf)		478	687	250	180
	Risked Recoverable (Tcf)		167	240	50	45

Basic Data	Basin/Gross Area		Austral-Magallanes Basin (65,000 mi²)		Parana-Chaco Basin (500,000 mi²)
	Shale Formation		L. Inoceramus	Magnas Verdes	San Alfredo
	Geologic Age		E. Cretaceous	E. Cretaceous	Devonian
Physical Extent	Prospective Area (mi^2)		19,500	19,500	50,000
	Thickness (ft)	Interval	400 - 2,000	100 - 300	100 - 12,000
		Organically Rich	600	300	2,000
		Net	300	240	1,000
	Depth (ft)	Interval	6,000 - 10,000	6,000 - 10,000	5,000 - 11,000
		Average	8,500	8,500	7,500
Reservoir Properties	Reservoir Pressure		Slightly Overpressured	Slightly Overpressured	Normal
	Average TOC (wt. %)		1.6%	2.0%	2.5%
	Thermal Maturity (%Ro)		1.30%	1.30%	0.90%
	Clay Content		Medium	Medium	Low
Resource	GIP Concentration (Bcf/mi^2)		86	72	347
	Risked GIP (Tcf)		420	351	2,083
	Risked Recoverable (Tcf)		84	88	521

Neuquen Basin (Argentina)

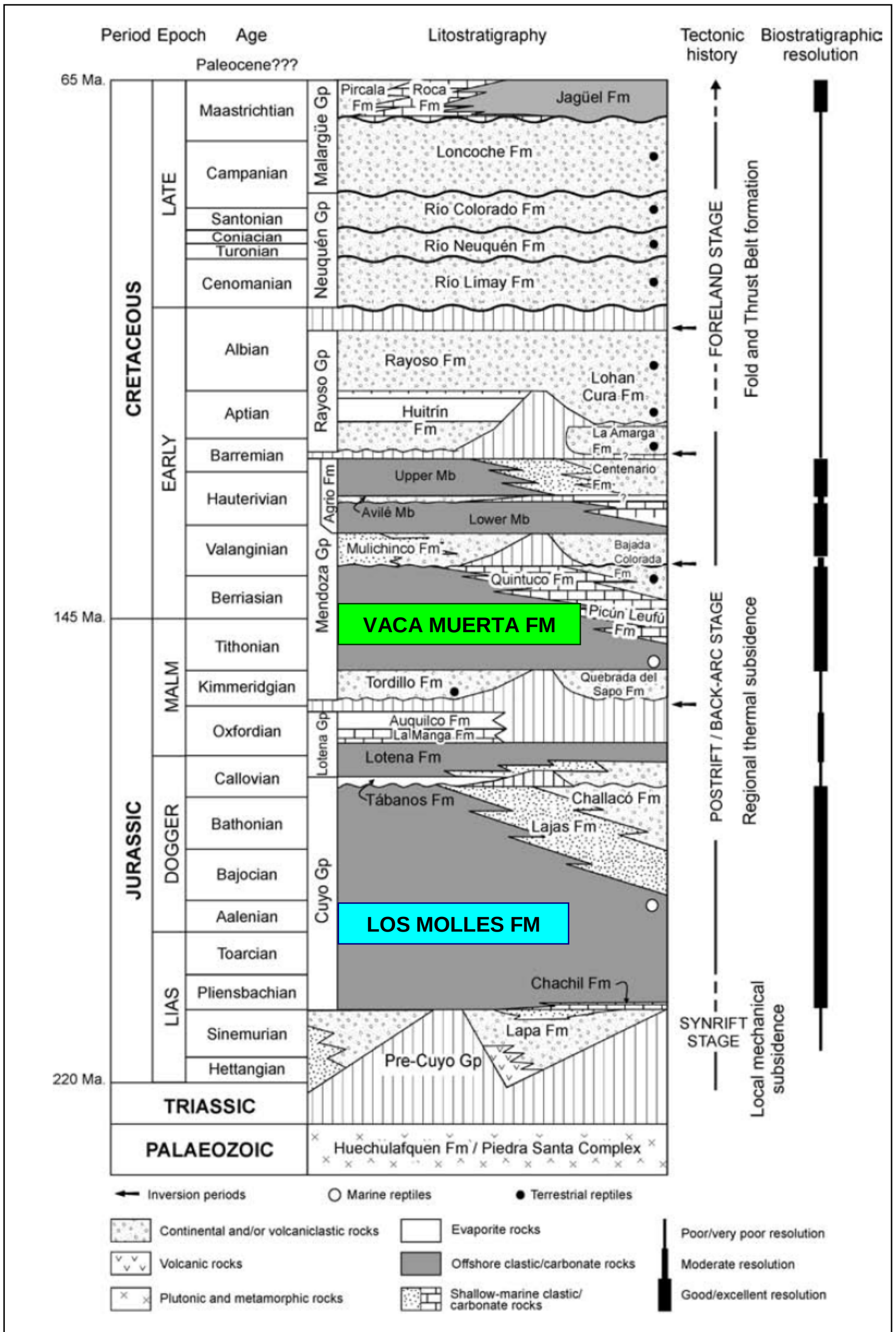
Geologic Characterization. Located in west-central Argentina, the Neuquen Basin contains Late Triassic to Early Cenozoic strata that were deposited in a back-arc tectonic setting.[2] Extending over a total area of 66,900 mi^2, the basin is bordered on the west by the Andes Mountains and on the east and southeast by the Colorado Basin and North Patagonian Massif, **Figure IV-2**. The sedimentary sequence exceeds 22,000 feet in thickness, comprising carbonate, evaporite, and marine siliclastic rocks.[3] Compared with the thrusted western part of the basin, the central Neuquen is deep, less structurally deformed. The Neuquen Basin is a major oil and gas production area for conventional and tight sandstones and could be an early site for shale gas development in South America.

Figure IV-2. Neuquen Basin Shale Gas Prospective Area and Basemap



The stratigraphy of the Neuquen Basin is shown in **Figure IV-3**. Of particular exploration interest are the shales of the Middle Jurassic Los Molles and Late Jurassic-Early Cretaceous Vaca Muerta Formations. These two thick deepwater marine sequences sourced most of the oil and gas fields in the basin and are considered the primary targets for shale gas development.

Figure IV-3. Neuquen Basin Stratigraphy

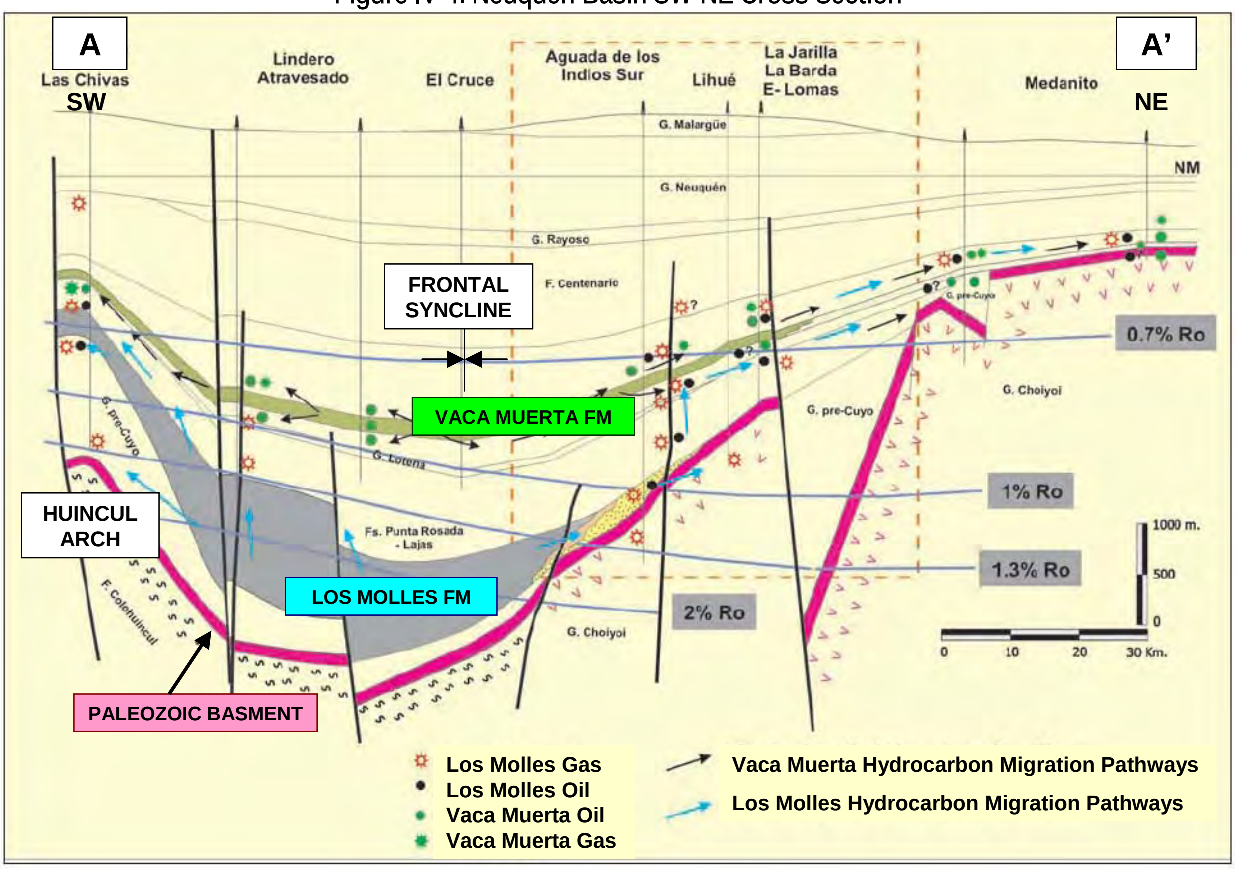


Modified from Howell, J., et al., 2005

Reservoir Properties (Los Molles Shale). The Middle Jurassic (Toarcian-Aalenian) Los Molles Formation is considered an important source rock for conventional oil and gas deposits in the basin. Basin modeling indicates that hydrocarbon generation took place in the Los Molles 50 to 150 Ma, with the overlying Lajas Formation tight sands serving as reservoirs.[4] The overlying Late Jurassic Aquilco Formation evaporites effectively seal this hydrocarbon system, resulting in overpressuring (0.60 psi/ft) in parts of the basin.

The Los Molles Shale is distributed across much of the Neuquen Basin, reaching more than 3,300 feet thick in the central depocenter. Available data shows the shale thinning towards the east.[5] A southeast-northwest regional cross-section, **Figure IV-4**, shows the Los Molles deposit particularly thick in the basin troughs. Well logs reveal a basal Los Molles Shale about 500 feet thick.[6]

Figure IV-4. Neuquen Basin SW-NE Cross Section



Mosquera et al., 2009

On average, the prospective Los Molles Shale occurs at depths of 9,500 to 12,500 feet, though maximum depth surpasses 15,000 feet in the basin center. In the south, the shale occurs at depths of 7,000 feet or shallower within the uplifted Huincul Arch. The Los Molles Shale is at shale-prospective depth across much of the Neuquen Basin.

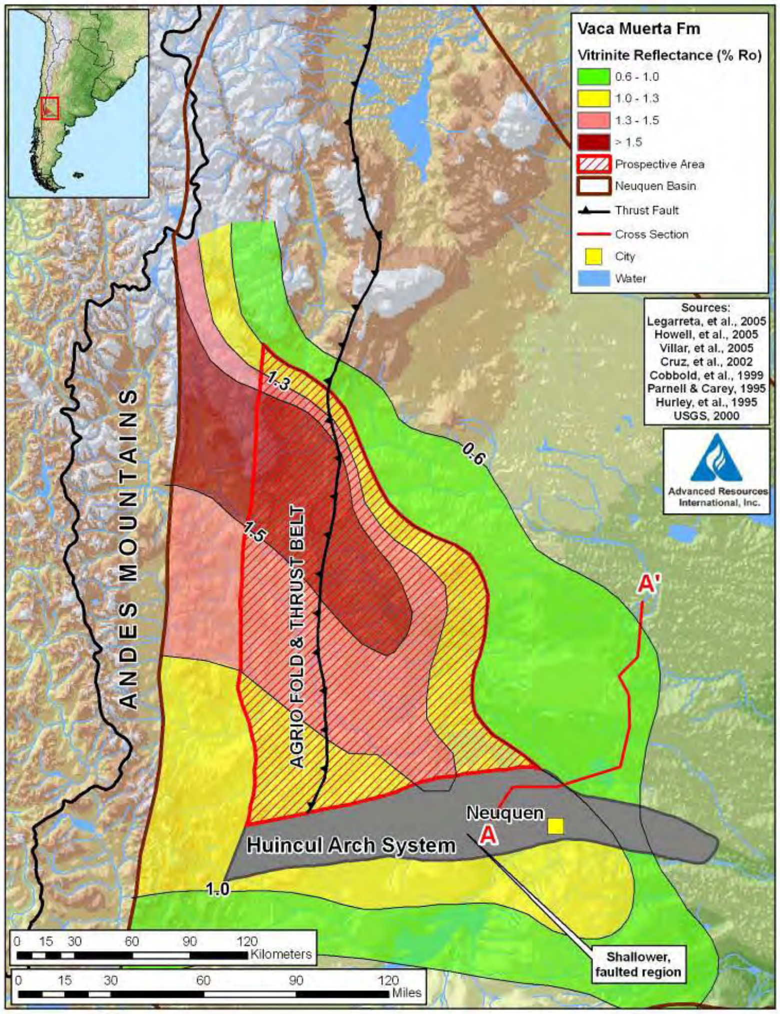
Total organic carbon for the Los Molles Shale was determined from various locations across the Neuquen Basin. Samples from five outcrops in the southwestern part of the basin showed average TOC ranging from 0.55 to 5.01%, with an overall mean of 1.62%.[7] In the southeast, TOC averaged 1.25% at depths near 7,000 feet at one location. Further east, another interval of the Los Molles Formation sampled from depths of 10,500 to 13,700 feet yielded TOC's in the range of 0.5% to nearly 4.0%. The lowermost 800-ft section here recorded a mean TOC of about 2%. Limited data were available for the central and northern regions, where shale is deeper and gas potential appears highest. One well in the basin's center penetrated two several-hundred-foot thick intervals of Los Molles Shale, with average 2% and 3% TOC, respectively. Regionally, the mean TOC of the Los Molles is in the range of 1.5%.[8]

The thermal maturity of the Los Molles Shale varies across the Neuguen Basin, from highly immature (R_o = 0.3%) in the shallow Huincul Arch region, oil-prone (R_o = 0.6%) in the eastern and southern parts of the basin, to fully dry-gas mature (R_o > 2.0%) in the basin center.[9,10] The lower portion of the Los Molles is marginally mature for gas (R_o > 1.0%) in a well located north of the Huincul Arch. Gas shows are prevalent throughout the Los Molles Formation.

The prospective area of the Los Molles, **Figure IV-5**, is defined by low vitrinite reflectance cutoff in the north, thinning in the east, and complex faulting and shallow depth of the Huincul Arch in the south. ARI extended the western play edge beyond the main productive Neuquen area, where most of the conventional oil and gas fields are located, into the Agrio Fold and Thrust Belt along the foothills of the Andes Mountains. While there is some geologic risk associated with this region, the thermal maturity is favorable for shale gas generation.

Resources (Los Molles Shale). The Los Molles Shale of the Neuquen Basin has an estimated resource concentration of approximately 123 Bcf/mi^2, benefitting from favorable thickness and overpressuring. The prospective area for this Middle Jurassic shale is estimated at approximately 9,730 mi^2, yielding a risked gas in-place of 478 Tcf. Risked technically recoverable resources for the Los Molles Shale are estimated at 167 Tcf, **Table IV-1**.

Figure IV-5. Vaca Muerta Fm, TOC, Thermal Maturity, and Prospective Area, Neuquen Basin



Reservoir Properties (Vaca Muerta Shale). The Late Jurassic to Early Cretaceous (Tithonian-Berriasian) shales of the Vaca Muerta Formation are considered the primary source rocks for oil production in the Neuquen Basin. The Vaca Muerta consists of finely-stratified black and dark grey shales and lithographic lime-mudstones that total 200 to 1,700 feet thick.[11] The organic-rich marine shale was deposited in reduced oxygen environment and contains Type II kerogen. Although somewhat thinner than the Los Molles Fm, the Vaca Muerta has higher TOC and is more widespread across the basin.

The Vaca Muerta Fm thickens from the south and east towards the north and west, ranging from absent to over 700 feet thick in the basin center.[12] Depth ranges from outcrop near the basin edges to over 9,000 feet deep in the central syncline.[13] Prospective depth for the Vaca Muerta Shale averages 8,000 feet.

The Vaca Muerta Formation generally is richer in TOC than the Los Molles Formation. Sparse available TOC data were derived from wells and bitumen veins sampled from mines in the north.[14] These asphaltites are very rich in organic carbon, increasing northward to a maximum of 14.2%. In the south, mapped TOC data range from 2.9 to 4.0%. TOC of up to 6.5% is reported in the lower bituminous shale units of the Vaca Muerta.

While the Vaca Muerta Formation is present across much of the Neuquen Basin, it is mostly immature for gas generation (<1% R_o). **Figure IV-4** shows the Vaca Muerta at depths approaching the upper end of the oil window; note that numerous conventional oil fields occur in this region. Thermal maturity increases from less than 0.6% R_o to >1.5% R_o into the deep northwest trough.[15] Northeast of the Huincul Arch, R_o of 0.8% was measured, immature for gas. Bounded in the east and north by the 1.0% R_o contour, the prospective play area of 8,540 mi^2 is further limited by the Huincul Arch to the south and Andes Mountains towards the west, **Figure IV-5**.

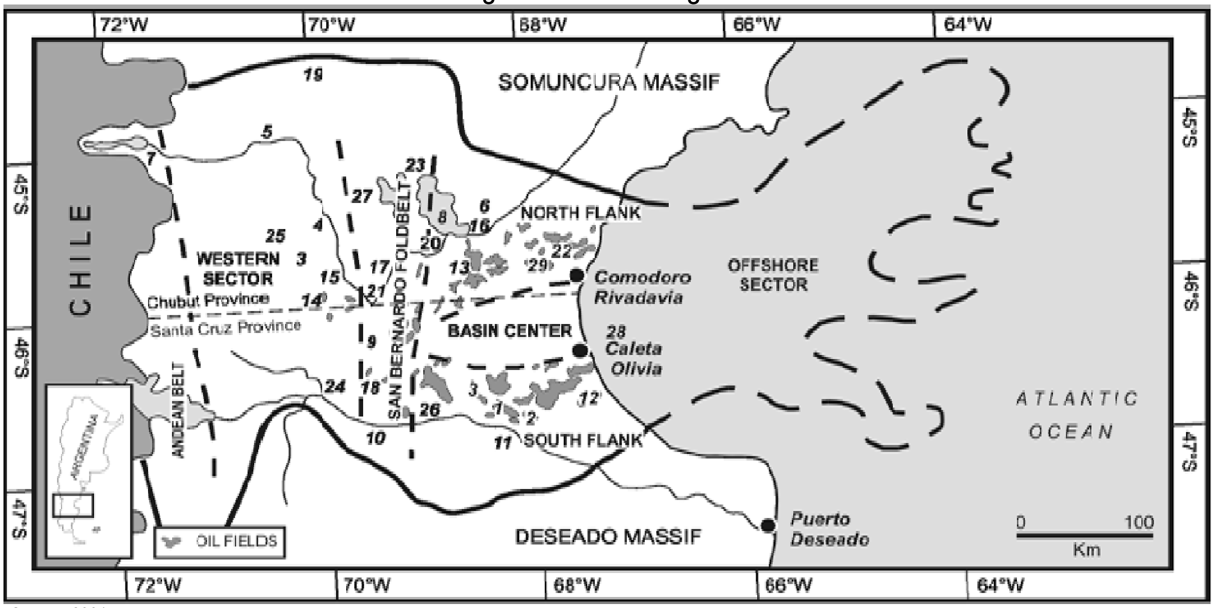
Resources (Vaca Muerta Shale). Based on the available geologic properties, the resource concentration of the Vaca Muerta Shale in the Neuquen Basin is estimated at 168 Bcf/mi^2, comparable to that of the age-equivalent Haynesville Shale in the United States. A risked shale gas in-place of 687 Tcf, with risked technically recoverable resources of 240 Tcf, **Table IV-1**.

Golfo San Jorge Basin (Argentina)

Geologic Characterization. Located in central Patagonia, the 67,000-mi^2 Golfo San Jorge Basin accounts for about 30% of Argentina's conventional oil and gas production.[16] An intra-cratonic extensional basin, the San Jorge extends across the width of southern Argentina, from the Andean foothills on the west to the offshore Atlantic continental shelf in the east. Excluding its small offshore extent, the onshore Golfo San Jorge Basin covers approximately 46,000 mi^2.

Figure IV-6 shows the basin bordered by the Deseado Graben and Massif to the south, by the Somuncura Massif to the north, and the Andes Mountains in the west. Compressional structures of the San Bernardo Fold Belt transect the west-central region.[17] Extensional faults are widespread in the northeastern and southern flanks, while the northwestern edge of the basin is less faulted.[18]

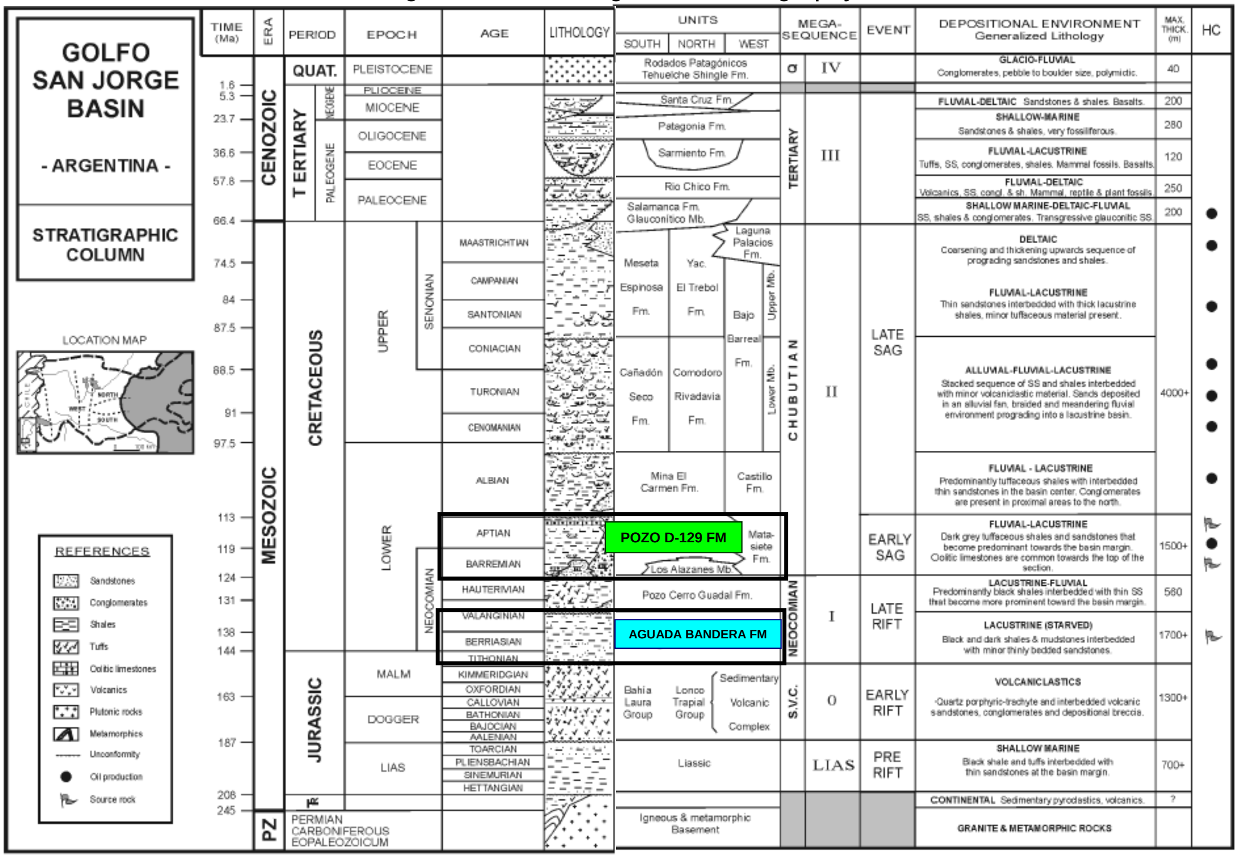
Figure IV-6. San Jorge Basin



Sylwan, 2001

Extensional events marked by the formation of grabens and half-grabens in the present-day location of the Golfo San Jorge Basin began in the Triassic to Early Jurassic as the Gondwana supercontinent began to break up.[19] A separate period of extension followed in the Middle Jurassic, as the Lonco Trapial Volcanics were deposited via northwest-striking faults. The region subsided by the end of the Jurassic and extensive, mainly lacustrine deposits formed, including the thick black source rock shales and mudstones of the Neocomian Aguada Bandera Formation, **Figure IV-7**.

Figure IV-7. San Jorge Basin Stratigraphy



Sylwan, 2001

Reservoir Properties (Aguada Bandera Shale). The Late Jurassic-Early Cretaceous Aguada Bandera Formation comprises fine gray sandstones grading into a tuffaceous matrix towards the top of the formation, with black shales and mudstones increasing towards its base.[20] Much of the sediments deposited are lacustrine in origin, though foraminifera found in western areas suggest possible marine sources in particular beds.[21] Towards the north, other biota indicative of an outer marine platform depositional environment were observed in well samples near Lago Colhue Huapi.[22]

The Aguada Bandera Formation is a heterogeneous unit comprising shale, sandstone, and occasional limestone. Total formation thickness varies widely, from more than 15,000 feet thick in the southwest to 0-2,000 feet thick about 60 miles offshore in the east. A similar thickness variation also is seen in the west. Limited data is present south of Lago Colhue Huapi to the north. The Aguada Bandara Fm is generally 1,000 to 5,000 feet thick in the central basin, probably only a fraction of which is high-quality organic shale.

Depth to the top of the Aguada Bandera Formation is based on the top of underlying Middle Jurassic Loncol Trapial volcanics. Burial depth reaches a maximum 20,000 feet along the onshore coast in the center of the basin. Depocenters in the western portion of the basin typically average a more prospective 10,000 to 12,000 feet deep. The Aguada Bandera is much shallower, 2,000 to 8,000 feet deep, along the northern and western flanks. In the eastern coastal onshore portion of the basin, the Aguada Bandera Shale is about 1,500 to 2,500 feet thick and 20,000 feet deep.

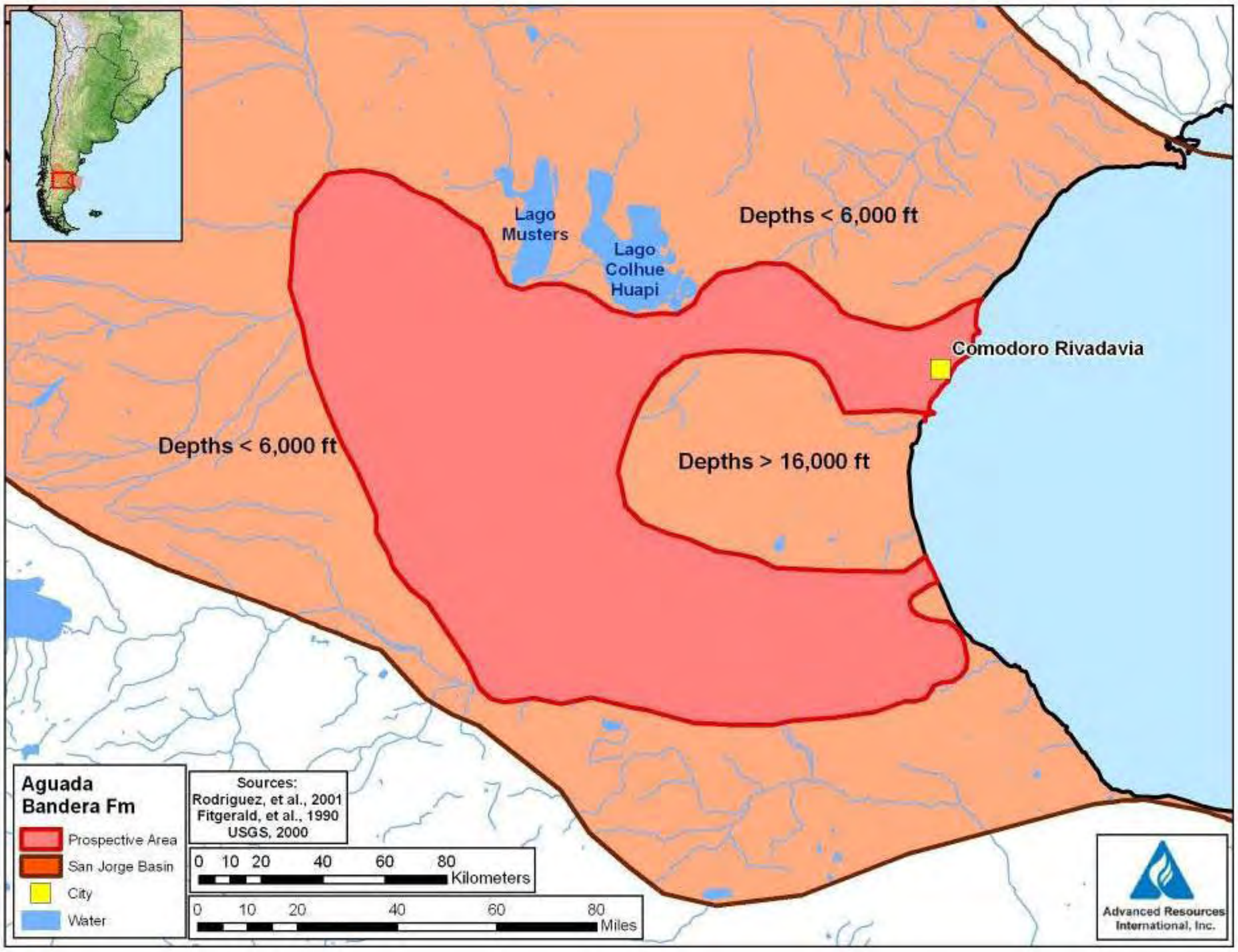
Limited mappable geochemical data were available for analysis in the Aguada Bandera, which is considerably deeper than the conventional reservoirs and thus rarely sampled. Only two available wells have TOC and R_o data, both located in the basin's western area. Average TOC ranged from 1.44% to 3.01% at depths of 12,160 feet and 11,440 feet, respectively.[23] Organic-rich intervals reached 4.19% TOC. Vitrinite reflectance averaged 1.07%, with dry-gas thermal maturity of 2.4% R_o.

Petroleum basin modeling indicates that the minimum gas generation threshold (R_o = 1.0%) is typically achieved across the basin at depths below 2,000 m, or roughly 6,600 feet. Thus, the Aguada Bandera Formation appears to be mature for gas generation across most of the basin. The unit is likely to be over mature in the deep basin center, where R_o is modeled to exceed 4%.

Using depth distribution and appropriate minimum and maximum R_o cutoffs, ARI's prospective area for the Aguada Bandera Shale, **Figure IV-8**, covers approximately 8,380 mi^2 of the onshore Golfo San Jorge Basin. The central coastal basin (>16,000 feet deep) and the northern Lake region (<6,000 feet deep) were excluded as not prospective.

Resources (Aguada Bandera Shale). The average resource concentration for the Late Jurassic to Early Cretaceous Aguada Bandera Shale is estimated to be 149 Bcf/mi^2. Based on the 8,380-mi^2 prospective area for shale gas potential, a risked gas in-place resource of 250 Tcf is estimated. The risked technically recoverable resource for the Aguada Bandera Shale is approximately 50 Tcf, reduced considerably by faulting. Estimated gas recovery also was reduced because of the lacustrine deposition environment of this unit, **Table IV-1**.

Figure IV-8. Aguada Bandera Fm, TOC, Thermal Maturity, and Prospective Area, San Jorge Basin



Reservoir Properties (Pozo D-129 Shale). The Early Cretaceous Pozo D-129 Formation comprises a wide range of lithologies, with the deep lacustrine sediments -- organic black shales and mudstones – considered most prospective for hydrocarbon generation.[24] The presence of pyrite, dark laminations, and the absence of fossil burrows in the marine shale portions of this unit all point to favorably anoxic depositional conditions.[25] Siltstones, sandstones, and oolitic limestones also were deposited in the shallower water environments of the Pozo D-129.

The Pozo D-129 Shale is consistently thicker than 3,000 feet in the central basin, with local maxima exceeding 4,500 feet thick. Along the northern flank the interval is typically 1,000 to 2,000 feet thick. A locally thick deposit occurs in the western part of the basin, but thins rapidly from about 1,000 feet thick to absent.

Northeast of Lago Colhue Huapi, the Pozo D-129 shoals rapidly from just under 6,000 feet to around 2,800 feet deep. Just southwest of the lake, depth increases from about 5,000 feet to nearly 9,500 feet. To the south, depths range from 5,000 feet to 6,400 feet, with similar depths in the west. The Pozo D-129 deepens along the eastern coastal flank of the basin to nearly 15,900 feet near the city of Comodoro Rivadavia.

Available data indicates organic richness in the southwest, 1.42% to 2.45% TOC, with a corresponding gas-mature 1.06% R_o. In the north-central region a low 0.32% TOC was recorded, with slightly higher 0.5% R_o near Lago Colhue Huapi.[26] Towards the basin center in the east, organic carbon rises to around 1.22%. The thermal maturity in this deep setting is correspondingly high, 2.49 to 3.15% R_o. In the south, thermal maturity drops to oil-prone levels, 0.83% R_o; the measured TOC here is about 0.84%.

ARI defined the shale gas prospective area for the Pozo D-129 Fm, based primarily on depth and available (but incomplete) vitrinite reflectance data. Depth was set at an approximate 6,600-foot minimum limit. The sub-1.0% R_o value confined the southeast, and the low TOC value limited the north. Based on these data, the prospective area for the Pozo D-129 Shale is estimated at approximately 4,990 mi^2.

Resources (Pozo D-129 Shale). Relying on the above geologic properties, the average resource concentration for the Pozo D-129 Shale in the Golfo San Jorge Basin is approximately 151 Bcf/mi^2. The total risked shale gas in-place is estimated to be 180 Tcf, with the risked technically recoverable resource estimated at 45 Tcf.

Austral-Magallanes Basin (Argentina and Chile)

Geologic Characterization. Located in southern Patagonia, the 65,000-mi^2 Austral-Magallanes Basin has promising but untested shale gas potential. Most of the basin is located onshore in Argentina, where it is usually called the Austral Basin. A small southernmost portion of the basin is located in Chile's Tierra del Fuego area, where it is commonly referred to as the Magallanes Basin. Conventional natural gas production in the Argentina (Austral) portion of the basin is mainly from deltaic to fluvial sandstones in the Early Cretaceous Springhill Formation at depths of around 6,000 feet. The Chile portion of the basin accounts for essentially all of that country's oil production.

The Austral-Magallanes Basin is bounded on the west by the Andes Mountains and on the east by the Rio Chico Ridge. To the north it is separated from the Golfo San Jorge Basin by the Deseado Massif. The southern part of the basin is truncated by the Fagnano fault system of the Andean thrust belt. The basin comprises two main structural regions: a normal faulted eastern domain and a thrust faulted western area.

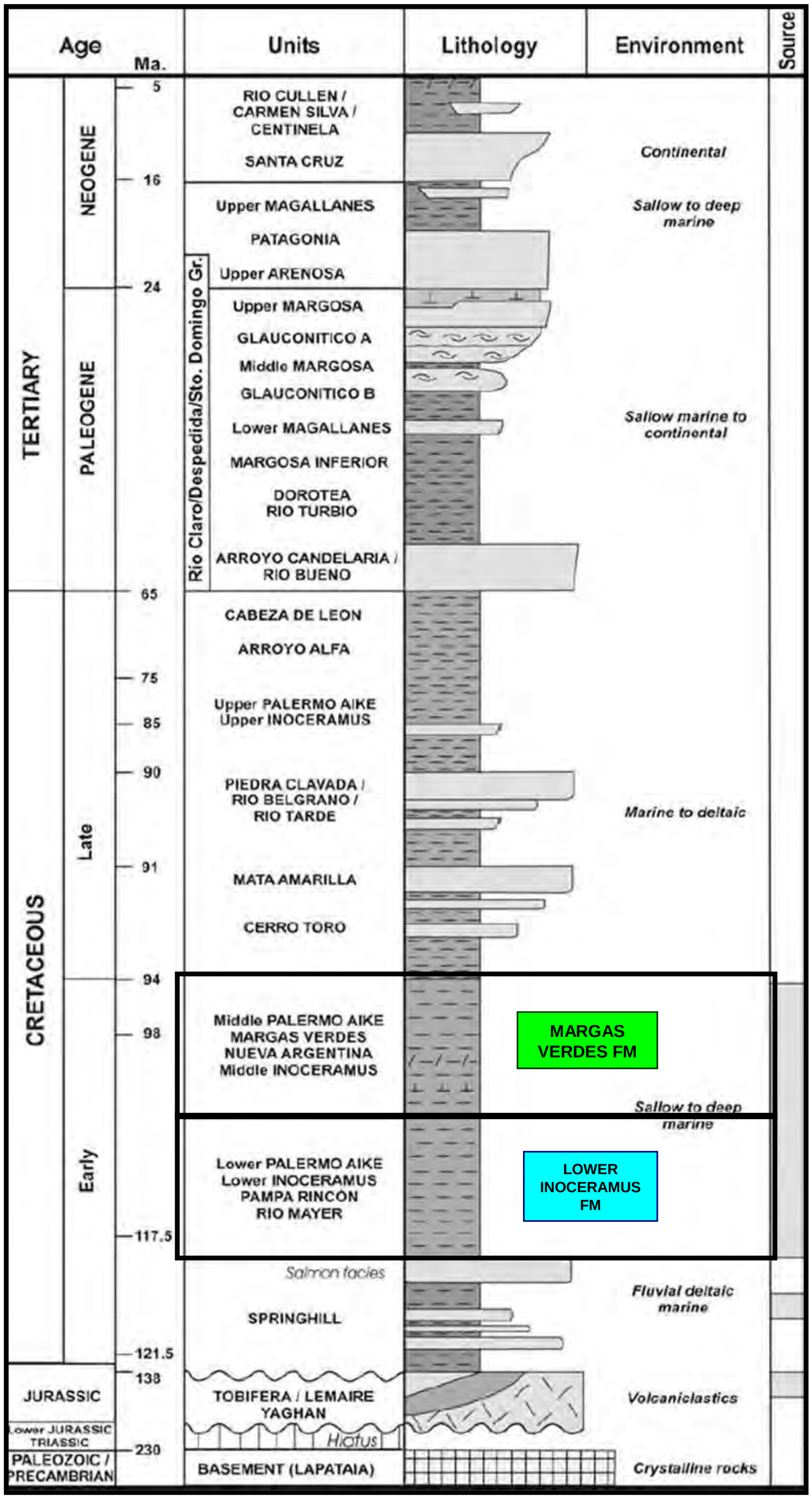
The basin contains a thick sequence of Upper Cretaceous and Tertiary sedimentary and volcaniclastic rocks unconformably overlying deformed metamorphic basement of Paleozoic age, **Figure IV-9**. Total sediment thickness ranges from 3,000 to 6,000 feet along the eastern coast to a maximum 25,000 feet along the basin axis. Petroleum source rocks in the basin, of Lower Cretaceous-age, are present at moderate depths of 6,000 to 10,000 feet across large areas.[27]

The main source rock in the basin is the Lower Cretaceous Lower Inoceramus Formation (Tithonian-Aptian), which contains black organic-rich shales. The equivalent Rio Mayer Fm occurs in the northwest portion of the basin, while another equivalent in the southeast is called the Palermo Aike Fm. The Palermo Aike Shale in the southeast part of the basin is approximately 200 m thick. Another important source rock in the Austral-Magallanes Basin is the Magnas Verdes Fm (Aptian-Albian), which comprises marine mudstones and marl with moderate TOC.

The Lower Inoceramus and Magnas Verdes shales together range from 800 feet thick in the north to 4,000 feet thick in the south, representing neritic facies deposited in a low-energy and anoxic environment.[28] Total organic content of these two main source rocks generally ranges from 1.0% to 2.0%, with hydrogen index of 150 to 550 mg/g.[29]

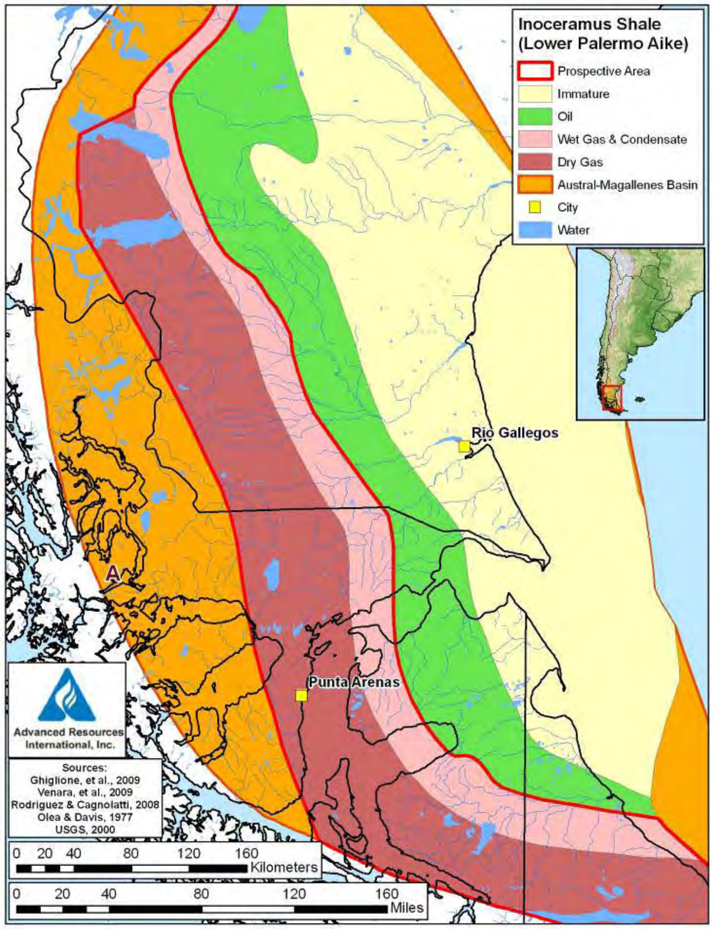
Thermal maturity of the Lower Cretaceous source rock shales increases with depth in a half-moon pattern, **Figure IV-10**. Source rocks are generally oil-prone (R_o = 0.6 to 0.8%) along an eastern belt extending from onshore to just off the southeastern Atlantic coast, increasing westward in maturity to gas-condensate (R_o = 1.0%), and finally becoming dry-gas-prone further west (R_o > 1.3%).

Figure IV-9. Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Rossello et al., 2008

Figure IV-10. Inoceramus Shale, Depth,TOC, and Thermal Maturity, Austral / Magallanes Basin, Argentina and Chile



Reservoir Properties (Lower Inoceramus Shale). The Lower Cretaceous Lower Inoceramus Formation (Tithonian-Aptian), considered the primary source rock in the Austral-Magallanes Basin, contains black organic-rich shales that are approximately 200 m thick, 2 to 3 km deep, with 0.6% to 2.0% TOC consisting of Type II and II kerogen. The Estancia Los Lagunas gas condensate field in the southeast measured a 0.46 psi/ft pressure gradient with elevated temperature gradients in the Serie Tobifera Fm, immediately underlying the Lower Inoceramus equivalent.[30]

Resources (Lower Inoceramus Shale). Based on the above geologic properties, the average resource concentration for the Lower Inoceramus Shale in the Austral-Magallanes Basin is approximately 86 Bcf/mi^2. The total risked shale gas in-place is estimated at 420 Tcf, due the large prospective area. The risked technically recoverable resource is estimated at about 84 Tcf.

Reservoir Properties (Magnas Verdes Shale). The Lower Cretaceous (Aptian-Albian) Magnas Verdes Formation comprises marine mudstones and marl with 0.5% to 2.0% TOC, including a rich 30-40 m thick basal section, and Type II-III kerogen. A 0.46 psi/ft pressure gradient and temperature gradient of 6.4°C/100 m was assumed. Lacking detailed data, many of the other reservoir properties of the Magnas Verdes Shale were carried over from the Lower Inoceramus Shale.

Resources (Magnas Verdes Shale). The average resource concentration for the Magnas Verdes Shale in the Austral-Magallanes Basin is approximately 72 Bcf/mi^2. The total risked shale gas in-place for this aerially extensive target is estimated to be 351 Tcf, with risked technically recoverable resources of 88 Tcf.

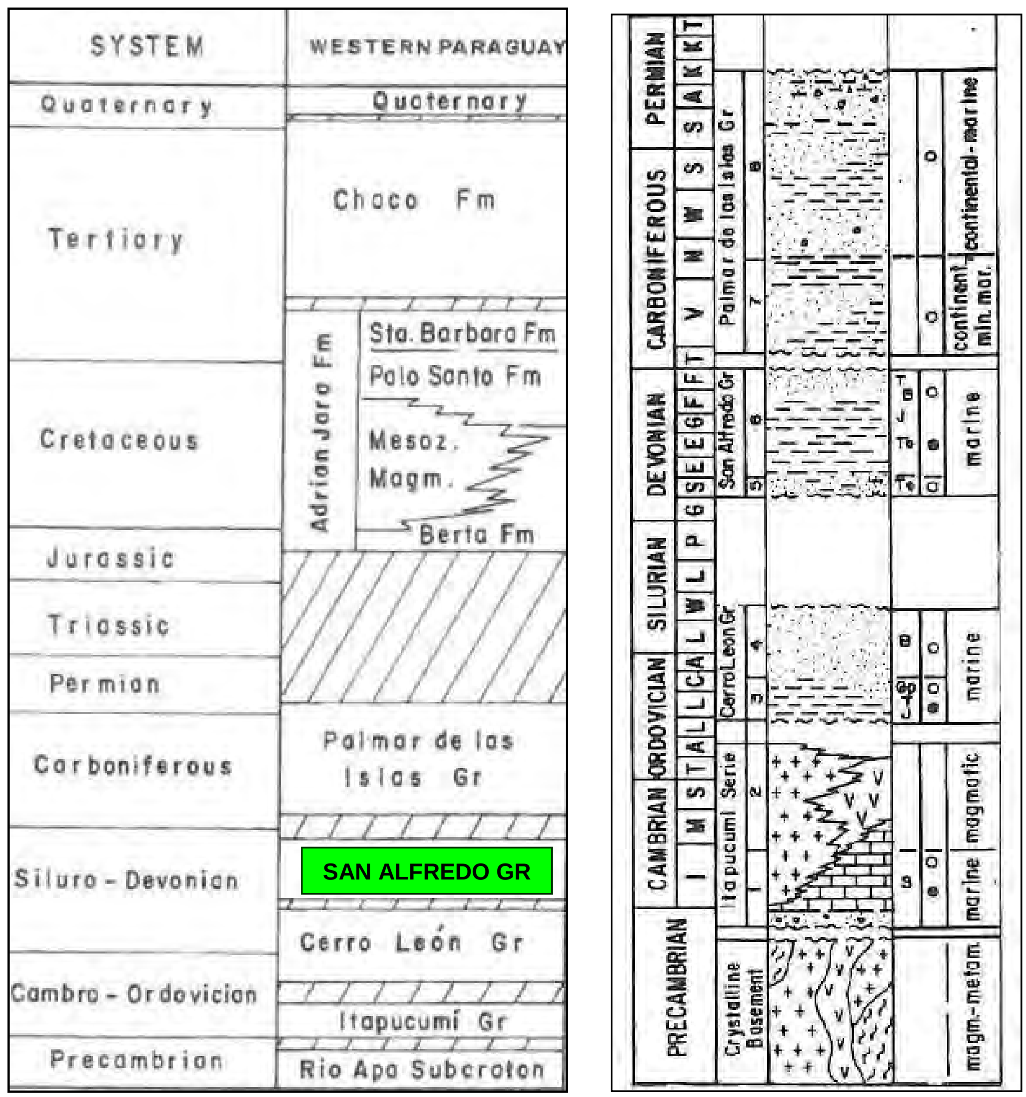
Parana-Chaco Basin (Brazil, Paraguay, Uruguay, Argentina, Bolivia)

Geologic Characterization. The very large (>500,000-mi^2) frontier Parana-Chaco Basin complex covers most of Paraguay and parts of southern Brazil, Uruguay, northern Argentina, and southern Bolivia. It is an intra-cratonic foreland basin broadly similar in origin to the Neuquen and other South American basins east of the Andes Mountains. On the Brazil (Parana) side of the basin, the surface is blanketed by thick plateau basalt flows which are impermeable to seismic monitoring, oil and gas production is very limited. Less than 150 exploration wells have been drilled in this basin.

The Parana-Chaco Basin contains a thick sequence of primarily marine Paleozoic rocks that are overlain by mostly continental Mesozoic deposits, **Figure IV-11**.[31] Devonian to Carboniferous rocks were deposited in a westward-regressing sequence of marine, transitional and continental facies. ARI's analysis indicates that large shale gas potential exists within the 8,000 to 12,000-foot thick Devonian Los Monos Formation in the Carandaity and Curupaity sub-basins of Paraguay, which include black, organic-rich, shallow-marine deposited shales. Scarce geochemical data suggest 0.5% overall average TOC for the entire Los Monos, but richer zones are likely to be present in this thick and poorly documented unit.

Structural highs partition the Parana-Chaco Basin into sub-regions. The Ascuncion Arch separates the 250,000-km^2 Chaco Basin in Paraguay from the Parana Basin in Brazil. Structural uplifts in the Chaco Basin have high geothermal gradients and are gas-prone. Structure is relatively simple, with scattered mainly vertical normal faults and none of the thrusting typical of Andean tectonics further to the west.

Figure IV-11. Stratigraphy, Parana-Chaco Basin

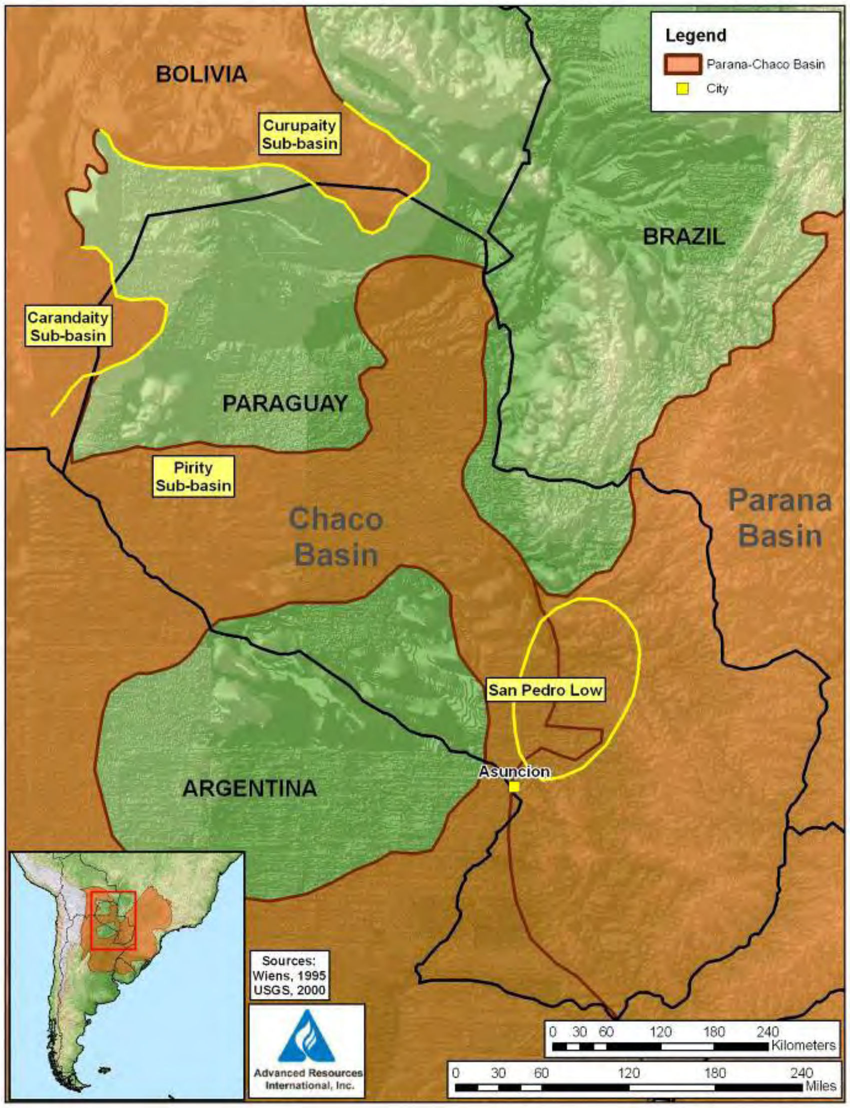


Wiens, 1995

Natural gas generated by Devonian marine shales sourced conventional Carboniferous–Permian reservoirs of the Itarare´ Group, which are thick, sand-rich units that were deposited during the Carboniferous–Permian glaciation.[32] These source rock shales reach thicknesses of 8,000 feet and 12,000 feet in the Carandaity and Curupaity sub-basins, respectively, in central Paraguay. Within this thick sequence, the Devonian San Alfredo Shales appear to be most prospective, comprising a lower sandy unit and an upper thick, monotonous black shale that formed under shallow marine conditions.[33]

An exploration well in the Curupaity sub-basin measured 0.3 to 2.1% TOC in this unit. Independent E&P Amerisur reports TOC of 1.44% to 1.86% in the Devonian Los Monos Fm in the Curupaity sub-basin.[34] Depth to the Los Monos Shale can exceed 10,000 feet (3,000 m) in deep synclines such as the San Pedro Trough, **Figure IV-12**.

Figure IV-12. Parana-Chaco Basin



The Devonian appears to be the most prospective source rock shale in the Parana-Chaco Basin. It is exceptionally thick in southern Bolivia but consists mainly of coarse-grained sandstones there. The thickest Devonian section (8,339 feet) penetrated in the Chaco Basin was in the Pure Oil Co. Mendoza-1 well. The Los Monos marine shale accounted for about 8,200 feet of this section.[35]

Reservoir Properties (San Alfredo and Equivalent Shales). The San Alfredo is exceptionally thick (as much as 12,000 feet), of which only 2,000 feet was assumed to be organically rich. The prospective area also is large, perhaps 10% of the basin, or 50,000 mi^2. Faulting is not extensive within the basin, thus relatively little area is sterilized due to structural complexity. The shale matrix reportedly consists primarily of brittle minerals such as calcite, dolomite, albite feldspar, ankerite, quartz as well as significant rutile and pyrite. Though clays are present, mainly illite, kaolinite and chlorite, they are less common.[36] Temperature gradients range from elevated 1.9°F/100 feet on structural highs to much lower 1.0°F/100 feet in the Carandaity sub-basin.

Amerisur reported that the Devonian Lima Fm has good (2-3%) TOC but R_o of only 0.87% at their conventional exploration block in Paraguay. In Brazil, the equivalent Devonian Ponta Grossa Fm is up to 600 m thick and includes shales with 1.5% TOC, but is thermally immature in the north part of the basin. The southern part of the Parana Basin has basaltic intrusions that may have boosted shale maturity, generating condensate and natural gas, but also complicate drilling and seismic.

Resources (San Alfredo and Equivalent Shales). Based on the above geologic properties, the average resource concentration for the San Alfredo Shale in the Parana-Chaco Basin is estimated at 347 Bcf/mi^2, due mainly to the great thickness of this Devonian shale. Heavily discounting this play due to poor data control, slightly low thermal maturity, and uncertainty about net thickness still yields a considerable 2,083 Tcf of risked shale gas in-place. Risked technically recoverable resources are estimated at about 521 Tcf, **Table IV-1**.

Natural Gas Profile

With total recoverable resources initially estimated at 1,195 Tcf, shale gas could contribute significant supplies to the natural gas sector of southern South America. Each of the six countries profiled has small but expanding natural gas production and transportation industries that could accommodate shale gas development.

ARGENTINA

Argentina produced about 4.3 Bcfd of natural gas during 2009 but became a net importer in 2008. Gas production in the country is centered on the Neuquen, Golfo San Jorge, and Austral basins, where extensive pipeline systems are in place. Argentina's proved reserves of natural gas have declined by 50% during the past decade to 13.3 Tcf in 2009. However, starting mid-2010 the country allowed unconventional gas production to be sold at higher prices ($5/MMBtu). This new "Gas Plus" policy is having a positive impact: Repsol-YPF recently announced discovery of 4.5 Tcf of reserves in tight sandstone reservoirs.[37]

Among all of Argentina's assessed basins, ARI estimates a risked shale gas in-place of 2,732 Tcf. This includes 1,165 Tcf in the Nequen Basin, approximately 430 Tcf in the San Jorge Basin, 483 Tcf in the Austral-Magallanes Basin, and finally the Parana-Chaco Basin with 654 Tcf. The cumulative risked recoverable resource for Argentina totals 774 Tcf, with individual region allocations of 408, 95, 108, and 164 Tcf for the above basins, respectively.

BOLIVIA

Natural gas production in Bolivia amounted to 446 Tcf in 2009, with only 100 Tcf being consumed domestically. The country's proved reserves were last reported at 27 Tcf.

Based on limited data, a risked resource of 192 Tcf was assigned to Bolivia, solely derived from the Devonian-age shales of the Parana-Chaco Basin. Ultimately, about 48 Tcf of risked recoverable gas in-place was estimated for the country.

BRAZIL

Brazil produced an average 446 MMcfd of natural gas in 2008, mostly from the offshore Campos Basin. Petrobras is the dominant producer, controlling about 90% of Brazil's 12.9 Tcf of proved reserves and operating the country's 4,000-mile gas pipeline system, which is concentrated in the southeast and northeast. The country consumed 835 MMcfd in 2008, importing the balance mainly from Bolivia. The industrial sector accounted for 80% of Brazil's natural gas consumption, though gas-fired power generation is growing rapidly.

All of Brazil's assessed shale gas potential lies within the vast Parana-Chaco Basin, with an estimated 906 Tcf in risked gas in-place and 226 Tcf of technically recoverable resources.

CHILE

Chile has limited natural gas reserves (3.5 Tcf), concentrated in the Magallanes Basin in the extreme southeastern part of the country, far from the dominant Santiago gas market. The country produced an average 170 MMcfd in 2009 and imported an additional 230 MMcfd, mostly through its two LNG regasification terminals.

The Early Cretaceous shales of the Austral-Magallanes Basin comprise Chile's prospective shale gas resource, approximately 287 Tcf of risked gas in-place. Technically recoverable gas is estimated at 64 Tcf.

PARAGUAY

Paraguay has no natural gas production or significant proved reserves, nor any measurable consumption. Thus, the addition of nearly 249 Tcf of potential risked gas in-place (62 Tcf recoverable) from Devonian shales of the Parana-Chaco Basin could fundamentally change the domestic energy outlook in Paraguay.

URUGUAY

Much like its neighbor to the north, Uruguay reportedly had no natural gas production or proved reserves, its small consumption of 1 Tcf consisted entirely of imports. ARI's shale gas analysis places approximately 83 Tcf of risked gas in-place in Uruguay, all from the Parana-Chaco Basin. Risked recoverable resources for the country are 21 Tcf.

Exploration Activity

Initial shale exploration drilling is underway in Argentina's Neuquen Basin, led by Apache and Repsol. Apache Corporation and YPF (Repsol) are partnered in the development of unconventional resources (including shale) in the Neuquen and Austral basins. Counting the acreage yet to be awarded from its three recent bid wins in the Neuquen, Apache controls approximately 1.6 million gross acres (900,000 net acres) in the basin that it considers to be prospective for shale gas.

As of December 9, 2010, Apache reported drilling Latin America's first horizontal multi-fracture well into a shale gas target.[38] The company also has performed three hydraulic fracture stimulation jobs in shale intervals (probably in vertical wells) and recovered cores of source rocks for laboratory analysis. In addition, Apache and Repsol have extensive 3D seismic coverage in the basin. Apache has not yet publicly estimated the shale gas resource potential of its Argentine blocks.

Independent E&P Apco Oil & Gas, 69% owned by Williams, also is active in the Neuquen Basin. Apco plans to test the Vaca Muerta Shale in two exploration wells at the Coiron Amargo block during 2011.[39] The company also holds onshore conventional oil and gas leases in the Chaco, Golfo San Jorge and Austral basins.

In October 2009 Schuepbach Energy LLC (Dallas) signed a one-year prospecting contract -- the first of its kind in Uruguay -- with government-owned ANCAP on a 10,000-km^2 area in north-central Uruguay. Schuepbach plans to conduct geochemical analysis of shale potential, which could lead to a production sharing contract on the block. The target is Devonian-age shale.

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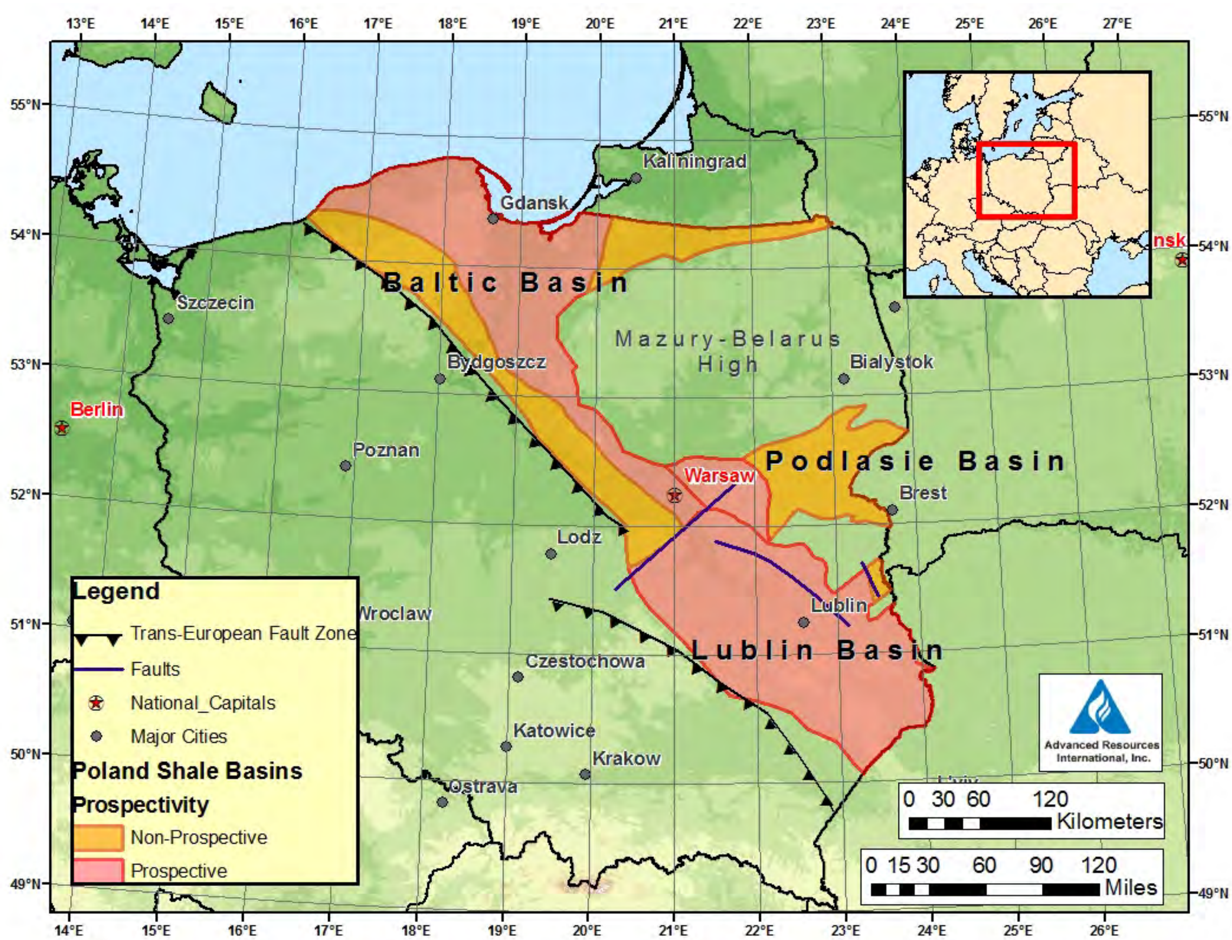
V. POLAND

INTRODUCTION

Active levels of shale gas leasing and exploration are already underway in Poland. The target is the Lower Silurian-Ordovician organically rich shales, present in the Lower Paleozoic sedimentary basin that exists as a northeast to southwest band through the center of the country. The shales are deposited in three basins – The Baltic in the north, the Lublin in the south, and the Podlasie in the east, Figure V-1. The organically rich shales in these three basins appear to have favorable characteristics for shale gas exploration.

Figure V-1. Major Shale Gas Basins of Poland



We estimate that Poland has 792 Tcf of risked shale gas-in place, 514 Tcf in the Baltic Basin, 222 Tcf in the Lublin Basin and 56 Tcf in the Podlasie Basin. We estimate a risked technically recoverable shale gas resource of 187 Tcf from these three basins, Table V-1.

Table V-1. Shale Gas Reservoir Properties and Resources of Poland

			Baltic Basin	Lublin Basin	Podlasie Basin
Basic Data	Basin/Gross Area		(101,611 mi²)	(11,882 mi²)	(4,306 mi²)
	Shale Formation		Lower Silurian	Lower Silurian	Lower Silurian
	Geologic Age		Llandovery	Wenlock	Llandovery
Physical Extent	Prospective Area (mi^2)		8,846	11,660	1,325
	Thickness (ft)	Interval	330 - 820	330 - 1,115	360 - 720
		Organically Rich	575	415	540
		Net	316	228	297
	Depth (ft)	Interval	8,200 - 16,400	6,560 - 13,450	5,740 - 11,350
		Average	12,300	10,005	8,545
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Overpressured
	Average TOC (wt. %)		4.0%	1.5%	6.0%
	Thermal Maturity (%Ro)		1.75%	1.35%	1.25%
	Clay Content		Medium	Medium	Medium
Resource	GIP Concentration (Bcf/mi^2)		145	79	142
	Risked GIP (Tcf)		514	222	56
	Risked Recoverable (Tcf)		129	44	14

BALTIC BASIN

Geologic Characterization

The Baltic Basin covers an area of approximately 102,000 square miles area in Poland, Lithuania, Russia, Latvia, Sweden and the Baltic Sea. Its southwestern border is formed by the Trans-European Fault Zone. Paleozoic sediments compose 75% of the basin fill, with the Silurian strata most prevalent[1]. The southwest margin of the Baltic Basin received very thick sediments of marine deposits as the basin subsided during the late Ordivician-Silurian collision of the Avalonia and Baltica tectonic plates. Anoxic conditions in the deep marine environment of the early Silurian allowed for the deposition of thick layers of organic rich shale, which were subsequently buried to depths sufficient to thermally mature the shales into the wet to dry gas window.

The deposition of the Silurian-age shales occurred along the Trans-European fault zone bounding the Baltic Basin, continuing southeast into the present day Lublin and Podlasie basins. These two basins share the same regional depositional environment as the Baltic Basin but are differentiated by local geologic features, such as the Mazury-Belarus High and regional tectonic faulting. Subtle differences in elevation and marine conditions created by these features caused organically rich shales to be deposited at different periods of the Silurian. In the Baltic and Podlasie basins, the most prospective shale intervals occur in the Lower Silurian Llandovery. In the Lublin Basin, organically rich shales were deposited in the slightly younger and thicker Wenlock strata.

The 8,850 mi^2 shale gas prospective area in the Baltic Basin was determined using the depth and thermal maturity of the Llandovery Formation. The formation shallows to the northwest, where its prospective area is limited by lack of sufficient thermal maturity. In the deep, western margin of the basin, the Llandovery Formation is highly thermally mature, with Ro values greater than 5.0%. However, the basin becomes very deep in this area. In the western areas, the prospective area is limited by the 5,000m depth contour interval, Figure V-2.

Reservoir Properties (Prospective Area)

Silurian. The Lower Silurian Llandovery-Wenlock graptolitic black shales are the main shale gas targets in the Baltic Basin, Figure V-3. Drilling depths to the base of the Silurian can be as deep as 18,000 feet, but generally range from 8,200 to 16,400 feet over the prospective area, Figure V-4. While the gross interval of the total Silurian formation covers 3,200 feet, the organically rich Llandovery strata has a gross thickness of 330 to 820 feet[2]. Based on well log data, ARI assumes a regional net to gross ratio of 55%, resulting in a net shale thickness of 316 feet[3]. Total organic content (TOC) in the prospective area can reach as high as 10%, but generally averages 4% for the net shale thickness investigated. Clay content is low in the Baltic Basin, with silica content generally above 50%. Thermal maturity varies in the basin, from over 5% in the northwest to below Ro 1% in the north east portions of the Baltic Basin. High Ro values indicate that some of the gas in the formations may have been converted to CO_2. However, in the prospective area, the Ro averages 1.75% and is in the dry gas window. A thin section of Ordovician Shale exists below the Silurian and is judged to be prospective. However, it is not sufficiently distinct from the Silurian to merit separate discussion and is included with the Silurian Shale[4].

Figure V-2. Onshore Baltic Basin, Lower Silurian Llandovery Shale Depth and Structure

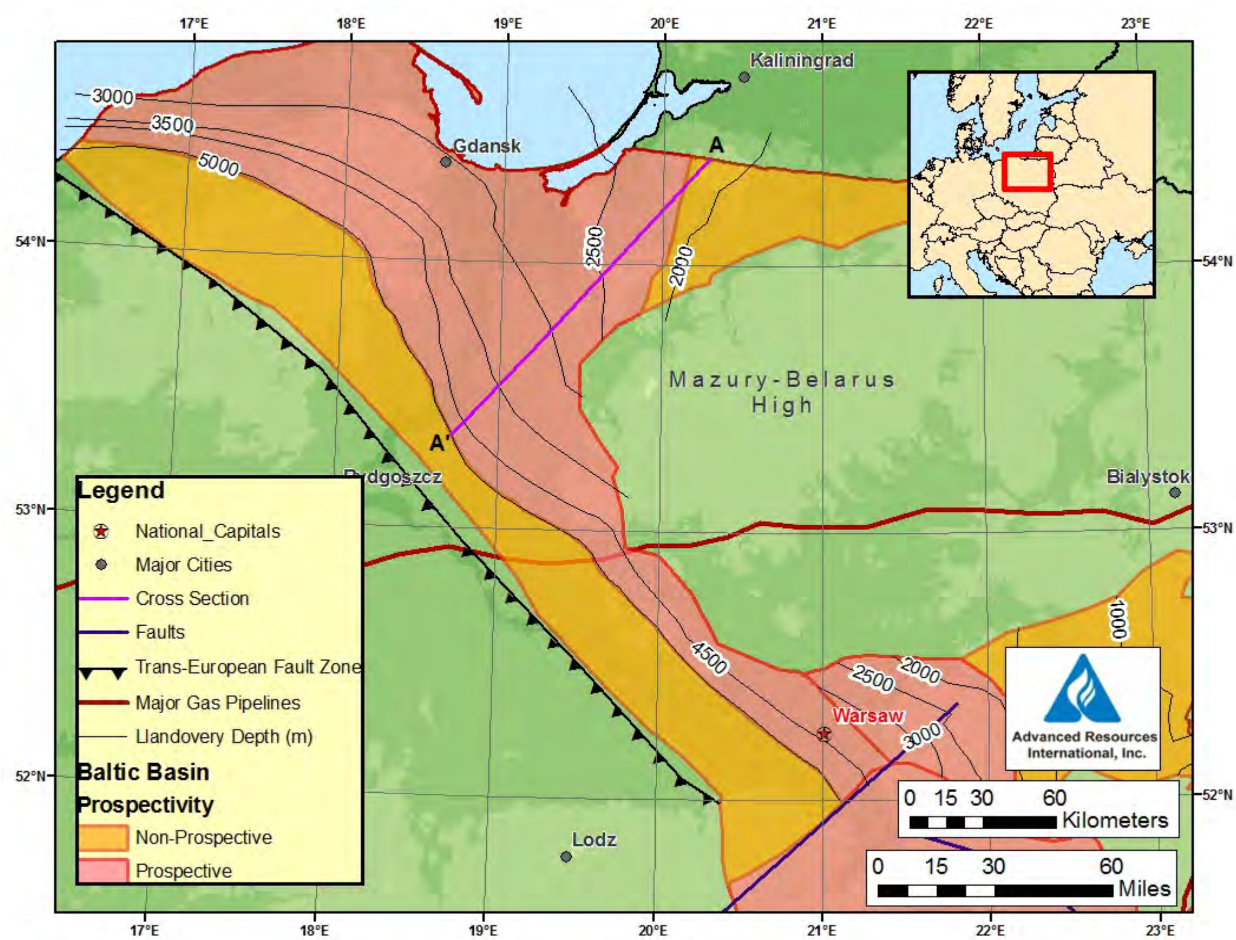


Figure V-3. Baltic Basin Stratigraphic Column[5]

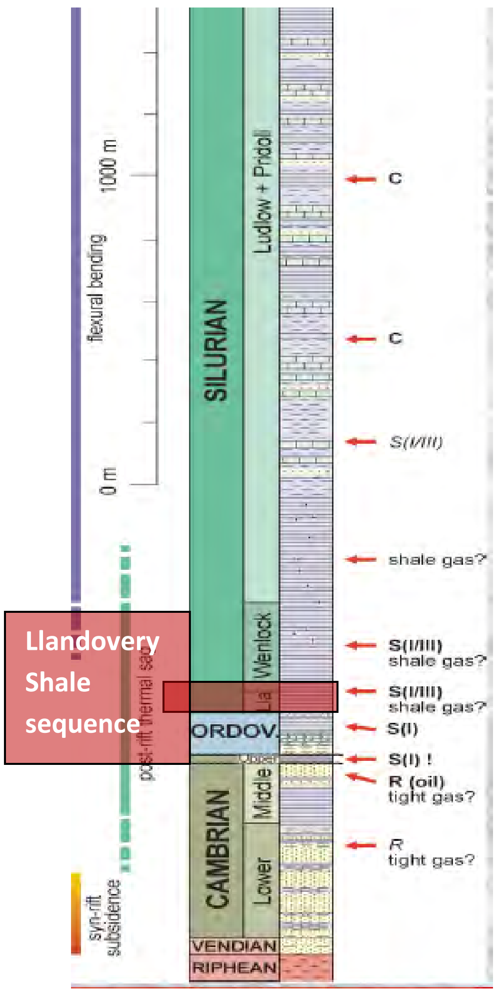
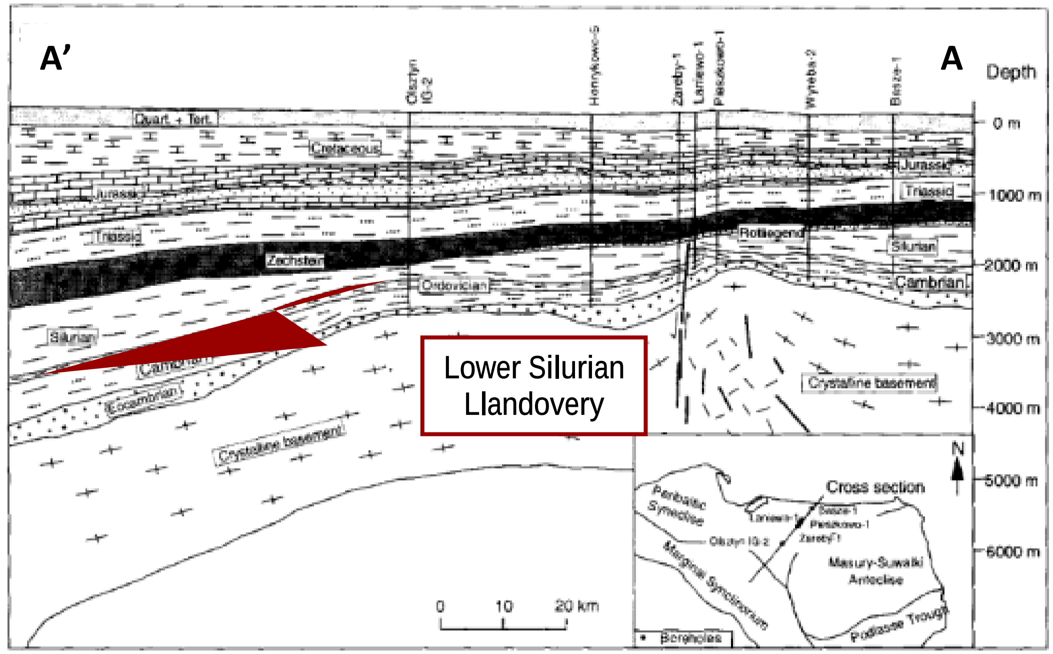


Figure V-4. Baltic Basin Depth and Structure Cross Section



Advanced Resources International, Inc.

Resources

The Baltic Basin Silurian Shale has a high resource concentration of 145 Bcf/mi^2. Given a 8,850 mi^2 prospective area, the risked shale gas in-place is 514 Tcf. Based on the favorable reservoir properties and mineralogy, we estimate a risked technically recoverable shale gas resource of 129 Tcf for the Baltic Basin, Table V-1.

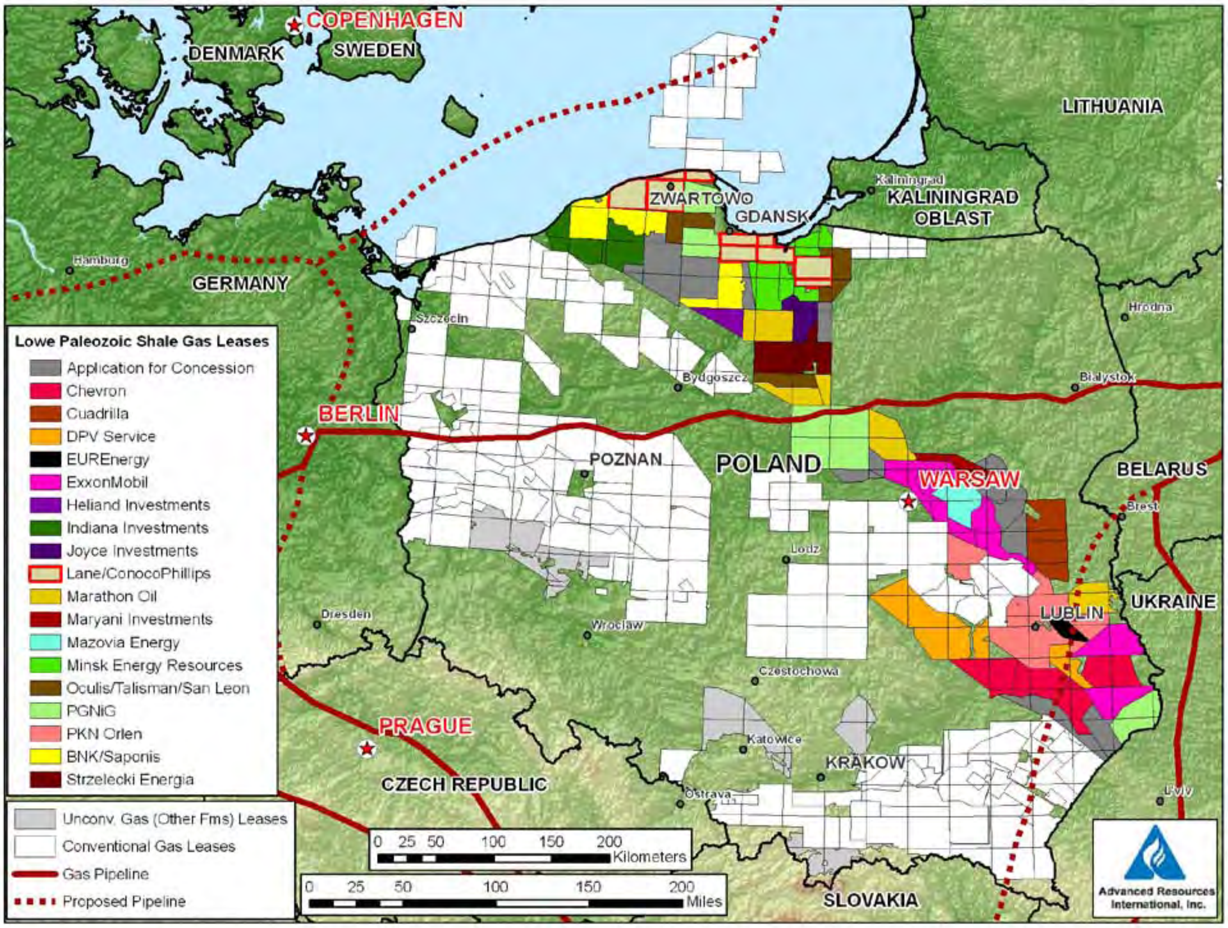
Activity

The majority of Poland's oil and gas fields are located in the southern Carpathian region. The northern region of the country is relatively undeveloped, excepting a group of oil and condensate fields approximately 75 miles northwest of Gdansk and a cluster of small fields offshore[6].

The shales in the Baltic Basin are being actively leased by numerous large international and smaller independent exploration companies, as well as the country's national gas entity, PGNiG, Figure V-5. The most active company in the basin is 3Legs Resources (a subsidiary of Lane Energy Poland). Conoco Phillips has partnered with 3Legs to jointly evaluate the shale potential of the Baltic Basin. In late September 2010, the joint venture drilled the basin's first shale exploration wells, Lebian LE1 and Łęgowo LE1. The wells were drilled vertically through the Silurian and Ordovician formations. No production information or other results have been released, as of the date of this report. A joint venture led by BNK Petroleum is planning to drill an exploratory well in October, also targeting the Silurian and Ordovician formations in the basin.

Talisman Energy has plans to drill three shale gas wells and perform seisimic testing during the next two years. Marathon Oil has one concession in the Baltic Basin in which it plans to drill one well and perform 2D seismic. Both Chevron and ExxonMobil have accumulated acreage in the Baltic Basin and have reported plans to drill exploratory wells within the next year. In addition to the major exploration companies, a number of smaller firms are acquiring and testing acreage in the Baltic Basin, including Realm Energy International, San Leon Energy and Aurealian Oil and Gas.

Figure V-5. Poland Shale Gas Leasing Activity[7]



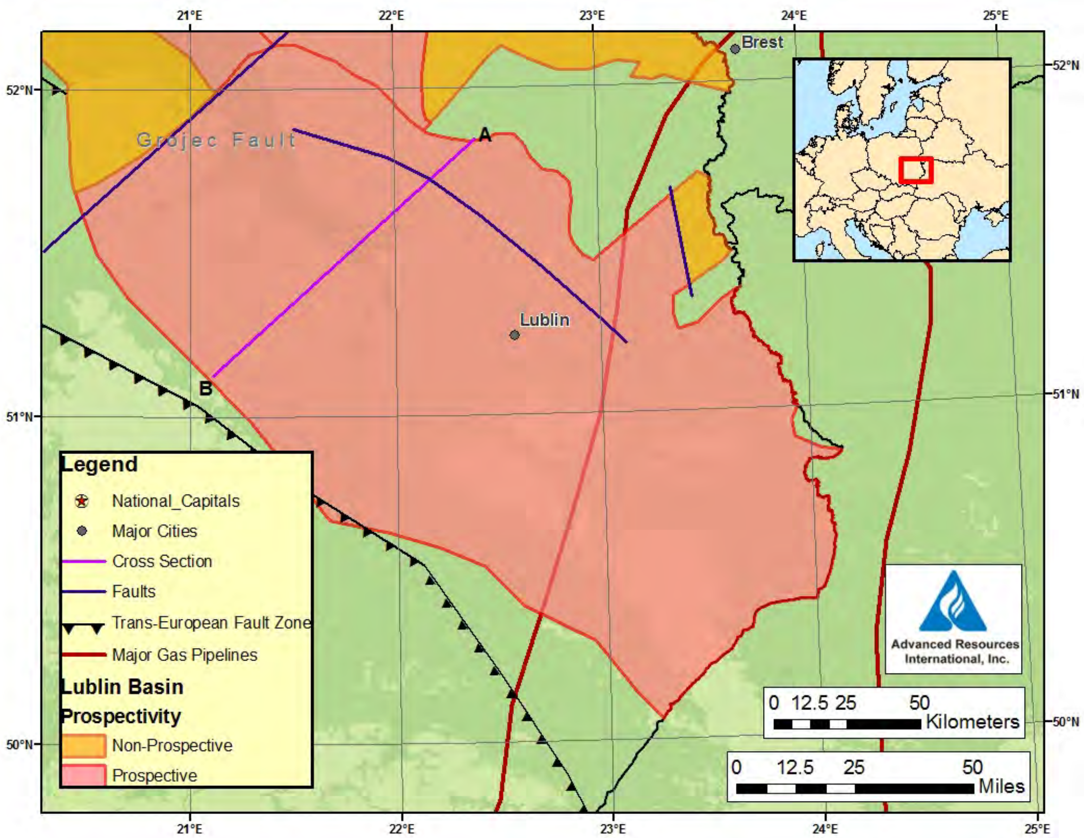
LUBLIN BASIN

Geologic Characterization

The Lublin Basin contains very similar Silurian depositional strata to the Baltic Basin, though regional tectonic events and rifting during the Devonian created a different maturity and depth profile than observed for Silurian Shale in the Baltic Basin. The basin covers an area of 10,010 square miles. It is bounded by the Grojec fault to the north (which separates it from the Baltic Basin), the Trans-European Fault Zone to the west, the Mazury-Belarus high in the east, and (for this study) the Polish-Ukrainian Border to the south. The Lublin Basin transitions from a Cambrian active rift basin in the north to a post rift thermal sag basin in the southeast, with moderate faulting throughout.

The primary shale gas target in the Lublin Basin is the Lower Silurian Wenlock Formation. Maturity and depth measurements suggest that almost the entire 11,880 square mile area may be prospective for shale gas development, though the recoverability of shale gas may be limited by regional faults. A small, 220 square mile area was excluded from the analysis due to the possibility of Silurian erosion, resulting in a prospective area of 11,660 square miles, Figure V-6.

Figure V-6. Lublin Basin Shale Gas Prospective Area



Reservoir Properties (Prospective Area)

Lower Silurian. The shale gas potential of the Lublin Basin exists in a 2,000 foot section of the lower Silurian Shale, from the Ludlow through Llandovery, Figure V-7. A thin interval of Ordovician Shale is also thought to be prospective, but due to its similarity to the Silurian Shale, it has been combined with the Silurian. Drilling depths to the Silurian range from 6,500 feet to 3,450 feet over most of the prospective area[8]. The prospective shale section thickens from east to west, from 330 feet to 1,115 feet and has an organically rich gross thickness of 415 feet with a net thickness of 228 feet, Figure V-8. Total organic content in the Wenlock Formation is lower than in the slightly older Llandovery Formation, ranging from 1% to 1.7% with an average of 1.5%. Thermal maturity ranges from over mature (>2.5%Ro) in the central areas of the trough to the threshold of the wet gas window (1.0% Ro) on the basin's eastern boundary. Average thermal maturity is 1.35% Ro in the prospective area.

Figure V-7. Lubin Basin Stratigraphic Column

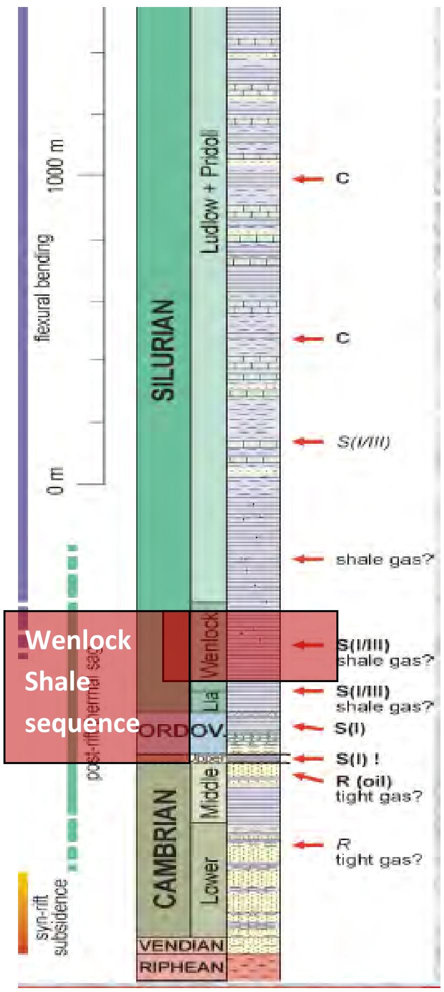
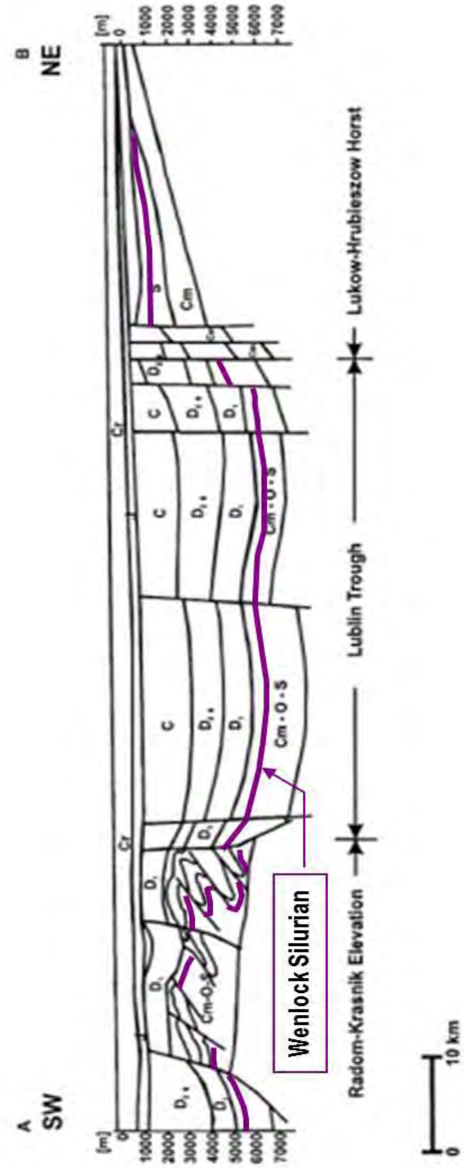


Figure V-8. Lublin Basin Fault Map and Cross Section[9]



Resources

The Silurian and Ordovician shales of the Lublin Basin contain a moderate resource concentration 79 Bcf/mi^2. However, considerable variability exists in shale thickness and organic content from east to west in the basin. As such, the shale gas resource concentration will vary considerably from this average value. Given a 11,660 mi^2 prospective area, the risked shale gas in-place is 222 Tcf. Based on reservoir properties and mineralogy, we estimate a risked technically recoverable shale gas resource of 44 Tcf, Table V-1.

Activity

The Lublin Basin is the site of modest oil and gas production from a small group of oil and gas conventional fields. As in the Baltic Basin, a number of international firms and Poland's state owned gas company (PGNiG) are actively evaluating the Lublin Basin's shale gas potential. In early August, Halliburton completed Poland's (and the Lublin Basin's) first shale gas well fracturing operation on the Markowola-1 exploratory well for PGNiG. Production and test results have not yet been released. At least six other exploration companies have acquired unconventional gas exploration concessions in the basin, including ExxonMobil, Chevron, Marathon Oil and others, Figure V-5.

PODLASIE BASIN

Geologic Characterization

The Podlasie Basin (Podlasie Depression) is an isolated section of the Lower Paleozoic sedimentary basin, east of the Baltic and Lublin basins. It is bounded on the north and south by the Mazury-Belarus high and (for this study) by the Polish-Belorussian border on the east. The Silurian interval in the Podlasie Basin crops out in the east, just inside the border with Belarus, and deepens rapidly to the west, where active shale gas leasing is underway.

The shale gas target in the Podlasie Basin is the lower Silurian Llandovery Formation, Figure V-5. Based on depth and thermal maturity data, ARI has established a 1,325 square mile prospective area for the Podlasie Basin shale. The prospective area is limited on the east by the 1.0 Ro% contour line.

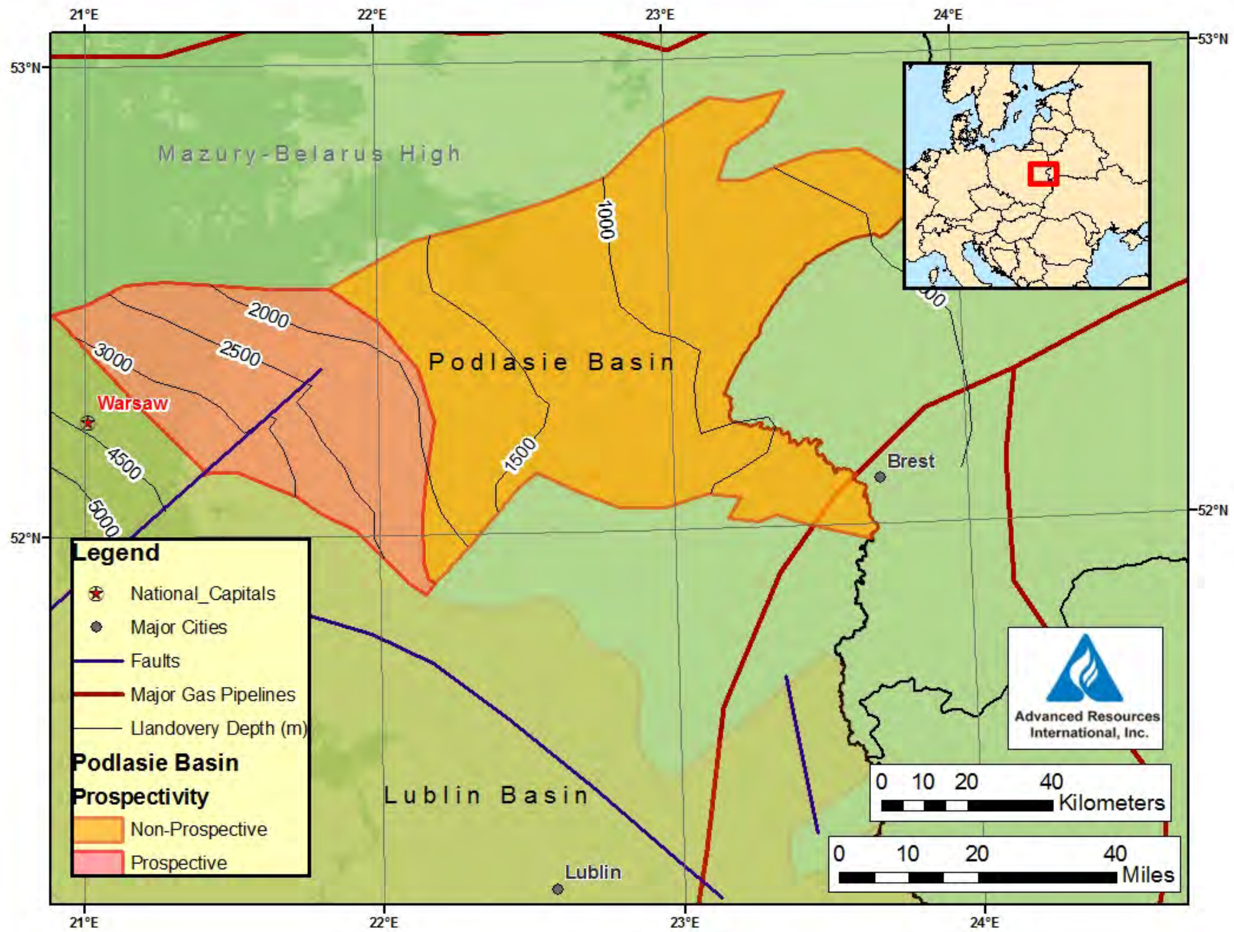
Reservoir Properties (Prospective Area)

Lower Silurian. In the prospective area of the Podlasie Basin shale thickness ranges from 360 feet to 720 feet. Within this larger trend is an organically rich section of 540 feet, with a net thickness of 297 feet. Depth to the base of the Silurian Shale ranges from 5,740 feet to 11,350 feet, with an average of 8,545 feet, Figure V-8. Total organic content is much higher in the Podlasie Basin than in the Baltic or Lublin, reaching 20% in places. Average TOC content in the basin is 6%. Thermal maturity in the basin decreases toward the east, where it quickly leaves the gas window. Average Ro% in the prospective areas of the Podlasie Basin is 1.25%.

Resources

Our analysis suggests the Silurian Shale of the Podlasie Basin contains an attractive resource concentration of 142 Bcf/mi^2. Given a 1,330 mi^2 prospective area, the risked shale gas in-place is 56 Tcf. Based on moderately favorable reservoir properties and mineralogy, we estimate a risked technically recoverable resource of 14 Tcf, Table V-1.

Figure V-8. Podlasie Basin Depth to Base of Llandovery Shale



Activity

Though no exploratory wells have yet been drilled into the Silurian Shale in the Podlasie Basin, it is being actively leased, Figure V-5. ExxonMobil holds the largest lease position in the basin, with three shale gas exploration concessions.

Poland is a large net importer of natural gas. Of the 577 Bcf of natural gas consumed in Poland in 2009, 350 Bcf (61%) was imported, almost all of which was supplied from Russia. After a plateau in production from 2004 to 2007, the country's natural gas production has again begun to decline. Annual production is currently 0.6 Bcfd, from proved reserves of 6 Tcf[10].

Realizing the potential for unconventional natural gas to support its declining conventional gas production, the Polish government has shown strong support for shale gas drilling. It has put into place very attractive fiscal terms for gas development, although infrastructure and regulatory issues remain as barriers to efficient development. Development of

Poland's large shale gas technically recoverable resource of 187 Tcf could significantly increase the country's natural gas reserves and internal gas production.

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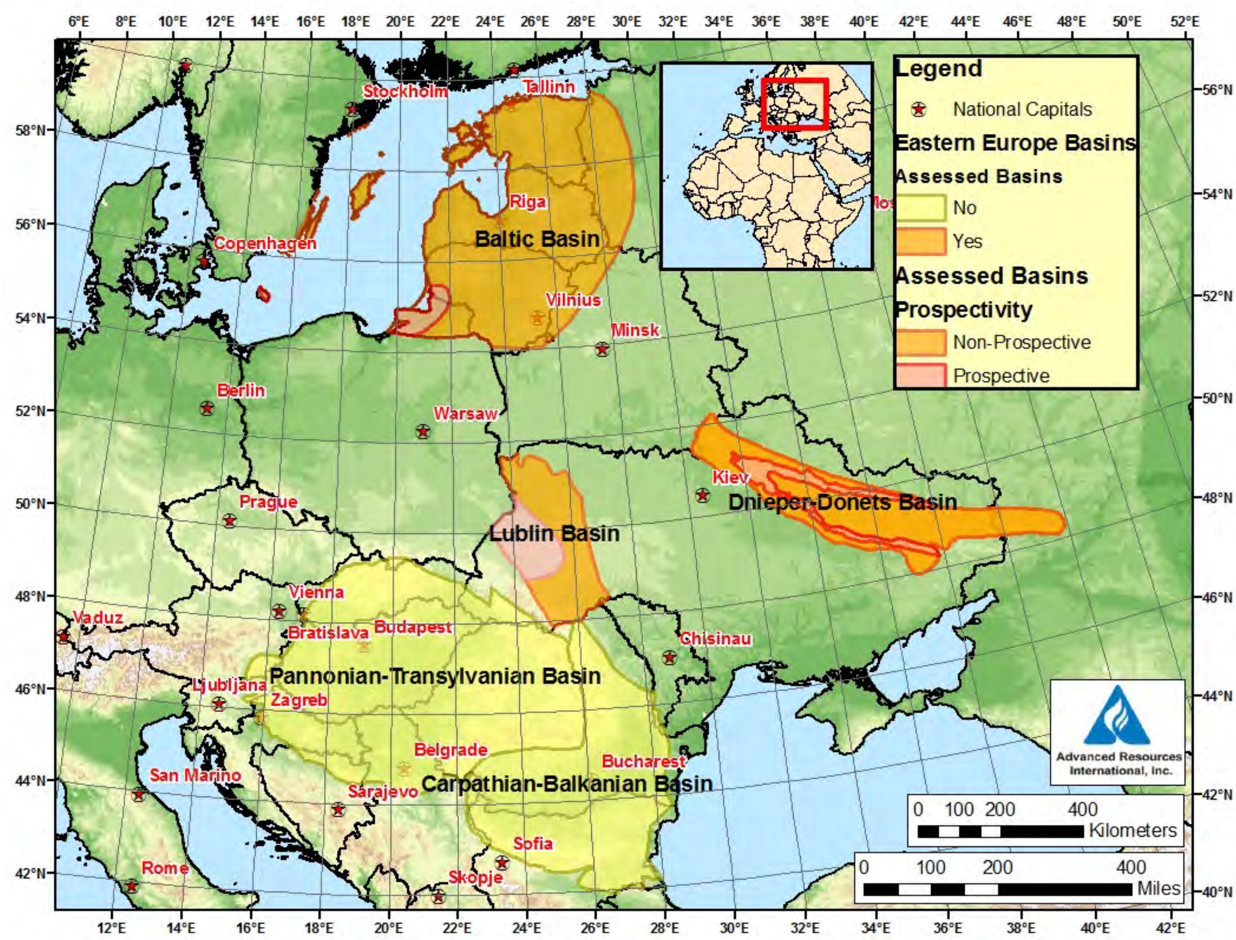
VI. EASTERN EUROPE

INTRODUCTION

Outside of Poland, the shale gas potential of Eastern Europe has not been widely explored. However, several basins contain promising shale gas targets, such as the northern Baltic Basin in Lithuania, the southeastern extent of the Lublin Basin into Ukraine and the Dnieper-Donets Basin in Ukraine, Figure VI-1. Additional potentially prospective basins include the Pannonian-Transylvanian Basin in Hungary and Romania, and the Carpathian-Balknian in Southern Romania and Bulgaria, but were not assessed by the study, Figure VI-1.

Figure VI-1. Shale Gas Basins of Eastern Europe



For the three Eastern European basins for which ARI was able to establish a prospective area, we estimate a risked shale gas in-place of 93 Tcf in the Baltic Basin, 48 Tcf in the Dnieper-Donets Basin, and 149 Tcf in the Lublin Basin, Table VI-1. Of this 290 Tcf of risked gas in-place, ARI estimates a technically recoverable shale gas resource of 65 Tcf, Table VI-1. Not enough information is available on the key shale reservoir properties in the Pannonian-Transylvanian and Carpathian-Balkanian basins for conducting a reliable resource assessment.

Table VI-1. Reservoir Properties and Resources of Eastern Europe

Basic Data	Basin/Gross Area		Baltic Basin (101,611 mi^2)	Dnieper-Donets (38,554 mi^2)	Lublin Basin (26,500 mi^2)
	Shale Formation		Lower Silurian	Rudov Bed	Lower Silurian
	Geologic Age		Silurian	Carboniferous	Silurian
Physical Extent	Prospective Area (mi^2)		3,071	7,134	7,850
	Thickness (ft)	Interval	393 - 524	26 - 230	1,312 - 3,260
		Organically Rich	459	128	415
		Net	284	102	208
	Depth (ft)	Interval	5,904 - 7,544	9,840 - 16,400	3,280 - 16,400
		Average	6,724	13,120	9,840
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Overpressured
	Average TOC (wt. %)		4.0%	4.0%	2.5%
	Thermal Maturity (%Ro)		1.20%	1.30%	1.35%
	Clay Content		Medium	Medium	Medium
Resource	GIP Concentration (Bcf/mi^2)		101	42	79
	Risked GIP (Tcf)		93	48	149
	Risked Recoverable (Tcf)		23	12	30

BALTIC BASIN

Geologic Characterization

The Baltic Basin (Baltic Syneclise) is a large marginal synclinal basin located in the southwestern part of the East European Craton and a major structure of the three Baltic States. The basin is about 700 km long and 500 km wide. The basin deepens along its NE to SW axis; depth below sea level of the Pre-Cambrian basement increases from a few hundred meters in Estonia to 1,900 m in southwestern Latvia, 2,300 m in western Lithuania, and 5,000 m in Poland. This chapter will focus on the non-Polish section of the basin. (The Polish Baltic Basin is discussed in Chapter V.)

The shale gas target in the Baltic Basin is the lower Silurian marine shale package, which, though less mature than in Poland, has favorable characteristics for shale gas development. ARI defined a 3,070 mi^2 prospective area for the Baltic Basin outside of Poland using the 1% Ro contour line, Figure VI-2.

Reservoir Properties (Prospective Area)

Depths to the base of the Lower Silurian Shale range from 5,900 feet to 7,550 feet over the prospective area, averaging 6,720 feet, Figure VI-3. While the gross interval of the total Silurian formation can reach 3,600 ft, the organically rich, Lower Silurian strata has a gross thickness of 459 and, a net thickness of 284 ft, Figure VI-4.[1] Total organic content (TOC) in the prospective area ranges from 2% to 6% with an average of 4%. The thermal maturity data ranges from 1.0% to 1.9% Ro, averaging 1.2%[2].

Resources

Our analysis suggests the Lower Silurian Shale of the Baltic Basin contain a moderate resource concentration of 101 Bcf/mi^2. Given a 3,071 mi^2 prospective area, the risked shale gas in-place is 93 Tcf. Based on favorable reservoir properties and mineralogy, we estimate a risked technically recoverable resource of 23 Tcf, Table VI-1.

Figure VI-2. Baltic Basin Structure Map

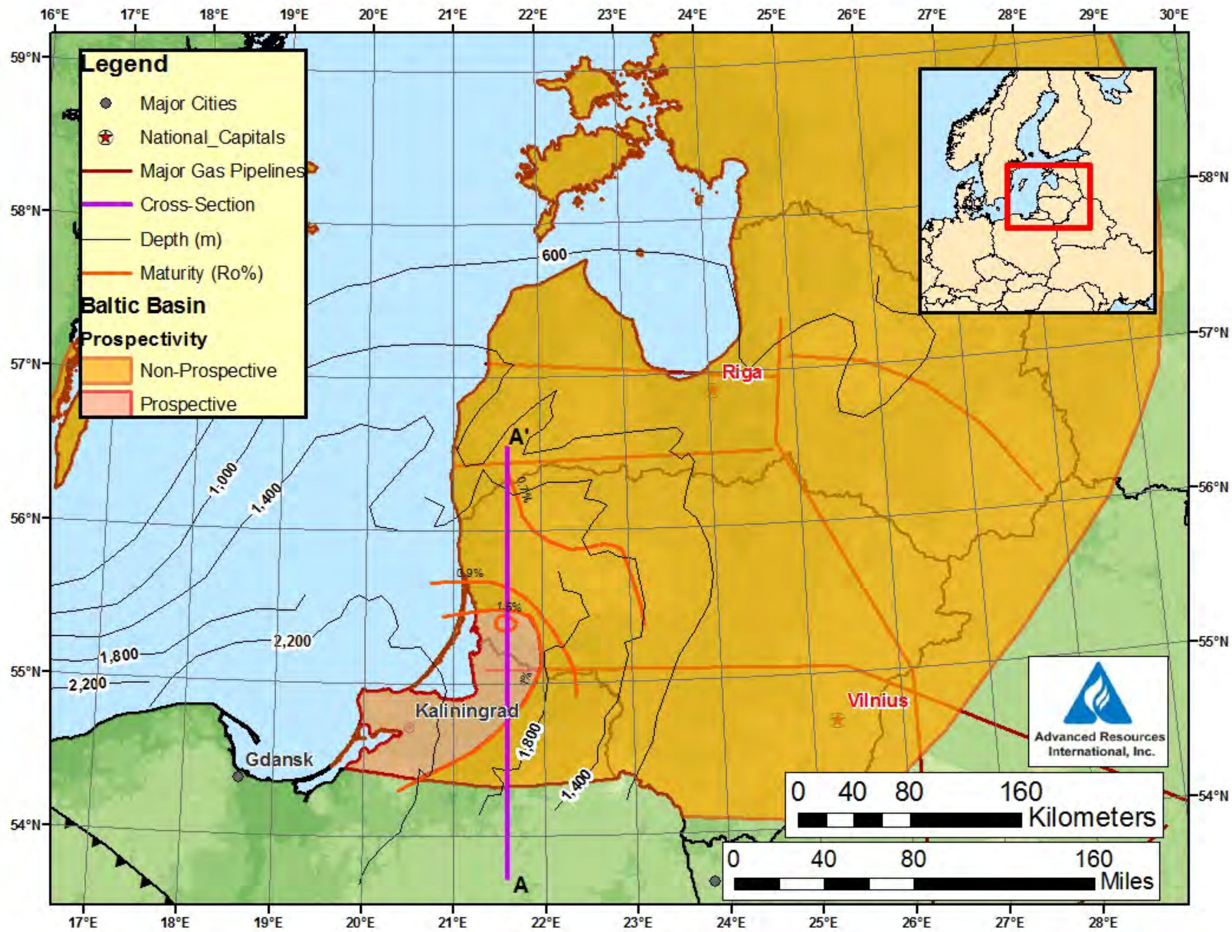


Figure VI-3. Baltic Basin Stratigraphic Column[3]

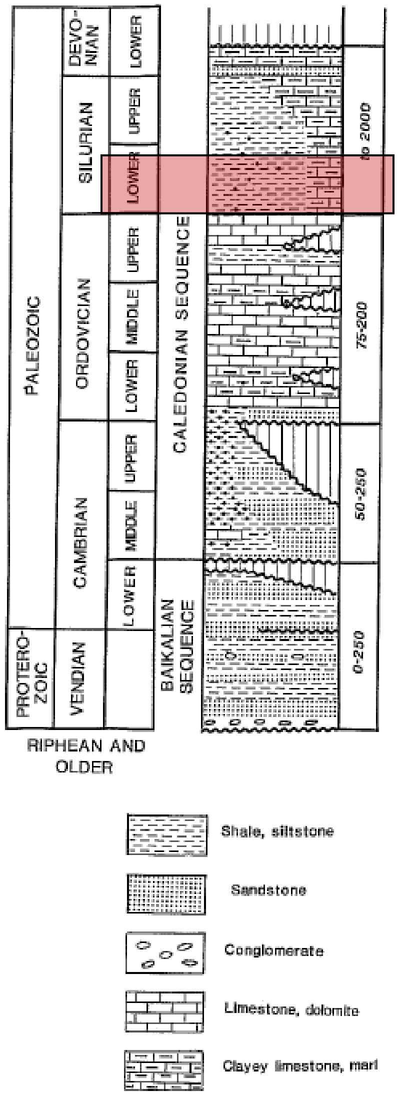
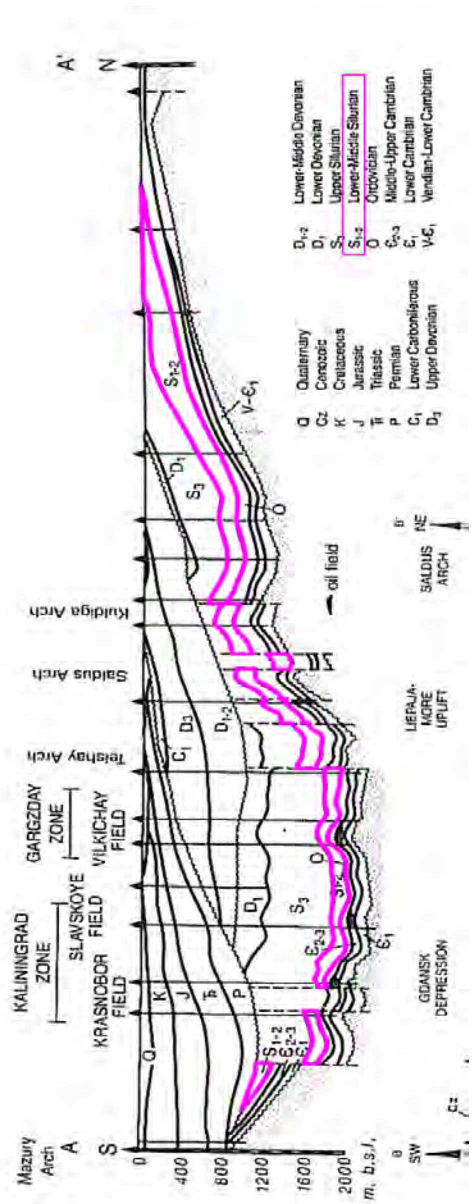


Figure VI-4. Baltic Basin Cross Section3:



Activity

Outside of Poland, the shale gas potential of the Baltic Basin has yet to be explored. Government representatives of the Lithuanian government have noted they are aware of the potential, but leasing is not underway in the country.

In its northern, thermally immature areas, the shallow high kerogen content shale in the Baltic Basin are mined for use for power and chemical production. The Ordovician/Silurian Kukersite oil shale in Estonia has been under development since WWII.

DNIEPER-DONETS BASIN

Geologic Characterization

The Dnieper-Donets (Dniepr-Donets) Basin forms a NW-SE trend through central Ukraine and into Russia. It is part of the larger Pripyat-Dniepr-Donets intercratonic rift basin, which trends further NW into Belarus. The basin is flanked by the regional highs: the Ukrainian Shield (to the south) and the Voronezh Massif (to the North).

After extensive rifting, faulting and volcanic activity during the basin's formation in the Devonian, it entered a period of calm, marine sedimentation during the Carboniferous. Shales deposited during this time are likely the source of hydrocarbons produced from Permian and Carboniferous reservoirs in the basin. Uplifting during the Permian created stress fractures on the basin margin, which penetrated localized areas of the lower Carboniferous strata. Furthermore, salt layers deposited in the Permian likely contributed to a regional overpressuing of the underlying Carboniferous strata.

The geochemical analysis of the natural gas produced in this basin suggests it was generated from marine shales of Carboniferous-age. These data also suggest the dominant shale gas formation in the Dnieper-Donets Basin is the "Rudov Bed," a Lower Carboniferous (Visean) black shale, Figure VI-6. Today, the Dnieper-Donets Basin provides approximately 90% of Ukraine's oil and gas, from over 140 producing fields. Additional shale gas potential may exist in Frasnian (Upper Devonian) shale and carbonate packages in more isolated portions of the basin, but insufficient data were available to estimate their potential.

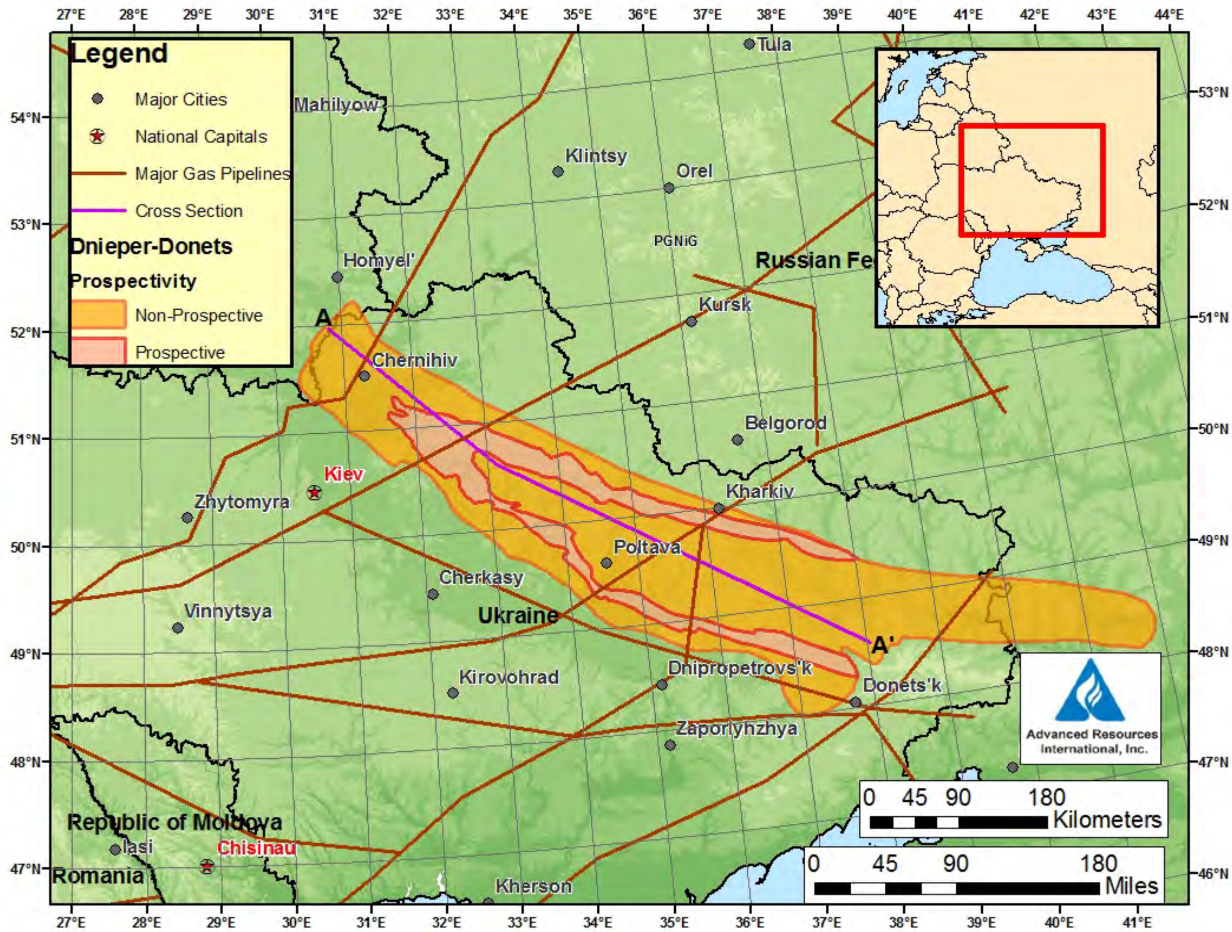
The 7,134 mi^2 prospective area used in this report is based on depth limits and shale thermal maturity. The prospective area along the eastern margin of the basin is formed by the 16,400 foot depth cutoff, the western boundary is formed by the 9,840 foot depth cutoff, which corresponds to the beginning of the gas window for Lower Carboniferous strata[4]. Thermal maturation in the deeper areas of the basin is not well understood, some data suggest areas of comparatively little heat flow in the central areas of the basin, which could limit the extent of the shale formation inside the gas window. ARI has compensated for this thermal maturity uncertainty in its estimation of risked gas in-place.

Reservoir Properties (Prospective Area)

Carboniferous (Rudov Bed). The prospective area of the Dneiper-Donets Basin is most limited by its great depth. The Carboniferous strata deepens toward the center of the basin, reaching over 12 kilometers below the surface in the basin center, Figure VI-7. As such, the prospective area defined in this study is confined to the north and lateral sections of the basin, with depth above 16,400 feet, Figure VI-5. Insufficient data was available to establish a prospective area in the southeastern portion of the basin.

Depths to the Rudov Bed Formation range from 9,840 feet to 16,400 feet over the prospective area, with an average of 13,120 feet4. The gross interval of the organically rich Rudov Bed Formation is between 26 feet to 230 feet, averaging 130 feet.[5] ARI assumes an 80% net to gross ratio, based on the formation's relatively stable marine sedimentary environment. Total organic content in the prospective area ranges from 2% to 6% with an average of 4%. Vitrinite reflectance data suggest this formation is in the wet to dry gas window, with Ro values between 1% to 1.6%, Table VI-14.

Figure VI-5. Dnieper-Donets Shale Gas Prospective Area



Resources

The Rudov Bed Shale in the Dnieper-Donets Basin contains a moderate resource concentration of 42 Bcf/mi^2. Given a 7,134 mi^2 prospective area, the risked shale gas in-place is 48 Tcf. This estimate accounts for development risks associated with the faulted margins of the basin, its depth and uncertain thermal maturity profile. Based on moderately favorable reservoir properties and mineralogy, we estimate a risked technically recoverable shale gas resource of 12 Tcf, Table VI-1.

Figure VI-6. Dnieper-Donets Basin Stratigraphic Column[6]

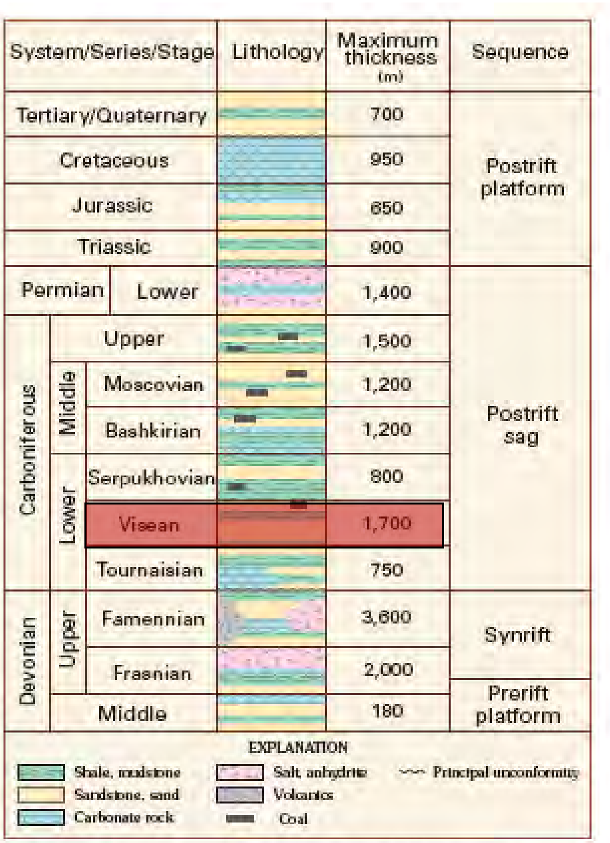
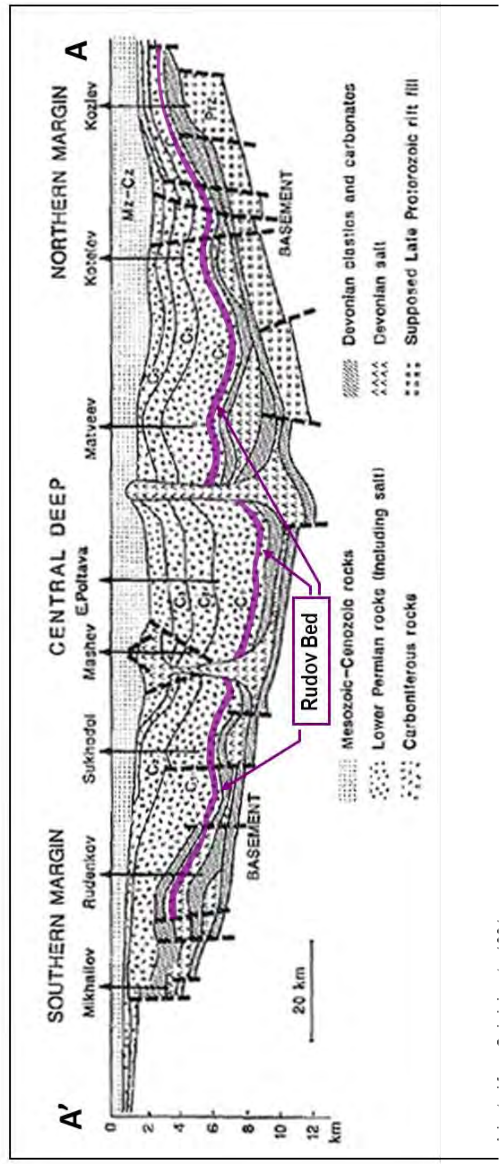


Figure VI-7. Central Dnieper-Donets Basin Stratigraphic Column[7]



Advanced Resources International, Inc.

Activity

The Dnieper-Donets Basin is under investigation for unconventional gas potential. At present, shallower CBM deposits in the eastern area of the basin are the primary exploration targets, but firms are also studying the deeper shale gas potential in the basin. EuroGas, an independent E&P company, recently partnered with Total to explore the shale gas potential of its recently acquired lease concessions in the Dnieper-Donets Basin. The firm intends to drill its first horizontal wells some time in 2010. No results have yet been reported.

Major E&P companies such as Shell and Exxon Mobil have also expressed interest in Ukrainian shale gas potential, but have not specified which areas they intend to explore. The large, U.S. E&P company, Marathon Oil, exited Ukraine in 2008[8].

UKRANIAN LUBLIN BASIN

Geologic Characterization

The Ukrainian Lublin Basin is the southern extension of the Lower Paleozoic sedimentary basin deposited along the western slope of the Baltica paleocontinent. It is bounded by the Grojec Fault in central Poland (which separates it from the Baltic Basin), the Trans-European Fault Zone to the west, the Mazury-Belarus high in the east, and, in this analysis, by the Romanian border to the south. The Ukrainian portion of the Lublin Basin covers an area of 26,500 mi^2.

The primary target in the Lublin Basin is shale in the Silurian-Ordovician section. Data on Ukrainian geology is sparse, so ARI relied heavily on data from the Polish Lublin Basin to establish a prospective area for the Silurian Shale in the Ukraine. Based on continuation of depth and maturity trends observed from Poland, ARI assumes 7,850 mi^2 of the Ukrainian Lublin Basin to be prospective. The basin becomes shallow to the North and east, and exhibits uplifted faulting to the south and west, limiting the prospective area to a deep, thick centralized area in the Northwest of Ukraine, Figure VI-8.

Reservoir Properties (Prospective Area)

Silurian Depths to the Lower Silurian Shale range from 3,280 feet to 16,400 feet over the prospective area, with an average of 9,840 feet. The gross interval of the total Lower Silurian Shale Formation is between 1,310 ft to 3,260 ft, Figure VI-9; the organically rich strata has an gross thickness of 415 ft and a net thickness of 208 ft, based on data from the Polish Lublin Basin. Total organic content in the prospective area ranges from 1% to 3% with an average of 2.5%. Vitrinite reflectance data suggest this formation is in the wet to dry gas window, with Ro values between 1% to 1.7%, Table VI-1[9].

Figure VI-8. Lublin Basin Shale Gas Prospective Area

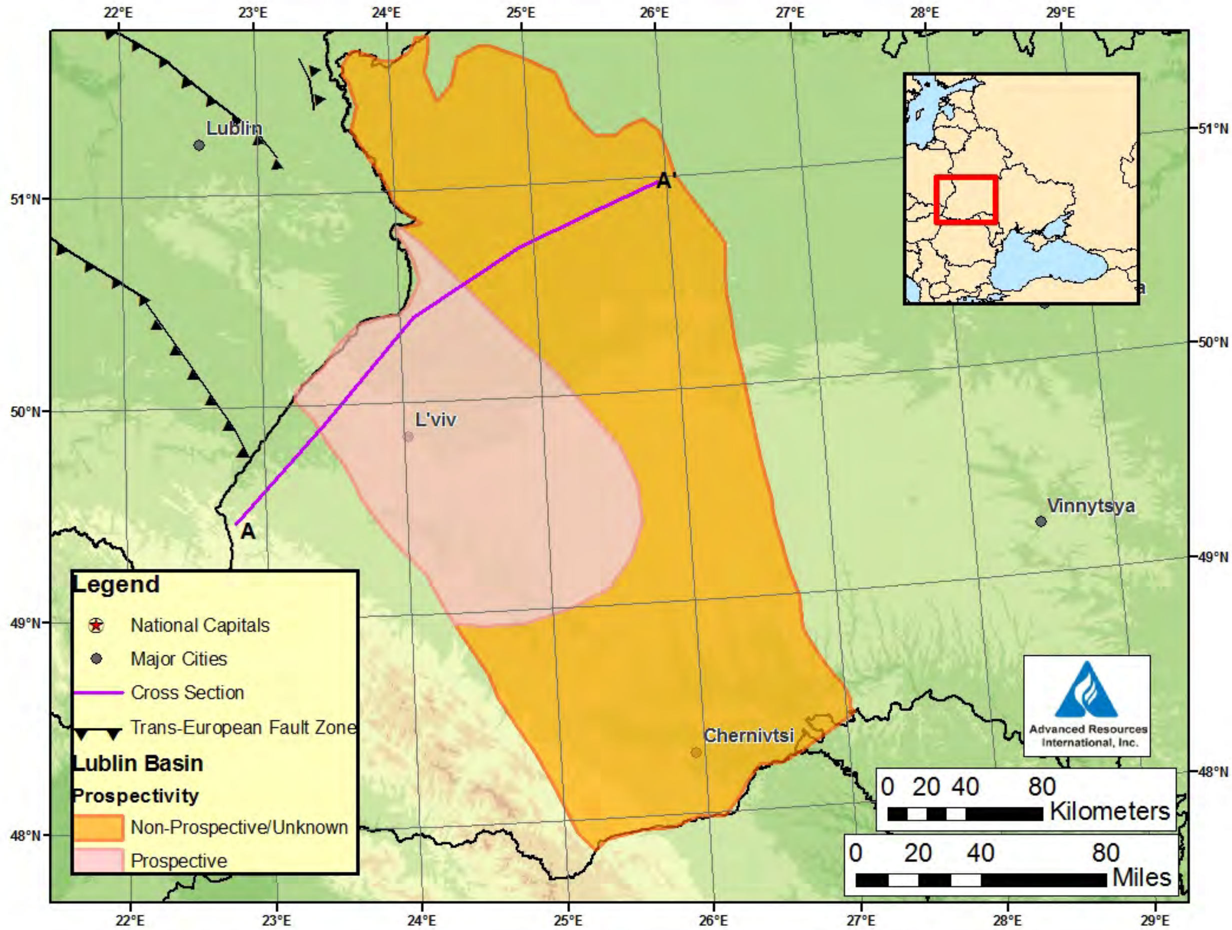
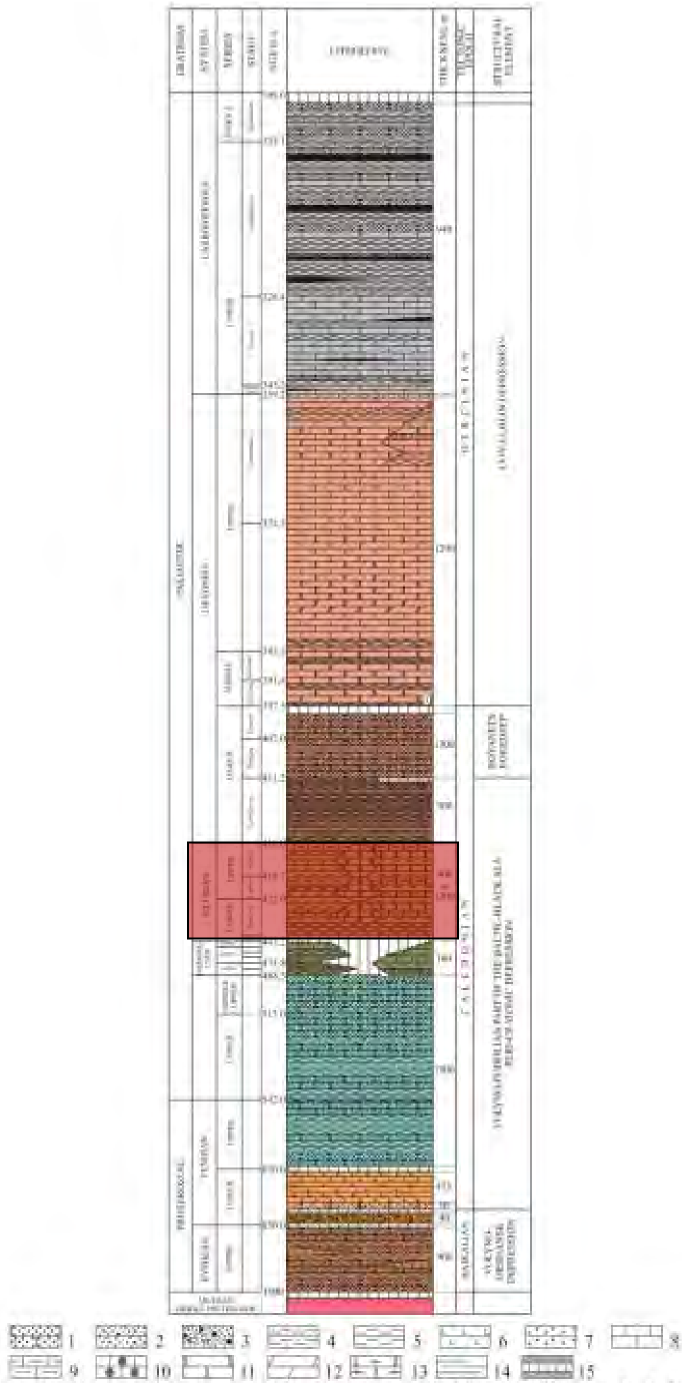
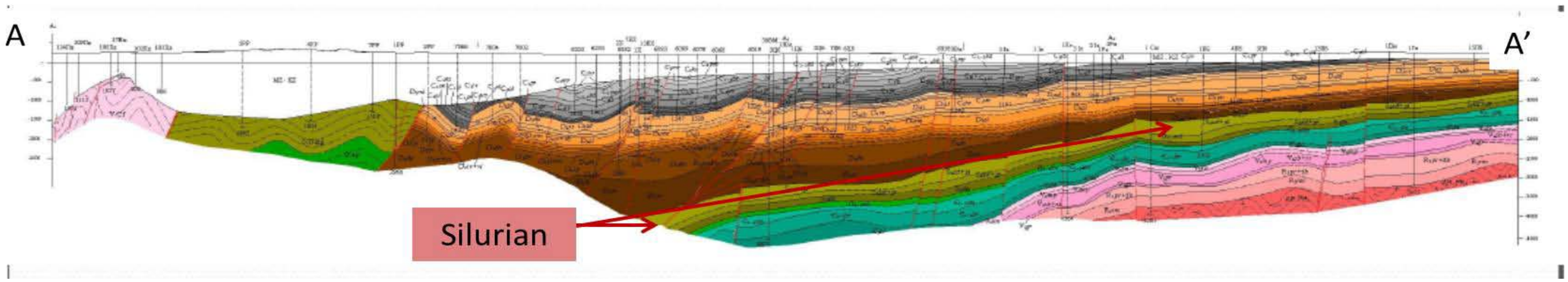


Figure VI-9. Lubin Basin Stratigraphic Column9



1 – sandstones, 2 – arkosic sandstones, gravelites, conglomerates, 3 – tillites, 4 – siltstones, 5 – shales, 6 – magmatic rocks, 7 – tuffs, 8 – limestones, 9 – clayey limestones, 10 – reef limestones, 11 – dolomites, 12 – marls, 13 – anhydrite, 15 – coal seams, 16 – lack of sediments, erosion surface.

Figure VI-10. Lublin Basin Geology and Cross Section9



Resources

The Silurian black shale in the Lublin Basin of Ukraine contains a resource concentration of 79 Bcf/mi^2. Given a 7,850 mi^2 prospective area, the risked shale gas in-place is 149 Tcf. Based on moderately favorable reservoir properties and mineralogy, we estimate a risked recoverable technically resource of 30 Tcf, Table VI-1.

Activity

To date, the major exploration companies have focused their Lublin Basin exploration activities in Poland, favoring the country's more transparent business climate. The only international firm actively exploring the Ukrainian Lublin Basin is Eurogas, Inc, which plans to test for commercial gas potential from CBM and shale formations.

PANNONIAN-TRANSYLVANIAN BASIN

Geologic Characterization

The Pannonian-Transylvanian Basin is a large, Neogene-age, extensional basin covering a 124,000 square mile area largely inside of Hungary, Romania and Slovakia, Figure VI-8. It is bounded to the north and east by the Carpathian Mountains and to the south and west by the Dinaric and Eastern Alps, Figure VI-11. During the Oligocene, the basin was a vast sea, at one point connected to the Mediterranean. The marine sediments deposited in this basin are believed to be the source rocks for much of Hungary's hydrocarbon reserves, Figure VI-12. A number of uplifted basement blocks separate the Pannonian Basin into subbasins, including the Great Hungarian Plain (site of the Mako Trough, a tight gas target), Danube Basin and Transcarpathian Basin, among others. Each of these subbasins share a similar sequence of Neogene fill[10].

Though the basin is relatively young, it has a very high geothermal gradient, allowing for organic matter to mature into the oil and gas window, Figure VI-13. However, the shale gas potential in the basin is low, as most of the regional organically rich source rocks are clay-like marls that offer limited commercial shale gas exploration potential. In the southeast of the basin, shale formations are immature and low in organic content[11].

Limited data are available from basement shale formations in Jurassic and Cretaceous strata may have favorable characteristics for shale gas development, though detailed source rock data is scarce.

Reservoir Properties (Prospective Area)

At this time, insufficient data is available to establish a prospective area for shale gas formations in the Panonnian-Transylvanian Basin. Shale gas potential is being investigated by one firm in northern Romania, but geologic data on their lease concessions is not publically available.

Figure VI-11. Pannonian-Translyvanian Basin

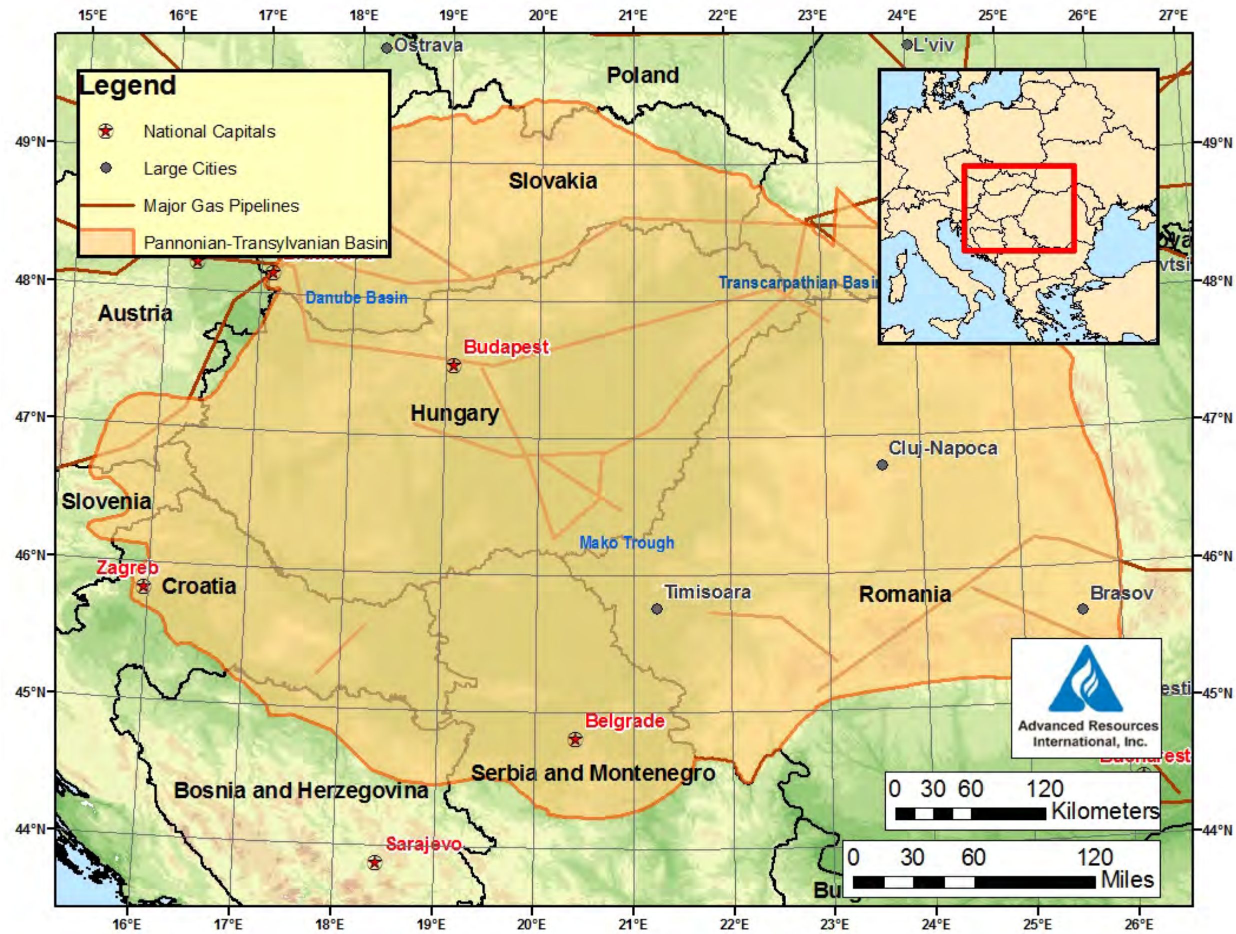


Figure VI-12. Pannonian-Transylvanian Basin Stratigraphic Column

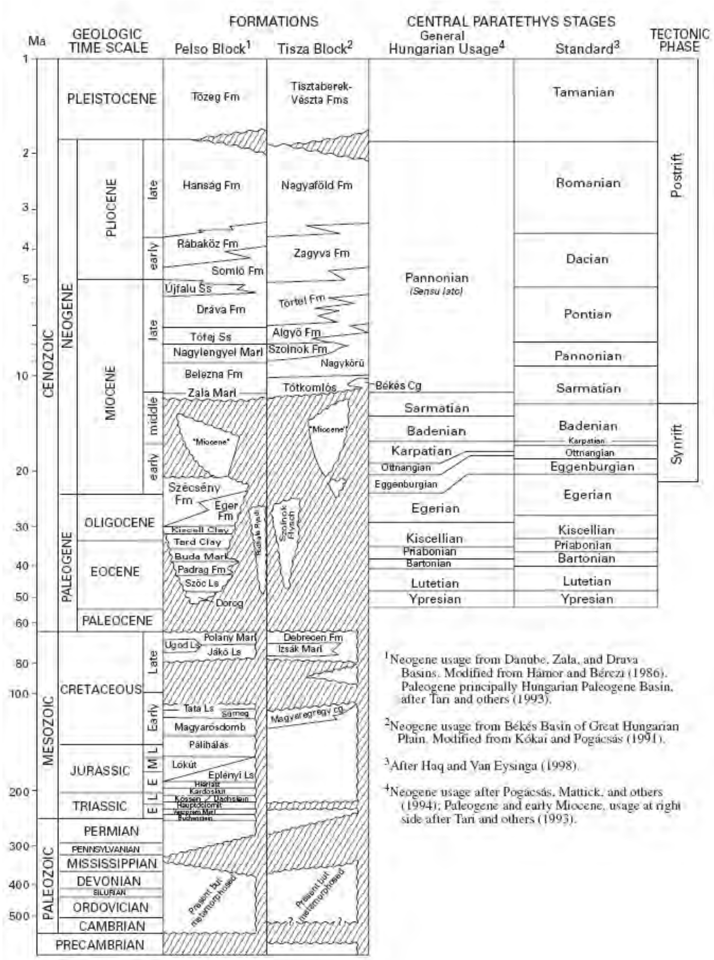
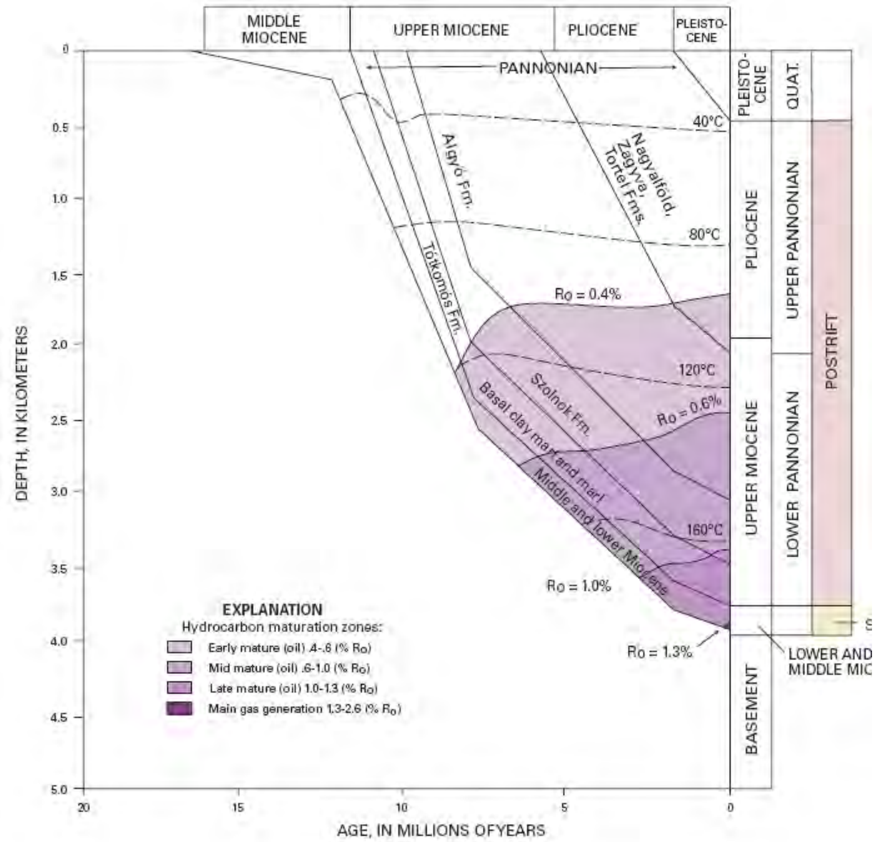


Figure VI-13. Generalized Pannonian-Transylvanian Depth and Structure Cross Section



Activity

Shale gas exploration in the Pannonian-Translyvanian Basin is still in a very speculative phase. East West Resources, an Alberta-based E&P company, is targeting shale formations in the Cretaceous-Jurassic pre-rift basement of the basin. It has applied for lease concessions to explore the conventional and shale horizons in the northern Romanian portion of the basin and should receive approval in 2011.

CARPATHIAN-BALKANIAN BASIN

Geologic Characterization

The Carpathian-Balkanian Basin is a geologically complex basin composed of a series of mountain nappes, foredeeps and plains in Southern Romania and Bulgaria, Figure VI-16. The basin is bounded by the Pannonian-Translyvanian Basin to the west, Moldova to the east, Ukraine to the north and the erosional boundary of the Moesian platform to the south, Figure VI-14. With access to additional data, the Moesian Platform and Getic depression may prove to have prospective areas for shale gas development, Figure VI-17. Several strata, including the Silurian Tandarei formation, Jurassic Dogger Balls and Lias Etropole formations appear to have high organic content and appropriate levels of maturity for shale gas development, Figure VI-15[12].

Reservoir Properties (Prospective Area)

Sufficient data is not currently available to establish the prospective shale gas areas in the Carpathian-Balkanian Basin.

Figure VI-14. Carpathian-Balkanian Basin Map

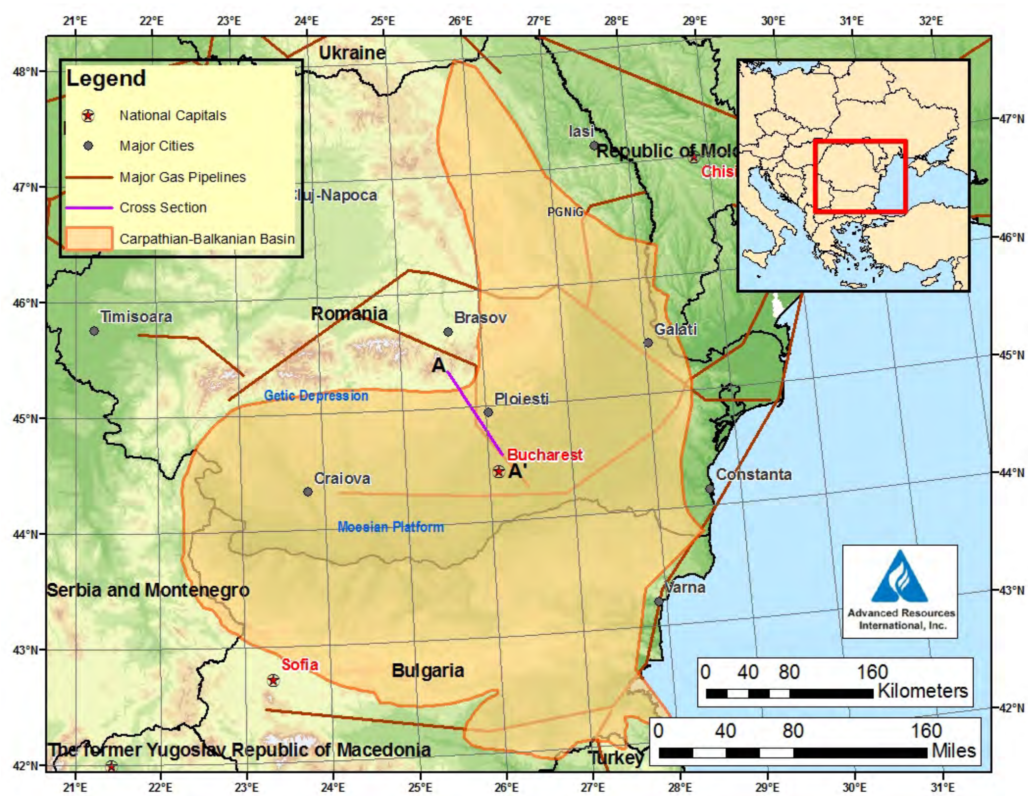


Figure VI-15. Carpathian-Balkanian Stratigraphic Column

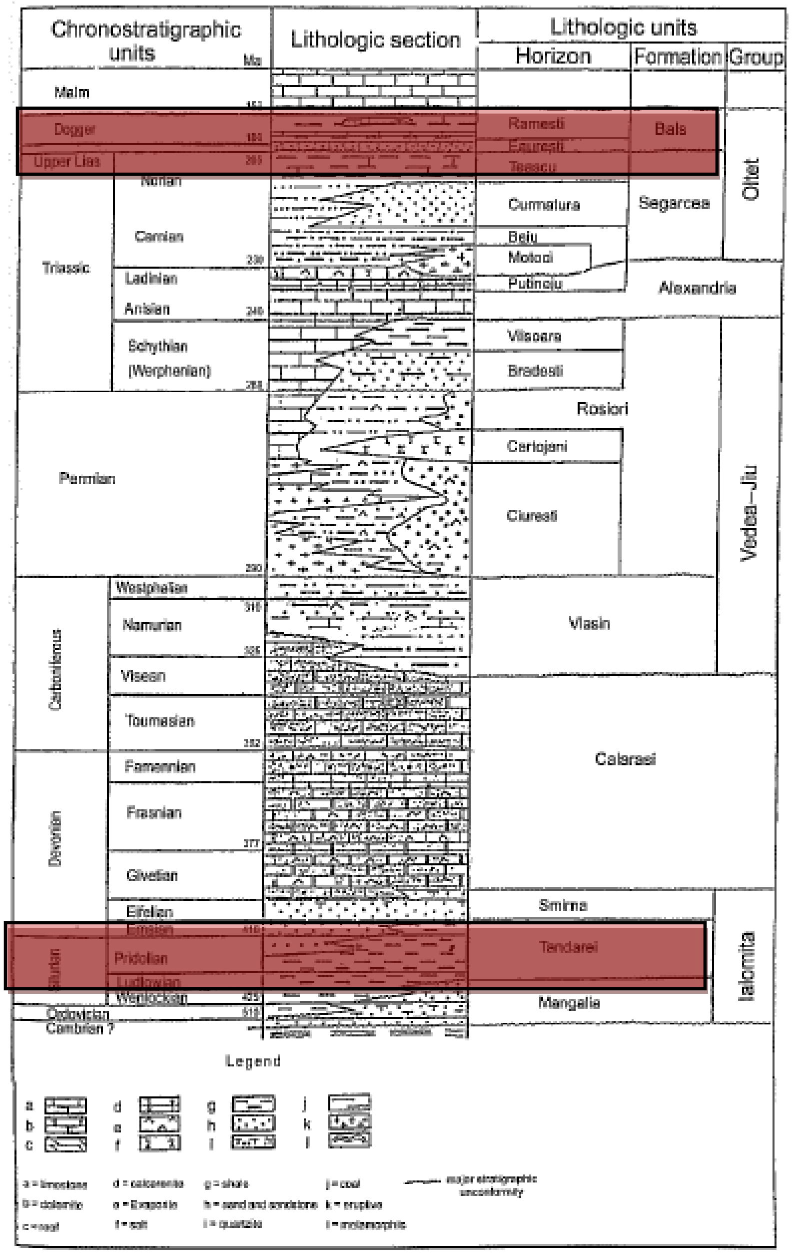


Figure VI-16. Carpathian-Balknian Basin Component Map[13]

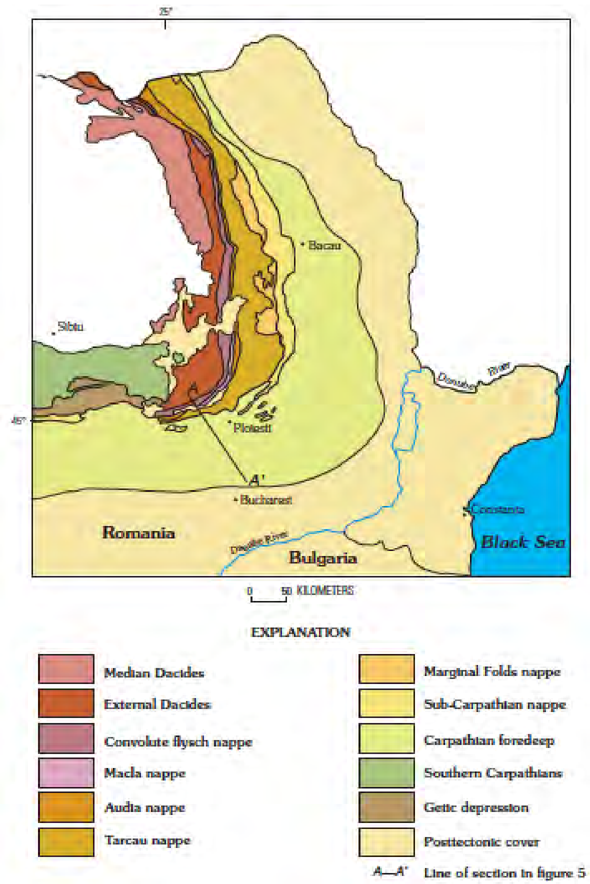
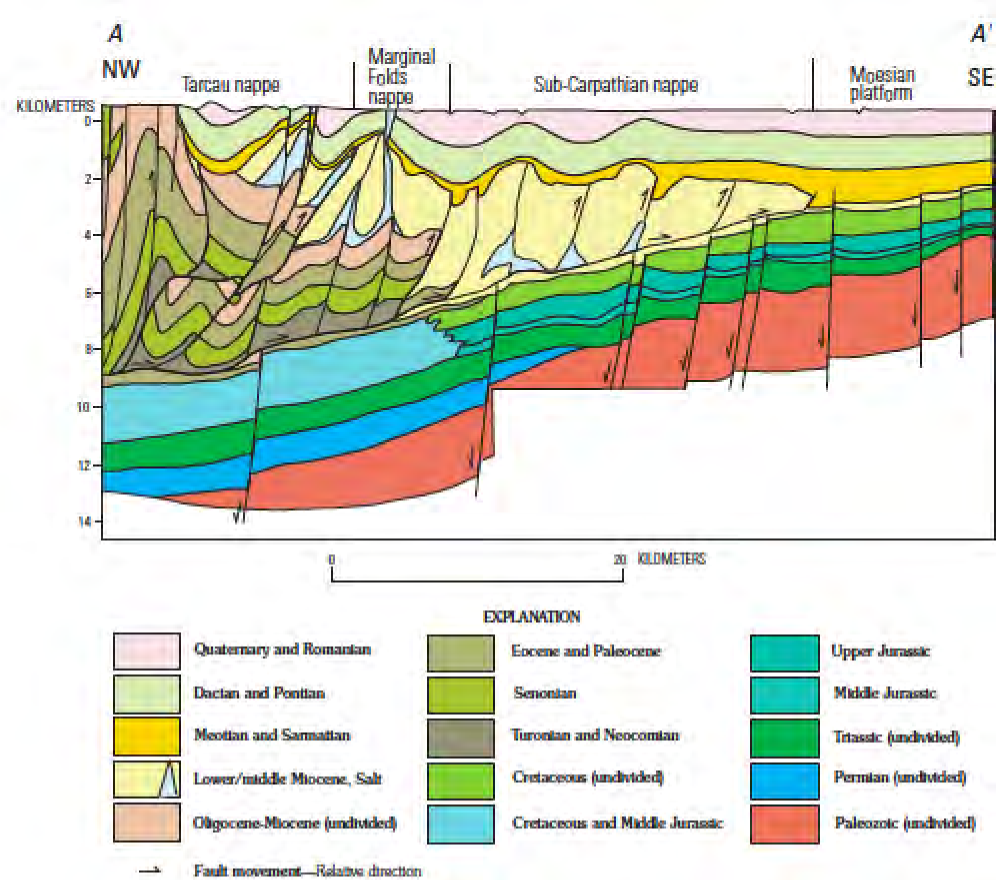


Figure VI-17. Carpathian-Balknian Basin Cross Section



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Activity

The shale gas potential of the Carpathian Balkanian Basin was first realized in 2008, when Direct Petroleum Exploration drilled through a gas-bearing shale formation while targeting the Alexandrovo sandstone interval. Several firms have since begun exploring the shale gas potential in Bulgaria, including Park Place Energy Group, Integrity Towers and U.S. super major Chevron[14].

In July 2010, Chevron reported that it secured three shale gas exploration blocks in the Romanian portion of the Carpathian-Balkanian Basin, totaling 675,000 acres. The company has not provided a timeline for exploration[15].

In an official statement after meeting with the Bulgarian government to petition for shale gas exploration rights, Chevron estimated that it could extract up to 8 Tcf of shale gas in the country[16]. Bulgaria's Energy and Economy ministry estimates that industrial production of shale gas could commence within 5 to 10 years[17].

LITHUANIA

Lithuania relies entirely on imports to satisfy its natural gas demand. In 2008, the country consumed 0.3 Bcfd of natural gas. We estimate that Lithuania has 17 Tcf of gas in-place (risked) in the prospective area of the Baltic Basin. Of this 17 Tcf, we estimate 4 Tcf could be ultimately technically recoverable.

RUSSIA (KALININGRAD OBLAST)

Russia has the world's largest natural gas proved reserves, estimated at 1,680 Tcf in 2009. It is also the world's largest natural gas exporter. Of the almost 60 Bcfd the country produced in 2009, it exported 17 Bcfd to Europe. With its large conventional natural gas resource base, Russia is unlikely to aggressively pursue shale gas reserves, though it likely is well endowed with these as well.

Within the portion of the Baltic Basin in Russia's Kaliningrad Oblast, we estimate a risked GIP of 76 Tcf. Of this 76 Tcf, we estimate 19 Tcf could be ultimately technically recoverable.

UKRAINE

Like most of Eastern Europe, Ukraine depends on Russian gas to meet its consumption needs. In 2008, the country consumed 7.8 Bcfd of natural gas, of which 1.9 Bcfd was produced domestically from 39 Tcf of proved reserves[18].

We estimate that Ukraine has 48 Tcf of gas in-place (risked) in the prospective area of the Dnieper-Donets Basin and 149 Tcf of gas in-place (risked) in the Lublin Basin. Of this 197 Tcf, we estimate 42 Tcf could be ultimately technically recoverable, representing a large increase in the country's current reserve base.

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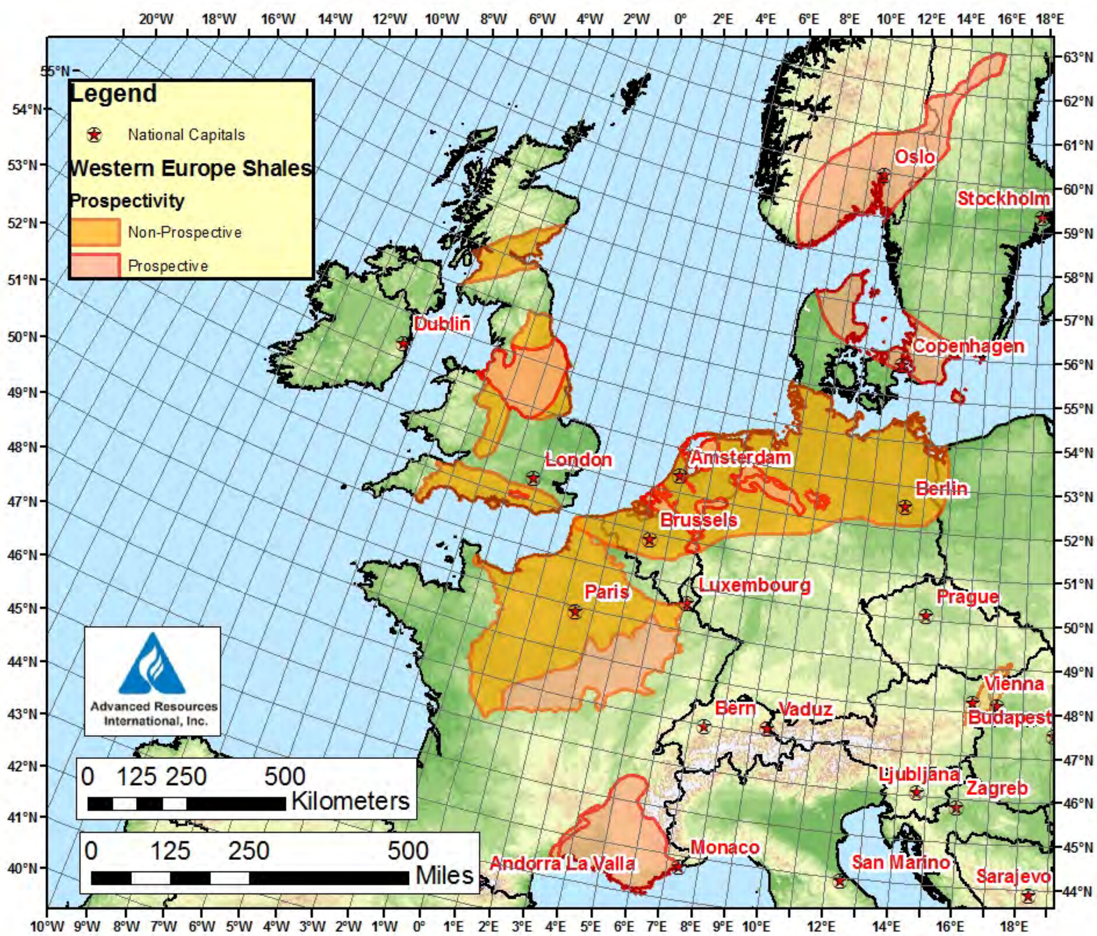
VII. WESTERN EUROPE

INTRODUCTION

The gas-bearing shales of Western Europe are being actively explored and evaluated by a host of small to large companies. Numerous shale gas basins exist in Western Europe, containing Carboniferous, Permian, Jurassic and Ordovician-age shales, Figure VII-1. Specifically, shale gas leasing is ongoing in France, Germany, the Netherlands, Sweden, Denmark and Austria (See Chapters VI and V for discussion of Eastern European and Poland shale gas).

Figure VII-1. Shale Gas Basins of Western Europe



We estimate a risked gas in-place for the Western European shales assessed by this study of 1,505 Tcf, of which 372 Tcf is estimated to be technically recoverable, Table VII-1. Because of its large area, the Scandinavian Alum Shale holds the largest shale gas resource. Shales of the Paris South-East France and North Sea-German basins exhibit favorable characteristics, but contain comparatively modest resource due to their moderate thickness and/or limited area.

Table VII-1. Shale Gas Reservoir Properties and Resources of Western Europe

			France Paris Basin (61,454 mi²)	France South-East Basin (17,800 mi²)		North Sea-German Basin (78,126 mi²)			Scandanivia Region (38,221 mi²)	U.K. Northern Petroleum System (22,431 mi²)	U.K. Southern Petroleum System (7,644 mi²)
Basic Data	Basin/Gross Area		France Paris Basin (61,454 mi²)	France South-East Basin (17,800 mi²)		North Sea-German Basin (78,126 mi²)			Scandanivia Region (38,221 mi²)	U.K. Northern Petroleum System (22,431 mi²)	U.K. Southern Petroleum System (7,644 mi²)
Basic Data	Shale Formation		Permian-Carboniferous	"Terres Noires"	Liassic Shales	Posidonia Shale	Namurian Shale	Wealden Shale	Alum Shale	Bowland Shale	Liassic Shales
Basic Data	Geologic Age		Permian Carboniferous	Upper Jurrasic	Lower Jurrasic	Jurassic	Carboniferous	Cretaceous	Ordovician	Carboniferous	Jurrasic
Physical Extent	Prospective Area (mi^2)		17,942	16,900	17,800	2,650	3,969	1,810	38,221	9,822	160
Physical Extent	Thickness (ft)	Interval	164 - 7,216	0 - 1,200	100 - 2,000	25 - 350	249 - 6,937	25 - 325	0 - 459	0 - 4,000	1,000 - 1,640
Physical Extent	Thickness (ft)	Organically Rich	382	333	525	148	407	112	328	492	415
Physical Extent	Thickness (ft)	Net	115	100	158	100	122	75	164	148	125
Physical Extent	Depth (ft)	Interval	8,528 - 13,120	3,280 - 6,560	8,200 - 16,400	3,280 - 16,400	8,200 - 16,400	3,280 - 9,840	-	3,280 - 6,300	11,500 - 15,500
Physical Extent	Depth (ft)	Average	10,824	4,920	12,300	9,840	12,300	6,560	3,280	4,800	13,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Overpressured	Normal	Normal	Normal	Normal
Reservoir Properties	Average TOC (wt. %)		4.0%	3.5%	2.5%	5.7%	3.5%	4.5%	10.0%	5.8%	2.4%
Reservoir Properties	Thermal Maturity (%Ro)		1.65%	1.25%	1.45%	1.50%	2.50%	1.25%	1.85%	1.40%	1.15%
Reservoir Properties	Clay Content		Medium	Low	Medium	Low/Medium	Medium	Medium	Low	Medium/High	Medium
Resource	GIP Concentration (Bcf/mi^2)		47	27	57	33	54	26	77	48	45
Resource	Risked GIP (Tcf)		303	112	305	26	64	9	589	95	2
Resource	Risked Recoverable (Tcf)		76	28	76	7	16	2	147	19	1

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PARIS BASIN

Geologic Characterization

The Paris Basin is a large 61,454 mi^2 intracratonic basin underlying most of North-Central France. The basin is bounded on the east by the Vosques mountain range, on the south by the Central Massif, on the west by the Armorican Massif and, for the purposes of this study, by the English Channel on the north.

The Paris Basin contains two organically rich shale source rocks: the Toarcian "Schistes Carton" black shale formation and the Permian-Carboniferous shales. The lower thermal maturity "Schistes Carton" shales are the source rock for most of the oil produced in the Paris Basin. These shale source rocks have high organic content, ranging from 1% to 10% throughout the basin. With thermal maturity ranging between 0.5 to 0.9% Ro, the "Schistes Carton" shales are still in the oil window and immature with respect to shale gas potential. A number of firms, such as Toreador Resources, are investigating the shale oil potential of the Liassic interval in the Paris Basin[1].

The deeper, more mature Permian-Carboniferous shales are less explored, but have promising characteristics for shale gas development. These strata were formed by continental deposits in the rift basins formed after the Hercynian orogeny and subsequent subsidence of the basin's granite basement. Based on available data, we have mapped a 17,942 mi^2 prospective area for the shales in the Paris Basin, Figure VII-2. The Northern boundary of the prospective area follows the 50 meter gross shale isopach line, its southern and eastern border is formed by the basin edge.

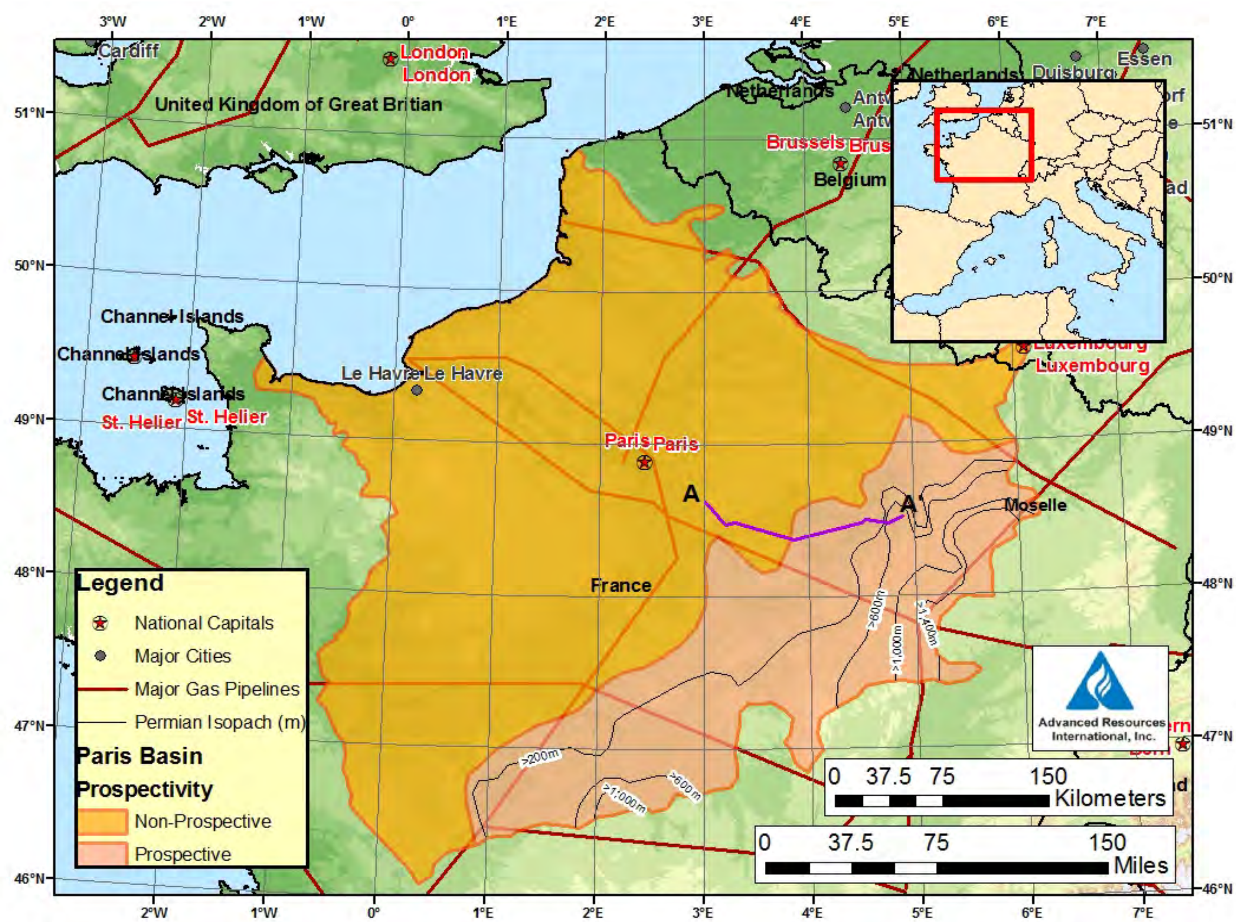
Reservoir Properties (Prospective Area)

Permian-Carboniferous Shales. As shown in Figure VII-3, the Permian-Carboniferous shales referred to in this report encompass a series of horizons ranging from the Pennsylvanian (Carboniferous) to late Permian. Detailed geologic data on these shale formations is scarce. Where information was lacking, we used data from regional analogue basins.

The Permian-Carboniferous shales range from 8,500 feet to 13,100 feet deep, averaging 10,824 feet deep over the prospective area. The shales thicken to the east, ranging from 160 feet thick in the central Paris Basin to over 7,200 feet in isolated sections of the basin's eastern margin, Figure VII-4. Average shale interval thickness in the prospective area is assumed to be

1,150 feet. Due to a lack of well log or other net shale thickness data, we assume one-third of the formation interval is organically rich, and apply a 30% net to gross factor, consistent with similar age shales in Poland, to reach an organically rich net shale thickness of 115 feet. Data on total organic content (TOC) in the prospective area was not available, so TOC data from the Dniper-Donets Basin, an analogue of similar age and depositional environment was used. Assumed TOC values range from 2% to 6% with an average of 4%. The Permian-Carboniferous shales are in the gas window, with Ro ranging from 1.3% to over 2% across the prospective area[2].

Figure VII-2. Prospective Area and Gross Isopach of Permian Carboniferous Shales, Paris Basin



Resources

Our analysis suggests the Permian-Carboniferous shales of the Paris Basin contain a moderate resource concentration of 47 Bcf/mi^2. Risked gas in-place for the Paris Basin is 303 Tcf, The risked technically recoverable shale gas resource is estimated at 76 Tcf, Table VII-1.

Figure VII-3. East Paris Basin Stratigraphic Column

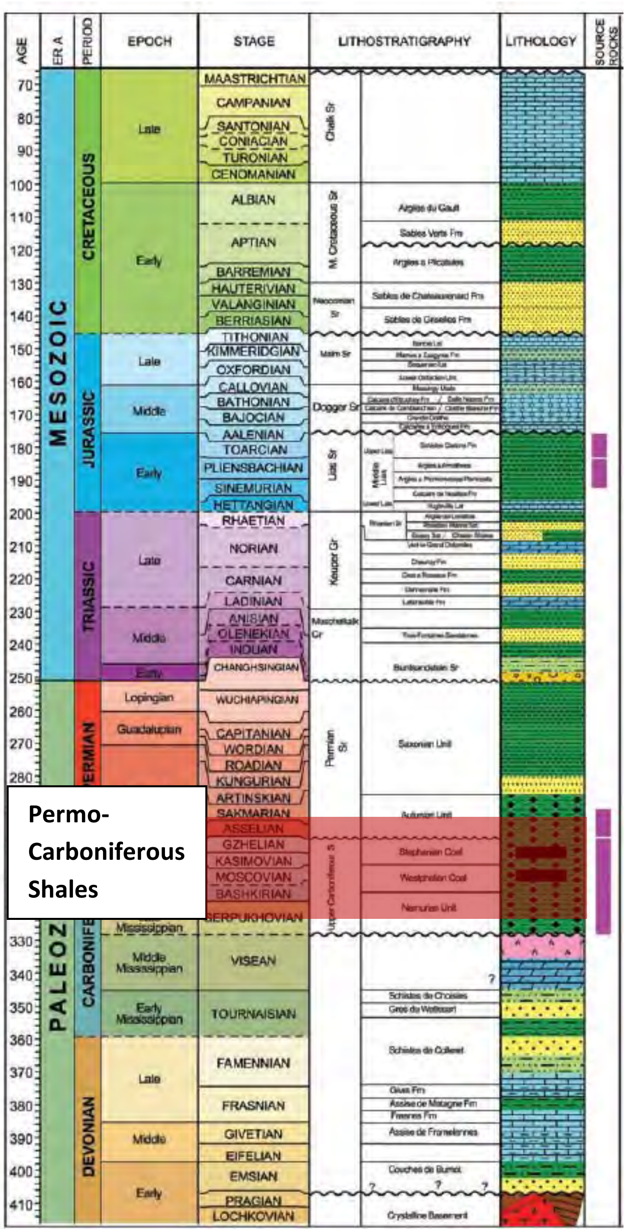
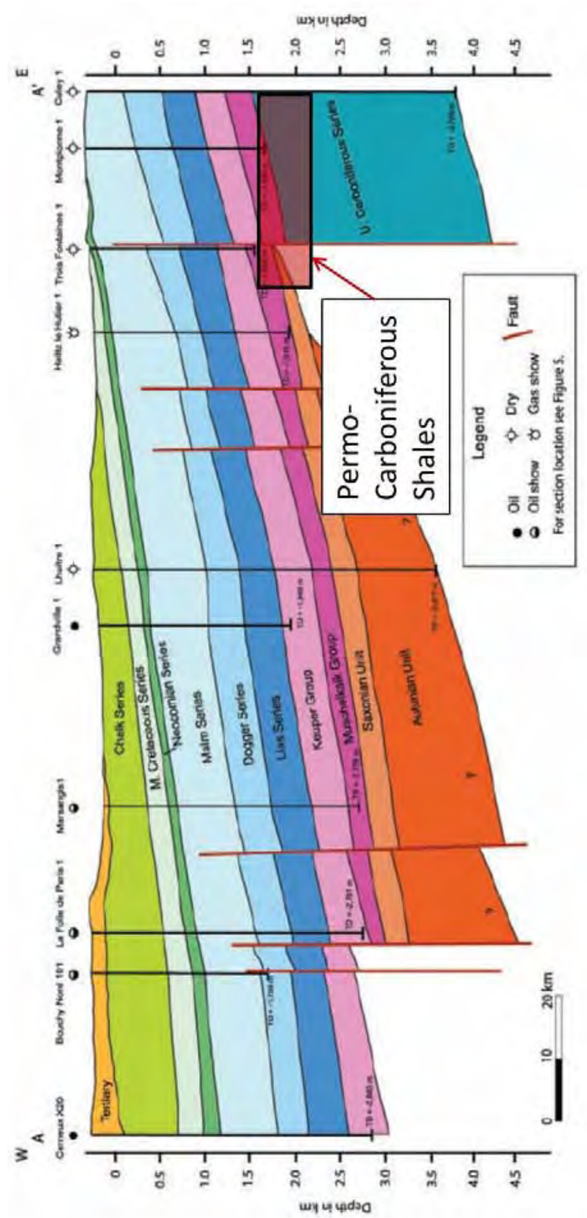


Figure VII-4. Paris Basin Cross Section:

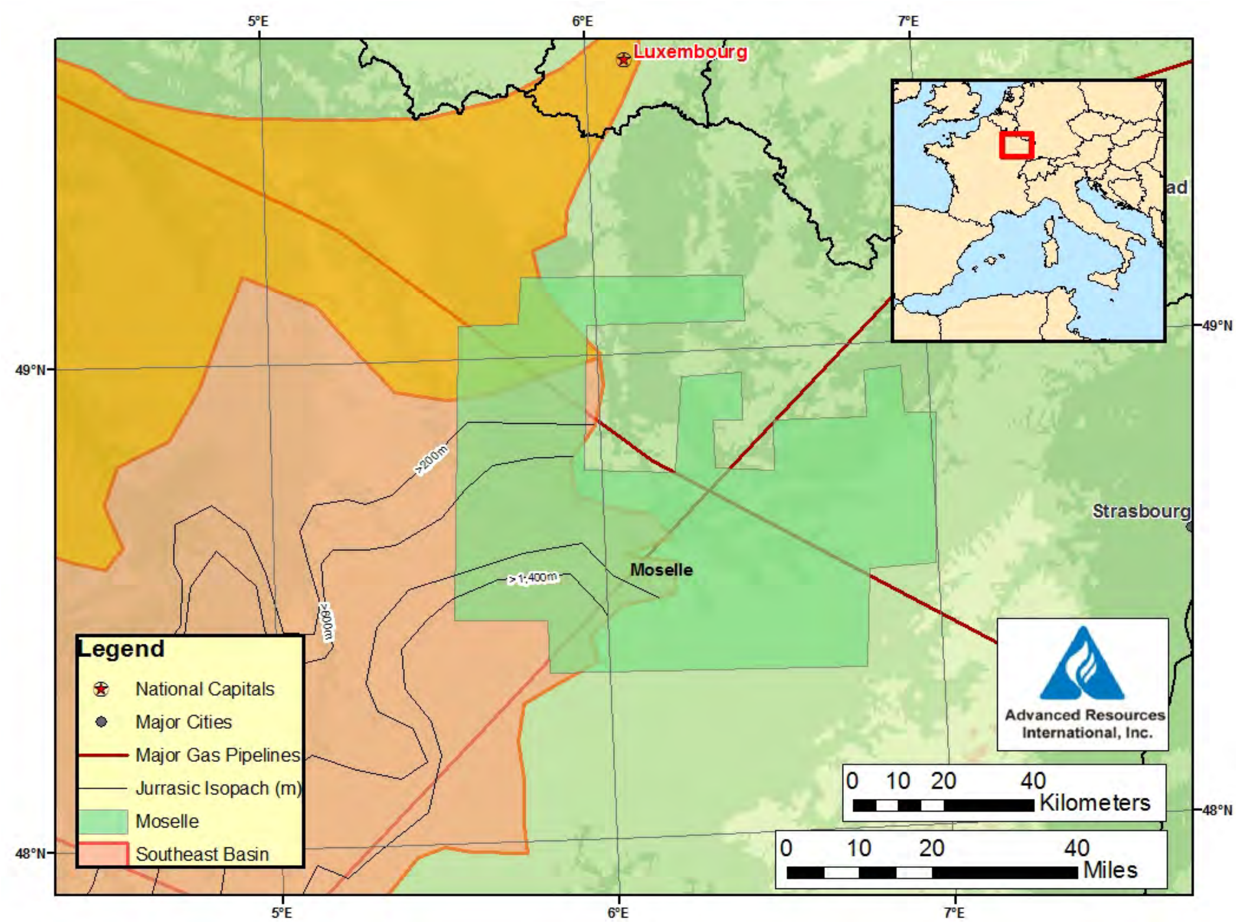


Activity

While most of the exploration activity in the Paris Basin is targeting the Liassic-age liquid shale oil plays in the center of the basin, some firms are beginning to acquire acreage in the eastern portions of the basin, where the Permian-Carboniferous shale gas formation is thickest.

The Moselle Permit (~$4 million dollars; 2,070 mi^2), first granted to East Paris Petroleum Development Corp, was acquired by Elixir Petroleum in February, Figure VII-5. While the terms of the lease do not require the company to drill any wells, Elixr has publically stated that it intends to investigate the unconventional gas potential (both CBM and shale gas) on its lease[3].

Figure VII-5. Moselle Permit, Paris Basin



SOUTHEAST BASIN

Geologic Characterization

The Southeast Basin is the thickest sedimentary basin in France, containing up to 10km of Mesozoic to Cenozoic sediments. The basin is bounded on the east and south by the Alpine thrust belt and on the west by the Massif Central, an uplifted section of the Paleozoic basement, Figure VII-6.

Local oil and gas seeps discovered in the 1940's encouraged hydrocarbon exploration early in the basin. However, despite the drilling of 150 wells in the onshore and offshore portions of the basin, no significant oil and gas deposits have been found. Recent re-evaluations of the basin's potential by the French research institute IFP and others have peaked interest once again. The deep Jurassic shales and marls present over much of the basin area appear to have favorable characteristics for oil and gas source rocks. Some limited leasing is ongoing to test this potential.

This study will focus on the shale gas potential of two formations in the Southeast Basin, the Upper Jurassic "Terres Niores" black shales, and the Lower Jurassic Liassic black shales. These shales are composed of Type II marine organic matter, and were deposited during a time of subsidence and rifting, when the "Liguro-Piemontais" ocean covered portions of what is now southern France[4]. These formations have been evaluated and mapped to establish their respective prospective areas. The Lower Jurassic shale sequence is prospective throughout the basin, while well data suggests the Upper Jurassic shales enter the oil window on their western boundary. ARI calculates a 16,900 mi^2 prospective area for the Upper Jurassic shale sequence[5].

Reservoir Properties (Prospective Area)

Upper Jurassic "Terres Niores". The "Terres Niores" black shales are marine shales deposited throughout the Southeast Basin. They range from 3,300 feet to 6,600 feet deep over the basin, averaging 4,900 feet, Figure VII-7. The gross interval of the shale reaches 1,200 feet, containing 333 feet of organically rich gross shale and 100 feet of net shale4, Figure VII-8. Total organic content (TOC) in the prospective area ranges from 1% to 3% with an average of 2%. In the eastern portions of the basin, the "Terres Niores" shale is in the gas window, with Ro of 1.5%. At the western edges, the shale enters the wet gas/oil window, with Ro of 1%. Average vitrinite reflectance (Ro) over the prospective area is 1.25% Ro5.

Lower Jurassic Liassic Shale. The Liassic Shale of the Southeast Basin is deeper, thicker and generally more mature than the "Terres Niores" Shale, though it has a higher clay content and is not as brittle. Uplifting along the western margin of the Southeast Basin has brought the Liassic Shale to a more reasonable depth for exploration. Depth to the Liassic Shale package ranges from 3,300 feet to 16,300 feet deep over the basin, with most of the prospective area at an average depth of 9,800 feet. Figure VII-8. The gross interval of the shale ranges from 100 to 2,000 feet with 525 feet of organically rich and 160 feet of net shale. Total organic content (TOC) in the prospective area ranges from 1% to 6% with an average of 3.5%. Thermal maturity in the Liassic Shale increases with depth, ranging from 1.2% Ro in the more shallow western areas to over 1.7% Ro in the deep eastern area. Average vitrinite reflectance (Ro) over the prospective area is 1.45%.

Figure VII-6. Southeast Basin Prospective Area and Upper Jurassic Shale Isopach

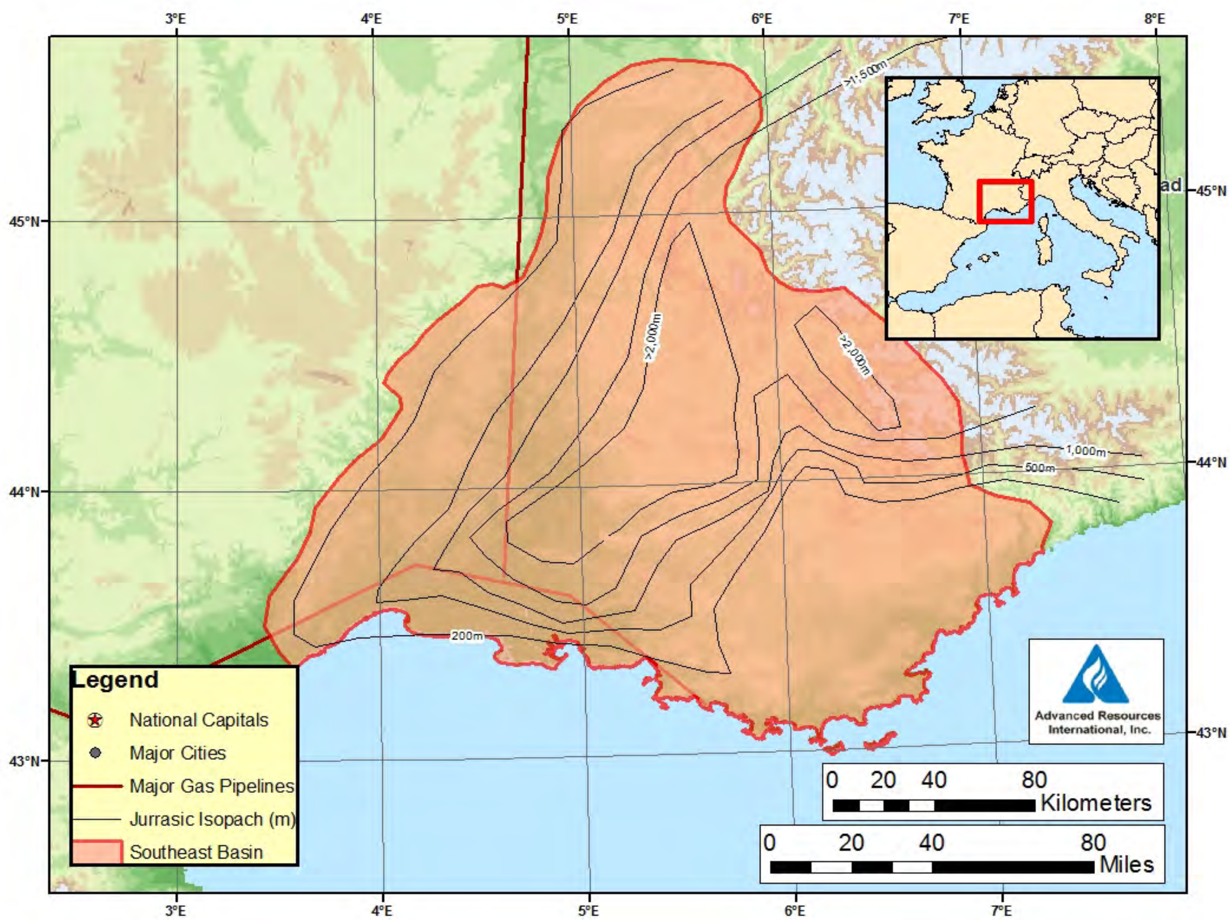


Figure VII-7. Southeast Basin Stratigraphic Column

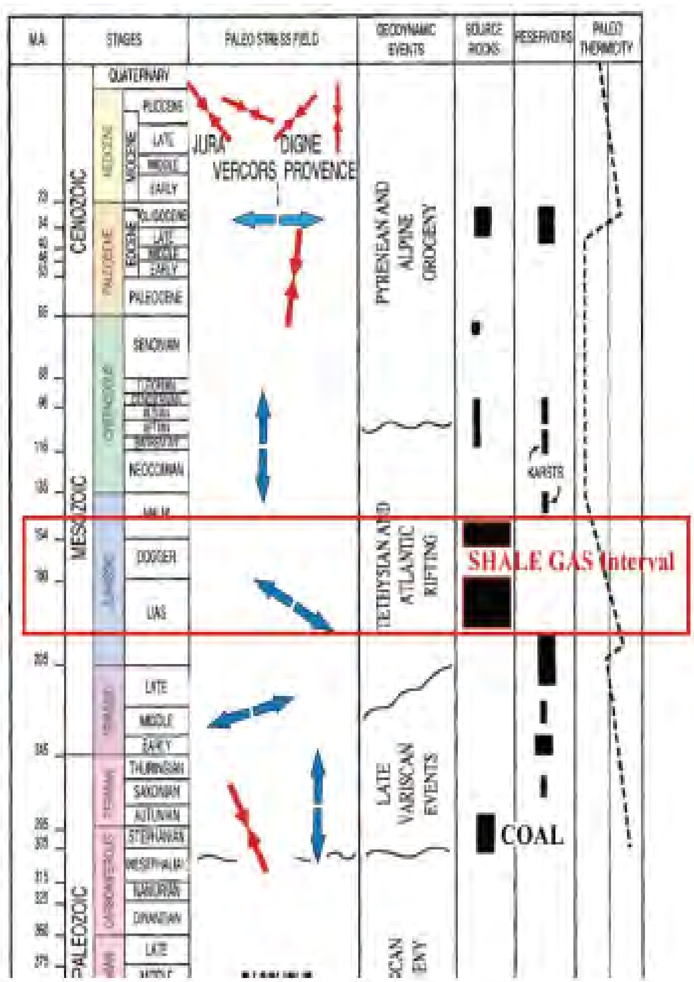
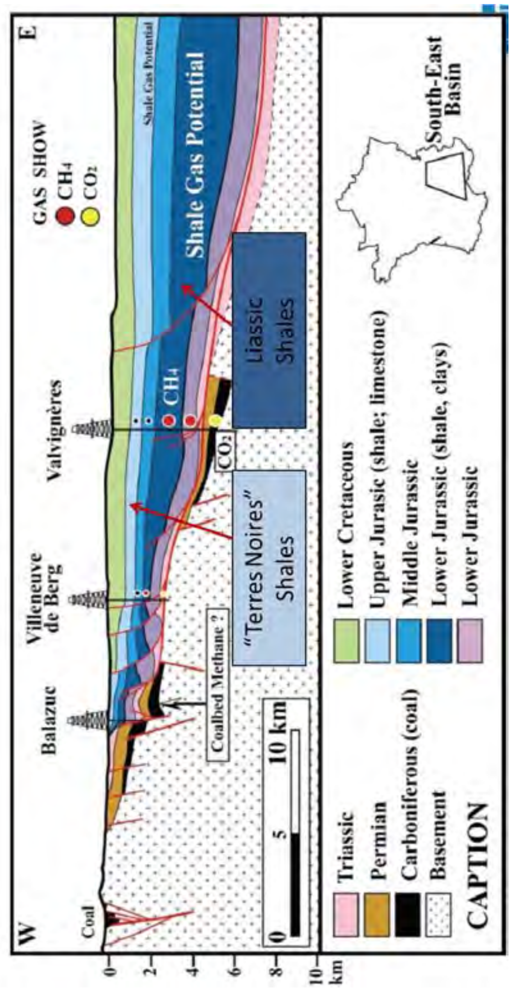


Figure VII-8. Generalized Southeast Basin Cross Section



Resources

Our analysis suggests the Upper Jurassic “Terres Niores” Shale of the Southeast Basin contains a relatively low resource concentration of 27 Bcf/mi^2, Table VII-1. Low average TOC content and relatively thin net shale thickness are the main determinants of this low resource concentration. Isolated areas throughout the basin with higher shale thickness or more organic richness would contain higher gas in-place. The risked gas in-place for the “Terres Niores” Shale is 112 Tcf, of which we estimate 28 Tcf will be technically recoverable.

The Upper Liassic Shale contains a slightly higher, though still moderate, resource concentration than the “Terres Niores” shales, averaging 57 Bcf/mi^2, Table VII-1. Risked shale gas in-place over the prospective area is 305 Tcf, of which 76 Tcf is technically recoverable.

Activity

A number of firms are beginning to explore the shale gas potential of the Southeast Basin; the initial permit award deadline was delayed due to the large numbers of applications. In March of this year, the French Ministry of Energy and the Environment awarded several exploration permits, worth over $115 million and covering over 4,000 mi^2 (~22% of the prospective area), to companies interested in investing in the drilling and exploration of shale formations in Southeast France. Where information was available, the leases are shown on Figure VII-9.

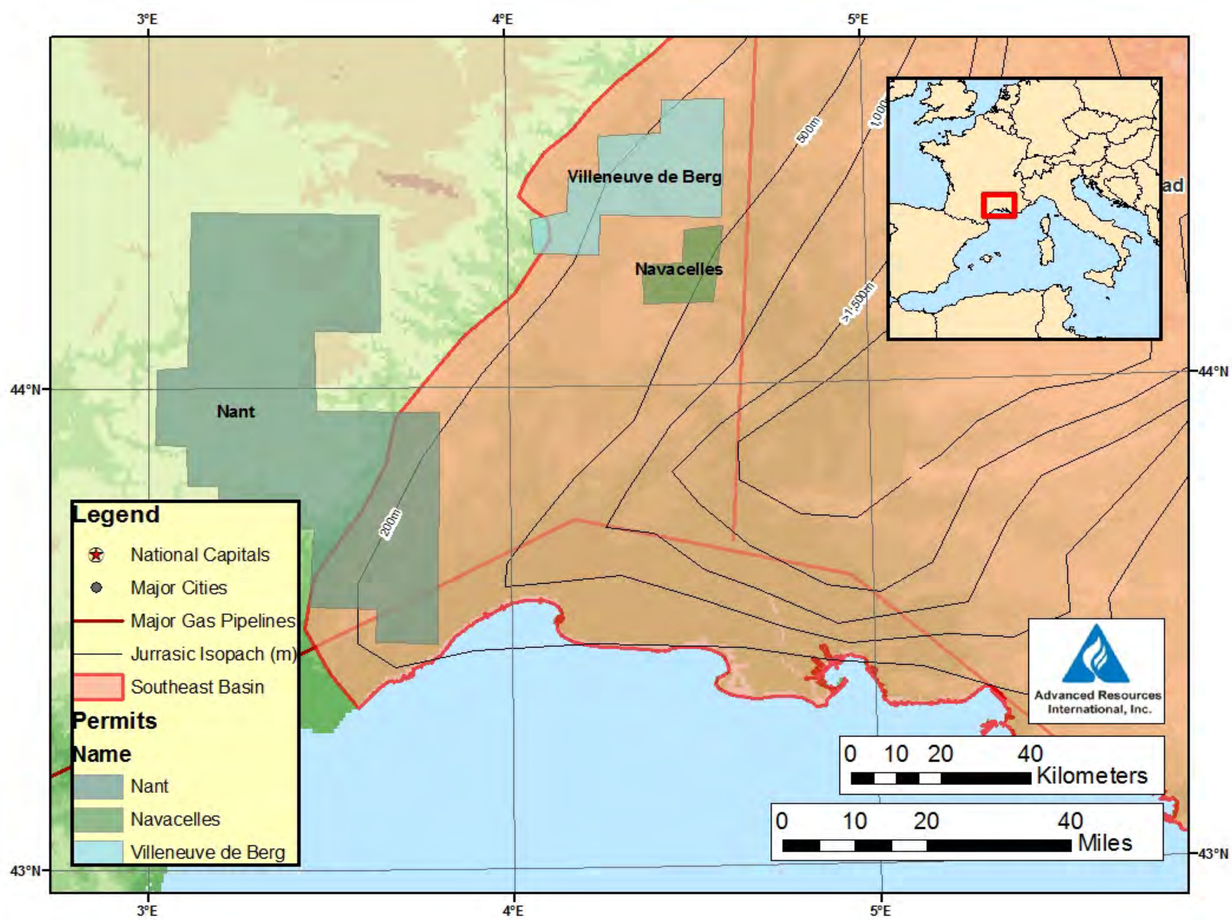
- **The Navacelle permit** (~ $5 Million dollars; 84 mi^2) was awarded to Egdon resources (later acquired by eCORP), Eagle Energy and YCI Energy to allow for seismic surveys and an exploration well over the next 5 years.
- **The Plaine d’Ales permit** (~$2 million dollars; 194 mi^2) was awarded to Bridgeoil Ltd and Diamoco Energy to perform seismic reprocessing and drill a new exploration well or reenter a 1949 well with heavy crude shows.
- **The Montelimar permit** (~$51 million dollars; 1,670 mi^2) was awarded to Total E&P and Devon energy (Devon’s stake was subsequently bought by Total) to perform geological and geochemical studies and, if warranted, exploratory drilling over 5 years.

- **The Villeneuve-de-Berg permit** (~$54 million dollars; 360 mi^2) was awarded to Schuepbach Energy LLC, Dallas, Dale Gas Partners LP of Texas, and Franco-Belgian GDF Suez. The companies agreed to perform 19 miles of new seismic surveys and drill two wells, one of which would hydraulically fracture the target shale formation, over the next 3 years.

- **The Nant permit** (~$2.3 million dollars; 1,701 mi^2) was awarded to these same companies, on which they will also perform 19 miles of seismic surveys and drill a shallow exploration well over the next 3 years.

- **The Bassin d'Ales permit** (~$1.4 million dollars) was awarded to Mouvoil SA to perform seismic studies and drill an exploration well.

Figure VII-9. Southeast Basin Leasing Map (Selected)



NORTH SEA-GERMAN BASIN

Geologic Characterization

For this report, we have defined the North Sea-German Basin as the large, 78,100 mi^2 area of Paleozoic through Tertiary fill, extending from Belgium to Germany's eastern border, from the North Sea to the Tornquist suture zone, Figure VII-10. A number of smaller, localized basins, such as the German Lower Saxony, Musterland and the West Netherlands basins exist as grabens within the more regional North Sea-German Basin.

Several formations in the North Sea-German Basin show potential for shale gas development. The three best identified formations are the marine Lower Jurassic "Posidonia" Shale, the deltaic Lower Cretaceous "Wealden" Shale and the marine Carboniferous Namurian Shale in the northwest of Germany and parts of the Netherlands. Each of these formations have been previously noted to be oil and gas source rocks, though their potential for shale gas development had not been realized until the past few years. Conventional drilling in areas of Germany and the Netherlands has provided logs and other geophysical data used to identify the prospective areas of these three shales, but there is still uncertainty, especially in the Netherlands, about the quality and producibility of these shale formations.

Additionally, the lacustrine Permian shales in northeast and southern Germany (not evaluated in this study) appear to have some shale gas potential.[6,7] Based on available data, we have identified a 2,650 mi^2 prospective area of Posidonia Shale in Germany and the Netherlands, a 3,969 mi^2 prospective area of Namurian Shale in the Netherlands, and a 1,810 mi^2 prospective area of the Wealden Shale in Germany. At this time prospective areas for the Namurian and Permian shales in Germany could not be established.

Reservoir Properties (Prospective Areas)

Lower Jurassic (Liassic) Posidonia Shale. The Lower Jurassic shale sequence referred to in the report as the Posidonia Shale actually contains three shale bearing members: The Posidonia Formation, the Aalburg Formation and the Sleen Formation. Though it is likely present throughout much of the North Sea-German Basin, the Posidonia Shale is prospective in isolated sections of Germany and the Netherlands, Figure VII-10. The Netherlands prospective area is based on reports released by energy company TNO, which used depth, maturity, thickness and other factors to identify highly prospective regions for shale gas development[8].

Depth to the Posidonia Shale ranges from 3,300 feet to 16,400 feet, with an average depth in the prospective area of 9,840 feet, Figure VII-11.[9] The prospective area is relatively thin, with an organically rich thickness of 148 feet and a net shale thickness of 100 feet. Organic content varies in the Posidonia Shale, ranging from 1% to 14% with an average of 5.7%. Thermal maturity is the major liming factor for shale gas potential in this formation; the majority of its area is outside of the gas generating window. The central, deeper areas of known accumulations of Posidonia Shale exhibit sufficient maturity, Figure VII-12, with Ro ranging from 1.0% to 1.5%, placing the shale in the wet to dry gas window.[10] Porosity data from the Netherlands suggests that much of the available pore space in the shale is water saturated.

Cretaceous Wealden Shale. The Wealden Shale is a known source rock in the Lower Saxony Graben of the North Sea-German Basin. Like the Posidonia Shale, it is immature with respect for gas generation throughout most of its area, but is prospective in its deeper core areas. The prospective area was defined by the erosional edge of the shale within the German Lower Saxony Graben at depths below 3,300 feet.

In this area, the Wealden Shale ranges from 3,300 feet to 9,840 feet, averaging 6,560 feet deep. Approximately 112 feet of the shale is organically rich, with 75 feet of net shale thickness[11]. TOC in the Wealden Shale is highly variable, ranging from 1% to 15%, averaging 4.5% in the prospective area. Thermal maturity is somewhat low for a shale gas target, ranging from 1% to 1.5% Ro, with an average Ro of 1.25%.

Carboniferious Namurian Shale. The Namurian sequence in the Netherlands contains two prospective formations, the Epen and Geverik, which are collectively termed the Namurian Shales in this report. Data provided in the TNO report discussed above were used to establish areas with prospective depth, maturity and thickness for shale gas potential.

Depth to the top of the Namurian Shales ranges from 8,400 feet to 16,400 feet, averaging 12,300 feet over the prospective area. Because the shale formation is so deep, it is very thermally mature, with an average Ro of 2.5%.8 Within the Namurian Shale package, the Epen Formation is very thick, reaching almost 7,000 feet in some areas. Organic rich shale thickness in the formation is approximately 407 feet, evenly split between the Geverik and Epen Formations[12]. Net shale thickness is assumed to be 122 feet, based on analogue net to gross ratios observed in British Namurian Shales. Total organic content ranges from 1% to 15%, averaging 3.5%.

Figure VII-10. North Sea-German Basin Prospective Shale Formations

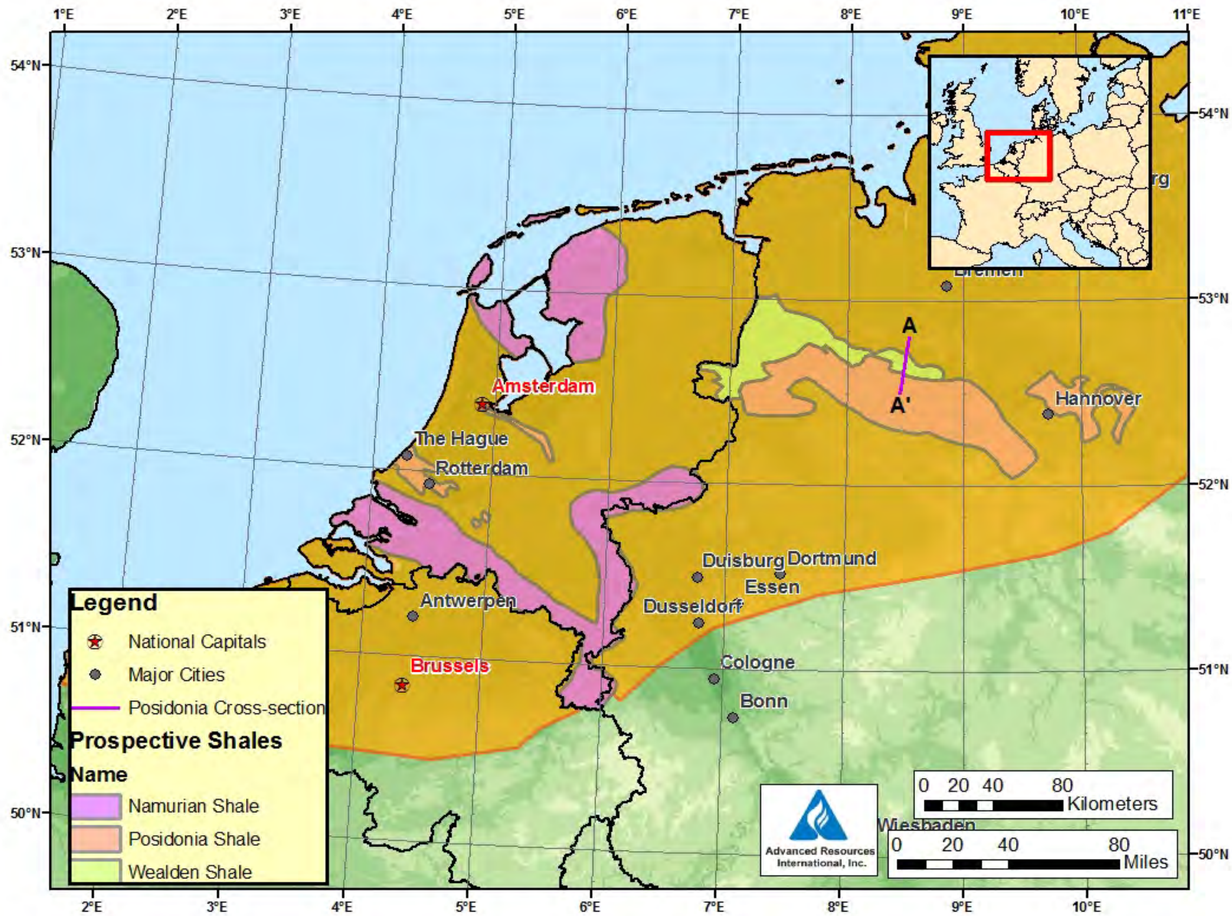


Figure VII-11. North Sea-German Basin Stratigraphic Column9

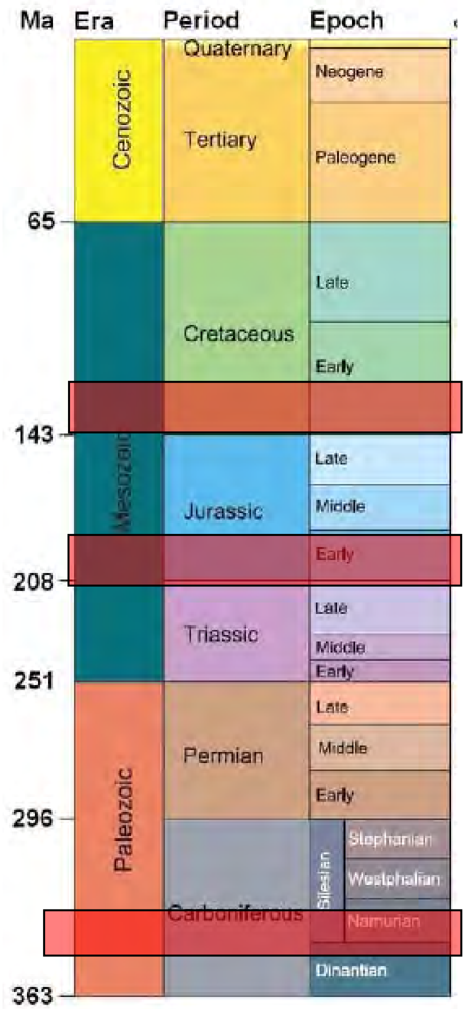
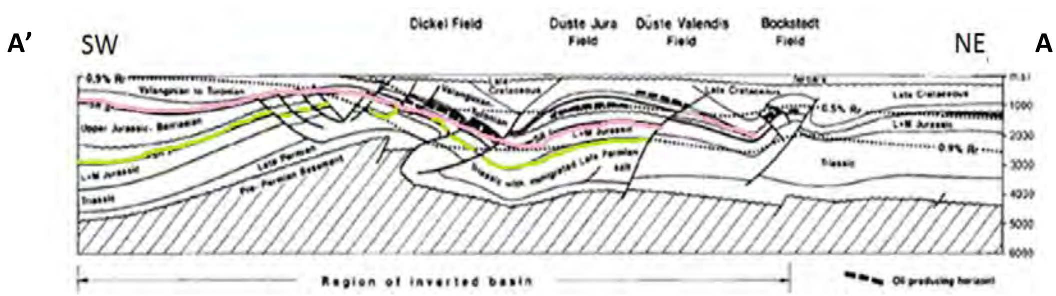


Figure VII-12. North Sea-German Basin Cross Section



Green line: Posidonia Shale; Pink line: Wealden shale

Resources

Based on the above data, we calculate that the prospective area of the Posidonia Shale contains a low resource concentration of 33 Bcf/mi^2, largely due to the shale's relatively low gas filled porosity, Table VII-1. Based on a prospective area of 2,650 mi^2, the Posidonia Shale contains 26 Tcf of risked gas in-place, with 7 Tcf of technically recoverable shale gas resource.

The 3,970 mi^2 prospective area of the Namurian Shale in the Netherlands contains a resource concentration of 54 Bcf/mi^2. Risked gas in-place is 64 Tcf, with 16 Tcf recoverable.

The less mature and shallower Wealden Shale in Germany also has a low average resource concentration, calculated at 26 Bcf/mi^2, Table VII-1. Based on a prospective area of 1,845 mi^2, we estimate a risked gas in-place of 9 Tcf, with 2 Tcf technically recoverable.

Activity

Super major Exxon Mobil has been the lead company leasing prospective shale gas acreage in Germany. The company has drilled five test wells on its exploration leases, at least three of which are reported to be testing shale gas potential, Figure VII-18. In early November, Exxon announced an additional 10 well exploration program that will be targeting shale gas potential in northwest Germany.

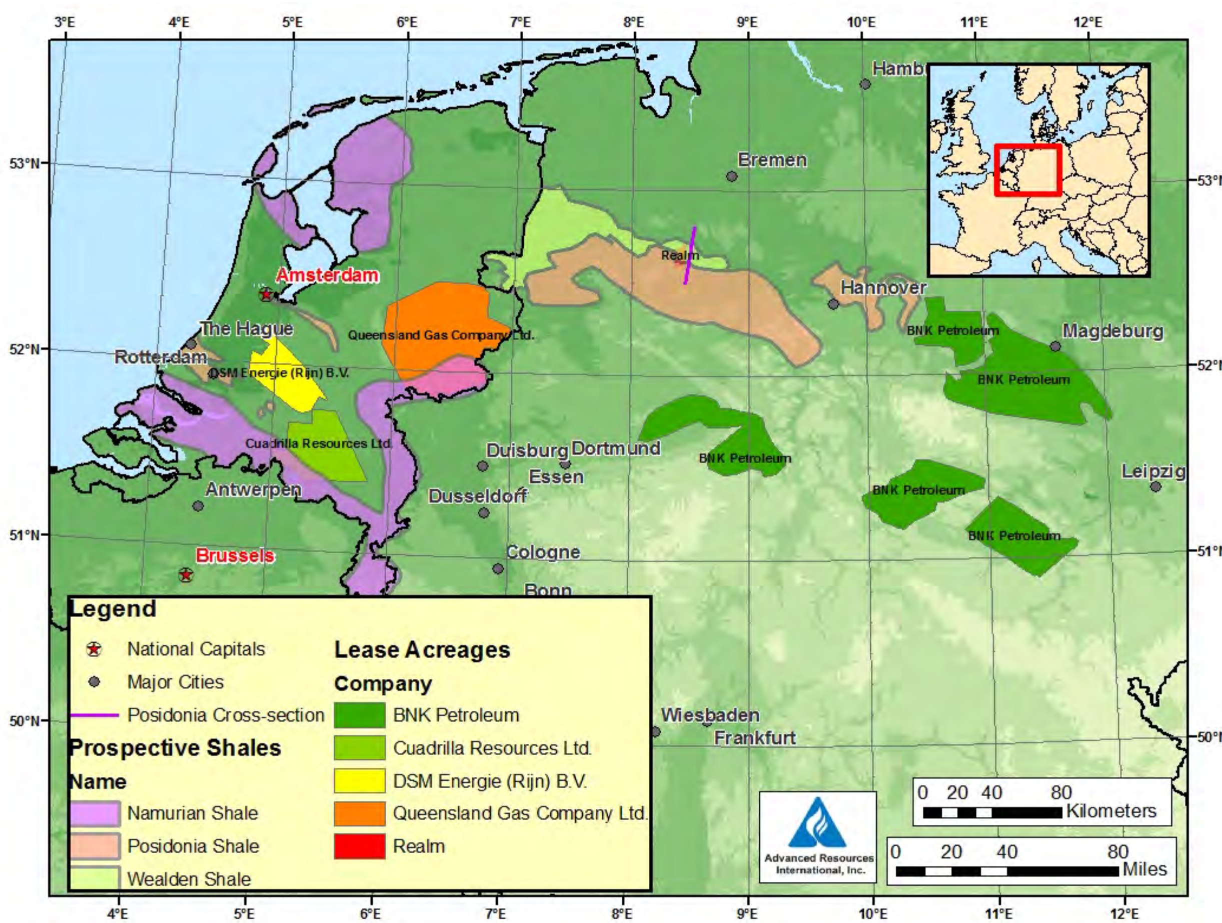
In May 2010, Realm Energy announced the receipt of a small, 25 mi^2 shale gas exploration permit in West Germany. The company plans to explore the oil and gas potential in the Posidonia and Weald shales underneath its acreage. Realm's concession is valid for three years and does not require well drilling, but does provide the company with data from the 21 wells drilled on its acreage in past years.

BNK Petroleum has leased approximately 3,745 square miles of land for shale, CBM and tight gas sand exploration in West and Central Germany. The company has yet to drill on any of its properties, but reports targeting "three different shale formations," most likely the Posidonia, Wealden and Permian shales. Most of its concessions are not near areas with recognized shale gas potential, suggesting the company is pursuing a wildcatting approach in Germany, Figure VII-13. To date, the company has not provided details of drilling plans.

In June 2009, 3Legs Resources secured a 980 mi^2 exploration permit for shale gas exploration in Permian-Carboniferous horizons. The permit is valid for 3 years and requires 2D and 3D seismic testing and the drilling of one exploration well. The company has not provided addition information at this time.

In the Netherlands, two companies have acquired exploration permits that are likely targeted toward shale gas exploration, Figure VII-13: Cuadrilla Resources, and DSM Energie (later sold to TAQA, the Abu Dhabi national energy company). Neither company has made public statements about their plans in the Netherlands. Queensland Gas Company (now BG Group) has a sizable exploration acreage position in east Netherlands, at the border with Germany in an area which may hold shale gas and CBM potential.

Figure VII-13. North Sea-German Basin Leasing Activity



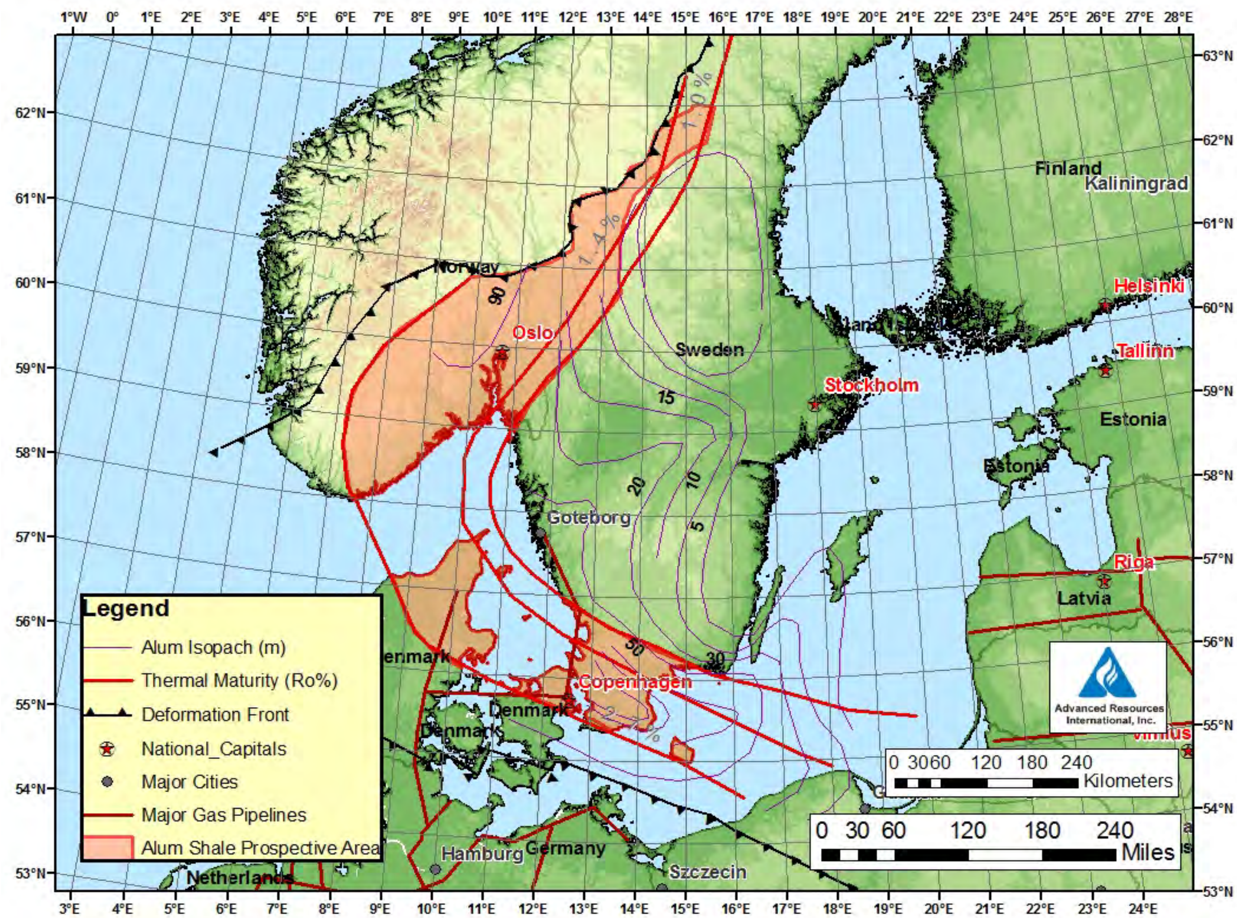
SCANDINAVIA

Geologic Characterization

Scandinavia's shale gas potential exists predominantly in the Cambrian-Ordovician Alum Shale. This highly organic rich shale was deposited over much of Scandinavia by the Lapetus Ocean and has been identified from Norway to Estonia, and south to Germany and Poland. The shale was deposited during an unusually long anoxic period, resulting in its high organic content and unusually high concentrations of uranium. The Alum shale outcrops in central and southern Sweden, where it has been mined as a source of oil shale for many decades.

Outside of outcroppings, geologic data on the Alum Shale is scarce. Though the shale is somewhat thin and outside of the gas window in most of the area, its high organic content and moderate depth make it a very promising target where prospective. ARI has identified a 38,221 mi^2 prospective area where maturity data indicate the shale is inside the gas window, Figure VII-14. Thermal activity along the Caledonian deformation front provided sufficient heat to mature the shale into the gas window. Elsewhere the Alum Shale appears to be mostly oil-prone. In northern Norway, the prospective area is further constrained by shale thickness and the Caledonian deformation front, which likely represents an erosional edge to the Alum shale. Note that, because of the Alum shale's wide areal coverage, only the prospective area is shown in Figure VII-14.

Figure VII-14. Alum Shale Geographic Extent



Reservoir Properties (Prospective Area)

Regional data on the Alum Shale is sparse. Where data was not available for the prospective area of the Alum shale in the Northern of Sweden, we used data from the Skane area at the southern tip of the country as an analogue.

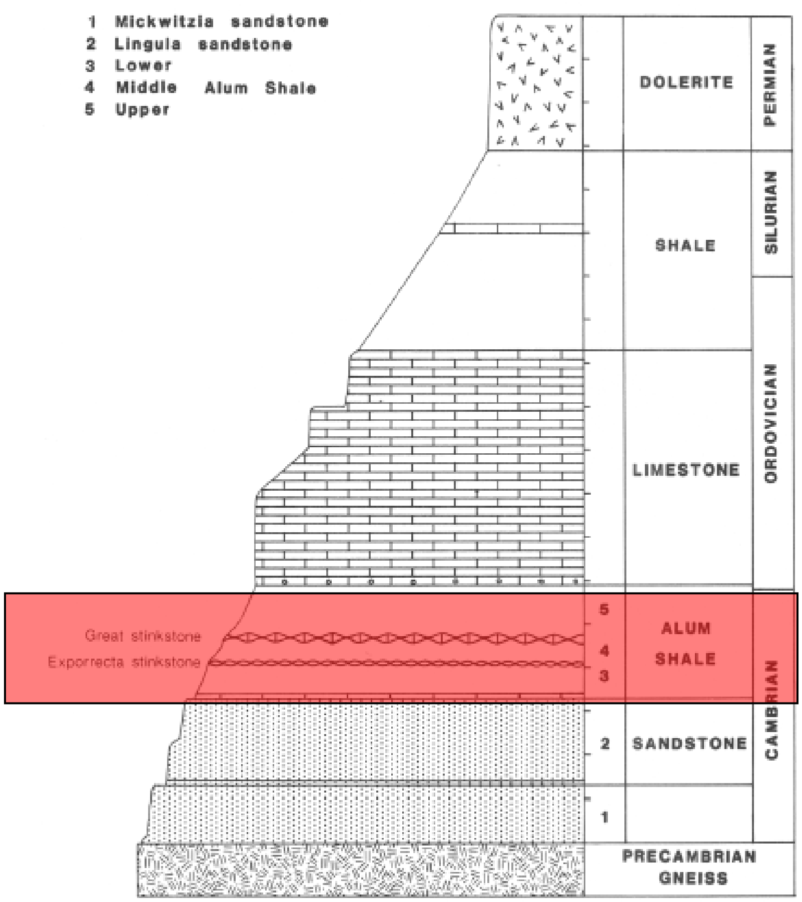
The area of the Alum Shale inside the gas window is shown in Figure VII-14. Thermal maturity in the gas window ranges from 1.0% to 2.7% Ro% with an average Ro of 1.9%[13]. Average thickness inside the prospective area is 330 feet with a net shale thickness of 160 feet[14]. Depth to the Alum Shale Formation is assumed to be 3,300 feet, based on the exploration well Shell reported drilling into its acreage in Southern Sweden, which reached a target depth of 1,000 meters (3,300 feet).

A generalized stratigraphic column for the Alum Shale is provided in Figure VII-15. Total organic content of the shale can reach up to 28% in localized areas, but averages 10% within the prospective area.

Resources

We calculate a moderate resource concentration of 77 Bcf/mi^2 for the Alum Shale. Though it has very favorable maturity and organic content, it is not as thick as the Baltic or Lublin shales of Poland, resulting in a lower resource concentration. Due to the relative lack of data on reservoir characteristics in large portions of the Alum shale prospective area, we employ high risk factors to calculate the risked recoverable resource. Within the Alum Shale's 38,221 mi^2 prospective area, we calculate a risked gas in-place volume of 589 Tcf, of which 147 Tcf is estimated to be technically recoverable.

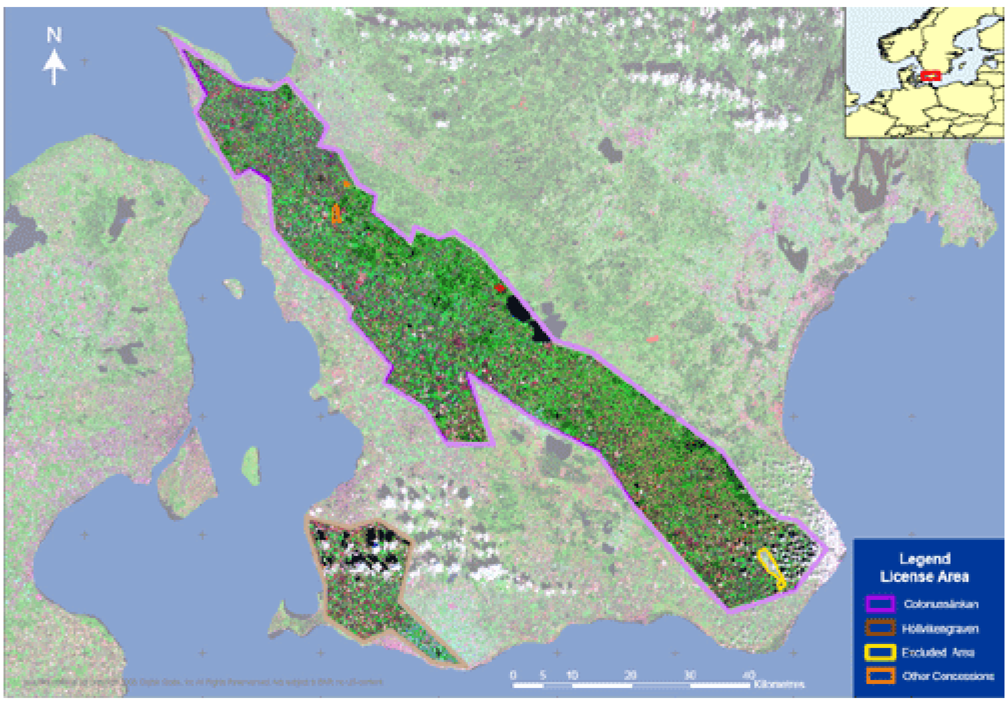
Figure VII-15. Central Sweden Stratigraphic Column[15]



Activity

Shell Oil is the most active firm currently investigating the resource potential of the Alum Shale. Beginning in 2008, the firm has been accumulating an acreage position in the Skane region of Southern Sweden, which now amounts to approximately 400 mi^2, Figure VII-16. Shell's leases provide three years for the firm to drill 3 exploration wells and evaluate the area's shale gas potential. Local opposition to well drilling delayed the start of the drilling until earlier this year, though the firm has now drilled two of the three wells. Representatives from Shell reported the firm will analyze the results of the well tests for one year before determining whether to proceed with the project.

Figure VII-16. Shell's Alum Shale Acreage in Southern Sweden



A coalition between the GFZ German Research Centre for Geosciences together and the Geological Survey of Denmark and Greenland (GEUS) will also be exploring the Alum Shale. In August 2010, the agencies announced they will be drilling a shallow (130 feet) well into the Alum Shale on the Danish island of Bornholm. This effort is being undertaken by GASH, the Gas Shales in Europe research organization.

Finally, in September 2010, Gripen Gas reported securing 5 exploration permits to investigate shale gas potential in the central Swedish county of Östergötland. The permits were awarded for a period of three years.

UK NORTHERN PETROLEUM SYSTEM

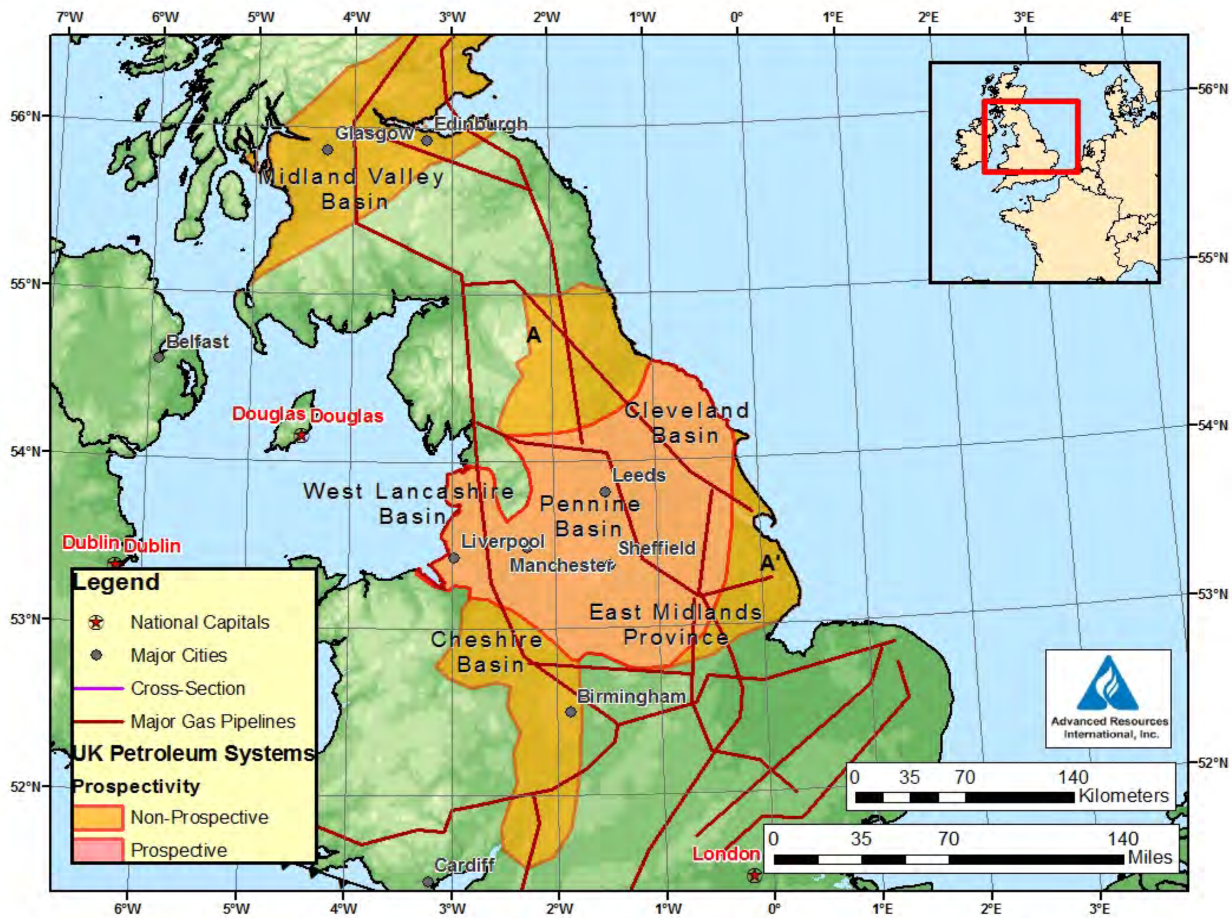
Geologic Characterization

The U.K. contains two major petroleum systems: a Carboniferous Northern Petroleum System that ranges from the Varascan Front in central England north through Scotland; and a Mesozoic Southern Petroleum System that exists between the Varascan Front and the English Channel in England and Wales. While, each of these petroleum systems contains several petroleum basins, they share similar depositional and tectonic history and contain the same shale gas prospective formations. For simplicity, this report will discuss shale gas potential in the U.K. at the level of the petroleum systems rather than by basin.

The Northern Petroleum System is a complex and highly faulted mosaic of mostly Carboniferous basins and uplifted highs. It contains the major Carboniferous Pennine Basin, as well as the Cheshire, West Lancashire, Cleveland and Scottish Midland Valley basins, Figure VII-17. Petroleum exploration has been ongoing in this area for over 100 years, leading to several large oil fields, containing over 2 billion barrels of oil in-place.[16]

The main source rock in the Northern Petroleum System is the marine Namurian Bowland Shale (also known as the Holywell Shale in the Cheshire and West Lancashire basins), Figure VII-18. This shale matured during the Carboniferous and was uplifted by the Variscan Orogeny, though its depth varies by basin due to major faulting events. Using data on Bowland Shale maturity and net organic rich thickness from well logs, ARI calculates a 9,820 mi^2 prospective area in the Northern U.K Petroleum System. However, current development has only targeted the shale's eastern areas. Additional exploration and data will be needed before the western extent of the shale can be established.

Figure VII-17. UK Northern Petroleum Province, Basins, and Shale Gas Prospective Areas



Reservoir Characteristics (Prospective Area)

The Boland Shale ranges from 3,280 to 6,300 feet deep, with an average depth of 4,800 feet in the prospective area, Figure VII-19.[17] Though its gross interval can reach up to 4,000 feet, approximately 500 gross feet are organically-rich, of which 200 feet is net shale.[18] The Boland Shale is organically rich, with total organic content ranging from 1% to 10%, averaging 5.8%.[19] Though most areas of the shale are in the oil window, the shale gas prospective area has a thermal maturity of 1% to 1.8% Ro, within the wet to dry gas window.

Figure VII-18. Northern Petroleum System Stratigraphic Column[16]

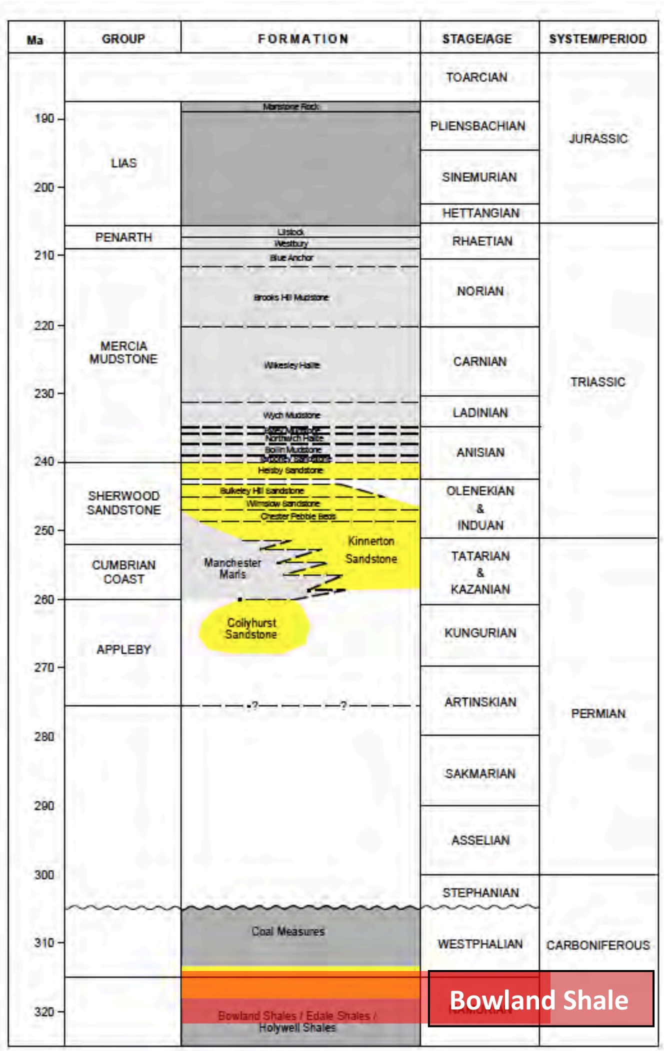
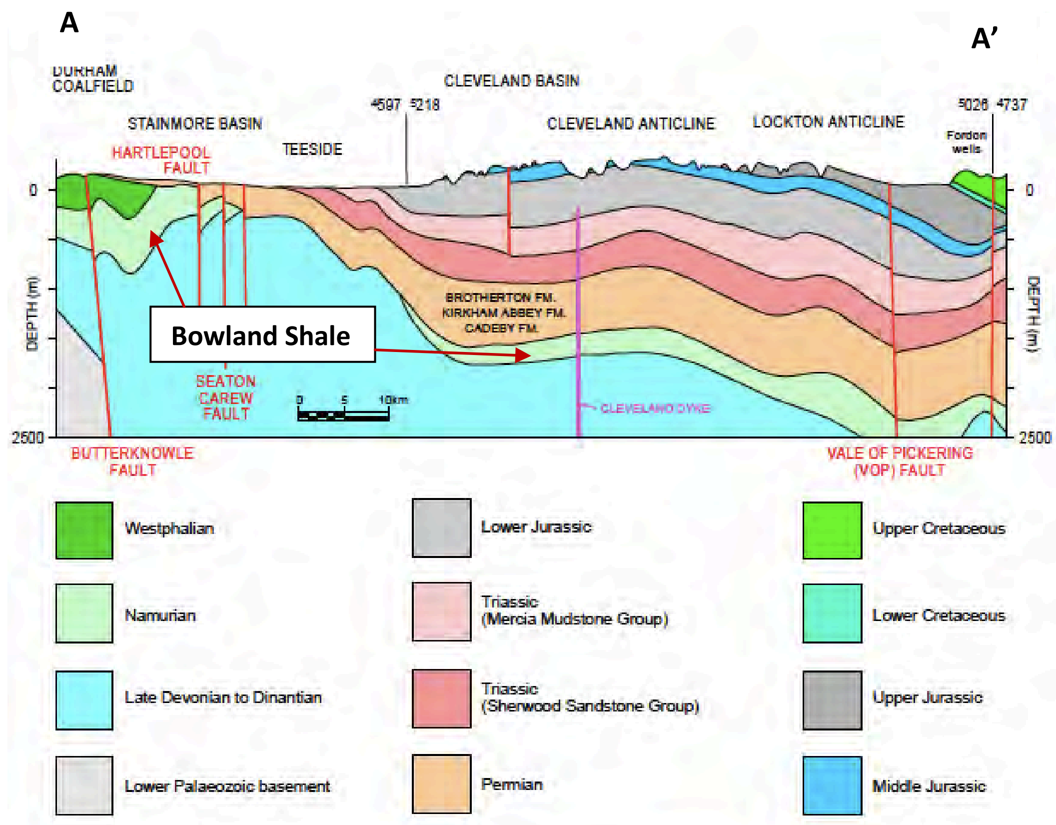


Figure VII-19. Cleveland Basin Cross-Section, U.K. Northern Petroleum System[16]



Resources

Based on the above data, ARI calculates that the Bowland Shale has a moderate resource concentration of 48 Bcf/mi^2 in the prospective area. However, data from the eastern margins of the shale formation were used as proxies for the currently unexplored western areas, which adds uncertainty to the assessment. Based on the shale's 9,820 mi^2 area, it contains a risked shale gas in-place of 95 Tcf, of which 19 Tcf is technically recoverable.

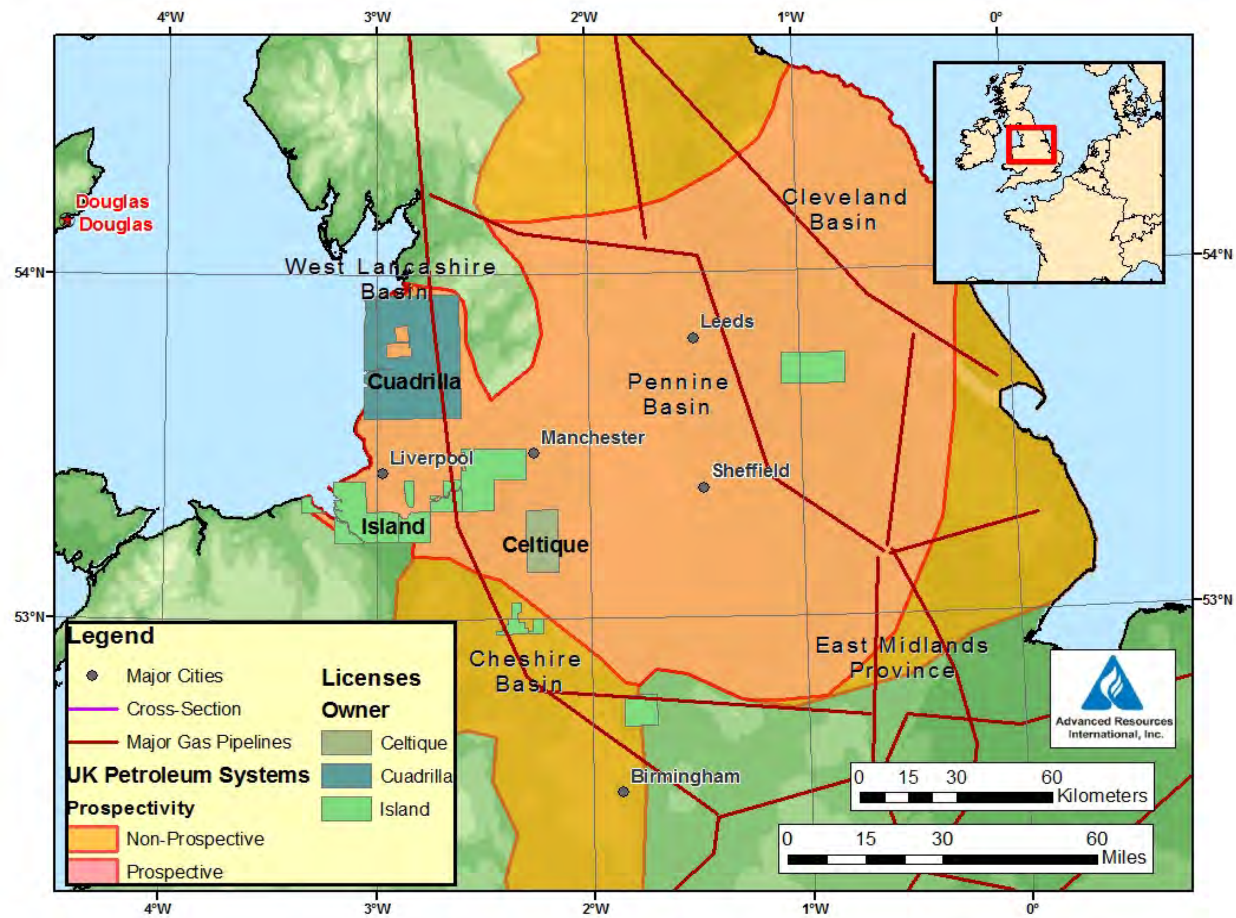
Activity

In December of 2010, Cuadrilla Resources finished drilling its first exploratory well into the Cheshire Basin's Bowland Shale. Initial results from the Preese Hall #1 well, as provided by Cuadrilla, indicate that the shale has high prospectivity for shale gas development. Cuadrilla plans to drill two additional wells into the formation in early 2011, Figure VII-20.

Though it has yet to drill any exploration wells, U.K. based Island Gas has a number of acreage positions in the U.K. Northern Petroleum System that it reports as having promising shale gas potential. The company is in the process of evaluating the shale gas resource potential of its acreage, which covers over 460 mi^2 in the West Lancashire, Cheshire and Cleveland basins.

Celtique Energy also has acreages positions in the Northern Petroleum System that could contain shale gas resources. The company reports acreage positions in the East Midlands and Cheshire basins, on which it plans to target Carboniferous and Triassic sands sourced by Namurian Shales. Though the company has not expressly stated that it intends to target shale formations on its North Petroleum System acreage, it is targeting the Weald Shale in southern England.

Figure VII-20. Operators Exploring Shale Gas in the U.K. Northern Petroleum System



U.K. SOUTHERN PETROLEUM SYSTEM

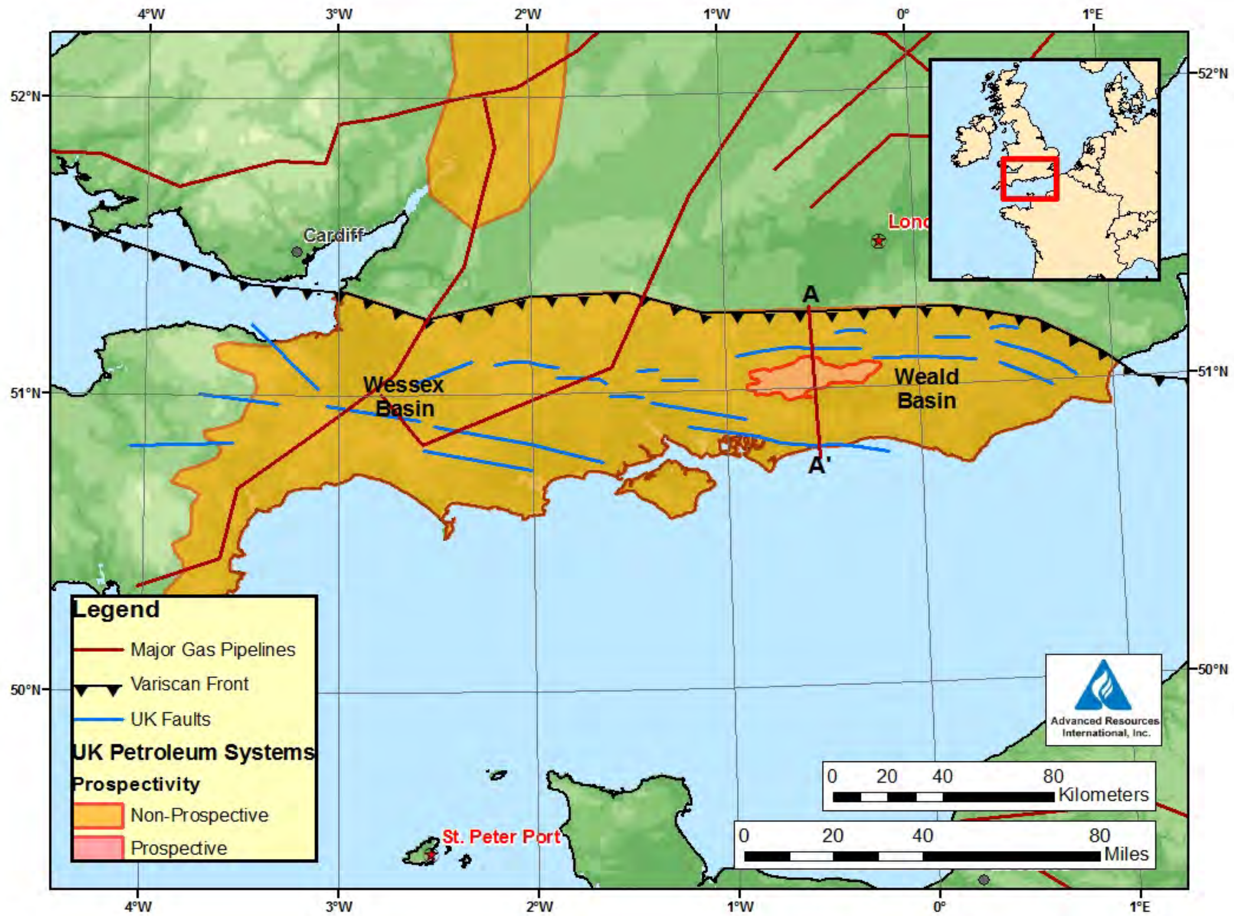
Geologic Characterization

The U.K. Southern Petroleum System contains the Mesozoic Weald and Wessex basins and ranges from the Variscan Front south to the English Channel, Figure VII-21. Petroleum basins in the U.S. Southern Petroleum System are characterized by Jurassic-age source rocks and Jurassic and Triassic clastic reservoirs. These formations are regionally equivalent with the shale formations in the Paris Basin across the English Channel, separated by the Hampshire-Dieppe High, a regional arch. Both basins began as Permo-Triassic depositional centers, which were later uplifted during Tertiary time along major structural faults.

Petroleum exploration has been ongoing in the Southern Petroleum System since the early 1920's, though few notable finds were discovered until 1973, when the Wytch Farm Oilfield, U.K.'s largest oil field, was discovered[16].

The most prospective source rock for shale gas development in the Southern Petroleum System is a group of Liassic interbedded shallow marine shales and clays, known as the Liassic Clays, Figure VII-22. Widely believed to be immature for gas development, selected portions of the Liassic Clays have recently been shown to be in the gas generation window. Throughout much of the Weald and Wessex basins, however, the formation is within the oil window. Using data provided by operators in the region, ARI has identified a 160 mi^2 area in which the Liassic Shales are within the gas window. A number of Upper Jurassic clays are also source rocks in the Southern Petroleum System, such as the Kimmeredge Clay, but are immature with respect to gas production.

Figure VII-21. U.K. Southern Petroleum System and Shale Gas Prospective Area



Reservoir Characterization (Prospective Area)

Depth to the top of the prospective area of the Liassic Shales ranges from 11,500 feet to 15,500 feet, with an average of 13,500 feet,[20] Figure VII-23. While the shale exists throughout the Weald and Wessex basins, it is only prospective in their deepest areas. At this depth, approximately 125 feet of the up to 2,000 feet of formation interval contains net, organic rich shale.[21] Total organic content varies from 1% to 7%, with an average of 2.4% in the deep, prospective areas.[18] While in the wet gas window, the Liassic Shale is still somewhat immature, with vitrinite reflectance ranging from 1% to 1.3% Ro.[20]

Figure VII-22. Southern Petroleum System Stratigraphic Column[16]

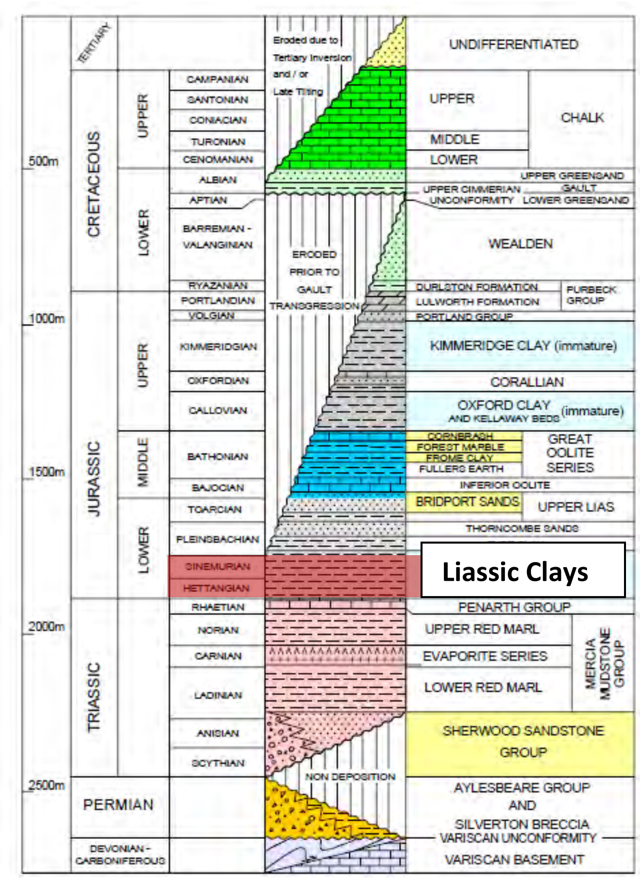
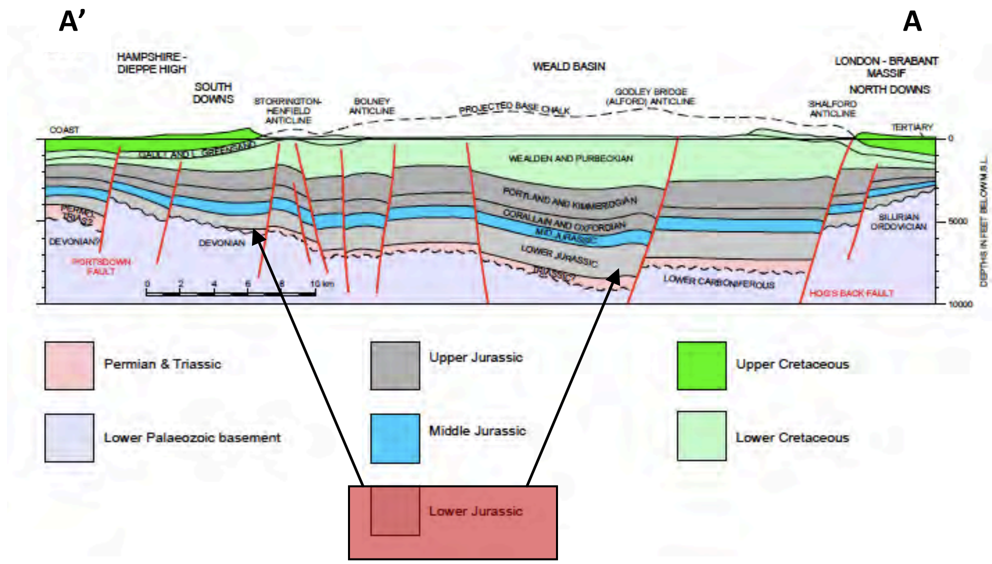


Figure VII-23. Weald Basin Cross-Section, U.K. Southern Petroleum System[16]:



Resources

We calculate that the Liassic Shale has a low to moderate resource concentration of 45 Bcf/mi^2 in its prospective area. Because the shale is only in the gas window in the deepest areas of the basin, its prospective area is small, approximately 160 mi^2. Our analysis suggests that this area contains 2 Tcf of risked GIP, of which about 1 Tcf is recoverable.

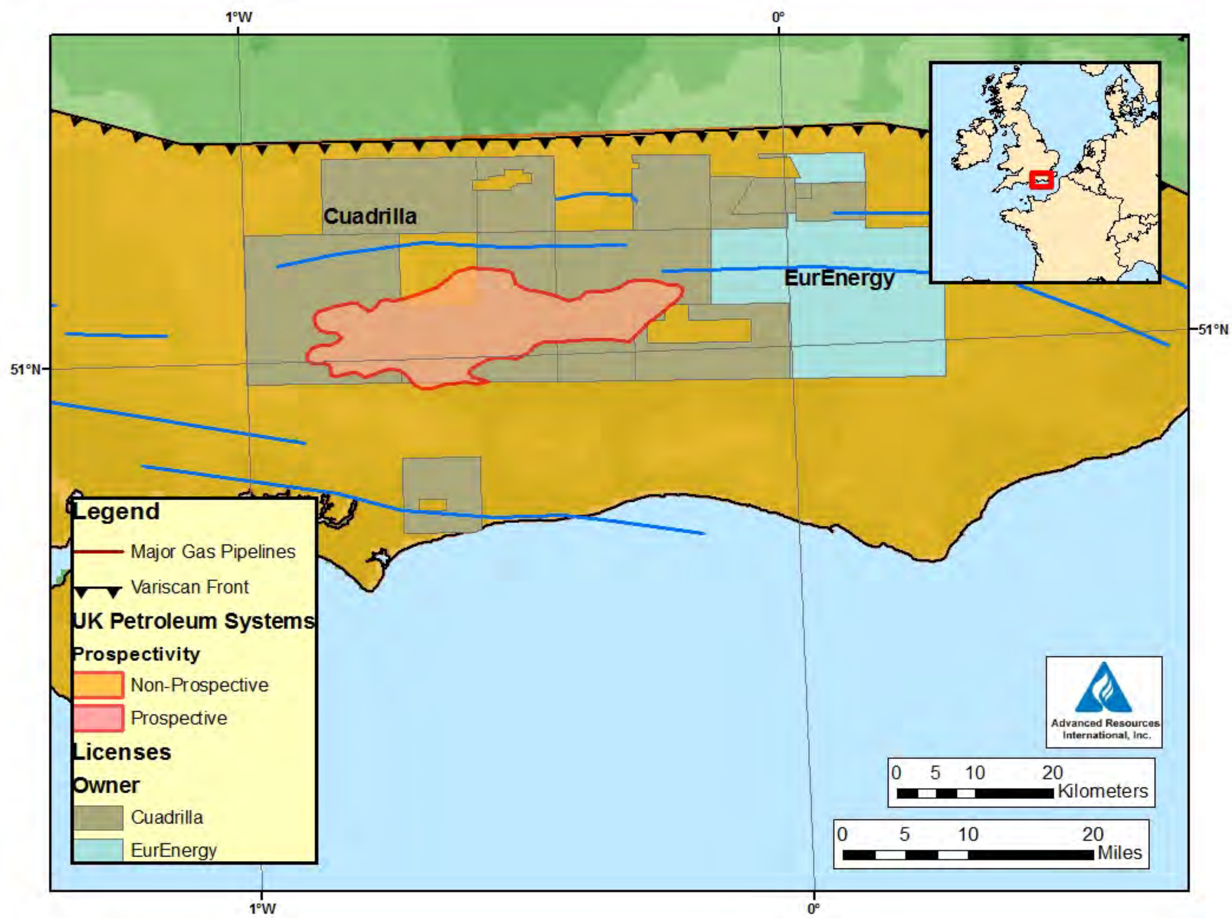
Activity

Celtique Energy (in 50/50 partnership with Magellan Petroleum) has acreage positions in the Southern Petroleum System. According to company data, its 386 mi^2 exploration licenses in the Weald Basin could contain up to 2 Tcf of recoverable resource, which is supported by the fact that that the company's acreage covers almost the entirety of the prospective area of the Liassic Shale, Figure VII-24. The company has not provided a timeline for its drilling plans, but its license is valid until 2014.

The U.K. based energy company Eden Energy is in a similar position to Celtique, with acreage it believes to be prospective for shale gas development that is currently untested. The company has license to 700 mi^2, on which it reports 40 Tcf of shale gas potential. The company is actively looking for a Joint Venture partner, but has not provided additional information.

Eurenergy, with acreage positions in Poland and France, has a small concession in the Weald Basin, totaling 192 mi^2. Cuadrilla also has small acreage positions in the Southern Petroleum System, though it has not made its plans in the region public.

Figure VII-24. Operators Exploring Shale Gas in the U.K. Southern Petroleum System



VIENNA BASIN

Geologic Characterization

The Vienna Basin is a Tertiary pull-apart basin located in northwest Austria and extending northward into the Czech Republic, Figure VII-25. The basin contains a thick, 33,000 feet sequence of Neogene through Mesozoic fill and rests atop the Calcareous Alps and Bohemian Massif basement, Figure VII-26. Faults traversing the basin provide pathways for hydrocarbons produced in Jurassic strata to migrate into a series of overlying stacked reservoirs. These reservoirs have provided over 1 billion barrels of oil to date, making the Vienna Basin one of Europe's most important hydrocarbon sources.[22]

Figure VII-25. Vienna Basin Regional Setting

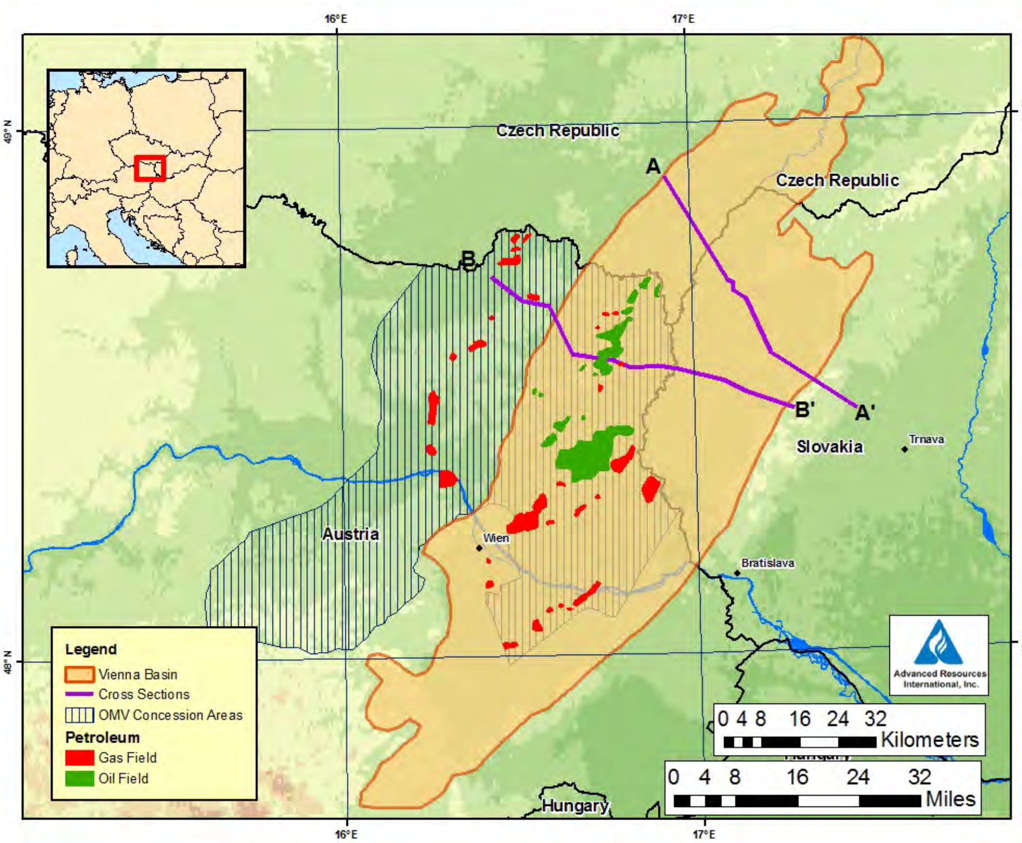
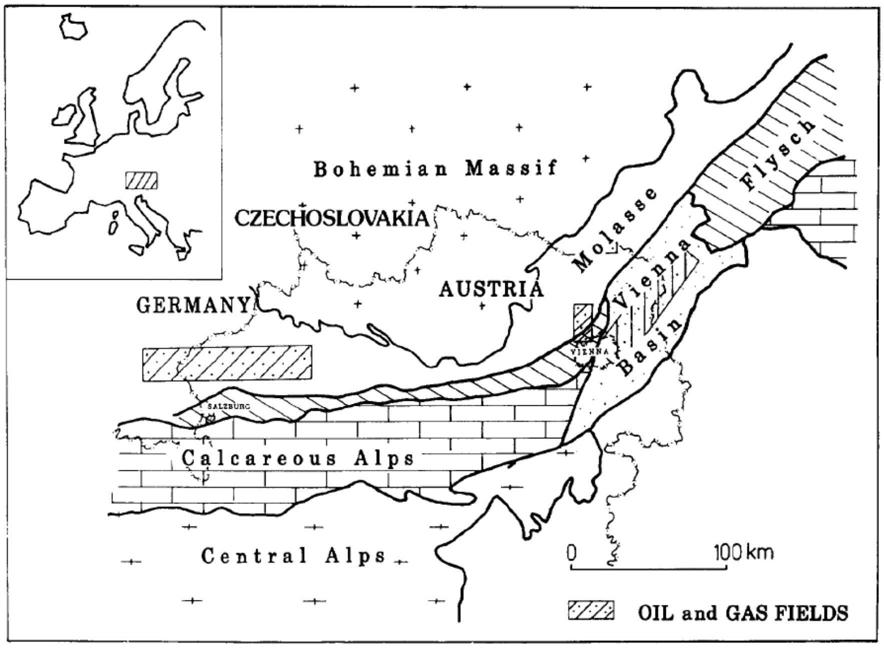


Figure VII-26. Geologic Setting of the Vienna Basin



Shale gas potential in the Vienna Basin occurs in the thick (up to 2km) succession of lime-rich mudstone known as the Upper Jurassic Mikulov Marl Formation. While not technically a shale, the Mikulov Marl Formation has an organic content of up to 10% in some areas, and is thought to be the main source of hydrocarbons in the basin. However, due to its clay-rich lithology, heavily faulted environment, and relative immaturity at prospective depths, the Mikulov Marl is a high risk shale gas target.[23]

Reservoir Properties (Prospective Area)

Due to the Mikulov Marl Formation's depth in the gas-prone areas, it is not prospective for shale gas development at this time. The formation ranges from 5,580 feet to 39,360 feet throughout the Vienna Basin, Figure VII-27.[24] However, at depths above 16,400 feet, it is immature for thermogenic gas development.[25,26]

Figure VII-27. Selected Vienna Basin Cross Sections

Activity

Austrian based OMB Exploration and Production GmbH is exploring the potential of the Mikulov Marl formation as part of a three year study. It has secured exploration concessions in Northern Austria, which include 820 mi^2 within the Vienna Basin, Figure VII-25.

Though the company has publically estimated that the Vienna Basin contains 200 to 300 Tcf of resource, it cautions that the great depth and pressure of shale gas formations may make exploration technically or economically infeasible[27]. In a recent interview, Wolfgang Ruttenstorfer, OMV's chief executive, noted that well costs at depths greater than 16,400 feet could be $20 million or more.

FRANCE

Approximately 98% of France's gas consumption (4.7 Bcfd) is provided by imports, of which 24% originate from Russia.[28,29] In 2009, the country produced 0.08 Bcfd of gas, from negligible proved reserves. The shale gas in-place (risked) in France's Paris and South-East basins equals 720 Tcf of which 180 Tcf is estimated to be technically recoverable.

GERMANY

Germany is also very dependent on natural gas imports to satisfy the country's demand for the fuel. In 2009, Germany consumed 9 Bcfd of natural gas, but only produced 1.4 Bcfd, from proved reserves of 6 Tcf. Of the balance that the country imported, approximately 43% came from Russia. The Posidonia, Namurian and Wealden shales discussed in this report contain 34 Tcf of risked shale gas in-place, with 8 Tcf of technically recoverable resource. Additional, still undefined shale potential likely exists in the Permian-Carboniferous shales.

NETHERLANDS

Due to its significant offshore North Sea resource base, the Netherlands is self-sufficient in natural gas. In 2009, the country produced 7.6 Bcfd of natural gas, of which 4.7 Bcfd were consumed domestically. Despite the country's abundance of conventional gas, there is interest in exploring for shale gas. The Netherlands' portion of the Posidiana, Namurian and Wealden shales contain 66 Tcf of risked shale gas in-place, with 17 Tcf technically recoverable.

SWEDEN

Sweden does not produce natural gas. The 164 Tcf of risked shale gas in-place and the 41 Tcf of technically recoverable shale gas resources could meet domestic consumption, at 0.1 Bcfd in 2009, far into the future.

DENMARK

Denmark is currently self-sufficient in natural gas, consuming 0.4 Bcfd of the 0.8 Bcfd it produced in 2009. However, the country is likely to become a net importer, as its natural gas reserves have been steadily falling (from 4 Tcf in 2005 to 2 Tcf in 2009) in the face of increasing production. The prospective area of Denmark contains an estimated 92 Tcf of risked shale gas in-place and 23 Tcf of technically recoverable resource, which could sustain the country's current level of consumption far into the future.

NORWAY

Like the United Kingdom, Norway has a large endowment of natural gas resources from its North Sea fields. In 2009, the country produced 9.9 Bcfd of natural gas from 82 Tcf of reserves (almost half of Europe's natural gas reserves), while only consuming 0.44 Bcfd. The Alum Shale could provide an additional 83 Tcf of recoverable resource, almost doubling the country's existing natural gas resource base.

UNITED KINGDOM

Though the United Kingdom's North Sea and onshore fields provide substantial amounts of natural gas (5.7 Bcfd in 2009), it is currently a net importer, with natural gas consumption of 8.5 Bcfd in 2009. Like Denmark, the United Kingdom's natural gas reserves have been in decline decreasing from 27 Tcf in 2000 to 12 Tcf in 2009. The gas in-place (risked) in the Bowland and Liassic shales are estimated at 97 Tcf, with 20 Tcf of technically recoverable resource.

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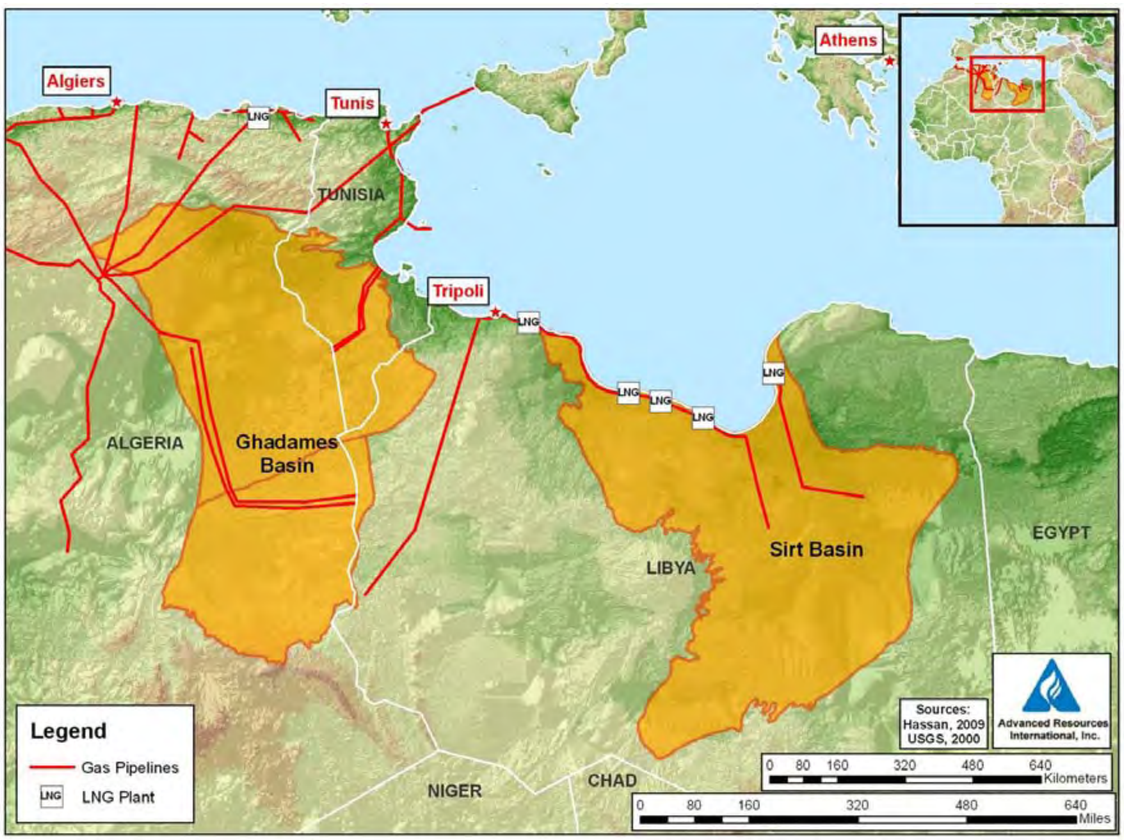
VIII. CENTRAL NORTH AFRICA

INTRODUCTION

The Central North Africa region (Algeria, Tunisia and Libya) contains two major shale gas basins*: (1) the Ghadames Basin, in eastern Algeria, southern Tunisia and northwestern Libya; and (2) the Sirt Basin, in north-central Libya. Figure VIII-1 provides the outline map for these two basins as well as the region's natural gas pipeline system[1]. Central North Africa holds significant volumes of shale gas resources, with 1,861 Tcf of risked gas in-place in the prospective areas of these two basins. Of this gas in-place, we estimate a risked recoverable resource of 504 Tcf, Table VIII-1.

Figure VIII-1. Shale Gas Basins and Pipeline System of Central North Africa



* Additional basins in the region include: the Murzuq, Pelagian, Kuffra, Benghazi, Derna and offshore Tripolitania Basins. These are not considered here due to their relative lack of development and limited shale gas potential.

Table VIII-1. Reservoir Properties and Resources of Central North Africa

Basic Data	Basin/Gross Area		Ghadames Basin (121,000 mi^2)		Sirt Basin (177,000 mi^2)	
	Shale Formation		Tannezuft	Frasnian	Sirt-Rachmat	Etel
	Geologic Age		Silurian	Middle Devonian	Upper Cretaceous	Upper Cretaceous
Physical Extent	Prospective Area (mi^2)		39,700	12,900	70,800	70,800
	Thickness (ft)	Interval	1,000 - 1,800	200 - 500	1,000 - 3,000	200 - 1,000
		Organically Rich	115	197	2,000	600
		Net	104	177	200	120
	Depth (ft)	Interval	9,000 - 16,500	8,200 - 10,500	9,000 - 11,000	11,000 - 13,000
		Average	12,900	9,350	10,000	12,000
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Normal	Normal
	Average TOC (wt. %)		5.7%	4.2%	2.8%	3.6%
	Thermal Maturity (%Ro)		1.15%	1.15%	1.10%	1.10%
	Clay Content		Medium	Medium	Medium/High	Medium/High
Resource	GIP Concentration (Bcf/mi^2)		44	65	61	42
	Risked GIP (Tcf)		520	251	647	443
	Risked Recoverable (Tcf)		156	75	162	111

GHADAMES BASIN

Geologic Characterization

The Ghadames (Berkine) Basin is a large, 121,000 mi^2 intracratonic, extensional basin underlying eastern Algeria, southern Tunisia and western Libya. In its western area, the basin contains reverse faulted structures, providing conventional oil and gas structural traps for petroleum sourced from Devonian- and Silurian-age shales. The central, deep portion of the basin contains uplifted fault blocks formed during the Cambrian-Ordovician[2].

The Ghadames Basin contains two major organic-rich shale formations: (1) The lower Silurian massive shales of the Tannezuft Formation; and (2) The Middle Devonian Frasnian “Hot Shale,” Figure VIII-2. The formations were mapped and screened to establish the prospective areas with favorable reservoir characteristics for shale gas resources.

Reservoir Properties (Prospective Area)

Silurian Tannezuft Formation. The depth of the prospective area of the Silurian Tannezuft Formation ranges from 9,000 along the northern and eastern edge to below 15,000 feet in the basin center, Figure VIII-3. The gross interval of the organically-rich portion of the Tannezuft formation reaches 1,800 feet, with an organically rich average net thickness of 104 net feet. The TOC of the Tannezuft Formation averages 5.7%. The lower portion of the formation is particularly organically-rich, with TOC values of up to 17%. The thermal maturity of the Tannezuft shale ranges from mature oil (Ro of 0.7% to 1.0%) in the northern portion of the basin, to gas/condensate (Ro of 1.0% to 1.2%) and to dry gas (Ro of 1.2% or greater) in the central and southern portion of the basin, Figure VIII-4.

Middle Devonian Frasnian "Hot Shale". The depth of the prospective area of the overlying Middle Devonian Frasnian "Hot Shale" ranges from 8,000 feet to 10,500 feet. The Frasnian "Hot Shale" interval ranges from 200 feet in the west to nearly 500 feet in the north-central area of the basin, with an organically-rich net thickness of 177 feet. The Frasnian "Hot Shale" has TOC values that range from 1% to 12% with an average of 4.2%.2 The average thermal maturity in the prospective area is 1.15% Ro, placing the shale in the gas and condensate window.

Resources

The Ghadames is an important conventional hydrocarbon basin. Recent conventional oil field discoveries in the basin have helped boost oil and natural gas production in Algeria and Tunisia. In its 2000 World Petroleum Assessment, the USGS estimated 4.5 billion barrels of undiscovered oil and 12 Tcf of undiscovered natural gas for the Ghadames Basin (Tanezuft-Ghadames Total Petroleum System[3]).

The Silurian Tannezuft shale has a low to moderate resource concentration of 44 Bcf/mi^2. Given a 39,700 mi^2 prospective area, the risked shale gas in-place is 520 Tcf. Based on favorable reservoir properties and mineralogy we estimate a risked technically recoverable resource of 156 Tcf, Table VIII-1. The Middle Devonian Frasnian "Hot Shale" has a moderate resource concentration of 65 Bcf/mi^2. Given a 12,900 mi^2 prospective area, the risked shale gas in-place is 251 Tcf, with a risked technically recoverable resource of 75 Tcf, Table VIII-1.

Figure VIII-2. Ghadames Basin Stratigraphic Column[4]

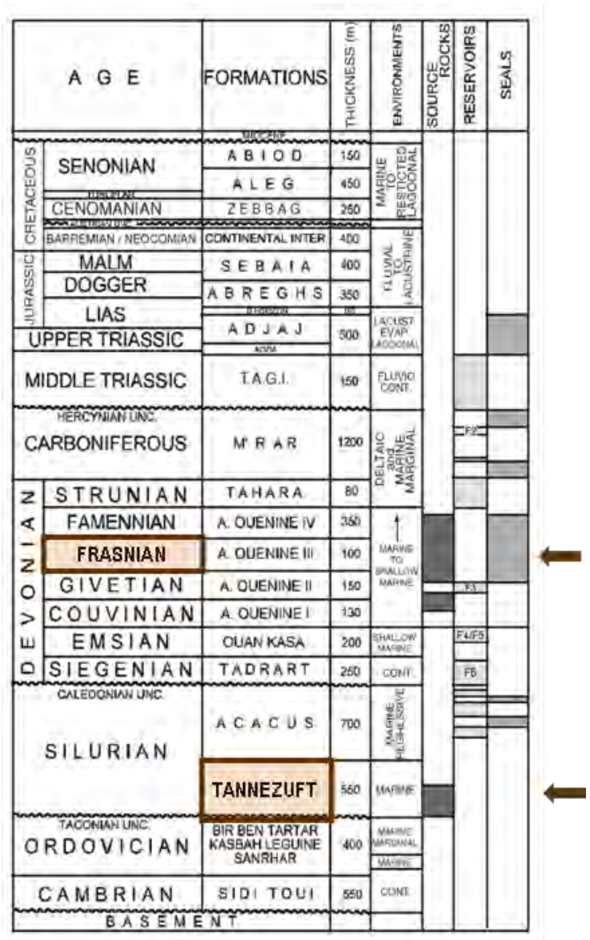


Figure VIII-3. Ghadames Basin Structure Depth Map and Cross Section4

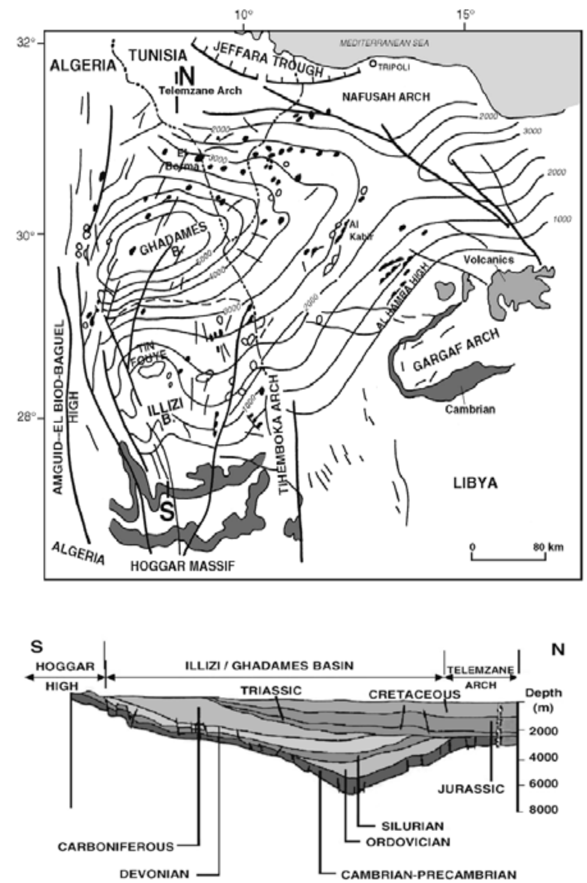


Figure VIII-4. Silurian Tannezuft Vitrinite Reflectance4

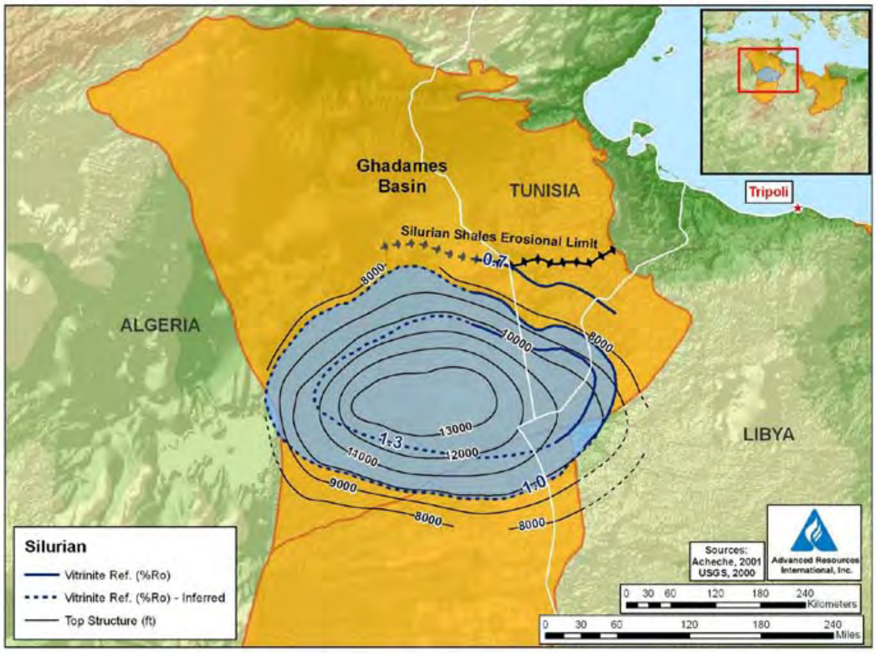
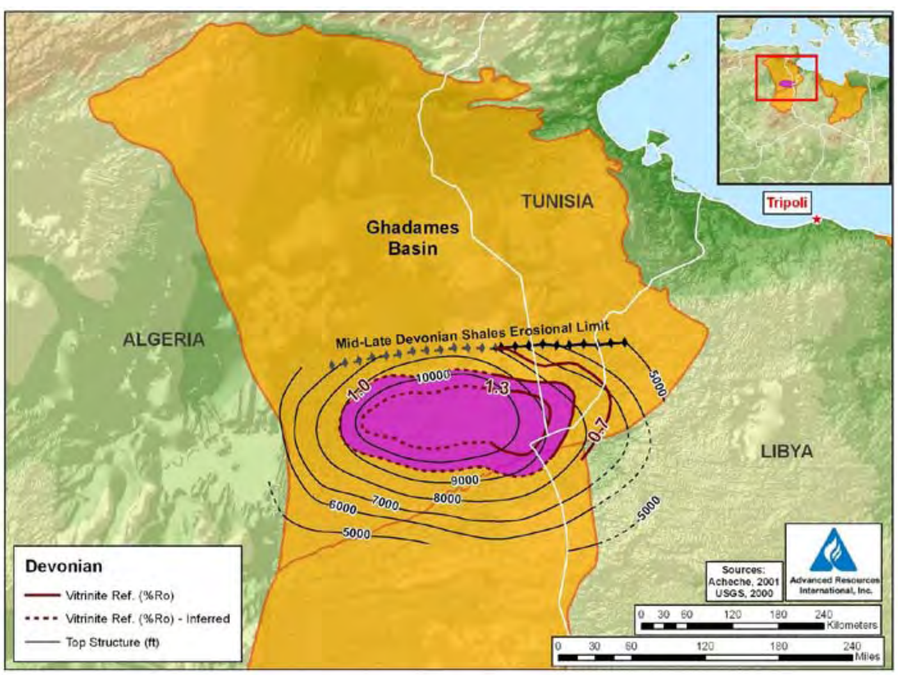


Figure VIII-5. Devonian Frasnian Vitirinite Reflectance4



Activity

Considerable exploration activity is underway in the Ghadames Basin. For example, Cygam Energy has acquired four permits in the Tunisia portion of the Ghadames Basin totaling 3.1 million gross acres[5]. Cygam's exploration program for 2010/2011 involves 2D/3D seismic, 3 exploration wells and 2 appraisal wells. Cygam Energy conducted a frac job in March 2010 on Well No. 1 in the Tannezuft shale at a depth of 13,000 ft in the Sud Tozeur permit area. No information has been provided on test results.

Chinook Energy Inc. has acquired 7 lease blocks in the Tunisia portion of the Ghadames Basin, totaling 3 million gross acres. The Sud Remada block totals 1.2 million acres with 5-6 structures identified, including the Tannezuft shale[6]. This year, the company plans to drill two appraisal wells in the Sud Remada lease block. Previous drilling into the deeper, oil bearing "TT" Ordovician reservoir, showed hydrocarbon potential in the Silurian Tannezuft formation.

To date, no shale gas production has been reported from the Ghadames Basin.

SIRT BASIN

Geologic Characterization

The Sirt (Sirte) Basin is a relatively young, rifted, intracratonic basin underlying an area of 177,000 square miles of Central-West Libya. Active subsidence and block faulting in the Upper Cretaceous through Eocene has created several large troughs in the Sirt Basin, containing large volumes of organically-rich shale, Figure VIII-6.

The Sirt Basin contains two prospective shale gas formations: (1) the Upper Cretaceous (Maestrictian-Coniacian) Sirt/Rachmat Shale, and (2) Upper Cretaceous (Turonian) Etel Shale, Figure VIII-7.

Reservoir Properties

Upper Cretaceous Sirt Formation. The Sirt Shale Formation covers a prospective area of 15,000 mi^2, with depth ranging from 9,000 to 11,000 feet. The interval thickness ranges from 1,000 to 3,000 feet, with an average organically rich thickness of 200 ft, Figure VIII-8[7].The TOC of the Sirt Shale ranges from 0.5% to 8%, averaging 2.8%.7 Measured thermal maturities in the shallower portion of the Upper Cretaceous strata indicate that the Sirt Shale is in the oil generation window (Ro of 0.7% to 1.0%). In the deeper, condensate/gas prospective area of the basin, the thermal maturity is higher, with an Ro of 1.1%.[8]

Upper Cretaceous Etel Formation. The Etel Shale covers a prospective area of 15,000 mi^2 at a depth of 11,000 to 13,000 feet. Gross shale thickness ranges from 200 to 1,000 feet, with an average organically rich net thickness of 120 feet. The average TOC of the Etel Shale is 3.6%. In the prospective area, the shale is in the condensate/gas generation window with a thermal maturity of 1.1 % Ro7.

Figure VIII-6. Structure and Cross Section of Northern Sirt Basin[9]

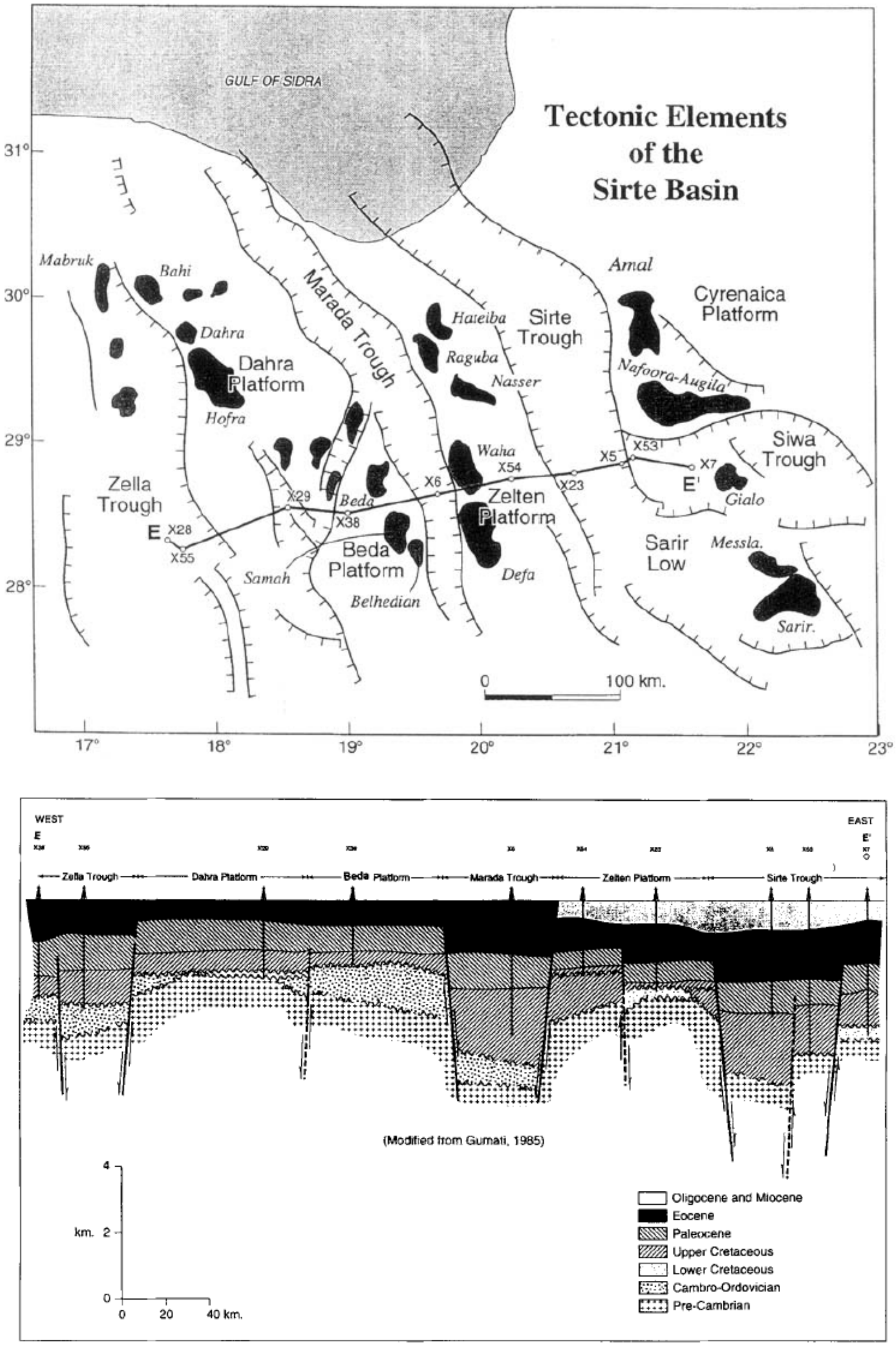


Figure VIII-7. Sirt Basin Stratigraphic Column7

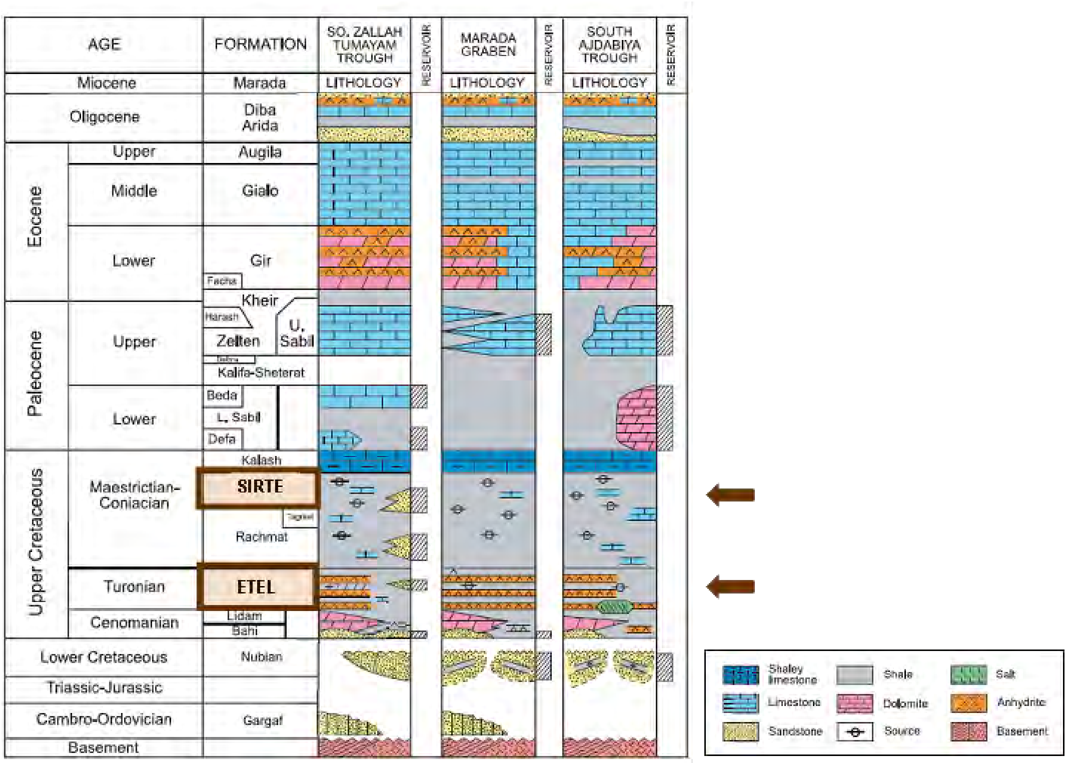
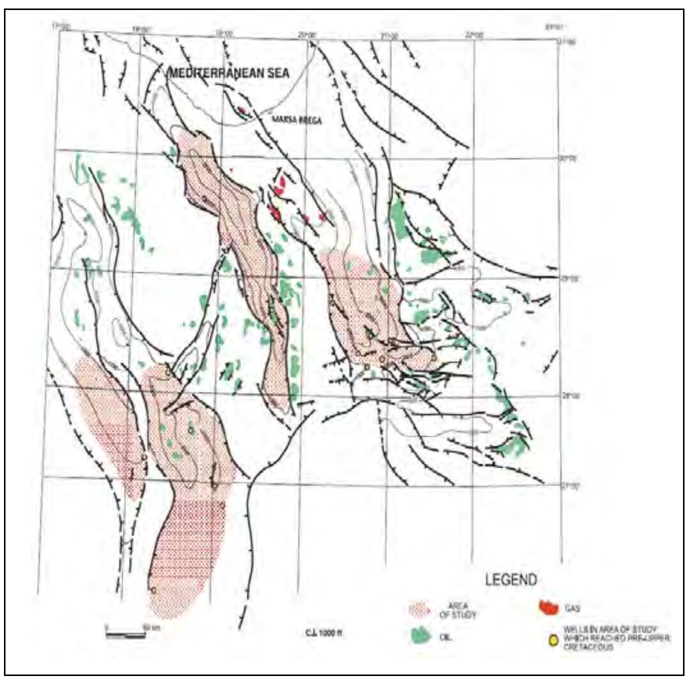


Figure VIII-8. Net Shale Isopach of Sirt and Rachmat Formations7



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Resources

Because the prospective shale gas formations in Libya's Sirt Basin lie in the deep subsided troughs, they are extremely lightly explored. Most of the identified conventional oil and gas fields are on the uplifted carbonate blocks, Figure VIII-6.

The Sirt Shale has a moderate resource concentration of 61 Bcf/mi^2. Given a 70,800 mi^2 prospective area, the risked shale gas in-place is 647 Tcf. Based on reservoir properties and mineralogy, we estimate a risked technically recoverable resource of 162 Tcf, Table VIII-1. The Etel Shale has a low-moderate resource concentration of 42 Bcf/mi^2. Given a 70,800 mi^2 prospective area, the risked shale gas in-place is 443 Tcf, with a risked technically recoverable resource of 111 Tcf, Table VIII-1.

Activity

There is no publically reported shale gas production or shale gas exploration activity underway in the Sirt Basin.

ALGERIA

Algeria is the sixth largest gas producer in the world, with marketed production of 8.2 Bcf per day and reserves of 159 Tcf, as of 2009. Gas production has been increasing over the recent decade, though at a slower rate than proved reserves. The country's natural gas infrastructure is well developed and includes one existing plus one planned LNG liquefaction plant and a regional natural gas pipeline system[10].

We estimate that northern Algeria has 653 Tcf of risked shale gas in-place with 428 Tcf in the Silurian Tannezuft Shale and 225 Tcf in the Middle Devonian Frasnian "Hot Shale" of the Ghadamas Basin. We estimate a risked technically recoverable resource of 196 Tcf. Additionally, the Tindouf Basin of southwestern Algeria, discussed in Chapter IX, contains 159 Tcf of risked gas in-place in the Tindouf basin, of which 35 Tcf are technically recoverable. Once developed, this would represent a very large increase over the current proved natural gas reserves of Algeria. At the recent World Energy Congress (September 2010), the Oil Minister of Algeria announced interest in assessing the natural gas resources of its shales and tight gas sands.

LIBYA

Libya is also a major hydrocarbon supplier, with 1.5 Bcfd of natural gas production from reserves of 50 Tcf and 1.7 million barrels per day of oil production from reserves of 41 billion barrels, in 2008[10]. Libya's natural gas production has more than doubled since 2004, when the "Greenstream" pipeline came online, linking Libya's previously unconnected productive capacity to European markets.

We estimate that Libya has 1,147 Tcf of risked shale gas in-place, with 49 Tcf in the Silurian Tannezuft Shale and 8 Tcf in the Middle Devonian Frasnian Shale of the Ghadames Basin. An estimated 647 Tcf is in the Sirt Shale and 443 Tcf is in the Etel Shale of the Sirt Basin. We estimate a risked technically recoverable resource of 290 Tcf, representing a major increase over current proved natural gas reserves. No public announcements of shale gas activity are reported for Libya.

TUNISIA

Though it shares many of the same geologic features with Algeria and Libya, Tunisia has a much smaller land mass than either of its neighbors, and thus much lower oil and gas production. In 2008, with gas consumption of 0.4 Bcfd and gas production of 0.3 Bcfd (from reserves of 2 Tcf), the country was a net natural gas importer. However, because of its favorable oil and gas investment incentives, Tunisia has attracted many international E&P countries, and it is the only country in North Central Africa where unconventional natural gas potential is being actively explored. Tunisia had the first shale gas well and frac in North Africa in March, 2010 and is actively supporting the pursuit of this resource.

We estimate that Tunisia has 61 Tcf of risked shale gas in-place, with 43 Tcf in the Silurian Tannezuft shale and 18 Tcf in the Frasnian "Hot Shales" of the Ghadames Basin. We estimate a risked technically recoverable resource of 18 Tcf, representing a major increase over current proved natural gas reserves.

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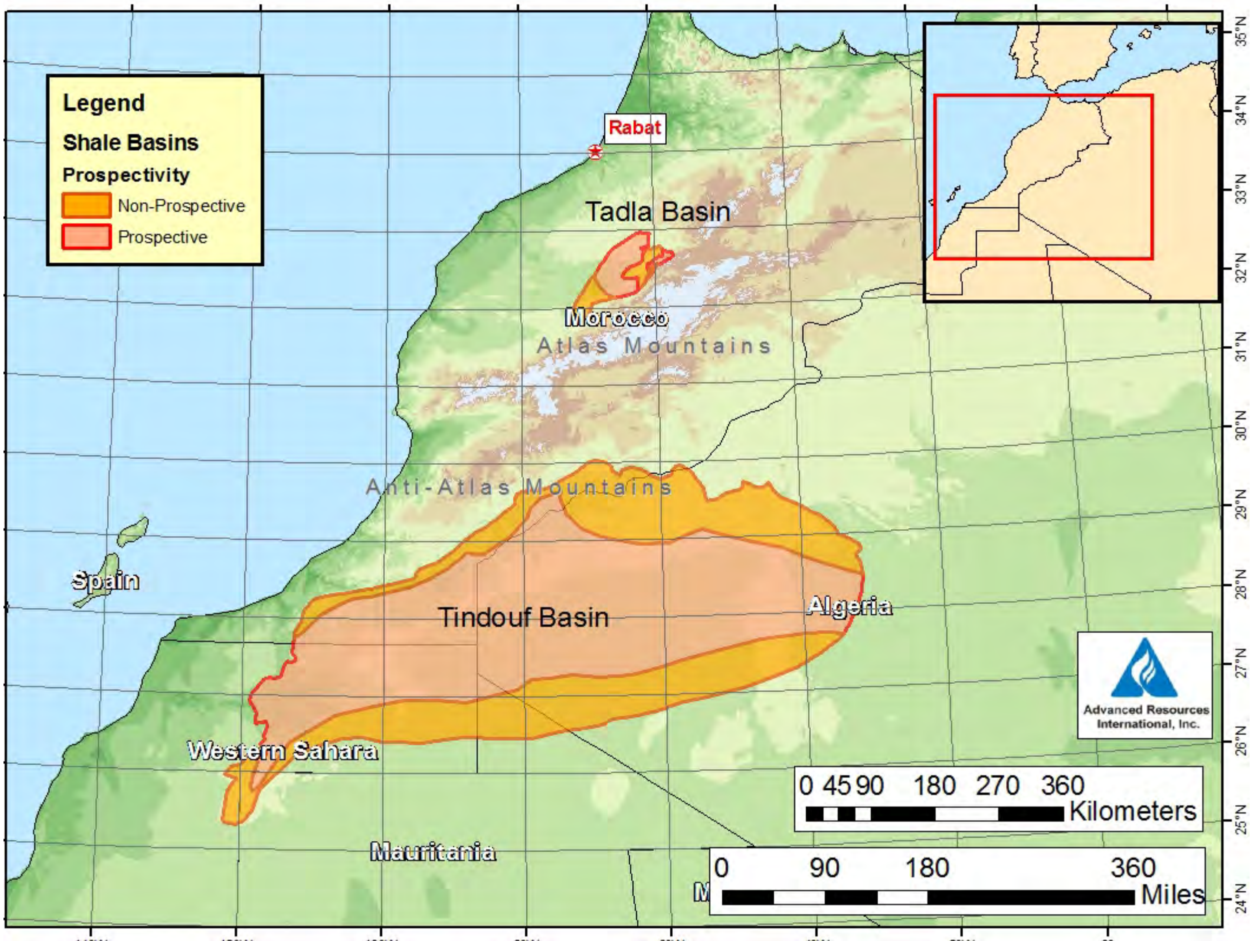
IX. WESTERN NORTH AFRICA

INTRODUCTION

Morocco has large accumulations of Late-Cretaceous immature oil shale (kerogen), at depths suitable for surface mining[1]. San Leon and Petrobras are beginning operations in this area and estimate their potential at over 50 billion barrels. However, Morocco also possesses organically rich Silurian- and Devonian-age shale gas potential in the Tindouf and Tadla basins, Figure IX-1. Mapping and resource characterization of these shales is difficult because regional deformation, erosion, and subsidence of Morocco's shale deposits resulted in their discontinuous and complex present day distribution.

Figure IX-1. Shale Gas Basins of Morocco



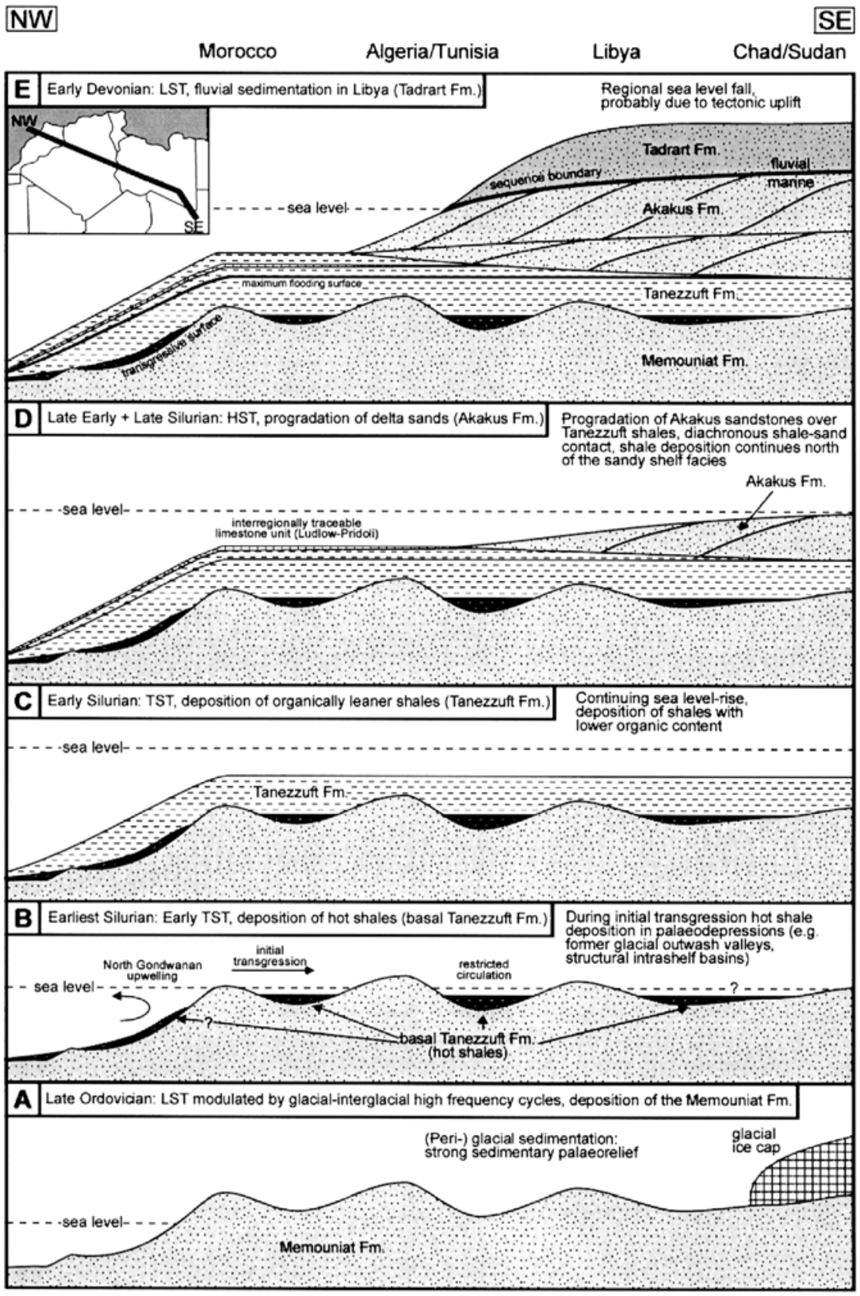
Accurately identifying promising shale basins and estimating their resource potential in such a geologically complex area requires significant amounts of data, which are not widely available in Morocco because of limited well drilling and data confidentiality. This report assesses the two basins which appear to have the highest potential for shale gas resource based on available data -- the Tindouf (Zag) Basin in the south, (extending into Algeria, Western Sahara, and Mauritania), and the central Morrocan Tadla Basin. ARI estimates that these two shale basins contain a risked shale gas in-place of 267 Tcf, of which 53 Tcf is technically recoverable, Table IX-1. Additional shale gas potential may exist in the Doukkala, Essaouira and Souss basins, but a lack of data prevents their assessment at this time.

Table IX-1. Reservoir Properties and Resources of Morocco

			Tindouf Basin	Tadla Basin
Basic Data	Basin/Gross Area		(89,267 mi²)	(2,794 mi²)
	Shale Formation		Lower Silurian	Lower Silurian
	Geologic Age		Silurian	Silurian
Physical Extent	Prospective Area (mi^2)		55,340	1,670
	Thickness (ft)	Interval	0 - 2,500	0 - 820
		Organically Rich	N/A	328
		Net	50	197
	Depth (ft)	Interval	3,280 - 15,000	3,280 - 9,840
		Average	9,000	6,560
Reservoir Properties	Reservoir Pressure		Underpressured	Underpressured
	Average TOC (wt. %)		5.0%	2.0%
	Thermal Maturity (%Ro)		3.50%	2.25%
	Clay Content		Medium	Medium
Resource	GIP Concentration (Bcf/mi^2)		18	49
	Risked GIP (Tcf)		251	16
	Risked Recoverable (Tcf)		50	3

The country's primary shale target, the lower Silurian "Hot Shale," was deposited during the late Ordovician to early Silurian when glacial melting across the African super continent lead to a large sea-level rise across much of what is now North Africa. During the early Silurian, sediments from the glacial melt settled in regional lows and precipitated thin, but very organically rich layers of marine organic matter during a regional anoxic event, Figure IX-2. Data from wells drilled across the country confirms the presence of organic rich Silurian shales, though these areas do not always correspond to currently recognized hydrocarbon basins. The presence of thick Silurian sections, observed in many Moroccan hydrocarbon basins, does not guarantee the presence of organically rich shale, as areas that were regional highs during the early Silurian did not receive organically rich sediments[2].

Figure IX-2. Simplified History of Morocco's Depositional Environment, Ordovician-Devonian2

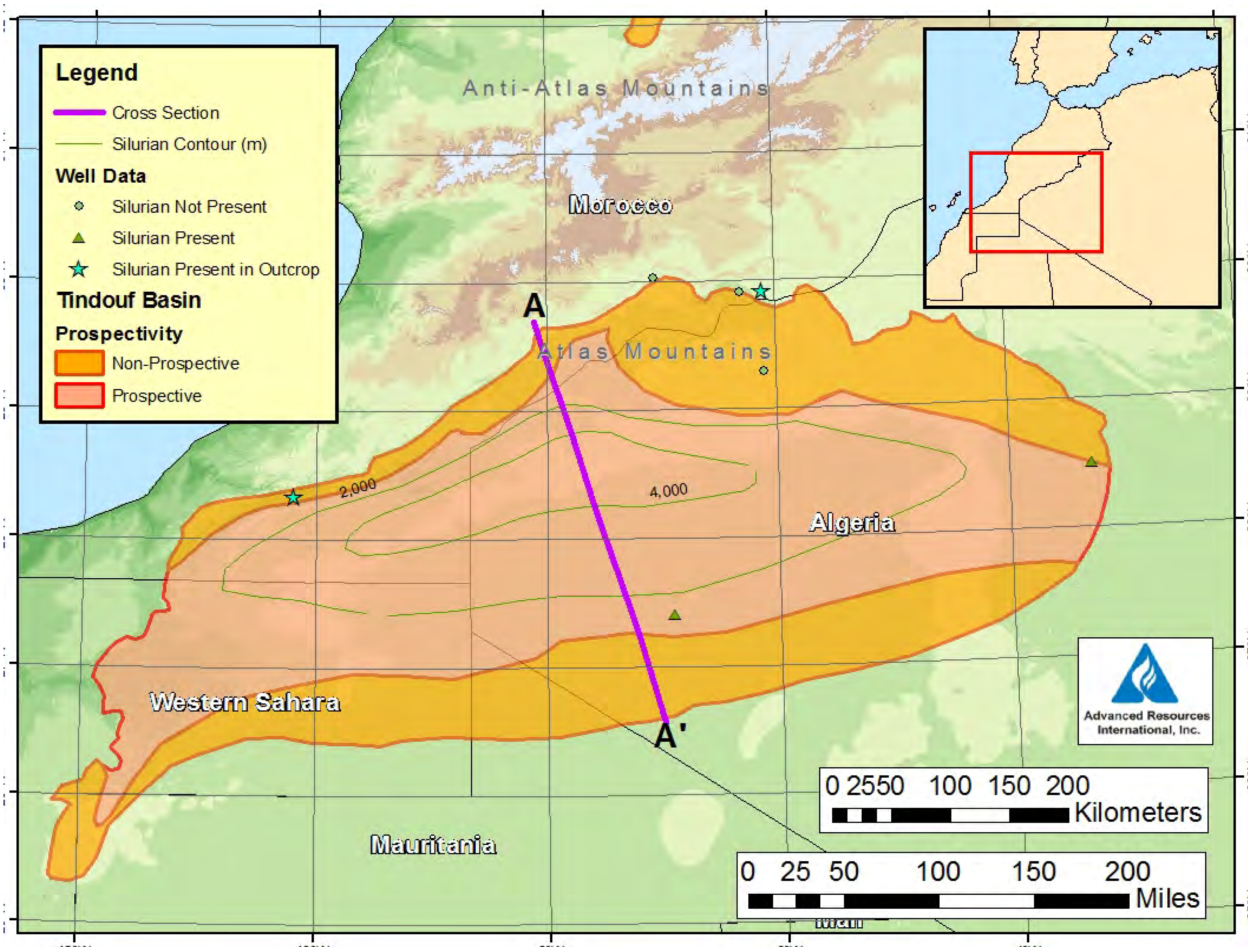


TINDOUF BASIN

Geologic Characterization

The Tindouf Basin is the westernmost of the major North African Paleozoic basins, covering 77,200 mi^2. It is bounded by the Anti-Atlas Mountains and Ougarta Arch to the north and the Reguibate Massif in the south, Figure IX-3. Although once covered unconformably by a blanket of Mesozoic to early Tertiary sediments, the Paleozoic now crops out over much of the region, preserved in an asymmetric depression with a broad gentle southern flank and steeply dipping more structurally complex northern margin, Figure IX-4.

Figure IX-3. Tindouf Shale Prospective Area, SE Anatolian Basin, Morocco



The basin was a large depocenter from late Ordovician to Carboniferous time and accumulated layers of organic rich Silurian, Devonian (Frasnian) and Carboniferous (Visean) shales, Figure IX-4. However, due to the Hercynian orogeny, the prospectively of these shale formations is uncertain. Heavy heat flow through the basin from igneous intrusion caused the Tindouf Basin shales to reach high maturity through the Carboniferous. Uplifting and erosion of these shales may have caused significant underpressuring, as the shales were not buried deep enough to replenish hydrocarbons dissipated during the orogeny. This report will focus on the Silurian “Hot Shale” because of greater data availability for this shale package.

We have identified a 53,340 mi^2 prospective area in the Tindouf Basin, based on depth and thermal maturity data. The northern boundary of the prospective area is formed by the 1,000 meter depth contour line. The southern boundary is formed by the 1% Ro thermal maturity contour line. While drilling density in the basin is extremely low, with an average of only one well for every 5,000 mi^2, the data suggest that organic rich, basal Silurian shales were deposited throughout the basin2. It appears that additional well and seismic data has been collected by various international companies in partnership with Moroccan oil company ONHYM, but these data are not in the public domain.

Reservoir Properties (Prospective Area)

Silurian. Within the prospective area, depth to the base of the Silurian “Hot Shale” ranges from 3,300 feet to 15,000 feet, Figure IX-5[3]. Present day TOC content ranges from 0.5% to 7%. It is likely that the TOC was much higher during the time of hydrocarbon generation, due to the basin’s very high thermal maturity[4]. ARI assumes an average TOC content of 5%. Thermal maturity decreases southward through the basin, ranging from 1% to over 3% Ro. Organically rich net thickness is assumed to be 50 feet, based on data from a well drilled in the southern flank of the basin[5].

Resources

We estimate that the Silurian “Hot Shale” in the Tindouf Basin contains a low resource concentration of 18 Bcf/mi^2. While the shale formation is organically rich and inside the gas window, it is very thin, thus limiting it’s resource potential. Over the 55,340 mi^2 prospective area of the basin, we estimate a risked shale gas in-place of 251 Tcf, with 50 Tcf technically recoverable.

Figure IX-4. Tindouf Basin Stratigraphic Column[6]

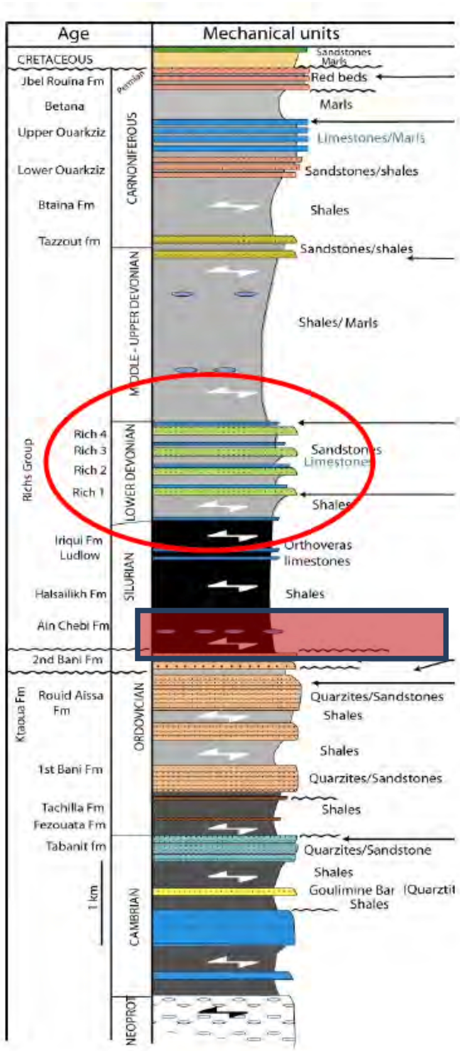
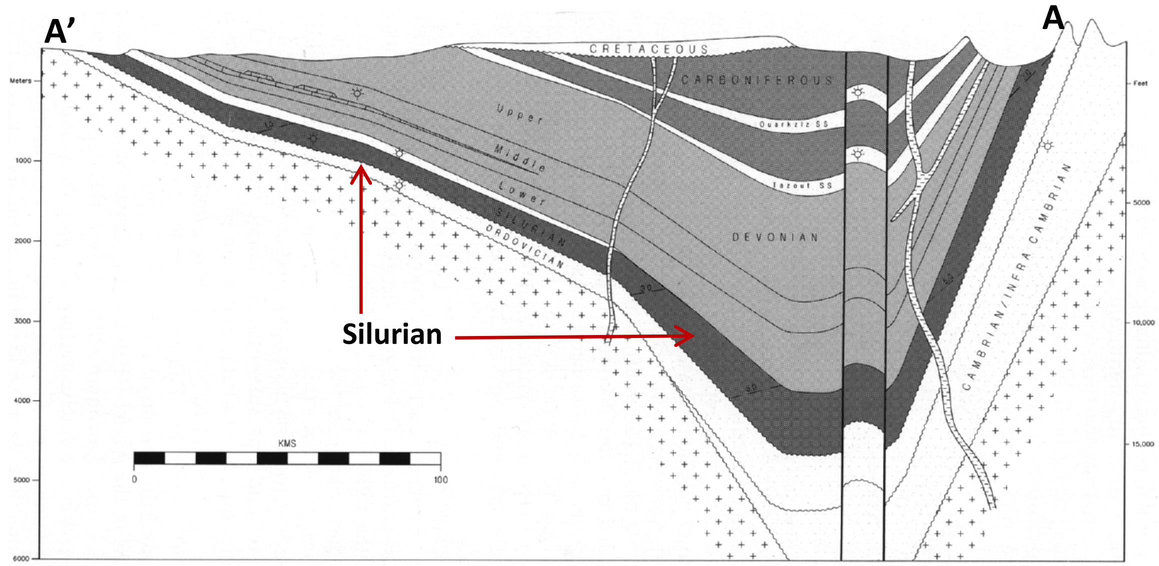


Figure IX-5. Tindouf Basin Cross Section3



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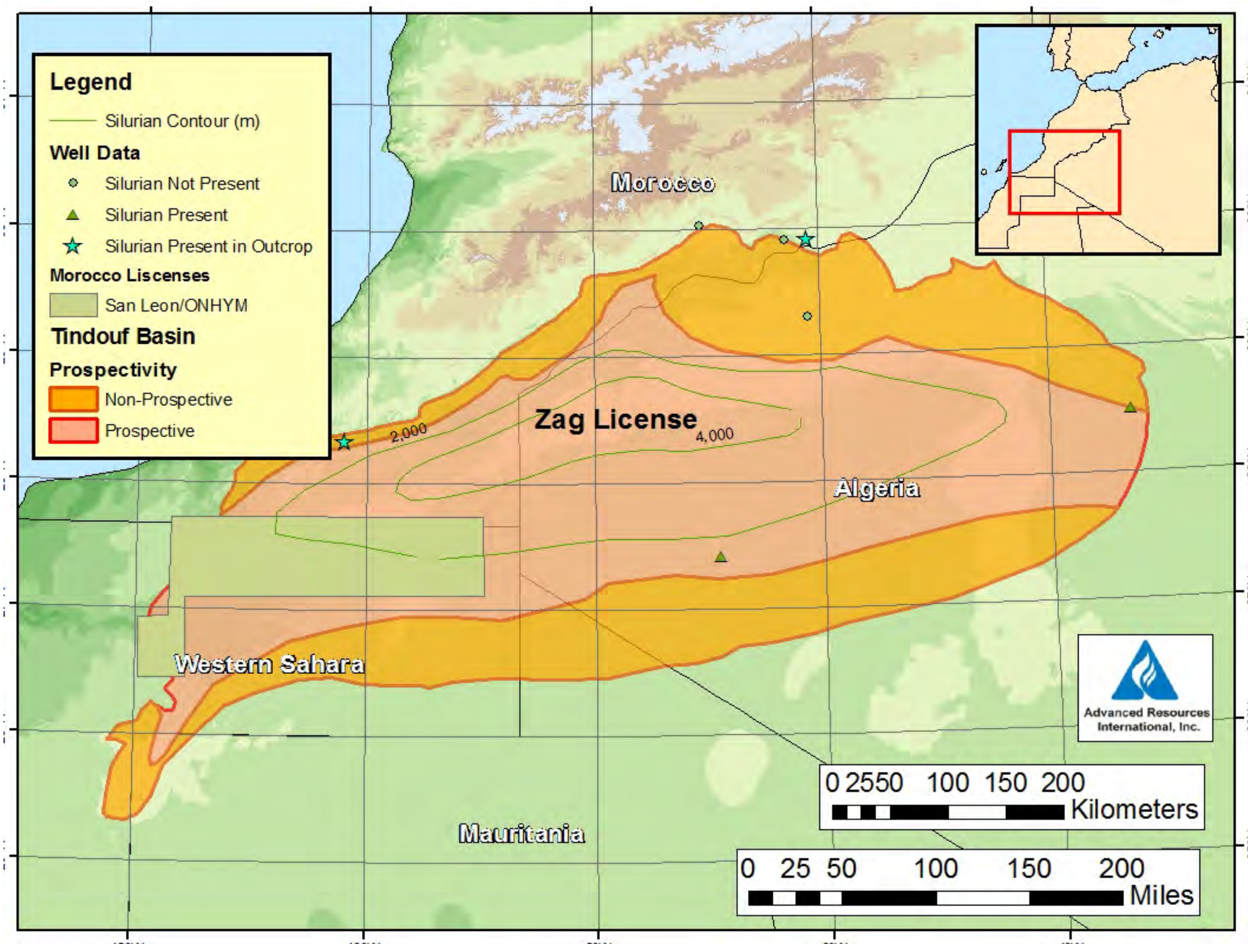
Activity

The Moroccan national oil and gas company ONHYM has been studying shale gas potential in the country since mid-2010 and plans to collect seismic data in the beginning of 2011 and drill its first shale gas exploration well in the second half of 2011. The well will be drilled in partnership with San Leon Energy (Ireland) and Longreach Oil and Gas (Canada), on the Zag exploration license, Figure IX-6[7].

Figure IX-6. Tindouf Basin Exploration Acreage



TADLA BASIN

Geologic Characterization

The Talda Basin is a 3,100 mi^2 intracratonic basin located in Central Morocco, within the Moroccan Mesta. The basin fill contains approximately 16,500 feet of Paleozoic through Cenozoic sedimentary strata, Figure IX-7. Paleozoic rocks dominate the basin, except in areas where uplift caused their erosion. The basin is bounded by the Central Massif in the north, the Atlas Mountains in the east, the Jebiliet Massif in the south and Rehamna Massif in the west. The Fkih Ben Salah Fault divides the basin into a southeast section, characterized by complex tectonics, heavy folding and faulting, and a northwest section, with thick carboniferous strata and minor, infrequent faulting.[8]

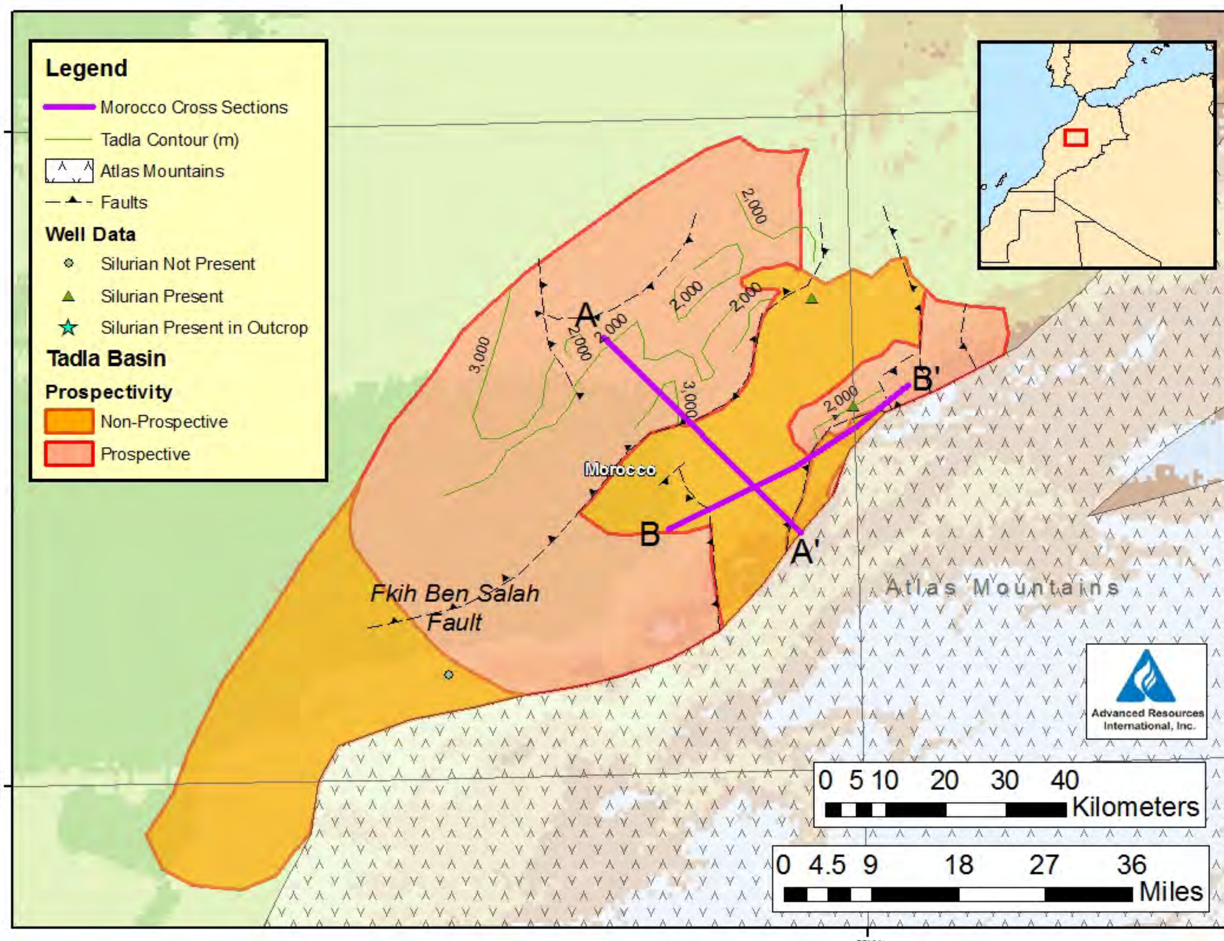
As in the Tindouf Basin, regional uplifting during the Hercynian and Alpine eroginies exposed the Silurian, Devonian and Ordovician shales after they had matured and begun to generate hydrocarbons, Figure IX-8. Though they were subsequently buried on the western edge of the basin by approximately 6,500 feet of Cretaceous and Tertiary sediments, it is unlikely the shales generated additional gas after reburial, Figure IX-98. As such, this basin is at high risk for underpressuring, though data is not available to confirm this assumption.

The 1,670 mi^2 prospective area of the Tadla Basin is bounded by the 1,000 meter depth contour line, various faults and the boundary with the Atlas Mountain range to the east. Little data is available in the southern portion of the basin. The southern boundary of the prospective area is assumed at the location of a well which did not encounter any organically-rich Silurian strata.

Reservoir Properties (Prospective Area)

Silurian. The lower Silurian "Hot Shale" is at its deepest west of the Fkih Ben Salah Fault, where they average 6,500 feet to 9,800 feet deep8. To the east, it becomes more shallow, rarely reaching lower than 6,500 feet, Figure IX-9. Average depth in the prospective area is assumed to be 6,5608. Where it has not been eroded, the Silurian section can reach up to 800 feet thick, with an approximately 300 feet of organically rich material, of which 200 feet are net shale.[9] Though TOC data from outcrops suggest organic content reaching as high as 10% to 12%[10], well data from inside the prospective area shows TOC values closer to 2%, which have been used in this analysis. The Silurian "Hot Shale" is highly mature over the prospective area, with Ro values between 1.5% and 3%.8

Figure IX-7. Talda Basin Prospective Area, Morocco



Resources

Based on the reservoir characteristics discussed above, we calculate a moderate 49 Bcf/mi^2 resource concentration for the Silurian "Hot Shale" of the Tadla Basin. Using the 1,670 mi^2 prospective area, we estimate the basin contains 16 Tcf of risked gas in-place, with 3 Tcf technically recoverable.

Activity

As of yet, there is no reported shale gas exploration activity underway in the Tadla Basin.

Figure IX-8. Tadla Basin Stratigraphic Column8

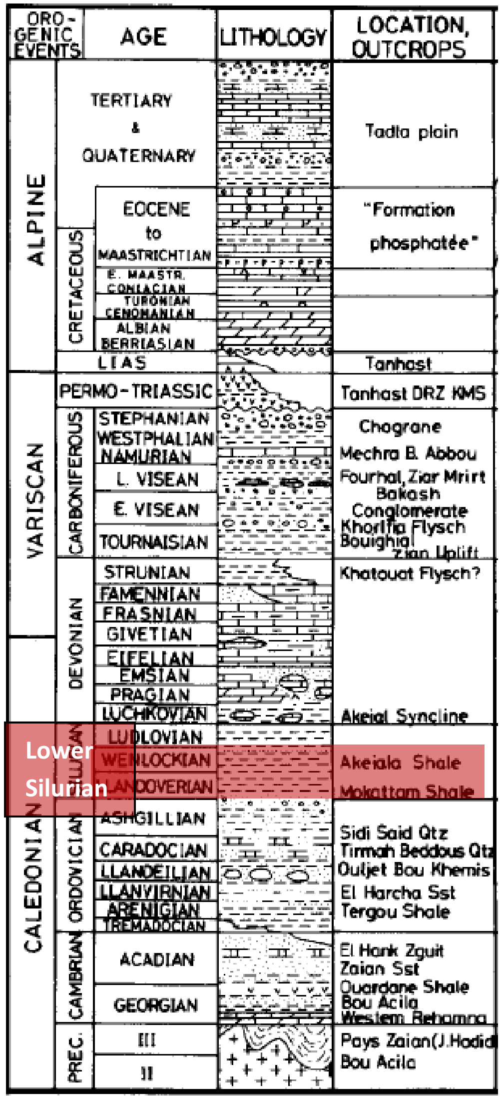
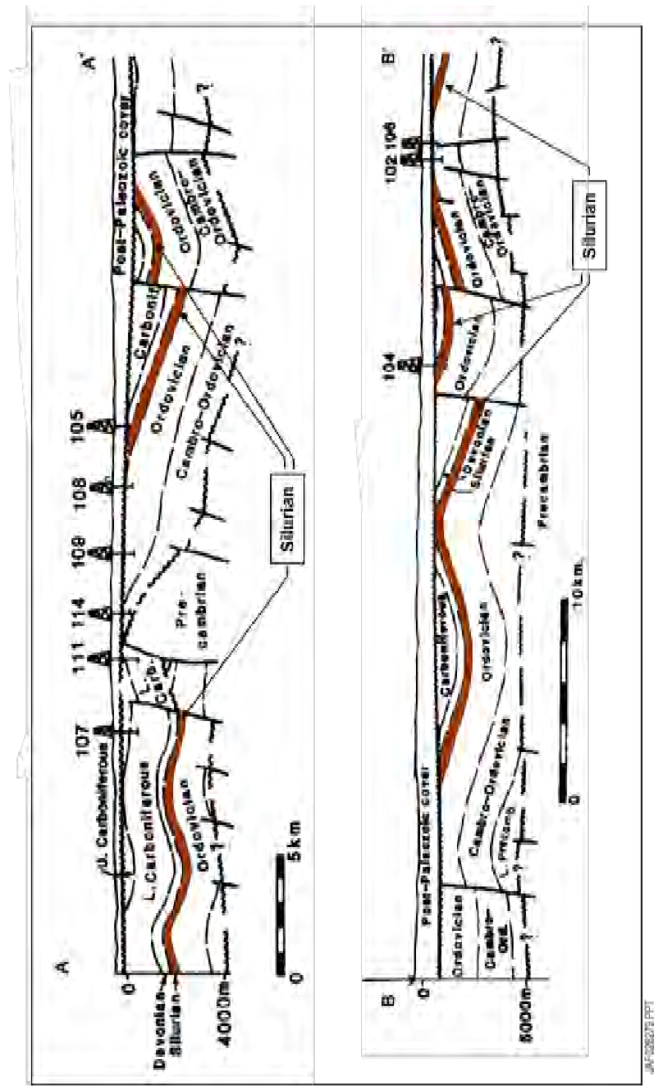


Figure IX-9. Tadla Basin Cross Sections



Advanced Resources International, Inc.

MOROCCO

Morocco is heavily dependent on natural gas imports to meet its consumption needs. In 2009, the country consumed 0.05 Bcfd of natural gas, of which 0.049 Bcfd were imported[11]. The country's natural gas reserves are too small to be reported by the EIA. ARI estimates that Morocco possesses 68 Tcf of risked shale gas in-place, of which 11 Tcf is technically recoverable.

WESTERN ALGERIA

Algeria is the sixth largest gas producer in the world, with marketed production of 8.2 Bcf per day and reserves of 159 Tcf, as of 2009. The country is also the eighth largest oil producer in OPEC, producing 2.1 million barrels of oil per day from reserves of 12.2 billion barrels. Gas production has been increasing over the recent decade, though at a slower rate than proved reserves. ARI estimates that southwestern Algeria possesses 160 Tcf of risked shale gas in-place, of which 35 Tcf is technically recoverable. The Ghadames basin in northern Algeria contains an additional 653 Tcf of risked gas in-place, of which 196 Tcf is technically recoverable.

WESTERN SAHARA

The EIA does not carry natural gas production or consumption data for Western Sahara. ARI estimates that there is 37 Tcf of risked shale gas in-place in Western Sahara, of which 7 is technically recoverable.

MAURITANIA

The EIA does not carry natural gas production or consumption data for Mauritania. ARI estimates that there is 2 Tcf of risked shale gas in-place in Mauritania, of which 0.4 Tcf is technically recoverable.

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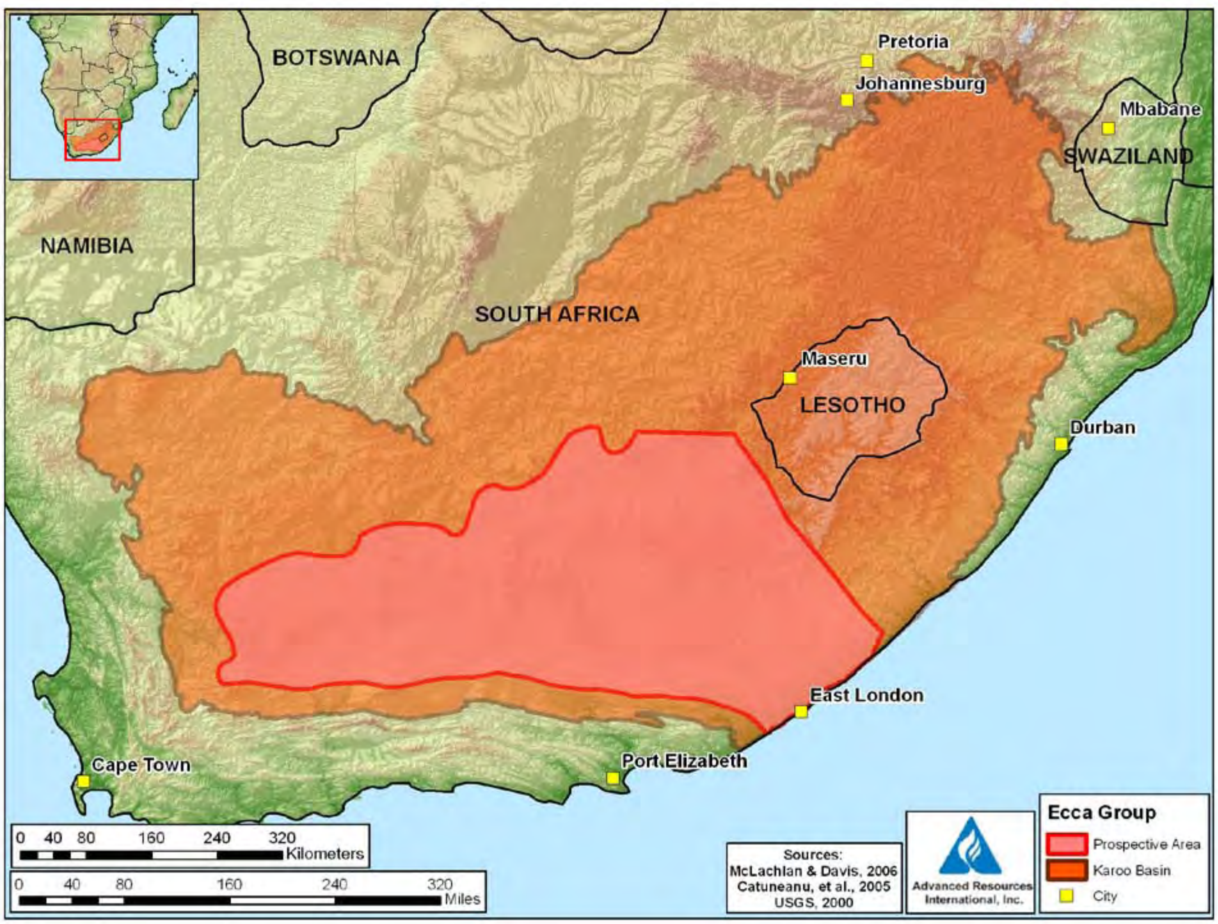
X. SOUTH AFRICA

INTRODUCTION

South Africa has one major sedimentary basin that contains thick, organic-rich shales - - the Karoo Basin in central and southern South Africa, Figure X-1. The Karoo Basin is large (236,000 mi^2), extending across nearly two-thirds of the country, with the southern portion of the basin potentially favorable for shale gas. However, the basin contains significant areas of volcanic (sill) intrusions that may impact the quality of the shale gas resources, limit the use of seismic imaging, and increase the risks of shale gas exploration.

Figure X-1: Outline of Karoo Basin and Prospective Shale Gas Area of South Africa[1,2,3]



The Permian-age Ecca Group, particularly the organically rich source rocks in the Lower Ecca Formation, is the shale gas resources targeted by this resource assessment. Of particular interest are the organically rich, thermally mature black shales of the Whitehill Formation. This unit is regionally persistent in composition and thickness and can be traced across most of the Karoo Basin. [4]

Based on limited preliminary data extracted from a variety of geological studies, ARI believes that the Karoo Basin holds significant volumes of shale gas resources. We estimate that the Lower Ecca Group shales in this basin contain 1,834 Tcf of risked gas in-place, with risked recoverable shale gas resources of 485 Tcf, Table X-1.

Table X-1: Shale Gas Reservoir Properties and Resources of the Karoo Basin

Basic Data	Basin/Gross Area		**Karoo Basin (236,400 mi²)**		
	Shale Formation		Prince Albert Fm	Whitehill Fm	Collingham Fm
	Geologic Age		Lower Permian	Lower Permian	Lower Permian
Physical Extent	Prospective Area (mi^2)		70,800	70,800	70,800
	Thickness (ft)	Interval	200 - 800	100 - 300	100 - 300
		Organically Rich	400	200	200
		Net	120	100	80
	Depth (ft)	Interval	6,000 - 10,500	5,500 - 10,000	5,200 - 9,700
		Average	8,500	8,000	7,800
Reservoir Properties	Reservoir Pressure		Overpressured	Overpressured	Overpressured
	Average TOC (wt. %)		2.5%	6.0%	4.0%
	Thermal Maturity (%Ro)		3.00%	3.00%	3.00%
	Clay Content		Low	Low	Low
Resource	GIP Concentration (Bcf/mi^2)		43	59	36
	Risked GIP (Tcf)		453	995	386
	Risked Recoverable (Tcf)		91	298	96

A number of major and independent companies have signed Technical Cooperation Permits (TCPs) to pursue shale gas in the Karoo Basin, including Royal Dutch Shell, Falcon Oil and Gas, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia and Anglo Coal of South Africa.

The Ecca Group Shales of the Karoo Basin

The Karoo foreland basin is filled by over 5 kilometers of Carboniferous to Early Jurassic sedimentary strata. The Early Permian-age Ecca Group shales underlie much of the 236,000-mi^2 Karoo Basin, cropping out along the southern and western basin margins, Figure X-1. The Ecca Group consists of a sequence of mudstone, siltstone, sandstone and minor conglomerates.[5]

The larger Ecca Group, encompassing an interval up to 10,000 feet thick in the southern portion of the basin, is further divided into the Upper Ecca (containing the less thick but organically rich Fort Brown and Waterford Formations) and the Lower Ecca (containing the Prince Albert, Whitehill and Collingham Formations), Figure X-2. The three Lower Ecca shale units are the exploration targets of this resource assessment.

A regional southwest to northeast cross-section illustrates the tectonics of the Cape Fold Belt that limits the Ecca Group on the south, establishing the oil-gas thermal maturity boundary within the Ecca Group on the north, Figure X-3.

The prospective area for the Lower Ecca shales is estimated at 70,800 mi^2 (unrisked). The boundaries of the prospective area are defined by the outcrop of the Upper Ecca Group on the east, south and west/northwest and the pinch-out of the Lower Ecca Shales on the northeast. The dry gas window is south of the approximately 30^o latitude line, Figure X-1.

Major portions of the prospective area have volcanic (sill) intrusions and complex geology, with the most extensive and thickest sills located within the Ecca Group.[6] This unusual condition creates significant exploration risk in pursuing the Lower Ecca shale gas resources in the Karoo Basin, Figure X-4.

Figure X-2. Stratigraphic Column of the Karoo Basin of South Africa

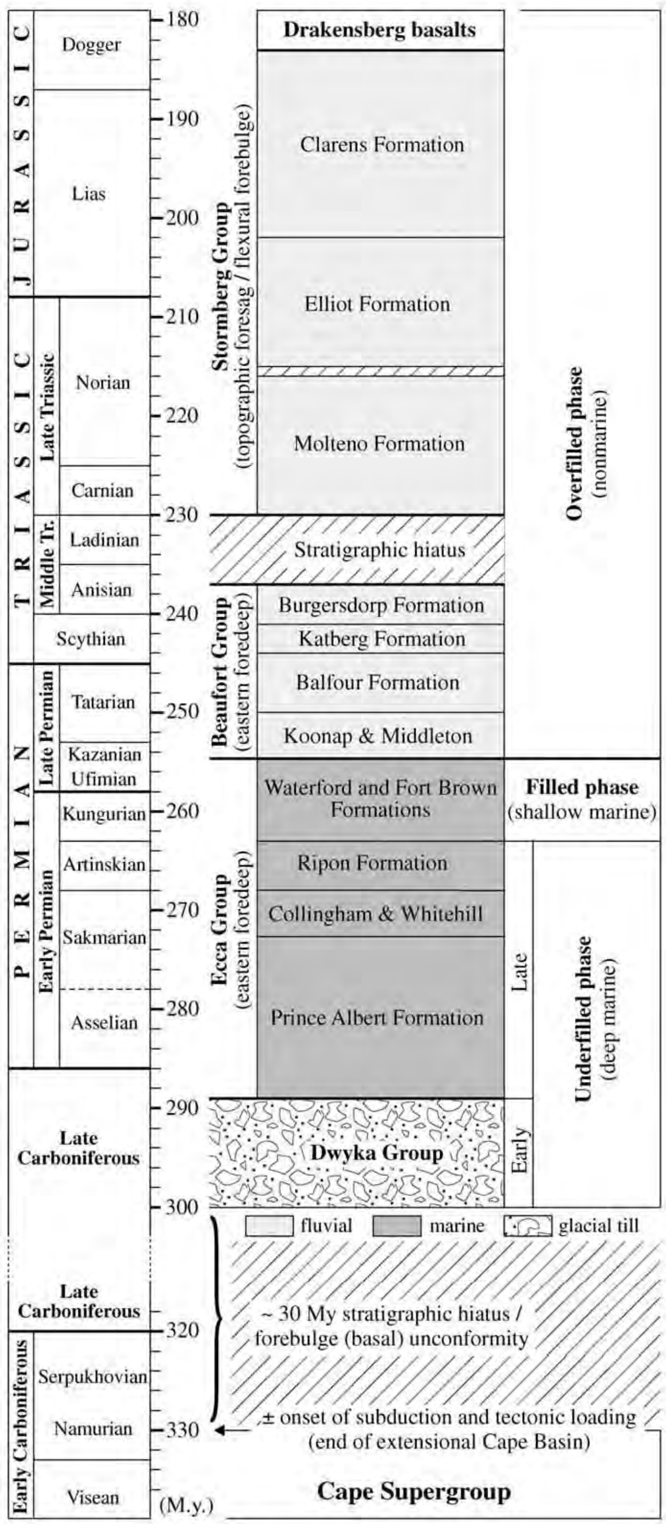


Figure X-3. Schematic Cross-Section of Southern Karoo Basin and Ecca Group Shales[7]

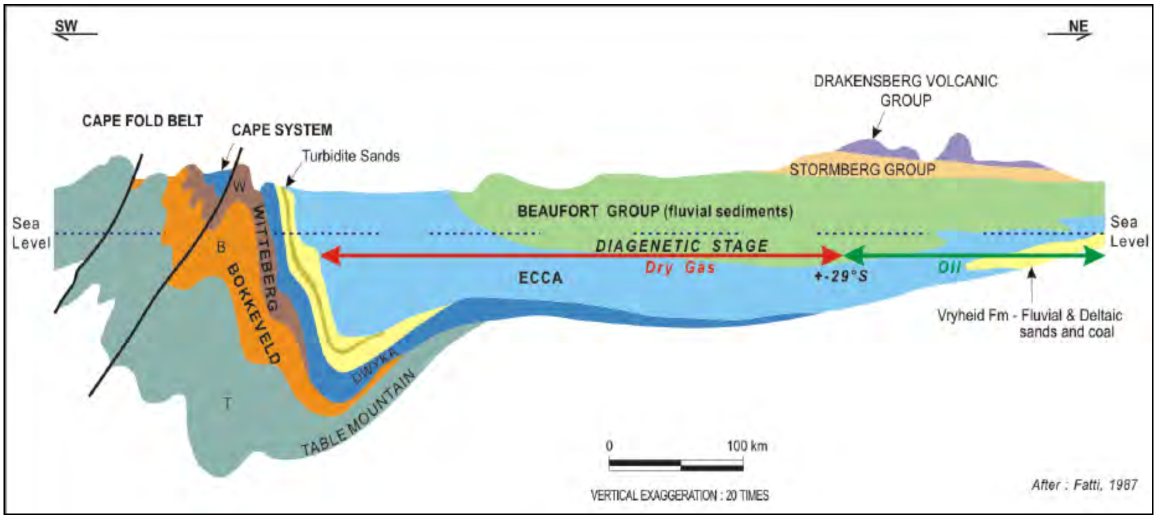
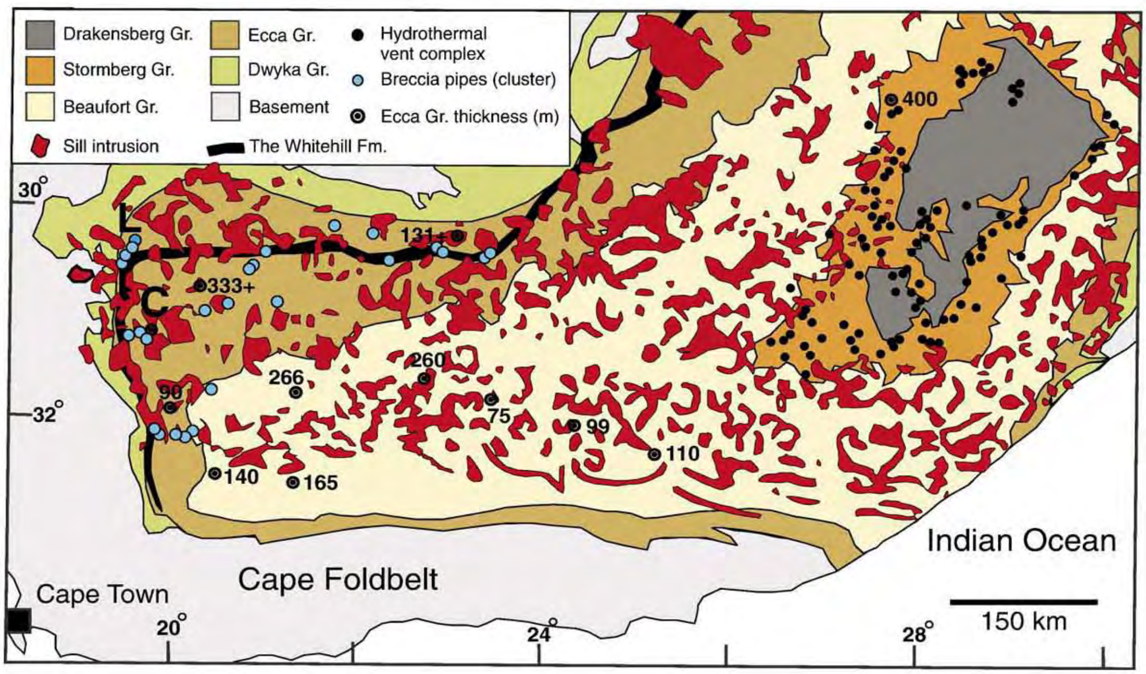


Figure X-4. Volcanic Intrusions in the Karoo Basin, South Africa[8]

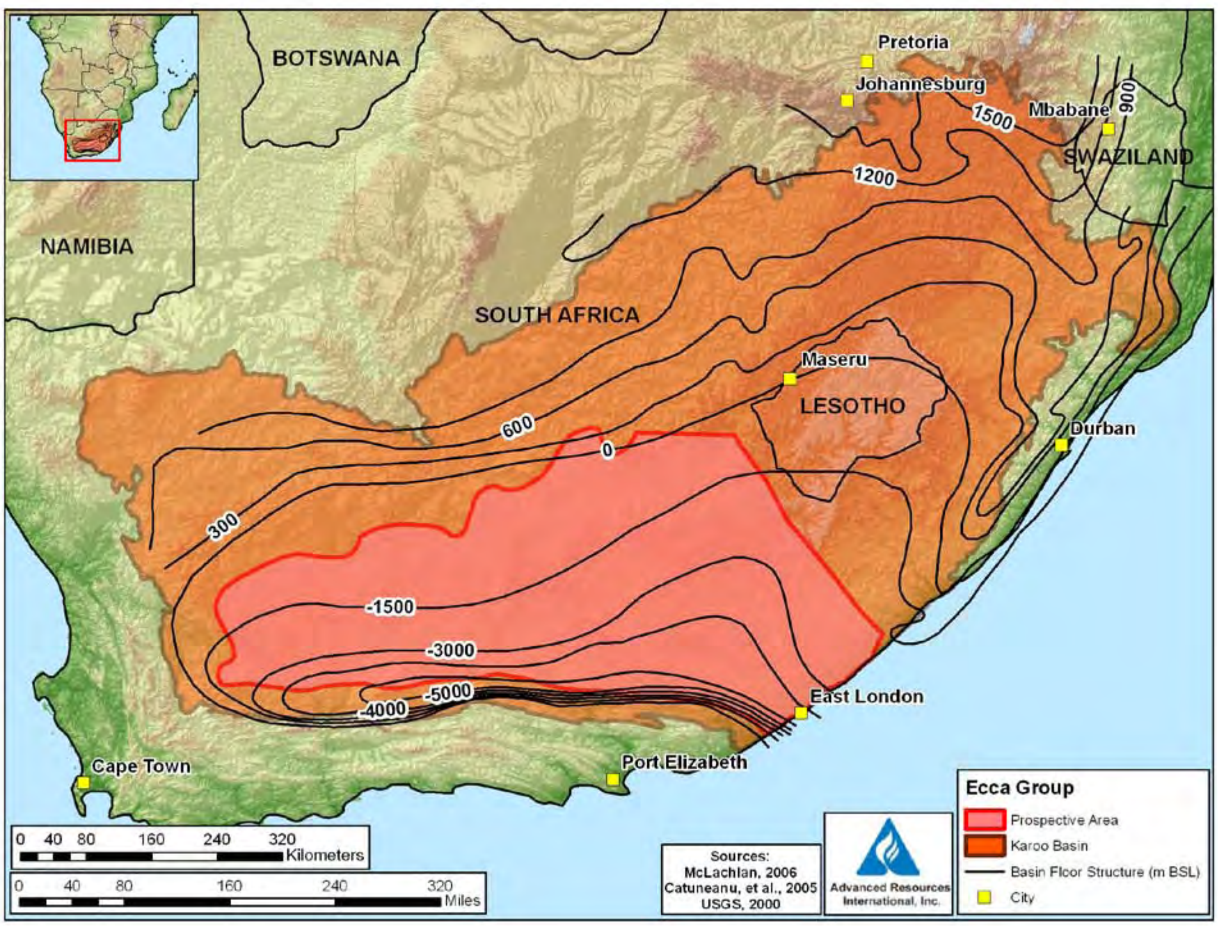


Lower Ecca Group Shales

The Lower Ecca Group comprises the thick basal Prince Albert Formation, overlain by the thinner Whitehill and Collingham Formations. Each of these sedimentary units has been individually assessed and is discussed below.

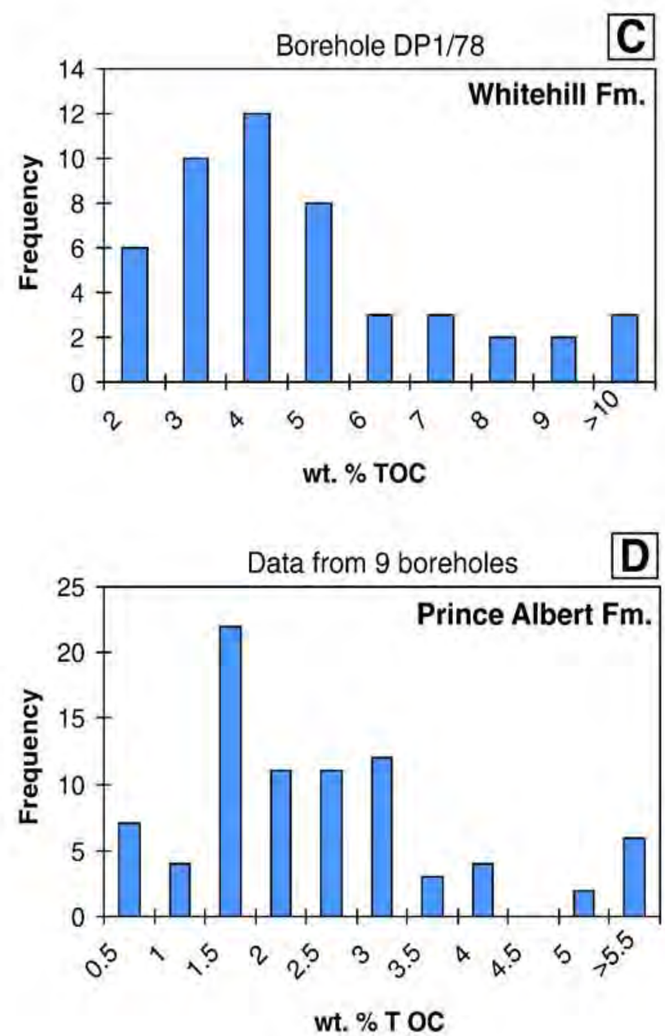
Prince Albert Shales. The Lower Permian Prince Albert Formation offers a thick, thermally mature shale gas area in the Karoo Basin. The drilling depths to the Prince Albert Shale range from 6,000 to over 10,000 feet, averaging about 8,500 feet in the deeper prospective area on the south, Figure X-5. The Prince Albert shale has a gross thickness that ranges from 200 to 800 feet, averaging 400 feet, with a net organically rich thickness of about 120 feet.

Figure X-5. Lower Ecca Group Structure Map, Karoo Basin, South Africa[1,2,3]



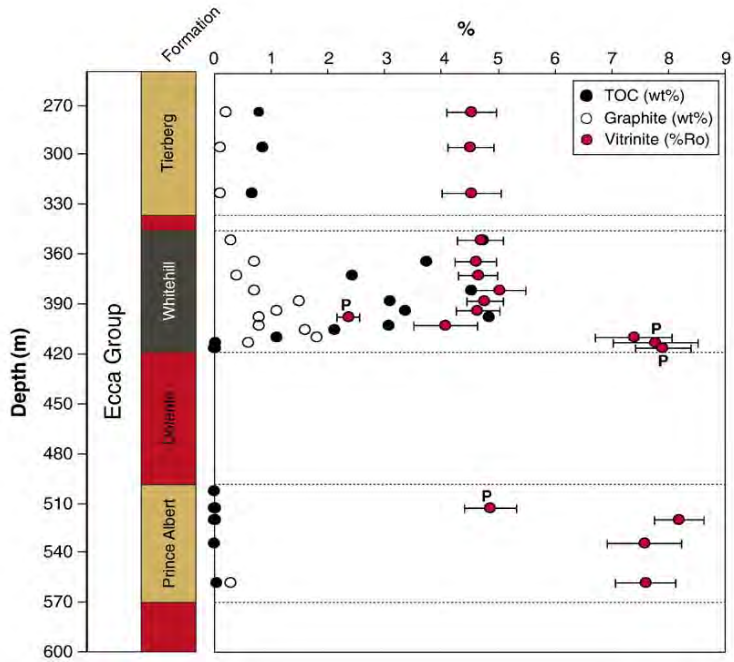
The total organic content (TOC) in the Prince Albert shale prospective area and within the organically rich net pay interval generally ranges from 1.5 to 5.5%, averaging 2.5%, Figure X-6. Local TOC values of up to 12% have been recorded.[9] However, in areas near volcanic intrusions, much of the organic content may have been lost or converted to graphite.

Figure X-6. Total Organic Content of Prince Albert and Whitehill Formations



Because of the presence of volcanics, the thermal maturity of the Prince Albert shale is high, estimated at 2% to 4% Ro, placing the shale well into the dry gas window. In areas locally influenced by volcanics the formation is over-mature, with vitrinite reflectance (Ro) values reaching 8%, indicating that the organic content has been transformed into graphite and CO_2, Figure X-7. The Prince Albert shale was deposited as a deep marine sediment and is inferred to have mineralogy favorable for shale gas stimulation.

Figure X-7. Carbon Loss in Lower Ecca Group Metamorphic Shale

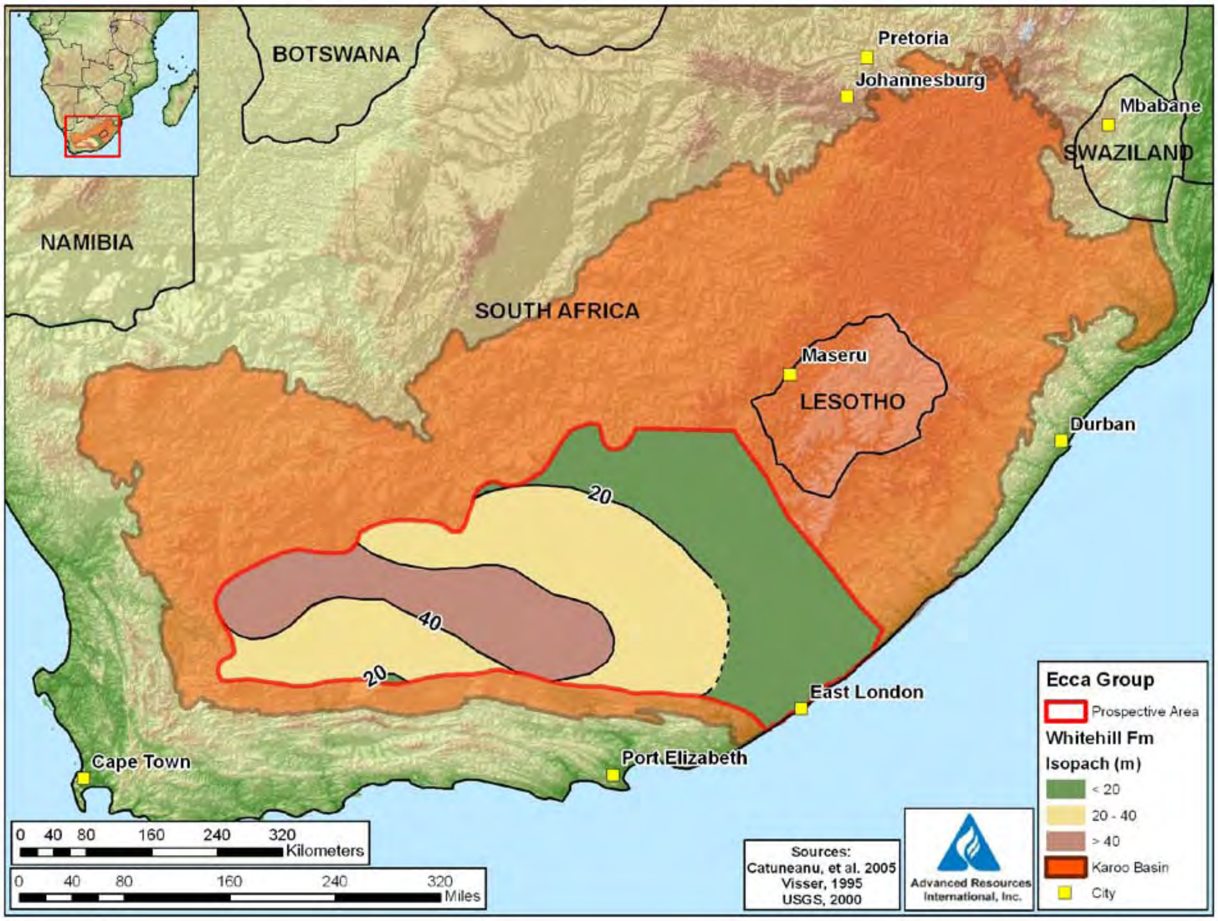


Based on limited well data, primarily from the Cranemere CR 1/68 well completed in the Upper Ecca interval, the Prince Albert shale appears overpressured and has a high geothermal thermal gradient.

Whitehill Shale. The highly organically rich Lower Permian Whitehill Formation contains one of the main shale gas targets in the Karoo Basin of South Africa. The drilling depth to the Whitehill Shale ranges from 5,500 to 10,000 feet, averaging 8,000 feet for the prospective area. The Whitehill Shale has an estimated gross organic thickness of 100 to 300 feet,[10] with an average net thickness of 100 feet within the prospective area, as shown by the isopach map on Figure X-8.[11]

The total organic content (TOC) in the prospective area (and within the net shale thickness) ranges from 3% to 14%, averaging a highly rich 6%, Figure X-6. Local areas show TOC contents up to 15%. In areas near volcanic intrusions, the remaining organic content may range from 2% to 4%, with portions of the organics converted to graphite, Figure X-7. The main minerals in the Whitehill Formation are quartz, pyrite, calcite and chlorite making the shale favorable for hydraulic fracturing. The Whitehill Shale is assumed to be overpressured. The thermal maturity (Ro) of the Whitehill Shale in the prospective area ranges from 2% to 4%, placing the shale well into the dry gas window.

Figure X-8. Preliminary Isopach Map of the Whitehill Formation[2,3,11]



The hydrogen and oxygen indexes of the Whitehill Formation indicate a mixture of Type I and Type II kerogen.9 The Whitehill carbon-rich shales were deposited in deep marine, anoxic algae-rich conditions and contain minor sandy interbeds from distal turbidites and storm deposits. [12,13]

Collingham Shale. The Lower Permian Collingham Formation (often grouped with the Whitehill Formation) is the third shale gas exploration target in the Karoo Basin. The Collingham Shale has an upward transition from deep-water submarine to shallow-water deltaic deposits.9 The drilling depth to the Collingham Shale averages 7,800 feet for the prospective area. Except for total organic content, the shale has reservoir properties similar to the Whitehill Shale. It has an estimated gross organic thickness of 200 feet; a net thickness of 80 feet; and TOC of 2% to 8%, averaging 4% for the net thickness investigated. Thermal maturity is high, estimated at 3% Ro, influenced by volcanic intrusions. The shale is assumed to be overpressured based on data from the Upper Ecca Group.

Shale Gas Resources

Prince Albert Shale. The prospective area of the Prince Albert Shale is estimated at 70,800 mi^2. Within the prospective area, the Prince Albert Shale has a resource concentration of about 43 Bcf/mi^2. Given the volcanic intrusives and the limited exploration data, the risked shale gas in-place is estimated at 453 Tcf. Based on favorable TOC and reservoir mineralogy, balanced by complex geology and volcanic intrusions in the prospective area, ARI estimates a risked technically recoverable resource of 91 Tcf for the Prince Albert Shale in the Karoo Basin.

Whitehill Shale. The prospective area for the Whitehill Shale is estimated at 70,800 mi^2. Within this prospective area, the shale has a moderate resource concentration of about 59 Bcf/mi^2. While somewhat more defined than the Prince Albert Shale, the exploration risk is still substantial, leading to a risked shale gas in-place of 995 Tcf. Based on favorable reservoir mineralogy but complex geology, ARI estimates a risked technically recoverable shale gas resource of 298 Tcf for the Whitehill Shale in the Karoo Basin.

Collingham Shale. With a prospective area of 70,800 mi^2 and a resource concentration of 36 Bcf/mi^2, the risked gas in-place for the Collingham Shale is estimated to be 386 Tcf, with a risked technically recoverable resource of approximately 96 Tcf.

Upper Ecca Shales

The Upper Ecca Formation extends over a particularly thick, 1,500 meter (~5,000 foot) vertical interval in the southern Karoo Basin. It contains two shale sequences of interest - - the Waterford and the Fort Brown Formations. These shales were interpreted by some investigators to have been deposited in a shallow marine environment,[2] although others[14] categorize them as lacustrine.

The organic content and thermal maturity of the Upper Ecca shale is considerably less than for the Lower Ecca shale, having a total organic content (TOC) ranging from less than 1% to about 2% and a thermal maturity ranging from 0.9% to 1.1% Ro. The reported thermal maturity places the Upper Ecca shale in the oil to wet gas window.[15]

The Fort Brown Formation shale, as evaluated in the Cranemere CR 1/68 well, was described as dark gray to black and carbonaceous with occasional siltstone stringers. These shales exist over a gross interval of nearly 5,000 feet. One interval of the Fort Brown shale, from 8,154 to 8,312 feet (2,563 to 2,612 m) tested 1.84 million cubic feet per day at a flowing pressure of 2,072 psig, with pressure depleting rapidly, indicating the depletion of gas in fractures and secondary porosity.

Because little additional information is publically available on the reservoir properties of the Fort Brown and Waterford Formations, and because these shales may be oil prone, no further assessment was conducted for the Upper Ecca shales.

The Role of the Karoo Basin on Early Jurassic (Toarcian) Global Warming and Extinction

A most interesting aspect of the Karoo Basin is its potential role in triggering Early Jurassic (Toarcian) global warming approximately 180 million years ago. The triggering mechanism for the global warming, as presented by Svensen et al. (2006), was the rapid formation and transport of greenhouse gases from the deep sedimentary Permian-age reservoirs in the Karoo Basin. This event lasted 200,000 years and was manifested by global warming of ~6^{o}C, anoxic conditions in the oceans and extinction of marine species.

Large volumes of mafic magma intruded the basin in the Early Jurassic. These magmatic sills and dykes were emplaced as part of the large Karoo-Ferrer igneous province, which originally extended across all of current southern Africa.

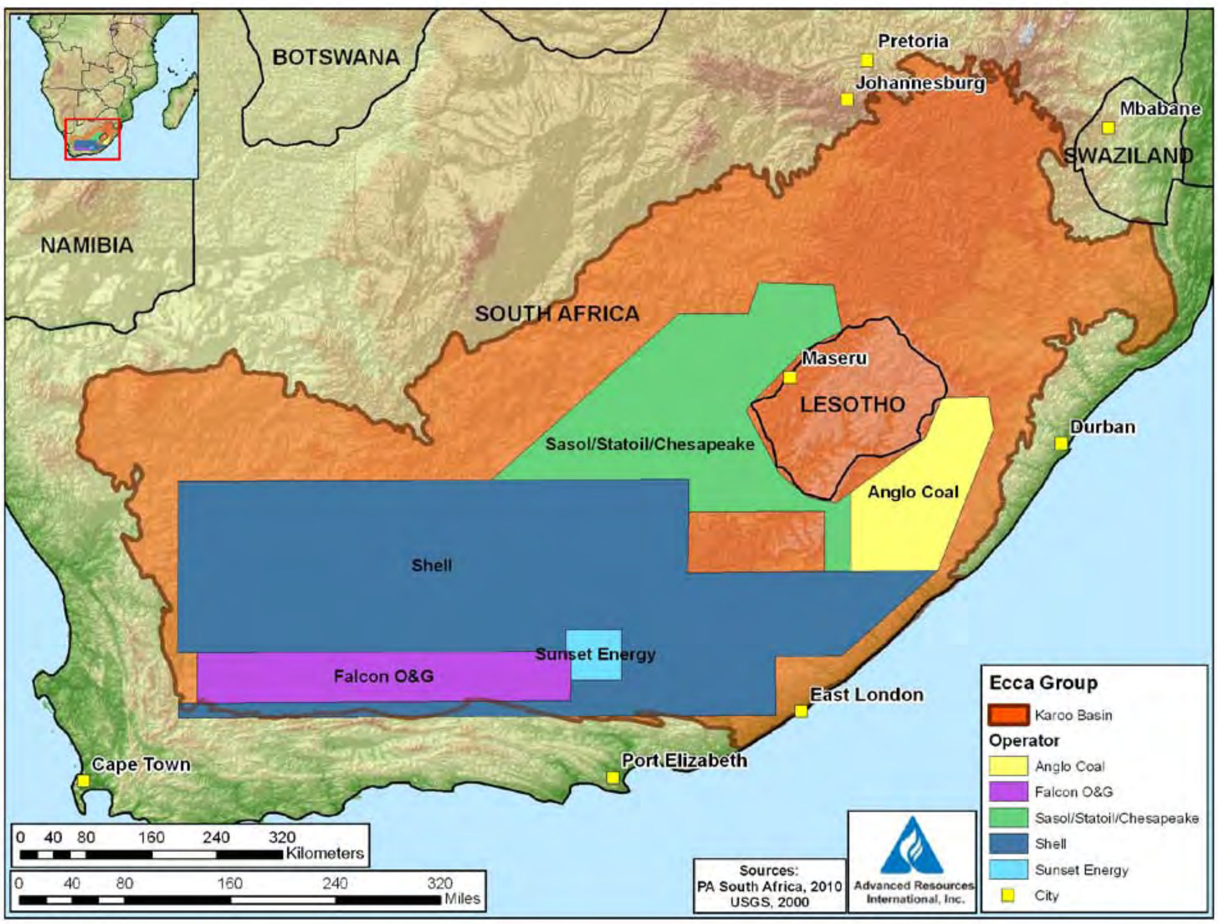
The magma intrusions in the western Karoo Basin created numerous breccia pipes which are sub-vertical cylindrical intrusions generally 20 to 150 meters in diameter, filled with brecciated and metamorphic shale. Based on areal photography, several thousand of these breccia pipes may exist in the Karoo Basin. The associated sills and contact metamorphism resulted in venting of natural gas and CO_2 created by the thermal conversion of the organics in the Ecca Group.

This massive intrusion to the organic-rich sedimentary host rocks of the Ecca Group caused release of up to 1,800 Gt of CO_2 from organic matter in the western Karoo Basin. (Potentially 15 times this amount of CO_2 (27,400 Gt) may have formed in the entire basin during the intrusive event.)[8] In addition, the sills heated shallow sedimentary strata, leading to metamorphic reactions and the formation of hundreds of hydrothermal vent complexes in the central part of the Karoo Basin.[8]

EXPLORATION AND DEVELOPMENT Activity

Falcon Oil and Gas Ltd. was an early entrant into the shale gas play of South Africa, obtaining an 11,600-mi^2 (30,000-km^2) Technical Cooperation Permit (TCP) along the southern edge of the Karoo Basin. Shell obtained a larger 71,400-mi^2 (185,000-km^2) TCP surrounding the Falcon area, while Sunset Energy holds a 1,780 mi^2 (4,600-km^2) TCP to the west of Falcon. The Sasol/Chesapeake/Statoil JV TCP area of 34,000-mi^2 (88,000-km^2) and the Anglo Coal TCP application area of 19,300 mi^2 (50,000-km^2) is to the north and east of Shell's TPC, Figure X-9.

Figure X-9. Map Showing Operator Permits in the Karoo Basin, South Africa[3.16]

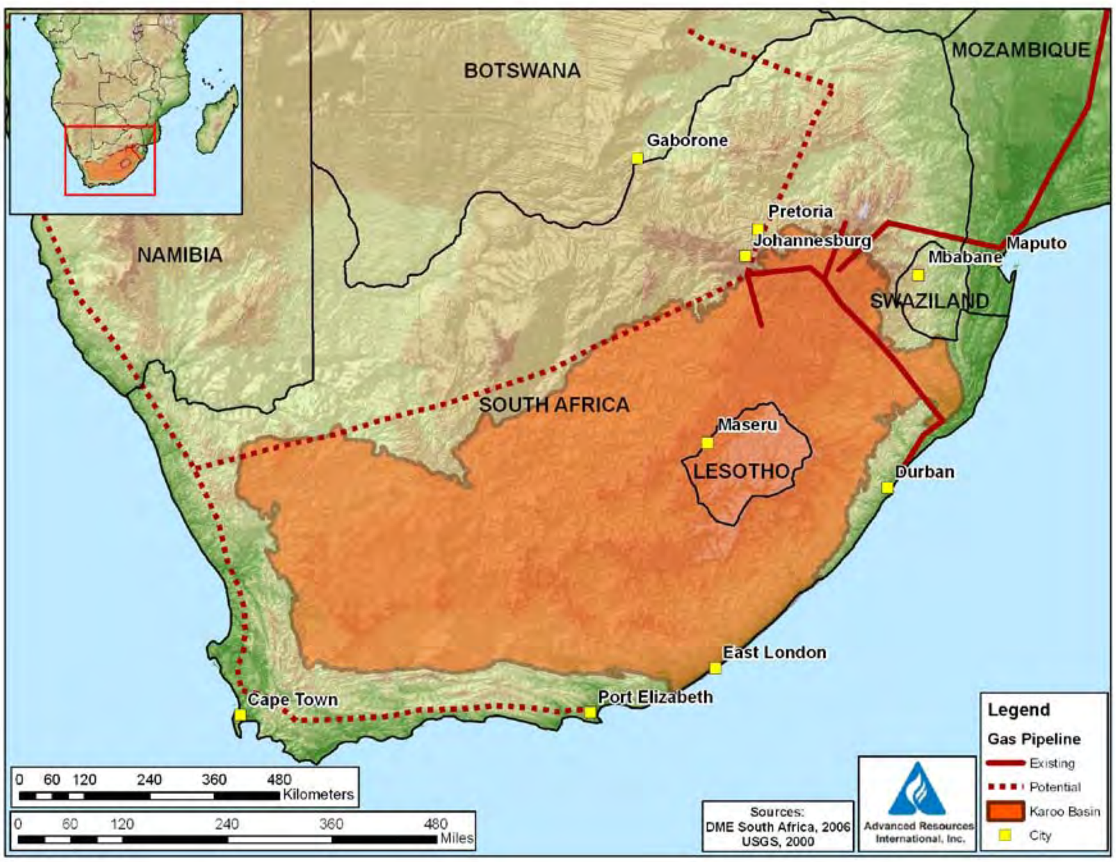


Five older (pre-1970) wells have penetrated the Ecca Shale interval. Each of the wells had gas shows, while one of the wells - - the Cranemere CR 1/68 well - - flowed 1.84 MMcfd from the test zone at 8,154 to 8,312 feet. The gas production, judged to be from fractures and secondary porosity in the shales, depleted relatively rapidly during the 24-hour test. The CR 1/68 well was drilled to 15,282 feet into the underlying Table Mountain quartzite and had gas shows from six intervals, starting at 6,700 to 8,700 feet and ending at 14,350 to 14,650 feet. These shows indicate that the South African shales may be gas saturated.

Natural Gas Profile

Southern Africa produced 115 Bcf of natural gas in 2008. With annual consumption that year of 228 Bcf, South Africa is a net importer, primarily from neighboring Mozambique and Namibia. The natural gas is used primarily for electricity production and as feedstock for the Mossel Bay gas-to-liquids (GTL) plant. (New natural gas production is expected from the Jabulani field in 2012 and the Ibhubesi field in 2013.) Natural gas from Mozambique is imported via a 535-mile pipeline, with current peak capacity of 524 MMcfd. Assuming access to new natural gas reserves, a variety of plans have been set forth to expand the natural gas pipeline system of South Africa, Figure X-10. The technically recoverable shale gas resource for South Africa is estimated at 485 Tcf.

Figure X-10. Natural Gas Pipeline System Map of South Africa[3,17]



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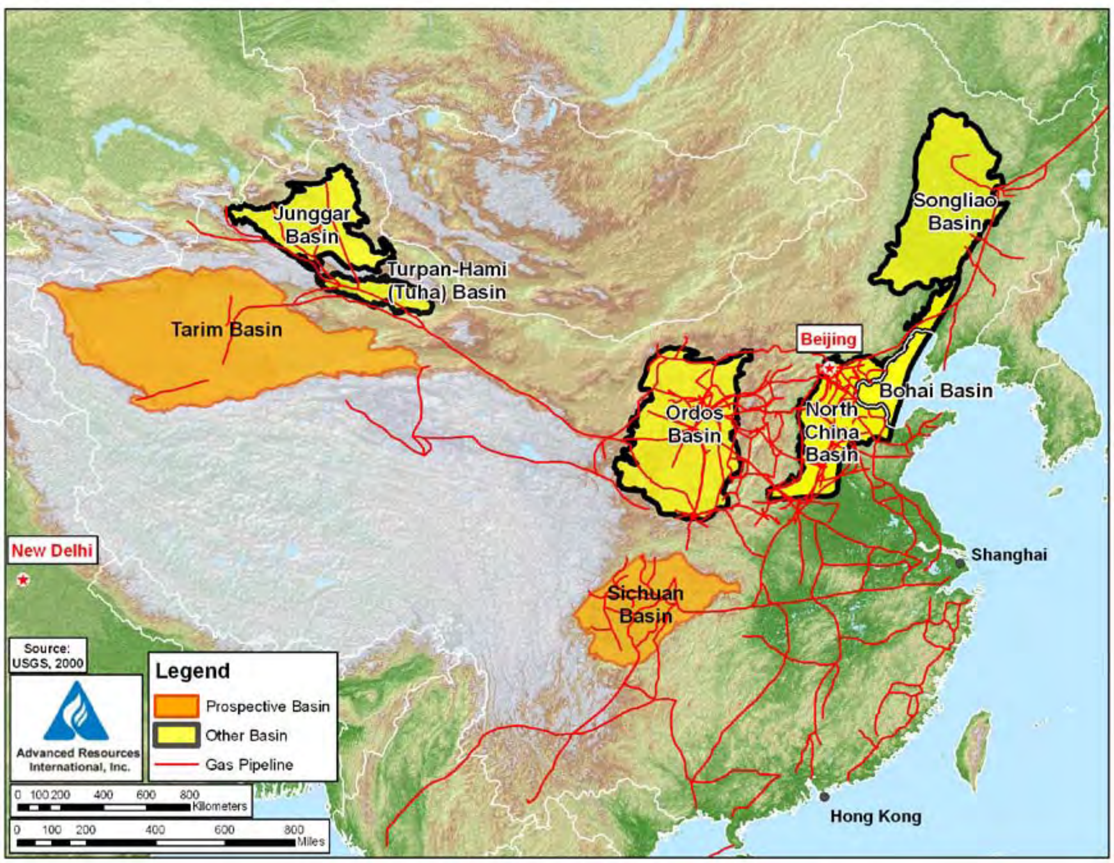
XI. CHINA

INTRODUCTION

China has two large sedimentary basins that contain thick, organic-rich shales with excellent potential for shale gas development, Figure XI-1. These two basins, the Sichuan and the Tarim, contain marine-deposited shales with potentially favorable reservoir quality, including prospective thickness, depth, TOC, thermal maturity, and brittle mineralogical composition. The basins are assessed in detail in this chapter. In addition, China has five sizeable but less prospective shale gas basins with non-marine shales that are only introduced in this chapter.

Figure XI-1. Major Shale Gas Basins and Pipeline System of China



With shale exploration drilling just now being initiated, public information on shale formations in China is quite limited. Reservoir quality remains uncertain, while in-country shale drilling and completion services are still nascent. The future of shale gas development in China is promising, but it seems likely that five to ten years will be needed before production will be at material levels.

The two large marine shale basins of China - - the Sichuan and Tarim - - contain an estimated 25,000 Tcf of total unrisked gas in place with 5,100 Tcf as the risked gas in place, Table XI-1. These estimates are comparable with estimates of prospective gas resources (in-place) published by PetroChina.[1,2] Our estimated risked recoverable resources from these two basins is 1,275 Tcf.

Table XI-1. Shale Gas Reservoir Properties and Resources - - Sichuan and Tarim Basins, China

Basic Data	Basin/Gross Area		**Sichuan Basin (81,500 mi^2)**		**Tarim Basin (234,200 mi^2)**	
	Shale Formation		Longmaxi	Qiongzhusi	O1/O2/O3 Shales	Cambrian Shales
	Geologic Age		Silurian	Cambrian	Ordovician	Cambrian
Physical Extent	Prospective Area (mi^2)		56,875	81,500	55,042	63,560
	Thickness (ft)	Interval	300 - 1,600	200 - 1,400	0 - 5,200	0 - 1,500
		Organically Rich	560	390	520	808
		Net	280	195	260	404
	Depth (ft)	Interval	7,900 - 13,500	8,500 - 15,000	6,500 - 19,700	7,500 - 21,000
		Average	10,700	11,500	13,000	14,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%	2.0%	2.0%
	Thermal Maturity (%Ro)		2.30%	2.50%	2.00%	2.50%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	GIP Concentration (Bcf/mi^2)		80	57	102	141
	Risked GIP (Tcf)		1,373	1,394	897	1,437
	Risked Recoverable (Tcf)		343	349	224	359

SICHUAN BASIN / YANGTZE PLATFORM

Geologic Characterization

The Paleozoic shales in the Yangtze Platform underlie a vast area of some 900,000 km^2 in the mid to lower reaches of the Yangtze River drainage area in south-central China, including portions of Sichuan, Yunnan, Guizhou, Hubei, and western Hunan Provinces. A total 6 to 12 km of sedimentary rock is present in this region, including thick, laterally widespread shales of both marine and non-marine origin within Pre-Cambrian, Cambrian, Ordovician, Silurian, Devonian, Permian, Triassic, and Eocene formations.

The Paleozoic shales in the Yangtze Platform are mainly of marine origin and generally considered prospective for shale gas development. In contrast, the Triassic and younger shales were deposited primarily in freshwater lacustrine environments. Our work, consistent with published information by PetroChina and industry, indicates that the Cambrian and Silurian shales offer the most promise for shale gas development.

The Sichuan Basin in south-central China covers a large 81,500-mi^2 area. This cratonic to foreland-style basin contains four tectonic zones: a Northwest Depression, a Central Uplift, and the East and South Fold Belts. The Central Uplift, characterized by simple structure and relatively few faults, appears the most attractive region for shale gas development. In contrast, the East and South Fold Belts are structurally more complex, with numerous tight folds and large faults, less conducive to shale gas development.

Two promising shale horizons have been identified in the Sichuan Basin. These are thick, organic-rich, thermally mature Lower Cambrian and Lower Silurian marine shales, Figures XI-2 and XI-3. Preliminary data indicate that these shales are low in clay and thus potentially favorable for hydraulic stimulation. However, the Sichuan Basin’s considerable structural complexity, with extensive folding and faulting, appears to be a significant risk for shale gas development.

Figure XI-2. Prospective Lower Silurian Shale Gas Areas, Sichuan Basin, Sichuan Province

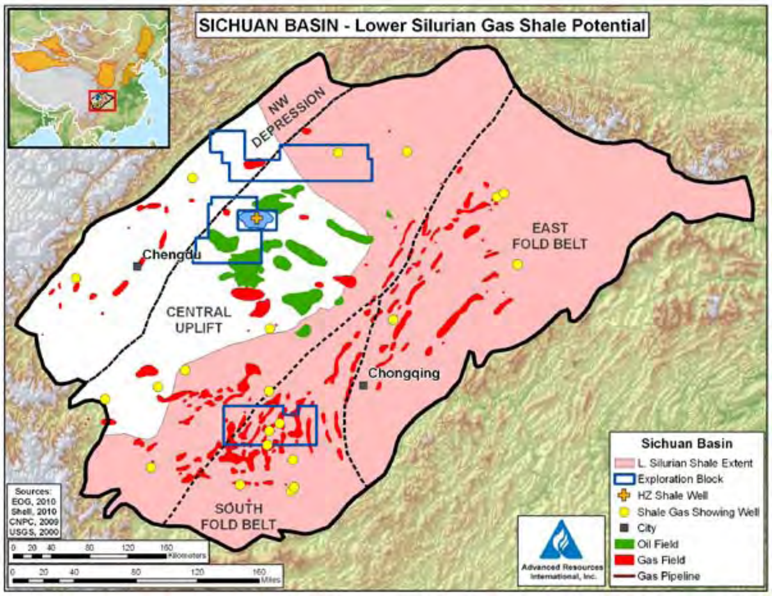
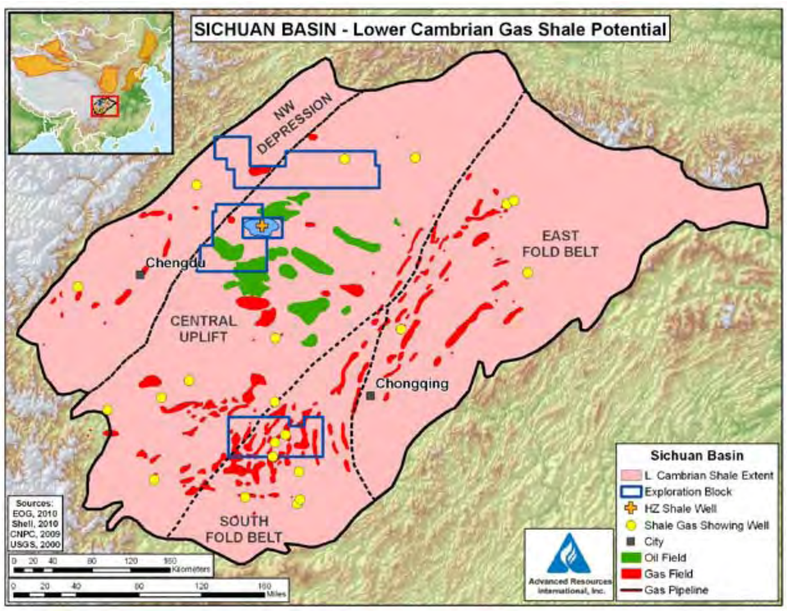
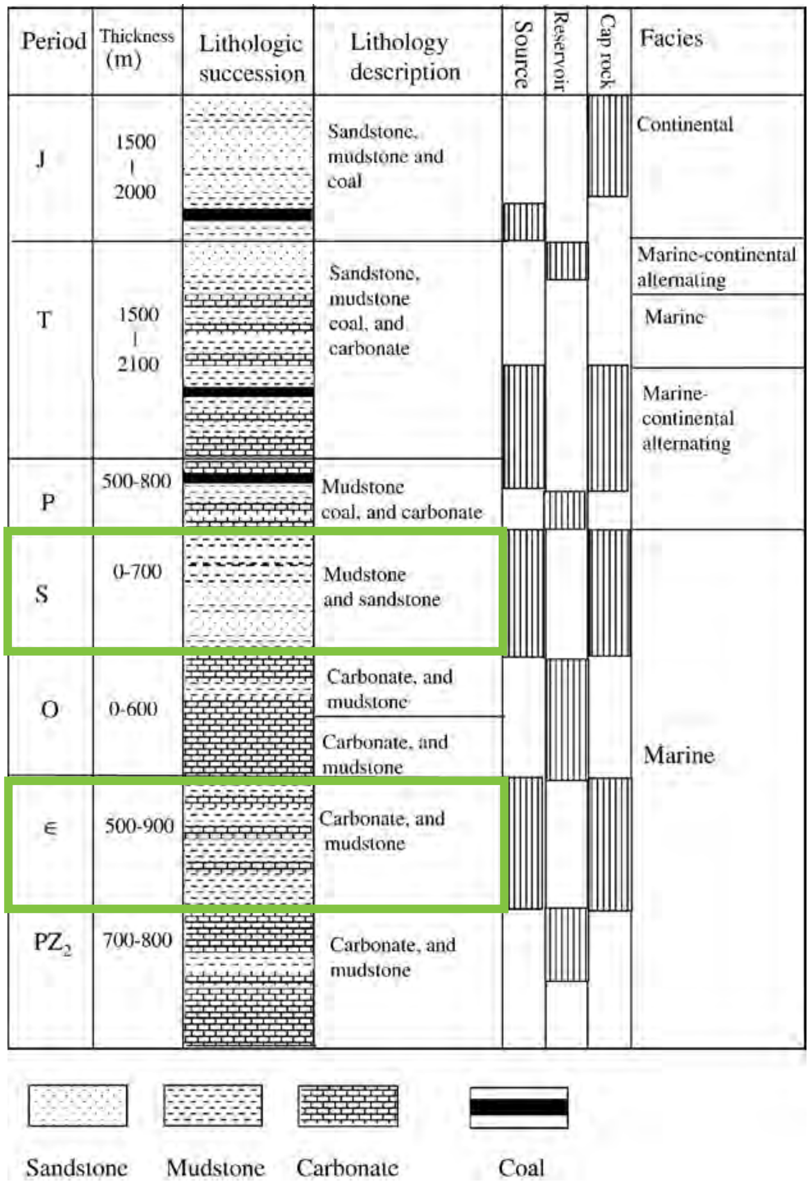


Figure XI-3. Prospective Lower Cambrian Shales Gas Area, Sichuan Basin, Sichuan Province



The Cambrian- and Silurian-age shales are the main targets for shale gas exploration in the Sichuan Basin, Figure XI-4. These two shale horizons have provided gas shows in exploration wells and appear to have low-clay mineralogical composition owing to their deepwater marine depositional environment. Conventional and tight gas reservoirs of Upper Paleozoic- and Triassic-age in the Sichuan Basin were sourced primarily by these Cambrian and Silurian black shales.

Figure XI-4. Stratigraphic Column for Cambrian- and Silurian-Age Shales, Sichuan Basin



Source: Modified from X.M. Xiao et al. / International Journal of Coal Geology 70 (2007) 264-276

JAF21301.AI

The Cambrian and Silurian shales are thick, grey to black, carbon-rich (TOC of 3%), thermally mature (R_o of 2.3% to 2.5%), and currently buried at moderate depths. Although freshwater lacustrine shales may locally be present, most shales of this age were deposited in a marine environment. In addition, many of these shales are silty and could have retained modest levels of porosity. ARI mapped Cambrian and Silurian shales to establish the prospective areas with favorable reservoir characteristics for shale gas resources.

Reservoir Properties (Prospective Area)

Conventional gas fields in the Sichuan Basin frequently have high levels of non-hydrocarbon gases. ARI assumed the following values for shale gas composition: H_2S levels often are hazardously high (1% or more), while CO_2 (5%) and N_2 (7.5%) also can be significant. For example, the Sinian (late Pre-Cambrian) natural gas reservoirs at Weiyuan gas field in southwestern Sichuan Basin have high H_2S content of 0.8% to 1.4%, while Chuangdongbei field reaches 15% H_2S.[3] The reservoir pressure gradient at Weiyuan is close to hydrostatic (0.44 psi/foot).

- ***Silurian Longmaxi Formation***. Best developed in the southern and eastern Sichuan Basin, the Longmaxi Fm is mainly a grey-black silty shale. The thickness of the organic-rich shale ranges from 100 m to 500 m, averaging about 170 m (560 ft). Depth in the prospective region ranges from about 2,400 m to 4,100 m, averaging about 3,250 m deep (10,660 ft). TOC ranges from 1.5 to 6%, averaging about 3%. Vitrinite reflectance ranges from 1.8% to over 4.0% (average 2.3%), placing the Longmaxi Shale fully in the dry gas window. Porosity is not known but estimated at 4% based on lithologic description. PetroChina has logged strong gas shows from the Longmaxi Fm in seven conventional exploration wells across the southern Sichuan Basin. Overall, the Silurian shales appear prospective, with high TOC, moderate depth, albeit with significant levels of non-hydrocarbon constituents (H_2S, CO_2, N_2).

- **Cambrian Qiongzhusi Formation.** The Cambrian Qiongzhusi Formation has fairly consistent thickness across the Sichuan Basin, averaging about 120 m with a maximum of 423 m. At Weiyuan gas field the Cambrian is 230 m to 400 m thick. The Cambrian organic-rich shale averages about 120 m (390 ft) thick and 2,800 m (9,180 ft) deep. TOC at Weiyuan is 2% to 4%, mainly sapropelic, and the shale is thermally mature with R_o above 2.5%, well within the dry gas window. Porosity is estimated at 4%. CO_2 content at this field is approximately 5%, while N_2 averages 7.5% and H_2S is assumed to be 1%. In 1966, a PetroChina well flowed nearly 1 MMcfd from an unstimulated carbonaceous shale at a depth of 2,800 m within the Qiongzhusi interval.

Shale Gas Resources

Sichuan is a large natural gas producing basin with 1.5 Bcfd productive capacity. A total of 112 individual natural gas fields have been discovered with estimated 25 Tcf recoverable resources. A significant proportion of these fields have challenging low-permeability reservoirs and H_2S levels often are high.

The **Silurian Longmaxi** organic-rich shale has an estimated average resource concentration of 80 Bcf/mi^2. These shales are at suitable depth and thermal maturity over about 70% of the Sichuan Basin, providing a prospective area of 56,875 mi^2. However, a significant portion of the prospective area was screened out (risked) due to structural complexity. ARI estimates 343 Tcf of risked recoverable resources from the Silurian Shale based on 1,373 Tcf of total risked gas in place, Table I-1.

The **Cambrian Qiongzhusi** shale has an average estimated 57 Bcf/mi^2 resource concentration. These shales are present essentially across the entire Sichuan Basin area, though they are somewhat thinner than the Silurian shales. Structural complexity sterilizes an estimated 70% of the basin area. ARI estimates 349 Tcf of risked recoverable resources from the Cambrian Shale, out of a total 1,394 Tcf of risked gas in-place, Table XI-1.

Exploration Activity

As China's earliest natural gas producing region, the Sichuan basin has a well-developed network of natural gas pipelines. Large cities (Chongqing, Chengdu) and industrial gas consumers (fertilizer, ceramics manufacturers) offer a ready market for the gas. Well drilling services are available, including horizontal drilling and hydraulic fracturing. The Sichuan Basin hosts numerous large operators (PetroChina, Shell, Chevron, ConocoPhillips, EOG) who are evaluating and testing the shale- and tight-gas resources in the basin. However, ConocoPhillips is the only operator in the Sichuan Basin to have selected its block based on shale gas exploration quality. The other PSC's in Sichuan were previously signed based on tight gas sand and carbonate gas potential and are being opportunistically re-evaluated for shale gas. These exploration programs are at an early data-gathering stage, with no commercial shale gas production reported yet.

- ***PetroChina***. China's most active shale gas explorer, PetroChina, is partnered with several foreign companies in the Sichuan Basin and also operates its own exploration program. PetroChina has noted that seven of the company's conventional exploration wells in the basin experienced gas kicks while penetrating shales, including one well that flowed 1 MMcfd from an unstimulated shale. The company reportedly spud its first dedicated shale gas test well in September 2010. In December 2010, Sinopec reported that its first shale well (Yuanba-1), a vertical test in the northeast part of the basin completed in shale at depths of 4,035-4,110 m, flowed an encouraging 406 Mcfd after stimulation. PetroChina and Sinopec plans to drill several more test wells and install several horizontal production pilots in various locations during 2011. PetroChina's production target for Sichuan shale gas is 100 MMcfd by 2015.

- ***Chevron***. In 2008, Chevron assumed operation and 49% ownership (CNPC 51%) of the 1,969-km^2 Chuandongbei block in the Sichuan Basin, in Dazhou, Wanyuan and Chongqing-Kaixian districts. The block, originally acquired for tight gas development, has extremely high H_2S levels of up to 15%. Chevron is evaluating the shale gas potential but no drilling has been announced yet. Further west of Sichuan, Chevron reported in September 2010 that it is negotiating with Sinopec for a shale gas exploration block near Guiyang.

- ***Shell***. In March 2010, Shell announced it and CNPC had jointly submitted a 30-year PSC application to the government for approval in the Sichuan basin, targeting tight gas and shale gas resources within the 4,000-km^2 Jinqiu region. In September 2010, Shell announced that, assuming its two planned exploration wells reveal good potential, the company's investment for this project could reach $1 billion annually for each of the next five to seven years.

- ***EOG Resources***. EOG holds a tight gas PSC in the Sichuan Basin that may also be prospective for shale gas. EOG currently is evaluating the shale gas potential and expects to decide sometime late 2010 whether or not to test the PSC with a shale gas exploration well.

- ***Newfield Exploration***. In 2006 Newfield reportedly evaluated shale gas at Weiyuan gas field, where PetroChina had flowed 868 Mcfd from Cambrian Jiulaodong

Formation in an unstimulated conventional vertical exploration well. However, Newfield decided not to further pursue this shale gas opportunity.

- ***ConocoPhillips***. The company reportedly is evaluating a 3,000-km^2 block in the Sichuan Basin for shale gas development and may sign a PSC later in 2010.

TARIM BASIN

Geologic Characterization

The Tarim basin in western China's Xinjiang Uyghur Autonomous Region is one of the world's largest frontier petroleum sedimentary basins, covering a total area of 234,200 mi^2. The primary shale gas targets within the Tarim Basin are the lower Paleozoic sediments, particularly the extensive shale source rocks of Cambrian and Ordovician age.[4] These shales have sourced major oil and gas resources in conventional reservoirs of Cambrian, Ordovician, Carboniferous, and Triassic age, including over 5 billion barrels of oil equivalent hydrocarbons in Ordovician carbonate rocks.

The Tarim Basin is sub-divided by fault systems into a series of distinct structural zones including: (1) the Manjiaer Depression in the north; (2) the Tangguzibasi Depression in the south; (3) the Awati Sag in the west; and (4) the Tadong Sag in the east, Figures XI-5 and XI-6. The west-to-east cross-section A-C, Figure XI-7, shows deep, organic-rich shales of Ordovician and Cambrian age at favorable depth and thermal maturity over the eastern Tarim Basin. The south-to-north cross-section D-E, Figure XI-8, shows similar prospective targets for the northern Tarim Basin. In the center of the Tarim Basin, the Tazhong and Tabei Uplifts – a west-plunging large-scale nose, where the Mid-Upper Ordovician section has been removed by erosion during the Hercynian Orogeny – the shales have low R_o and are not prospective for development.[5]

Figure XI-5. Tarim Basin's Organic-rich Ordovician Shales. (Note location of cross sections A-B-C- and D-E.)

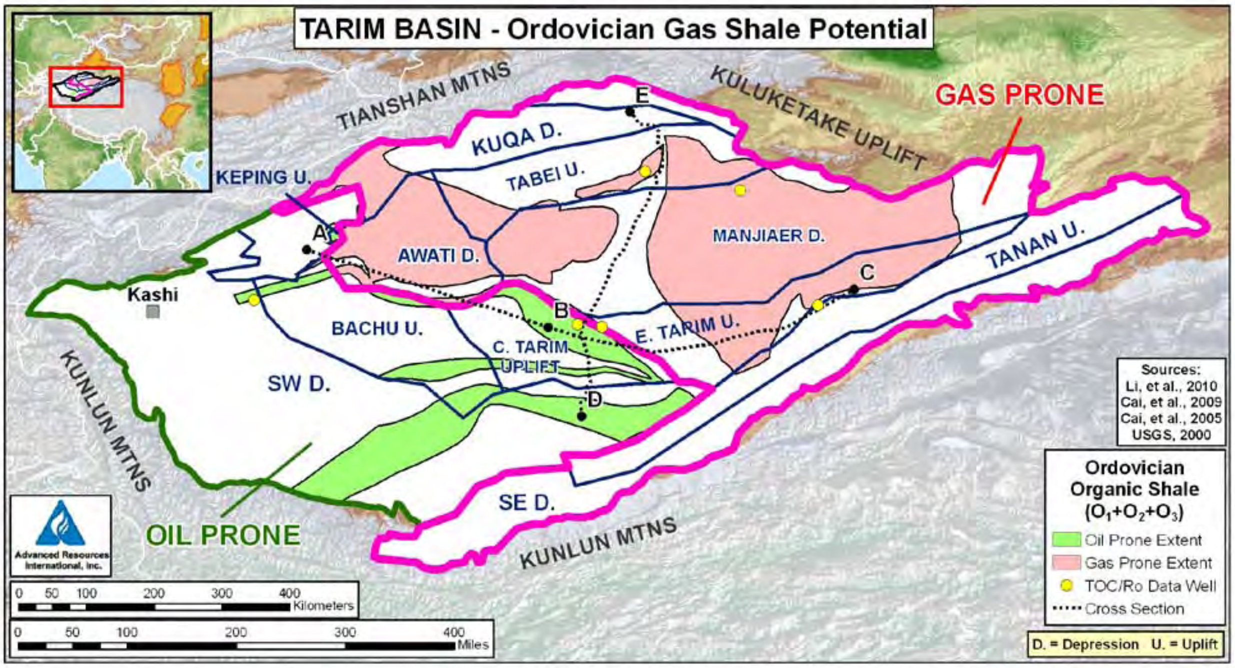


Figure XI-6. Tarim Basin's Cambrian Shales. (Note location of cross sections A-B-C- and D-E.)

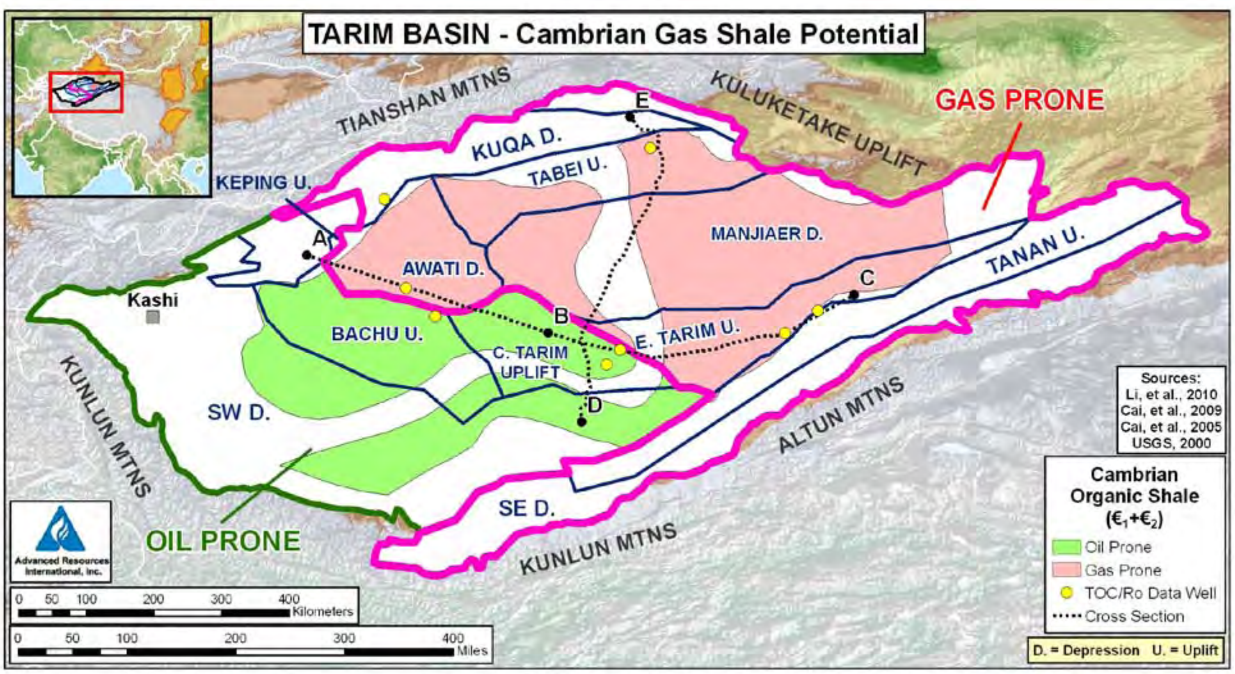


Figure XI-7. Tarim Basin West-To-East Cross-Section A-C for Ordovician- and Cambrian-Age Shales.
(See Figures XI-6 and XI-7 for Cross Section Location.)

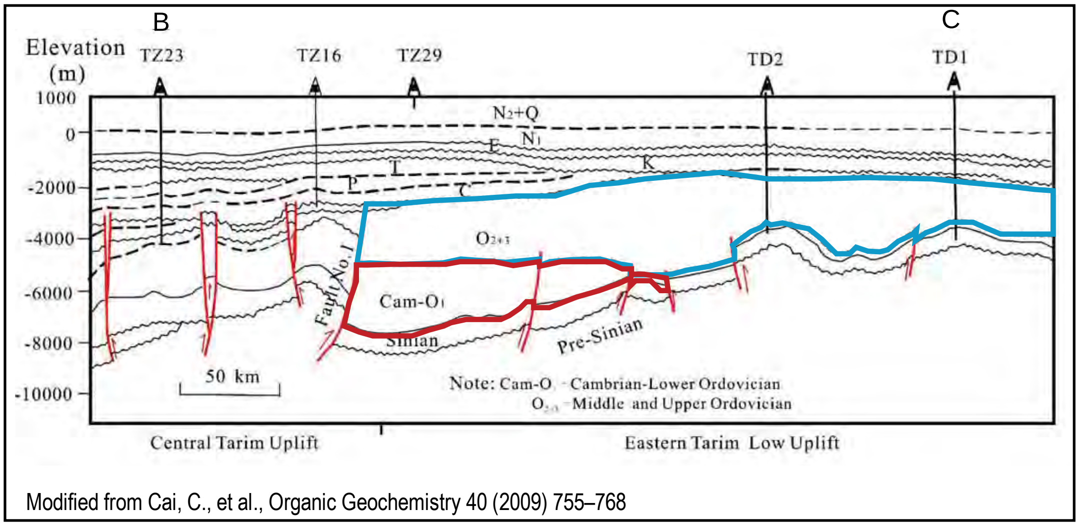


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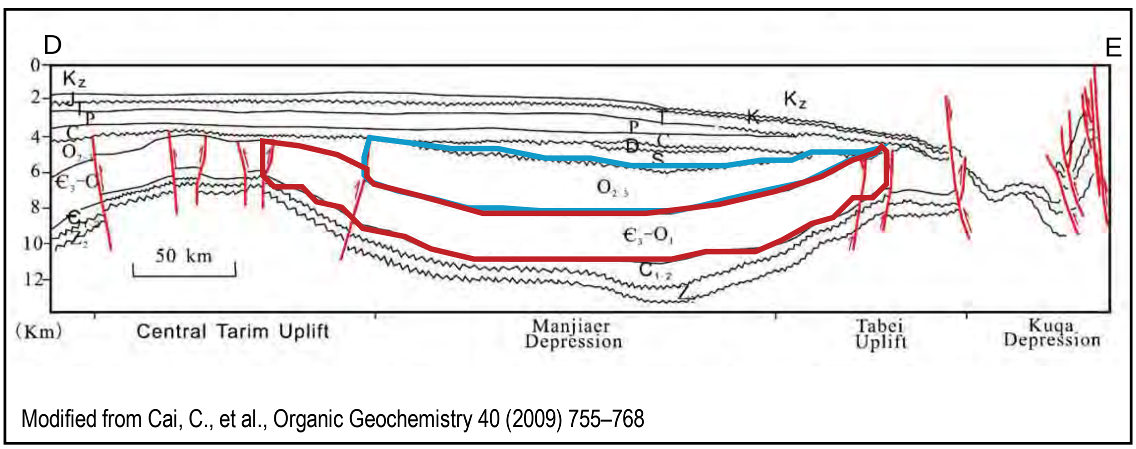
Figure XI-8. Tarim Basin South-To-North Cross-Section D-E for Ordovician- and Cambrian-Age Shales.
(See Figures XI-6 and XI-7 for Cross Section Location.)



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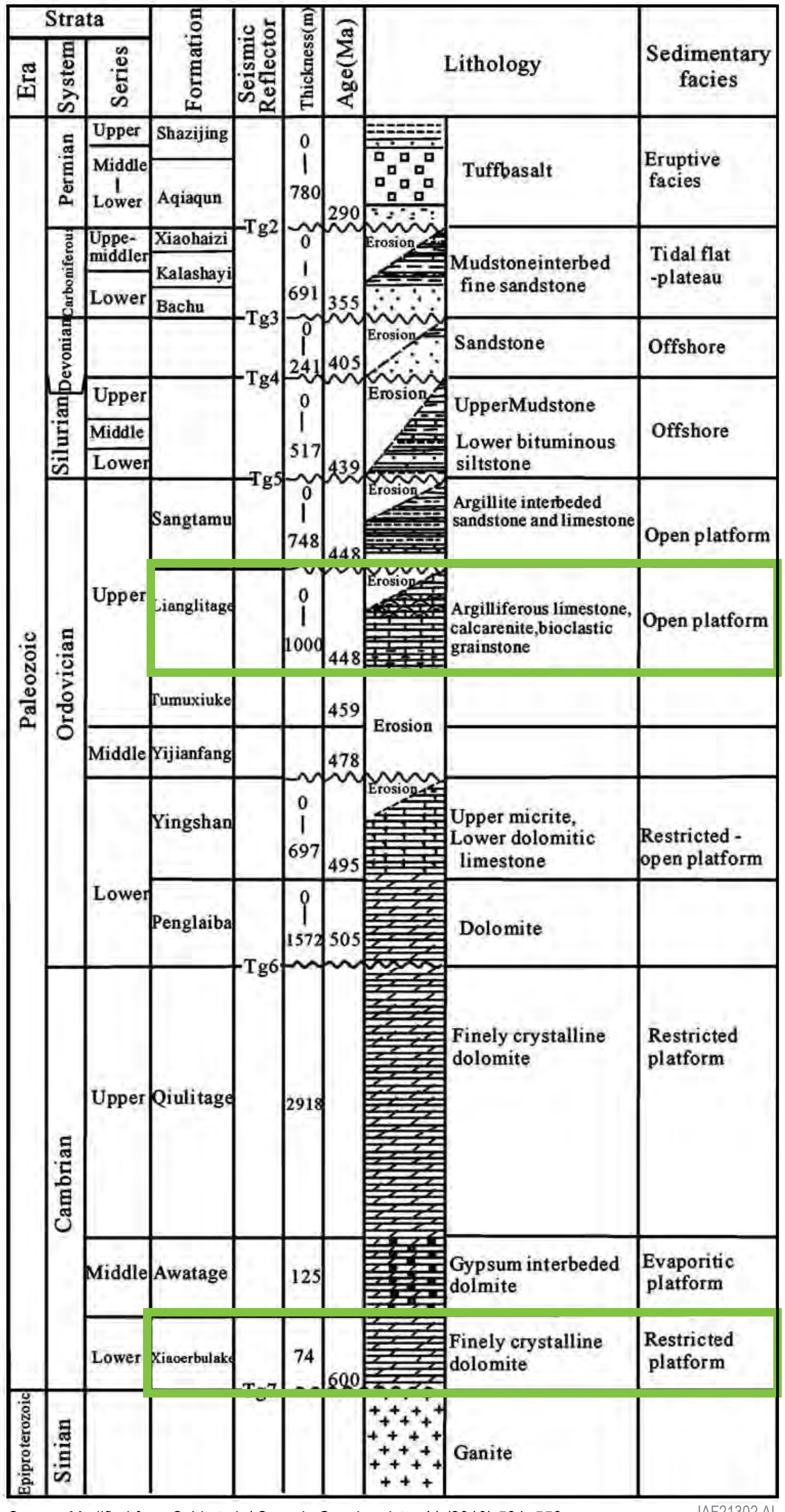
Ordovician black shales are the most important petroleum source rocks in the Tarim Basin, Figure XI-9. Conventional oil reservoirs in the Tazhong Uplift are mainly found within Mid-Upper Ordovician carbonates. Shale source rocks in the Heituao, Yijianfang, and Lianglitage Formations grade from black and dark grey mudstone, to silty mudstone, to argillaceous limestone. TOC ranges from 0.3% to 2.5%, averaging about 2.0% in the richer sequences. Organics consist of kerogen, vitrinite-like macerals, as well as bitumen. Shale depths range from 2,000 m to over 6,000 m (6,500 to 20,000 feet).

Figure XI-9. Tarim Basin Stratigraphy Showing Organic-Rich Upper Ordovician and Lower Cambrian Shales.



Source: Modified from S. Li et al. / Organic Geochemistry 41 (2010) 531–553

The Lower Ordovician Heituao (O_{1-2}) shales appear to be the most prospective. These shales range from 48 to 63 m thick, extend over the entire Manjiaer Depression, and consist of carbonaceous, siliceous mudstone with radiolarian shale that are likely to be quite brittle. The Middle Ordovician Yijianfang (O_2) Saergan Formation shales, present in the Keping Uplift and Awati Depression, are marine black mudstones some 10 m to 30 m thick, with TOC of 0.56% to 2.86% (average 1.56%). Upper Ordovician Lianglitage (O_3) shales occur in the Central Tarim, Bachu, and Tabei areas, where they are 20 m to 80 thick, carbonate-rich, but with relatively low TOC (average 0.93%).

The Cambrian organic-rich shales, consisting of abyssal to bathyal facies mudstones, occur in the Manjiaer Depression and the eastern Tarim and Keping Uplifts. TOC is reasonably high (1.2% to 3.3%) in the Low (C_1) and Middle (C_2) Cambrian Formations and exceeds 1% over about two-thirds of the Cambrian sequence. Evaporitic dolomites occur in the middle Cambrian, with extensive salt and anhydrite beds totaling 400 to 1,400 m thick. Net organically-rich shale thickness ranges from 120 m to 415 m, averaging about 120 m (400 ft). Thermal maturity is well into the dry gas window (R_o = 2.5%).

Shale Gas Resources

Ordovician organic-rich shales were mapped to define thickness, depth, TOC, and thermal maturity. The thickest shale deposits occur in the Manjiaer Depression, reaching an incredible 1,600 m of net organic-rich source rock. A second slightly thinner but still very substantial deposit occurs in the Awati Depression, where organic-rich shales reach maximum 400 m thick. Both of these deposits are within the dry gas window (average R_o approximately 2%). However, shale thickness and thermal maturity both decline markedly westward into the Central Tarim and Bachu Uplifts (R_o = 0.6% to 0.7%). TOC is moderately high, about 2% on average with higher values indicated on well logs. Porosity is unknown but speculated to be fairly high (6%) based on the marine, clay-poor environment of deposition.

Much of the organic-rich shale in the Tarim is too deep for shale development (>15,000 ft). Thus, the thickness in the Ordovician was reduced to an estimated average net 80 m (260 ft) at an average depth of approximately 3,960 m (13,000 ft). Based on these assumptions, ARI estimates that the 55,042 mi^2 of prospective Ordovician shales in the Tarim Basin contain a total 897 Tcf of risked gas in place and 224 Tcf of risked recoverable resources, Table XI-1. Average resource concentration is estimated at 102 Bcf/mi^2, likely higher in sweet spots.

Cambrian organic-rich shales appear to have even more gas potential than the Ordovician shales. Cambrian shales reach more than 1 km thick in the Awati Depression and over 1.4 km thick in the Manjiaer Depression, but are thin and become thermally immature further to the west. Due to excessive depth (>15,000 ft), net organic-rich shale thickness was reduced to about 404 ft at an average depth of 14,000 ft. Both of these deposits are well into the dry gas window (average R_o approximately 2.5%). TOC also is moderately high, about 2.0% on average and reaching higher levels in well logs. Porosity is unknown but speculated to be about 5% based on a favorable marine, clay-poor environment of deposition.

Based on these assumptions, ARI estimates that Cambrian shales in the Tarim Basin contain a total 1,437 Tcf of risked gas in place and approximately 359 Tcf of risked recoverable resources, Table XI-1. Average resource concentration is estimated at 141 Bcf/mi^2, likely higher in sweet spots.

Exploration Activity

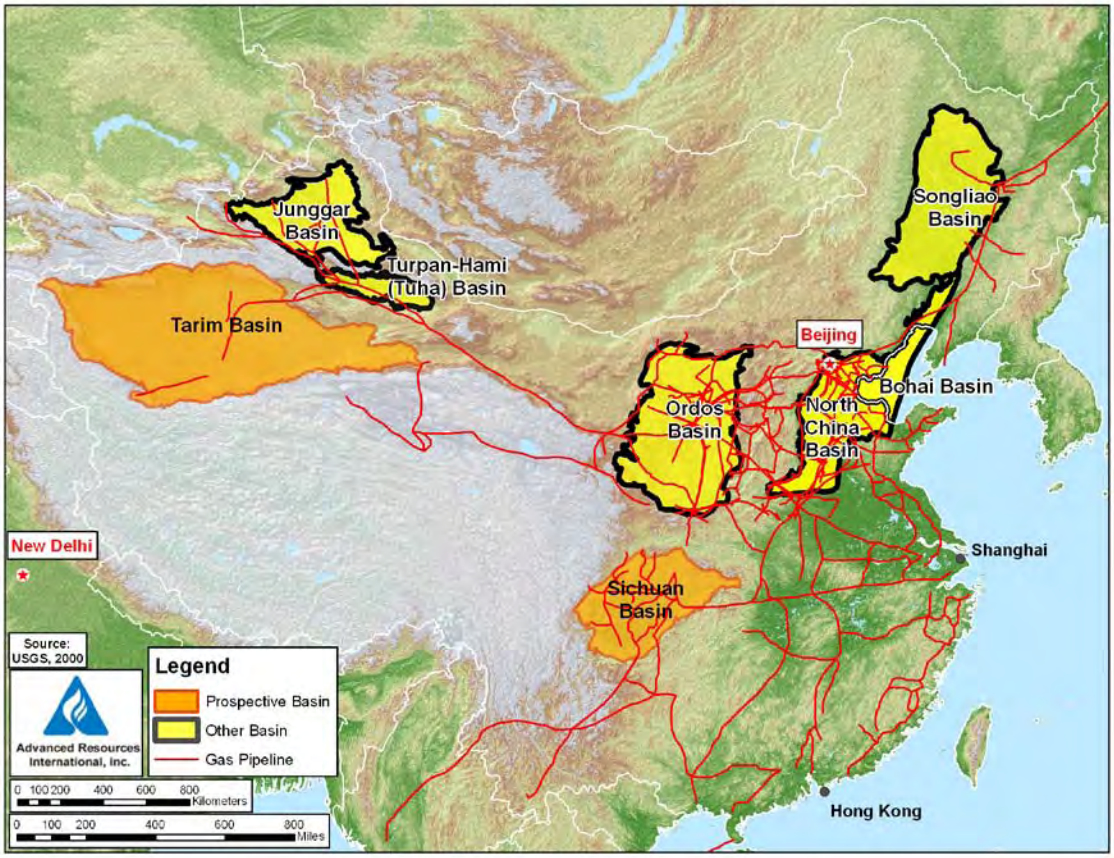
The Tarim Basin in remote western China holds the Kuche-Tabei, Bachu-Taxinan and Tadong natural gas complexes, where 15 gas fields have been discovered with estimated recoverable resources of about 21 Tcf. The Kela-2, Dina-2, Yaha and Hetianhe gas fields have been developed. With productive capacity of close to 2 Bcfd, the Tarim Basin is China's largest gas-producing basin and a major source for the West-East Gas Pipeline.

To date no shale gas exploration or evaluation activity has been announced for the Tarim Basin.

CHINA'S OTHER SHALE GAS BASINS

China has five other large sedimentary basins that contain shales deposited in mainly non-marine environments, most often in ancient lakes (lacustrine) or fluvial settings that were close to terrigenous sediment sources. These non-marine shale basins are likely to be clay-rich and thus less prospective. In addition, many shale targets in these basins are thermally immature and oil-prone. China's five major non-marine basins include the Ordos, the Junggar, the North China (Huabei), the Turpan-Hami, and the Songliao, shown on Figure XI-10.

Figure XI-10. China's Other Shale Gas Basins.



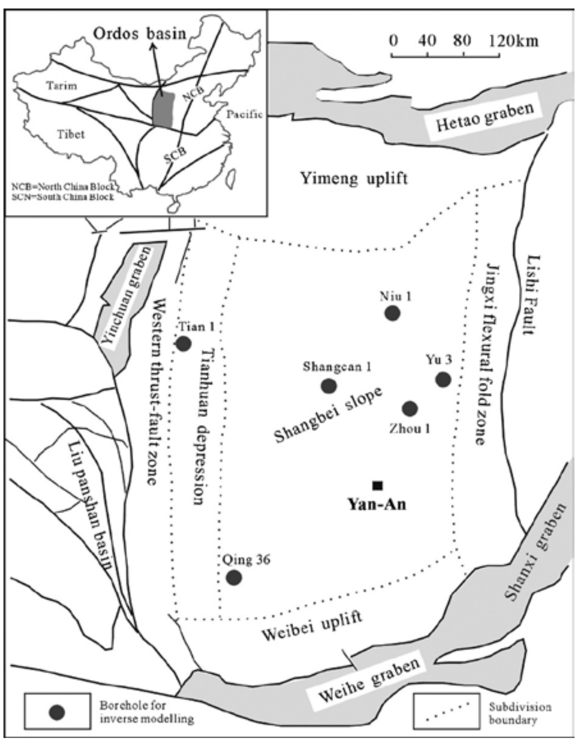
Ordos Basin

The Ordos basin, a large (320,000-km^2) coal-, petroleum- and CBM-productive sedimentary basin is located in Shaanxi, Shanxi, Ningxia, and Inner Mongolia in north-central China, Figure XI-11. Apart from its overthrusted western margin, the basin is structurally simple with gently dipping flanks. Significant natural gas, nearly 2 Bcfd, is produced from low-permeability carbonate reservoirs in the central Ordos Basin. The sedimentary sequence comprises Paleozoic and Mesozoic clastic rocks, along with extensive coal deposits that were deposited in mainly fluvial and lacustrine environments. The shales in the Ordos Basin exist in the Triassic, Carboniferous and Permian.

The Triassic Tongchuan Formation shales in the Ordos Basin do not appear to have viable shale gas potential. These shales were deposited in fluvial or lacustrine environments, are low in TOC, and are very high in clay (80%; mainly illite and chlorite), with very low quartz (15%) and feldspar (5%) content. Likewise, Triassic Hujiachun Fm shales are lean, dominantly clay (75%, mainly illite and chlorite), with low quartz (15%) and feldspar (10%).

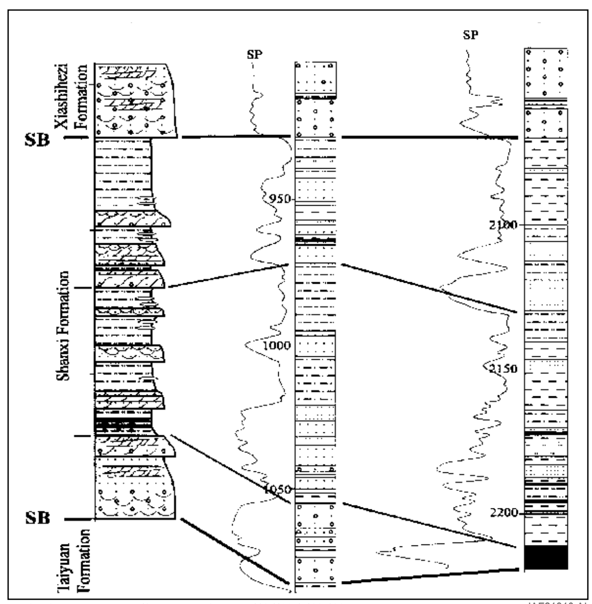
Potentially higher quality shales occur in Carboniferous and Permian mudstones.[6] The Carboniferous Taiyuan Formation contains black shales and limestones, but the formation is interbedded with coal seams and other dominantly non-marine clastic sediments. The overlying fluvial-dominated Permian Shanxi Fm contains thinner coal seams as well as thick non-marine clastic rocks, Figure XI-12. Gas isotope data indicate that these coal seams, rather than interbedded shales, were the main source rocks for the Ordovician gas fields in the central Ordos Basin, Figure XI-13.[7,8]

Figure XI-11. Ordos Basin's Overthrusted Western Margin and Simple Central Deep Shangbei Slope.



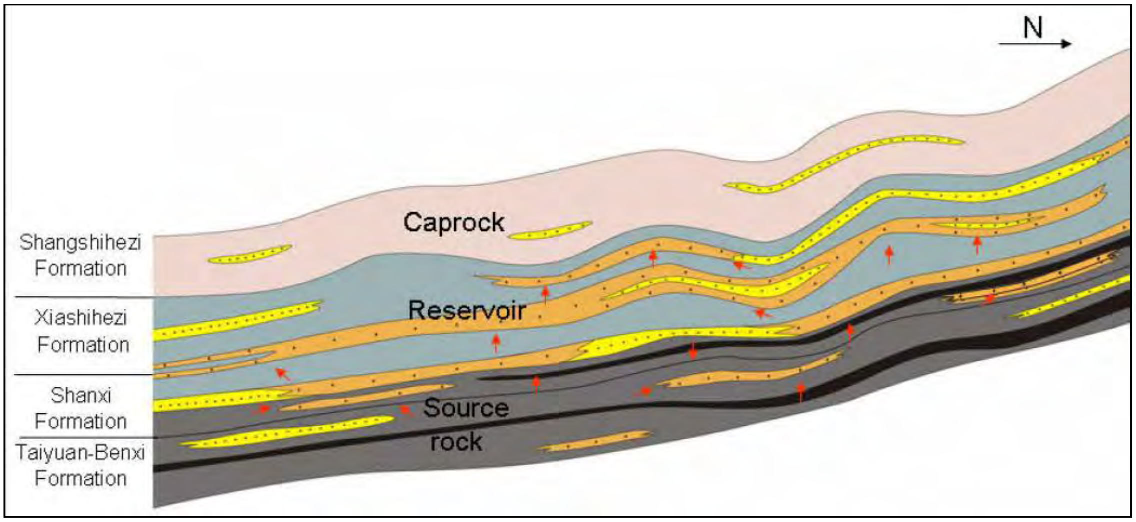
Source: Y. Yuan et al. / Journal of Geodynamics 44 (2007) 33–46 JAF21309.AI

Figure XI-12. Ordos Basin (Permian Shanxi Fm) Non-Marine, Mainly Lacustrine Shales



Modified from Z. Zhang et al./Sedimentary Geology 112 (1997) 123-136 JAF21310.AI

Figure XI-13. Cross-Section of Paleozoic Formations in the Ordos Basin, Showing Organic-Rich Source Rocks in the Carboniferous Taiyuan and Permian Shanxi Formations.



Yuan et al., 2007

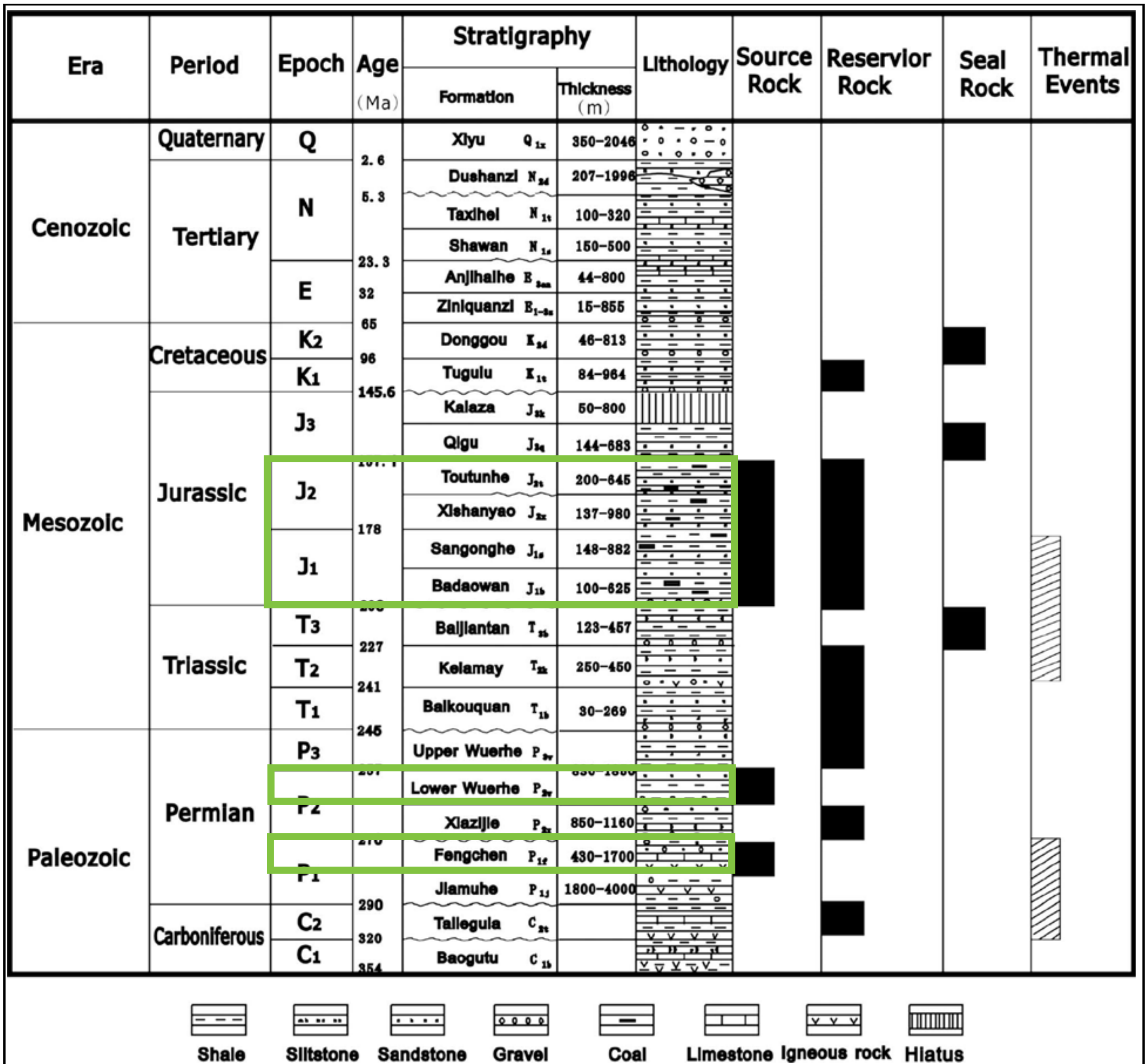
Junggar Basin

The Junggar Basin, a large (130,000-km^2) petroliferous basin in western China's Xinjiang Autonomous Region, contains oil-prone and non-marine shales of Carboniferous to Jurassic age. The Junggar is an asymmetric foreland basin containing a thick segment of Paleozoic and Mesozoic sedimentary rocks, Figure XI-14. The Wulungu and Central Depression contain thermally immature source-rock shales. Only the North Tianshan Foreland Depression is deep enough for gas-mature shales, Figures XI-15 and XI-16.

The Lower Carboniferous sequence is 2 to 3 miles thick, holding mainly marine volcaniclastics that are high in clay and low in TOC. Overlying Mesozoic rocks, up to 4 miles thick, are mainly non-marine clastic rocks. The primary target for shale gas exploration appears to be the thick mudstones of Permian age, the main petroleum source rock in the basin, Figure 15. TOC can be high, averaging 4.3% in one 1,000 foot thick interval of dark gray Upper Permian Lucaogou Fm mudstone and often reaching 20%, making this shale one of the world's richest petroleum source rocks.[9]

The shales in the Junggar Basin were deposited primarily in lacustrine and fluvial environments, resulting in clay-rich shales. Moreover, the Junggar is a thermally immature basin with abnormally low heat flow. Gas window maturities (R_o > 1%) are attained only in the North Tianshan foreland region at depths of greater than about 5,000 m, thus excluded from our definition of prospective areas.[10]

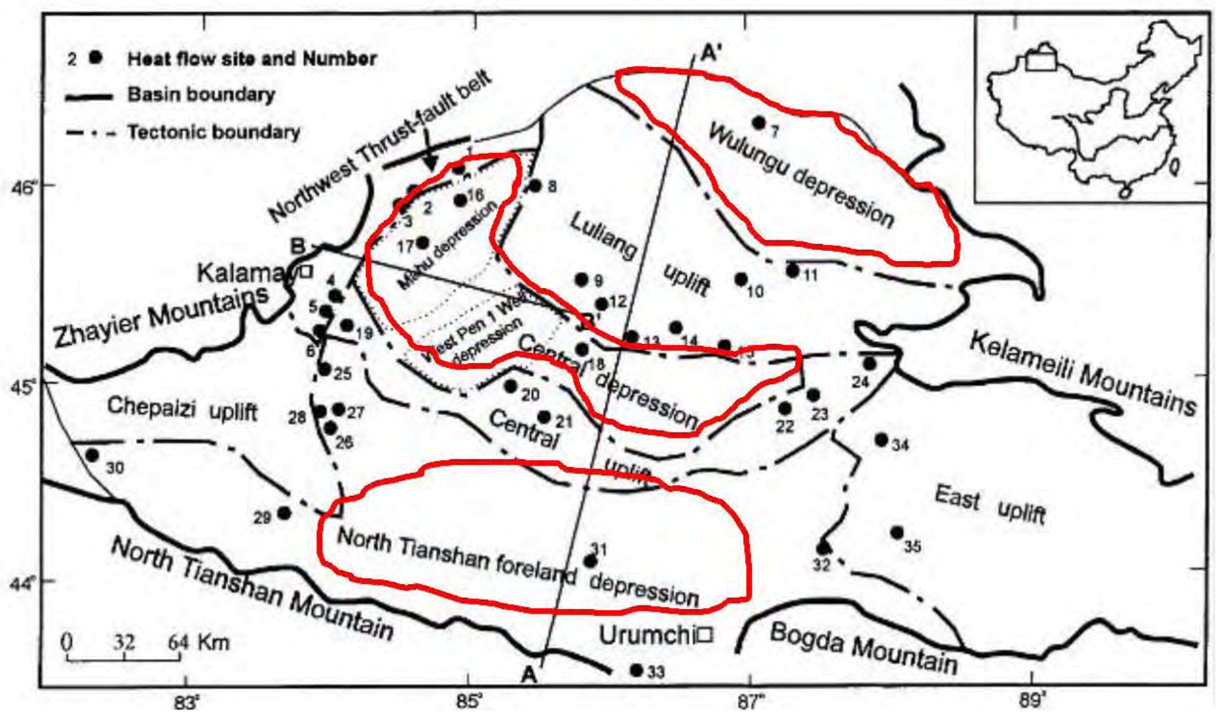
Figure XI-14. The Junggar Basin's Organic-Rich Jurassic and Permian Source Rocks.



Source: Modified from Xiao et al., AAPG Bulletin, v. 94, no. 7 (JULY 2010), pp. 937–955

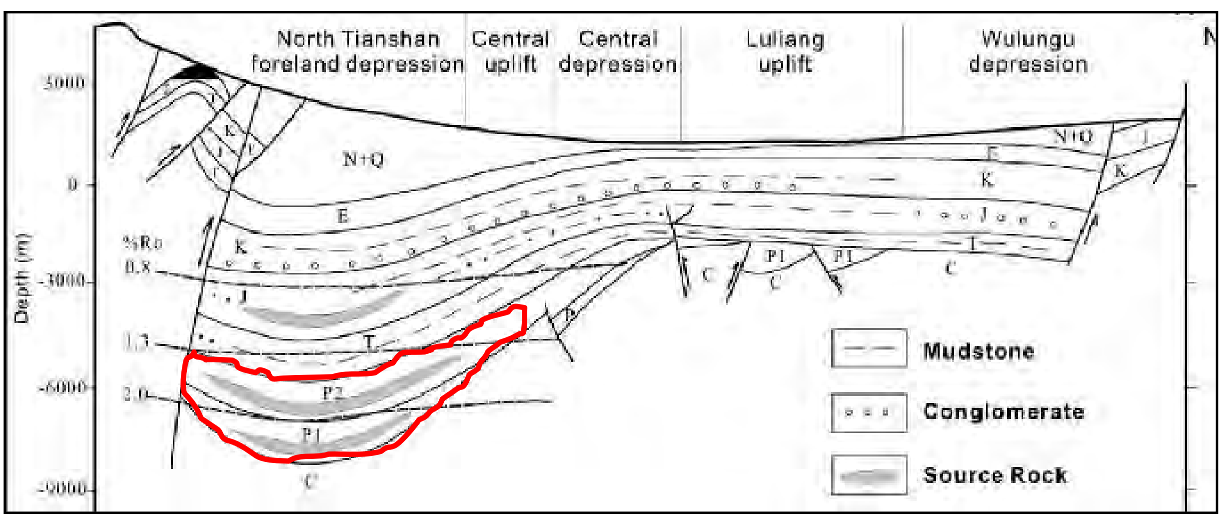
JAF21303.AI

Figure XI-15. Junggar Basin Structural Elements showing Wulungu, Central, and North Tianshan Foreland Depressions. (Note location of cross-section line A-A'.)



Modified from Wang et al., 2001

Figure XI-16. Junggar Basin Source-Rock Shales in the Jurassic and Permian



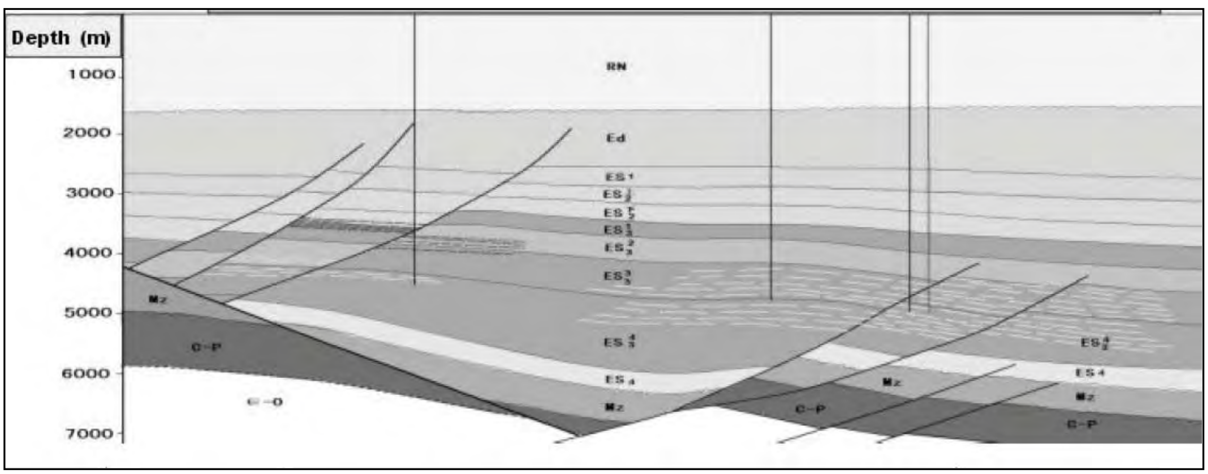
Modified from Wang et al., 2001

North China (Huabei) Basin

East-central China's North China Basin (Huabei) is a conventional oil and gas producing region and includes the Shengli Oilfield, China's second largest. The North China Basin, which covers portions of Hebei, Henan, and adjoining provinces, contains extensive Carboniferous and Permian source rock shales that are stratigraphically and lithologically similar to those in the Ordos Basin, Figure XI-17.[11]

The Carboniferous Taiyuan and Permian Shanxi Formations contain organic-rich but non-marine deposited shales that are associated with coal seams. These shales are likely to be clay-rich and ductile. In addition, the North China Basin is structurally complex with numerous small grabens defined by northeast-southwest trending normal faults, active tectonics and seismicity, and ongoing regional subsidence.[12] Until additional data are obtained, the non-marine nature of the shales and their structural complexity make the North China Basin non-prospective for shale gas.

Figure XI-17. Cross-Section of the North China Basin with Active Normal and Strike-Slip Faults.

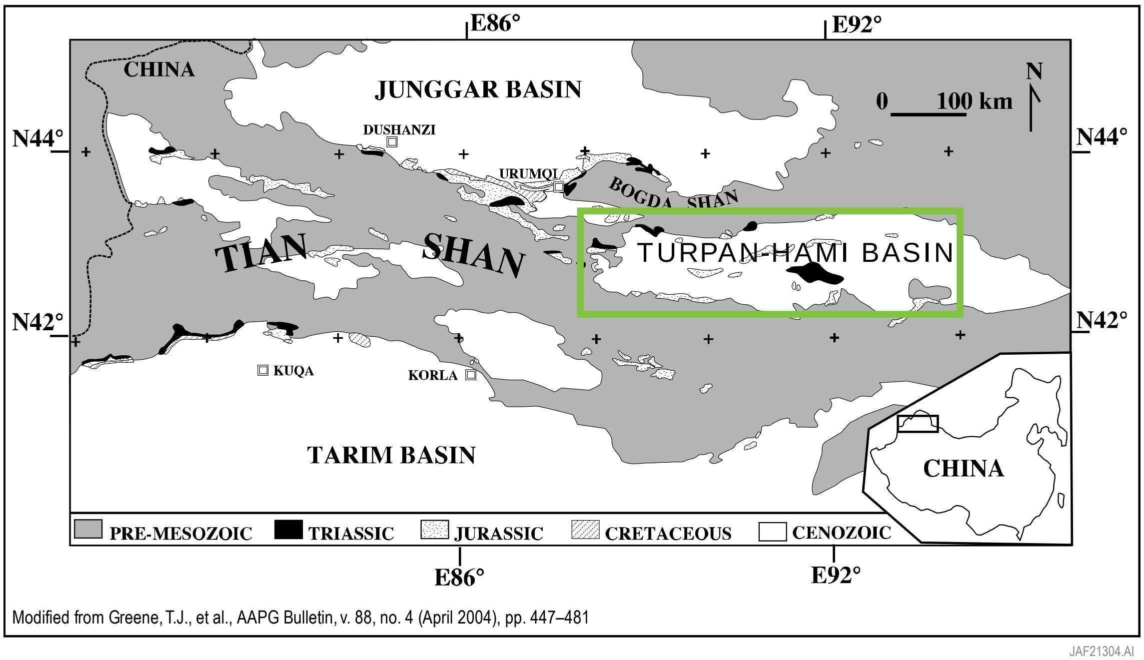


Pu and Qing, 2001

Turpan-Hami Basin

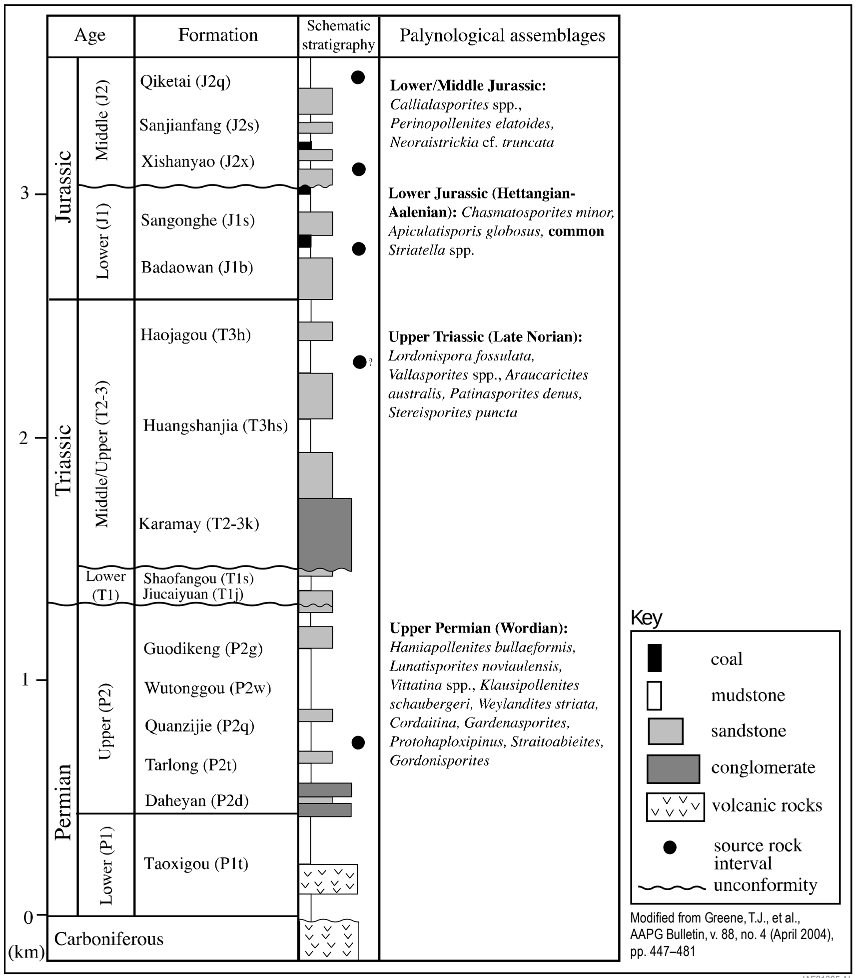
The Turpan-Hami Basin, a medium-sized (54,000-km^2) intermontane basin, is located in Xinjiang, western China, midway between the Tarim and Junggar basins, Figure XI-18. Much as in the Junggar basin, with which it was connected prior to early Mesozoic tectonic uplift, the Turpan-Hami basin contains late Paleozoic to Mesozoic lacustrine-deposited shales that are thermally immature for gas.[13]

Figure XI-18. The Turpan-Hami Basin Source Rocks Include Upper Permian And Middle Jurassic Mudstones with High TOC.



Upper Permian source rock mudstones in this basin correlate with similar-aged, low-rank lacustrine deposits in the adjacent Junggar Basin, Figure XI-19. For example, the Permian Tarlong Formation mudstones can have high TOC (3.6% to 8.2%), but are thermally immature (R_o = 0.5%), even in the deep Tainan depression where shales reach 5,000 m depth. Middle Jurassic Qiketai Formation lacustrine shales are not yet gas mature (R_o = 0.76%) in the Taibei depression. The shallower Lower to Middle Jurassic coal-rich mudstones appear to be clay-rich and are even less thermally mature (maximum R_o = 0.56%). The Turpan-Hami Basin does not appear to be prospective for shale gas.

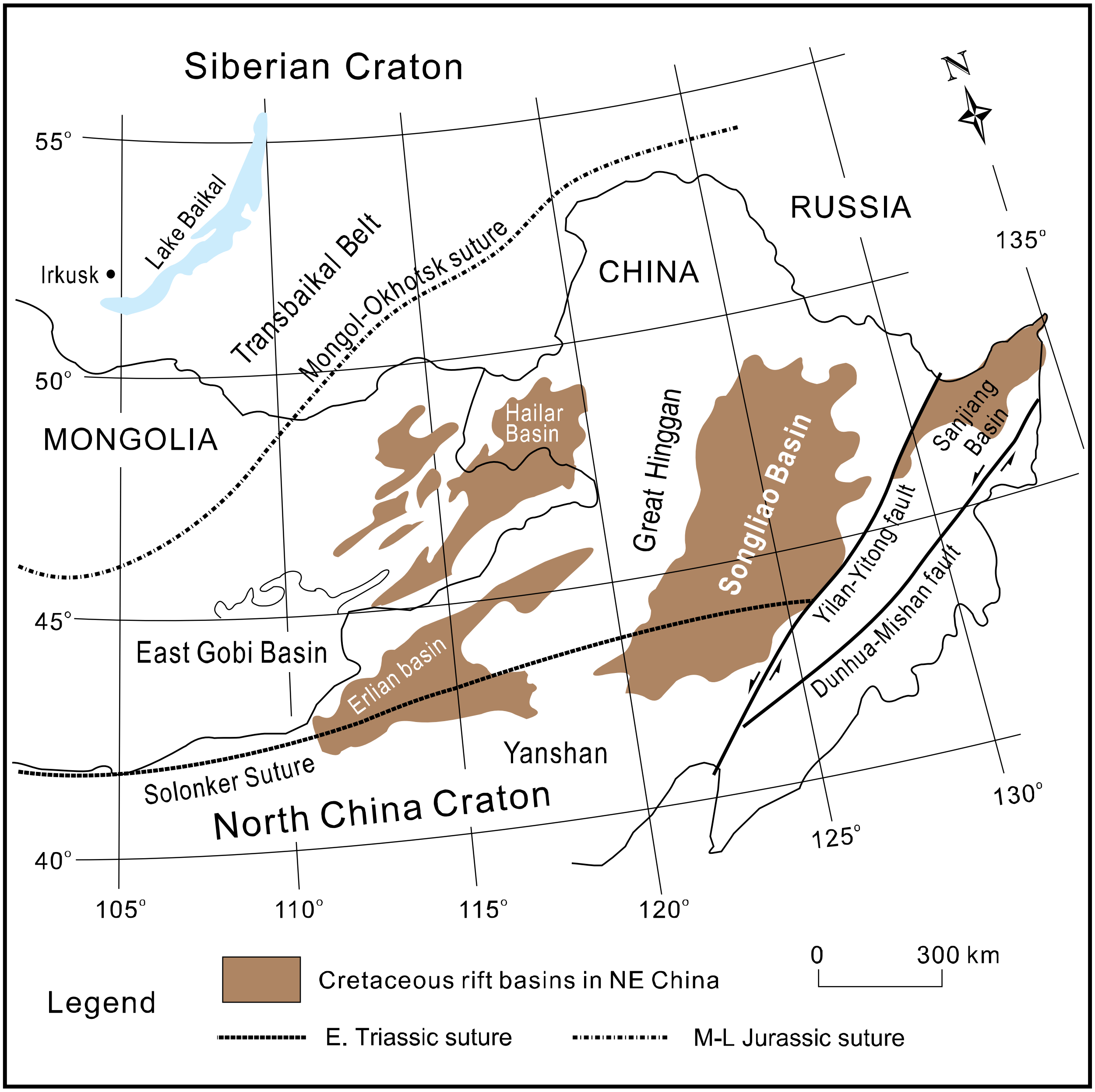
Figure XI-19. Turpan-Hami Basin Stratigraphic Column.



Songliao Basin

The Songliao Basin, a large (150,000-km^2) petroliferous basin in northeastern China hosts the Daqing Oilfield (China's largest), also contains Mesozoic non-marine shale source rocks, Figure XI-20. Located in Heilongjiang and Jilin Provinces, the Songliao, along with the nearby Hailar and Erlian basins, consist of dozens of small pull-apart half-grabens which formed during Late Jurassic to Cretaceous time as India collided with the Asian continent, Figure XI-21.[14]

Figure XI-20. The Songliao, Hailar, and Erlian Rift Basins in Northeast China.

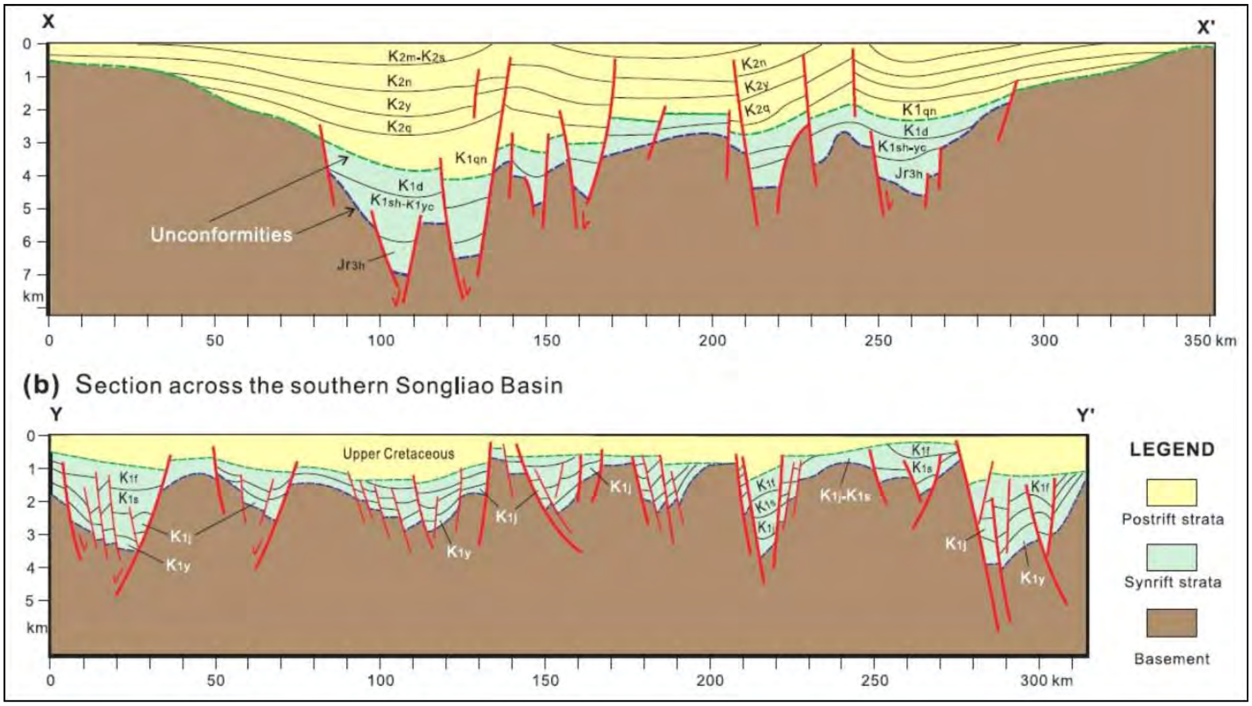


Modified from Wei, et al., AAPG Bulletin, v. 94, no. 4 (April 2010), pp. 533–566

JAF21308.AI

The main organic-rich shales are the Lower Cretaceous Shahezi and Yingcheng Formations, comprising 2,000 feet of dark mudstone with TOC ranging from 0.46% to 2.46%. In addition, high TOC shales exist in the Cretaceous Jiufotang Formation, up to 2,400 feet thick with 2.5% to 3.5% TOC. These shales were formed in lakes with no significant deepwater marine influence. Because these shales are deep, exceeding 5,000 m, thermally immature, and rich in clay they are classified as non-prospective.

Figure XI-21. The Songliao Basin's Numerous Small Pull-Apart Grabens.



Source: Cai, C., et al., Organic Geochemistry 40 (2009) 755–768 JAF028245.PPT

Natural Gas Profile

China produced 2,929 Bcf of natural gas in 2009[15], up 8 percent from 2008, with consumption slightly higher at 3,075 Bcf. Approximately 45 percent of the consumed gas was utilized for industrial purposes. As of January 2010, China's proven natural gas reserves stand at 107 Tcf.

Exploration Activity

The level of industry interest in China shale gas is increasingly rapidly. China's Ministry of Land and Resources (MLR) established a National Gas Shale Research Center in August 2010. PetroChina, Sinochem and CNOOC are initiating exploration in China, as are several foreign oil companies. MLR recently (October 28, 2010) announced plans to offer six shale gas exploration blocks within the next month. Bidding will be limited to four Chinese companies (PetroChina, Sinopec, CNOOC, and Shanxi Yanchang Petroleum Group). Foreign companies would be allowed to cooperate with bid winners. MLR envisions opening blocks to foreign bidding eventually, but no timetable has been announced.

As China's earliest natural gas producing region, the 230,000-km^2 Sichuan Basin has a well-developed network of natural gas pipelines. Large cities (Chongqing, Chengdu) and industrial gas consumers (fertilizer, ceramics manufacturers) are present. PetroChina, Shell, Chevron, ConocoPhillips, BP, as well as EOG Resources are investigating the shale gas potential in Sichuan and further southwest in Guizhou Province.

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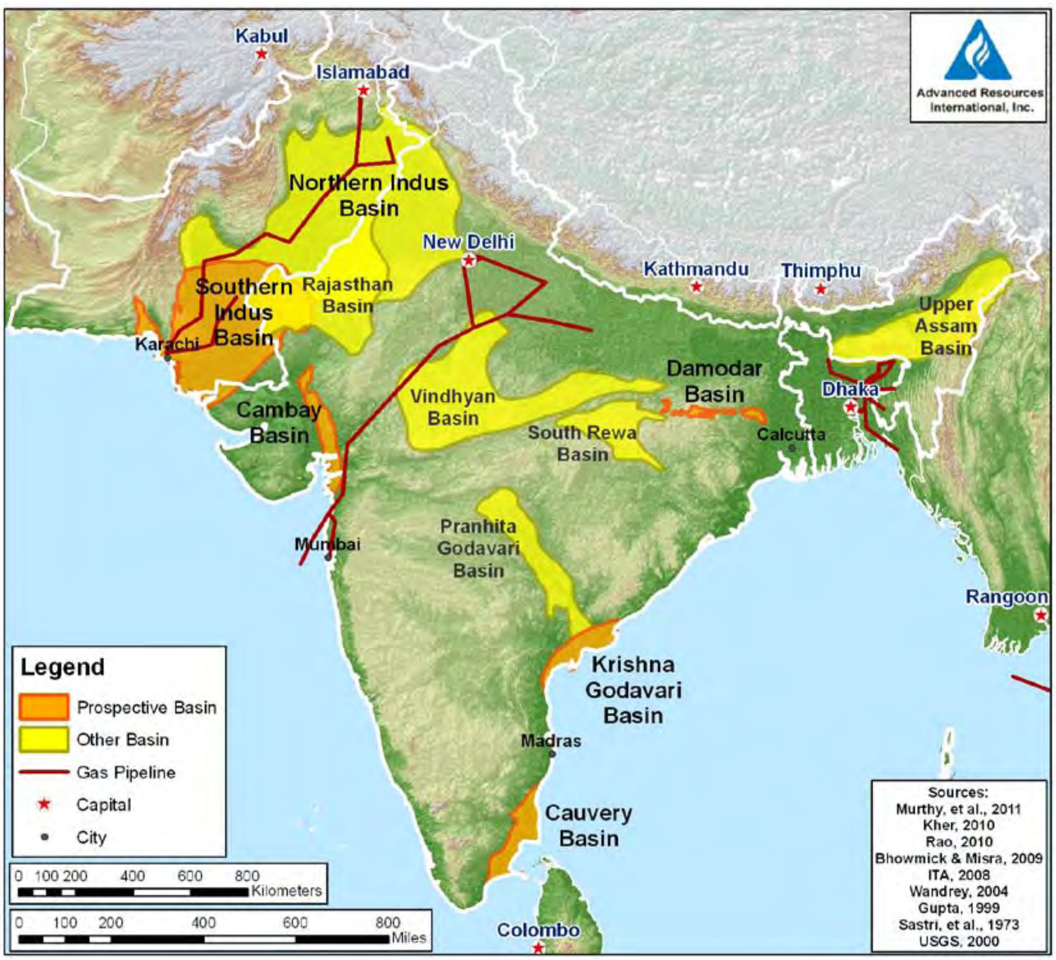
XII. INDIA/PAKISTAN

INTRODUCTION

India and Pakistan contain a number of basins with organic-rich shales. For India, the study assessed four priority basins: Cambay, Krishna Godavari, Cauvery and the Damodar Valley sub-basins such as Raniganj, Jharia and Bokaro. The study also screened several other basins of India, such as the Upper Assam, Vindhyan, Pranhita-Godavari and South Rewa, but found that either the shales were thermally too immature for gas or the data with which to conduct a resource assessment were not available. For Pakistan, the study addressed one priority shale gas basin - - Southern Indus, Figure XII-1.

Figure XII-1. Shale Gas Basins and Natural Gas Pipelines of India/Pakistan



Shale basins in India and Pakistan are geologically highly complex. Many of the basins, such as the Cambay and the Cauvery, have horst and graben structures and are extensively faulted. The prospective area for shale gas in these basins is restricted to a series of isolated basin depressions (sub-basins). While the shales in these basins are thick, considerable uncertainty exists as to whether (and what interval) of the shale is sufficiently mature for gas generation.

Recently, ONGC drilled and completed the India's first shale gas well, RNSG-1, northwest of Calcutta in West Bengal. The well was drilled to a depth of 2,000 meters and reportedly had gas shows at the base of the Permian-age Barren Measure Shale. Two vertical wells (Well D-A and D-B) were previously tested in the Cambay Basin and had modest oil and shale gas production in the shallower, 4,300-foot thick intervals of the Cambay "Black Shale".[1]

Overall, ARI estimates a total of 496 Tcf of risked shale gas in-place for India/Pakistan, 290 Tcf in India and 206 Tcf in Pakistan, Table XII-1. The technically recoverable shale gas resource is estimated at 114 Tcf, with 63 Tcf in India and 51 Tcf in Pakistan. These estimates could increase with collection of additional reservoir information.

Table XII-1. Shale Gas Reservoir Properties and Resources of India/Pakistan

Basic Data	Basin/Gross Area		Cambay Basin (20,000 mi²)	Damodar Valley Basin (1,410 mi²)	Krishna-Godavari Basin (7,800 mi²)	Cauvery Basin (9,100 mi²)	Southern Indus Basin (67,000 mi²)	
	Shale Formation		Cambay Shale	Barren Measure	Kommugudem Shale	Andimadam Formation	Sembar Formation	Ranikot Formation
	Geologic Age		Upper Cretaceous/Tertiary	Permian-Triassic	Permian	Cretaceous	Early Cretaceous	Paleocene
Physical Extent	Prospective Area (mi^2)		940	1,080	4,340	1,005	4,000	4,000
	Thickness (ft)	Interval	1,600 - 4,900	0 - 2,100	3,100 - 3,500	600 - 1,200	1,500 - 2,500	2,000 - 4,000
		Organically Rich	1,500	1,050	1,000	800	1,000	1,500
		Net	500	368	300	400	300	450
	Depth (ft)	Interval	11,500 - 16,400	3,280 - 6,560	6,200 - 13,900	7,000 - 13,000	13,000 - 15,000	10,000 - 13,000
		Average	13,000	4,920	11,500	10,000	14,000	11,500
Reservoir Properties	Reservoir Pressure		Moderatly Overpressured	Moderatly Overpressured	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		3.0%	4.5%	6.0%	2.0%	2.0%	2.0%
	Thermal Maturity (%Ro)		1.10%	1.20%	1.60%	1.15%	1.25%	1.15%
	Clay Content		Medium	HIgh	High	High	Low	Low
Resource	GIP Concentration (Bcf/mi^2)		231	123	156	143	100	157
	Risked GIP (Tcf)		78	33	136	43	80	126
	Risked Recoverable (Tcf)		20	7	27	9	20	31

Cambay BASIN, INDIA

The Cambay Basin is an elongated, intra-cratonic rift basin (graben) of Late Cretaceous to Tertiary-age located in the State of Gujarat in northwestern India. The basin covers an onshore area of about 20,000 mi^2. The basin is bounded on its eastern and western sides by basin-margin faults. It extends south into the offshore Gulf of Cambay, limiting its onshore area, and north into Rajasthan[2], Figure XII-2.

Geologic Characterization (Cambay "Black Shale")

The Deccan Trap Group, composed of horizontal lava flows, forms the basement of the Cambay Basin. Above the Deccan Trap, separated by the Olpad Formation, is the late Paleocene and early Eocene Cambay "Black Shale", Figure XII-3[3]. The Cambay "Black Shale" represents the marine transgressive episode in the basin. The organic matter, ranging from 2.0% to over 4.0%, averages 3% and is primarily Type III (humic) with some Type II, Figure XII-4. With a thermal maturity ranging from about 0.6% to 2%, the shale is in the oil to dry gas window.[4] However, considerable uncertainty exists as to the specific location of the top of the gas window in the depression areas of this basin. For purposes of this study, we have assumed that the gas window is generally below 10,000 feet, Figures XII-5 and XII-6

The depth to the top of the Cambay "Black Shale" ranges from about 6,000 feet in the north to greater than 13,000 feet in the lows of the southern fault blocks, Figure XII-7. The "Black Shale" interval ranges from 1,500 feet thick to more than 5,000 feet thick.[5] In the northern Mehsana-Ahmedabad Block, the Kadi Formation forms an intervening 1,000-foot thick non-marine clastic wedge within the "Black Shale" interval. In this block, the organic-rich shale thickness varies from 300 to 3,000 feet, with the net completable gas bearing shale thickness located in the lower portion of the Cambay "Black Shale" interval, averaging about 500 feet, Figure XII-8. Thermal gradients are high, estimated at 3^oF per 100 feet, contributing to accelerated thermal maturity of the organics.[6]

Figure XII-2. Cambay Basin Study Area.

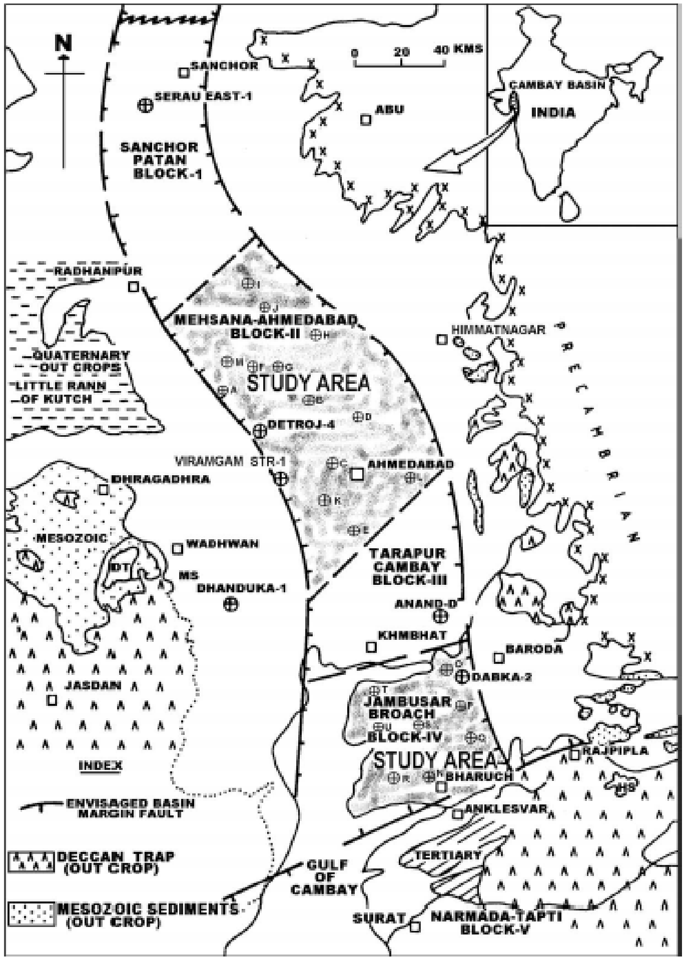


Figure XII-3. Generalized Stratigraphic Column of the Cambay Basin.

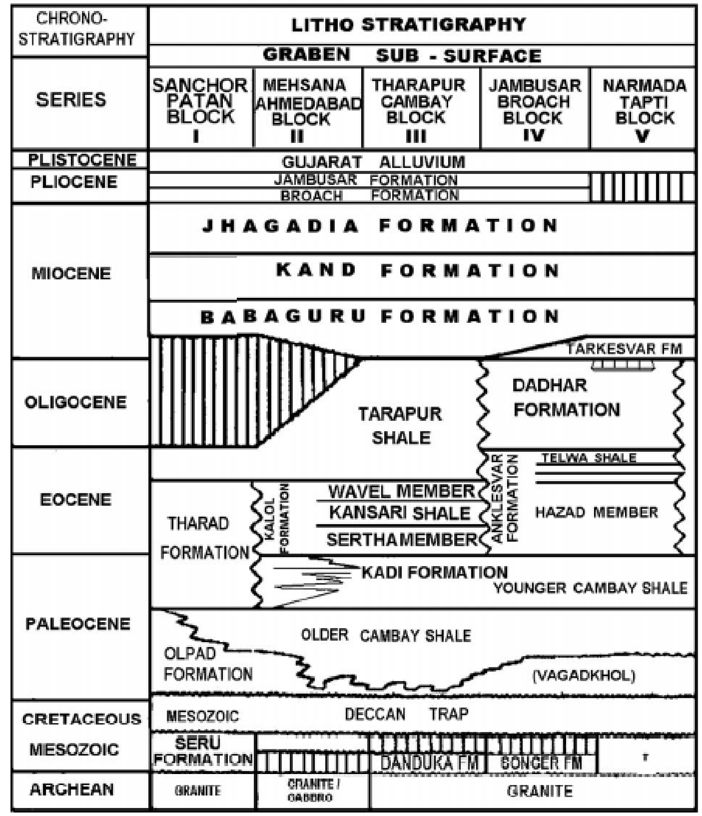


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Figure XII-4. Organic Content of Cambay "Black Shale", Cambay Basin

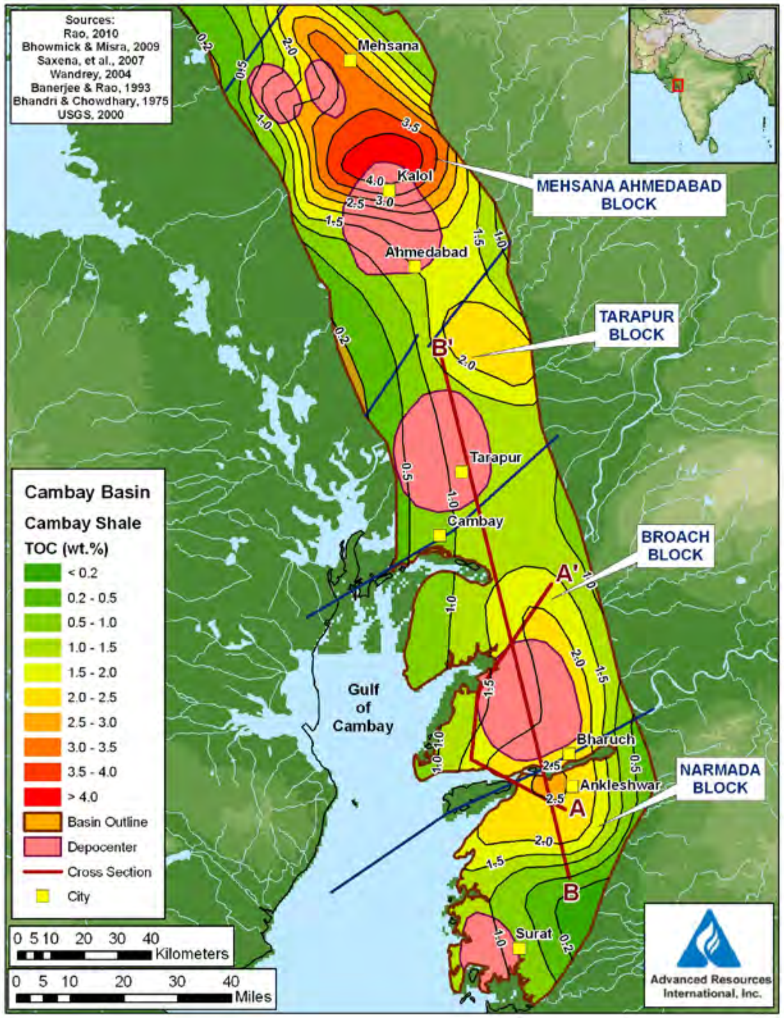


Figure XII-5. Cross Section of Cambay "Black Shale" System

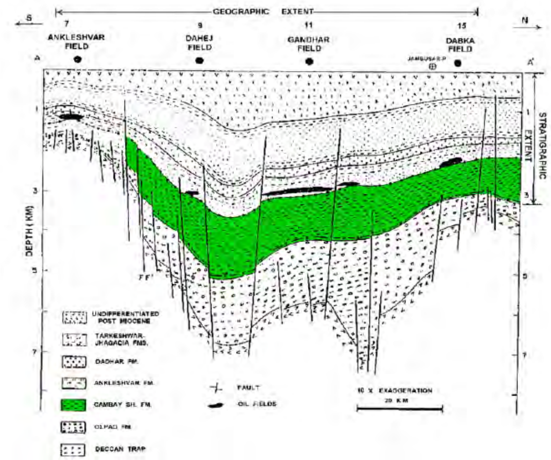


Figure XII-6. N-S Geological Cross-Section Across Cambay Basin

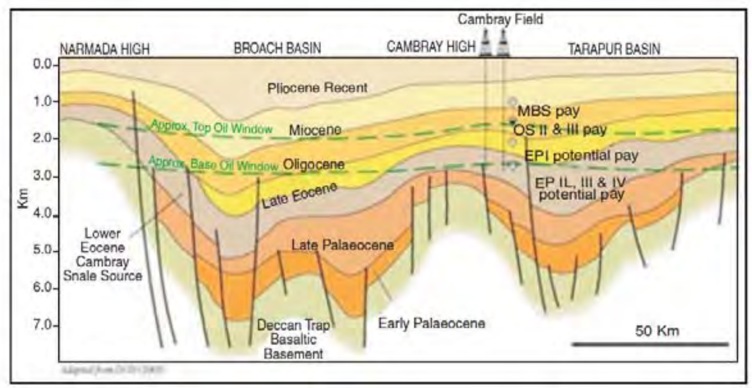


Figure XII-7. Depth and Thermal Maturity of Cambay "Black Shale", Cambay Basin

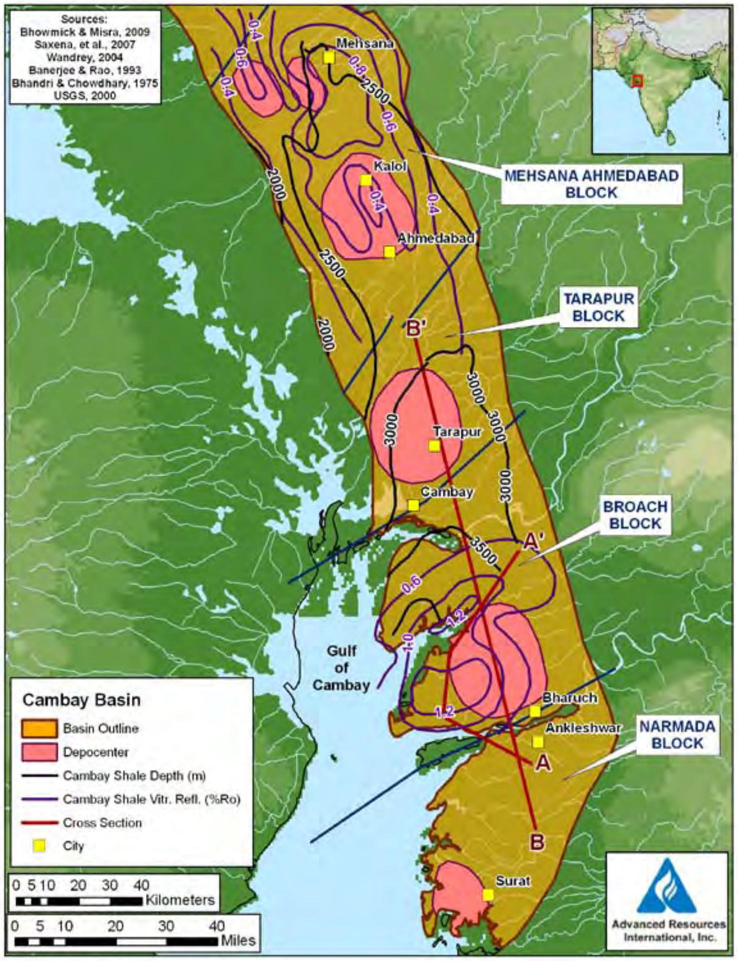
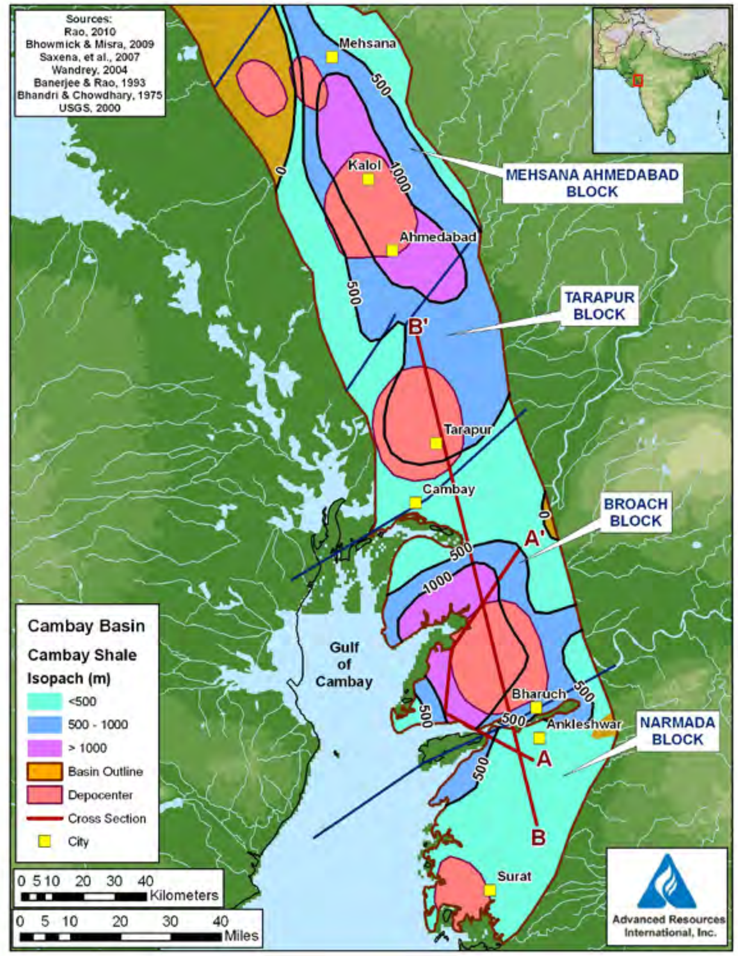


Figure XII-8. Gross Isopac of Cambay Black Shale, Cambay Basin



The Cambay Basin contains five distinct fault blocks, from north to south: (1) Sanchor Patan; (2) Mehsana-Ahmedabad; (3) Tarapur; (4) Broach; and (5) Narmada (Sivan et al., 2008), Figure XII-2. Each of these blocks is characterized by local lows, some of which appear to have sufficient thermal maturity to be prospective for shale gas, Table XII-2.[7]

Table XII-2. Prospective Areas For "Black Shale" of Cambay Basin

Fault Blocks		Depocenter Area (mi^2)	Comments
1.	Sanchor Patan	240	Too Shallow for Shale Gas
2.	Mehsana-Ahmedabad	290	One Prospective Area
3.	Tarapur	320	One Prospective Area
4.	Broach	330	One Prospective Area
5.	Narmada	120	Insufficient Data

- ***Mehsana-Ahmedabad Block.*** Three major deep gas areas (depressions) exist in the Mehsana-Ahmedabad Block - - the Patan, Worosan and Wamji. A deep well, Well-A, was drilled in the eastern flank of the Wamji Low to a depth of nearly 15,000 feet, terminating below the "Black Shale". In addition, a few wells were recently drilled to the Cambay Shale in the axial part of the graben low. A high pressure gas zone was encountered in the Upper Olpad section next to the Cambay Shale, with methane shows increasing with depth. Geochemical modeling indicates an oil window at 6,600 feet, a wet gas window at 11,400 feet and a dry gas window at 13,400 feet respectively.[8]

- ***Broach and Tarapur Blocks.*** The deeper Tankari low in the Broach Block and the low in the Tarapur Block appear to have a similar thermal history as the Mehsana-Ahmedabad Block depression and thus also may have shale gas potential, particularly in the lower interval of the Cambay "Black Shale" in the Broach and Tarapur depocenters.

Resources (Cambay "Black Shale")

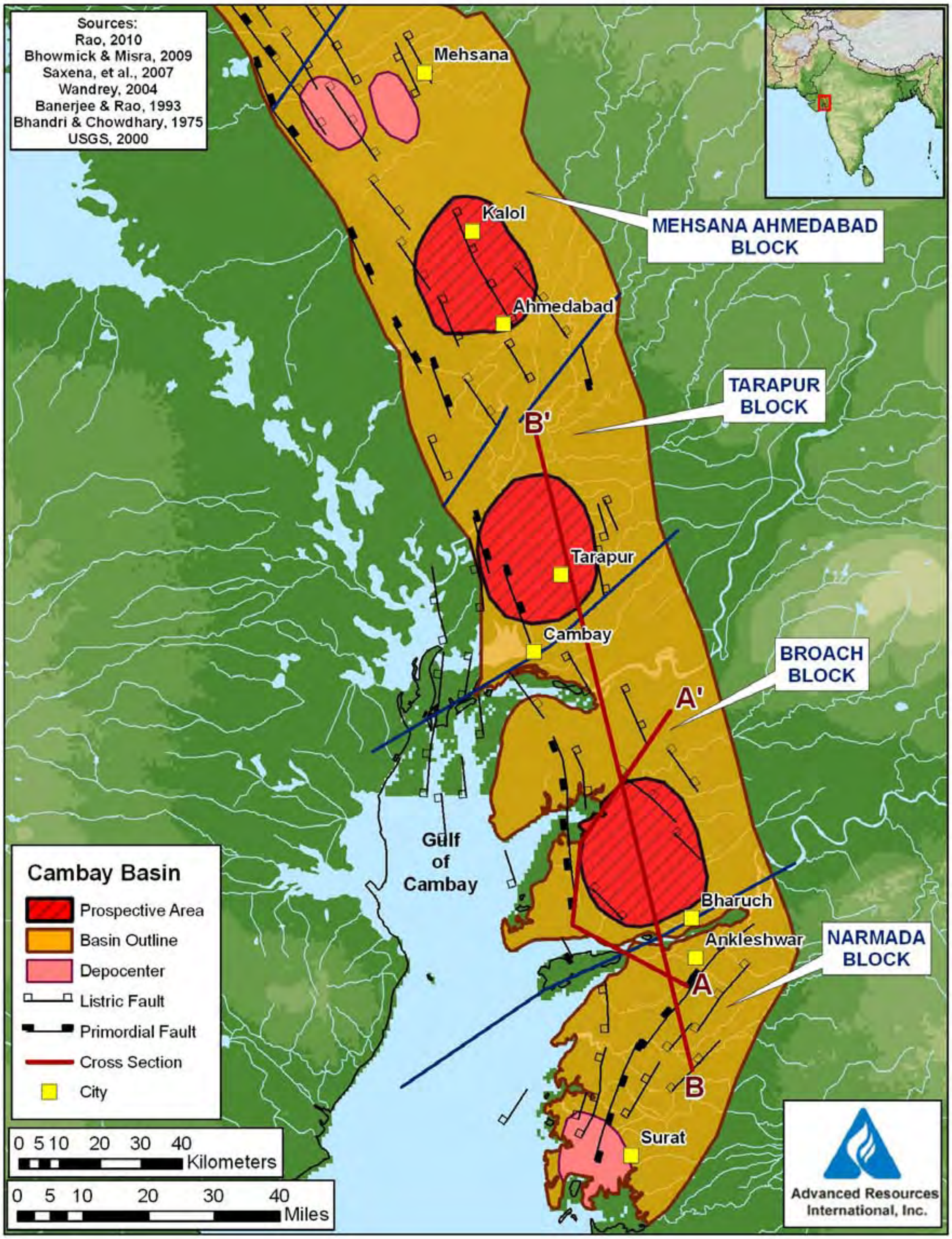
Using the criteria of vitrinite reflectance (Ro) greater than 1.0% and formation depth between 10,000 and 16,500 feet, we calculate a prospective area of 1,940 mi^2 for the "Black Shale" of the Cambay Basin, Figure XII-9.[9]

Based on the estimated prospective area of 1,940 mi^2 and an average value of 500 feet for net shale, ARI estimates a risked gas in-place for the Cambay "Black Shale" of 79 Tcf, approximately 20 Tcf of which may be technically recoverable.

Activity

Although the shales in the Cambay Basin have been identified as a priority area by ONGC, no plans for exploring these shales have yet been publically announced. However, two shallower conventional exploration wells (targeting the oil-bearing intervals in the basin) penetrated and tested the Cambay "Black Shale". Well D-A, a vertical well, had gas shows while drilling the Cambay "Black Shale" in a 90-foot section at a depth of about 4,300 feet. After hydraulic stimulation, Well D-A produced 13 B/D of oil and 11 Mcfd of gas. Well D-B, an older vertical well drilled in 1989 to a depth of 6,030 feet, had also encountered the Cambay Shale at about 4,300 feet. The well was subsequently hydrofractured and produced 13 B/D of oil and 21 Mcfd of gas.

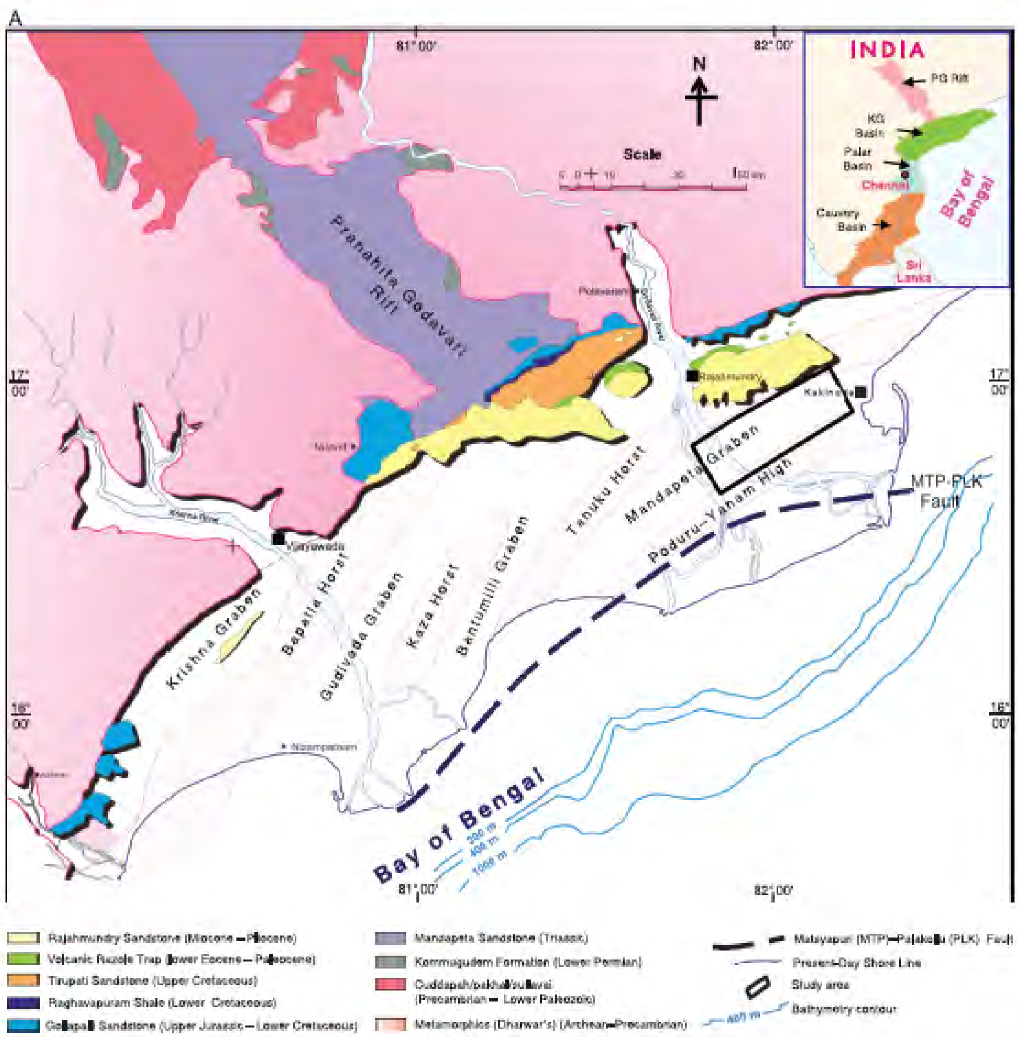
Figure XII-9. Prospective Areas of the Cambay "Black Shale", Cambay Shale Basin



KRISHNA GODAVARI BASIN, INDIA

The Krishna Godavari Basin extends over a 7,800 mi^2 area onshore (plus additional area in the offshore) in eastern India. The basin consists of a series of horsts and grabens, as shown on Figure XII-10[10]. The basin contains a series of organically rich shales, including the deeper Permian-age Kommugudem Shale, which is gas prone (Type III organics) and appears to be in the gas window in the basin grabens. The Upper Cretaceous Raghavapuram Shale and the shallower Paleocene- and Eocene-age shales are in the oil window and thus were not assessed by this study.

Figure XII-10. Krishna Godavari Basin's Horsts and Grabens



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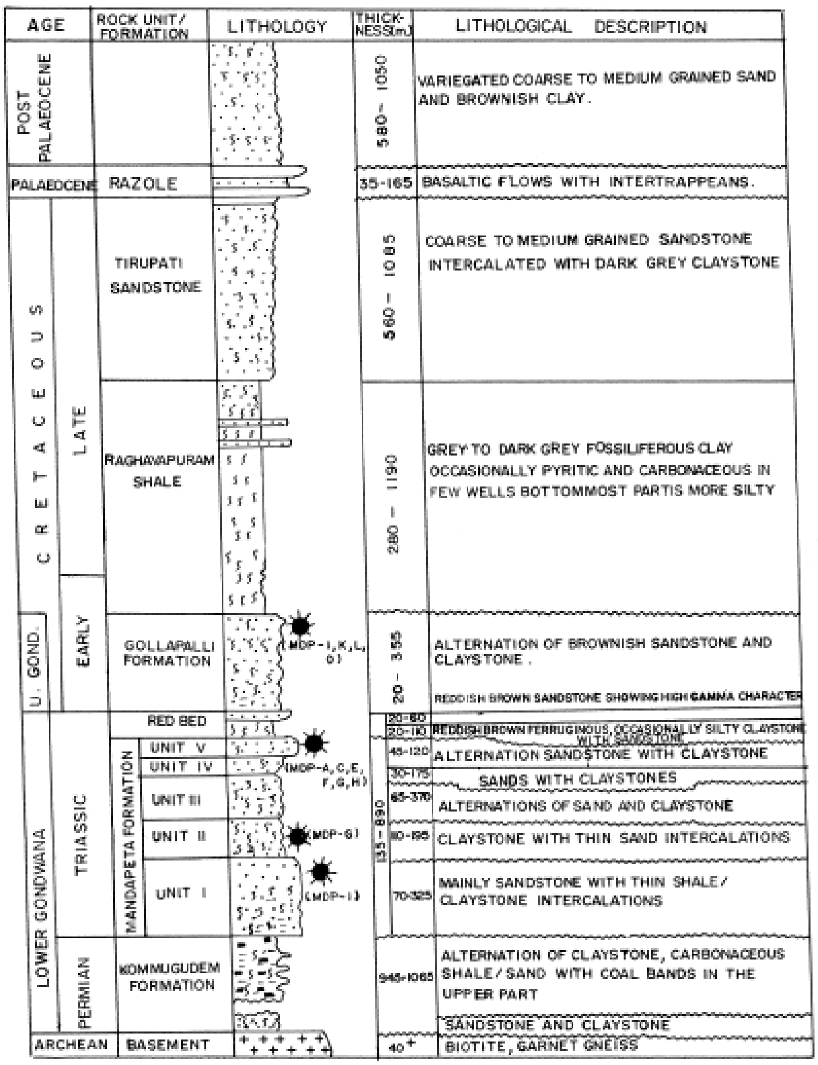
Geologic Characterization (Kommugudem Shale)

The Kommugudem Shale is a thick Permian-age rock interval containing alternating sequences of carbonaceous shale, claystone, sand and coal, Figure XII-11. The Mandapeta Graben, the most extensively explored area of the Krishna Godavari Basin, provides much of the geologic characterization data for this basin. The shale interval in this graben ranges from 945 to 1,065 m in thickness.[11]

Figure XII-11. Stratigraphic Column, Mandapeta Area, Krishna Godavari Basin[11]



An average continuous organic-rich area of 140 m was tested in 10 wells. The data show that the TOC of the Kommugudem Shale ranges up to 11% with a more typical range of 3% to 9%, averaging 6%, for ten rock samples at various depths, Table XII-3.

Table XII-3. Analysis of Ten Rock Samples, Kommugudem Shale[12]

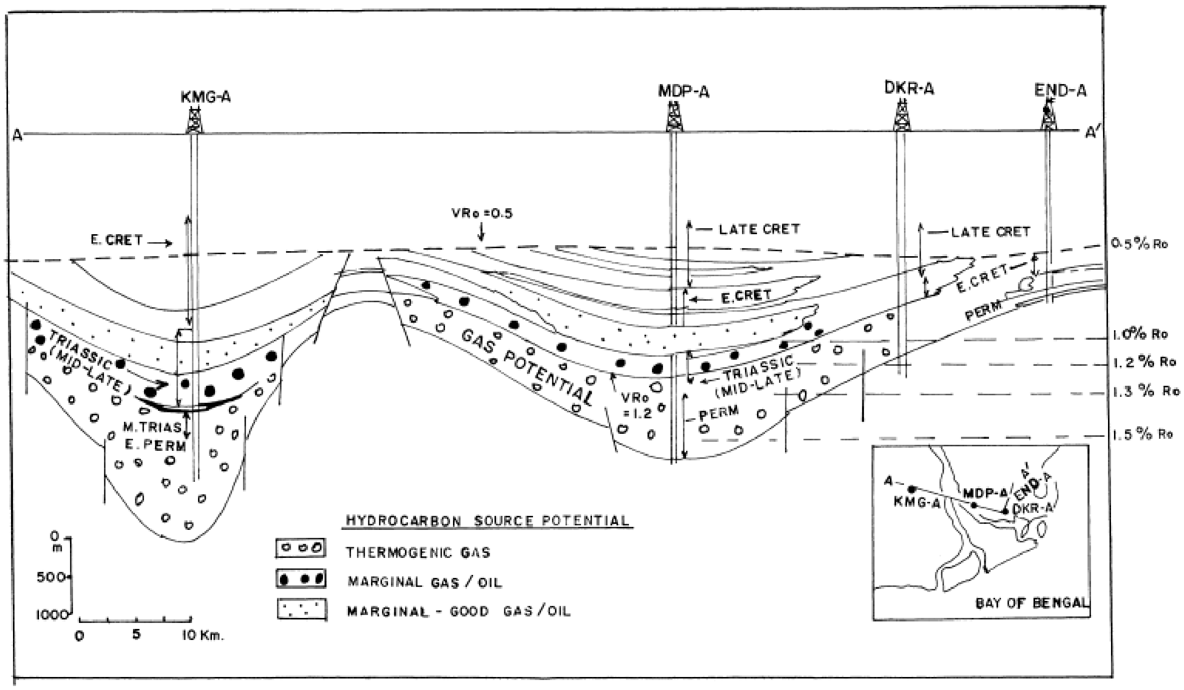
Well	Depth (m)	TOC (%)	S_2*	Shale Interval Tested (m)
AA-1	3,320-3,880	10.4	7.0	110
AA-2	3,585-3,630	4.2	2.9	45
AA-9	3,330-3,360	7.1	6.4	30
AA-10	3,880-3,920	3.1	0.6	40
AA-11	2,890-3,150	7.0	7.9	260
BW-1A	3,915-4,250	5.6	0.8	335
BW-2	2,970-3,085	8.8	5.5	115
BW-2	3,100-3,175	7.8	6.0	75
BW-9	2,800-3,040	11.2	6.9	315
DE-1	1,900-2,040	8.9	13.9	120

*Volume of hydrocarbon cracked from kerogen by heating to 550°C, measured in terms of mg hydrocarbon/g rock.

The Kommugudem Shale was deposited in fluvial, lower deltaic, and lacustrine environments. While an effective source rock with excellent organic matter richness, analysis of the shale indicates hydrogen-deficient organic matter (based on low S_2 values from pyrolysis) and high levels of primary inertinite. The average depth of the shale is 11,500 feet in the graben structures. The organically rich shale interval is estimated at 1,000 feet, with a completable net pay of 300 feet.

Vitrinite reflectance of the Kommugudem Shale in the deep graben structures ranges from 1.2% to 2% Ro, placing the shale inside the wet to dry gas window. Figure XII-12 provides a useful illustration of the relationship of the depth and geologic age of the deposition in the Krishna Godavari Basin to the thermal maturity (Ro) for two of the graben structures, Kommugudem (KMG) and Mandapeta (MDP).

Figure XII-12. Cross Section for the Krishna Godavari Basin [11]



The shale appears to be normally overpressured. Given the fluvial lacustrine deposition, we anticipate the clay content of the shale to be moderately high.

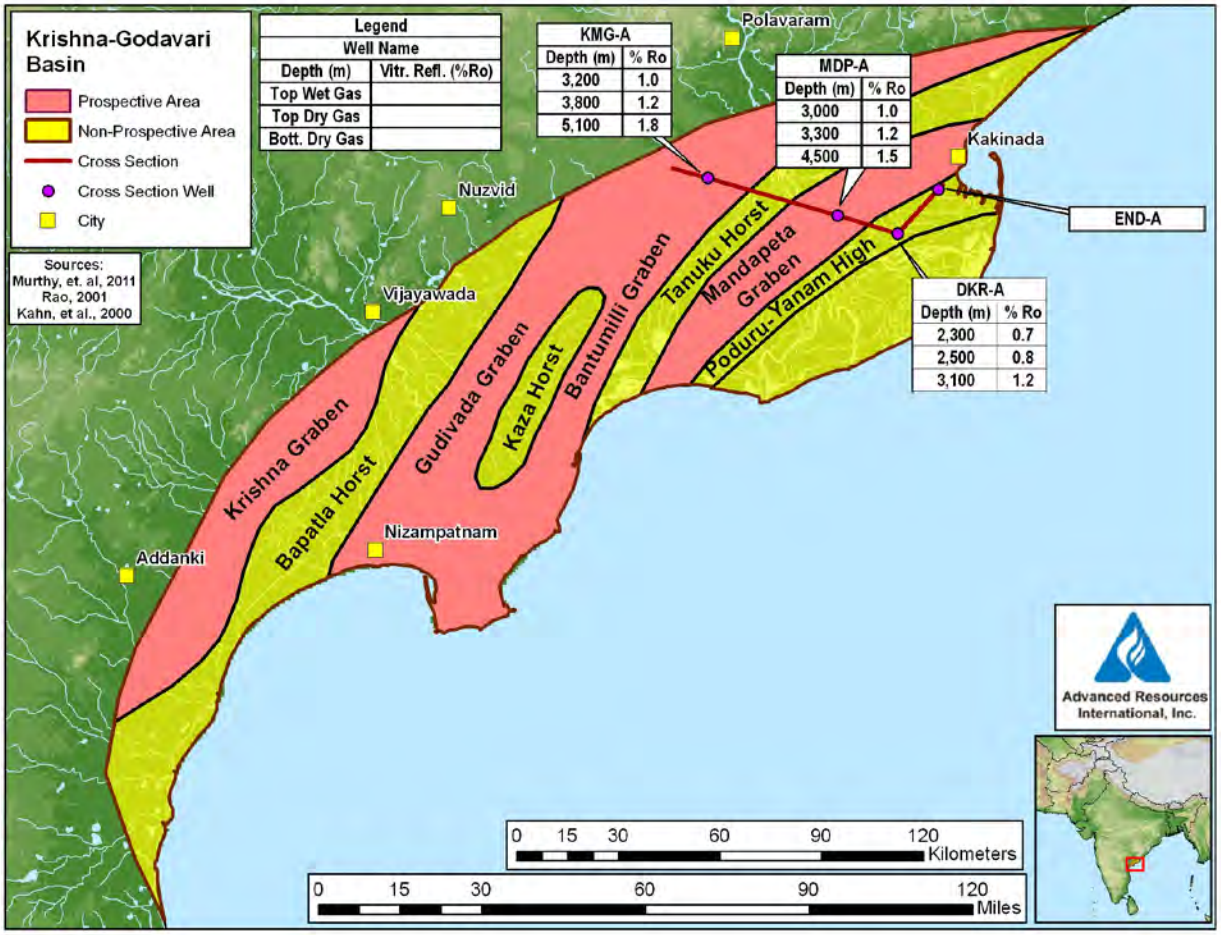
Resources (Kommugudem Shale)

The 4,340 mi^2 prospective area of the Kommugudem Shale in the Krishna Godavari Basin is limited to the four grabens (sub-basins) where the thermal maturity is sufficiently high for wet to dry gas generation, Figure XII-13. Based on an average resource concentration of 156 Bcf/mi^2 for the four graben areas, we estimate a risked shale gas in-place of 136 Tcf, with a risked technically recoverable resource of 27 Tcf.

Activity

The technical literature discusses 16 wells that have been drilled at the Mandapeta graben into or through the Kommugudem Shale in search for hydrocarbons in the Mandapeta and Gollapalli sandstone reservoirs. The information from these 16 wells has provided valuable data for this study.

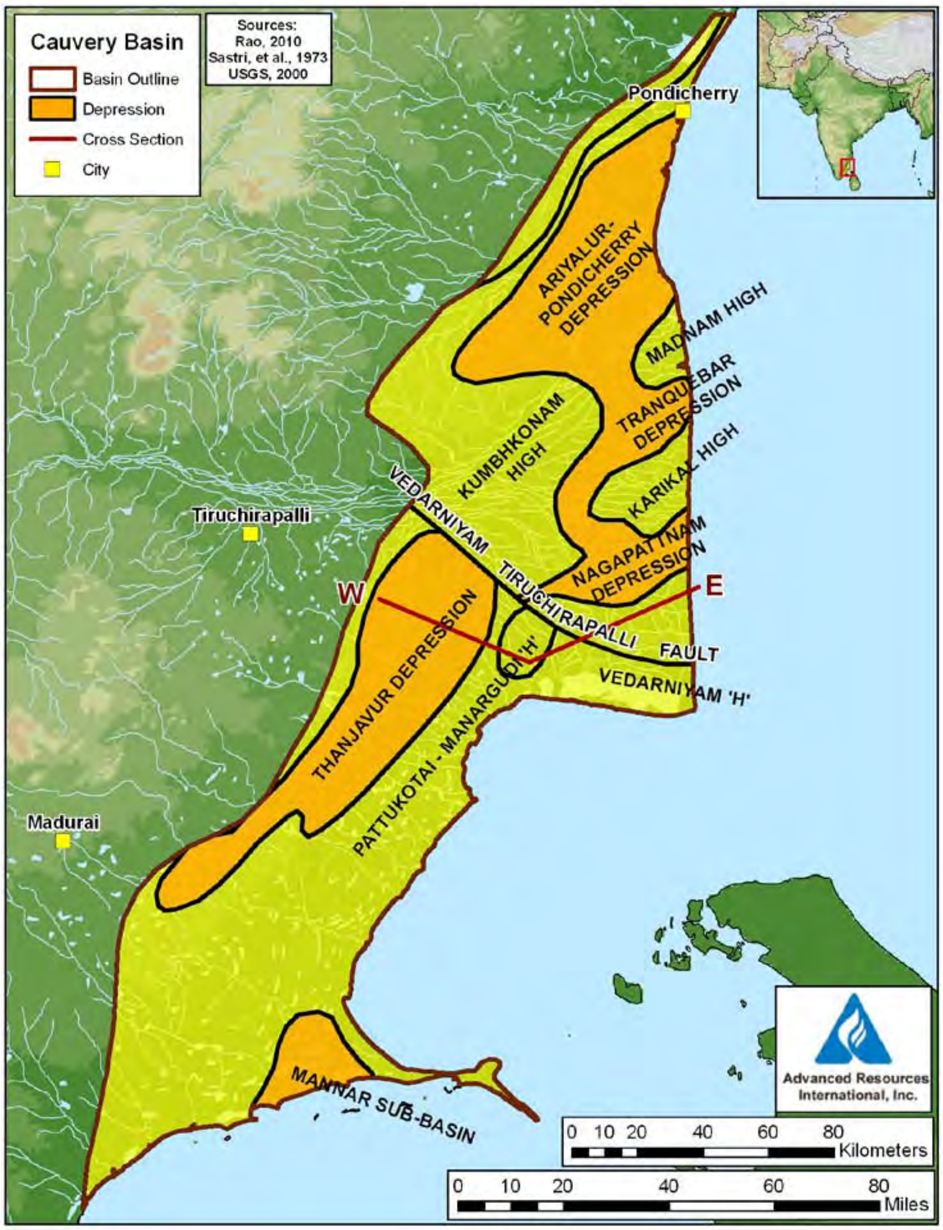
Figure XII-13. Prospective Areas for Shale Gas in the Krishna Godavari Basin



CAUVERY Basin, India

The Cauvery Basin covers an onshore area of about 9,100 mi^2 on the east coast of India, plus an additional area of about 9,000 mi^2 in the offshore, Figure XII-14. The basin comprises numerous horsts and rifted grabens. The basin contains a thick interval of organic-rich source rocks in Lower Cretaceous Andimadam and Sattapadi shale formations which overly the Archaean basement.

Figure XII-14. Cauvery Basin Horsts and Grabens



Geologic Characterization

The gas prone source rocks in the Cauvery Basin are the Lower Cretaceous Andimadam Formation and the Sattapadi Shale, Figure XII-15 and Figure XII-16. The source rock is generally Type III with some Type II. The thermally mature source rocks are limited to the deeper Andimadam Formation which contain thermogenic natural gas.

The oldest rocks in the Cauvery Basin are the shallow marine, late Jurassic sediments and early Cretaceous deposits. The thickness of the Lower Cretaceous interval is 3,000 to 5,000 feet, with the Andimadam/Sattapadi Shale accounting for the bulk of the gross interval. The TOC of the Andimadam/Sattapadi Shale is estimated at 2% to 2.5%.

The Cauvery Basin contains a series of depressions (sub-basins) that hold potential for shale gas, with two of these - - Ariyalur-Pondicherry and Thanjavur - - containing thick, thermally mature shales, Figure XII-17.

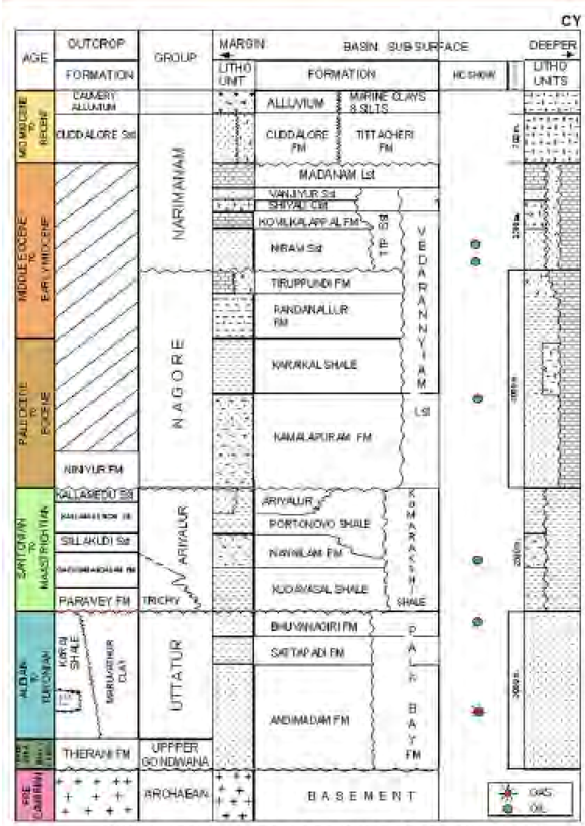
- ***Ariyalur-Pondicherry Sub-Basin***. The Ariyalur-Pondicherry Depression (sub-basin) is in the northern portion of the Cauvery Basin. The Lower Cretaceous Andimadam/ Sattapadi Shale encompasses a 5,000 foot thick interval at a depth of 6,600 to 11,600 feet. Organic-rich gross pay ranges from 600 to 1,200 feet thick, with an average completable net pay of about 450 feet, Figure XII-16. The organic richness (TOC) ranges from 0.3 to 2.8%, averaging about 2%. The thermal maturity of 1.15% Ro places the shale in the wet gas window at 10,000 feet deep. The onshore prospective area with thick organic-rich shale is rather small, estimated at 620 mi^2, Figure XII-18.

- ***Thanjavur Sub-Basin.*** The Thanjavur Depression (sub-basin), in the center of the Cauvery Basin, has a thick section of Andimadam and Sattapadi shale encompassing an over 8,000 foot thick interval at a depth of 5,000 feet (top of Sattapadi Shale) to 13,000 feet (base of Andimadam Fm), averaging 9,000 feet deep. The organic-rich interval is 600 feet thick, with an average completable net pay of about 300 feet, Figure XII-19. Given limited data, we assume the TOC and thermal maturity for the shale in this sub-basin to be similar to the Ariyalur-Pondicherry sub-basin. The onshore prospective area with thick organic-rich shale is small, estimated at 385 mi^2, Figure XII-18.

Figure XII-15. Generalized Straigraphy of the Cauvery Basin

AGE		FORMATION		THICKNESS in m
Recent to Mid. Miocene		Tittacheri Sandstone		300-500
Lower Miocene		Madanam Limestone		600-1200
		Vanjiyur Sandstone		
		Shiyali Clay stone	CAP	
Oligocene		Kovilkalappai Fm.		500-800
		Niravi Sandstone	PLAY	
Eocene		Pandanallur Fm.		200-400
		Karaikal Shale	CAP	
		Up.Kamalapuram Fm.	PLAY	
Paleocene		Lr.Kamalapuram Fm.	PLAY	200-800
Creta-ceous	Upper	Porto-Novo Shale	CAP	600-1500
		Nannilam Fm.	PLAY	
		Kudavasal Shale	CAP	
	Lower	Bhuvanagiri Fm.	PLAY	1000-1500
		Sattapadi Shale	SOURCE+CAP	
		Andimadam Fm.	SOURCE+PLAY	
Archaean		Basement	PLAY	

Figure XII-16. Generalized Straigraphy of the Cauvery Basin



GENERALIZED STRATIGRAPHY OF CAUVERY BASIN

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Figure XII-17. Shale Isopach and Presence of Organics, Cauvery Basin

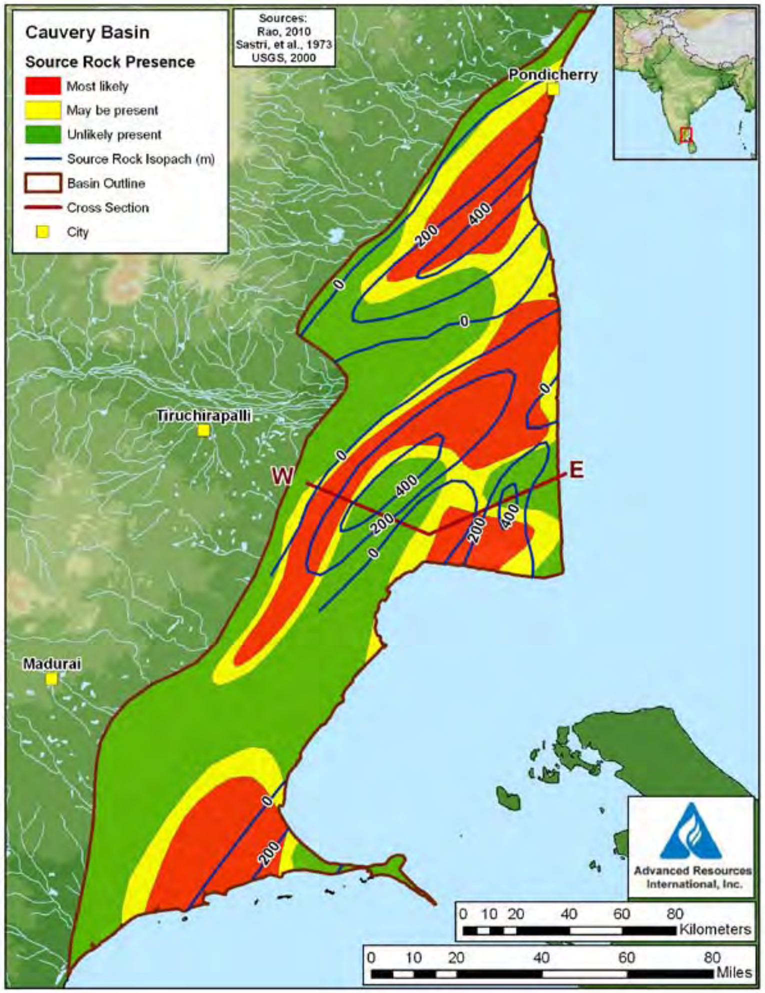


Figure XII-18. Prospective Areas for Shale Gas, Cauvery Basin

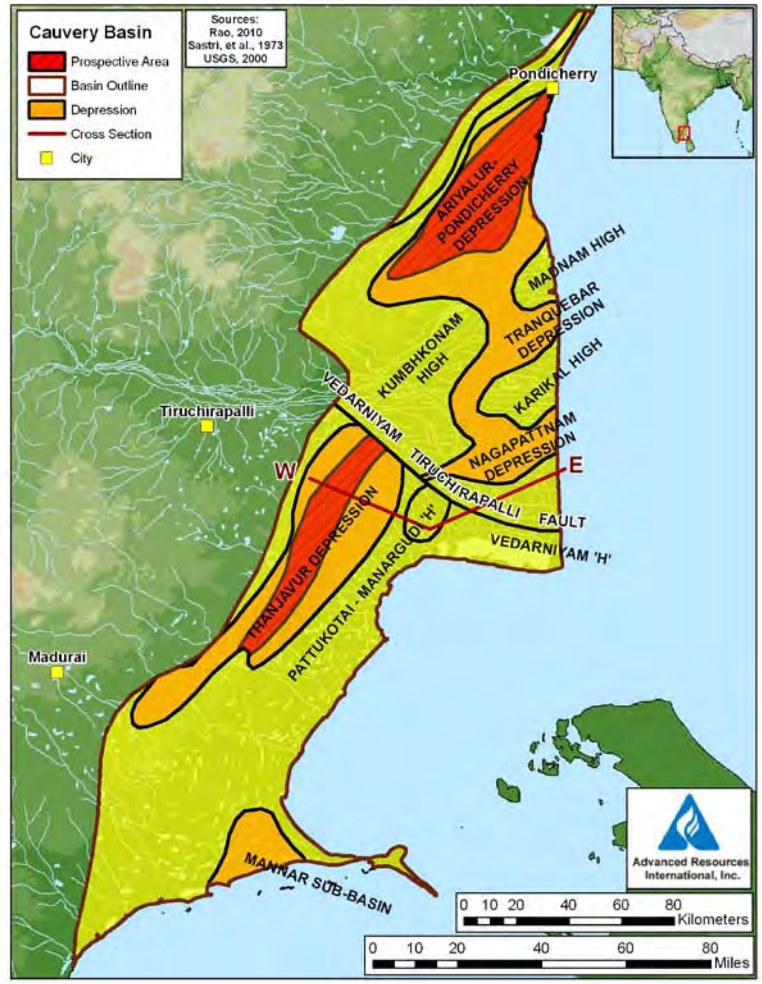
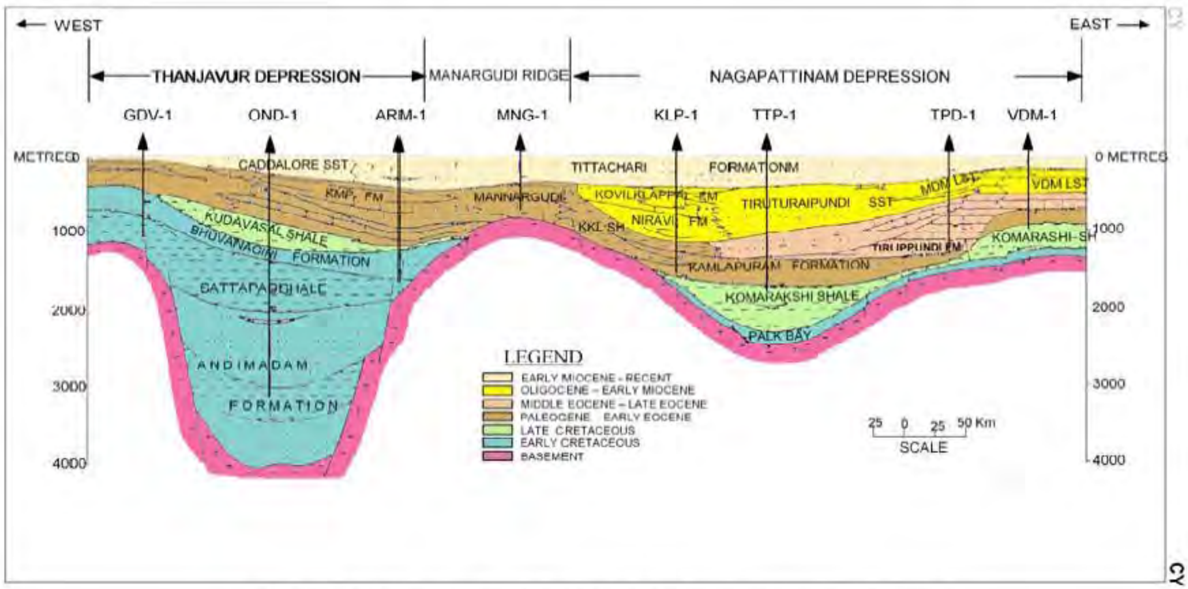


Figure XII-19. Thanjavur Sub-Basin and Geological Section Across Cauvery Basin.



E-W GEOLOGICAL PROFIE, GDV-1 TO VDM-1, CAUVERY BASIN

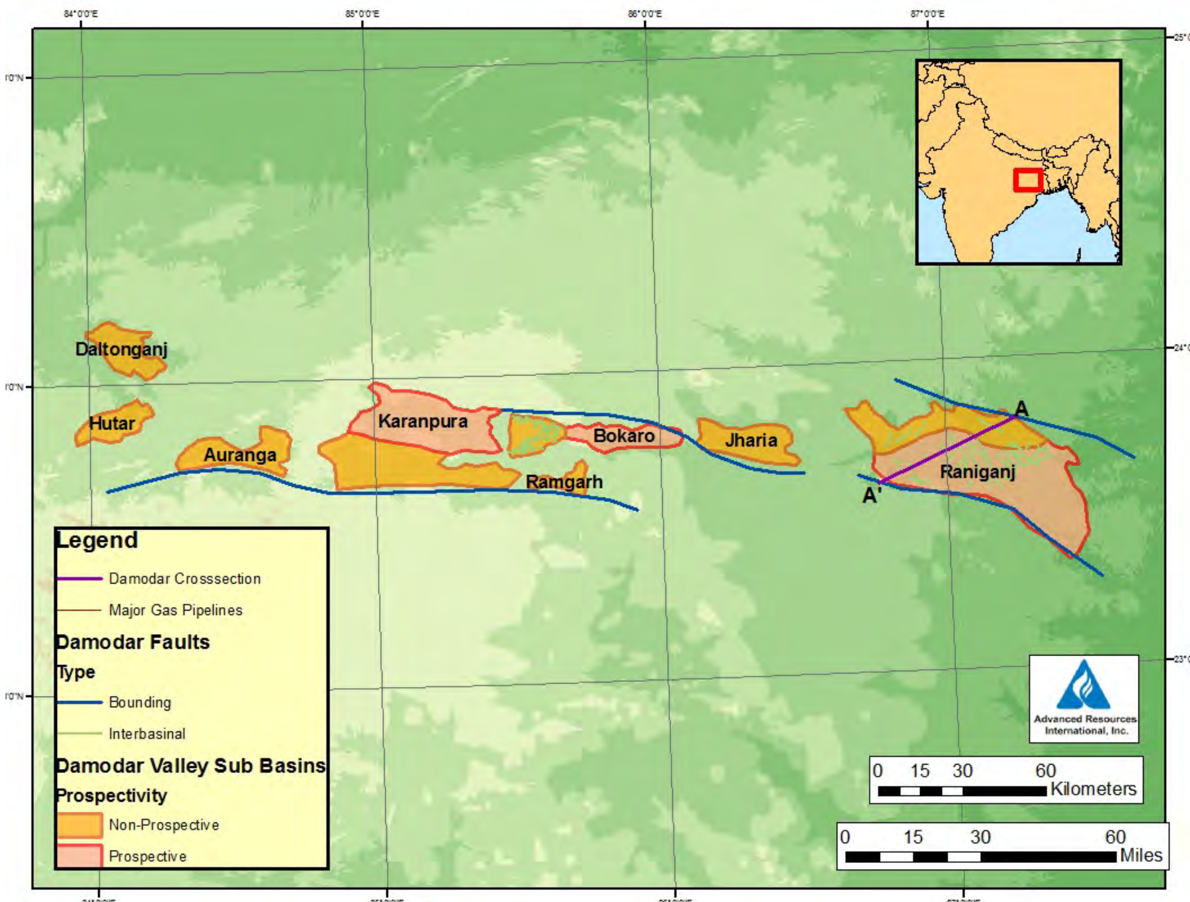
Resources

With a combined prospective area of 1005 mi^2 and an average resource concentration of 143 Bcf/mi^2, we estimate a risked shale gas in-place of 43 Tcf, of which 9 Tcf are considered technically recoverable.

Damodar Valley Basin, India

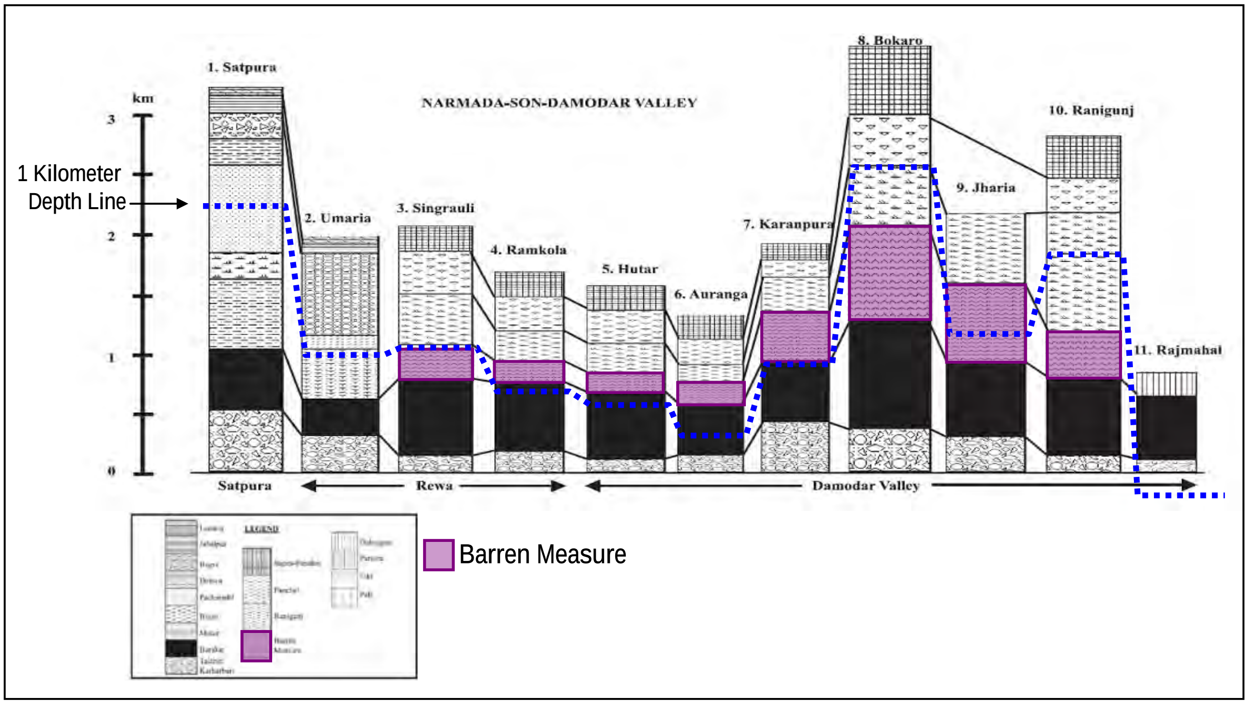
The Damodar Valley Basin is part of a group of basins collectively named the “Gondwanas”, owing to their similar dispositional environment and Permo-Carboniferious through Triassic stratigraphic fill. The “Godwanas,” comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar basins, were part of a system of rift channels in the Northeast of the Gondwana super continent. Tectonic activity formed the major structural boundaries of many of the Gondwana basins, notably the Damodar Valley Basin, Figure XII-20.

Figure XII-20. Damodar Valley Basin and Prospectivity for Shale Gas



Sedimentation in the Early Permian Gondwana basins was primarily glacial-fluvial and lacustrine, resulting in significant deposits of coal. As such, the majority of the exploration activities have focused on the basins’ coal resource potential, which accounts for essentially all of India’s coal reserves (about half of which are in the Damodar Valley Basin). However, a marine incursion took place between periods of continental deposition, depositing a layer of early Permian shale, called the “Barren Measure” Shale Formation, Figure XII-21[13]. This formation, called the Ironstone Shale in the Raniganj sub-basin is the target of India's first shale gas exploration well in the eastern Damodar Valley. Though present in other Gondwanan basins, such as the Rewa Basin in the state of Orissa, data suggest that the shale is only thermally mature to the east, probably only within the Damodar Valley Basin[14].

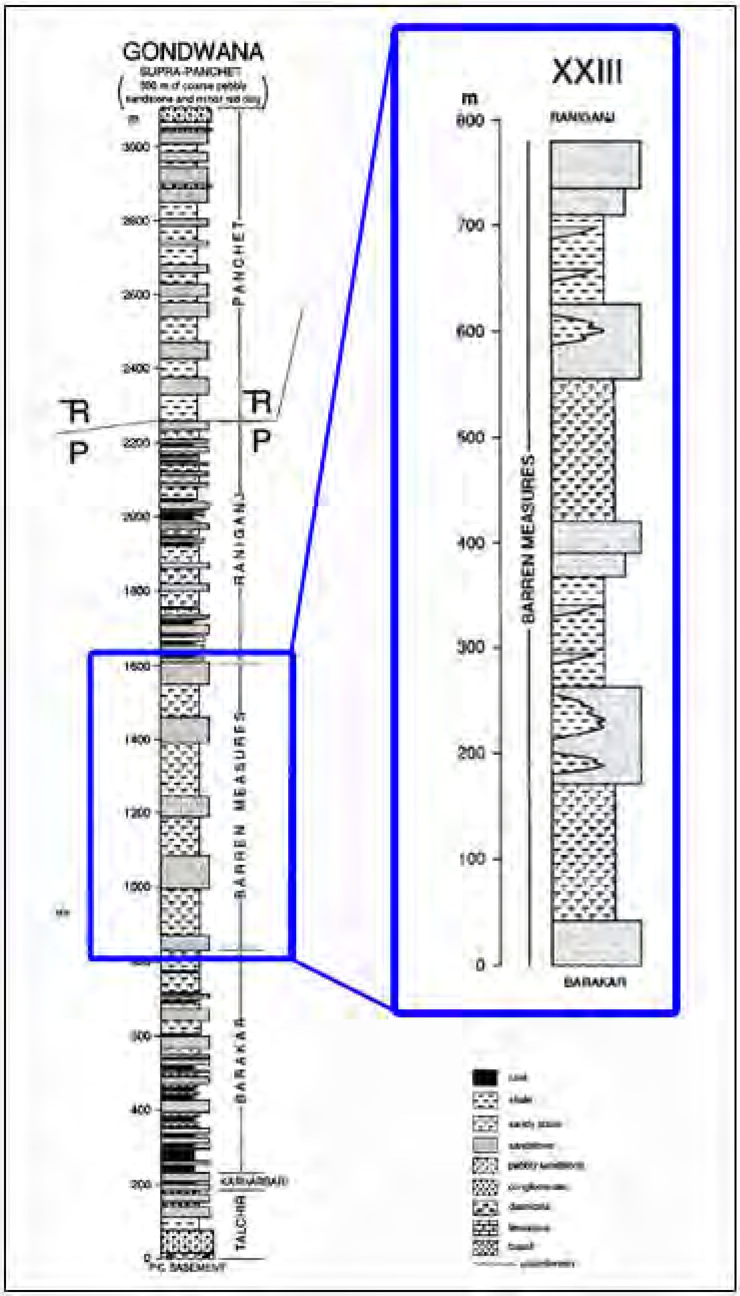
Figure XII-21. Regional Stratigraphic Column of the Damodar Valley Basin, India[15].



The Damodar Valley Basin comprises of a series of sub-basins (from west to east, the Hutar, Daltonganj, Auranga, Karanpura, Ramgarh, Bokaro, Jharia and Raniganj). Though these sub-basins share a simalar geologic history, tectonic events and erosion since the early Triassic have caused extensive variability in the depth and thickness of the Barren Measure Shale formation.

Because exploration has focused on the coal deposits within the Damodar Valley basin, relatively little geologic data is available on the Barren Measure Shale. Thermal maturity data on coals surrounding the Barren Measure Shale suggest that it is within the gas window, and regional studies have shown favorable TOC. Shallower burial depth is the main limitation for the shale gas prospectively of the Barren Measure Shale in the Damodar Valley Basin. In some sub-basins, regional erosion has removed up to 3 kilometers of overlying sediments. Based on regional stratigraphic columns, such as that shown in Figure XII-22, and operator data, the prospective area for the Barren Measure Shale was limited to the Bokaro, Karanpura and Raniguj sub-basins. The small prospective area within the Bokaro (110 mi^2) and Raniganj (650 mi²) basins was limited by surface outcrops of formations underlying the Barren Measure to the west and north, respectively. We have estimated a moderate size prospective area for the northern half of the Karanpura Basin (320 mi²), based on statements by Schlumberger and ONGC.[16]

Figure XII-22. Generalized Stratigraphic Column of the Gondwana Basin.



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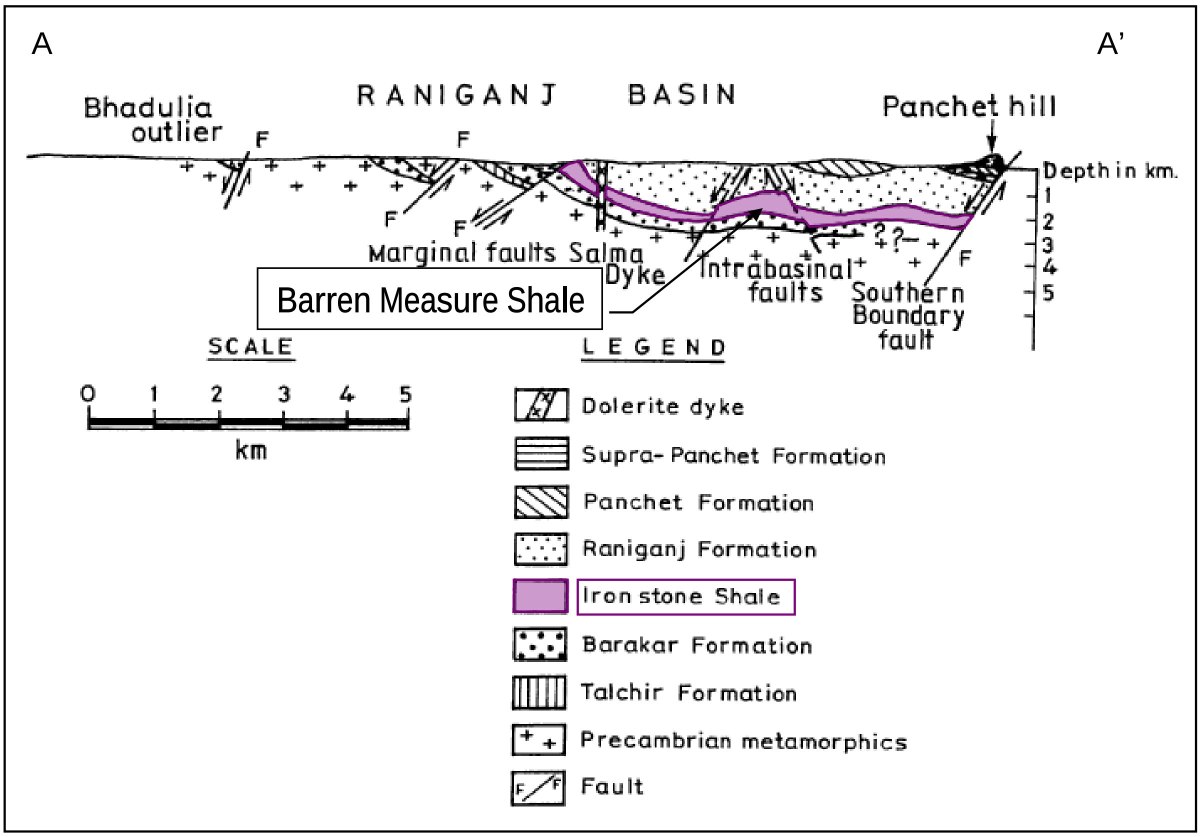
Geologic Characterization (Barren Measure Formation)

Absent specific data on thermal maturity and organic content in each of the sub-basins, We assigned average published values for the region. TOC is assumed to range between 3% and 6%, based on information from INOC and ESSAR[17,18]. Thermal maturity was estimated from the coal formations surrounding the Barren Measure Shale, indicating values between 1.1% to 1.3% Ro, placing the shale within the wet gas window[19]. Depth to the Barren Measure Shale averages about 5,000 feet, based on reports from the shale gas well drilled into the Raniganj sub-basin and regional cross sections, Figure XII-23. Using regional stratigraphic columns, we estimate a weighted average gross interval thickness in the three prospective sub basins of 2,100 feet, of which about 1,050 feet are organically rich and 368 feet are net shale, Figure XXII-22[20].

Figure XII-23. Raniganj Sub-Basin Cross Section.[21]



Resources

Using the geologic characteristics discussed above, we estimate that the Damodar Valley Basin contains a favorable resource concentration of 123 Bcf/mi^2. Risked gas in-place is 33 Tcf, reduced for the significant faulting present in the basin, Figure XII-20. We estimate approximately 7 Tcf of shale gas may be technically recoverable from the Barren Measure shale in this basin.

Activity

Along with the Cambay Basin, the Damodar Valley Basin is a priority basin for shale gas exploration by the Indian government. In late September 2010, Indian National Oil and Gas Company (ONGC) spudded the country's first shale gas well, RNSG-1 in the Raniganj sub-basin. The well was completed mid-January 2011, having reportedly encountered gas flows from the Barren Measures Shale at approximately 5,600 feet. Detailed well test or production results are not publicly available. This well was the first of a 4 well R&D program in the basin. The plan calls for an additional well in the Raniganj sub-basin and an additional two wells in the Karanpura sub-basin by March 2012.

UPPER ASSAM BASIN, INDIA

The Upper Assam Basin is an important onshore petroleum province in northeast India. The basin has produced oil and some associated gas, mainly from the Upper Eocene-Oligocene Barail Group of coals and shales. In general, the TOC in the lower source rocks ranges from 1% to 2% but reaches 10% in the Barail Group. These source rocks are in the early thermal maturity stage (beginning of the oil window) in the shallower parts of the Upper Assam Basin and may have sufficient thermal maturity for peak oil and onset of gas generation in the deeper parts of the basin toward the south and southwest.[22]

The thermal maturity values range from Ro of 0.5 to 0.7% for the Sylhet and Kopili formations and range from Ro of 0.45% to 0.7% for the Barail Group, placing these shales in the early oil window.[23] While the shales may reach the wet gas window in the deepest portion of the basin, the measured vitrinite reflectance is still at only 0.7% (oil window) down to a depth of 14,800 feet.[24]

PRANHITA-GODAVARI BASIN, INDIA

The Pranhita-Godavari Basin, located in eastern India, contains thick, organically rich shales in Permian-age (Lower Gondwana) Jai Puram and Khanapur formations. While the kerogen is Type III (humic) and thus favorable for gas generation, the 0.67% Ro indicated the shales are thermally immature for shale gas production.

VINDHYAN BASIN, INDIA

The Vindhyan Basin, located in north central India, contains a series of Proterozoic-age shales. While certain of these shales, such as the Hinota and Pulkovar, appear to have sufficient organic richness, no public data exists on their thermal maturity.

RAJASTHAN BASIN, INDIA

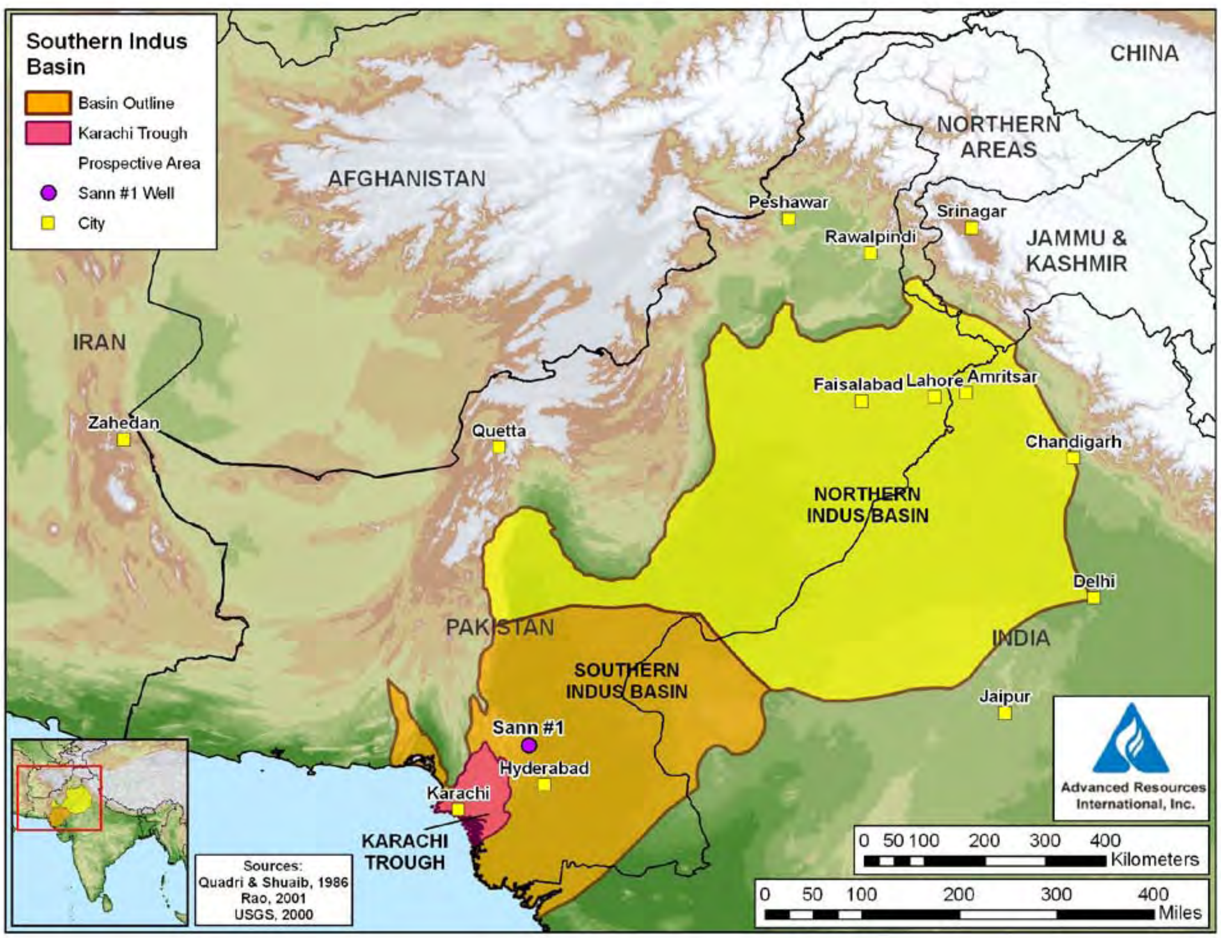
The Rajasthan Basin covers a large onshore area in northwest India. The basin is structurally complex and characterized by numerous small fault blocks. The Permian-age Karampur Formation is the primary source rock in this basin. While the source rock is Type III and classified as mature, only limited data are available on the reservoir properties of this shale.

SOUTHERN INDUS BASIN, PAKISTAN

The Southern Indus Basin is located in southern Pakistan adjacent to the border with India. The basin is bounded by the Indian Shield in the east and highly folded and thrust mountains on the west. On the north, the Jacobabad Arch separates the Southern Indus Basin from the Central Indus Basin. Within the basin, the shales in the deeper portions of the Karachi Trough appear to have reached the wet to dry gas window, Figure XII-24.[25]

The Southern Indus Basin has five commercial oil discoveries and one gas discovery in the conventional Cretaceous-age Goru Fm sands and three gas discoveries and one gas-condensate discovery in shallower formations. While oil and gas shows have been recorded in the Sembar Shale on the Thar Platform, no productive oil or gas wells have been drilled into the Sembar Shale.[26]

Figure XII-24. Basin Outline and Karachi Trough, Southern Indus Basin



Geologic Characterization (Sembar Shale)

The Lower Cretaceous Sembar Formation is considered to be the main source rock in the Southern Indus Basin due to its organic richness and thermal maturity. The formation contains of shale, silty shale and marl in the western and northwestern portion of the basin and becomes sandy in the eastern part of the basin. While the reported log porosities in a previously drilled well were high, ranging from 9% to 30%, a drill stem test showed water with only a small volume of gas.

The Sembar Formation was deposited under open-marine conditions. In the shale gas prospective area of the Karachi Trough, the thickness of the Sembar Shale ranges from 1,500 to 2,500 feet, Figure XII-25. We identified an organically rich interval 1,000 feet thick and a completable net shale thickness 300 feet thick. We estimate TOC of approximately 2% and an Ro of 1.0% to 1.5%, with low clay content. The bulk of the sediments in the basin appear to be primarily in the oil window with the lower limit of the oil window at about 10,000 feet in the Karachi Trough. In the deeper portions of the Karachi Trough, the Sembar Shale enters the wet gas window.

The thermal gradients in the basin increase from east to west, from 1.31^{o}F/100 ft on the Thar Slope in the east to 2.39^{o}F/100 ft in the Karachi offshore in the west. The thermal gradient in the Karachi Trough is about 2.1^{o}F/100 ft.

Resources (Sembar Formation)

Based on an estimated prospective area of 4,000 mi^2 and a resource concentration of 100 Bcf/mi^2, we estimate the risked shale gas in-place for the Sembar Formation at 80 Tcf, with 20 Tcf as technically recoverable.

Figure XII-25. Isopach of Sembar Shale, Southern Indus Basin, Pakistan[25]

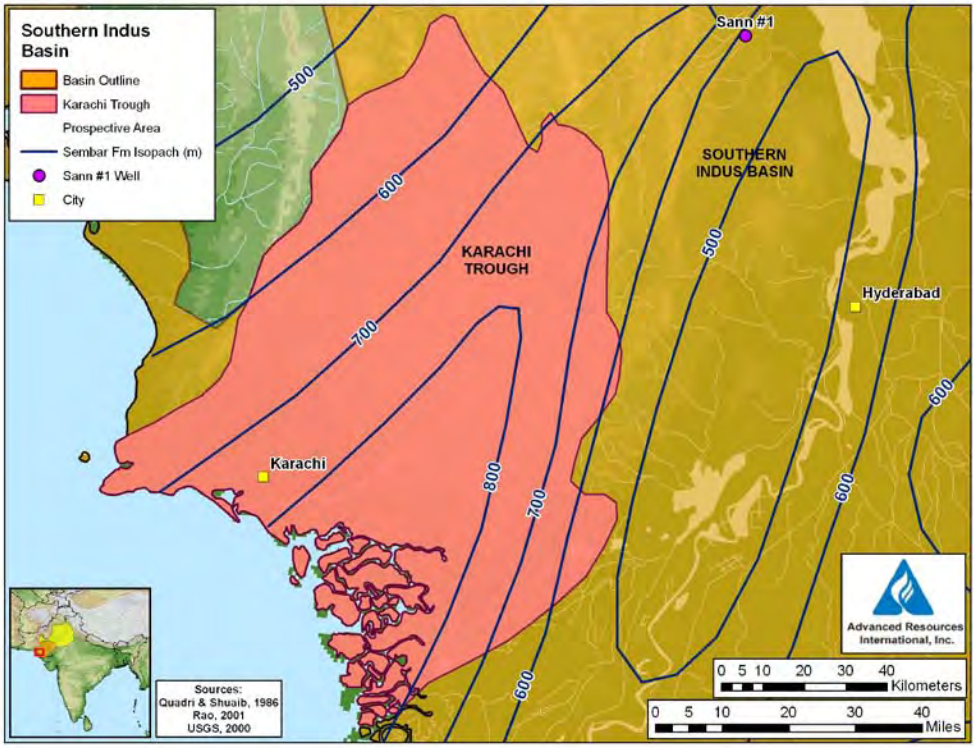
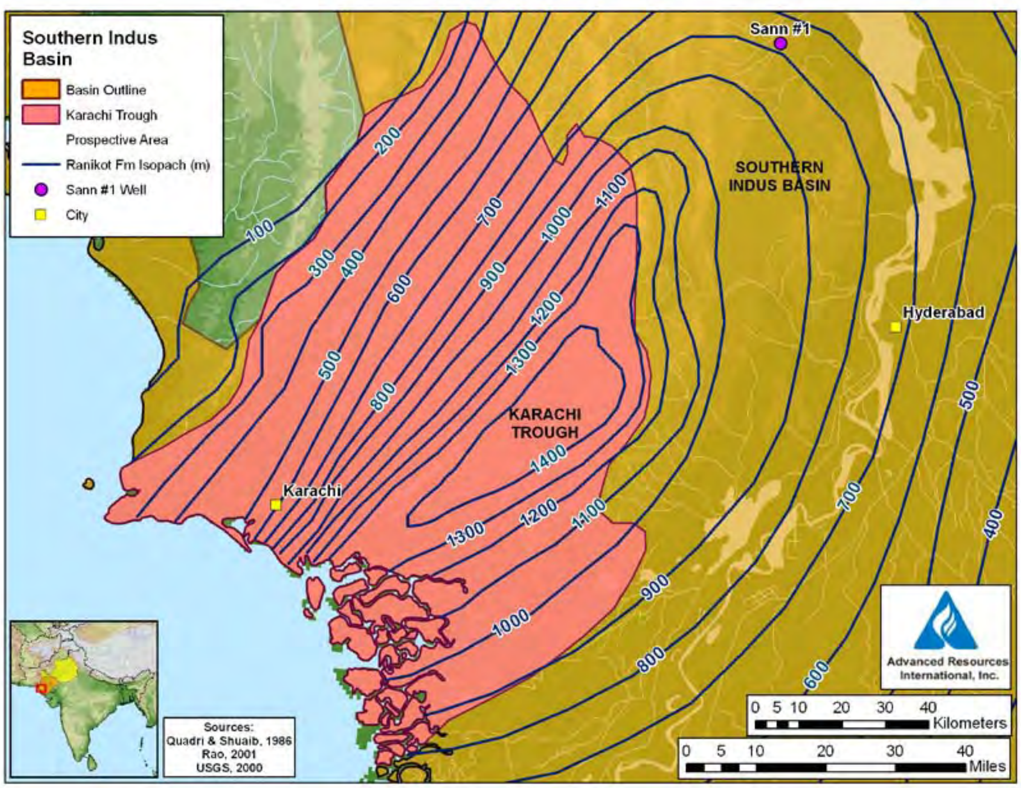


Figure XII-26. Isopachs and Facies of Paleocene Ranikot Formation , Southern Indus Basin, Pakistan



Geologic Characterization (Ranikot Formation)

The Paleocene Ranikot Formation contains three gas fields in the Karachi Trough. The shales in the Ranikot Formation are primarily in the upper carbonate unit which consists of fossiliferous limestone, interbedded with dolomitic shale, calcareous sandstone and "abundant" bituminous material. The upper unit was deposited in a restricted marine environment. West of the Karachi Trough axis, the upper (and lower) Ranikot Formation becomes dominantly shale (Korara Shale) of deep marine depositional environment.

ARI estimates an interval thickness of 2,000 to 4,000 feet for the Randikot Formation in the center of the Karachi Trough, with an organic-rich section of 1,500 feet and a net completable shale thickness of 450 feet with low clay content, Figure XII-26. We assume 2% TOC and thermal maturity of 1.0% to 1.3%, placing the shale in the wet gas window.

Resources (Ranikot Formation)

Based on an estimated prospective area of 4,000 mi^2, and a resource concentration of 157 Bcf/Mi^2, we estimate the risked shale gas in-place for the Ranikot Formation at 126 Tcf, with 31 Tcf as technically recoverable.

Activity

No publically available data was found on shale gas exploration or development in the Southern Indus Basin of Pakistan.

India

Though India possess significant reserves of natural gas, 38 Tcf in 2009, it still relys on imports to satisfy domestic consumption. In 2009, the country consumed 5.1 Bcfd of natural gas, while producing 3.9 Bcfd. Were India to develop the technically recoverable shale gas resources identified in this report, it may add an additional 63 Tcf of natural gas to its domestic reserve base[27].

Pakistan

At present, Pakistan's natural gas production and consumption are in equilibrium, each at 3.7 Bcfd in 2009. The country possesses 28 Tcf of natural gas reserves, and has added to its reserve base each year for the past decade. The technically recoverable shale gas resource identified in this report could add an additional 51 Tcf to Pakistan's reserve base, allowing it to continue to satisfy domestic into the foreseeable future.

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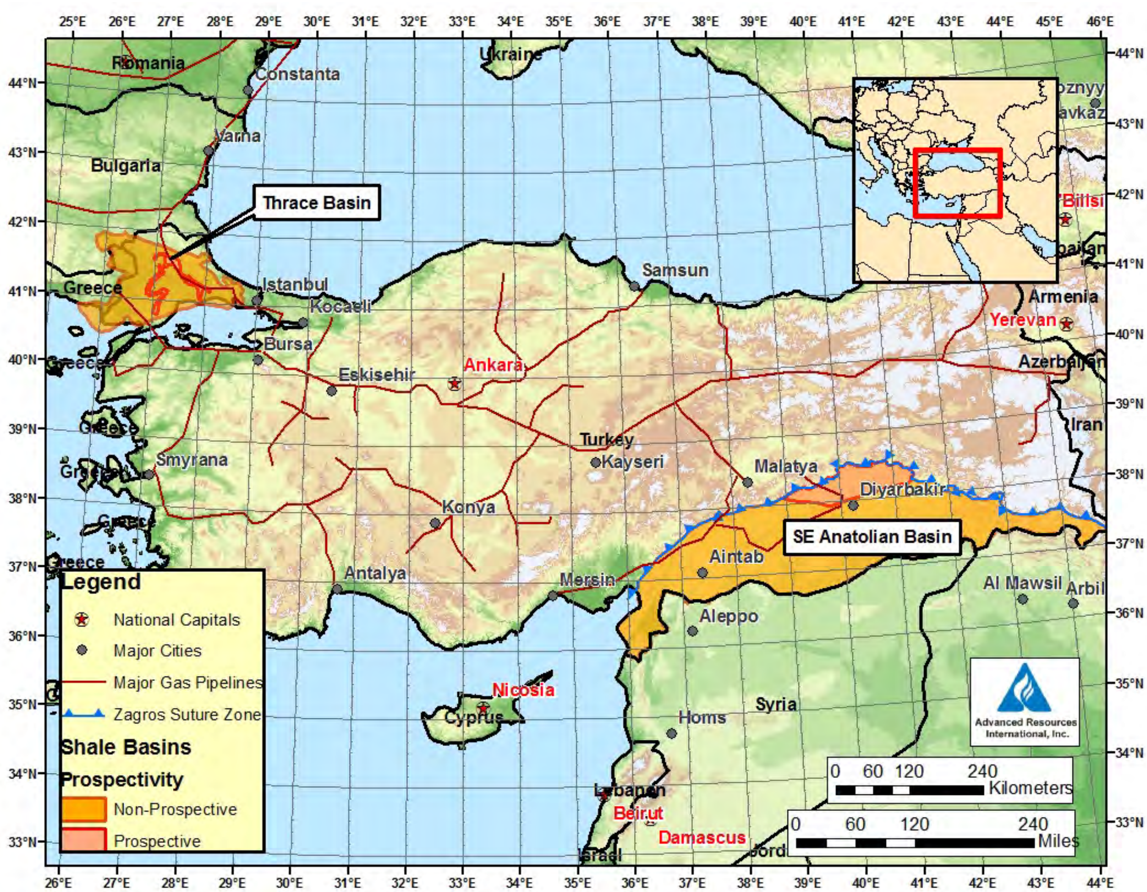
XIII. TURKEY

INTRODUCTION

This report assesses the two shale gas basins in Turkey - - the Thrace Basin in western Turkey and the Southeast Anatolia Basin along the border with Iraq and Syria, Figure XIII-1. These two basins are under active shale and conventional gas exploration by the Turkish national petroleum company, TPAO, and international exploration companies.

Turkey may also have shale gas potential in the interior Blacklake and Taurus basins, as well as the onshore portion of the Black Sea Basin. However, because detailed reservoir data on shale formations in these basins is not readily available, their shale gas resource potential has not been assessed.

Figure XIII-1. Shale Gas Basins of Turkey



ARI estimates that the Thrace and SE Anatolian basins contain 64 Tcf of risked gas in-place from three prospective shale formations. These formations contain an estimated 15 Tcf of technically recoverable shale gas resource, Table XIII-1.

Table XIII-1. Shale Gas Reservoir Properties and Resources of Turkey

Basic Data	Basin/Gross Area		SE Anatolia Basin (32,450 mi²)	Thrace Basin (8,586 mi²)	
	Shale Formation		Dadas Shale	Hamitabat	Mezardere
	Geologic Age		Devonian-Silurian	Mid-Lower Eocene	Lower Oligocene
Physical Extent	Prospective Area (mi^2)		2,950	312	303
	Thickness (ft)	Interval	328 - 1,300	3,280 - 8,200	1,640 - 8,200
		Organically Rich	500	1,722	1,476
		Net	150	344	295
	Depth (ft)	Interval	6,560 - 9,840	12,136 - 16,400	8,200 - 10,168
		Average	8,200	14,268	9,184
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		5.5%	3.9%	2.5%
	Thermal Maturity (%Ro)		1.10%	1.75%	1.10%
	Clay Content		Medium	Medium	Medium
Resource	GIP Concentration (Bcf/mi^2)		61	128	74
	Risked GIP (Tcf)		43	14	7
	Risked Recoverable (Tcf)		9	4	2

SOUTHEAST ANATOLIAN BASIN

Geologic Characterization

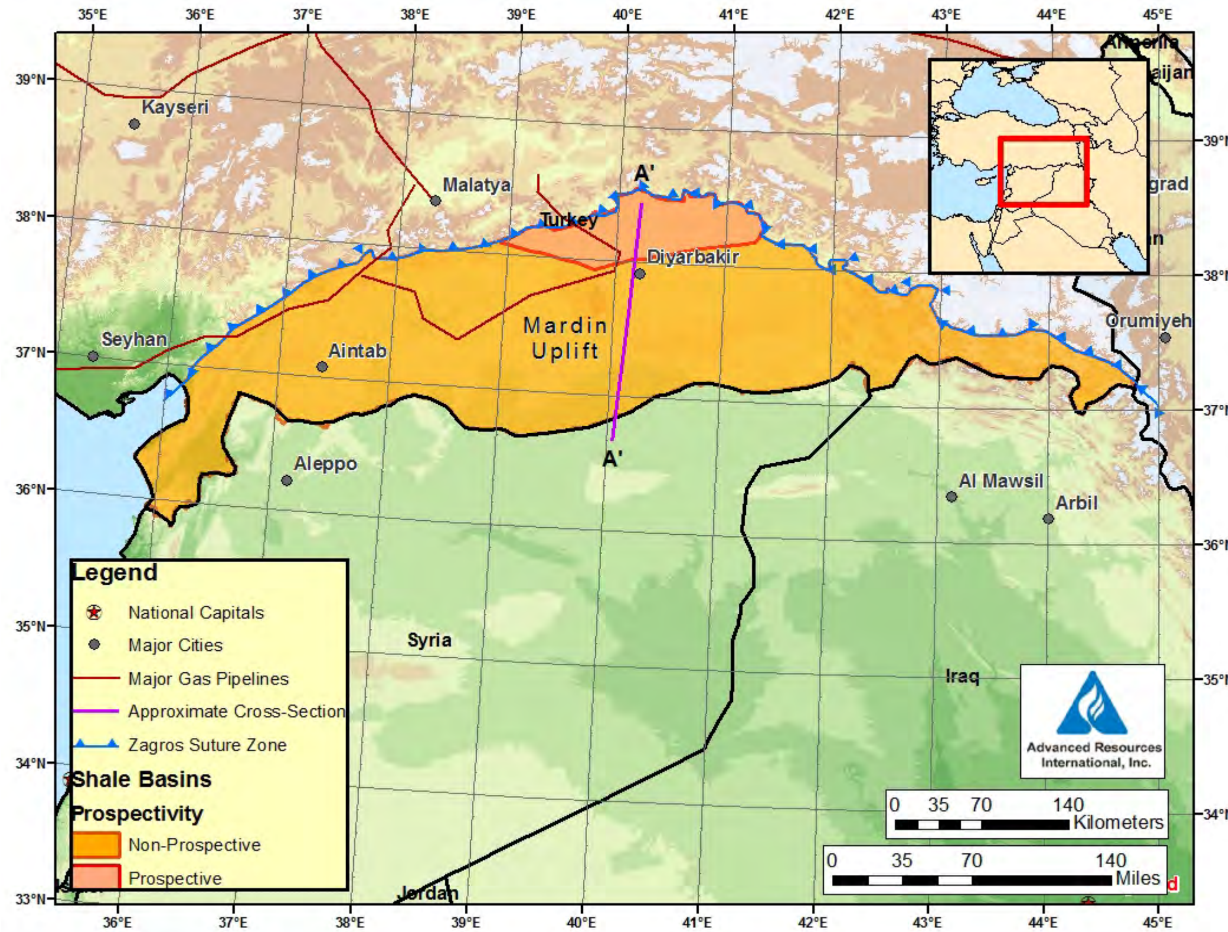
The SE Anatolian Basin encompasses a large, 32,450 mi^2 area of the Arabian plate inside the Turkish border, Figure XIII-2. The basin is bounded on the north by the Zagros suture zone, which marks the juncture of the Arabian and Eurasian tectonic plates.

In the early Paleozoic, Silurian-age shale formations were deposited throughout the northern Godwana super continent (present day North Africa and the Middle East) after major sea level rise caused by melting Ordovician-age glaciers. Regional lows and offshore deltas with anoxic conditions received layers of organically rich sediments that now represent promising shale targets. The SE Anatolian Basin was part of the northern edge of the Godwana super continent, which later separated to form the Arabian plate. As such, the basin shares similar geology with the oil-producing regions of Saudi Arabia and Iraq, though it exhibits greater faulting and thrusting caused by the collision with the Eurasian plate. This basin is the primary source of Turkish oil production.

The most promising source rock within the SE Anatolian Basin is the Silurian-Devonian Dadas Shale, Figure XIII-3. The basin covers an area the size of the Barnett Shale along the Zagros suture margin. The basal member of the Dadas Shale has long been recognized as the regional oil source rock, but the formation was recently discovered to be gas-prone in its northern areas.

Using available reservoir data, ARI mapped a 2,950 mi^2 area of the Dadas Shale as prospective for shale gas development. The Dadas Shale is present over approximately 20% of north central SE Anatolian Basin, but is only inside the gas window in the most northern areas. Detailed thermal maturity data for the formation was not available, but guidance provided by TPAO in corporate presentations enables us to establish the prospective area for shale gas development.

Figure XIII-2. Dadas Shale Prospective Area, SE Anatolian Basin, Turkey



Reservoir Properties (Prospective Area)

The Dadas Shale deepens and thickens to the north, where it enters the gas generation window, Figure XIII-4. Within the prospective area, essentially the northern half of the shale's areal extent in the SW Anatolian Basin, the depth of the Dadas Shale ranges from 6,560 feet to 9,840 feet deep, averaging 8,200 feet. The shale comprises three members, which together can reach a gross thickness of up to 1,300 feet, Figure XIII-3. However, organically rich pay is primarily concentrated in the basal Dadas member (Dadas I), which has a net shale thickness of approximately 150 feet.[1] Organic content within this horizon ranges from 2% to 16%, averaging 5.5%, and increasing to the north.[2] The prospective area is within the wet-gas generation window, with a thermal maturity between 1% and 1.2% Ro.

Resources

Using the Dadas Shale reservoir characteristics discussed above, ARI calculated a moderate gas in-place resource concentration of 61 Bcf/mi^2. Within the 2,950 mi^2 prospective area, we estimate the shale formation contains a risked gas in-place of 43 Tcf, of which 9 Tcf is estimated to be technically recoverable. However, while the formation exhibits favorable properties for shale gas development, the prospective area exhibits heavy faulting, which could pose significant development risks, Figure XIII-4. Additional data on the maturity and organic thickness of the Dadas Shale throughout its depositional area would help refine the prospective area and improve the reliability of this resource estimation, Table XIII-1.

Figure XIII-3. SW Anatolia Basin Stratigraphic Column2

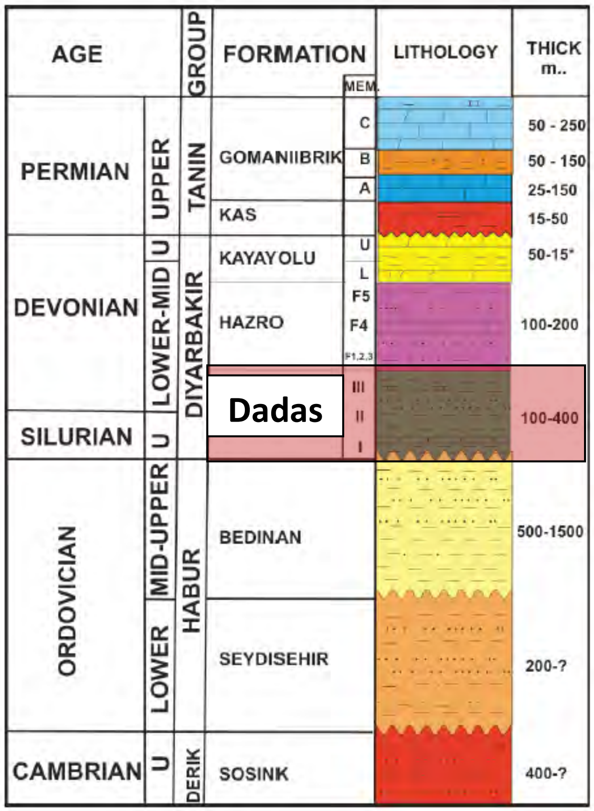
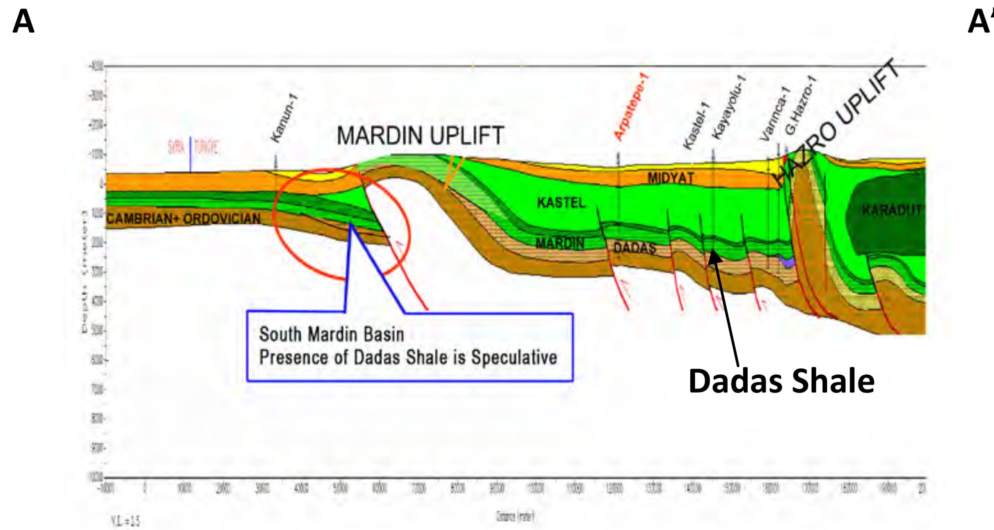


Figure XIII-4. SW Anatolian Basin Cross-Section1



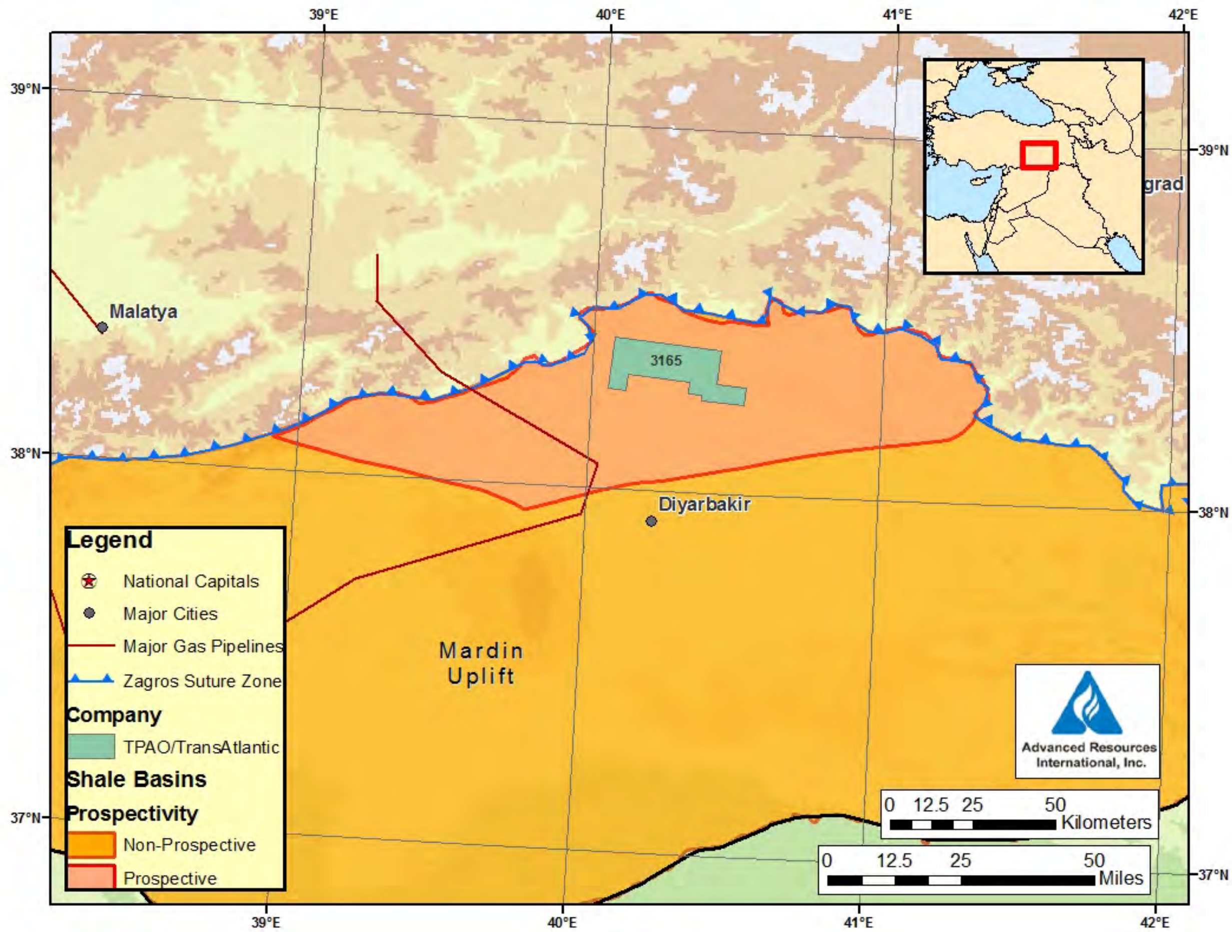
Activity

As an area of active oil production and exploration, the SE Anatolian Basin has been largely leased for conventional crude oil exploration. The Turkish National Petroleum Company (TPAO) holds the majority of the leases in this area, but small international petroleum exploration companies, such as Aladdin, Perenco and others are also active. At present, TPAO's ability to explore its unconventional potential is limited by the lack of horizontal drilling and fracturing equipment in country and personnel experience.

Shale gas exploration is proceeding through a partnership between TPAO and Canadian-based exploration firm Transatlantic Petroleum. The former has brought in well drilling and completion equipment suited for shale gas drilling and personnel with experience in unconventional gas development. As part of this partnership, Transatlantic Petroleum will reenter and fracture stimulate existing conventional wells drilled by TPAO in the Dadas Shale and overlying sandstone reservoirs. The first test will be performed in the Abdul Aziz well on TPAO's lease 3165, Figure XIII-5.

TPAO holds acreage within the Dadas Shale prospective area and has been evaluating shale formations throughout Turkey. However, the company has yet to report specific plans to independently develop or explore its shale gas resource potential.

Figure XIII-5: Exploration Leases for Dadas Shale, SE Anatolian Basin, Turkey



THRACE BASIN

Geologic Characterization

The Thrace Basin covers an 8,600 mi^2 area in European Turkey. The Basin is bordered on the north by the Istranca Massif, by the Rhodope Massif on the west and the Sakarya Massif on the south, Figure XIII-6. Tertiary-age (Eocene through Miocene) basin fill is extremely thick in the Thrace Basin, nearly 30,000 feet in its center including a number of petroleum source rocks and reservoirs. Following the discovery of the Hamitabat Gas Field in 1970, the basin quickly became Turkey's most important gas producing basin, accounting for approximately 85% of the country's total gas production. About 350 wells have been drilled in the basin in thirteen gas fields (one offshore in the Marmara Sea) and three oil fields. These assets are mainly operated by TPAO.

The Thrace Basin contains two source rock formations with shale gas potential, the Lower-Mid Eocene Hamitabat Formation and the Lower Oligocene Mezardere Formation, Figure XIII-7. The Hamitabat Formation is a very thick sequence of sandstone, shale and marl deposited in a molasse or turbiditie shallow marine environment. The Mezardere Formation was deposited in a deltaic environment, and also contains interbedded layers of sandstone, shale and marl[3]. In the deeper central-southern areas of the basin, these shales have sufficient thermal maturity to be in the gas window. Additional data may help identify further areas with organically rich shales.

The prospective area for the Mezardere and Hamitabat sections depends on settings with sufficiently thick net shale sequences and adequate thermal maturity. Because of their complex depositional environments, accurately locating packages of prospective shale intervals within the Mezardere or Hamitabat formations requires detailed geologic data, which were not available for this report.

The prospective areas ARI identified for the Mezardere and Hamitabat formations are based primarily on thermal maturity data. Because these formations are relatively young, they only reach the gas window at great depth, often deeper than the 5,000 m threshold used in this analysis. The 312 mi^2 prospective area of the Hamitabat Shale was constructed based on work by Gurkey, who used well data and laboratory analysis to establish the area inside the gas window[4]. The 303 mi^2 prospective area of the Mezardere Formation is based on analysis by Karahanoglu et al., which identified a gas-prone area of the shale based on mathematical modeling of the basin's thermal history,[5] Figure XIII-6.

Reservoir Properties (Prospective Area)

Hamitabat Shale. The deepest and oldest shale formation in the Thrace Basin, the Hamitabat Shale, is also the most thermally mature. The shale is in the gas window at depths of 12,100 feet to 16,400 feet in the center of the basin, Figure XIII-8,4 with Ro ranging from 1% to 2.5%.[Error! Bookmark not defined.] Organic content is highly variable throughout the formation, ranging from fractions of a percent to above 6%.[6] Within the prospective area, TOC ranges from 1.5% to 6.4%, averaging 3.9%[7]. The gross interval of the Hamitabat Shale ranges from 3,280 feet to 8,200 feet thick, Figure XIII-7. Because data on net shale thickness is not widely available, one-third of the average shale interval, 1,722 feet, is assumed to be organically rich. Applying a net to gross ratio of 20%, the net shale thickness is estimated to be 344 feet.[8]

Mezardere Shale. The Mezardere Shale is another very thick, regionally extensive shale interval in the Thrace Basin. However, its prospectivity is limited by low organic content and thermal maturity. (Some of the available literature suggests that the entire Mezardere Shale is outside the gas window.[Error! Bookmark not defined.]) Within the formation's prospective area, the target shale interval ranges from 8,200 to 10,168 feet deep, Figure XIII-8. Total organic content ranges from 1% to 4%, with an average of 2.5%.2 Thermal maturity is assumed to be in the wet-gas window, ranging from 1% to 1.2% Ro.[Error! Bookmark not defined.] The gross interval of the Mezardere Shale ranges from 1,640 feet to 8,200 feet thick, Figure XIII-7. Net organically rich shale was determined by the same methodology used for the Hamitabat Shale, resulting in an assumed organically-rich thickness of 1,476 feet and a net shale thickness of 295 feet.

Figure XIII-6. Prospective Shale Formations of the Thrace Basin, NW Turkey

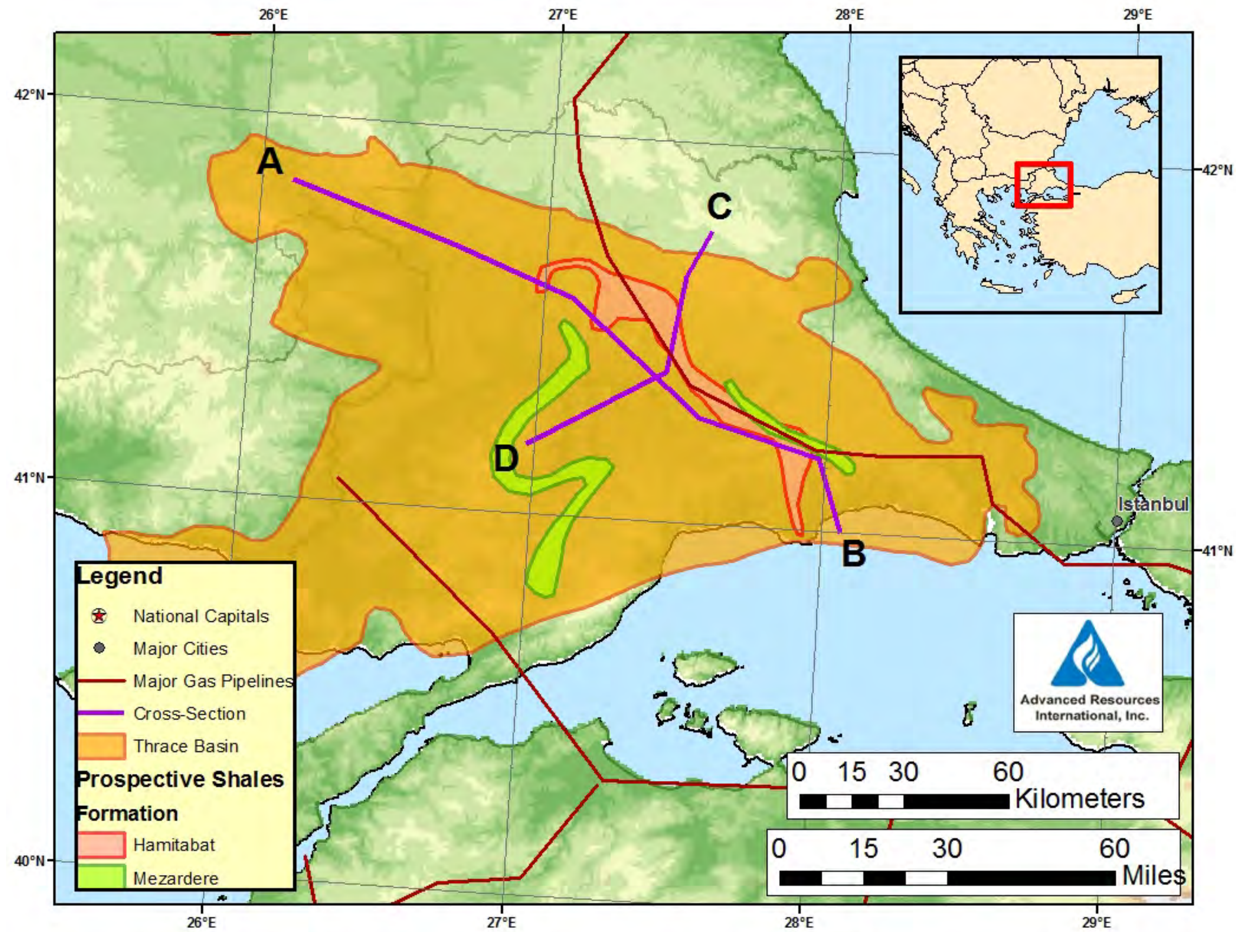


Figure XIII-7. Thrace Basin Stratigraphic Column3

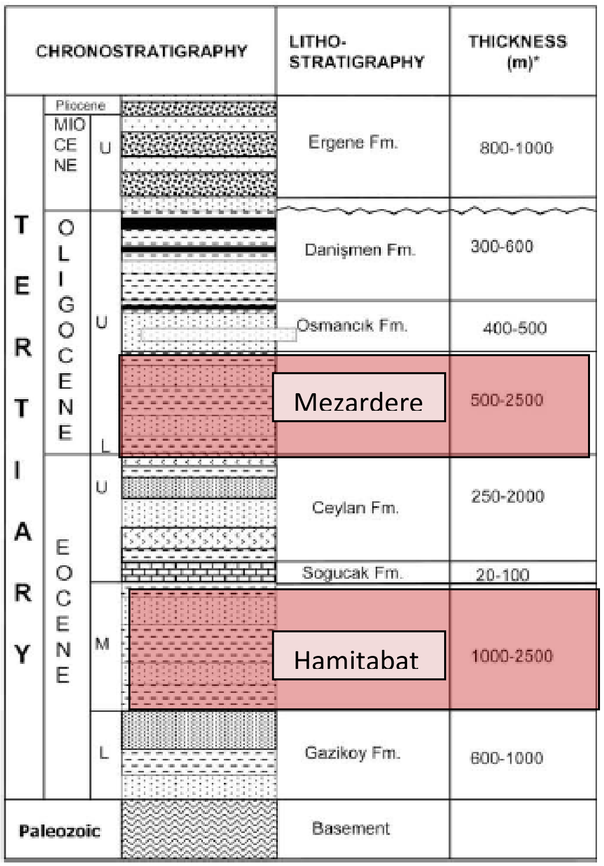
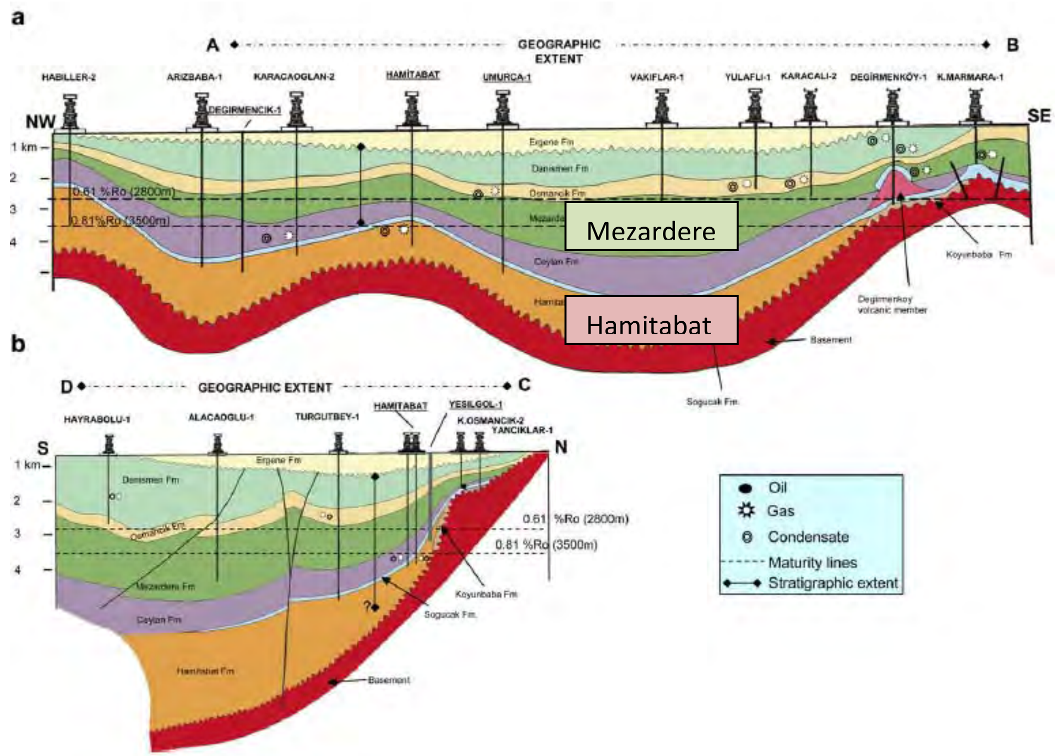


Figure XIII-8. Thrace Basin Cross SectionError! Bookmark not defined.



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Resources

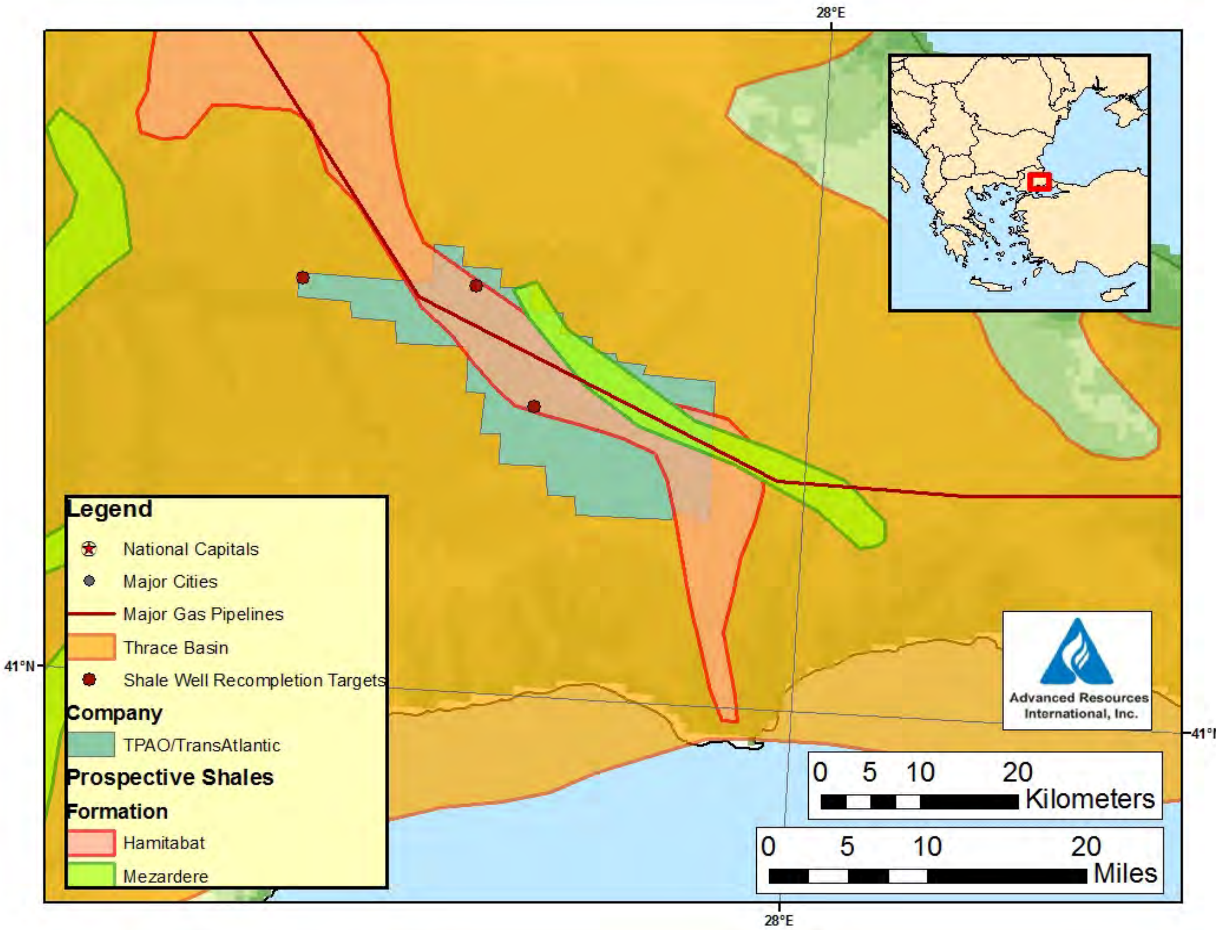
Based on reservoir characteristics discussed above, ARI calculates a shale gas resource concentration of 128 Bcf/mi^2 for the Hamitabat Shale and 74 Bcf/mi^2 for the Mezardere Shale. Within their prospective areas, the Hamitabat and Mezardere shales contain a risked gas in place of 14 Tcf and 7 Tcf, respectively. Of this, an estimated 4 Tcf could be technically recoverable in the Hamitabat Shale and 2 Tcf could be technically recoverable in the Mezardere Shale, Table XIII-1. Additional data on these shale formations' net thickness will help to provide a more accurate estimate of their resource potential.

Activity

Though the Thrace Basin is under active conventional gas development by a number of domestic and international firms, its shale gas potential is only being targeted by Transatlantic Petroleum. As in the SE Anatolia Basin, Transatlantic has entered into an agreement with TPAO to recomplete and test wells in prospective shale formations. Transatlantic's current agreement calls for the company to recomplete three wells on a centrally located lease in the Thrace Basin and drill an additional three to four wells over the coming year, Figure XIII-9.

Transatlantic also has been acquiring additional acreage in the Thrace Basin. On November 8, 2010, the company entered into an option agreement to acquire Thrace Basin Natural Gas Turkiye Corp and Pinnacle Turkey (TBNG) in a combination cash/stock transaction. TBNG currently produces 25 MMcfd in the Basin and holds interests in approximately 600,000 net onshore acres in Turkey.

Figure XIII-9: Shale Gas Exploratory Leases , Thrace Basin, Turkey



TURKEY

Turkey is highly dependent on imports to meet its natural gas consumption needs. In 2009, the country consumed 3.4 Bcfd of natural gas, of which only 0.07 Bcfd was produced domestically. The country's current natural gas reserves are very limited. With estimated technically recoverable shale gas resources of 15 Tcf, successful development could contribute to Turkey's energy independence.

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XIV. AUSTRALIA

INTRODUCTION

Australia has major gas shale potential in four main assessed basins. Additional potential may exist in other basins that were not assessed due to budget and data limitations. With geologic and industry conditions resembling those of the USA and Canada, the country appears poised to commercialize its gas shale resources on a large scale. The Cooper Basin, Australia's main -onshore gas-producing basin, could be the first to develop, although its Permian-age shales have a non-marine (lacustrine) depositional origin and the gas has elevated CO_2 concentrations. Santos and Beach Energy testing the shale reservoirs in this basin, with reservoir core wells being drilled and initial frac production test wells planned for later in 2011.

Other prospective shale basins in Australia include the small, scarcely explored Maryborough Basin in coastal Queensland, which contains prospective Cretaceous-age marine shales that are over-pressured and appear gas saturated. The Perth Basin in Western Australia, undergoing initial testing by AWE and Norwest Energy, has prospective marine shale targets of Triassic and Permian age. Finally, the large Canning Basin in Western Australia has deep, Ordovician-age marine shale that is roughly correlative with the Bakken, Michigan, and Baltic basins. **Figure XIV-1** shows the main prospective gas shale basins of Australia. These basins hold an estimated total 396 Tcf of technically recoverable shale gas resources, **Table XIV-1**.

Figure XIV-1. Australia's Prospective Gas Shale Basins, Gas Pipelines, and LNG Infrastructure

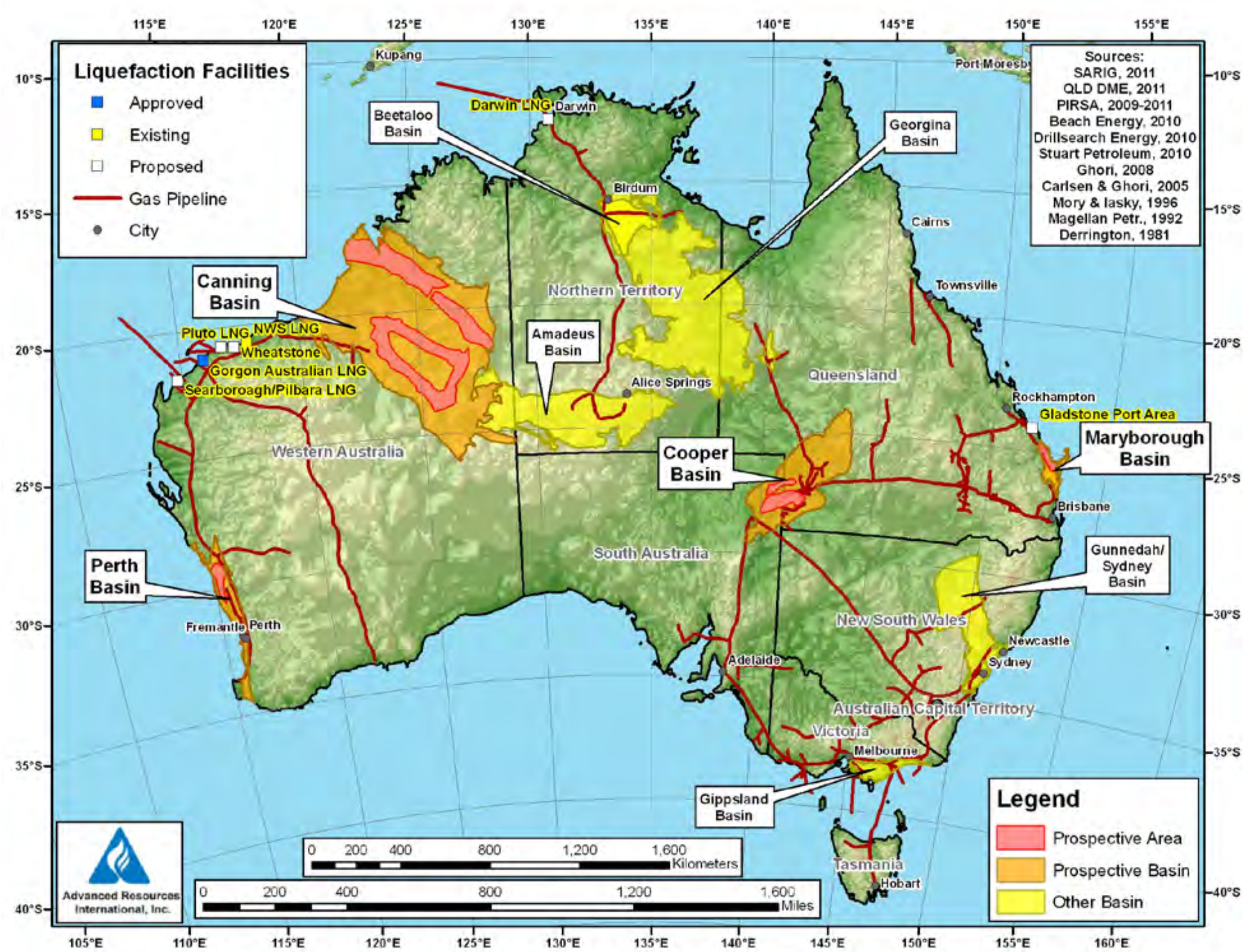


Table XIV-1. Shale Gas Reservoir Properties and Resources of Australia

Basic Data	Basin/Gross Area		Cooper Basin (46,900 mi²)	Maryborough Basin (4,290 mi²)	Perth Basin (12,560 mi²)		Canning Basin (181,000 mi²)
	Shale Formation		Roseneath-Epsilon-Murteree	Goodwood/Cherwell Mudstone	Caryngia Shale	Kockatea Fm	Goldwyer Fm
	Geologic Age		Permian	Cretaceous	Upper Permian	Lower Triassic	M. Ordovician
Physical Extent	Prospective Area (mi^2)		5,810	1,555	2,180	2,180	48,100
	Thickness (ft)	Interval	0 - 1,800	300 - 3,000	300 - 1,500	300 - 3,000	300 - 2,414
		Organically Rich	500	1,250	950	2,300	1,300
		Net	300	250	250	230	250
	Depth (ft)	Interval	6,000 - 13,000	5,000 - 16,500	4,000 - 16,500	3,300 - 16,500	3,300 - 16,500
		Average	8,500	9,500	10,700	10,000	12,000
Reservoir Properties	Reservoir Pressure		Moderately Overpressured	Slightly Overpressured	Normal	Normal	Normal
	Average TOC (wt. %)		2.5%	2.0%	4.0%	5.6%	3.0%
	Thermal Maturity (%Ro)		2.00%	1.50%	1.40%	1.30%	1.40%
	Clay Content		Low	Low	Low	Low	Low
Resource	GIP Concentration (Bcf/mi^2)		105	110	107	110	106
	Risked GIP (Tcf)		342	77	98	100	764
	Risked Recoverable (Tcf)		85	23	29	30	229

Given budget limitations for this study, other less promising basins in Australia were rapidly screened out as non-prospective for gas shale development. These include the Sydney Basin (where Permian coal measures are mature but appear ductile); Lorne Basin (no apparent potential source rocks); the Clarence-Moreton, Ipswich, Surat, Eromanga basins (Jurassic Walloon Coal Measures are mature but appear ductile); Gippsland Basin (coaly shale appears ductile); and Amadeus Basin (thin shale in a mostly sandstone unit). However, these and other basins warrant further evaluation at a future time.

COOPER BASIN (SOUTH AUSTRALIA AND QUEENSLAND)

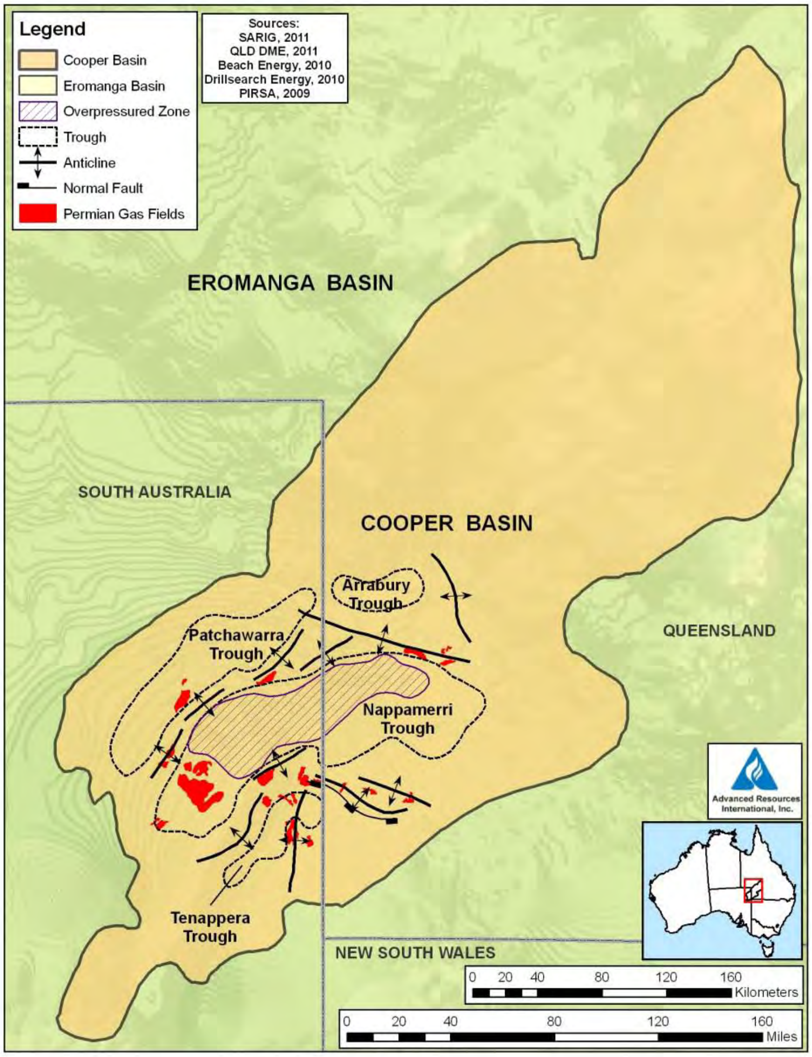
Straddling the South Australia and Queensland border, the Cooper Basin has been the Australia's main onshore gas supply region for the past several decades. Current production from the basin is about 0.5 Bcfd of natural gas from conventional and low-permeability reservoirs. Within the basin, the Nappamerri Trough contains thick, overpressured and organic-rich shales at prospective depth, as well as extensive deep coal deposits. Gas pipelines connect the basin to Sydney and other urban markets in eastern Australia. With extensive tight sandstone gas production, the basin has service industry capability for advanced hydraulic fracturing that could be adapted for developing gas shale reservoirs.

However, while overall the Cooper Basin appears favorable for shale gas development, a key risk remains that the shales were deposited in a lacustrine (not marine) environment. In addition, high CO_2 occurs in the deeper more mature troughs, though concentrations may be lower in shallower settings.

Geologic Characterization. The Cooper Basin is a Gondwana intracratonic basin containing about 2.5 km of entirely non-marine Late Carboniferous to Middle Triassic strata, which include prospective Permian-age shales. Following an episode of regional uplift and erosion during the late Triassic, the Cooper Basin continued to gently subside and the Paleozoic sequence was unconformably overlain by up to 1.3 km of Jurassic to Tertiary deltaic deposits of the Eromanga Basin, which contain the basin's conventional sandstone reservoirs.[1]

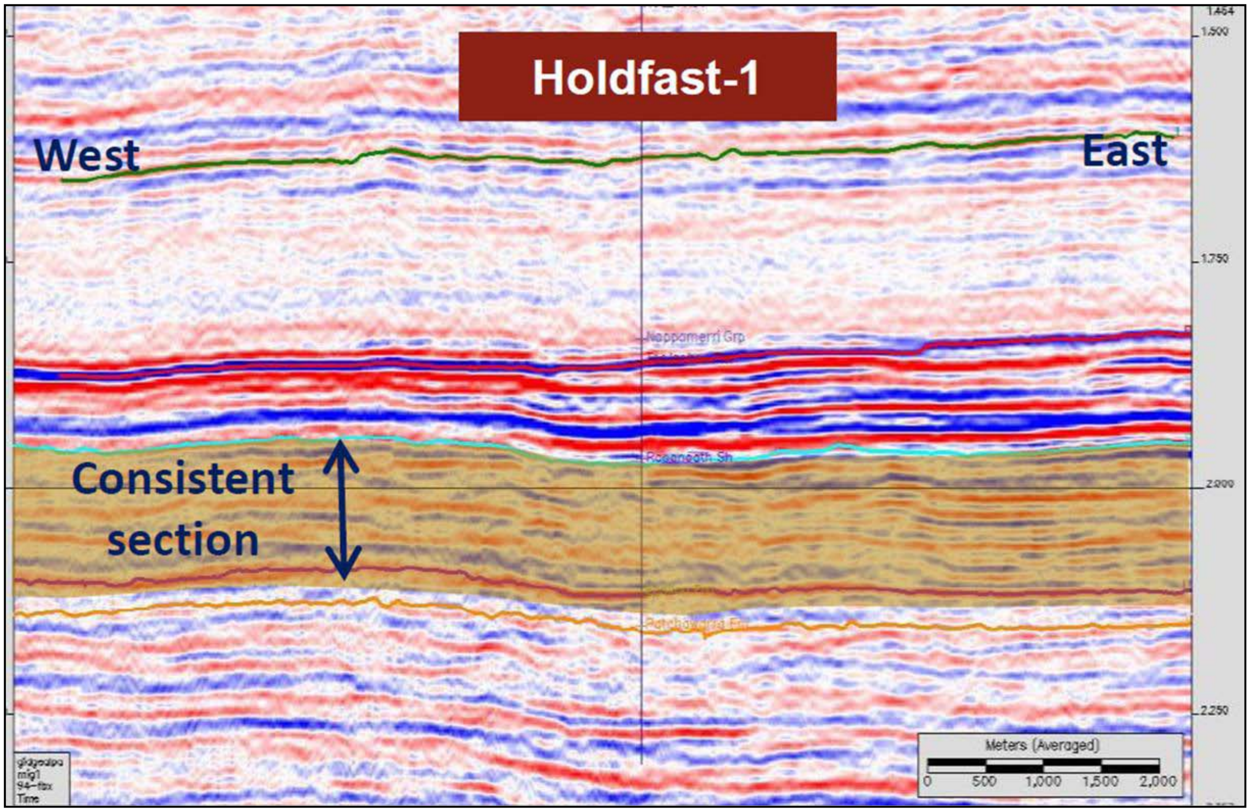
Extending over a total area of about 130,000 km^2, the Cooper Basin contains four major deep troughs with shale gas potential (Nappamerri, Patchawarra, Tenappera, and Arrabury; **Figure XIV-2**). These troughs are separated by faulted anticlinal structural highs, from which the Permian shale-bearing strata largely have been eroded.[2] Conventional oil and gas generated by the organic-rich shales and coals within the Nappamerri, Tenappera and other deep hydrocarbon kitchens accumulated along the Murteree and other uplifted ridges.

Figure XIV-2. Major Structural Elements of the Cooper Basin.



The Nappamerri Trough is particularly large (15,000 km^2), deep (>10,000 feet), thermally mature, and overpressured, and thus appears to be the most prospective portion of the Cooper basin for gas shale development. The top Permian horizon reaches maximum depths of over 9,000 feet in the center of the Nappamerri Trough and over 10,000 feet in the Patchawarra Trough. Prospective Permian shales, approximately 2,000 feet below the top Permian, occur at depths of 10,000 to 14,000 feet. Nearly the entire extent of the two troughs appears to be depth-prospective for shale development. Furthermore, relatively little faulting occurs within these troughs, **Figure XIV-3,** as structural deformation is confined largely to the upflifted ridges.

Figure XIV-3. Seismic Reflection Line Showing Permian REM Sequence In The Cooper Basin And Location Of Beach Energy's Planned Holdfast-1 Test Well, Scheduled For January 2011.

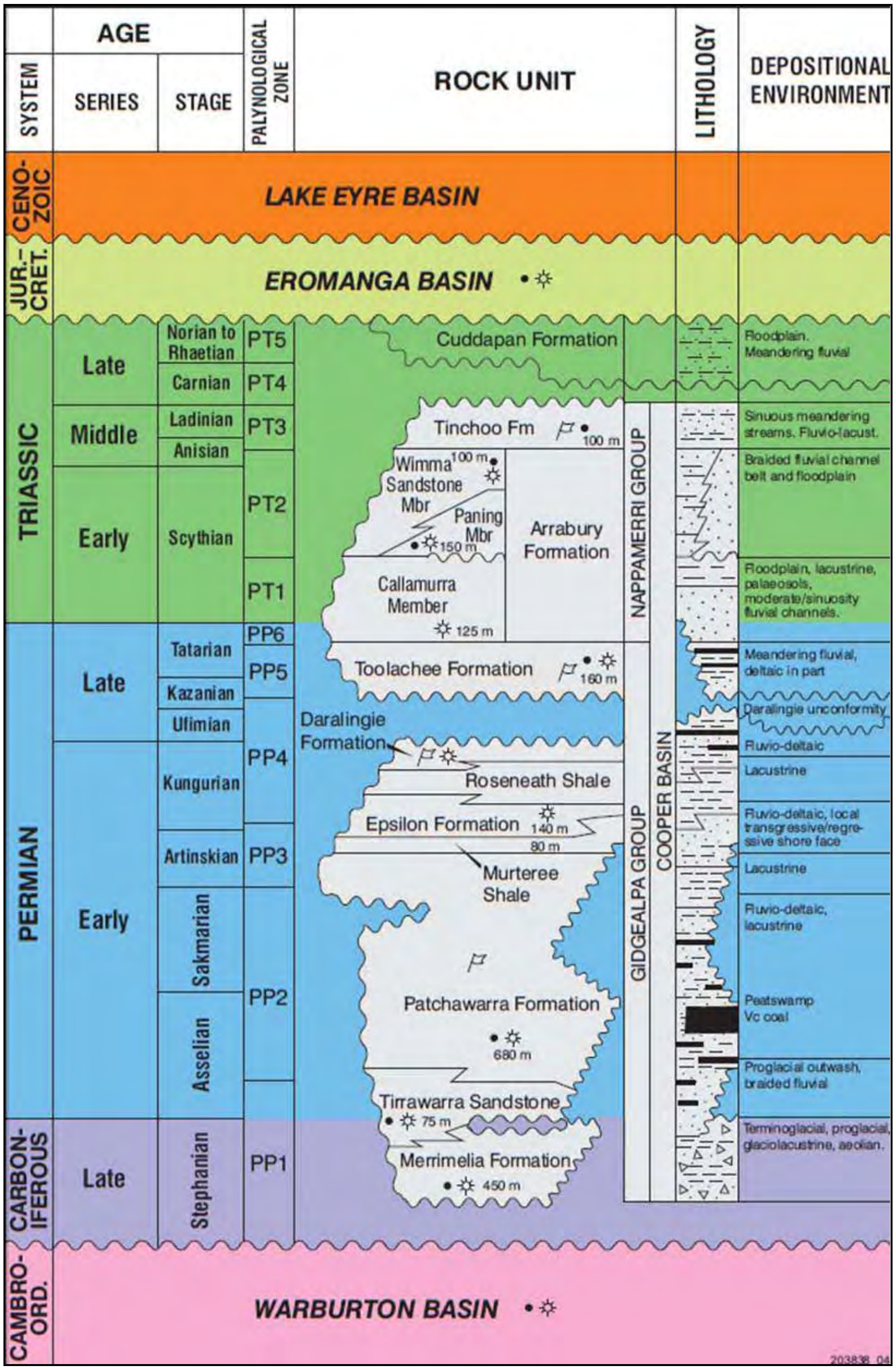


Source: Beach Energy, 2010

The stratigraphy of the Cooper Basin is shown in **Figure XIV-4**. Conventional and tight sandstone oil & gas reservoirs are found in the Patchawarra and Toolachee formations, interbedded with coal deposits. These were sourced by two organic-rich complexes: the Late Carboniferous to Late Permian Gidgealpa Group and the Late Permian to Middle Triassic Nappamerri Group, both of which were deposited in non-marine settings. Of the two source rock groups, the Gidgealpa Group appears the more prospective. Most of the gas generated by the Nappamerri Group likely came from its multiple, thin, discontinuous coal seams; shales in this unit are low in TOC, humic, and often oxidized.

Although deposited in lacustrine environments, the best shale exploration targets within the Gidgealpa Group appear to be the Early Permian Roseneath and Murteree shales.[3] **Figure XIV-5** shows a stratigraphic cross-section of the Roseneath, Epsilon, and Murteree (collectively termed REM) sequence in the Nappamerri Trough.

Figure XIV-4. Stratigraphy of the Cooper Basin, Showing Permian-Age Shale Targets (Roseneath, Epsilon, Murteree)



Source: South Australia DMER, 2010

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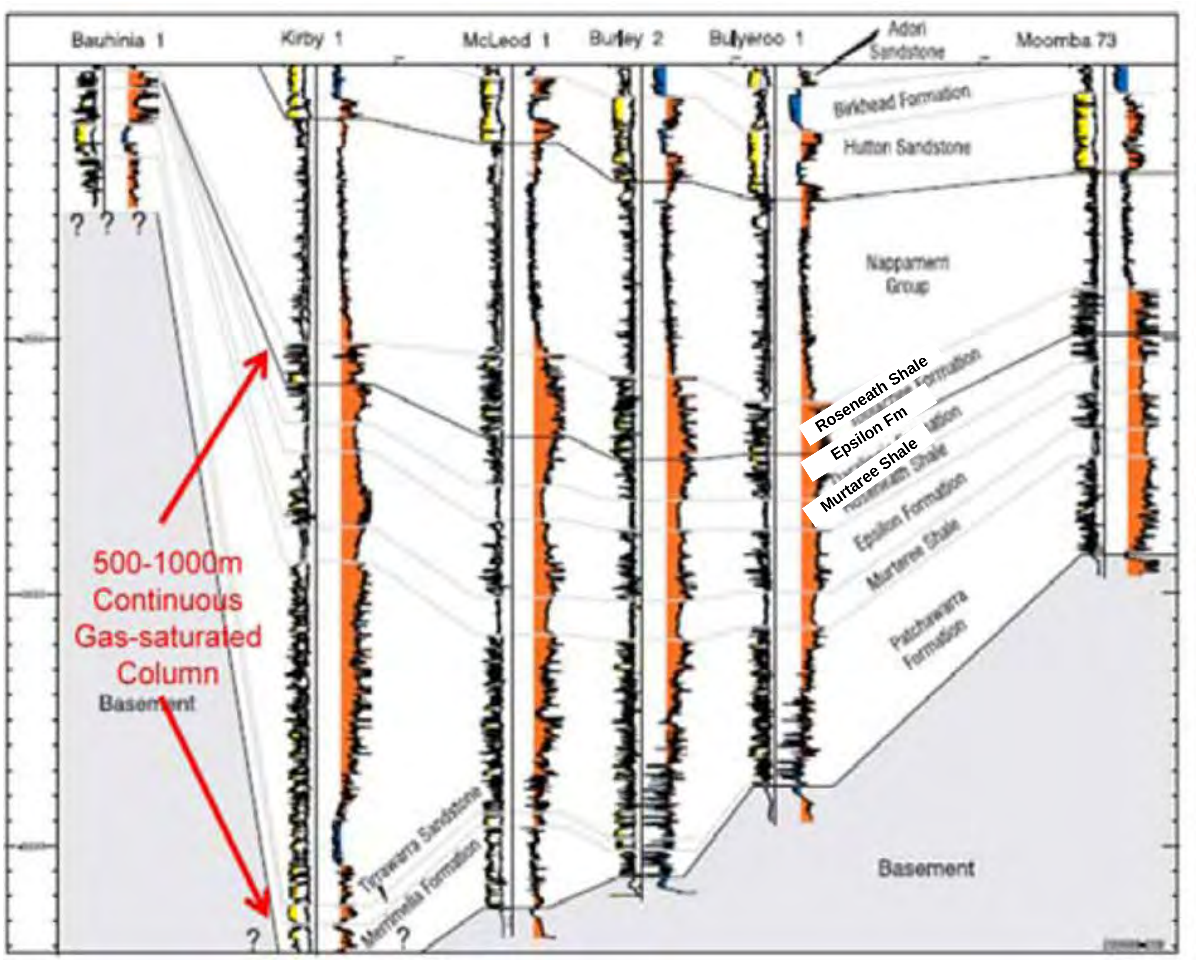
Figure XIV-5. Stratigraphic Cross-Section In The Cooper Basin Showing The Laterally Continuous REM Section.



Source: DrillSearch Energy, 2010

The Murteree Shale (Artinskian) is a widespread, primarily shaley formation typically 50 m thick across the Cooper Basin, becoming as thick as 80 m in the Nappamerri Trough. The Murteree consists of dark organic-rich shale, siltstone and fine-grained sandstone, becoming sandier to the south. TOC of the Murteree Shale averages approximately 2.5%, about 84% of which is inertinite, based on analyses from seven wells. The Roseneath Shale, less widespread than the Murteree due to erosion on uplifts, averages 37 m thick, reaching up to 100 m thick in the Nappamerri Trough. The Roseneath is somewhat leaner than the Murteree, with TOC averaging just over 1.0%. The intervening Epsilon Fm consists primarily of low-permeability (0.1 to 10 mD) quartzose sandstone with carbonaceous shale and coal. The Epsilon, averaging about 53 m thick in drill cores, was deposited in a fluvial-deltaic environment.[4]

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The total thickness of the REM sequence in the western Nappamerri Trough averages about 1,000 feet.[5] The unit becomes generally thicker to the east and north, where it reaches a maximum of about 1,800 feet. The REM sequence appears to have prospective shale thickness across the entire western Nappamerri Trough.

The REM source rocks are dominated by Type III kerogens derived from plant assemblages. They have generated medium to light (30-60º API gravity) oil rich in paraffin. Initial mineralogical data indicate that these shales consist mainly of quartz and feldspar (50%) and carbonate (30%; mainly iron-rich siderite). Clay content is relatively low (20%; predominately illite).[6] In spite of the lacustrine depositional origin, this lithology appears brittle and could respond well to hydraulic fracturing.

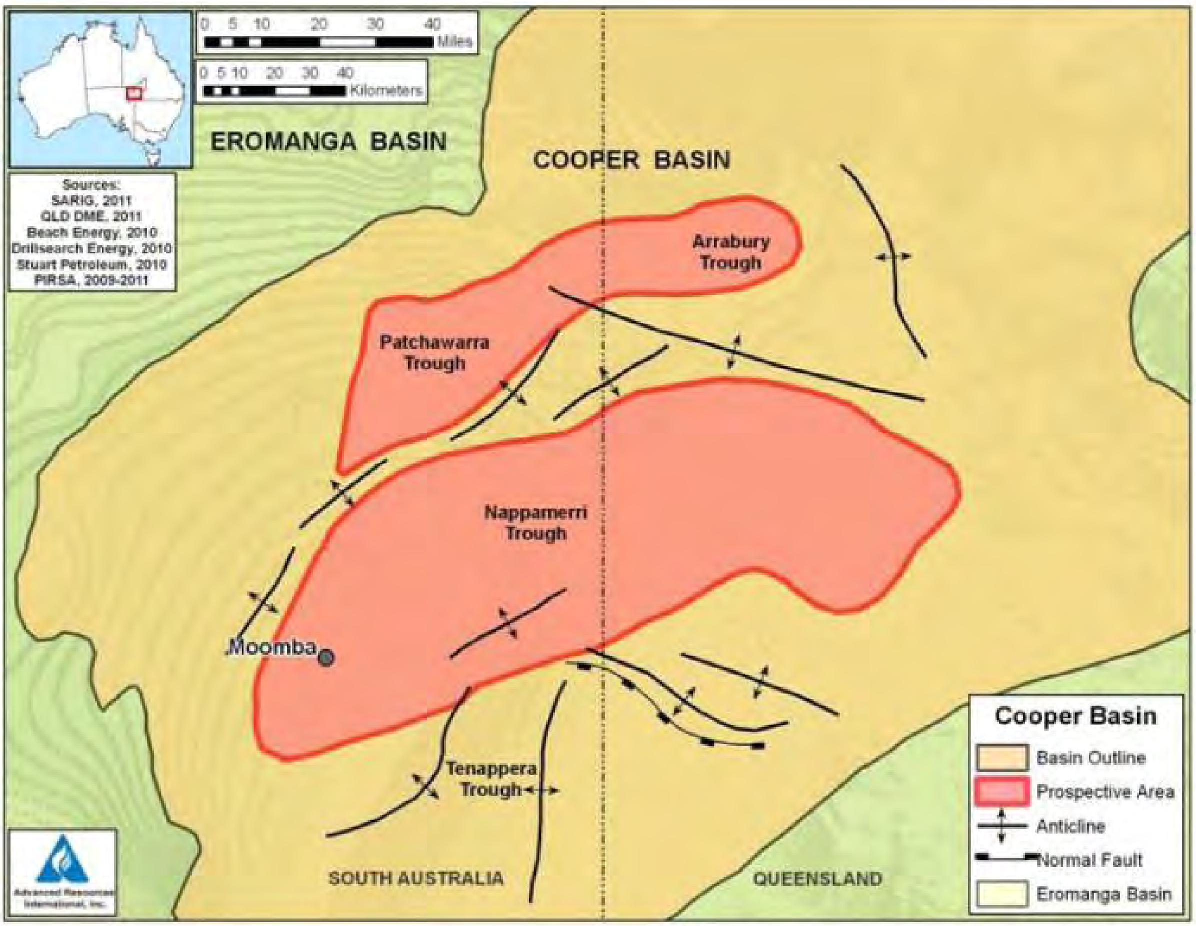
Temperature gradients in the Cooper Basin are high, averaging 2.55ºF/100 ft. Bottomhole temperature at depths of 9,000 feet average about 300ºF. The Nappamerri Trough is even hotter, with a gradient of up to 3.42ºF/100 ft, due to its radioactive granite basement. The Patchawarra Trough, which has a sedimentary-metamorphic basement, has a lower but still elevated 2.02ºF/100 ft temperature gradient.

The thermal maturity of the Permian REM section in the Nappamerri Trough is gas prone (R_o = 3% to 4%), whereas the Patchawarra Trough has lower thermal maturity (Ro = 1%). Hydrostatic regional pressure gradients occur in most of the Cooper Basin, but locally in the Nappamerri Trough can become overpressured at depths of 2,800 to 3,700 m.[7] Pressure gradients of up to 0.7 psi/ft have been recorded in the deepest portions of the Nappamerri Trough.

High levels of carbon dioxide are common in the Cooper Basin. Gas produced from tight sandstones in the Epsilon Formation (central portion of the REM sequence) contains elevated CO_2, typically ranging from 8% to 24% (average 15%). Gas produced from the Patchawarra sandstone, which underlies the REM shale sequence, contains even higher levels of CO_2 (8-40%).[8]

Resources (REM Sequence). ARI evaluated the area that could be prospective for shale gas development in the Cooper Basin, using standard minimum depth (6,000 feet) and vitrinite reflectance (R_o > 1.0%) cutoffs, **Figure XIV-6**. Completable shale intervals in the Rosemead, Epsilon, and Murteree (REM) formations have an estimated resource concentration of 105 Bcf/mi^2, benefitting from favorable thickness, moderate TOC, high thermal maturity, and overpressuring, but reduced for 15% average CO_2 content. The prospective area for this Permian shale-bearing sequence is estimated to be approximately 5,500 mi^2, covering portions of the Nappamerri, Arrabury, and Tenappera troughs. Net of 15% CO_2 content, the estimated risked completable shale gas-in-place for the REM sequence is approximately 342 Tcf, while risked recoverable resources are approximately 85 Tcf, **Table XIV-1**.

Figure XIV-6. Western Portion Of The Cooper Basin Showing Approximate Prospective Shale Gas Area.



Activity. The Cooper Basin is Australia's largest onshore oil and gas production region. Oil and gas development began in the basin during the 1960's, while hydraulic fracturing of low-permeability formations began in 1968 and has been extensively used since. More than 400 wells have been hydraulically stimulated in the Cooper basin to date, though the jobs were much smaller (typically 50,000 lbs sand with 50,000 gal fluid) than used in modern horizontal shale wells. Nevertheless, the Cooper basin has Australia's best capabilities for fracking shale reservoirs. Current production from conventional and tight formations in the basin totals nearly 600 Mcfd from 700 gas wells and 2,500 bopd from 50 oil wells.

The Cooper Basin also has been Australia's most active area for gas shale leasing and testing. Santos, Beach Energy, and DrillSearch Energy have active shale evaluation programs, though only Beach is known to have drilled a test well. Starting in October 2010 Beach drilled and completed a vertical shale test well in the eastern Nappamerri Trough, thought to be Australia's first dedicated shale test well. Drilled to a total depth of 3,612 m, the well penetrated 393 m of REM shale formation with continuous gas shows. The company is analyzing five REM cores for gas content and mechanical properties. Beach plans to conduct an 8-stage frac of the Encounter-1 test well during 2Q-2011.

MARYBOROUGH BASIN (QUEENSLAND)

This small basin in coastal southern Queensland, located about 250 km north of Brisbane, has two potential gas shale targets within the Cretaceous Maryborough Formation. Only five conventional oil & gas exploration wells have been drilled in the Maryborough Basin. No shale activity has been reported.

Geologic Characterization. The Maryborough Basin is a half-graben bounded on the west by the major Electra Fault, **Figure XIV-7**. Extending over an area of 4,300-mi^2 in the onshore northern portion of the basin, where geologic data exist, it is filled with up to about 5 km of Late Triassic to Recent sedimentary rocks that were deposited in a trans-tensional back-arc rift basin. Major folding and faulting, along with significant erosion, occurred during the Cretaceous-Palaeogene. Three main anticlines occur onshore within the basin, all of which have been drilled but without conventional discoveries.[9]

Two main depositional sequences are present, **Figure XIV-8**.[10] The Duckinwilla Group comprises Late Triassic to mid-Jurassic non-marine sediments and is not considered a prospective shale gas target. Overlying the Duckinwilla is the Grahams Creek Formation, which contains Late Jurassic to Cretaceous (Neocomian) strata, including the marine-deposited Maryborough Formation and the fluvial-lacustrine Burrum Coal Measures.

Figure XIV-7. Location And Shale-Prospective Area Map For Maryborough Formation, Maryborough Basin.

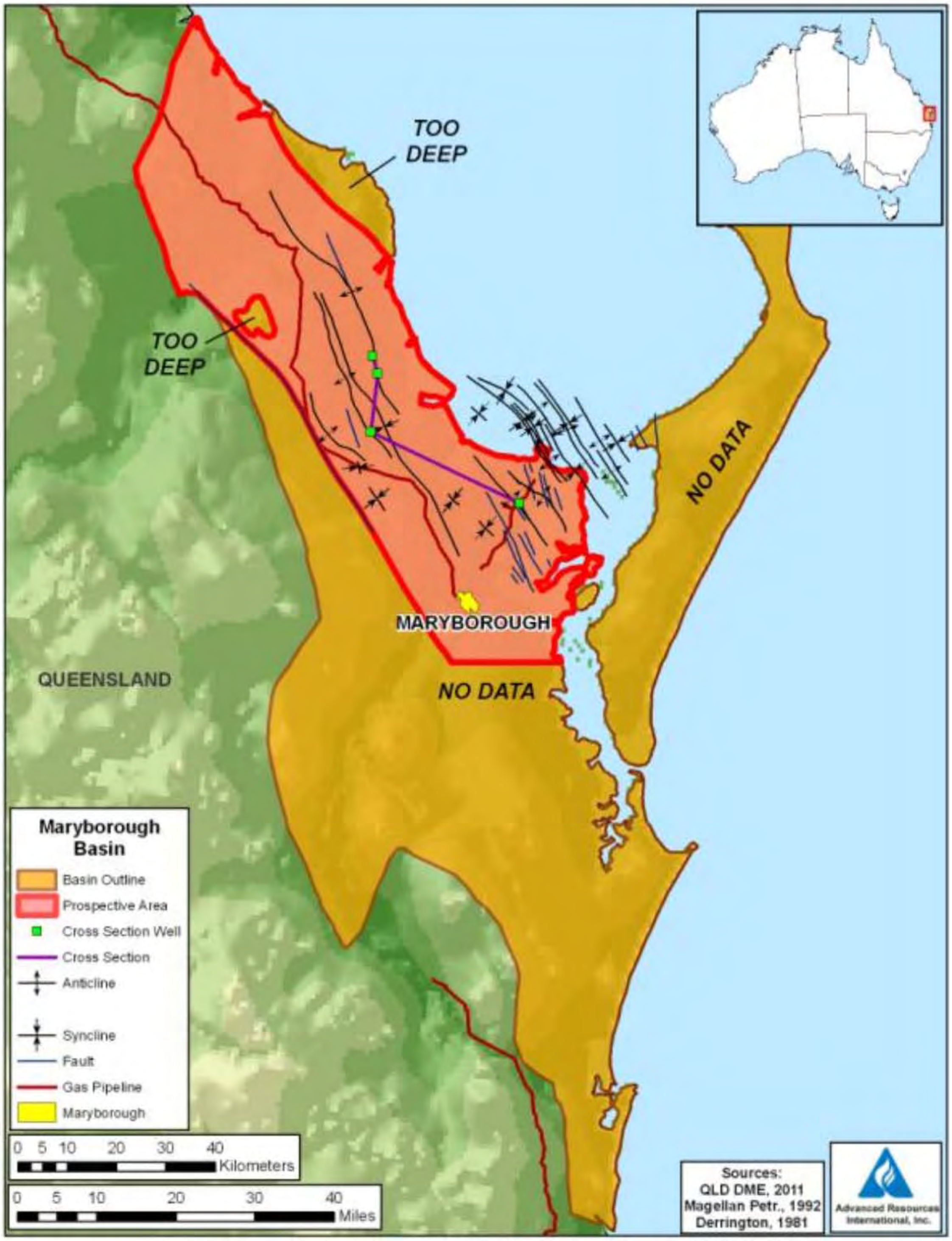
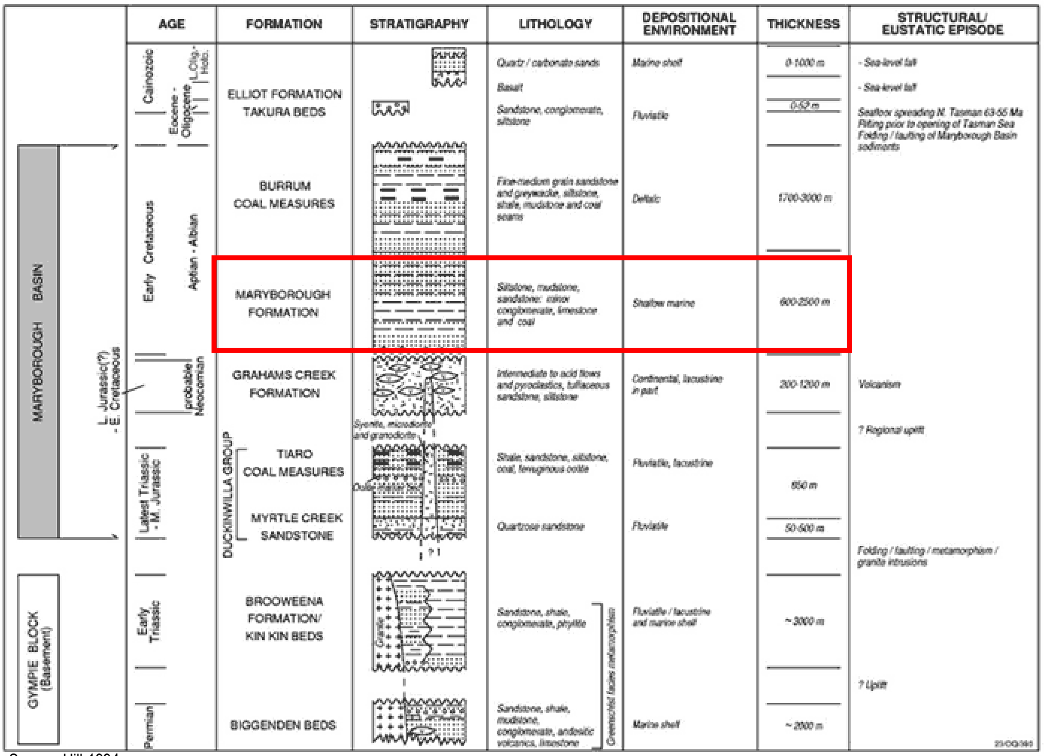


Figure XIV-8. Stratigraphy Of The Maryborough Basin Showing Marine Organic-Rich Shale In The Maryborough Formation

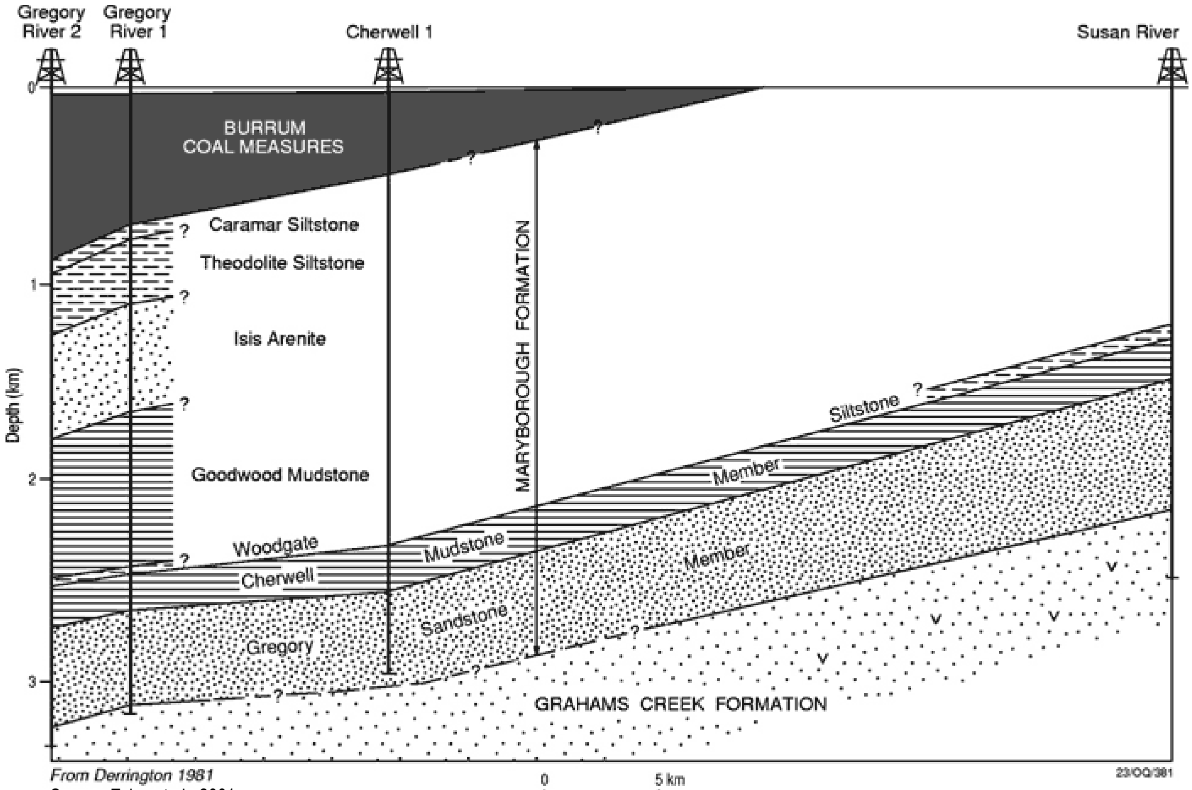


Source: Hill 1994

The Maryborough Formation (Neocomian-Aptian) appears the most prospective shale gas target in the Maryborough Basin. Up to 2.6 km thick, it is the only definitely marine unit in the basin. The unit consists primarily of mudstones, siltstone, and sandstone, with minor conglomerate, limestone, and coal. Within the Maryborough Fm, the most prospective sub-units are the Goodwood Mudstone, Woodgate Siltstone, and Cherwell Mudstone members, **Figure XIV-9**. These have been described as a monotonous series of mudstones with minor shales and siltstones that characterize the marine portion of the Maryborough Formation. The mudstones are light to dark grey, slightly calcitic and pyritic, and slightly silty. Calcite veins are common in the lower section.[11]

The Goodwood Mudstone is approximately 800 m thick (gross), with TOC averaging 1.5%, and is within the dry gas maturity window (R_o of 2.0 to 3.0%). The Cherwell Mudstone consists mainly of black shale about 230 m thick, but no TOC data are available. The Cherwell ranges from 8,000 feet deep on anticlines to a projected 17,000 feet deep in the troughs. TOC averages 1.5% and is thermally mature (R_o of 2.0 to 3.5%). Mineralogy is uncertain.

Figure XIV- 9. Cross-Section Of The Maryborough Basin Showing The Cherwell And Goodwood Mudstone Members Of The Cretaceous Maryborough Formation.



Source: Eyles et al., 2001

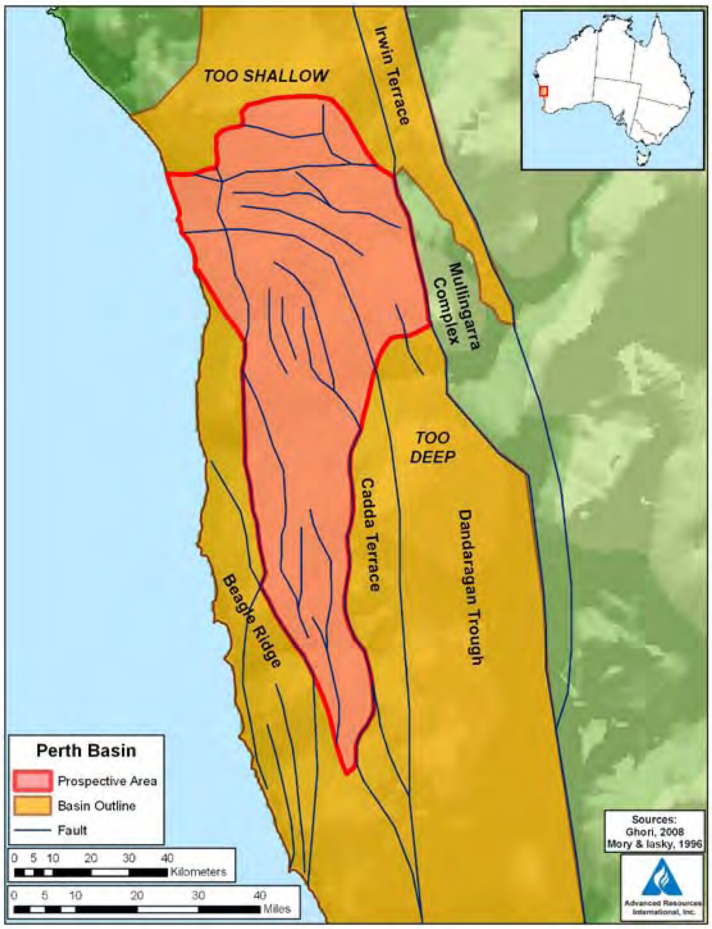
Resources (REM Sequence). ARI evaluated only the northern portion of the Maryborough Basin where geologic data exist. Approximately 1,540 mi^2 could be prospective for shale gas development, using standard minimum depth (6,000 feet) and vitrinite reflectance (R_o > 1.0%) cutoffs. Additional area in the poorly constrained southern half of the basin may be prospective. Completable shale intervals in the basal shales of the Maryborough Formation (Cherwell and Goodwood mudstones) have an estimated resource concentration of approximately 110 Bcf/mi^2. Risked completable gas in-place for the REM sequence is estimated to be 77 Tcf, with risked technically recoverable resource of 23 Tcf, **Table XIV-1**.

PERTH BASIN (WESTERN AUSTRALIA)

The Perth Basin is a petroleum producing region that extends on- and offshore in the southwest of Western Australia. It contains two main organic-rich shale formations with gas development potential: the Permian Carynginia and Triassic Kockatea shales, portions of which already produce oil and gas from conventional reservoirs. Local operator AWE is evaluating the shale potential over approximately 1 million gross acres. AWE and partner Norwest Energy have cored these shale targets and may fracture stimulate a shale well in the basin during 2011.

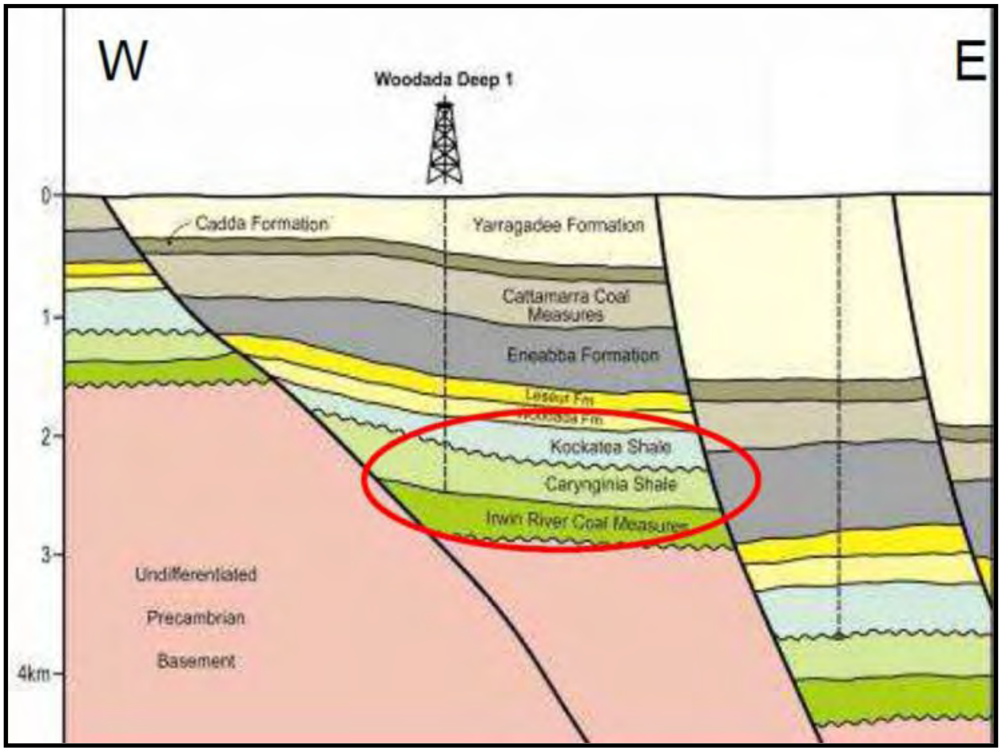
Geologic Characterization. The Perth Basin is a north-northwest trending half-graben with relatively simple structure that generally appears favorable for shale gas development. About half of the basin is onshore, covering an area of approximately 20,000 mi^2. The onshore portion of the basin contains two large deep sedimentary sub-basins, the Dandaragan and Bunbury troughs, which are separated by the Harvey Ridge structural high, **Figure XIV-10**.[12] Further south, across the Harvey Ridge, is the Bunbury Trough with an estimated 10 km of Permian to Cretaceous sediments but limited reservoir data.

Figure XIV-10 : Location And Shale-Prospective Area Map Of The Perth Basin



The Dandaragan Trough, a large syncline in the northern Perth Basin, contains the deepest, thickest, and most prospective gas shale formations. Some 500 km long and up to 45 km wide, the Dandaragan contains as much as 15 km of Silurian to early Cretaceous sedimentary rocks. Some of the Dandaragan is too deep for shale development, but its northern extent and the adjoining Beagle Ridge appear to be within the shale depth window. The area is not structurally complex but does have some significant faulting, **Figure XIV-11**.[13]

Figure XIV-11. Perth Basin Operator AWE's Woodada Deep 1 Well Cored the Organic-Rich Carynginia Shale



Source: AWE 2010

Approximately 100 petroleum exploration wells have been drilled in the onshore Perth Basin, resulting in the discovery of six conventional natural gas fields, all located within the Dandaragan Trough in the north. Proved reserves to date total about 600 Bcf with small amounts of associated oil, found in the main conventional reservoirs (Upper Permian Dongara Sandstone and Beekeeper Formation). Natural gas recovered from the deeper Permo-Triassic reservoirs (Dongara, Mondarra, Yardarino, Woodada and Whicher Range) tends to be dry, reflecting higher thermal maturity and the higher proportion of gas-prone organic matter in the Permian TOC. CO_2 is generally low, generally nil, apart from isolated readings of 4.11% in the Woodada-1 well and 3.92% in the Mondarra-1 well.

Tight sandstone reservoirs, still undeveloped, include the Eneabba and Yarragadee formations and the Cattamarra Coal Measures. These reservoirs were sourced by the Triassic and Permian source rock shales and coals, which modeling indicates are within the oil-maturation window in the far north of the Perth basin, entering the gas window to the southeast into the deep Dandaragan Trough.

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The sedimentary sequence in the Perth basin comprises three successions: a) Lower Permian largely argillaceous glaciomarine to deltaic rocks (including the prospective Carynginia Shale); b) Upper Permian nonmarine and shoreline siliciclastics to shelf carbonates; and c) Triassic to Lower Cretaceous nonmarine to shallow marine siliciclastics (including the prospective Kockatea Shale) deposited in a predominantly regressive phase, **Figure XIV-12**.[14]

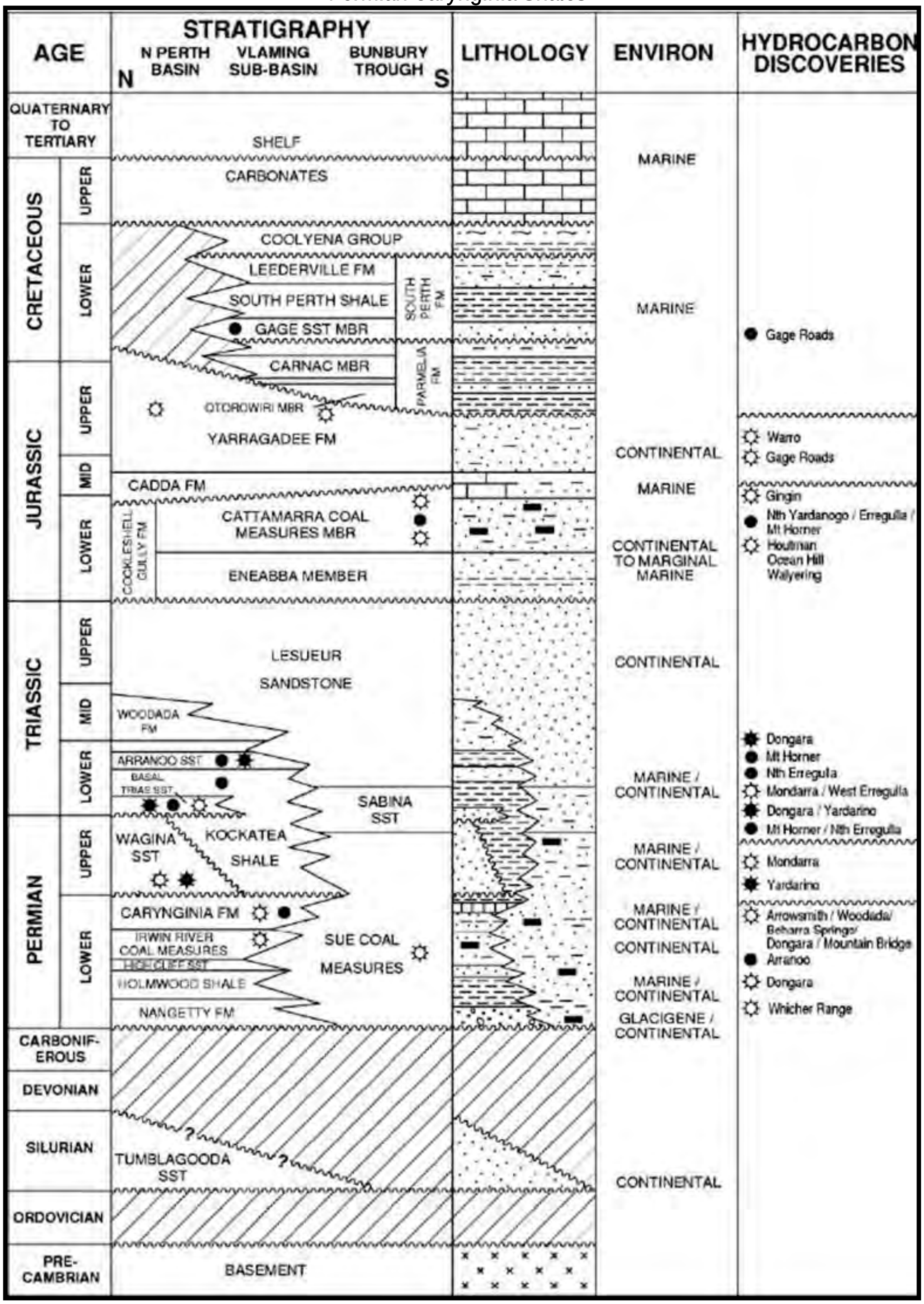
Other marine shales in the Perth Basin that were evaluated but rejected as targets include the Triassic Woodada and Jurassic Cadda formations (too lean), the Jurassic Parmelia (Yarragadee) Formation and (lacustrine origin, located only in the offshore), and the Cretaceous South Perth Formation (immature, offshore only).

The Lower Triassic **Kockatea Shale** is considered the primary oil source-rock as well as the main hydrocarbon flow seal in the basin. It consists of dark shale, micaceous siltstone, and minor sandstone and limestone. The Kockatea thickens to the south within the Perth basin, reaching maximum 1,060 m thickness in the Woolmulla-1 well, but more typically averaging about 700 m thick (**Figure XIV-13)**. The most organic-rich portion of this unit (Hovea Member) is a thin (15-38 m), basal shale that averages 2.0% TOC, well above the overall formation average of about 0.8% TOC. This basal unit contains abundant phytoplankton, suggesting that terrigenous clay is low. The dominantly Type II organic kerogen in this unit is rich in sapropel and finely divided exinite.[15]

Core samples from the Hovea Member of the Late Permian to lower Triassic Kockatea Shale cut from the Hovea-3 petroleum exploration well provide data on reservoir quality.[16] The base of this unit, from a depth of about 1,980 m, is a distinct organic-rich zone of fossiliferous dark grey mudstone, sandy siltstone, and shelly storm beds. These sediments were deposited at a relatively low paleo-latitude in a shallow marine environment during the earliest stage of a marine transgression. TOC of the Kockatea Shale sampled from this well ranged from 2.31% to 7.65% (average 5.6%) over a 30-cm interval, consisting of inertinite-rich (Type III) kerogen.[17]

The clay content from the Hovea Member of the Kockatea Shale in the Hovea-3 well ranged from 24% to 42% (average 33%). Separately, AWE cored the high-TOC, 50-m thick Hovea section of the lower Kockatea in the conventional Redback-2 exploration well on EP-320 during 2010, but reported discouragingly high clay content. The Kockatea is thermally mature in the Dongara Trough, but less mature and possibly oil-prone on the Dongara Saddle and the flanks of the Beagle Ridge. CO_2 and N_2 contents tested quite low (0.5% and 0.4%, respectively) from a 1,448-m deep Kockatea Shale zone in the Dongara-24 well.[18]

Figure XIV-12. Stratigraphy of the Perth Basin Showing the Prospective Lower Triassic Kockatea and Permian Carynginia Shales

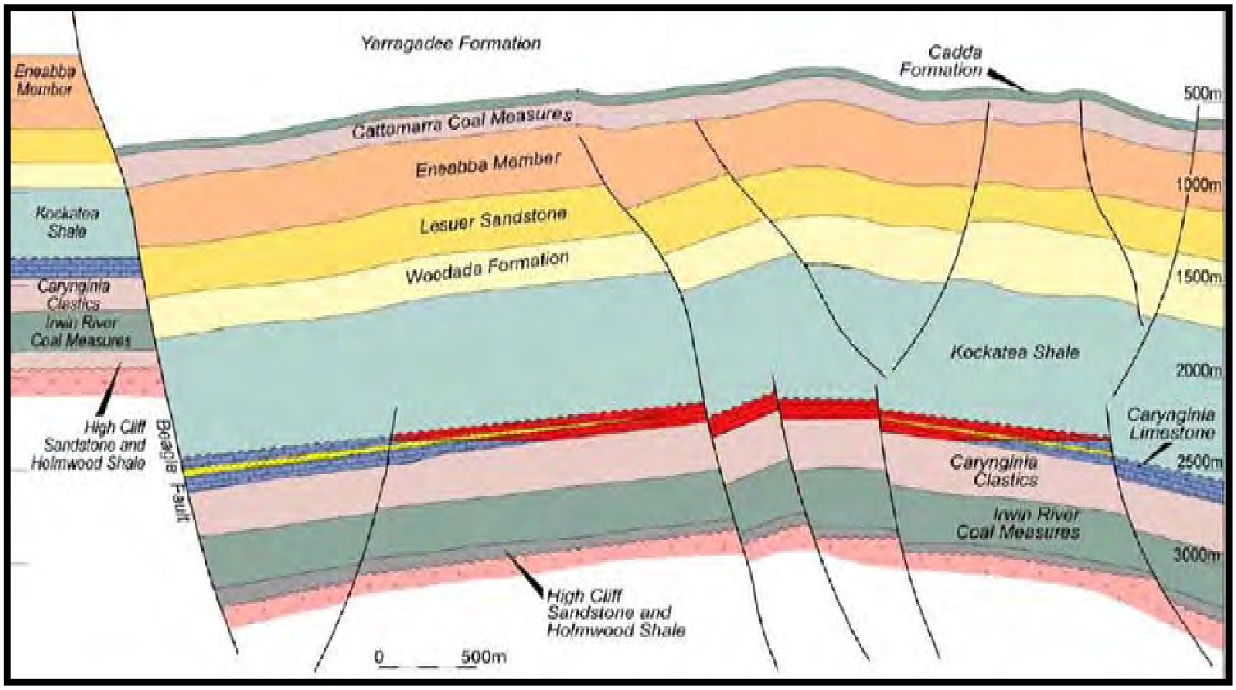


Source: Cadman et al., 1994

Figure XIV-13. Structural Cross-Section of the Perth Basin Showing 700-m Thick Kockatea and 250-m Thick Carynginia Shales at Prospective 1500-2800 m Depth.

WEST
Beagle Ridge

EAST
Dandaragan Trough



Source: Norwest Energy, 2010

The Permian **Carynginia Shale** is a restricted-marine deposit present over a wide area of the northern Perth Basin. The Carynginia conformably underlies the Kockatea Shale. Although considered a less important source rock than the overlying Kockatea Shale, AWE recently reported encouraging organic-shale characteristics for this 240- to 330-m thick unit. Deposited in a shallow-marine environment under proglacial conditions, the Carynginia overlies the Irwin River Coal Measures. A deeper water shale member occurs near the base of the Carynginia Shale, including thin interbeds of siltstone, sandstone, and limestone.

Overlying the basal shale is a shallow-water, shelf limestone unit. It contains conventional gas reservoirs, such as at Dongara field, thin, discontinuous sandstones sealed by intraformational shales and limestones. Primary porosity in this limestone was filled by clays and calcite during diagenesis, thus porosity is secondary dissolution or fracture porosity. Conventional Gas is produced from the Carynginia Limestone at Woodada field, sealed by the overlying Kockatea Shale as well as updip shaling out of the limestone facies. CO_2 and N_2 tested fairly low (2.23% and 2.54%, respectively) from a 2,437-m deep Caryngia Fm zone in the Elegans-1 well.

TOC values of up to 11.4% have been recorded in the Carynginia Shale, dominated by inertinite derived from land plants. Gas-prone, the Carynginia Shale is overmature and in the dry gas window over most of the Perth basin. Sapropelic organic material was found in one well, indicating that the unit may have some potential as an oil source. Source rocks are less mature on the Dongara Saddle and the flanks of the Beagle Ridge, where the shale facies is partly replaced by shallow-water, limestone facies.

Geothermal gradients in the Perth Basin can be elevated, ranging from 2.0ºC to 5.5ºC/100 m, but the gradient in the Dandaragan Trough less extreme (2°to 2.5°C/100 m). Vitrinite reflectance data show poor relationship with depth, with extreme data scatter probably caused by subertinite and bitumen suppression. Triassic and Permian strata are in the mature gas window over large portions of the basin's center. The Kockatea Shale source rocks appear to be mature for gas generation in large tracts of the northern Perth Basin, due to the relatively high geothermal gradient and burial depth.

Resources (Carynginia and Kockatea Shales). ARI identified the prospective portions of the Beagle Ridge and Dandaragan Trough in the northern portion of the Perth basin, where the Carynginia and Kockatea Shale source rocks are thick, deep, and thermally mature. An estimated 2,180-mi^2 area could be prospective for shale gas development, using standard minimum and maximum depths (6,000-16,500 ft) and vitrinite reflectance (R_o > 1.0%) cutoffs. Additional area in the poorly constrained southern half of the basin also may be prospective but was not evaluated.

Completable shale intervals in the Permian Carynginia Shale have an estimated resource concentration of approximately 107 Bcf/mi^2, risked completable gas in-place of 98 Tcf, and risked recoverable resources of approximately 29 Tcf. For the Triassic Kockatea Shale, the prospective area has 110 Bcf/mi^2, risked completable gas in-place of 100 Tcf, and risked technically recoverable resources of approximately 30 Tcf, **Table XIV-1**.

Activity. In April 2010, AWE cut five cores in the 280-m thick shale in its Woodada Deep exploration well in the northern Perth Basin. The company found the upper and lower zones to have high clay content. However, the middle zone was considered more prospective, with lower clay (value not reported), 1-4% TOC, estimated 3-6% porosity, and depths of 1,600 to 3,200 m. AWE estimated a total 13 to 20 Tcf of gas in-place at its permit within the middle portion of the Carynginia Shale.[19]

AWE plans to drill a second core well (Arrowsmith-2) to basement at about 3,200 m depth, coring the Kockatea and Carygina shales and the Irwin Coal Measures. The company may fracture stimulate a shale well sometime during 2011. Australian independent Norwest Energy, which produces oil and gas from conventional fields in the Perth Basin, is partnered with AWE and evaluating the shale potential on EP413. In August 2010, Indian firm Bharat PetroResources agreed to acquire half of Norwest's interests in EP413 and TP/15, committing up to A$15 million for exploration and drilling.

CANNING BASIN (WESTERN AUSTRALIA)

The large and scarcely explored Canning Basin in northwestern Western Australia has emerging potential in several organic-rich shales, including the Laurel, Lower Anderson, and Goldwyer shales, though their potential remains poorly defined. Several conventional and tight gas discoveries have been made in the basin, though not developed due to lack of gas pipelines, indicating that source rocks here may be mature. Buru Energy (with partner Mitsubishi) and New Standard Energy hold most of the leases in this area and currently are evaluating the basin's shale potential.

Geologic Characterization. The 234,000-mi^2 Canning Basin (150,000 mi^2 of which is onshore) is Western Australia's largest sedimentary basin, **Figure XIV-14**. A broad intracratonic rift basin, the Canning contains up to 18 km of Ordovician to Cretaceous age sedimentary rocks. The basin is separated from the Amadeus basin to the east by a Precambrian arch. A series of northwest-trending, fault-bounded troughs within the basin (Fitzroy Trough, Willara and Kidson sub-basins) may contain deep shale potential.[20]

Although petroleum exploration started in the Canning basin in 1922, the first commercial oil discovery was made only in 1981. Conventional exploration in the Canning Basin has focused on the Lennard Shelf, where petroleum occurs in the Hoya Formation (Boundary, Sundown, and West terraces) and in the Anderson Formation. Only about 60 wells have intersected the principal source rocks in the basin, but these have all been on the uplifted terraces; the deeper shale source rocks in the troughs have not yet been penetrated. Although source rock data in the basin are quite limited, the oil fields discovered to date likely were sourced by the Carboniferous Laurel Formation shale.

Figure XIV-14. Structural Elements of the Canning Basin in Northwestern Australia

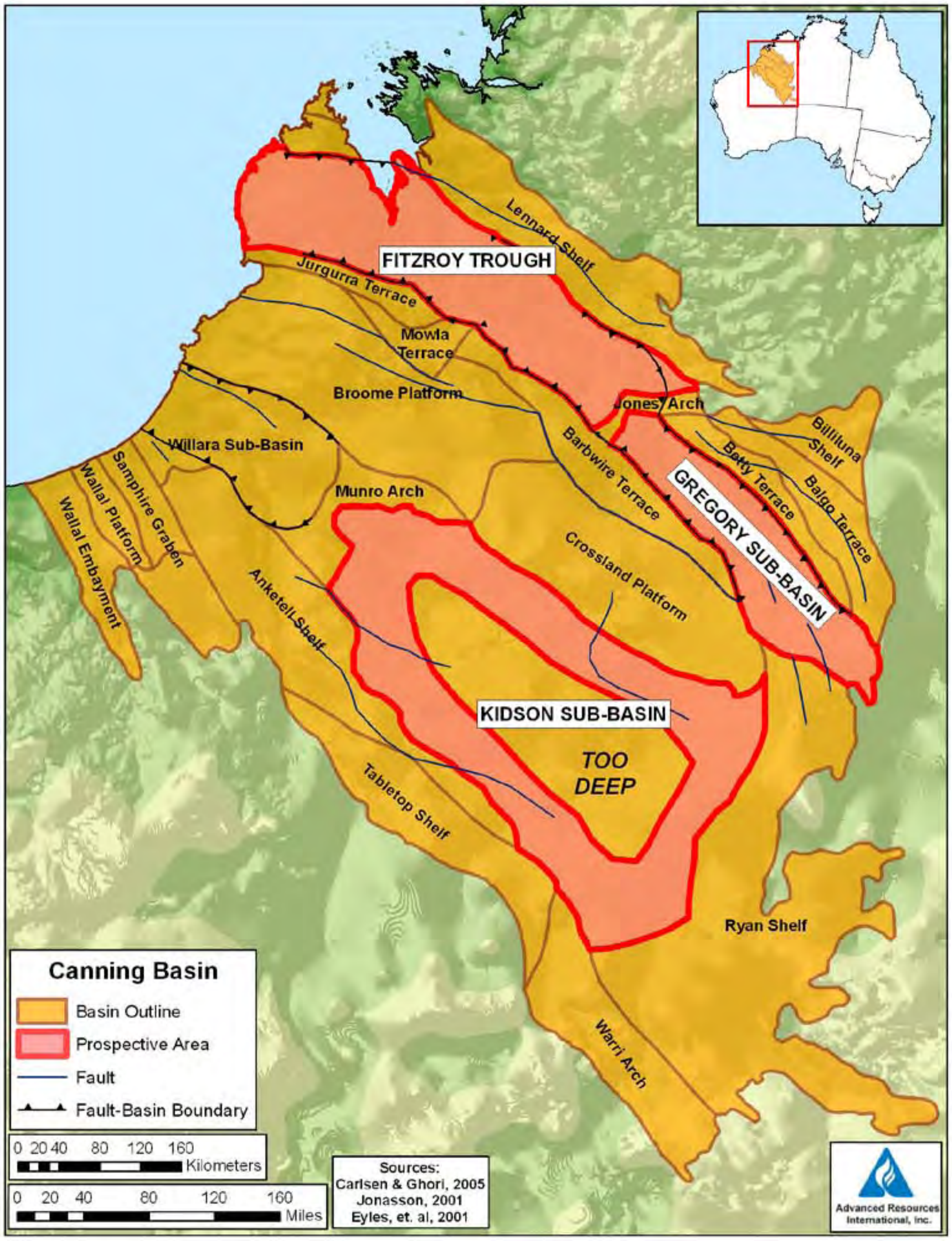
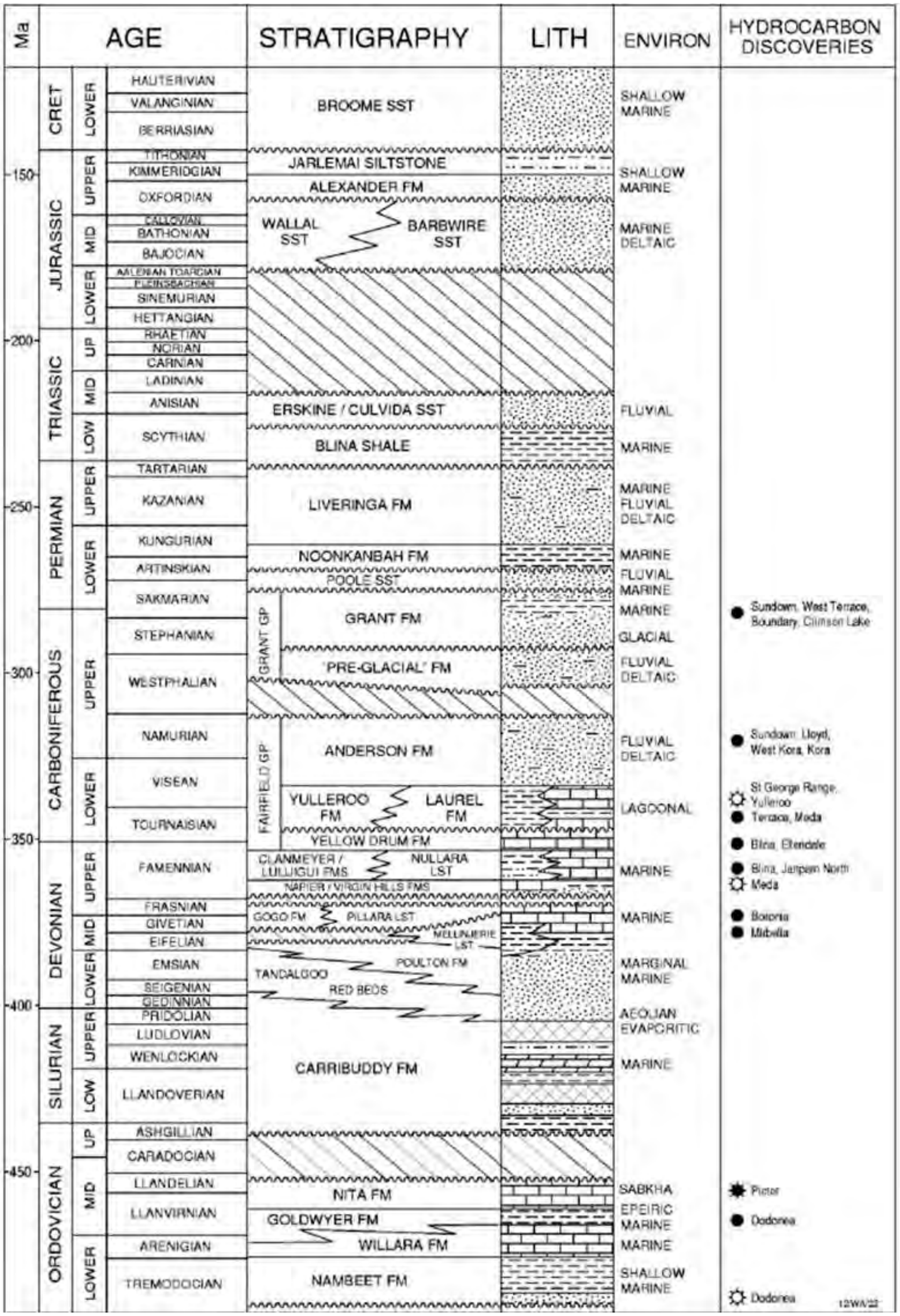


Figure XIV-15 shows the stratigraphy of the Canning Basin. Initial data suggest that the two primary gas shale targets in the basin are the organic-rich Ordovician Goldwyer Formation and the Carboniferous Laurel Formation. However, the Laurel Formation could not be rigorously assessed due to insufficient data control. Other marine shales in the Canning Basin, such as the Calytrix Formation, appear to be too lean and have limited petroleum generative potential.

Figure XIV- 15. Stratigraphy Of The Canning Basin Showing Carboniferous Goldwyer And Laurel Fm Shales



Cadman et al., 1993

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The Middle Ordovician **Goldwyer Formation** conformably overlies the Lower Ordovician Willara Formation. The Goldwyer was deposited mainly in open marine to intertidal conditions. Highly fossiliferous, it varies from mudstone-dominated in basinal areas to limestone-dominated in some platform and terrace areas. The Goldwyer Formation averages about 400 m thick, reaching a maximum thickness of 736 m in the Willara-1 well in the Willara Sub-basin.[21]

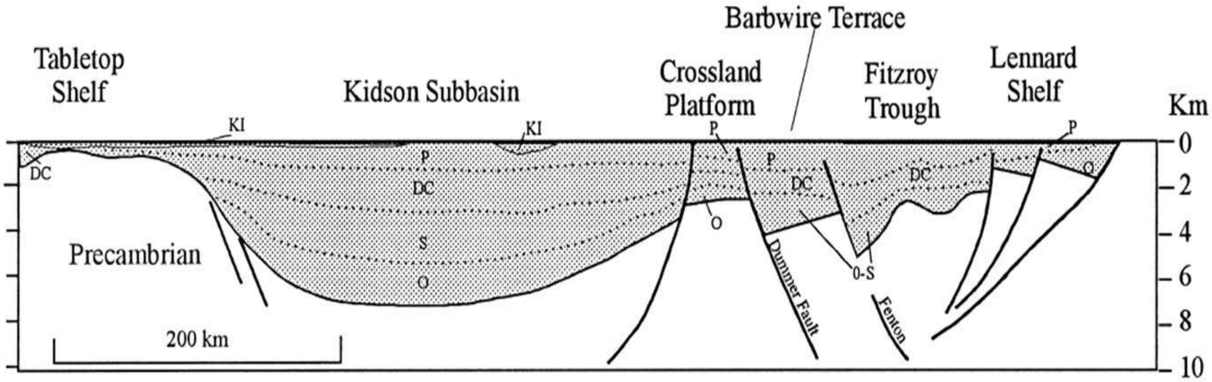
The Goldwyer Formation is dominated by mudstone and carbonate, with ratios of these components varying widely across the basin. The color ranges from grey-green to black, indicating anoxic reducing conditions. Major carbonate build-ups are present locally, but have low permeability due to secondary mineralization. Coarser siliciclastic rocks generally are absent or restricted to minor fine-grained sandstone, which becomes more abundant towards the southeastern margin of the basin.

Kukersite is locally abundant in the Upper Goldwyer Formation, with lesser abundance in lower parts of the formation. In addition, the Goldwyer locally contains horizons with high concentrations of the marine alga *Gloeocapsomorpha prisca*, considered to have excellent source-rock potential. This alga also is abundant in the Amadeus, Baltic, Michigan–Illinois, and Williston basins, each of which, including the Canning Basin, lay within 5° of the equator during the Ordovician.[22] Locally, the Goldwyer has undergone significant secondary dolomitization. The Goldwyer Formation is thermally immature and oil prone in most petroleum wells on the uplifted platforms and terraces, but likely mature in the adjacent deep troughs.

Figure XIV-16 shows a regional cross-section of the southern Fitzroy Trough and Jones Arch regions of the Canning basin, where the Carboniferous Laurel Shale source rock is about 2 km deep. A more detailed cross-section shows the Laurel to be approximately 500 m thick and 1700 m deep, **Figure XIV-17**.

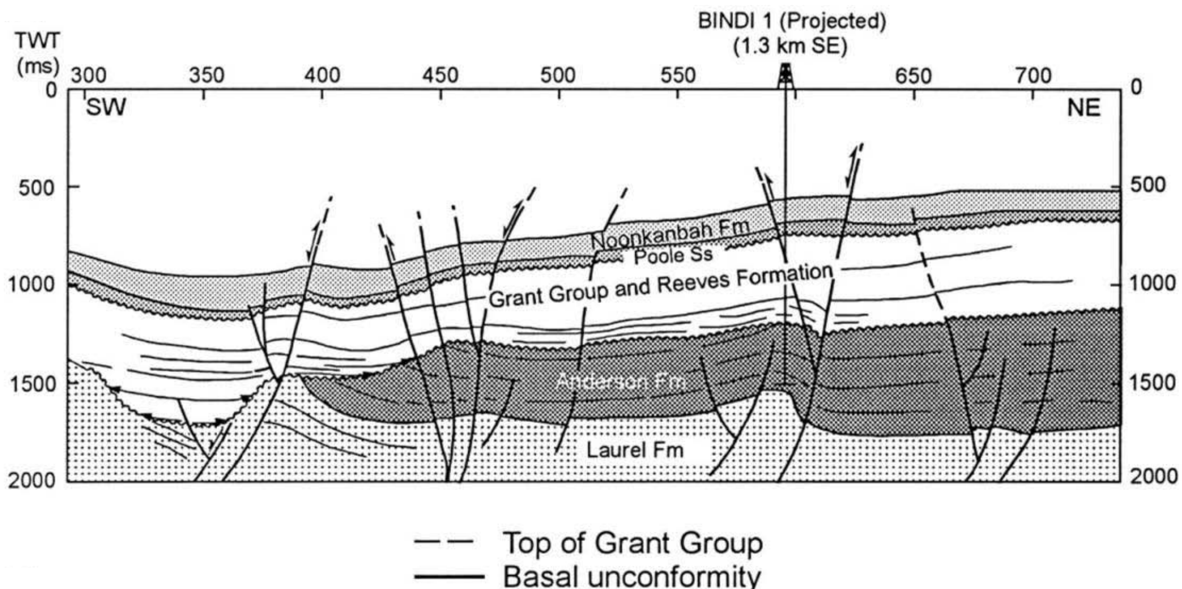
Selected TOC in the Goldwyer Fm generally ranges from 1% to 5% (mean 3%), with some values in excess of 10%, **Figure XIV-18**.[23] The upper member of the Goldwyer is particularly rich, with TOC of 0.46% to 6.40%, nearly all of which originated from cyanobacterium. Rock-Eval pyrolysis indicates that source rocks from the Upper Goldwyer have the capacity to generate 12 kg of hydrocarbon per metric ton. Modeling indicates this source rock is gas-mature in the Fitzroy Trough but within the oil window over much of the southern Canning basin and the mid-basin platform. The Kidson Sub-basin, where the Goldwyer deepens to over 6 km, also is likely to be in the dry gas window.

Figure XIV-16. Regional Cross-Section Showing Middle Ordovician Goldwyer Shale Is Excessively Deep (>5 Km) In the Central Kidson Sub-Basin, But At Prospective Depth On Its Flanks As Well As Throughout The Southern Fitzroy Trough.



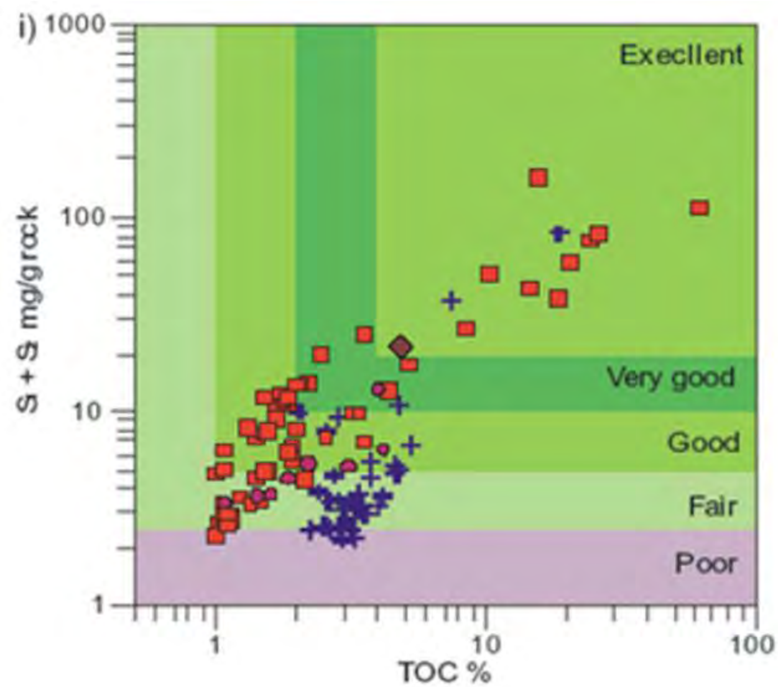
Source: Eyles et al., 2001

Figure XIV-17. Detailed Cross-Section Showing Carboniferous Laurel Shale, The Canning Basin's Main Source Rock, Is About 500 M Thick And 1700 M Deep In The Southern Fitzroy Trough – Jones Arch Region.



Source: Eyles et al., 2001

Figure XIV-18. TOC In The Goldwyer Fm, Canning Basin Generally Ranges From About 1% To 5% (Mean 3%), With Some Values Over 10%.



Source: Ghori and Haines, 2007

Other potential shale targets in the Canning Basin include the Carboniferous Grant Formation and Fairfield Group, the Devonian Gogo and equivalent formations, and Ordovician Upper Nambeet Formation. However, these all have less than 0.5% TOC and thus are not prospective.

Resources (Goldwyer Formations). ARI identified a prospective area in the Fitzroy Trough in the northern portion of the Canning basin, where the Goldwyer Formation source rocks are thick, deep, and thermally mature. An estimated 48,100 mi^2 may be prospective for shale gas development in the Fitzroy, Gregory, and Kidson Troughs, although data for these largely undrilled areas had to be extrapolated from the adjoining uplifts. Completable shale intervals in the Goldwyer Formation has an estimated resource concentration of approximately 106 Bcf/mi^2, risked completable gas in-place of 764 Tcf, and risked technically recoverable resources of about 229 Tcf (**Table 1**).

Activity. Buru Energy, a new company formed by the de-merger of ARC Energy, controls exploration permits with shale gas potential in the Canning basin. The company reported cores of gas-mature, organic-rich shale from the Laurel formation taken from the

Yulleroo-1 conventional exploration well in permit EP-391. Drilled in 1967, the Yulleroo-1 flowed gas from sandstone and shales within the Laurel Formation. Other potential shale targets include the Early Permian Noonkanbah, Carboniferous Lower Anderson, Gogo, and Goldwyer Formations. On November 30, 2010 Mitsubishi agreed to fund an A$152.4 million exploration & development program, including 80% (A$40 million) of Buru's 2011 unconventional oil & gas exploration budget, to earn a 50% interest in most of Buru's permits.

New Standard Energy (NSE), the other principal operator in the Canning basin, holds a 45,000 km^2 exploration license with Goldwyer Shale potential and additional acreage in EP413 with Laurel Shale potential. NSE's independent consultant has estimated 40-480 Tcf of gas in place within shale formations at the company's leases. Throughout 2010 the company sought a partner for its shale project but has been unsuccessful to date due, it said, to the immaturity of the play and lack of data. NSE currently is evaluating newly acquired gravity data across its position but has not yet announced drilling plans.[24]

NATURAL GAS PROFILE

Australia produced 1.5 Tcf of natural gas in 2009, though only consumed 0.94 Tcf[25]. Much of the gas in converted into LNG to be distributed domestically and exported to Asian markets. As of January 2010, Australia's estimated proven natural gas reserves is approximately 110 Tcf.

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APPENDIX A

Table A-1. Detailed Tabulation of Shale Gas Resources: 48 Major Basins and 69 Formations

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
North America	I. Canada	Appalachian Fold Belt	Utica	155	31
		Windsor Basin	Horton Bluff	9	2
		Horn River	Muskwa/Otter Park	378	132
			Evie/Klua	110	33
		Cordova	Muskwa/Otter Park	83	29
		Liard	Lower Besa River	125	31
		Deep Basin	Montney Shale	141	49
			Diog Phosphate	81	20
		Colorado Group	2WS & Fish Scales	408	61
		Sub-Total		*1,490*	*388*
	II. Mexico	Burgos Basin	Eagle Ford Shale	1,514	454
			Tithonian Shales	272	82
		Sabinas Basin	Eagle Ford Shale	218	44
			Tithonian La Casita	56	11
		Tampico Basin	Pimienta	215	65
		Tuxpan Platform	Tamaulipas	25	8
			Pimienta	28	8
		Veracruz Basin	U. K Maltrata	38	9
		Sub-Total		*2,366*	*681*
	Total			**3,856**	**1,069**
South America	III. Northern South America	Maracaibo Basin	La Luna	42	11
		Catatumbo Sub-Basin	La Luna	29	7
			Capacho	49	12
		Sub-Total		*120*	*30*
	IV. Southern South America	Neuquen Basin	Los Molles	478	167
			Vaca Muerta	687	240
		San Jorge Basin	Aguada Bandera	250	50
			Pozo D-129	180	45
		Austral-Magallanes Basin	L. Inoceramus	420	84
			Magnas Verdes	351	88
		Parana-Chaco Basin	San Alfredo	2,083	521
		Sub-Total		*4,449*	*1,195*
	Total			**4,569**	**1,225**

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
Europe	V. Poland	Baltic Basin	Silurian Shales	514	129
		Lublin Basin	Silurian Shales	222	44
		Podlasie Depression	Silurian Shales	56	14
		Sub-Total		*792*	*187*
	VI. Eastern Europe	Baltic Basin	Silurian Shales	93	23
		Dnieper-Donets Basin	Visean Shales	48	12
		Lublin Basin	Silurian Shales	149	30
		Sub-Total		*290*	*65*
	VII. Western Europe	North Sea-German Basin	Posidonia Shale	26	7
			Namurian Shale	64	16
			Wealden Shale	9	2
		Paris Basin	Permo-Carboniferous Shale	303	76
		Scandinavia Region	Alum Shale	589	147
		South-East French Basin	Terres Niores	112	28
			Liassic Shale	305	76
		N. U.K. Petroleum System	Bowland Shale	95	19
		S. U.K. Petroleum System	Liassic Shale	2	1
		Sub-Total		*1,505*	*372*
	Total			**2,587**	**624**
Africa	VIII. Central North Africa	Ghadames Basin	Tannezuft Formation	520	156
			Frasnian Formation	251	75
		Sirt Basin	Sirt-Rachmat Formation	647	162
			Etel Formation	443	111
		Sub-Total		*1,861*	*504*
	IX. Morocco	Tindouf Basin	Silurian Shales	251	50
		Tadla Basin	Silurian Shales	16	3
		Sub-Total		*267*	*53*
	X. South Africa	Karoo Basin	Prince Albert	453	91
			Whitehill	995	298
			Collingham	386	96
		Sub-Total		*1,834*	*485*
	Total			**3,962**	**1,042**

Continent	Region	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)
Asia	XI. China	Sichuan Basin	Longmaxi	1,373	343
			Qiongzhusi	1,394	349
		Tarim Basin	O1/O2/O3 Shales	897	224
			Cambrian Shales	1,437	359
		Sub-Total		*5,101*	*1,275*
	XII. India/Pakistan	Cambay Basin	Cambay Shale	78	20
		Damodar Valley Basin	Barren Measure	33	7
		Krishna-Godavari Basin	Kommugudem Shale	136	27
		Cauvery Basin	Andimadam Formation	43	9
		Southern Indus Basin	Sembar Formation	80	20
			Ranikot Formation	126	31
		Sub-Total		*496*	*114*
	XIII. Turkey	Thrace Basin	Hamitabat	14	4
			Mezardere	7	2
		SE Anatolian Basin	Dudas Shale	43	9
		Sub-Total		*64*	*15*
	Total			**5,661**	**1,404**
Australia	XIV. Australia	Cooper Basin	Roseneath-Epsilon-Murteree	342	85
		Maryborough Basin	Goodwood/Cherwell Mudstone	77	23
		Perth Basin	Carynginia Shale	98	29
			Kockatea Fm	100	30
		Canning Basin	Goldwyer Fm	764	229
	Total			**1,381**	**396**
Grand Total				**22,016**	**5,760**

APPENDIX B

Table B-1. Play Success Probability Factors, Prospective Area Success (Risk) Factors and Composite Success Factors

Continent	Country/Region	Basin	Formation	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
North America	I. Canada	Appalachian Fold Belt	Utica	100%	40%	40%
		Windsor Basin	Horton Bluff	50%	40%	20%
		Horn River	Muskwa/Otter Park	100%	75%	75%
			Evie/Klua	80%	75%	60%
		Cordova	Muskwa/Otter Park	80%	60%	48%
		Liard	Lower Besa River	80%	50%	40%
		Deep Basin	Montney Shale	100%	75%	75%
			Diog Phosphate	80%	50%	40%
		Colorado Group	2WS & Fish Scales	80%	50%	40%
	II. Mexico	Burgos Basin	Eagle Ford Shale	80%	50%	40%
			Tithonian Shales	50%	50%	25%
		Sabinas Basin	Eagle Ford Shale	40%	40%	16%
			Tithonian La Casita	40%	20%	8%
		Tampico Basin	Pimienta	60%	40%	24%
		Tuxpan Platform	Tamaulipas	40%	50%	20%
			Pimienta	40%	50%	20%
		Veracruz Basin	U. K Maltrata	40%	40%	16%
South America	III. Northern South America	Maracaibo Basin	La Luna	50%	50%	25%
		Catatumbo Sub-Basin	La Luna	50%	60%	30%
			Capacho	50%	60%	30%
	IV. Southern South America	Neuquen	Los Molles	80%	50%	40%
			Vaca Muerta	80%	60%	48%
		San Jorge	Aguada Bandera	50%	40%	20%
			Pozo D-129	60%	40%	24%
		Austral-Magallanes	L. Inoceramus	50%	50%	25%
			Magnas Verdes	50%	50%	25%
		Parana-Chaco	San Alfredo	30%	40%	12%
Europe	V. Poland	Baltic Basin	Silurian Shales	80%	50%	40%
		Lublin Basin	Silurian Shales	60%	40%	24%
		Podlasie Depression	Silurian Shales	60%	50%	30%
	VI. Eastern Europe	Baltic Basin	Silurian Shales	60%	50%	30%
		Dnieper-Donets Basin	Visean Shales	40%	40%	16%
		Lublin Basin	Silurian Shales	60%	40%	24%
	VII. Western Europe	North Sea-German Basin	Posidonia Shale	60%	50%	30%
			Namurian Shale	60%	50%	30%
			Wealden Shale	50%	40%	20%
		Paris Basin	Permo-Carboniferous Shale	60%	60%	36%
		Scandinavia Region	Alum Shale	50%	40%	20%
		South-East French Basin	Terres Niores	50%	50%	25%
			Liassic Shale	60%	50%	30%
		N. U.K. Petroleum System	Bowland Shale	40%	50%	20%
		S. U.K. Petroleum System	Liassic Shale	40%	60%	24%

Continent	Country/Region	Basin	Formation	Play Success Factor	Prospective Area Success Factor	Composite Success Factor
Africa	VIII. Central North Africa	Ghadames Basin	Tannezuft Formation	60%	50%	30%
			Frasnian Formation	60%	50%	30%
		Sirt Basin	Sirt-Rachmat Formation	50%	30%	15%
			Etel Formation	50%	30%	15%
	IX. Morocco	Tindouf Basin	Silurian Shales	50%	50%	25%
		Tadla Basin	Silurian Shales	40%	50%	20%
	X. South Africa	Karoo Basin	Prince Albert	50%	30%	15%
			Whitehill	60%	40%	24%
			Collingham	50%	30%	15%
Asia	XI. China	Sichuan Basin	Longmaxi	60%	50%	30%
			Qiongzhusi	60%	50%	30%
		Tarim Basin	O1/O2/O3 Shales	40%	40%	16%
			Cambrian Shales	40%	40%	16%
	XII. India/Pakistan	Cambay Basin	Cambay Shale	60%	60%	36%
		Damodar Valley Basin	Barren Measure	50%	50%	25%
		Krishna-Godavari Basin	Kommugudem Shale	50%	40%	20%
		Cauvery Basin	Andimadam Formation	50%	60%	30%
		Southern Indus Basin	Sembar Formation	50%	40%	20%
			Ranikot Formation	50%	40%	20%
	XIII. Turkey	Thrace Basin	Hamitabat	60%	60%	36%
			Mezardere	60%	50%	30%
		SE Anatolian Basin	Dudas Shale	40%	60%	24%
Australia	XIV. Australia	Cooper Basin	Roseneath-Epsilon-Murteree	75%	75%	56%
		Maryborough Basin	Goodwood/Cherwell Mudstone	75%	60%	45%
		Perth Basin	Carynginia Shale	60%	70%	42%
			Kockatea Fm	60%	70%	42%
		Canning Basin	Goldwyer Fm	60%	25%	15%