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APEC Unconventional Natural Gas Census

APEC Energy Working Group

January 2013

The overall report entitled, “APEC Unconventional Natural Gas Census”, is provided in two parts:

- Part I contains “Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions”.

- Part II contains “Suggested Framework, Scope, and Content for an APEC Unconventional Gas Census and Recommended Follow-on Supporting Activities”.

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APEC Unconventional Natural Gas Census
Part I

Evaluating the Potential for Unconventional Gas Resources to
Increase Gas Production and Contribute to
Reduced CO2 Emissions

APEC Energy Working Group

January 2013

APEC Unconventional Natural Gas Census

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

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EXECUTIVE SUMMARY

A. Purpose

The purpose of Part I of our APEC Unconventional Gas Census report is to: (1) document information on surveys of unconventional gas resources completed, underway or planned by the various APEC economies, including relevant activities underway by other international agencies; and (2) to set forth the potential amounts of unconventional gas, by type, that could be practically and economically produced in each APEC economy, including a time frame for their availability.

Part II of our APEC Unconventional Gas Census report (provided separately) provides: (1) a suggested framework, scope and content of an APEC Unconventional Gas Census and relationship to other relevant international and national activities; and (2) recommendations for setting up an APEC Unconventional Gas Census, including scope, content, timing and management responsibility.

B. Introduction

This report, entitled *"APEC Unconventional Gas Census: Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions",* transmits the work by Advanced Resources International, Inc. for the APEC Secretariat on the status of unconventional gas - - shale gas, coalbed methane, and tight gas - - in the 21 APEC Economies.

The report takes a look at natural gas consumption and production in each APEC economy, including an in-depth tabulation of the volumes of unconventional gas being produced and the currently assessed size of each APEC Economy's unconventional gas resource base.

- For economies with official values for technically recoverable unconventional gas resources and production, such as for Canada, Mexico and the U.S., the report tabulates these official resource estimates and also augments these estimates with other information assembled from private (non-public) sources.

- For economies with no official values for technically recoverable unconventional gas resources or production, such as Russia, Indonesia and Malaysia, the report provides information on the size of the in-place resource (where available), discusses the geologic settings that might support future development of unconventional gas and presents (where available) private (non-public) estimates for unconventional gas production and resources.

The overall report contains regional summaries of unconventional gas activity as well as a more detailed chapter for each APEC Economy with assessed potential for unconventional gas.

C. Summary of Findings

Our APEC Unconventional Gas Census shows that unconventional gas already provides (in year 2011) significant volumes of natural gas supply, 560 Bcm or 54 Bcfd, equal to over 30% of annual natural gas production in the 21 APEC Economies. Moreover, if all of the unconventional gas being produced, particularly the tight gas produced in Australia, China and Mexico, were fully tabulated, the contribution of unconventional gas would be significantly higher.

The APEC "Census" also shows that the official size of the technically recoverable unconventional gas resource base in the 21 APEC Economies is large - - 114,700 Bcm or 4,048 Tcf. This would support over 200 years of unconventional gas production at current production rates. Importantly, industry's perception of the size of the technically recoverable unconventional gas resource base will most likely increase with time. For example,

- Even modest pursuit and assessment of Russia's estimated 83,700 Bcm (2,950 Tcf) and Indonesia's estimated 16,000 Bcm (453 Tcf) of coalbed methane in-place would provide a noticeable jump to the volume of recoverable coalbed methane resources in the APEC Economies.

- The addition of emerging new shale gas plays, such as the Utica Shale in the U.S. and the Liard Basin shales in Canada, would also add significant volumes to the resource base of shale gas.

- The quantification of the already being developed tight gas plays in Mexico (Burgos Basin) and China (Ordos and Sichuan basins) would also boost the official tabulation of tight gas resources.

One of the goals of this APEC Unconventional Gas “Census Report” (and subsequent presentations and workshops) is to provide a structure and motivation for a more complete official tabulation of unconventional gas resources. This would provide a foundation for better understanding the important and growing potential of increasing the use of natural gas within APEC.

D. APEC’s Natural Gas Consumption

Natural gas already meets a significant portion of the energy needs of the APEC Economies. Last year (2011), these 21 Economies consumed 1,750 Bcm (169 Bcfd), equal to more than half (54%) of worldwide natural gas use. APEC’s consumption of natural gas has grown steadily, up by 17% from 2005, including a significant jump in recent years, Table EX-1. With growing populations, increasing economic growth and pressures for greater use of natural gas for electricity generation, expectations are that natural gas use will continue to increase, assuming availability of sufficient, affordable supply.

Table EX-1: APEC’s Natural Gas Consumption

	Bcm	Bcfd
2005	1,490	144
2010	1,692	164
2011	1,750	169

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The U.S. and Russia together currently account for nearly two-thirds (1,114 Bcm, 124 Bcfd) of APEC's natural gas consumption, with China and Japan each using over 100 Bcm (10 Bcfd) last year (2011). Significant growth in gas consumption is anticipated in China, Japan, Republic of Korea and several of the other APEC Economies based on their construction of LNG receiving terminals and their entry into long-term natural gas supply contracts.

E. APEC's Natural Gas Production

The APEC Economies are also major producers of natural gas. Last year (2011), these 21 Economies produced 1,830 Bcm (177 Bcfd) of natural gas, up substantially from prior years, Table EX-2.

Table EX-2: APEC's Natural Gas Production

	Bcm	Bcfd
2005	1,600	155
2010	1,771	171
2011	1,830	177

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APEC's overall excess of natural gas production of 75 Bcm (7.3 Bcfd) in 2011 was exported, primarily to Europe. In addition, an active market for natural gas exports and imports exists among the APEC economies, particularly in Asia.

Russia with 182 Bcm (17.6 Bcfd), Canada with 60 Bcm (5.8 Bcfd), Indonesia with 38 Bcm (3.6 Bcfd), and Malaysia with 33 Bcm (3.2 Bcfd) accounted for the great bulk of APEC's natural gas exports, Table EX-3. Japan with 103 Bcm (9.9 Bcfd), Republic of Korea with 47 Bcm (4.6 Bcfd), the U.S. with 38 Bcm (3.6 Bcfd), and China with 28 Bcm (2.6 Bcfd) are the major APEC natural gas importers. Australia, with numerous world-scale LNG export facilities under construction, is poised to join the top ranks of APEC natural gas exporters.

Table EX-3: Major APEC Natural Gas Exporters and Importers, by size (2011)

		Bcm	Bcfd
1. Major Exporters			
▪	**Russia**	182	17.6
▪	**Canada**	60	5.8
▪	**Indonesia**	38	3.6
▪	**Malaysia**	33	3.2
2. Major Importers			
▪	**Japan**	103	9.9
▪	**Republic of Korea**	47	4.6
▪	**U.S.**	38	3.6
▪	**China**	28	2.6

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Tables EX-4 and EX-5 provide more detailed information on natural gas consumption and production, for years 2010 and 2011, by the APEC Economies.

Table EX-4: APEC Economies Natural Gas Consumption and Supply, by size (2010)

	Bcm			Bcf			Bcfd		
	Consumption	Production	Exports/ Imports*	Consumption	Production	Exports/ Imports*	Consumption	Production	Exports/ Imports*
North America	**834**	**817**	**15**	**29,430**	**28,850**	**500**	**80.7**	**79.1**	**1.3**
▪ United States	683	611	72	24,090	21,570	2,520	66.0	59.1	6.9
▪ Canada	83	151	(70)	2,940	5,330	(2,470)	8.1	14.6	(6.8)
▪ Mexico	68	55	13	2,400	1,950	450	6.6	5.4	1.2
South America **	**10**	**9**	**1**	**360**	**320**	**40**	**1.0**	**0.9**	**0.1**
Australia/New Zealand	**30**	**50**	**(20)**	**1,060**	**1,760**	**(700)**	**2.9**	**4.8**	**(1.9)**
China	**108**	**95**	**13**	**3,800**	**3,350**	**450**	**10.4**	**9.2**	**1.2**
Russia	**414**	**589**	**(175)**	**14,610**	**20,790**	**(6,180)**	**40.0**	**56.9**	**(16.9)**
Asia Producing Economies	**132**	**205**	**(73)**	**4,690**	**7,250**	**(2,560)**	**12.9**	**19.9**	**(7.0)**
▪ Indonesia	40	82	(42)	1,420	2,890	(1,470)	3.9	7.9	(4.0)
▪ Malaysia	32	63	(31)	1,130	2,210	(1,080)	3.1	6.1	(3.0)
▪ Other ***	60	60	-	2,140	2,150	(10)	5.9	5.9	-
Asia Non-Producing Economies	**164**	**6**	**158**	**5,780**	**200**	**5,590**	**15.8**	**0.5**	**15.3**
▪ Japan	95	5	90	3,330	170	3,170	9.1	0.5	8.6
▪ Republic of Korea	43	1	42	1,520	30	1,490	4.2	*	4.2
▪ Other ****	26	-	26	930	-	930	2.5	-	2.5
Total	**1,692**	**1,771**	**(81)**	**59,730**	**62,520**	**(2,860)**	**163.7**	**171.3**	**(7.9)**

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*Positive value means imports are used to balance natural gas consumption and production; negative value means excess natural gas production (over consumption) is exported.
**Includes Chile and Peru.
***Includes Brunei, PNG, Philippines, Thailand, and Viet Nam.
****Includes Hong Kong, China; Singapore; and Chinese Taipei

Table EX-5: APEC Economies Natural Gas Consumption and Supply (2011)

	Bcm			Bcf			Bcfd		
	Consumption	Production	Exports/ Imports*	Consumption	Production	Exports/ Imports*	Consumption	Production	Exports/ Imports*
North America	**844**	**855**	**(6)**	**29,770**	**30,170**	**(220)**	**81.6**	**82.7**	**(0.6)**
▪ United States	689	651	38	24,310	23,000	1,310	66.6	63.0	3.6
▪ Canada	86	151	(60)	3,030	5,320	(2,110)	8.3	14.6	(5.8)
▪ Mexico	69	53	16	2,430	1,850	580	6.7	5.1	1.6
South America **	**11**	**13**	**(2)**	**420**	**450**	**(30)**	**1.1**	**1.2**	**(0.1)**
Australia/New Zealand	**30**	**49**	**(19)**	**1,040**	**1,730**	**(690)**	**2.9**	**4.8**	**(1.9)**
China	**131**	**103**	**28**	**4,610**	**3,630**	**980**	**12.6**	**10.0**	**2.6**
Russia	**425**	**607**	**(182)**	**15,000**	**21,430**	**(6,430)**	**41.1**	**58.7**	**(17.6)**
Asia Producing Economies	**129**	**200**	**(71)**	**4,550**	**7,040**	**(2,490)**	**12.5**	**19.3**	**(6.8)**
▪ Indonesia	38	76	(38)	1,340	2,670	(1,330)	3.7	7.3	(3.6)
▪ Malaysia	29	62	(33)	1,010	2,180	(1,170)	2.8	6.0	(3.2)
▪ Other ***	62	62	-	2,200	2,190	10	6.0	6.0	-
Asia Non-Producing Economies	**180**	**3**	**177**	**6,350**	**130**	**6,220**	**17.4**	**0.3**	**17.1**
▪ Japan	106	3	103	3,740	120	3,620	10.2	0.3	9.9
▪ Republic of Korea	47	*	47	1,660	10	1,650	4.6	-	4.6
▪ Other ****	27	-	27	950	-	950	2.6	-	2.6
Total	**1,750**	**1,830**	**(75)**	**61,740**	**64,580**	**(2,660)**	**169.2**	**177.0**	**(7.3)**

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*Positive value means imports are used to balance natural gas consumption and production; negative value means excess natural gas production (over consumption) is exported.
**Includes Chile and Peru.
***Includes Brunei, Thailand, PNG, Philippines, and Viet Nam.
****Includes Chinese Taipei, Singapore and Hong Kong, China.

F. APEC's Unconventional Gas Production

With the emergence of shale gas in the U.S., coalbed methane in Australia, and tight gas in China, unconventional gas is steadily capturing a larger role within APEC. Our survey of unconventional gas shows that in 2011 about 30% (560 Bcm, 54 Bcfd) of APEC's total natural gas production of 1,830 Bcm (177 Bcfd) was from unconventional gas, Table EX-6, with additional detail on Table EX-7.

Table EX-6: APEC's Natural Gas Production (2011)

		Bcm/Yr	Bcfd
Conventional		**1,270**	**123**
Unconventional		**560**	**54**
▪	**Tight Gas**	277	27
▪	**Shale Gas**	217	21
▪	**CBM**	66	6
Total		**1,830**	**177**

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- Tight gas at nearly 277 Bcm/Yr (27 Bcfd) is still the worldwide leader of unconventional gas production, with 239 Bcm (23 Bcfd) in the U.S. and Canada and 36 Bcm (3.5 Bcfd) estimated for China.

- Shale gas at 217 Bcm/Yr (21 Bcfd) is the fastest growing source of unconventional gas production, essentially all from the U.S. and Canada. With active exploration in other APEC Economies, such as Australia, China and Mexico, shale gas may soon become the dominant source of unconventional gas in APEC.

- Coalbed methane, the previous "bright star" of unconventional gas in North America, currently provides 66 Bcm (over 6 Bcfd). Significant CBM production increases are expected from Australia, Indonesia and Russia.

Table EX-7. APEC Economies Annual Unconventional Gas Production, by size (2011)

	Annual Production (Bcm/Yr)				Annual Production (Bcfd)			
	Shale Gas (Bcm/Yr)	CBM (Bcm/Yr)	Tight Gas (Bcm/Yr)	Total (Bcm/Yr)	Shale Gas (Bcfd)	CBM (Bcfd)	Tight Gas (Bcfd)	Total (Bcfd)
North America	**217**	**58**	**241**	**516**	**21.0**	**5.6**	**23.3**	**49.9**
▪ United States	212	50	179	441	20.5	4.8	17.3	42.6
▪ Canada	5	8	61	74	0.5	0.8	5.9	7.2
▪ Mexico	-	-	1	1	-	-	0.1	0.1
South America*	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Australia/New Zealand	**-**	**6**	**-**	**6**	**-**	**0.6**		**0.6**
China	**-**	**2**	**36**	**38**	**-**	**0.2**	**3.5**	**3.7**
Russia	**-**	**-**	**-**	**-**	**-**	**Small**	**-**	**-**
Asia Producing Economies**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Asia Non-Producing Economies***	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**217**	**66**	**277**	**560**	**21.0**	**6.4**	**26.8**	**54.2**

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*Includes Chile and Peru.
**Includes Brunei, Indonesia, Malaysia, PNG, Philippines, Thailand, and Viet Nam.
***Includes Hong Kong, China; Japan; Republic of Korea; Singapore and Chinese Taipei

G. APEC's Unconventional Gas Resources

The currently assessed technically recoverable unconventional gas resource base is large, estimated at 114,700 Bcm (4,048 Tcf), Table EX-8.

Table EX-8. APEC's Technically Recoverable Unconventional Gas Resource Base and 2011 Production

Resource	Bcm	Bcfd
Shale Gas	65,840	2,323
Coalbed Methane	28,700	1,015
Tight Gas	20,100	710
	114,640	**4,048**

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- Shale gas, with 65,840 Bcm (2,323 Tcf) accounts for well over half of the unconventional gas resource base.

- Next is coalbed methane with 28,700 Bcm (1,015 Tcf) of technically recoverable resource. Assessment of the recoverable portion of Russia's in-place CBM resources of 83,700 Bcm (2,950 Tcf) and Indonesia's in-place CBM resources of 16,000 Bcm (453 Tcf) would significantly boost the recoverable CBM resource estimates for APEC.

- Tight gas with 20,160 Bcm (710 Tcf) of recoverable resources has been the least rigorously assessed, even by Australia, Mexico and China, three economies that already produce significant volumes of tight gas.

Currently, China dominates the unconventional gas resource base with 36,000 Bcm (1,271 Tcf), including having the largest volume of technically recoverable shale gas, 25,100 Bcm (886 Tcf), as well as significant volumes of recoverable coalbed methane. China does not have an official estimate for recoverable tight gas resources, although tight gas development and production (estimated at 36 Bcm/yr (3.5 Bcfd)) is underway in the Ordos and Sichuan basins, Table EX-9.

Table EX-9. Technically Recoverable Unconventional Gas Resource Base, Selected APEC Economies, by size

	Shale Gas		Coalbed Methane		Tight Gas		Total	
	(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm)	(Tcf)
China	25,100	886	10,900	385	n/a	n/a	36,000	1,271
U.S.	16,410	579	3,960	140	14,730	520	35,100	1,239
Australia	11,300	398	12,400	439	600	20	24,300	857
Canada	2,550	90	1,270	45	4,830	170	8,650	305
Mexico	8,410	297	110	4	n/a	n/a	8,520	301

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The U.S. has the second largest assessed unconventional gas resource base at 35,100 Bcm (1,239 Tcf), with shale gas and tight gas accounting for nearly 90% of total resource base volumes. However, the official shale gas estimate for the U.S. appears quite conservative and is likely to be increased in coming years.

Australia, with its large coalbed methane resource base of 12,400 Bcm (439 Tcf), a shale gas resource base of 11,300 Bcm (398 Tcf) plus tight gas, ranks third with 24,300 Bcm (857 Tcf) of total recoverable unconventional gas. Canada, with large tight gas resources has 8,650 Bcm (305 Tcf) and Mexico with large shale gas resources has 8,520 Bcm (301 Tcf) of total recoverable unconventional gas. Once its technically recoverable coalbed methane, shale gas and tight gas are assessed, Russia undoubtedly will join APEC's ranks of major unconventional gas resource holders. Table EX-10 provides additional detail on the size of the unconventional gas resource base.

Table EX-10. APEC Economies Technically Recoverable Unconventional Gas Resource Base

	Shale Gas (Bcm)	CBM (Bcm)	Tight Gas (Bcm)	Total (Bcm)	Shale Gas (Tcf)	CBM (Tcf)	Tight Gas (Tcf)	Total (Tcf)
North America	**27,370**	**5,340**	**19,560**	**52,270**	**966**	**189**	**690**	**1,845**
▪ United States	16,410	3,960	14,730	35,100	579	140	520	1,239
▪ Canada	2,550	1,270	4,830	8,650	90	45	170	305
▪ Mexico	8,410	110	n/a	8,520	297	4	n/a	301
South America **	**2,070**	**n/a**	**n/a**	**2,070**	**73**	**n/a**	**n/a**	**73**
Australia/New Zealand	**11,300**	**12,450**	**600**	**24,350**	**398**	**441**	**20**	**859**
China	**25,100**	**10,900**	**n/a**	**36,000**	**886**	**385**	**n/a**	**1,271**
Russia	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Asia Producing Economies	**-**	**10**	**-**	**10**	**-**	**-**	**-**	**-**
▪ Indonesia	-	-	-	-	-	-	-	-
▪ Malaysia	-	-	-	-	-	-	-	-
▪ Other ***	-	10	-	10	-	-	-	-
Asia Non-Producing Economies	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**65,840**	**28,700**	**20,160**	**114,700**	**2,323**	**1,015**	**710**	**4,048**

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*Includes Chile and Peru.
**Includes Brunei, Indonesia, Malaysia, PNG, Philippines, Thailand, and Viet Nam.
***Includes Hong Kong, China; Japan; Republic of Korea; Singapore and Chinese Taipei

H. Outlook for Unconventional Gas

With the completion of the "APEC Unconventional Gas Census", what conclusions can we draw from "Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions?"

- First, the size of the currently assessed technically recoverable unconventional gas resource base within the APEC Economies is large - - 114,700 Bcm (4,048 Tcf). Inclusion of future assessments of recoverable coalbed methane in Russia, Indonesia and Chile and recoverable tight gas in Mexico, China and the Asian APEC Economies would further increase the defined size of the technically recoverable unconventional gas resource base.

- Second, unconventional gas already makes a major contribution to APEC Economies' natural gas production, providing 558 Bcm/yr (54 Bcfd), equal to nearly a third of APEC's total natural gas production of 1,831 Bcm (177 Bcfd) last year (2011).

- Third, the outlook for future production from unconventional gas is highly promising, as summarized below:

  − North America (U.S., Canada and Mexico) expects unconventional gas production to increase from 516 Bcm (50 Bcfd) last year (2011) to 611 Bcm (59 Bcfd) by 2020, and further to 799 Bcm (77 Bcfd) by 2035, Table EX-11.

Table EX-11: Outlook for North American Unconventional Gas Production

	2011		2020		2035	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
U.S.	441	42.6	497	48.0	610	59.0
Canada	74	7.2	95	9.2	134	13.0
Mexico*	1	0.1	19	1.9	55	5.4
Total	**516**	**49.9**	**611**	**59.1**	**799**	**77.4**

Sources: EAI AEO 2012; NEB 2011; Pemex 2012. JAF2013_002.XLS

- Australia projects its total natural gas production to reach 212 Bcm (20 Bcfd) by 2035, up from 49 Bcm (5 Bcfd) in 2011, with contribution from both conventional and unconventional gas. Assuming that unconventional gas (particularly coalbed methane) accounts for the bulk of the natural gas production growth, we estimate Australia will produce 93 Bcm (9 Bcfd) of unconventional gas in 2035.

- China has set forth ambitious official goals for future shale gas and coalbed methane production, totaling 120 Bcm (12 Bcfd) by 2020. Our judgment, given the relative complexity of China's geology, is that shale gas and coalbed methane production will grow moderately to reach 42 Bcm (4 Bcfd) by 2020. Adding an estimated 52 Bcm (5 Bcfd) of tight gas production, China's unconventional gas production would reach 94 Bcm (9 Bcfd) by year 2020 and continue to grow to 217 Bcm (21 Bcfd) by year 2035, up from 38 Bcm (3.7 Bcfd) today.

- Russia has only just started its exploration and assessment of unconventional gas resources, first targeting coalbed methane. Expectations are that annual coalbed methane production from one of its large coal basins, Kuzbass, will reach 4 Bcm (0.4 Bcfd) by 2020 and 21 Bcm (2 Bcfd) in the longer-term. Russia's large-scale gas resources and tight gas would add substantial additional production.

- Indonesia, with its large, defined CBM resource and its potentially large but still undefined shale gas resource, could provide 7 Bcm (0.7 Bcfd) of unconventional gas production by 2020 and 62 Bcm (6 Bcfd) by 2035.

Numerous other APEC Economies, such as Chile, New Zealand, Peru, Philippines, Thailand and Viet Nam (among others) hold further promise for future production of unconventional gas.

Overall unconventional gas production within the APEC economies is projected to increase from 560 Bcm (54 Bcfd) in 2011 to 764 Bcm (74 Bcfd) in 2020 and to 1,299 Bcm (125 Bcfd) in 2035, as summarized on Tables EX-12 and EX-13.

Table EX-12. APEC Economies Natural Gas Consumption and Supply (Bcm/Yr)

	2011			2020			2035		
	Shale	Coalbed Methane	Tight	Shale	Coalbed Methane	Tight	Shale	Coalbed Methane	Tight
North America	**217**	**58**	**241**	**310**	**56**	**246**	**470**	**54**	**275**
▪ United States	212	50	179	274	51	172	386	50	174
▪ Canada	5	8	61	19	4	72	41	2	91
▪ Mexico	-	-	1	17	1	2	43	2	10
South America	**-**	**-**	**-**	**2**	**1**	**0**	**14**	**3**	**0**
▪ Chile	-	-	-	1	1	-	4	3	-
▪ Peru	-	-	-	1	-	-	10	-	-
Australia/New Zealand	**-**	**6**	**-**	**7**	**29**	**2**	**37**	**56**	**10**
▪ Australia	-	6	-	5	28	2	31	52	10
▪ New Zealand	-	-	-	2	1	-	6	4	-
China	**-**	**2**	**36**	**21**	**21**	**52**	**103**	**31**	**83**
Russia	**-**	**-**	**-**	**5**	**4**	**1**	**31**	**21**	**10**
Asia Producing Economies	**-**	**Small**	**-**	**1**	**4**	**2**	**34**	**40**	**27**
▪ Brunei	-	-	-	-	-	-	2	1	3
▪ Indonesia	-	-	-	1	4	2	21	31	10
▪ Maylasia	-	-	-	-	-	-	4	-	4
▪ Phillipines	-	-	-	-	-	-	-	3	1
▪ Thailand	-	-	-	-	-	-	5	2	4
▪ Viet Nam	-	-	-	-	-	-	2	3	5
Asia Non-Producing Economies	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**217**	**66**	**277**	**346**	**115**	**303**	**689**	**205**	**405**

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Table EX-13. APEC Economies Natural Gas Consumption and Supply (Bcfd)

	2011			2020			2035		
	Shale	Coalbed Methane	Tight	Shale	Coalbed Methane	Tight	Shale	Coalbed Methane	Tight
North America	**21.0**	**5.6**	**23.3**	**29.9**	**5.4**	**23.8**	**45.6**	**5.2**	**26.6**
▪ United States	20.5	4.8	17.3	26.5	4.9	16.6	37.4	4.8	16.8
▪ Canada	0.5	0.8	5.9	1.8	0.4	7.0	4.0	0.2	8.8
▪ Mexico	-	-	0.1	1.6	0.1	0.2	4.2	0.2	1.0
South America	**-**	**-**	**-**	**0.2**	**0.1**	**-**	**1.4**	**0.3**	**-**
▪ Chile	-	-	-	0.1	0.1	-	0.4	0.3	-
▪ Peru	-	-	-	0.1	-	-	1.0	-	-
Australia/New Zealand	**-**	**0.6**	**-**	**0.7**	**2.8**	**0.2**	**3.6**	**5.4**	**1.0**
▪ Australia	-	0.6	-	0.5	2.7	0.2	3.0	5.0	1.0
▪ New Zealand	-	-	-	0.2	0.1	-	0.6	0.4	-
China	**-**	**0.2**	**3.5**	**2.0**	**2.0**	**5.0**	**10.0**	**3.0**	**8.0**
Russia	**-**	**-**	**-**	**0.5**	**0.4**	**0.1**	**3.0**	**2.0**	**1.0**
Asia Producing Economies	**-**	**-**	**-**	**0.1**	**0.4**	**0.2**	**3.3**	**3.9**	**2.1**
▪ Brunei	-	-	-	-	-	-	0.2	0.1	0.3
▪ Indonesia	-	-	-	0.1	0.4	0.2	2.0	3.0	1.0
▪ Maylasia	-	-	-	-	-	-	0.4	-	0.4
▪ Phillipines	-	-	-	-	-	-	-	0.3	-
▪ Thailand	-	-	-	-	-	-	0.5	0.2	0.4
▪ Viet Nam	-	-	-	-	-	-	0.2	0.3	-
Asia Non-Producing Economies	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total	**21.0**	**6.4**	**26.8**	**33.4**	**11.1**	**29.3**	**66.9**	**19.8**	**38.7**

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I. Detailed Projections of Unconventional Gas Productivity APEC Economy

This section of the APEC Unconventional Gas Census Report sets forth: (1) our assessment of the amounts of unconventional gas, by type, that could be practically and economically produced in each APEC economy, and (2) the level of activity and support for unconventional gas in each APEC economy, providing the rationale for our estimates of commercial development and time frame for availability.

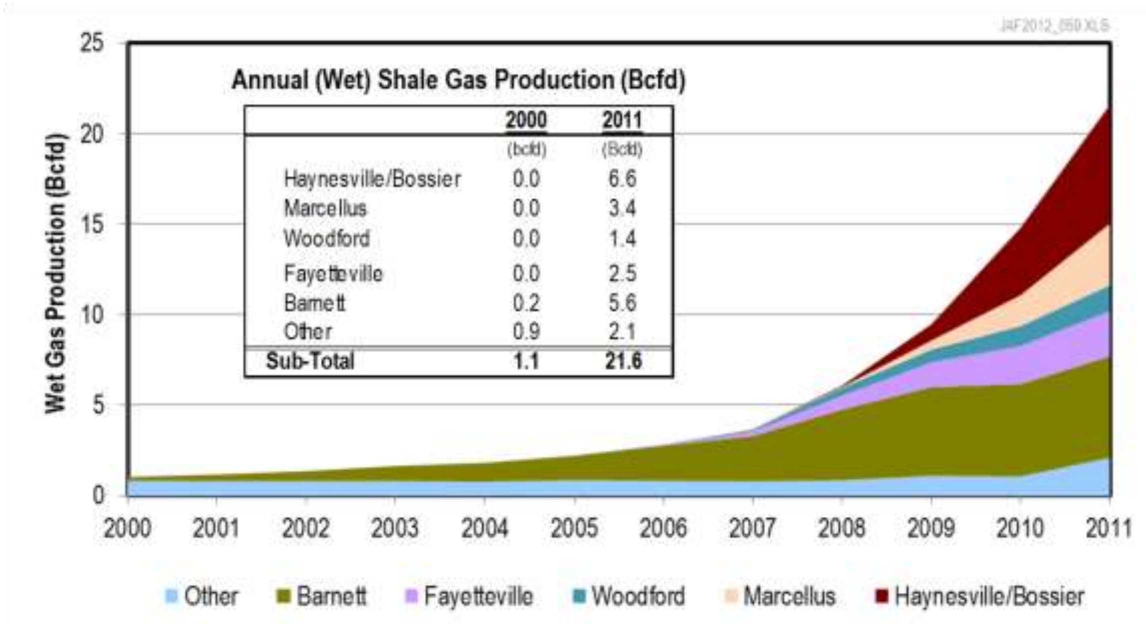
The assessment of the potential for unconventional gas production in each APEC economy uses as its foundation the unconventional gas data assembled and documented in the Census Report for each APEC economy. Of particular value are the census data on: (1) the size and quality of the unconventional gas resource base; (2) the current levels of unconventional gas production; (3) the level of current unconventional gas exploration activity; and (4) the level of support, in terms of leasing regulations and infrastructure, available for unconventional gas in each APEC economy.

Section 1. North America

United States. Driven by the recent “explosion” in shale gas development, the outlook for the U.S. is for rapid growth of unconventional gas production. Production from shale gas formations has increased dramatically in the past eleven years from a base of just over 1 Bcfd in 2000 to nearly 22 Bcfd in 2011, Figure EX-1. Much of the activity and growth in shale gas production has been from the “Big Four” shale gas plays - - the Barnett, Fayetteville, Haynesville/Bossier and Marcellus.

Based on the latest projections by the U.S. Energy Information Administration, as set forth in AEO 2012, the outlook for U.S. unconventional gas production is for steady growth from 441 Bcm (42.6 Bcfd) in 2011 to 610 Bcm (59.0 Bcfd) in 2035, as further defined by resource type, in Table EX-14.

Figure EX-1. U.S. Shale Gas Production Has Increased Dramatically in the Past Decade



Note that the shale gas production values on Figure I-4 are shown for wet gas production (which includes natural gas liquids). The wet gas production value of 21.6 Bcfd becomes 20.5 Bcfd of dry gas, after extraction of NGLs.

Source: Advanced Resources International (2012)

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Table EX-14. Outlook for U.S. Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	212	20.5	50	4.8	179	17.3	441	42.6
2012	217	21.0	54	5.2	173	16.7	444	42.9
2015	238	22.6	52	5.0	172	16.7	462	44.3
2020	274	26.5	51	4.9	172	16.6	497	48.0
2025	319	30.9	50	4.8	175	16.9	544	52.6
2035	386	37.4	50	4.8	174	16.8	610	59.0

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Canada. Canada's Western Sedimentary Basin holds a particularly large volume of unconventional gas, most of which is already under active development from plays such as the Horn River Shale, Montney Resource Play and numerous tight gas and coalbed methane deposits.

Based on the latest projections by the National Energy Board, the outlook for Canadian unconventional gas production is for growth from 74 Bcm (7.2 Bcfd) in 2011 to 134 Bcm (13.1 Bcfd) by 2035, as further defined by resource type in Table EX-B.

Table EX-15. Outlook for Canadian Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight*		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	5	0.5	8	0.8	61	5.9	74	7.2
2012	6	0.6	7	0.7	61	5.9	74	7.2
2015	11	1.1	6	0.6	61	5.9	78	7.6
2020	19	1.8	4	0.4	72	7.0	95	9.2
2025	27	2.6	3	0.3	83	8.0	113	10.9
2035	41	4.0	2	0.2	91	8.8	134	13.0

*Includes Montney Resource Play

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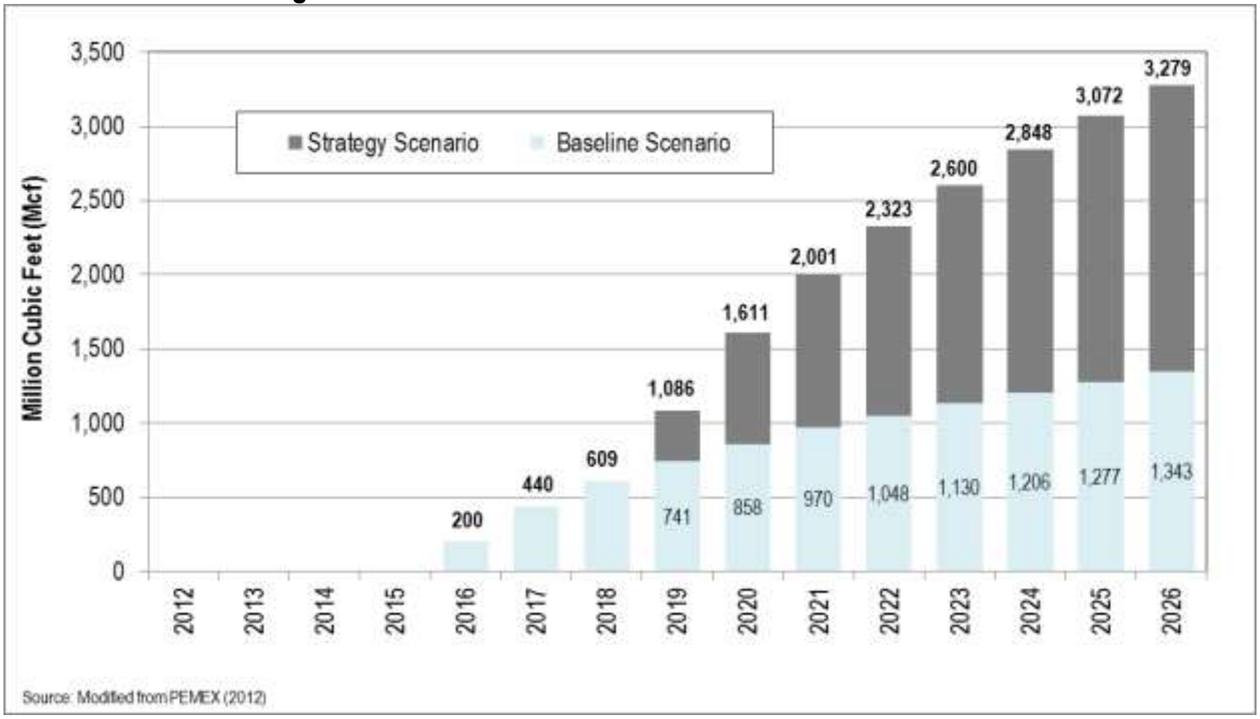
Mexico. Even though Mexico has only recently begun to appraise and develop its unconventional gas, particularly its shale gas, Mexico has set forth ambitious targets for the next two decades. At the end of 2012 PEMEX announced that it has made a major shale gas discovery in northeastern Mexico and plans to drill 20 to 25 shale gas wells in 2013. In addition, Mexico has attractive tight gas deposits under development in the Burgos Basin, although little public data is available on this activity.

Based on information from the Ministry of Energy and PEMEX, the outlook for Mexico is for up to 17 Bcm (1.6 Bcfd) of shale gas production by 2020 and up to 32 Bcm (3.1 Bcfd) by 2025, Figure EX-2. Tight gas and coalbed methane would add to these totals.

Figure EX-2. Outlook for Mexico's Shale Gas Production*



*Mexico's unconventional gas production data are from the "Strategy Scenario" for shale gas and do not include CBM or tight gas; Mexico's unconventional gas production estimate for 2035 is set at expectations of shale gas production in 2026 (the last year of projected data.)

Table EX-16. Outlook for Mexico Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	1	0.1	1	0.1
2012	-	-	-	-	1	0.1	1	0.1
2015	-	-	-	-	2	0.2	2	0.2
2020	17	1.6	1	0.1	2	0.2	20	1.9
2025	32	3.1	2	0.2	5	0.5	39	3.8
2035	43	4.2	2	0.2	10	1.0	55	5.4

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Section 2. South America

Chile. While no rigorous assessments have been performed for Chile's unconventional natural gas resources, geologic work by Advanced Resources indicates significant potential for coalbed methane, shale gas and potentially tight gas in the Magallanes Basin. ENAP, Chile's national oil and gas company, has drilled several coalbed methane appraisal wells in the Magallanes Basin and is planning to drill two shale gas exploration wells in this basin. Several smaller companies are also exploring for CBM and shale gas in Chile. Our outlook for Chile is for modest, steady growth in production of coalbed methane and shale gas, Table EX-16.

Table EX-16. Outlook for Chile Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	1	0.1	1	0.1	-	-	2	0.2
2025	2	0.2	2	0.2	-	-	4	0.4
2035	4	0.4	3	0.3	-	-	7	0.7

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Peru. Peru's government has been aggressively pursuing foreign investment and exploration, bidding out many of its onshore exploration blocks. With an estimated 2,070 Bcm (73 Tcf) of technically recoverable shale gas, unconventional resources have the potential to play a large role in Peru's push to expand natural gas production, increase exports and provide energy for its growing energy-intensive mining industry. However, this potential is still many years in the future as much of Peru's basins have yet to be rigorously explored for hydrocarbons, Table EX-17.

Table EX-17. Outlook for Peru Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	1	0.1	-	-	-	-	1	0.1
2025	5	0.5	-	-	-	-	5	0.5
2035	10	1.0	-	-	-	-	10	1.0

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As a note of comparison, the IEA in their Golden Rules Case projects that about 5 Bcm (0.5 Bcfd) of shale gas could be produced in Peru by 2035.

Section 3. Australia/New Zealand

Australia. With its world-class coalbed methane resources plus significant shale gas deposits, the outlook for unconventional gas production for Australia is strong.

Coalbed methane or coalseam gas (CSG) development, which began in Australia in 1976, has increased greatly in the past ten years, primarily from the high-rank Permian coalbeds in the Bowen Basin and the lower rank Jurassic coals in the Surat Basin. In addition, exploratory wells are being drilled for shale gas in the Cooper, Georgina, Canning and numerous other basins. Finally, tight gas is being produced from the Cooper and Perth basins.

With the pending completion of three world-scale LNG projects (in 2015-2016) and several others on the drawing board, we anticipate significant growth in coalbed methane as well as increased volumes of shale gas and tight gas production in future years, Table EX-18.

Table EX-18. Outlook for Australia Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	6	0.6	-	-	6	0.6
2012	Small	Small	8	0.8	Small	Small	8	0.8
2015	1	0.1	10	1.0	Small	Small	11	1.1
2020	5	0.5	28	2.7	2	0.2	35	3.4
2025	10	1.0	42	4.0	5	0.5	57	5.5
2035	31	3.0	52	5.0	10	1.0	93	9.0

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As a note of comparison, the IEA in their Golden Rules Case projects unconventional gas production for Australia of 60 Bcm (5.8 Bcfd) in 2020 and 110 Bcm (10.7 Bcfd) in 2035.

New Zealand. Coalbed methane (CSG) exploration began in New Zealand in the 1980s, leading to the discovery of nearly 2 Tcf of coal seam gas. Currently, eight companies are active in CSG exploration, holding 17 petroleum permits. In addition, exploration is underway in the East Coast Basin for shale oil, associated shale gas and potentially free shale gas in the deeper portion of the basin. No estimates exist for tight gas resources of New Zealand. Our outlook is for modest but steady growth in unconventional gas production for New Zealand, Table EX-19.

Table EX-19. Outlook for New Zealand Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	Small	Small	-	-	Small	Small
2015	Small	Small	Small	Small	-	-	Small	Small
2020	2	0.2	1	0.1	-	-	3	0.3
2025	3	0.3	2	0.2	-	-	5	0.5
2035	6	0.6	4	0.4	-	-	10	1.0

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Section 4. China

China has large unconventional gas resources and an active program of shale gas, coalbed methane and tight gas development. Currently, China's commercially most developed unconventional gas resource is tight gas, with large-scale production from the Ordos and Sichuan basins. Coalbed methane, while considered highly promising in the 1990's, has lagged behind its expected development pace due to geologic and reservoir challenges. Shale gas, currently in the earliest phases of exploration, has potential to become a major gas supply source for China. However, shale gas output likely will grow more slowly than anticipated as industry adapts gas extraction technology to China's complex reservoir settings and gains operating experience from its overseas joint ventures.

While shale gas development is just starting, China' Ministry of Land and Mineral Resources (MLR) projects rapid growth in shale gas production for the rest of this decade. China's coalbed methane industry has been slow to develop, reaching 2 Bcm (0.2 Bcfd) in 2012 after nearly 20 years of aggressive exploration. We estimate China's current tight gas production (which may include some conventional gas production) at 35 Bcm (3.5 Bcfd), primarily from the Ordos and Sichuan basins. Our outlook is for China's unconventional gas production, currently at about 38 Bcm (3.7 Bcfd) will reach 94 Bcm (9 Bcfd) by year 2020 and continue to increase thereafter, Table EX-20.

Table EX-20. Outlook for China's Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	2	0.2	36	3.5	38	3.7
2012	Small	Small	2	0.2	36	3.5	38	3.7
2015	10	0.9	5	0.5	38	3.7	53	5.1
2020	21	2.0	21	2.0	52	5.0	94	9.0
2025	41	4.0	21	2.0	62	6.0	124	12.0
2035	103	10.0	31	3.0	83	8.0	217	21.0

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As a note of comparison, the IEA in their Golden Rules Case projects unconventional gas production for China of 110 Bcm (10.6 Bcfd) in 2020 and 390 Bcm (37.7 Bcfd) in 2035.

Section 5. Russia

With its large resources of conventional gas, the pursuit of unconventional gas has not been a priority for Russia. However, recently Russia has expressed interest in evaluating its potentially large shale gas deposits in the Timan-Pechora and Western Siberia basins. In addition Gazprom has launched a small CBM pilot in the Kuznets Coal Basin, has entered into an agreement with YPF to pursue shale oil and gas in Argentina, and has begun to increasingly rely on hydraulic fracturing to accelerate the production from its conventional and "near-tight" gas fields.

Given the high geological and reservoir quality of its shale and coalbed methane resources, we project significant long-term, unconventional gas production for Russia, Table EX-21.

Table EX-21. Outlook for Russia's Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	Small	Small	-	-	Small	Small
2015	1	0.1	1	0.1	-	1.0	2	1.2
2020	5	0.5	4	0.4	1	0.1	10	1.0
2025	10	1.0	10	1.0	5	0.5	25	2.5
2035	31	3.0	21	2.0	10	1.0	62	6.0

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As a note of comparison, the IEA in their Golden Rules Case projects unconventional gas production for Russia of 29 Bcm (2.8 Bcfd) in 2020 and 47 Bcm (4.5 Bcfd) in 2035.

Section 6. Asian Natural Gas Producing APEC Economies

Seven of the Asian Economies - - Brunei, Indonesia, Malaysia, Papua New Guinea (PNG), Philippines, Thailand and Viet Nam - - currently produce small to significant volumes of natural gas. However, with the exception of Indonesia, these conventional natural gas producing APEC Economies do not currently produce unconventional gas. In our view, a handful of these seven APEC economies have moderately to highly favorable geologic conditions for unconventional and gas resources and production, as further discussed below.

Brunei. The technical literature reports that Shell has been developing tight gas deposits offshore Brunei with hydraulic fracturing. However, our assessment is that these offshore deposits have conventional gas levels of permeability, greater than the 0.1 md level of permeability used as the standard in the U.S.

Our initial geologic review suggests that there may be relatively small but prospective tight gas deposits in the Berakas, Badas and Belait synclines located onshore. Brunei's identified onshore coal deposits are relatively thin, areally limited and low-rank lignite. However, it is possible that thicker coals are present in the onshore troughs such as the Berakas Syncline. No publically available information exists on the nature of shale gas deposits in Brunei although shales are not an important source rock for conventional gas in Brunei. Given the limited data, we judge the potential for unconventional gas production in Brunei to be highly speculative (Table EX-22).

Table EX-22. Outlook for Brunei Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-
2025	1	0.1	-	-	1	0.1	2	0.2
2035	2	0.2	1	0.1	3	0.3	6	0.6

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Indonesia. Indonesia has significant coalbed methane resources, located mainly in the sedimentary basins on the islands of Sumatra and Borneo. We estimate current CBM production to be 5 MMcfd from the Sanga-Sanga PSC in East Kalimatan with a production target of 400 MMcfd for 2020. In addition, Indonesia has geologically attractive shale gas resources in the Barito and Kutei basins of Kalimantan and the Central and South Sumatra basins as well as tight gas prospects in the North and South Sumatra basins. (Note that Indonesia's standard for "tight gas" is less than 5 to 10 md.)

Based on very preliminary data, we project the following levels of unconventional gas production, by type, for Indonesia, recognizing that our projections for shale gas and tight gas are speculative, Table EX-23.

Table EX-23. Outlook for Indonesia's Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	Small	Small	-	-	Small	Small
2015	-	-	1	0.1	-	-	1	0.1
2020	1	0.1	4	0.4	2	0.2	7	0.7
2025	2	0.2	10	1.0	3	0.3	15	1.5
2035	21	2.0	31	3.0	10	1.0	62	6.0

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As a note of comparison, the IEA in their Golden Rules Case projects unconventional gas production for Indonesia of 2 Bcm (0.2 Bcfd) in 2020 and 57 Bcm (5.5 Bcfd) in 2035 without data for type of unconventional gas.

Malaysia. No publically available data or studies exist on the unconventional gas resources of Malaysia. Onshore peninsular Malaysia is underlain by crystalline basement with limited oil and gas potential, but eastern Malaysia in northern Bornea has onshore portions of adjacent, prolific offshore sedimentary basins. Given the lack of data, we judge the potential for unconventional gas production in Malaysia to be highly speculative (Table EX-24).

Table EX-24. Outlook for Malaysia Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-
2025	2	0.2	-	-	2	0.2	4	0.4
2035	4	0.4	-	-	4	0.4	8	0.8

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Papua New Guinea (PNG). While unconventional gas resources have not yet been defined in PNG, a series of onshore hydrocarbon basins exist in PNG that may be prospective for shale gas or CBM. Given the PNG's abundant conventional gas deposits and the limited pace of leasing and development to date, we do not project any substantial volumes of unconventional gas production for PNG at this time.

Philippines. The best defined unconventional gas resource in the Philippines is coalbed methane in the sub-bituminous coals of the Mindoro basin on Semirara Island. The geologic setting and reservoir quality of the onshore shale gas and tight gas of the Philippines is reported to be quite poor. We project a modest volume of long-term, speculative CBM production for the Philippines, able EX-25.

Table EX-25. Outlook for Philippines Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-
2025	-	-	1	0.1	-	-	1	0.1
2035	-	-	3	0.3	-	-	3	0.3

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Thailand. Thailand has four main onshore sedimentary basins and regions with the potential for unconventional gas resources - - Khorat Plateau, Northern Inter-Montane Basin, Central Plain and Southern Plains. Based on internal geological review, we judge the shale gas deposits in the Khorat Plateau to be the most promising followed by the tight sandstones in the Khorat and Central/Southern Plains and modest size CBM deposits in the Northern Inter-Montane Basin.

In 2011. The Petroleum Authority of Thailand signed a MOU with Statoil to study the unconventional (and conventional) gas resources of Thailand and a small lease block has been awarded for CBM exploration in southern Thailand. Based on this initial but still limited activity, we project the following volumes of speculative unconventional gas production for Thailand, Table EX-26.

Table EX-26. Outlook for Thailand Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-
2025	2	0.2	2	0.2	2	0.2	6	0.6
2035	5	0.5	2	0.2	4	0.4	11	1.1

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Viet Nam. While Viet Nam has prolific offshore sedimentary basins, most of its onshore is underlain by crystalline rocks with little hydrocarbon potential. However, several small Tertiary-age “pull-apart” basins are located in northern Viet Nam, notably the Hanoi Basin which has potential for CBM. No publically available data exist for shale gas or tight gas resource at this time although the Hanoi Basin appears to have organically rich shales. A small CBM exploration effort was recently conducted in the Hanoi Basin by Dart Energy and Keeper Resources. Assuming eventual success, we project the following volumes of speculative CBM and shale gas production for Viet Nam, Table EX-27.

Table EX-27. Outlook for Viet Nam Unconventional Gas Production

Years	Shale		Coalbed Methane		Tight		Total	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
2011	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-
2025	1	0.1	2	0.2	-	-	3	0.3
2035	2	0.2	3	0.3	-	-	5	0.5

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Section 7. Asian Natural Gas Non-Producing Economies

Five of the APEC Economies - - Japan, Southern Republic of Korea, Chinese Taipei, Singapore and Hong Kong, China - - have little to no indigenous natural gas production and the geologic conditions essential for favorable unconventional gas exploration do not appear to be present. As such, we do not project any unconventional gas production from these five APEC Economies.

I. Organization of the Main Report

Part I of the report, *"APEC Unconventional Gas Census: Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO2 Emissions",* is organized into seven sections, as follows.

Section 1. North American, including United States, Canada and Mexico

Section 2. South America, including Chile and Peru

Section 3. Australia/New Zealand

Section 4. China

Section 5. Russia

Section 6. Asia Natural Gas Producing Economies, including Brunei, Indonesia, Malaysia, PNG, Philippines, Thailand, and Viet Nam

Section 7. Asia Natural Gas Non-Producing Economies, including Hong Kong, China; Japan; Republic of Korea; Singapore; and Chinese Taipei

Each section provides an overview for the region (where appropriate) as well as individual chapters for each natural gas producing economy.

APEC Unconventional Natural Gas Census Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 1. NORTH AMERICAN UNCONVENTIONAL GAS

SECTION 1.
NORTH AMERICAN APEC ECONOMIES
UNCONVENTIONAL GAS

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SECTION 1. OVERVIEW: NORTH AMERICAN UNCONVENTIONAL GAS

A. Introduction

Each of the three North American APEC economies - - Canada, Mexico and the US- - has pursued quite separate and distinct pathways on unconventional gas development. Yet, for each economy the future outlook for this increasingly important source of natural gas supply appears to be equally promising.

- Canada adopted and further customized unconventional gas completion and production technology to meet the requirements of its special coalbed methane and tight gas reservoir conditions. More recently, Canada has identified and begun to develop its geologically favorable shale gas resources in the Horn River and Liard basins of northwest British Columbia.

- Mexico, while already active in tight gas development in the Burgos Basin, is starting to explore its rich resources of shale gas in its numerous east coast hydrocarbon basins. Mexico has a most favorable outlook for shale gas, with expectations of significant production in the coming decade.

- The U.S. is the birthplace of unconventional gas, starting in the 1980s with the pursuit of tight gas in numerous Rocky Mountain Cretaceous-age basins. This was followed in the 1990s with the completion of high productivity coalbed methane wells in the San Juan Basin that helped launch the worldwide coalbed methane hunt. The most recent U.S. technological accomplishment has been “breaking the technical code” for deep shale gas locked in the Fort Worth Basin’s Barnett Shale and then extending this technological breakthrough to numerous other shale gas basins.

Currently, the overall North American natural gas market is essentially in balance. Last year (2011), the three North American economies consumed 844 Bcm (29,770 Bcf) of natural gas equavalent to 81.6 Bcfd. These three economies produced 855 Bcm (30,170 Bcf) of natural gas equal to 82.7 Bcfd, Table 1-1. A comprehensive grid of natural gas pipelines transports natural gas from Canada to the U.S. on the north and from the U.S. to Mexico in the south. North America's natural gas consumption and supply have both increased in recent years.

Table 1-1. North American Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
1. United States							
Consumption		683	24,090	66.0	689	24,310	66.6
Supply							
▪	Marketed Production (Dry)	611	21,570	59.1	651	23,000	63.0
▪	Net Exports/Imports	72	2,520	6.9	38	1,310	3.6
2. Canada							
Consumption		83	2,940	8.1	86	3,030	8.3
Supply							
▪	Marketed Production (Dry)	151	5,330	14.6	151	5,320	14.6
▪	Net Exports/Imports	(70)	(2,470)	(6.8)	(60)	(2,110)	(5.8)
3. Mexico							
Consumption		68	2,400	6.6	69	2,430	6.7
Supply							
▪	Marketed Production (Dry)	55	1,950	5.4	53	1,850	5.1
▪	Net Exports/Imports	13	450	1.2	16	580	1.6
4. Total							
Consumption		**834**	**29,430**	**80.7**	**844**	**29,770**	**81.6**
Supply							
▪	**Marketed Production (Dry)**	**817**	**28,850**	**79.1**	**855**	**30,170**	**82.7**
▪	**Net Exports/Imports**	**15**	**500**	**1.3**	**(6)**	**(220)**	**(0.6)**

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B. Unconventional Gas Resources and Production

Each of the three North American economies has a rich base of unconventional gas resources (proved reserves plus undiscovered "unproven" resources), Table 1-2. Based on Mexico's recent announcements, each economy now also has an active program of unconventional gas exploration and production. Much of the undeveloped unconventional gas resource resides in the host of shale gas basins illustrated on Figure 1-1.

Table 1-2. Official Estimates of North American Unconventional Gas Resources

Resource		Technically Recoverable		Annual Production (2011)	
		(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
1. United States (1)					
▪	Shale Gas	16,410	579	212	20.5
▪	CBM	3,960	140	50	4.8
▪	Tight Gas	14,730	520	179	17.3
	TOTAL	**35,100**	**1,239**	**441**	**42.6**
2. Canada (2)					
▪	Shale Gas*	2,550	90	5	0.5
▪	CBM	1,270	45	8	0.8
▪	Tight Gas**	4,830	170	60	5.8
	TOTAL	**8,650**	**305**	**73**	**7.1**
3. Mexico (3)					
▪	Shale Gas	8,410	297	just starting	just starting
▪	CBM	110	4	n/a	n/a
▪	Tight Gas	n/a	n/a	n/a	n/a
	TOTAL	**8,520**	**301**		
4. North America Total					
▪	Shale Gas	27,370	966	217	21.0
▪	CBM	5,340	189	58	5.6
▪	Tight Gas	19,560	690	239	23.1
	TOTAL	**52,270**	**1,845**	**514**	**49.7**

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*Does not include recent estimates of 48 Tcf (1,360 Bcm) of recoverable shale gas from the Liard Basin. **Includes Montney tight gas of 3,060 Bcm (108 Tcf). (1) Assumptions to AEO 2012 (U.S. EIA, August, 2012). (2) Canada's Energy Future: Energy Supply and Demand Projections to 2035 (December, 2011). (3) Investor presentation from PEMEX, March 2012.

Figure 1-1. North American Shale Gas Basins

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

- The U.S. has a 29,090 Bcm (1,027 Tcf) undiscovered (unproved) unconventional gas resource base, plus 6,010 Bcm (212 Tcf) of proved unconventional gas reserves for a total remaining unconventional gas resource base of 35,100 Bcm (1,239 Tcf). Shale gas, conservatively estimated at 16,410 Bcm (579 Tcf), accounts for about half of the unconventional gas resource base. Unconventional gas production of 441 Bcm equal to 42.6 Bcfd in 2011 provided 68% of total U.S. natural gas supply. The identification of numerous emerging shale gas basins and liquids-rich tight gas plays, such as the Utica Shale and the Granite Wash, will further add to U.S. unconventional gas resources and productive capacity.

- Canada has 8,650 Bcm (305 Tcf) of proved and undiscovered technically recoverable unconventional gas resources including a shale gas resource base of 2,550 Bcm (90 Tcf). Unconventional gas production (in 2011) of 73 Bcm, equal to 7.1 Bcfd, provided 49% of Canada's overall natural gas supply. Unconventional gas is expected to provide an increasing share of Canada's future natural gas production as the geologically favorable shale gas resources in the Horn River and Liard basins and the tight gas sands in the massive Montney Resource Play are further developed.

- Mexico recently assessed its shale gas resources, estimating a "most likely" 8,410 Bcm (297 Tcf) recoverable resource, with a range of 4,250 to 13,000 Bcm (150 to 459 Tcf). While just starting, Mexico has proposed an ambitious program of shale gas development. Mexico also has an estimated 110 Bcm (4 Tcf) of potentially recoverable coalbed methane, with much of this resource located in the Sabinas Basin. Finally, Mexico has substantial tight gas resources, although no publicly reported assessment or production data are available.

In addition to the unconventional gas resource estimates provided by official government sources shown on Table 1-2, a separate and independent assessment of the shale gas resources of Canada and Mexico has been prepared by Advanced Resources International for the U.S. Energy Information Administration in 2011.[1] The in-place and technically recoverable shale gas resources from this "landmark study" (as characterized by the International Energy Agency) are shown on Table 1-3.

For Canadian shale gas, the EIA/ARI study estimates a technically recoverable resource that is about four times higher (10,060 Bcm; 355 Tcf) than the current Canadian official estimate of 2,550 Bcm (90 Tcf) as shown on Table 1-2. For Mexican shale gas, the EIA/ARI study has a technically recoverable resource that is two times higher (19,290 Bcm; 681 Tcf) than the current Pemex official estimate of 8,410 Bcm (297 Tcf).

---

[1] "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", sponsored by the U.S. Energy Information Administration (April, 2011) prepared by Advanced Resources International.

Table 1-3. Other Estimates of North America Unconventional Gas Resources [1]

		Gas In-Place		Technically Recoverable	
		(Bcm)	(Tcf)	(Bcm)	(Tcf)
1. Canada					
▪	Shale Gas	37,570	1,326	10,060	355
▪	CBM	14,160	500*	n/a	n/a
2. Mexico					
▪	Shale Gas	67,030	2,366	19,290	681
▪	CBM	n/a	n/a	170	6**

[1]Shale gas resource estimates from the U.S. EIA/Advanced Resources Int'l study "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States (April, 2011).
*In-place CBM resource for Canada estimates by the Alberta Geological Survey.
**Technically recoverable CBM resource estimates for Mexico by U.S. EPA's Coalbed Methane Outreach Program (CMOP).

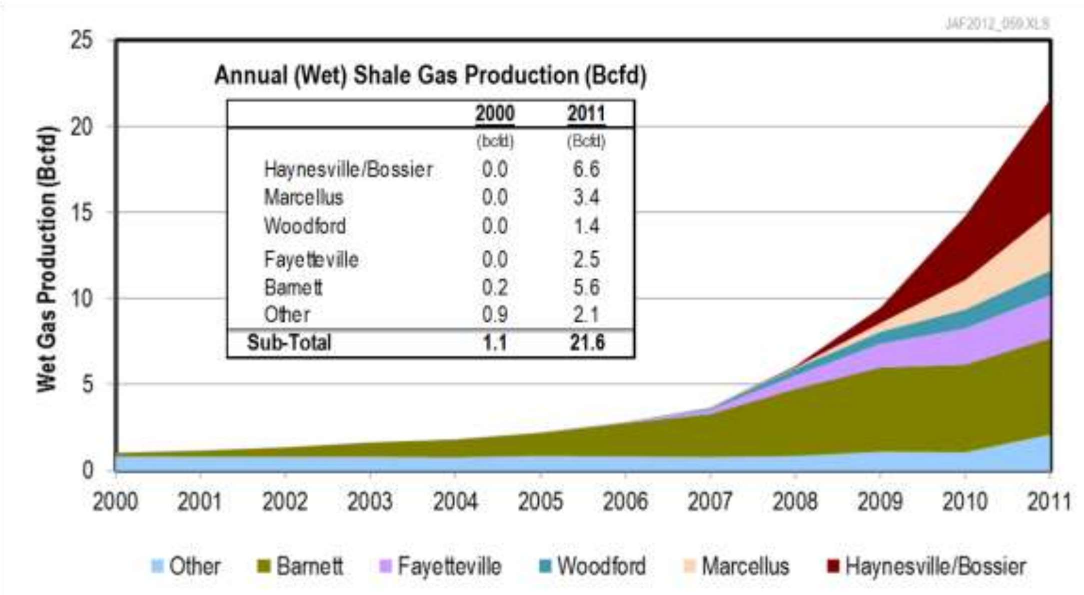
C. Notable Recent Unconventional Gas Activity

In the U.S., much of the recent unconventional gas activity targets shale gas development. The production of shale gas, shown for years 2000 through 2011 on Figure 1-2, reached 21.6 Bcfd (wet) (20.5 Bcfd dry) in 2011 and is expected to average about 25 Bcfd (dry marketed production) in 2012.

For the longer term, as set forth by EIA in AEO 2012, future U.S. shale gas production (dry) is projected to significantly grow, reaching 37.4 Bcfd in year 2035. Given the strong base of activity and large resource base, our view (Advanced Resources International) is that both near- and longer-term shale gas production will be higher than set forth in EIA's AEO 2012.*

*The recently issued AEO 2013 Early Release projected substantially higher U.S. shale gas production of 42 Bcfd in year 2035.

Figure 1-2. U.S. Shale Gas Production Has Increased Dramatically in the Past Decade



Note that the shale gas production values on Figure I-4 are shown for wet gas production (which includes natural gas liquids). The wet gas production value of 21.6 Bcfd becomes 20.5 Bcfd of dry gas, after extraction of NGLs.

Source: Advanced Resources International (2012)

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For Canada, the most notable recent activity is the initiation of construction on the Kitimat LNG export terminal on the West Coast of British Columbia, Figure 1-3. This LNG terminal, with an initial plant capacity of 5 million metric tons per annum (mmtpa) and potential expansion to 10 mmtpa or more, would provide a market outlet for the large shale gas resources held in the Horn River, Cordova Embayment and Liard basins of northeast British Columbia. (Recently, Apache Corporation released a new resource estimate of 1,360 Bcm (48 Tcf) of shale gas for its leases in the Liard Basin.)

Expanded development of shale gas and the Montney Resource Play plus coalbed methane provide the basis for Canada's NEB to expect (in their Reference Case) unconventional gas production to reach 7.5 Bcfd in 2015, increase further to 9.2 Bcfd in 2020, and reach 13.1 Bcfd in 2035.

Figure 1-3. Canada's Kitimat LNG Export Terminal

For Mexico, the notable recent unconventional gas activity is the first official assessment and recognition of its large, 8,410 Bcm (297 Tcf) shale gas resource, leading the Mexican Ministry of Energy to set forth plans for aggressive exploration of this resource.

Mexico's plans are to first pursue and achieve about 1 Bcfd of production from the Eagle Ford Shale by 2021 with further growth to 1.3 Bcfd by 2026 (Baseline Scenario). Adding the less defined but promising La Casita Formation shales and tight sands could enable Mexico to achieve 2 Bcfd of unconventional gas production by 2021 and exceed 3 Bcfd by 2026 (Strategy Scenario), Figure 1-4.

Figure 1-4. Outlook for Mexico's Unconventional Gas Production

D. Outlook for Unconventional Gas

The outlook for unconventional gas production in North America is highly favorable. From a base of 514 Bcm (49.7 Bcfd) in 2011, longer-term expectations are for unconventional gas production to reach 609 Bcm (58.9 Bcfd) by 2025 and increase further to 779 Bcm (75.4 Bcfd) by 2035, Table 1-4.

As such, North America's unconventional gas resources provide the foundation for "increased gas production and reduced CO_2 emissions", answering, for this region, the question posed for the APEC Unconventional Gas Census.

Table 1-4: Outlook for North American Unconventional Gas Production

	2011		2020		2035	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
U.S.	441	42.6	497	48.1	610	59.0
Canada	73	7.1	95	9.2	135	13.1
Mexico*	n/a	n/a	17	1.6	34	3.3
Total	**514**	**49.7**	**609**	**58.9**	**779**	**75.4**

Sources: EAI AEO 2012; NEB 2011; Pemex 2012. JAF2012_094.XLS

*Mexico's unconventional gas production data are from the "Strategy Scenario" for shale gas and do not include CBM or tight gas; Mexico's unconventional gas production estimate for 2035 is set at expectations of shale gas production in 2026 (the last year of projected data.)

1.1 UNITED STATES OF AMERICA UNCONVENTIONAL GAS

A. Introduction

The U.S. is a major producer and consumer of natural gas as well as the overall leader in unconventional gas production and technology innovation.

Tight gas and coalbed methane production started in the 1980s, initially in the low permeability Mesaverde sands of the Rocky Mountain basins and then in the Fruitland coals of the San Juan Basin. In addition, small volumes of shale gas were produced from the Appalachian Basin's shallow Huron Shale and the Michigan Basin's high-water-producing Antrim Shale. The application of horizontal drilling and intensive well stimulation in the 1990s unlocked the large natural gas resources held in deep, low permeability shales, first in the Fort Worth Basin's Barnett Shale and then in the Fayetteville, Haynesville, Marcellus and other shales in the following decades, Figure 1-1-1.

Last year (2011), the U.S. consumed 66.6 Bcfd of natural gas, primarily in its electric power and industrial sectors. Natural gas production (dry) of 63.0 Bcfd plus imports of natural gas from Canada and small volumes via LNG provided the required supply. U.S. consumption and production of natural gas have steadily increased with shale gas driving the growth in natural gas supply, Table 1-1-1.[2]

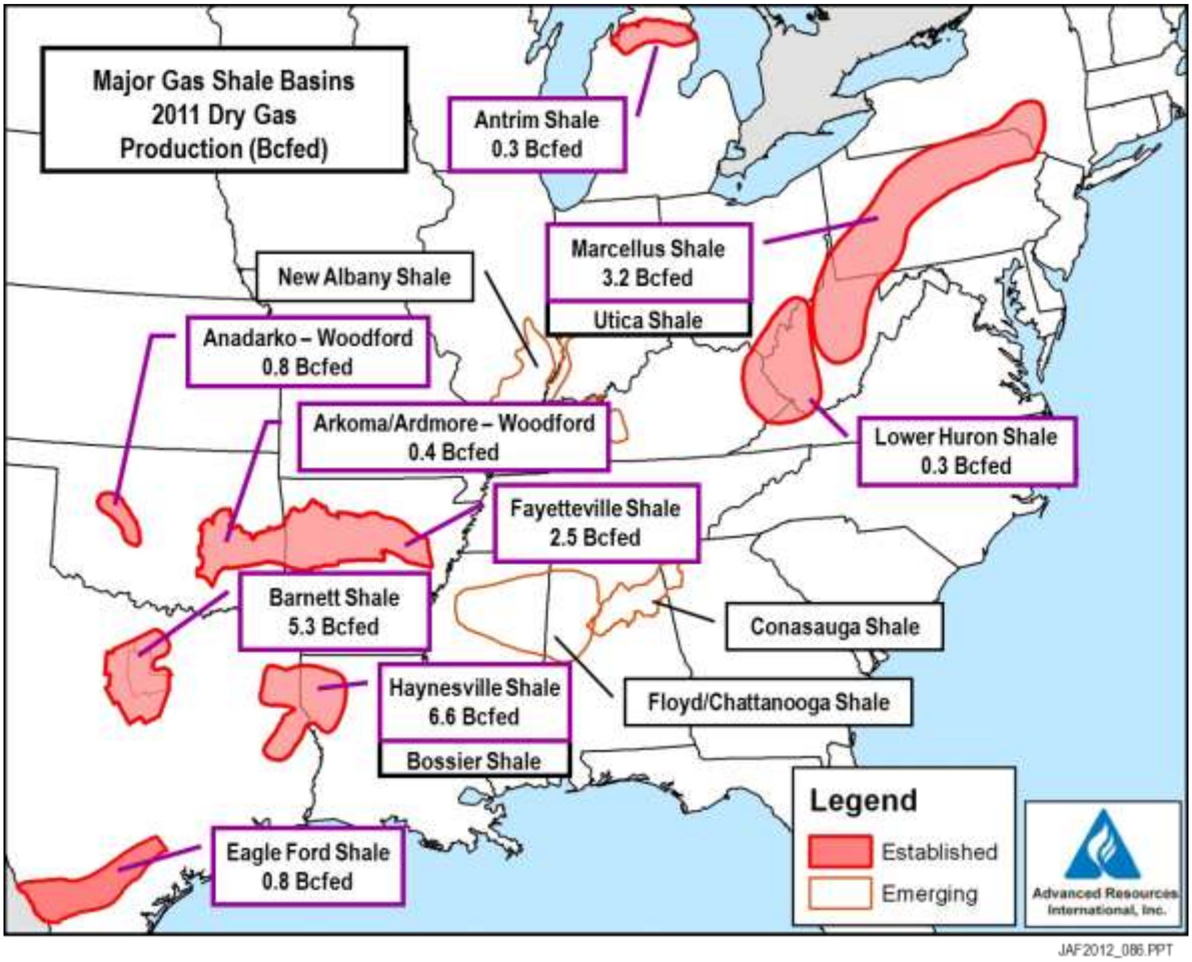
Table 1-1-1. U.S. Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		683	24,090	66.0	689	24,310	66.6
Supply							
▪	Marketed Production (Dry)	611	21,570	59.1	651	23,000	63.0
▪	Net Exports/Imports/Other*	72	2,520	6.9	38	1,310	3.6

Source: EIA Short-Term Energy Outlook, August 2012. *Other includes net storage, supplemental fuels and balancing items.

[2] U.S. Department of Energy, Energy Information Administration Short-Term Energy Outlook, August 2012.

Figure 1-1-1. Location of Established Shale Gas Basins*



*The Williston and Permian emerging shale gas basins provided 0.3 Bcf of dry shale gas production.
Source: Advanced Resources International, 2012

The U.S. has a large undeveloped unconventional natural gas resource base of 29,090 Bcm (1,027 Tcf) plus proved unconventional gas reserves of 6,010 Bcm (212 Tcf) for a total remaining unconventional gas resource base of 35,100 Bcm (1,239 Tcf), as estimated by the U.S. Energy Information Agency, Table 1-1-2.[3,4] Drawing on this large reserve and resource base, the U.S. produced 441 Bcm (42.6 Bcfd) of unconventional gas in 2011.[5]

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[3] U.S. Department of Energy, Energy Information Administration Assumptions to AEO 2012, August 2012
[4] U.S. Department of Energy, Energy Information Administration "U.S. Crude Oil, Natural Gas and Natural Gas Liquids Priced Reserves, 2010, August 2012
[5] U.S. Department of Energy, Energy Information Administration Annual Energy Outlook 2012 with Projections to 2035 DOE/EIA-0383(2012) | June 2012

Table 1-1-2. U.S. Undeveloped Unconventional Gas Resources

		Proved and Unproven Resource				Dry Production (2011)	
		Gas In-Place		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	16,410	579	212	20.5
▪	CBM	n/a	n/a	3,960	140	179	17.3
▪	Tight Gas	n/a	n/a	14,730	520	50	4.8
	TOTAL	n/a	n/a	**35,100**	**1,239**	**441**	**42.6**

Source: EIA, Assumptions to AEO 2012, August 2012

B. Governmental Agencies Engaged with Hydrocarbon Industry

A variety of Federal and state agencies are involved with the assessment, regulation and development of U.S. natural gas, including the Department of Energy, the Federal Energy Regulatory Commission, the Department of the Interior, and individual state oil and gas regulatory commissions.

- *U.S. Department of Energy (U.S. DOE).* The U.S. Department of Energy (U.S. DOE) and its key agencies - - the Energy Information Administration (EIA) and the National Energy Technology Laboratory (NETL) - - provide much of the policy analysis, data compilation, reporting and technology research for unconventional gas. The U.S. DOE also has legislative authority for the approval of natural gas exports.

    − Energy Information Administration (EIA). The EIA maintains and supports the development of a comprehensive data base on unconventional gas proved reserves and undeveloped resources. EIA also provides projections of unconventional gas production to year 2035 in their Annual Energy Outlook.

    − The National Energy Technology Laboratory (NETL), partly through its management of the Research Partnership for Securing Energy for America (RPSEA), supports R&D on unconventional gas technology and environmental issues.

- *Federal Energy Regulatory Commission (FERC).* The Federal Energy Regulatory Commissions (FERC) is an independent agency that regulates the interstate transmission of natural gas, oil and electricity. FERC also has responsibility for approving the siting of interstate natural gas pipelines and storage facilities, reviewing proposals to build liquefied natural gas (LNG) terminals, and ensuring safe operation and reliability for LNG terminals. A series of State Public Utility Commissions provide additional regulatory functions for natural gas at the state level.

- *U.S. Department of the Interior (DOI).* The U.S Department of the Interior and its Mineral Management Service and Bureau of Land Management provide resource assessments, publications and oversight of oil and gas resources on onshore and offshore Federal lands.

In addition, a host of state-level agencies are involved in the permitting and oversight of oil and gas development and the publication of information on unconventional gas production. For example:

- The Texas Railroad Commission provides information on the status of Barnett Shale and Eagle Ford Shale drilling and production in Texas. The Texas Bureau of Economic Geology provides insightful studies and reports on oil and gas development in the state.

- The North Dakota Industrial Commission's Oil and Gas Division tracks the development of the Bakken/Three Forks Shales and provides periodic reviews of the potential size and future contribution from this major shale oil and associated gas resource.

- The Wyoming Oil and Gas Commission maintains an outstanding website and data base that tracks unconventional gas development and production in the state's numerous hydrocarbon basins.

- The Oklahoma Department of Energy and the Oklahoma Geological Survey provide periodic reviews on unconventional gas development in the state.

An overall coordinating body, the Interstate Oil and Gas Compact Commission (IOGCC), provides a central organization that assists the various oil and gas producing states with information, education and regulatory matters.

C. Unconventional Gas Resource Assessments

The U.S. has a large volume of unconventional (as well as conventional) gas in multiple basins across the U.S. Two agencies - - the U.S. EIA and the USGS - - provide period resource assessments for key shale gas, coalbed methane and tight gas basins.

The EIA estimates of shale gas, coalbed methane and tight gas resources are provided within a well-documented "assumptions and data" report that accompanies the EIA Annual Energy Outlook[3]. The Oil and Gas Model section of this report provides detailed resource assessment information on U.S. conventional and unconventional gas resources - - by region, basin and play.

The EIA reports that the U.S. has a bountiful 29,090 Bcm (1,027 Tcf) of unproved unconventional gas resources, Table 1-1-3. With the emergence of new shale gas plays, such as the Eagle Ford and Utica, the size of the defined unconventional gas resource base will likely continue to increase as new assessments of these emerging plays are completed. The regional distribution of the U.S. unproved technically recoverable unconventional gas resource is shown on Figure 1-1-2.

In addition, the U.S. EIA provides annual compilations of proved reserves for shale gas of 2,760 Bcm (97 Tcf), for coalbed methane 500 Bcm (18 Tcf) for end of 2010, Table 1-1-4.[4] Based on internal work by Advanced Resources International, we have added tight sand proved reserves of 2,750 Bcm (97 Tcf) to EIA's shale gas and coalbed methane compiled proved reserves to establish total U.S. unconventional gas proved resources of 6,010 Bcm (212 Tcf). Today's proved reserves of shale gas, now at 2,760 Bcm (97 Tcf), have nearly tripled in the past two years.

Table 1-1-3. Regional Distribution of Unproved Technically Recoverable Unconventional Gas Resources (as of 1/1/2010)

Region	Unproved Resource			Total
	Shale Gas	Coalbed Methane	Tight Sands	
	(Tcf)	(Tcf)	(Tcf)	(Tcf)
Northeast	217	4	52	**273**
Gulf Coast	130	2	96	**228**
Mid-Continent	40	38	22	**100**
Southwest	46	6	24	**76**
Rocky Mountain	37	62	222	**321**
West Coast	12	10	7	**29**
Total	**482**	**122**	**423**	**1,027**

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Figure 1-1-2. Unproved Technically Recoverable Unconventional Gas Resources by Oil and Gas Supply Model Regions.

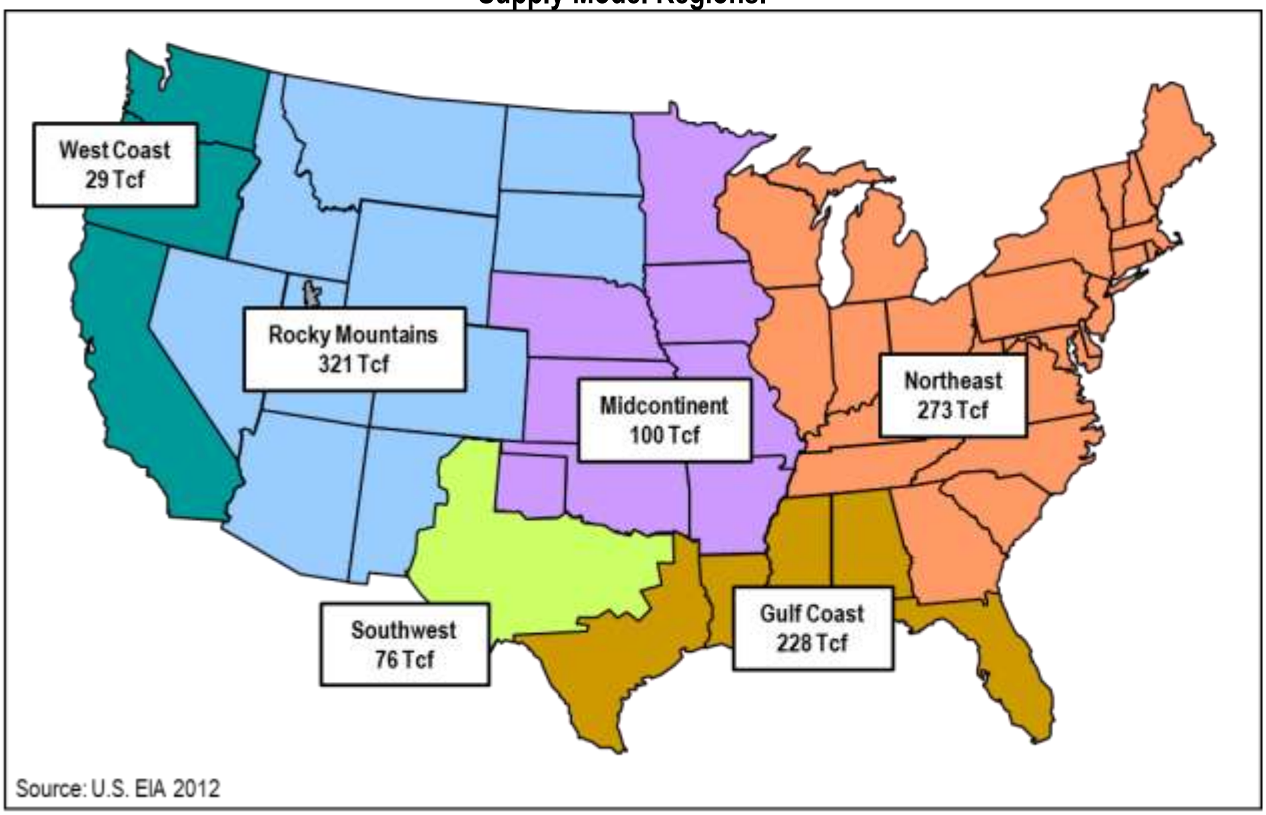

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Table 1-1-4. Shale Gas and Coalbed Methane Proved Reserves (2008-2010)

	(Bcm)			(Tcf)		
	2008	2009	2010	2008	2009	2010
Shale Gas	970	1,720	2,760	34.4	60.6	97.4
Coalbed Methane	590	530	500	20.8	18.6	17.5

The total U.S. natural gas resource base, which includes conventional and unconventional natural gas (as published by the U.S. EIA) is large, estimated at 63,740 Bcm (2,250 Tcf), including proved reserves and unproved resources, Table 1-1-5.[3,5]

Table 1-1-5. Technically Recoverable U.S. Natural Gas Resources

	Proved Reserves		Unproved Resources		Total Recoverable Resources	
	(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm)	(Tcf)
Conventional Gas						
▪ Onshore Non-Associated	2,410	85	10,470	370	12,880	455
▪ Offshore Non-Associated	340	12	7,440	263	7,780	275
▪ Alaska	250	9	7,700	272	7,950	281
Subtotal Conventional Gas	**3,000**	**106**	**25,610**	**905**	**28,610**	**1,011**
Unconventional Gas*						
▪ Shale Gas	2,760	97	13,650	482	16,410	579
▪ Tight Gas Sands	2,750	97	11,980	423	14,730	520
▪ Coalbed Methane	500	18	3,460	122	3,960	140
Subtotal Unconventional Gas	**6,010**	**212**	**29,090**	**1,027**	**35,100**	**1,239**
TOTAL US	**9,010**	**318**	**54,700**	**1,932**	**63,710**	**2,250**

*The proved reserves as of 12/31/2010; the unproved reserves are as of 1/1/2010.

Source: Assumptions to the AEO 2012 (Aug 2012); EIA Crude Oil, Natural Gas and Natural Gas Liquids Proved Reserves 2010 Annual Report.

The EIA resource assessments for unconventional gas are derived from a variety of sources, including: (1) resource assessments performed by the U.S. Geological Survey (USGS); (2) resource assessments prepared for EIA by expert private company resource assessment firms; and (3) resource assessments from internal analysis by EIA staff. Appendix 1 to this report provides an informative tabulation of the assessments (for unproven unconventional gas resources) prepared by the USGS and the assessment used by the EIA. Appendix 2 provides a listing of key unconventional gas resource assessment studies recently prepared by the USGS that provide the foundation for the USGS resource values tabulated in Appendix 1.

Shale Gas. Shale gas resources now dominate U.S. unconventional gas, accounting for 2,760 Bcm (97 Tcf) of proved reserves (end of 2010) and 13,650 Bcm (482 Tcf) of unproved resources (beginning of 2010). Note that the shale gas resource estimate appears conservative in light of new discoveries and play expansions and is likely to be increased in coming years.

While the two initial shale gas plays, Barnett Shale with 880 Bcm (31.0 Tcf) and Fayetteville Shale with 690 Bcm (24.5 Tcf) dominate proved reserves, the still emerging Marcellus Shale with 3,980 Bcm (140.5 Tcf) and Eagle Ford Shale with 1,420 Bcm (50.2 Tcf) shale plays dominate unproved resources.

Coalbed Methane. The coalbed methane resource in the U.S., once the “bright new star”, has become mature. While large speculative CBM resources still exist in deep (below 1,500m) settings, technology has yet to emerge that could convert this deep CBM in-place resource to economically recoverable reserves. EIA’s latest tabulation shows that coalbed methane accounts for 500 Bcm (18 Tcf) of proved reserves and 3,460 Bcm (122 Tcf) of unproven reserves.

The highly productive San Juan Basin and its Fruitland coals, after many years of production, still has 380 Bcm (13.3 Tcf) of remaining unproved resources plus an estimated 270 Bcm (9.5 Tcf) of proved reserves. The low-rank but thick Tertiary-age coals of the Powder River Basin now hold the lead with 660 Bcm (23.3 Tcf) of remaining unproven resources plus 80 Bcm (2.7 Tcf) of proved reserves.

Tight Gas. Tight gas resources, which until recently held the majority of U.S. unconventional reserves and unproven resources, are still an important source of U.S. natural gas. Proved reserves of tight gas (estimated by ARI) of 2,750 Bcf (97 (Tcf) are essentially equal to those for shale gas; remaining unproved resources (estimated by the EIA) are 11,980 Bcm (423 Tcf).

The East Texas Cotton Valley and Deep Bossier tight sands, with 1,970 Bcm (69.7 Tcf) of remaining unproved technically recoverable resources and the Greater Green River (Lance, Mesaverde and other Cretaceous-age tight sands) with 3,080 Bcm (108.7 Tcf) are two of the largest contributors.

D. Unconventional Gas Activity and Production

The outlook for U.S. natural gas supply has changed dramatically in recent years. This change in outlook has been due to advances in natural gas extraction technology and an improved understanding of the large volumes of economically recoverable natural gas held in shales.

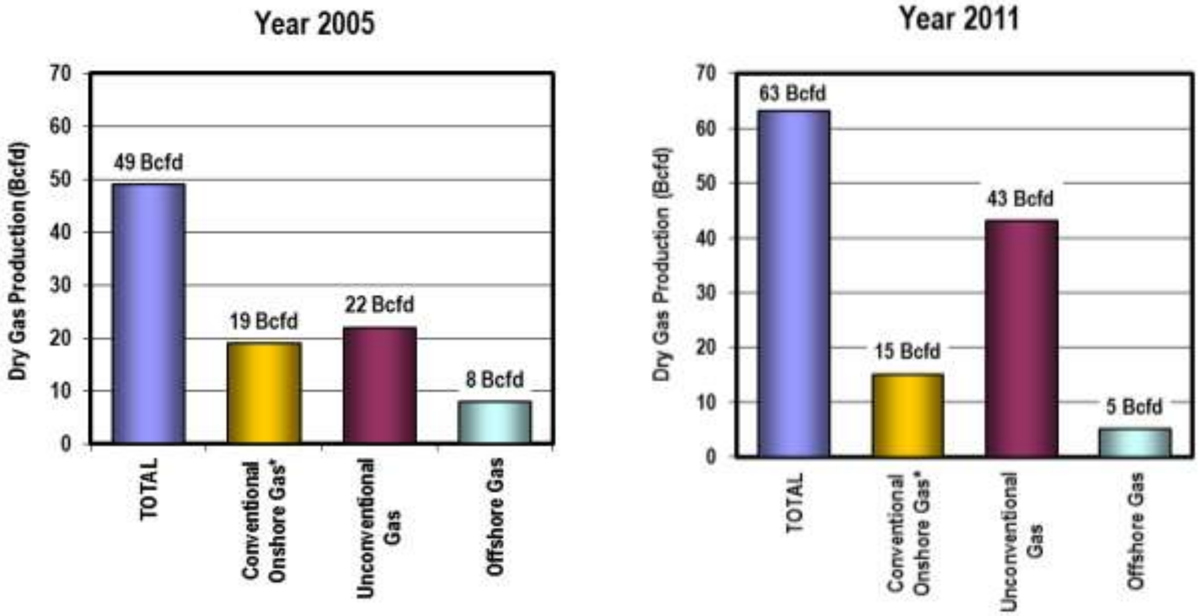
Building on science and technology investments made in the 1980s and 1990s, production of unconventional gas (tight gas sands, coalbed methane and particularly shale gas) has recently surged in the United States.

- Domestic natural gas production (dry) has increased by 14 Bcfd - - from 49 Bcfd in 2005 to 63 Bcfd in 2011. Increases in unconventional gas production have more than overcome the declines in conventional gas production, Figure 1-1-3.

- After two decades of little growth, proved reserves of conventional and unconventional natural gas (wet) have also increased, from 213 Tcf (end of 2005) to 318 Tcf (end of 2010), Figure 1-1-4.[6] Based on survey data published by the American Gas Association, proved reserves of natural gas increased further during 2011.[7]

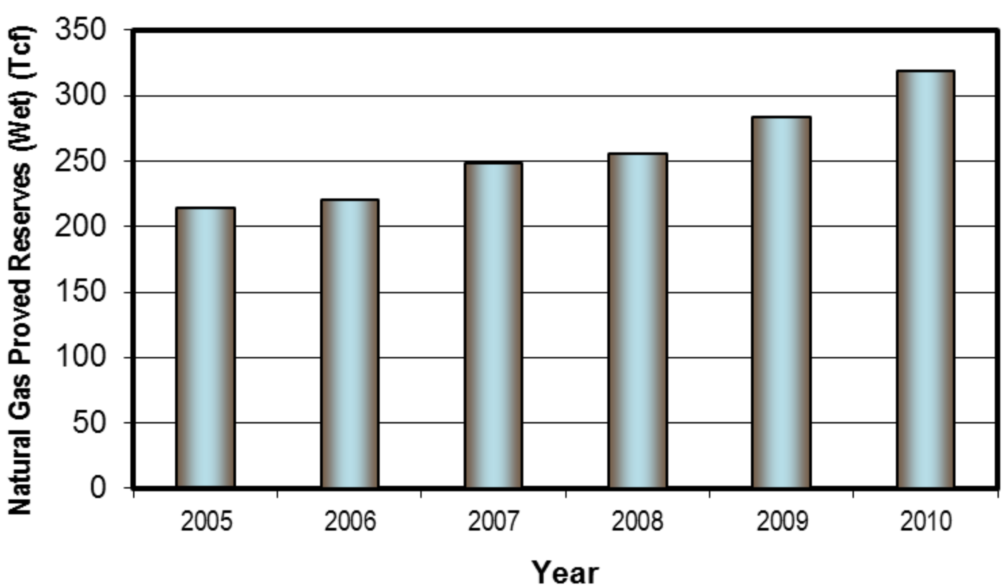
[6] EIA U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 2010.
[7] “Preliminary Findings Concerning 2011 Natural Gas Reserves”, American Gas Association, EA 2012-02, April 3, 2012.

Figure 1-1-3. Increases in Unconventional Dry Natural Gas Production Have More Than Replaced Declines in Conventional Natural Gas Production



*Includes onshore associated, non-associated and Alaska.
Source: U.S. Energy Information Agency (2012); Advanced Resources Int'l (2012).

Figure 1-1-4. Conventional and Unconventional Natural Gas Proved Reserves (Wet) Have Risen Sharply in the Past Five Years



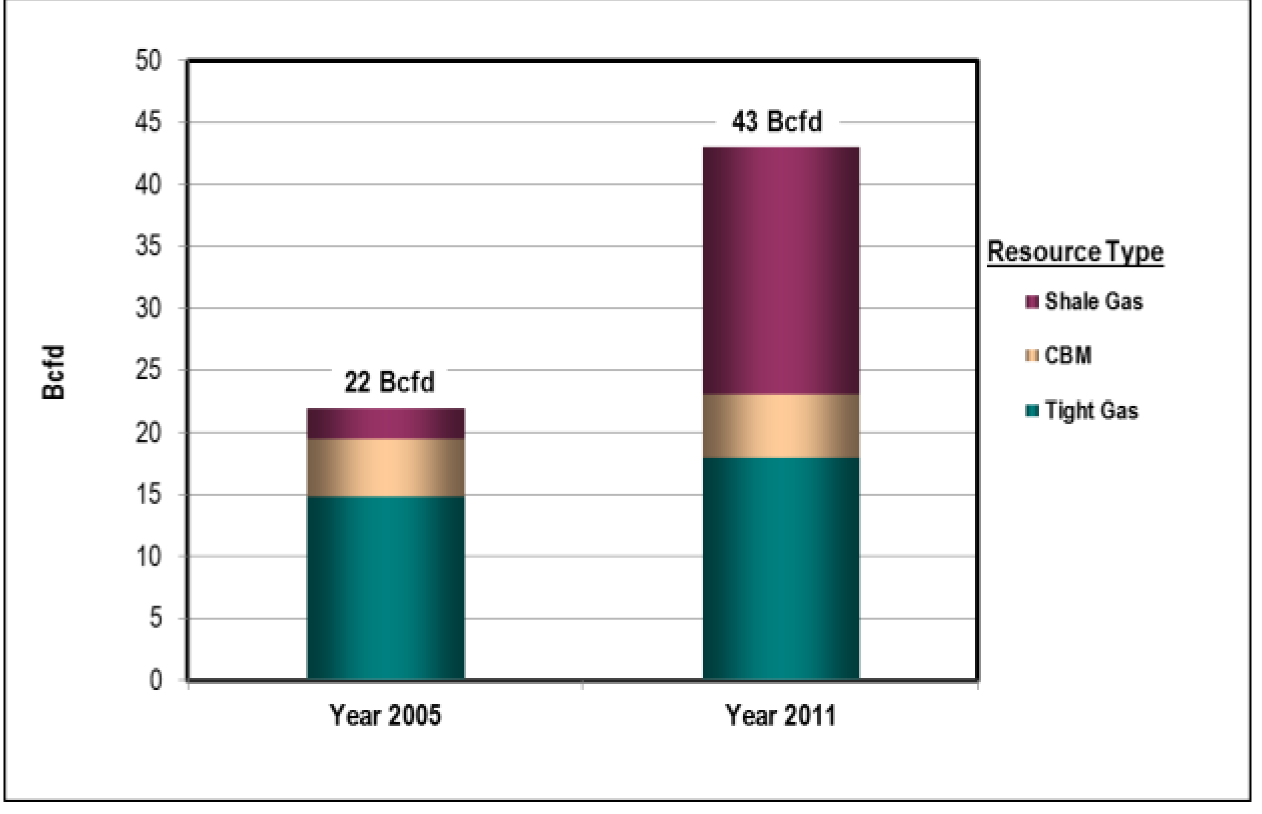
Source: EIA, U.S Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 2012.

A closer look at the data helps illustrate the contribution that unconventional gas has made during the past six years:

- Production of tight gas sands, coalbed methane and gas shales has increased from 22 Bcfd in 2005 to 43 Bcfd in 2011 and today account for two-thirds of domestic natural gas supply, Figure 1-1-5.

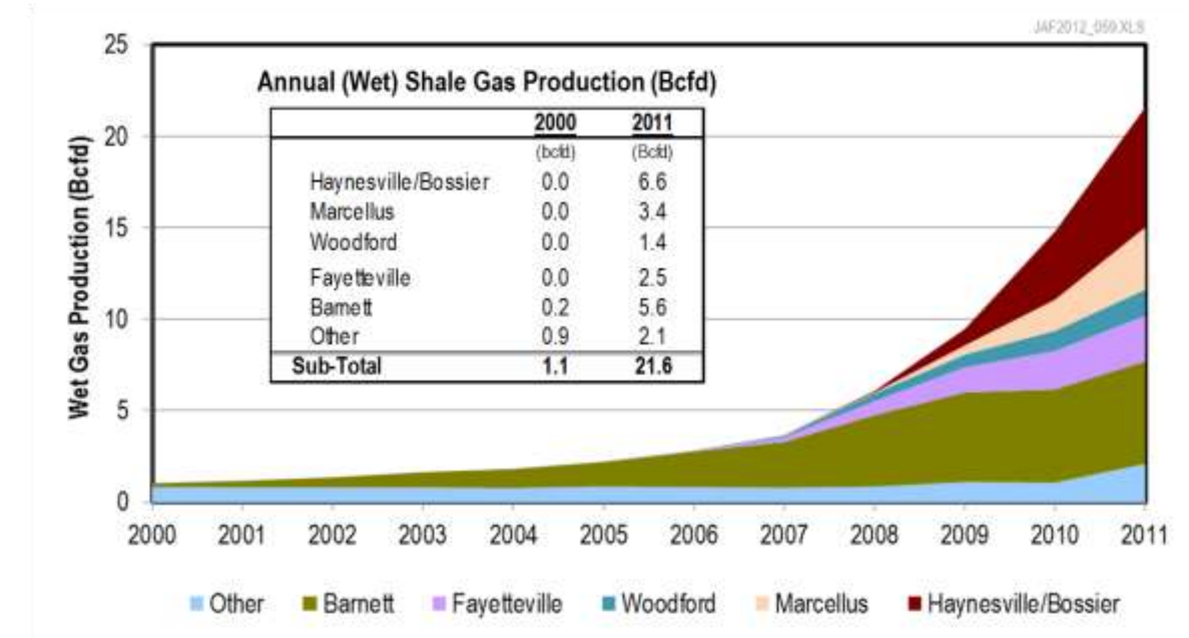
- Shale gas production has provided the great bulk of the recent growth in domestic natural gas supply reaching 21.6 Bcfd (wet) (20.5 Bcfd (dry)) in 2011. Further increases in production are anticipated, particularly from the Marcellus, Eagle Ford, Utica and Wolfcamp shales.

Figure 1-1-5. Changes in Unconventional Dry Natural Gas Production by Resource Type



Shale Gas. Production from shale gas formations has grown dramatically in the past eleven years from a base of just over 1 Bcfd in 2000 to an estimated 22 Bcfd in 2011, Figure 1-1-6. Much of the activity and growth in shale gas production has been from the "Big Four" shale gas plays - - the Barnett, Fayetteville, Haynesville/Bossier and Marcellus.

Figure 1-1-6. Shale Gas Production (Wet) Has Increased Dramatically in the Past Decade



Note that the shale gas production values on Figure I-4 are shown for wet gas production (which includes natural gas liquids). The wet gas production value of 21.6 Bcfd becomes 20.5 Bcfd of dry gas, after extraction of NGLs.

Source: Advanced Resources International (2012)

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Table 1-1-6 tracks EIA's official tabulation of U.S. shale gas production for 2008-2010, highlighting the increasing contribution from the "Big Four" shale plays.[8] Annual shale gas production of 60 Bcm (5.8 Bcfd) in 2008 more than doubled to 151 Bcm (14.6 Bcfd) by 2010.

8 EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2008 through 2010 annual reports.

Table 1-1-6. Growth of Shale Gas Production, 2008-2010

Shale Play	Production (2008)		Production (2009)		Production (2010)	
	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)	(Bcm)	(Bcfd)
Barnett	43	4.2	49	4.7	54	5.2
Haynesville/Bossier	1	0.1	9	0.9	41	4.0
Fayetteville	8	0.8	15	1.5	22	2.1
Marcellus	0	0.0	2	0.2	13	1.3
Sub-Total	**52**	**5.0**	**75**	**7.3**	**130**	**12.6**
Other Shale Plays	9	0.9	13	1.3	20	1.9
All U.S. Shale Plays	**61**	**5.9**	**88**	**8.5**	**150**	**14.5**

Source: EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2008 through 2010 annual reports.

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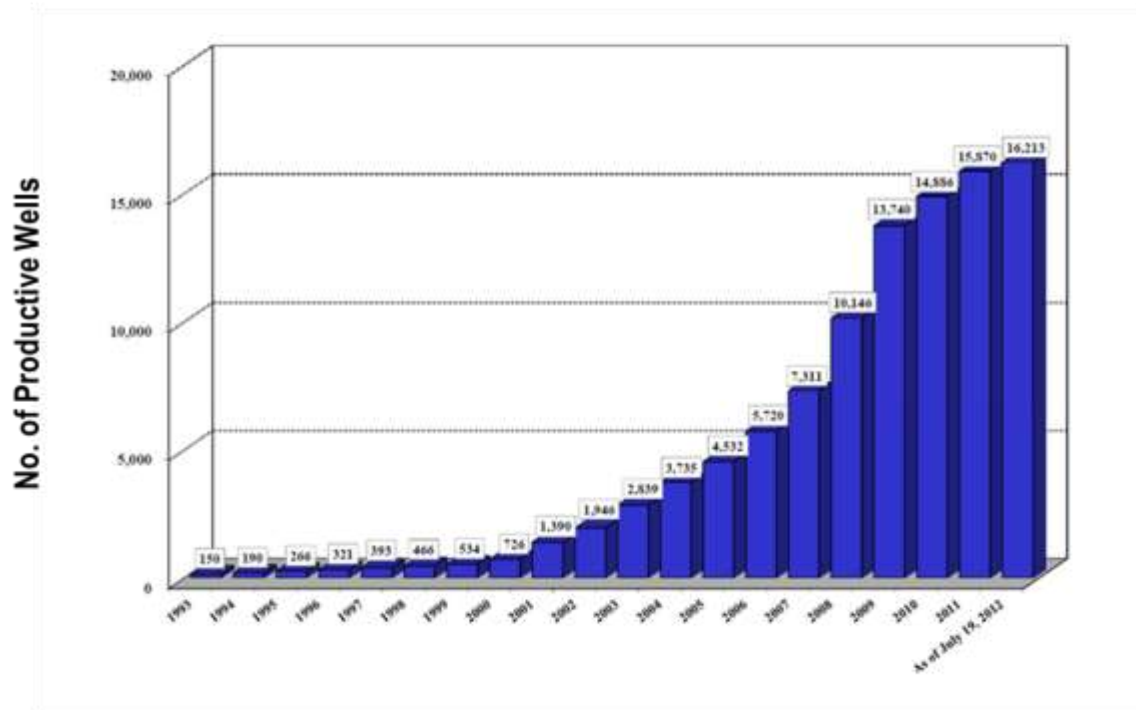
- ***Barnett Shale.*** The Barnett Shale established the shale gas "revolution" in the U.S. Natural gas production from the Barnett Shale of 5.2 Bcfd (54 Bcm) in 2010 increased in 2011 to an estimated 5.6 Bcfd from a total of 15,870 wells placed on production, Figure 1-1-7. With a declining active rig count, 43 active rigs as of mid-2012, down from 66 active rigs a year ago, the pace of new well additions has slowed and annual gas production has plateaued.

- ***Fayetteville Shale.*** The Fayetteville Shale was the second major U.S. shale gas play to come "on stream". Natural gas production from the Fayetteville Shale of 2.2 Bcfd (22 Bcm) in 2010 has continued to increase reaching an estimated 2.5 Bcfd in 2011. With the recent decline in active rigs, the number of new wells placed on production, which reached about 700 in 2011, will decline and production will likely plateau.

Figure 1-1-7. Cumulative Number of Producing Barnett Shale (Newark East) Wells.



Source: Railroad Commission of Texas (July 2012)

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- ***Haynesville/Bossier.*** The Haynesville/Bossier Shale was one of the driving forces behind the massive shale gas production increases in 2009 through 2011. Natural gas production from the Haynesville/Bossier Shale of less than 0.1 Bcfd (1 Bcm) in 2008, climbed rapidly to 4 Bcfd (41 Bcm) in 2010 and then to an estimated 6.6 Bcfd in 2011. Since then, with a rig count of 31 active rigs as of mid-2012, down from 114 active rigs a year ago, the pace of well drilling has slowed dramatically and gas production has plateaued.

- ***Marcellus Shale.*** The Marcellus Shale has replaced the Haynesville/Bossier as the “dominant force” of new shale gas activity. Natural gas production that barely registered on the production charts in 2008, jumped sharply to 1.3 Bcfd (13 Bcm) in 2010 and has continued to climb to an estimated 3.4 Bcfd in 2011. Even though the number of rigs active in the Marcellus is down somewhat at 120 as of mid-2012 from 153 a year earlier, shale gas production and wells brought on-line have continued to increase.

With the decline in natural gas prices, much of the unconventional gas rig fleet has moved to liquids-rich shale gas and shale oil plays. Several of the shale plays, such as the Eagle Ford and Cana-Woodford, produce a combination of hydrocarbons including dry gas, wet gas and condensate/oil. As such, the two most active shale plays today are the Eagle Ford with 240 rigs and the Bakken with 220 rigs (mid-2012). While much of the target is liquids, significant volumes of associated gas are also being produced along with the oil and condensate.

Coalbed Methane. U.S. coalbed methane provided 5.2 Bcfd (54 Bcm) of production in 2010, primarily from four major basins/plays, Table 1-1-7. While coalbed methane production had remained relatively steady in recent years, the low gas prices and reduced drilling in 2011 and 2012 will likely result in significant reductions in proved CBM reserves and production in future years. Unofficial estimates of coalbed methane production are 4.8 Bcfd (50 Bcm) in 2011.

Table 1-1-7. Major Coalbed Methane Plays: Production (2008-2010)

CBM Play	Production (2008)		Production (2009)		Production (2010)	
	(Bcm)	(Bcf)	(Bcm)	(Bcf)	(Bcm)	(Bcf)
San Juan (Fruitland)	26	917	26	904	26	908
Powder River	17	587	15	547	16	576
Warrior	3	107	3	105	3	102
Central Appalachia	3	101	3	111	3	97
Other	7	254	7	247	6	203
Total	**56**	**1,966**	**54**	**1,914**	**54**	**1,886**

Tight Gas. No official data are collected on tight gas production or proved reserves, although the EIA provides data on tight gas production as part of its Annual Energy Outlook and EIA's reserve reports provide a valuable base of data for estimating tight gas reserves. Tight gas production estimated by EIA of 17.3 Bcfd (179 Bcm) in 2011 has remained relatively level in recent years.

The dominant tight gas basins/plays include: (1) the numerous Cretaceous-age tight gas formations in the Greater Green River Basin (Wyoming), including the Lance Formation tight gas sands at Pinedale and Jonah gas fields, (2) the Upper Cretaceous lenticular sands in the Piceance Basin (Colorado) including the Mesaverde Formation tight gas sands at Rulison, Grand Valley/Parachute and Mamm Creek gas fields, and (3) the Upper Jurassic East Texas Cotton Valley and Deep Bossier tight gas sands at Carthage, Overton and Mimms Creek gas fields.

Appendix 1. Comparison of EIA and USGS Resource Assessments for Unconventional Gas

Two U.S. organizations publish resource assessment data for technically recoverable undiscovered (unproved) unconventional gas - - the U.S. Energy Information Administration (EIA) and the U.S. Geological Survey (USGS). The EIA often relies on the USGS resource assessment, but also uses its own information and work for emerging unconventional basins/plays when the USGS has yet to assess that basin or play, and when significant new data become available on the productivity of a previously assessed USGS basin/play.

A comparison of the EIA and USGS resource assessments shows that EIA uses significantly higher values for undiscovered (unproven) unconventional gas resources than set forth by the USGS, Table A1-1:

Table A1-1: Comparison of EIA and USGS Resource Assessments for Technically Recoverable Undiscovered Unconventional Gas Resources in Lower-48 Basins and Plays

Resource	EIA's Unproven Unconventional Gas Resources (1/1/2010)	USGS's Undiscovered Unconventional Gas Resources		Difference EIA vs. USGS
		Original Assessments*	Adjusted to 1/1/2010**	1/1/2010
	(Tcf)	(Tcf)	(Tcf)	(Tcf)
Shale Gas	482	347	338	+ 144
Tight Gas	423	201	177	+ 246
Coalbed Methane	122	96	79	+ 43
Total	**1027**	**644**	**594**	**+ 433**

*Prepared in years 2002 through 2012.

**The USGS original resource assessments have been adjusted to subtract the natural gas that has been produced during the years since the data used in the assessment.

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An overview of the primary reasons for the differences in the EIA and USGS unconventional gas resource assessment numbers is provided below.

- For shale gas, much of the 144 Tcf larger resource value used by EIA is due to: (1) a 57 Tcf higher estimate for the Marcellus Shale due to new data on well productivity; (2) a 30 Tcf higher estimate for the Appalachian Basin's Devonian Shale; and (3) the inclusion by EIA of 16 Tcf for the Utica Shale (not yet assessed by the USGS).

- For tight sands, much of the 246 Tcf larger resource value used by EIA is due to: (1) the inclusion of 70 Tcf of recoverable resources for the East Texas Bossier and Cotton Valley tight gas sands, 27 Tcf for the Texas Gulf Coast Olmos, Vicksburg and Wicox/Lobo tight sands, 20 Tcf for the Anadarko Basin Cherokee, Cleveland and Granite Wash/Atoka tight sands, and 24 Tcf for the Permian Basin Abo and Canyon tight sands; (2) a 37 Tcf higher estimate for the Piceance-Uinta tight gas sands due to new data on well productivity; and (3) a 33 Tcf higher estimate for the Greater Green River tight gas sands also due to new data on well productivity.

- For coalbed methane, much of the 43 Tcf larger resource value used by EIA is due to: (1) a 32 Tcf higher estimate for the Mid-Continent and (2) a 13 Tcf higher estimate for the Powder River Basin, countered by somewhat lower resource values than by the USGS for other CBM plays.

Appendix 2. Geological Studies of Unconventional Gas Resources

The most extensive set of publically available studies on unconventional gas resources is by the U.S Geological Survey (USGS). As part of their Energy and Minerals Program, the USGS has issued an extensive series of assessments of undiscovered oil and gas resource of key unconventional gas basins, with a sampling of these studies as highlighted below:

1. Assessment of Undiscovered Oil and Gas Resources of the Bend Arch-Fort Worth Basin Province of North-Central Texas and Southwestern Oklahoma, 2003
2. Assessment of Undiscovered Oil and Gas Resources in Cretaceous-Tertiary Coal Beds of the Gulf Coast Region, 2007
3. Assessment of Undiscovered Oil and Gas Resources of the Permian Basin Province of West Texas and Southeast New Mexico, 2007
4. Assessment of Undiscovered Biogenic Gas Resources, North-Central Montana, 2008
5. Assessment of Undiscovered Oil and Gas Resources of the Bighorn Basin Province, Wyoming and Montana, 2008
6. Assessment of Undiscovered Oil and Gas Resources of the Anadarko Basin Province of Oklahoma, Kansas, Texas, and Colorado, 2010.
7. Assessment of Undiscovered Oil and Gas Resources of the Williston Basin Province of North Dakota, Montana, and South Dakota, 2010
8. Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011
9. Assessment of Undiscovered Oil and Gas Resources in the Paradox Basin Province, Utah, Colorado, New Mexico, and Arizona, 2011
10. Assessment of potential Oil and Gas Resource in Source Rocks of the Alaska North Slope, 2012

In addition, the various state geological surveys and oil/gas divisions provide a rich set of in-depth geological studies on the key hydrocarbon basins in their state.

1.2 CANADA UNCONVENTIONAL GAS

A. Introduction

A large portion of Canada's economy is related to energy, particularly oil and natural gas development. In 2010, energy accounted for 6.7% of Canada's GDP, with expenditures for exploration, development operations and royalty payments of $61 billion. Natural gas exports (net) generated about $11 billion of revenue.

Last year, Canada consumed 86 Bcm or 8.3 Bcfd of marketable natural gas and produced 151 Bcm or 14.6 Bcfd. Canada has net natural gas exports of 65 Bcm or 6.3 Bcfd, primarily to the U.S., Table 1-2-1.[9,10] In recent years natural gas consumption has grown, largely for use in extracting Canada's oil sands, while natural gas production has slightly declined.

Table 1-2-1. Canada Natural Gas Consumption and Supply

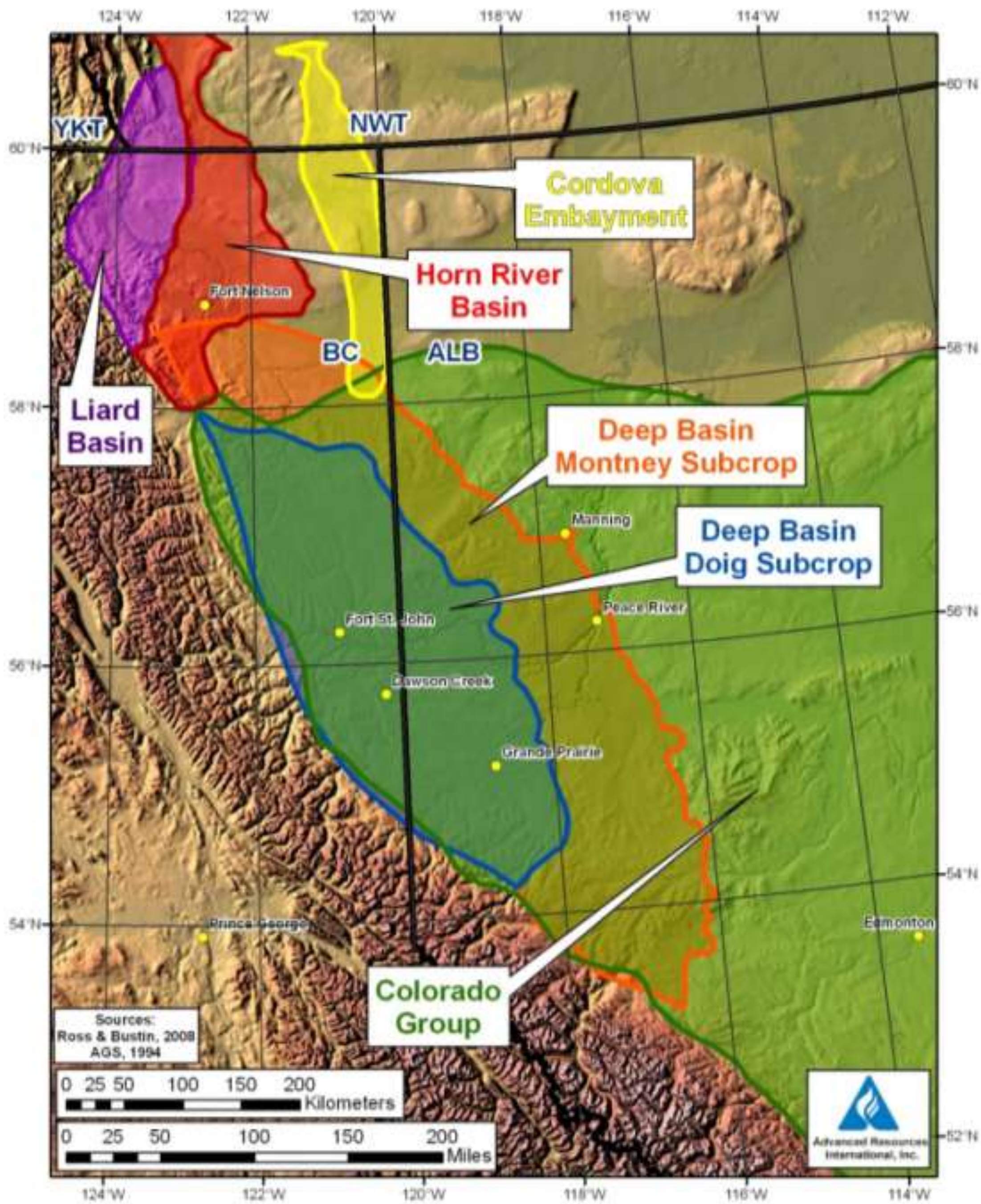
		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		83	2,940	8.1	86	3,030	8.3
Supply							
▪	Marketed Production (Dry)	151	5,330	14.6	151	5,320	14.6
▪	Net Exports/Imports	(70)	(2,470)	(6.8)	(60)	(2,110)	(5.8)

Source: EIA CAB Canada, 2012; NEB Short-Term Canadian Natural Gas Deliverability 2012-2014, 2012.

Canada's Western Sedimentary Basin holds a bountiful assemblage of unconventional gas resources - - with shale gas in the Horn River Basin, tight gas sands in the Deep Basin and coalbed methane in the southern plains. Figure 1-2-1 shows the location of the major shale gas basins of Western Canada.

9 U.S. Energy Information Administration, Country Analysis Brief; Canada, April 2012.
10 Short-Term Canadian Natural Gas Deliverability 2012-2014, an Energy Market Assessment March 2010, National Energy Board, Calgary, Alberta, Canada, April 2012.

Figure 1-2-1. Shale Gas Basins of Western Canada



Source: Advanced Resources International, Inc., 2011.

Unconventional gas, primarily from the Western Canadian Sedimentary Basin, provides a major portion of Canada's natural gas supply.

- Based on recently completed studies by the NEB, Canada has a technically recoverable unconventional gas resource base of 8,640 Bcm (305 Tcf), including 2,550 Bcm (90 Tcf) of shale gas in the Horn River Basin, 1,270 Bcm (45 Tcf) of coalbed methane, and 4,820 Bcm (170 Tcf) of tight gas, primarily in the Montney Resource Play, Table 1-2-2.[11]. (A more in-depth study of the Montney is scheduled for the end of 2012 or early 2013.) NRCan refers to the Canadian Society for Unconventional Resources (CSUR) for estimates of 376 to 947 Tcf of unconventional gas.

- Last year (2011), Canada produced 73.5 Bcm, equal to 7.1 Bcfd of unconventional gas. Tight gas and the Montney Resource Play provided 60.0 Bcm (5.8 Bcfd), coalbed methane provided 8.3 Bcm (0.8 Bcfd), and shale gas output was 5.2 Bcm (0.5 Bcfd), Table1-2-2.

- In response to the recognition of Canada's large unconventional gas resources, its growing volume of unconventional gas production, and the reduced demand for natural gas imports by the U.S., the Canadian government recently gave permission for an LNG export terminal to be built on British Columbia's coast, allowing Canadian operators to export natural gas to Asia.

Table 1-2-2. Canada's Unconventional Gas Resources and Production (NEB, 2011)****

		Resource Estimates				Production (2011)	
		Gas In-Place		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	*	*	2,550	90	5.2	0.5
▪	CBM			1,270	45	8.3	0.8
▪	Tight Gas**			4,830	170	60.0	5.8
	TOTAL			**8,650**	**305**	**73.5**	**7.1**

*The EIA/ARI Assessment of Canada's shale gas estimated 1,326 Tcf of gas in-place with 355 Tcf technically recoverable for five major Canada shale gas basins.12 ** Includes Montney Resource Play. ***NRCan relies on CSUR for estimates of technically recoverable unconventional gas resources which range from 376 to 947 Tcf.
Source: Canada's Energy Future: Energy Supply And Demand Projections To 2035, NEB, 2011.

11 Canada's Energy Future: Energy Supply And Demand Projections To 2035, An Energy Market Assessment November 2011, National Energy Board, Calgary, Alberta, Canada, 2011, Cat. No. NE23-15/2011E-PDF
12 "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", sponsored by the U.S. Energy Information Administration (April, 2011) prepared by Advanced Resources International.

B. Governmental Authorities Engaged with Hydrocarbon Industry

The two main governmental agencies involved with the assessment, policy formation and facilitation of natural gas activities in Canada are Natural Resources Canada and the National Energy Board.

- *Natural Resources Canada (NRCan)*: NRCan's Energy Sector develops energy policy for the Canadian Government, within the goal of ensuring that Canadians benefit from the secure and sustainable production of Canada's energy resources. The Minister of NRCan is a member of the Canadian Cabinet.
- *National Energy Board (NEB)*: The NEB is an independent federal agency charged with international and interprovincial aspects of Canada's oil, natural gas and electric utility industries. The NEB provides a variety of reports on the outlook for Canada's energy supply and demand. It also publishes national hydrocarbon production reports that include monthly production volumes for the individual Canadian provinces.

In addition, a number of province-level government agencies regulate natural gas development within their lands, as further discussed in the subsequent sections on Alberta and British Columbia.

C. Resource Assessments

As of 2011, the NEB estimated that there were 8,650 Bcm (305 Tcf) of remaining marketable unconventional natural gas resources (including remaining proved reserves) in Canada. The NEB study states that there is greater certainty for the resource estimates for shale gas and coalbed methane, based on provincial reserves data and completed studies, and less certainty for the tight gas resource estimates given the limited number of studies completed so far on this resource. While Canada's tight gas resource potential is still being defined, the expectation is that this resource will be "very large" given the Montney Resource and Deep Basin tight gas plays in Alberta and British Columbia.

C.1 Shale Gas. The NEB and British Columbia Ministry of Energy and Mines (MEM) collaborated on a resource assessment of the Horn River Basin shale gas resource in 2011, establishing a recoverable resource of 2,210 Bcm (78 Tcf). Adding the other, preliminary assessed shale gas basins and plays such as the Duverney and Exshaw shales in Alberta, the Utica Shale in Quebec and the Horton Shale in new Brunswick raised the recoverable shale gas resource to 2,550 Bcm (90 Tcf). For more discussion of this joint assessment, please see the Horn River Basin portion of the British Columbia section of this report.

C.2 Coalbed Methane (CBM). The NEB estimates 1,270 Bcm (45 Tcf) for Canada's remaining recoverable and marketable coalbed methane resource. The NEB completed its CBM assessment report "An Overview of and Economics of Horseshoe Canyon Coalbed Methane Development" in 2007 that discussed the activity in Alberta's primary CBM play. For more information regarding Horseshoe Canyon Formation CBM development please see the CBM discussion in the Alberta section of this report.[13]

C.3 Tight Gas/Montney. The NEB and British Columbia MEM are currently in the process of assessing the Montney Resource Play. An earlier study in 2006 by MEM estimated 2,800 to 19,800 Bcm (80 to 700 Tcf) of gas in-place for the Montney.[14] The full study is due to be released in winter 2012/2013. Currently, the NEB records 4,830 Bcm (170 Tcf) of remaining marketable tight gas resource with 3,050 Bcm (108 Tcf) assigned to the Montney.

D. Unconventional Gas Activity and Production

Until recently, Canada's unconventional gas production had seen steady growth, particularly from tight gas. However, with low gas prices and reductions in demand for exports, unconventional gas production has decreased and is expected to remain static or decline slightly in the near future. Increasing production from the Horn River Shale and the Montney Resource Play is expected to decline in production from coalbed methane and other (non Montney) tight gas sands. [10]

[13] Overview and Economics of Horseshoe Canyon Coalbed Methane Development. National Energy Board. May 2007

[14] Personal correspondence with Mark Hayes, BC Ministry of Energy and Mines (MEM).

D.1 Unconventional Gas Activity and Production. In 2011 unconventional gas accounted for nearly two-thirds of Canada's new well drilling and nearly half of Canada's total gas production, shown previously on Table 1-2-2.[15,10]

- Tight gas development provided 1,843 new wells,[16] with the Montney Resource Play providing an additional 250 new wells.[10]

- Coalbed methane accounted for 418 new wells,[10] and shale gas accounted for 75 new wells.[16]

D.2 Near-Term Outlook for Unconventional Gas Activity and Production. Near-term expectations for natural gas drilling and production are published annually by the NEB. These reports provide a valuable set of data, with detail by province, area and type of natural gas (conventional, shale, tight, CBM, Montney).[10]

With current low natural gas prices, unconventional well drilling is projected to decline, particularly for tight gas and coalbed methane, Table 1-2-3.[10]

With declining well drilling, production from tight gas plays is expected to fall from 4.3 Bcfd in 2012 to 3.7 Bcfd in 2014. The Montney Resource Play is expected to increase in production from 1.6 Bcfd in 2012 to 1.9 Bcfd in 2014. Production of coalbed methane is expected to decline moderately from 0.7 Bcfd in 2012 to 0.6 Bcfd in 2014. Shale gas production is also projected to decline somewhat from 0.6 Bcfd in 2012 awaiting higher natural gas prices and completion of the LNG export terminal.

[15] Short-Term Canadian Natural Gas Deliverability 2011-2013, an Energy Market Assessment March 2010, National Energy Board. Calgary, Alberta, Canada, May 2011

[16] Short-Term Canadian Natural Gas Deliverability 2010-2012, an Energy Market Assessment March 2010, National Energy Board. Calgary, Alberta, Canada, March 2010

Table 1-2-3. Expectations for Canada's Unconventional Gas Activity and Production

Resource	New Wells			Projected Annual Production		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
	(#)	(#)	(#)	(Bcfd)	(Bcfd)	(Bcfd)
Tight Gas	845	628	492	4.3	4.0	3.7
Montney	229	222	202	1.6	1.8	1.9
CBM	91	36	23	0.7	0.7	0.6
Shale	39	43	43	0.6	0.6	0.5
Total	**1,204**	**929**	**760**	**7.2**	**7.1**	**6.7**

Source: NEB Short-Term Gas Deliverability 2012-2014

D.3 Longer-Term Outlook for Unconventional Gas Production. The NEB provides long-term energy supply and demand projections, in reports such as "Canada's Energy Future: Energy Supply and Demand Projections to 2035." In this report, the NEB projects Canada's unconventional gas production will increase to about 9.2 Bcfd by 2020 and 13.1 Bcfd by 2035, accounting for nearly three-quarters of Canada's total expected natural gas production of 18 Bcfd in 2035 (assuming mid-range gas prices).[11]

1.2.A ALBERTA UNCONVENTIONAL GAS

A. Introduction

The Alberta oil and gas industry accounts for nearly three-quarters of Canada's oil and gas production and supports a major portion of the Alberta economy. In 2011, Alberta produced 10.4 Bcfd of marketable natural gas from all sources, with 5.8 Bcfd from conventional gas and 4.6 Bcfd from unconventional gas (tight gas, shale gas, natural gas).[17] Alberta's conventional gas production and remaining reserves have steadily declined in the past decade and particularly in the past five years, while its unconventional gas production and reserves have grown. Tight gas and the Montney Resource Play provided 3.8 Bcfd, with coalbed methane providing 0.8 Bcfd.[17] Only small volumes of shale gas are currently being produced in Alberta. However, given the high quality of its shale gas and plays, shale gas production will likely increase.

The province has large undeveloped unconventional gas resources, particularly in the Montney multi-hydrocarbon "Resource Play", in the Duvernay Shale, and in Horseshoe Canyon coalbed methane. These resources offer promise for reversing the current decline in Alberta's natural gas production.

B. Governmental Authorities Engaged with Hydrocarbon Industry

The main provincial governmental agencies involved with the assessment, regulation and facilitation of natural gas activities in the province are the Alberta Ministry of Energy, the Energy and Resources Conservation Board (ERCB), and the Alberta Geological Survey, which is a component of the ERCB. The Petroleum Registry of Alberta facilitates natural gas production data gathering and reporting for the province.

- *Ministry/Department of Energy (DOE)*: The Alberta Ministry/Department of Energy (Alberta DOE) develops policy for Alberta's energy development and supply. The DOE also establishes and administers fiscal and royalty systems

[17] Energy Market Assessment: Short-Term Natural Gas Deliverability 2012-2014. National Energy Board. April 2012

related to resource development and offers royalty selected incentives for shale gas, CBM and horizontal gas wells.

- *Energy Resources Conservation Board (ERCB)*: The Energy Resources Conservation Board (ERCB) is the independent and regulatory agency responsible for overseeing the development of Alberta's energy resources. The ERCB collects data and reports on industry activity – drilling, well types, and production. The ERCB also hosts a Data Dissemination System (DDS) which provides public reports and publications dealing with industry regulations, recommendations, activity, and production. The Alberta Geological Survey (AGS) is a component of the ERCB and performs geological assessments for the province.

- *Petroleum Registry (PR)*: The Petroleum Registry (PR) is a joint private-public organization supporting Canada's upstream oil and gas industry that was formed at the behest of the government. The PR receives hydrocarbon production data from all operators in Alberta and provides private sector operators, the DOE and the ERCB with access to its database and information services.

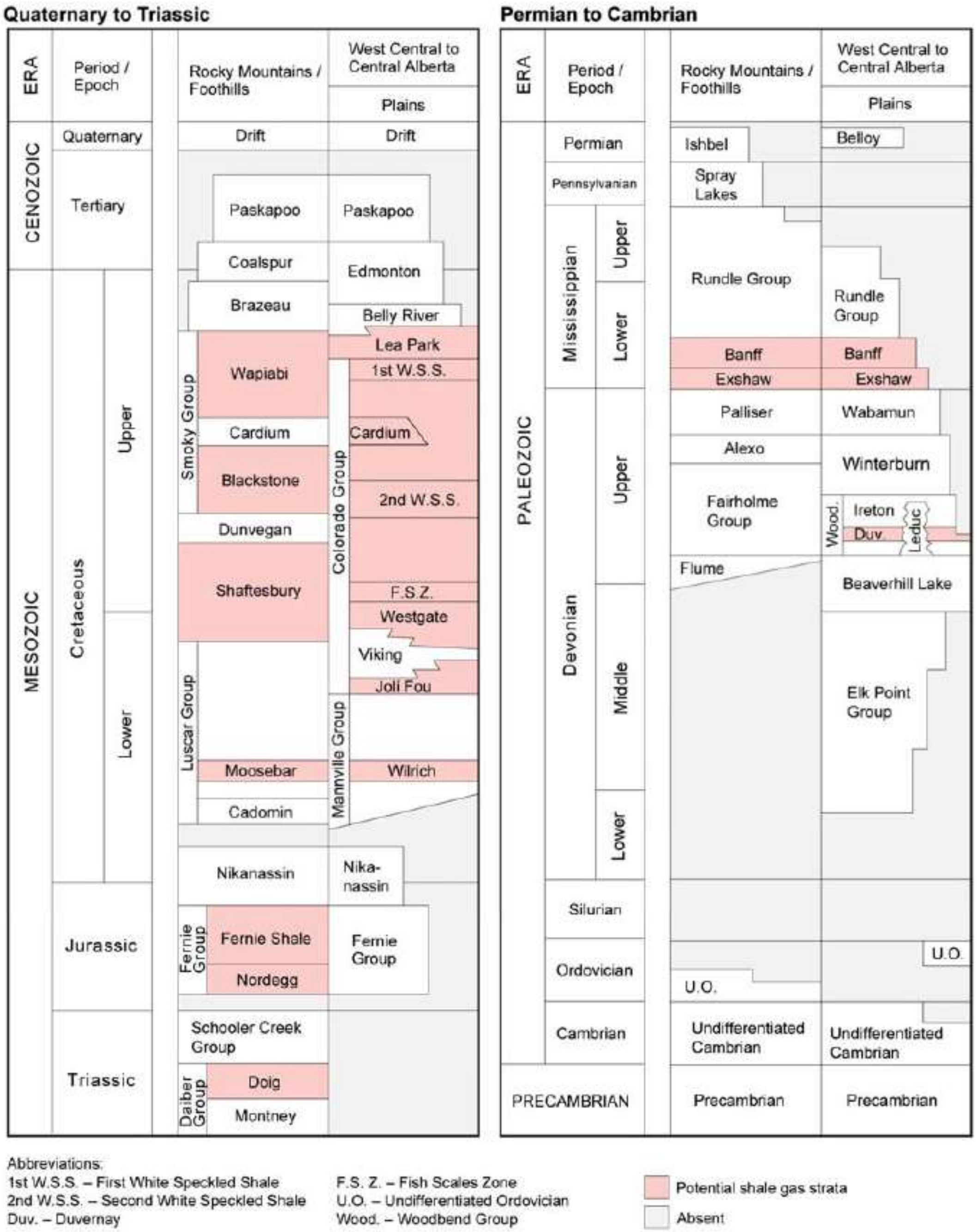
C. Resource Assessments of Unconventional Gas in Alberta

Shale Gas

The ERCB notes that shale are known to underlie much of Alberta and that the province has more than 15 shale formations with potential for shale gas, natural gas liquids, or oil as identified on the generalized stratigraphic chart of formations in Figure 1-2-A-1. However, a number of these formations are not sufficiently organic-rich or otherwise prospective for commercially attractive development.

The more significant of the shale gas formations include the Cretaceous-age Colorado Group and equivalents, the Jurassic-age Fernie Group (including the Nordegg Shale), the Lower Mississippian Banff and Exshaw Shales and the Duvernay/Muskwa Shales of the Upper Devonian Woodbend Group.

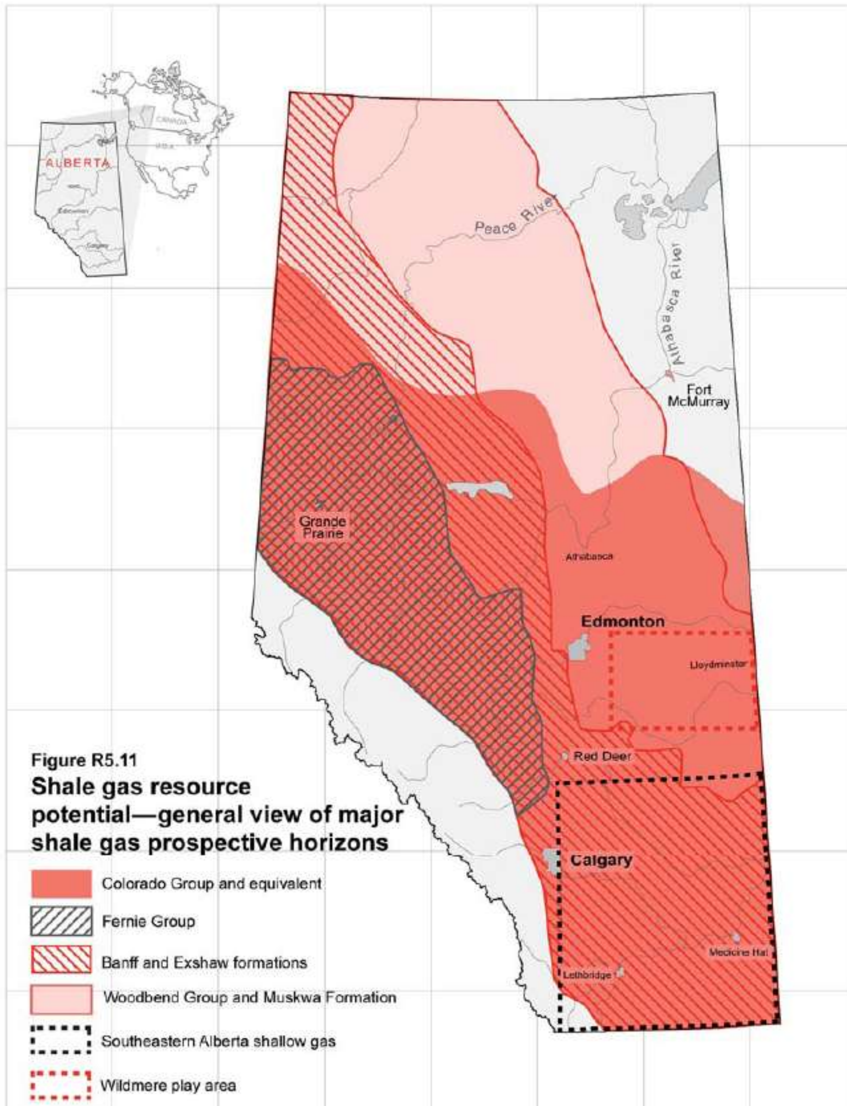
Figure 1-2-A-1. Potential Shale Gas Strata for Alberta Province, Canada



Source: ERCB ST98-2012: Alberta's Energy Reserves 2011 and Supply/Demand Outlook—Contents

Figure 1-2-A-2 provides the geographical extent of the four more significant shale gas formations in Alberta.

Figure 1-2-A-2. Shale Gas Resource Potential – General View of Major Shale Gas Prospective Horizons, Alberta Province, Canada



Source: ERCB ST98-2012: Alberta's Energy Reserves 2011 and Supply/Demand Outlook—Contents

Colorado Group. The Cretaceous-age Colorado Group encompasses a thick sequence of sands, mudstones and shales over a vast 124,000 mi^2 area in southern Alberta and southeastern Saskatchewan. Within the Colorado group there are two primary 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.

No official NEB or ERCB resource assessment exists for the Colorado Group shale formations. However, the EIA/ARI 2011 study assessed a 48,750 mi^2 area of the Colorado Group containing the Fish Scale Shale and Second White Speckled Shale Formations. The study estimated risked shale gas in-place of 408 Tcf with a risked technically recoverable shale gas resource of 61 Tcf for these two shallow shale gas formations.[18] Much of the shale gas development to date has been in the shallow shales of the Colorado Group in eastern Alberta.

Other Shales. Significant shale oil (and associated gas) development is currently underway in the Exshaw/Lower Banff shales, as part of the extension of the Williston Basin Bakken Shale play across the border from North Dakota and Montana. Moderate volumes of associated gas are currently being produced from this shale oil play.

The bulk of recent exploration has targeted the Duvernay and Nordegg shales in western Alberta, with both formations rich in natural gas liquids and oil. The depth of these shale formation increases westward in Alberta, providing higher pressure and potentially more thermally mature horizons for commercial development.

[18] Energy Information Administration. (2011) World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States.

Tight Gas/Montney

Alberta's tight gas reserves and undeveloped resources are currently combined with conventional gas by the ERCB. However, the NEB separates conventional and tight gas production in Alberta, providing the basis for our estimate of remaining proved reserves of 12 Tcf of tight gas and 1 Tcf of Montney resources.

Coalbed Methane (CBM)

Alberta has considerable potential for coalbed methane, particularly in the Upper Cretaceous Horseshoe Canyon (HSC) Formation and the deeper Lower Cretaceous Mannville Group, Figure 1-2-A-3. The ERCB reports 3.5 Tcf initially established CBM reserves for Alberta, with remaining reserves of 2.2 Tcf as of the end of 2011.[19]

The Alberta Geological Survey (AGS), in Earth Sciences Bulletin 2003-03, estimated that there is 500 Tcf of gas in-place within the coals of Alberta.[20] This estimate is accepted as the initial determination of Alberta's CBM gas in-place, Table 1-2-A-1. However, due to the early stage of CBM development and the resulting uncertainty of recovery factors, the recoverable portion of these large values—the ultimate potential—has yet to be determined.

Table 1-2-A-1. Estimated Alberta Coalbed Methane Resources

Upper Cretaceous/Horseshoe Canyon—Plains	148 Tcf
Mannville Coals—Plains	321 Tcf
Foothills/Mountains	31 Tcf
Total	**500 Tcf**

Source: EUB/AGS Earth Sciences Report 2003-03: Production Potential of Coalbed Methane Resources in Alberta.

[19] Energy Resource Conservation Board. (June 2012) ST98-2012: Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021

[20] Beaton, A. (2003): Production potential of coalbed methane resources in Alberta; Alberta Energy and Utilities Board, Alberta Geological Survey. Earth Sciences Report 2003-03.

Horseshoe Canyon Formation (HSC). The HSC Formation is located in the Upper part of the Cretaceous section in south-central Alberta. This formation contains low rank coals in the sub-bituminous C to highly volatile bituminous B range. HSC coals typically have low gas content, but are fully saturated with methane. The HSC's coal resource is notable for its low water content which eliminates the need to dewater the formation before production commences.

According to the ERCB, the initially established HSC CBM reserves are about 2.5 Tcf with remaining established reserves of approximately 1.1 Tcf. Currently, over 17,500 wells exist within the HSC play (ERCB).[19] The NEB conservatively estimates 20,000 potential new well locations in the HSC core area and 6 to 12 Tcf of remaining recoverable coalbed methane resource.[21]

The AGS estimates 148 Tcf of gas in-place for HSC coals in the Plains of Alberta.[20]

Mannville Group. The Mannville coals of the Lower Cretaceous are amongst the oldest, deepest, and most widely distributed coals of the Alberta Plains. They are thick, continuous and contain higher gas contents than most other prospective CBM coals in Alberta due to their higher rank and greater degree of coalification. Despite the high gas content of the Mannville coals, commercially economic production has been difficult to achieve due to the high saline water content, depth and complex nature of the coal beds. The coals require extensive dewatering (and its disposal) before production of methane can commence.

The Mannville Group CBM resource in the Corbett area has initial established reserves of about 1 Tcf with remaining established reserves of approximately 0.8 Tcf.[19] The AGS estimates 321 Tcf of ultimate gas in-place for Mannville Group coals in the Plains of Alberta.[20]

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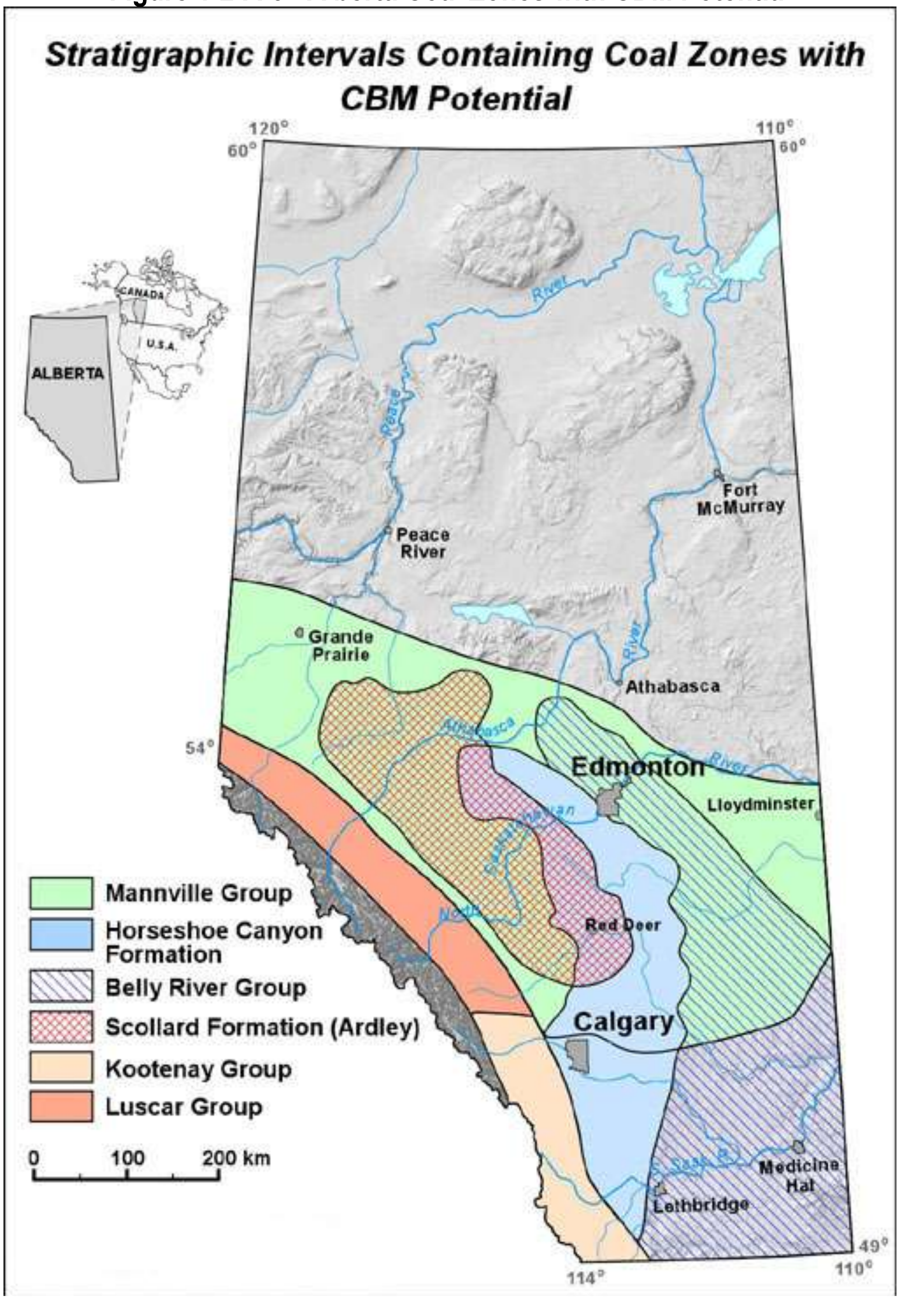
[21] Overview and Economics of Horseshoe Canyon Coalbed Methane Development. National Energy Board. May 2007

Other CBM. Additional CBM resources exist in the Taber and MacKay coals of the Scollard Formation and the Kootenay coals of the Mist Mountain Formation. No recoverable CBM resources or reserves have been established for these coals.

Figure 1-2-A-3. Alberta Coal Zones with CBM Potential



Source: Alberta Geological Survey – Alberta Coal Occurrences and Potential Coalbed Methane Exploration Areas

D. Unconventional Gas Activity and Production

Until recently Alberta's unconventional gas production had previously seen steady growth. However, with today's low natural gas prices and limits on natural gas exports, Alberta unconventional gas production is expected to remain static or steadily decline in the near future.

D.1 Historical Unconventional Gas Activity and Production

Unconventional gas development is an important part of Alberta's natural gas activity, Table 1-2-A-2.

Table 1-2-A-2. Alberta Unconventional Gas Activity and Production (2011)

Resource	Wells 2011	Annual Production 2011*
	(#)	(MMcfd)
CBM	418	777
Montney	n/a	213
Tight Gas	1,409	3,601
Total	**1,827**	**4,591**

Source: NEB Short-Term Natural Gas Deliverability 2012-2014

- Most active has been tight gas development with 1,409 new wells and 3,601 MMcfd of marketed production in 2011, from 1,055 new wells and 3,749 MMcfd of marketed production in 2010.[17]

- Coalbed methane accounted for 418 wells and 777 MMcfd of production in 2011, down from 612 wells and 812 MMcfd of marketed production in 2010.[17]

- The Montney Resource Play provided 213 MMcfd of marketed production in 2011, up from 192 MMcfd in 2010. The NEB combined Montney well drilling with conventional and tight gas drilling in 2010 and 2011.[17]

- The ERCB recognized 147 producing and commingled shale wells as of 2011, with 19 horizontal and 7 vertical shale wells placed on production in 2011.[19]

D.2 Near-Term Unconventional Gas Activity and Production

Expectations for Alberta's unconventional gas activity and production are provided by the NEB in the Annual Gas Deliverability Report (2011, mid-range case), Table 1-2-A-3:

- With declining well drilling, production from tight gas plays steadily declines from 3.4 Bcfd in 2012 to 3.0 Bcfd in 2014.[17]
- The Montney Resource Play is expected to increase in production reaching 0.3 Bcf of production in 2012 and 0.4 Bcfd in 2014.[17]
- Coalbed methane declines moderately from 0.7 Bcf in 2012 to 0.6 Bcfd in 2014.[17]

Table 1-2-A-3. Expectations for Alberta's Unconventional Gas Activity and Production

Resource	New Projected Wells			Projected Annual Production		
	2012	2013	2014	2012	2013	2014
	(#)	(#)	(#)	MMcf/d	MMcf/d	MMcf/d
CBM	91	36	23	721	655	597
Montney	45	42	38	264	319	370
Tight Gas	687	520	461	3,415	3,192	2,964
Total	**823**	**598**	**522**	**4,400**	**4,166**	**3,931**

D.3 Longer-Term Unconventional Gas Production

For the longer term, the NEB projects Alberta unconventional gas production will decline to about 3.2 Bcfd by 2020 but then rebound to 3.8 Bcfd by 2035 assuming mid-range gas prices.[22]

In addition to current tight gas and CBM production, additional unconventional gas production may be provided in the province by emerging shale gas and oil plays, such as the Colorado Group and the Duverney.

[22] Energy Market Assessment: Canada's Energy Future: Energy Supply and Demand Projections to 2035, Appendix A4.2. National Energy Board. November 2011

Appendix 1. Geological Studies of Unconventional Gas Formations in Alberta

Numerous geological assessments of unconventional gas plays have been undertaken by Alberta's Energy Resources Board and the Alberta Geological Survey. These studies help build the foundation for assessing the size and characteristics of the unconventional gas resources of Alberta. The following are a sample of key geological studies prepared by the ERCB/AGS:

"Regional evaluation of the coalbed methane potential of the Foothills/Mountains of Alberta," (second edition) (2002)

"Production Potential of Coalbed Methane Resources in Alberta," (2003)

"Horseshoe Canyon – Bearpaw Transition and Correlation of Associated Coal Zones Across the Alberta Plains," (2005)

"Overview and Economics of Horsehoe Canyon Coalbed Methane Development, (NEB) 2007

Geochemical and Sedimentological Investigation of the Colorado Group for Shale Gas Potential: Initial Results," (2008)

"Geochemical and Sedimentological Investigation of Banff and Exshaw Formations for Shale Gas Potential: Initial Results," (2008)

"Mineralogy, Permeametry, Mercury Porosimetry, Pycnometry and Scanning Electron Microscope Imaging of the Duvernay and Muskwa formations in Alberta: Shale Gas Data Release," (2010)

"Rock Eval™, Total Organic Carbon and Adsorption Isotherms of the Duvernay and Muskwa Formations in Alberta: Shale Gas Data Release," (2010)

"Rock Eval™, Total Organic Carbon and Adsorption Isotherms of the Colorado Group in Alberta: Shale Gas Data Release," (2010)

"Organic Petrography of the Duvernay and Muskwa Formations in Alberta: Shale Gas Data Release," (2010)

1.2.B BRITISH COLUMBIA UNCONVENTIONAL GAS

A. Introduction

A growing portion of the British Columbia (BC) economy is related to oil and gas development. Oil and gas capital investment in the province was $7.1 billion in 2010 and the province's 2011 royalty and tax revenues from oil and gas activity were $731.3 million.[23]

In 2011, British Columbia produced 3.6 Bcfd of natural gas, with unconventional gas, tight gas and shale gas productivity of 2.3 Bcfd accounting for nearly two-thirds of total production.[24] The province has large undeveloped resources of unconventional natural gas, as further discussed in this section.

B. Governmental Authorities Engaged with Unconventional Gas Development

The main governmental agencies involved with the assessment, regulation and facilitation of natural gas activities in the province are the British Columbia Ministry of Energy and Mines, the British Columbia Ministry of Finance, and the British Columbia Oil and Gas Commission.

- *British Columbia Ministry of Energy and Mines (MEM):* The British Columbia Ministry of Energy and Mines Oil and Gas Division promotes oil and gas development through resource assessments and public private partnerships to upgrade infrastructure. Gas production data is obtained from natural gas plants and published by the MEM on a monthly basis.

  In 2011, the MEM in collaboration with the NEB, released a resource assessment of the unconventional shale gas resources in the Horn River Basin. A similar assessment (by the MEM/NEB) for the Montney Resource Trend is due at the

[23] Adams, C. (2012): The Status of Exploration and Development Activities in the Montney Play Region of Northeast British Columbia. British Columbia Ministry of Energy and Mines, Oil and Gas Division, Geoscience and Strategic Initiatives Branch. 6th Unconventional Gas Technical Forum. Victoria, BC.
[24] Energy Market Assessment: Short-Term Natural Gas Deliverability 2012-2014. National Energy Board April 2012.

end of 2012. The MEM also produces a variety of studies on BC's oil and gas development, petroleum geology, and hydrocarbon resources.

- *British Columbia Ministry of Finance, Oil and Gas Royalty Branch:* Royalties from natural gas production are collected by the British Columbia Ministry of Finance's Oil and Gas Royalty Branch which also collects monthly production and sale data from producers and midstream gas processors. The Ministry of Finance provides a number of incentives to encourage unconventional gas development, including royalty credits for horizontal wells, based on drilled depth and geological area, and for construction of roads and other infrastructure in northwest British Columbia.

- *British Columbia Oil and Gas Commission:* The British Columbia Oil and Gas Commission is the independent regulatory agency in charge of overseeing hydrocarbon operations in British Columbia. The Commission's jurisdiction includes exploration, development, pipeline transportation, reclamation, and the decommissioning of wells. The Commission collects and makes available information for wells drilled in BC, including completion techniques per well, injection wells, and water disposal.

  The Commission maintains a gas development database which it uses to issue a variety of reports, including: Drilling and Production Data by Field and Pool and an Annual Hydrocarbon Reserves Report which provides considerable information regarding unconventional gas activity and reserves. The Commission's website makes it possible to query wells by location, name and company.

C. Resource Assessments of Unconventional Gas in British Columbia

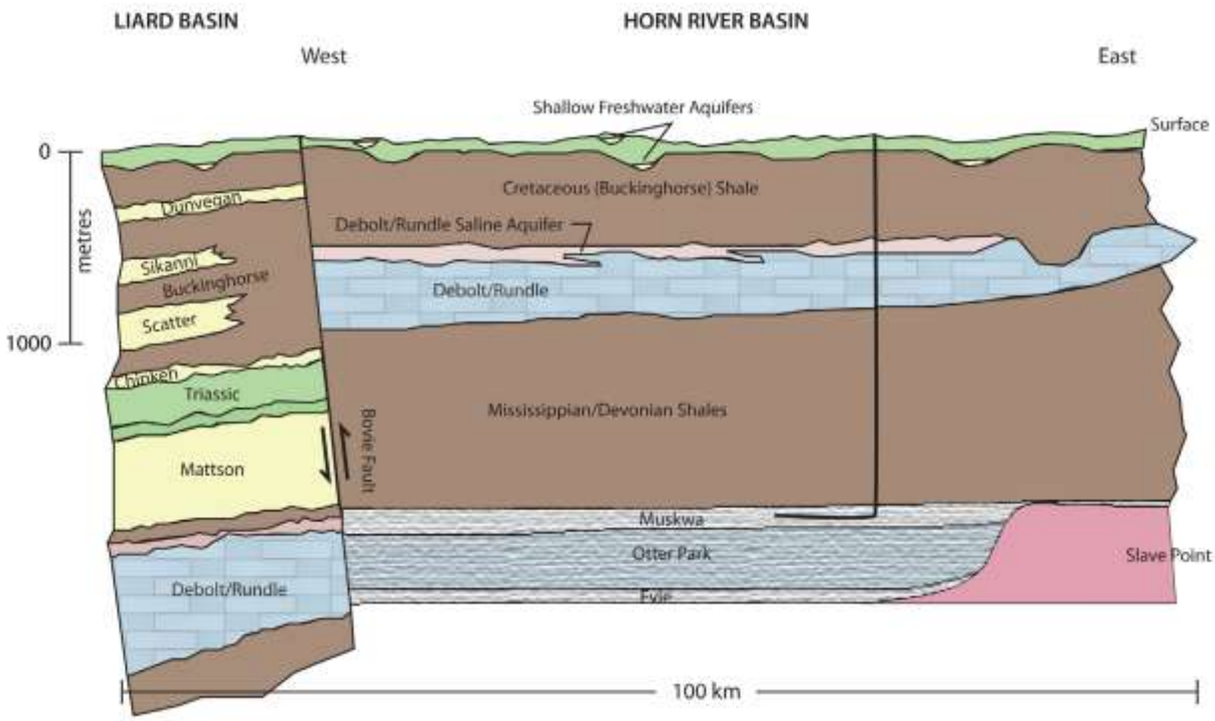
C.1 Shale Gas

Horn River Basin Shale Gas. The shale gas resource in the Horn River Basin underlies approximately 1.1 million hectares of land in northeastern British Columbia, north of Fort Nelson and south of the Northwest Territories border. Figure 1-2-B-1 provides an outline of the Horn River Basin. Figure 1-2-B-2 depicts the main shale formations within the Horn River Basin – the Muskwa, Otter Park and Evie. These formations exist between the Fort Simpson, a thick sequence of low organic content ductile shales, and the underlying Keg River, a low permeability carbonate formation.

Figure 1-2-B-1: Horn River Basin Area

Source: British Columbia Oil and Gas Commission

Figure 1-2-B-2: Schematic Stratigraphic Cross-Section of the Horn River Basin and Adjacent Liard Basin



Source: British Columbia Oil and Gas Commission (modified from Petrel Robertson)

According to the 2011 NEB and MEM assessment, the ultimate recoverable resource potential for the Horn River Basin's marketable shale gas is 78 Tcf, including 3 Tcf of discovered resources and 75 Tcf of undiscovered resources, based upon a gas in-place assessment of 448 Tcf.[25] The latest British Columbia Oil and Gas Commission reserves study reports that the Horn River Basin has 10.3 Tcf of initial established reserves, with 93 Bcf of produced shale gas as of 2010.[26]

[25] Energy Market Assessment: Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin. BC MEM and NEB. May 2011.
[26] 2010 Hydrocarbon and By- Product Reserves in British Columbia. British Columbia Oil and Gas Commission. December 2011.

In 2011 Advanced Resources International, Inc. (ARI) prepared for the U.S. Energy Information Administration a study of the Horn River Basin's shale gas resources, estimating a risked resource in-place of 488 Tcf, with 165 Tcf of risked recoverable resources.[27] In contrast, the NEB/MEM report estimated 448 Tcf of gas in-place and 78 Tcf of marketable gas for this basin. While the gas-in-place estimates for the EIA/ARI and NEB/MEM studies are comparable, considerable variation exists in the recoverable and marketable gas estimates due to the following:

- The EIA/ARI technically recoverable gas of 165 Tcf includes approximately 10% CO_2 and gas used as lease fuel; the NEB marketable gas excludes about 12% CO_2 and approximately 5% of gas used as lease fuel.
- The EIA/ARI study uses a gas recovery factor of about 33% of gas in-place; the NEB study uses a more conservative recovery factor of approximately 25% of gas in-place.

An independent resource study by Macquarie Tristone estimated that the Horn River Shales hold 500 Tcf with 20-40% recoverable.

Other Shale Basins. British Columbia also has shale gas resources in the Cordova Embayment in a 379,000-hectare area east of the Horn River Basin and in the multiple shale gas formations within the large 1.25 million hectare Liard Basin to the west of the Horn River Basin.[28] No official NEB or MEM resource assessment of these plays exists. However, recently Apache Corp. estimated 48 Tcf of net recoverable sales of gas resources exist within the company's 430,000-hectare lease area. The aforementioned EIA/ARI study estimated that the Cordova Embayment has a risked shale gas in-place of 83 Tcf with a risked technically recoverable resource of 29 Tcf and that the Liard Basin has a risked shale gas in-place of 125 Tcf with a technically recoverable resource of 31 Tcf.[27] Exploratory drilling is underway in both of these basins.

[27] Energy Information Administration. (2011) World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States.
[28] Adams, C. (2012): Summary of shale gas activity in northeast British Columbia 2011, *BC Ministry of Energy and Mines.*

Doig Phosphate Shale. The Doig Phosphate Shale overlies the Montney formation in the western Deep Basin. No formal NEB or MEM resource assessment exists for this shale gas play. The EIA/ARI report estimated that a 3,000-mi^2 prospective area for the Doig Phosphate Shale (Figure 3) has a risked shale gas in-place of 81 Tcf with a risked technically recoverable shale gas resource of 20 Tcf.[27] The British Columbia Oil and Gas Commission estimates that the Doig Phosphate shale within the Montney Area Resource Play holds about 0.3 Tcf of initial raw gas reserves.[4]

C.2 Tight Gas

The dominant tight gas play in British Columbia is the Devonian-age Jean Marie in the Sierra area of northeast British Columbia, although additional tight gas plays exist in the Deep Basin and British Columbia Foothills. The British Columbia Oil and Gas Commission estimates that the Jean Marie formation, with its 30 years of production history, has produced 1.9 Tcf of tight gas and has 1.8 Tcf of remaining reserves.[4] Additional un-assessed tight gas resources exist in the British Columbia Deep Basin and the British Columbia Foot Hills.

C.3 Coalbed Methane

The Rocky Mountain Coal Belt contains about 80 percent of the province's coal in its Upper Jurassic to Lower Cretaceous coalfields.

Beginning in the 1990s, the British Columbia Ministry of Energy and Mines Geosciences Branch and the British Columbia Geological Survey performed a series of studies on the size of the coal resource and the potential of coalbed methane in the province. Based upon these studies, British Columbia has a measured coal resource of over 3 billion tonnes and an in-place coal resource available for coalbed methane exploration that exceeds 250 billion tonnes. The potentially recoverable coalbed methane resource is estimated to be 90 Tcf, Figure 1-2-B-3.[29,30]

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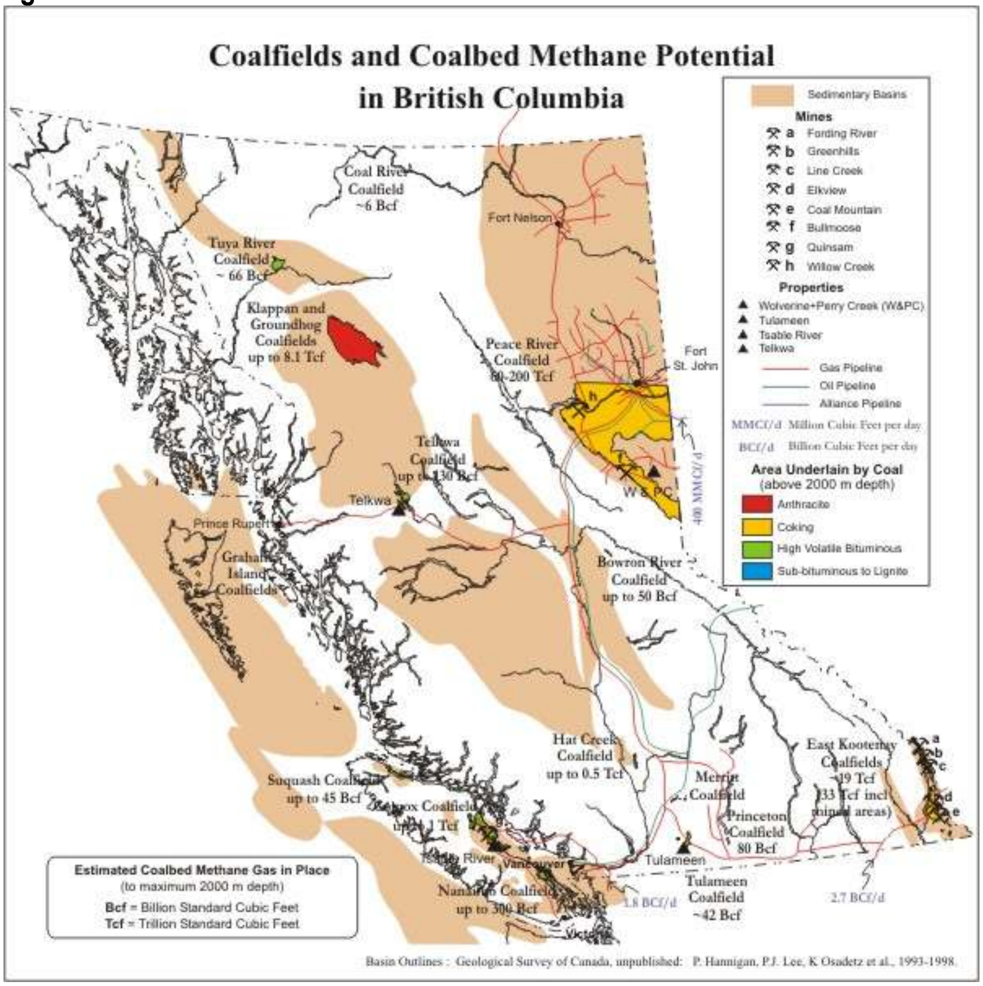
[29] Ryan, B. (2003): A Summary of Coalbed Methane Potential in British Columbia; *Canadian Society of Exploration Geophysicists Recorder,* Vol.28, No.9, November 2003, pages 32-40.
[30] Coalbed Gas Potential in British Columbia; BC Ministry of Energy and Mines Petroleum Geology Paper 2004-1. June 2004.

Figure 1-2-B-3. Coal Fields and Coalbed Methane Potential in British Columbia.

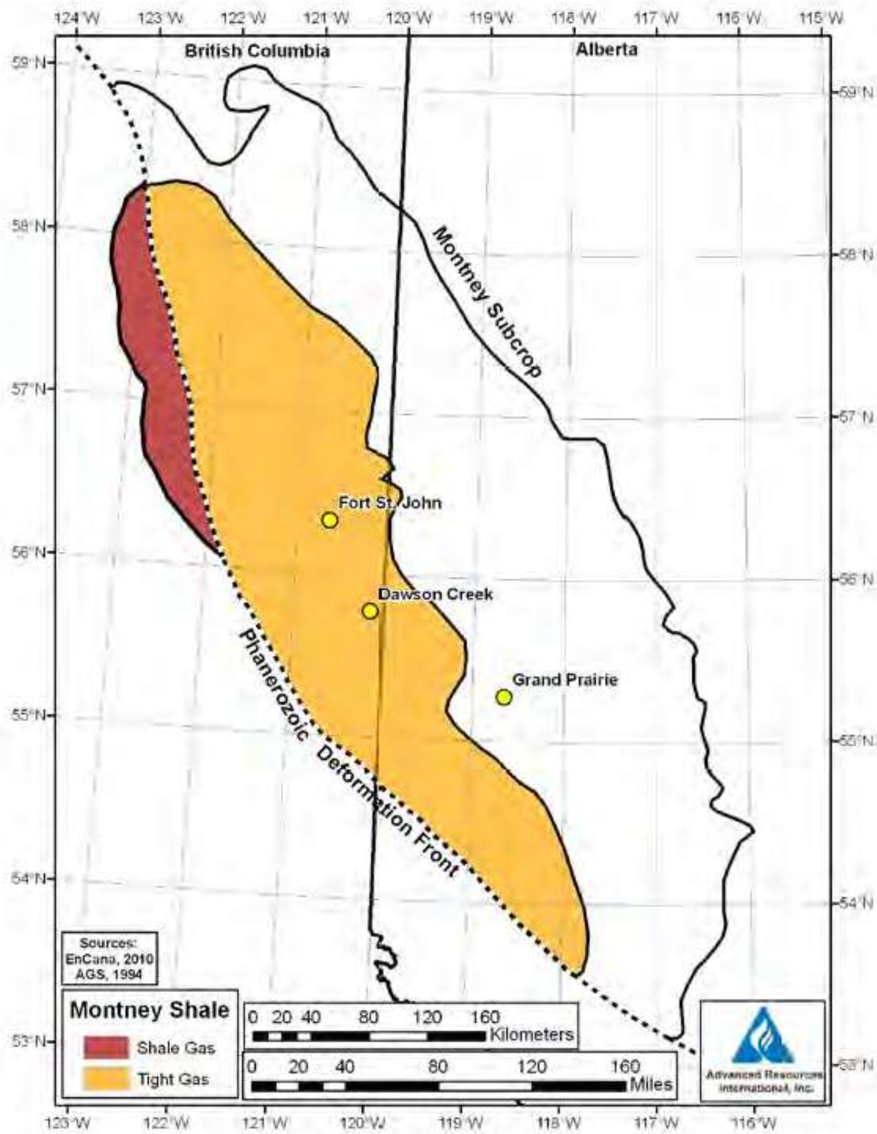


Source: British Columbia Ministry of Energy and Mines

C.4 Montney Resource Play Resource Assessment

The Montney Resource Play includes a shale gas area in the west, a tight gas area in the center and a potential oil/condensate area along the eastern portion of the Deep Basin, Figure 1-2-B-4. The NEB and British Columbia's MEM are working on a joint resource assessment of the Montney Trend's unconventional shale and tight gas, scheduled for completion in winter 2012/2013. This Triassic-age resource trend extends from north-central Alberta to northwest of Fort St. John, British Columbia and covers about 10,200 km^2 in the Peace River Region of BC.

Figure 1-2-B-4. Deep Basin Montney Resource Play



Source: ARI/EIA 2011

In ARI's 2011 study, the Montney's 1,900-mi^2 prospective shale gas area, located in the northwestern portion of the play, is estimated to hold 141 Tcf of risked shale gas in-place and a risked technically recoverable shale gas resource of 49 Tcf (EIA 2011). No estimates for tight gas or oil/condensate for the Montney Resource Play are contained in the EIA/ARI study. A study by Macquarie Tristone estimates that the Montney holds 900 Tcf of gas in-place with a recovery factor of 20-40%.

The British Columbia Oil and Gas Commission estimates that the Montney has 7.9 Tcf of initially established gas reserves, with 0.6 Tcf produced as of 2010.[4] While a significant number of wells have been drilled into the Montney Resource Play, most of the wells have targeted the tight gas area.

D. Unconventional Gas Activity and Production

British Columbia has seen steady growth in unconventional gas drilling, reserves, and production, particularly from the large Montney Resource and Horn River Shale plays, in the Western Canadian Sedimentary Basin.

D.1 Historical Unconventional Gas Activity and Production.

Drilling and development of unconventional gas has accounted for much of British Columbia's natural gas activity, Table1-2-B-1:

- Most active has been the Montney Resource Play with 250 new producing wells and 1,056 MMcfd of marketed production in 2011, up from 217 new producing wells and 709 MMcfd of marketed production in 2010.

- The Horn River Shales provided 75 new producing wells and 495 MMcfd of marketed production in 2011, up from 52 new producing wells and 306 MMcfd of marketed production in 2010.

- In spite of declining well drilling, 51 new production wells in 2011, tight gas production increased to 787 MMcfd, up from 711 MMcfd in 2010.

Table 1-2-B-1. British Columbia Unconventional Gas Activity and Production

Resource	Wells		Annual Production	
	2010	2011	2010	2011
	(#)	(#)	(MMcfd)	(MMcfd)
Tight Gas	171	51	711	787
Montney	217	250	709	1,056
Horn River Shale	52	75	306	495
Total	**440**	**376**	**1,726**	**2,338**

Source: NEB Annual Gas Deliverability Reports (2010, 2011)

D.2 Near-Term Unconventional Gas Activity and Production

Expectations for British Columbia's unconventional gas activity and production are provided by the NEB in the Annual Gas Deliverability Report (2012, mid-range case), Table 1-2-B-2:

Table 1-2-B-2. Expectations for BC's Unconventional Gas Activity and Production

Resource	New Projected Wells			Annual Production		
	2012	2013	2014	2012	2013	2014
	(#)	(#)	(#)	MMcf/d	MMcf/d	MMcf/d
Tight Gas	44	39	25	716	639	561
Montney	184	180	163	1,353	1,497	1,580
Horn River Shale	39	43	43	555	587	522
Total	**267**	**262**	**231**	**2,624**	**2,722**	**2,663**

Source: British Columbia, NEB Annual Gas Deliverability Report (2012)

- The Montney Resource Area is expected to remain the dominant unconventional gas play in B.C., reaching 1.4 Bcf of production in 2012 and 1.6 Bcfd in 2014.
- Until gas prices improve and the LNG export market is established, the gas production from the Horn River Shale remains relatively flat at 0.5 to 0.6 Bcfd
- With declining well drilling, production from tight gas plays steadily declines from 0.7 Bcfd in 2012 to below 0.6 Bcfd in 2014.

D.3 Longer-Term Unconventional Gas Production

For the longer term, the NEB projects British Columbia's unconventional gas production including tight gas, shale gas, and CBM production, will grow to nearly 6 Bcfd in 2020 and further to 9.3 Bcfd by 2035. These production projections assume LNG exports and mid-range gas prices.[31] In addition to increasing unconventional production from the already active Montney Resource Play and the Horn River Shale, additional unconventional gas production may be provided by the organically rich gas shales in the Cordova Embayment and Liard Basin as well as from the numerous coalbed methane plays in the province.

31 Energy Market Assessment: Canada's Energy Future: Energy Supply and Demand Projections to 2035, Appendix A4.2. National Energy Board. November 2011.

Appendix 1: Geological Studies of Unconventional Gas Formations in British Columbia

Numerous geological assessments of potential unconventional gas plays have been undertaken by British Columbia's of Ministry of Energy and Mines and the Geological Survey of Canada. These studies help build the foundation for assessing the size and characteristics of the unconventional gas resources of British Columbia. The following are a sample of British Columbia geological studies:

- "A Summary of Coalbed Methane Potential in British Columbia," (2003)
- "Liard Basin – Middle Devonian Exploration," (2005)
- "Regional "Shale Gas" Potential of the Triassic Doig and Montney Formations, Northeastern British Columbia," (2006)
- "Shale Units of the Horn River Formation, Horn River Basin and Cordova Embayment, Northeastern British Columbia," (2008)
- "Geological Controls on Matrix Permeability of the Doig-Montney Hybrid Shale-Gas–Tight-Gas Reservoir, Northeastern British Columbia," (2012)

1.3 MEXICO UNCONVENTIONAL GAS

A. Introduction

Mexico has a long and proud history of oil and gas development with world class oil fields such as Cantarell with a peak oil production rate of 2.14 million barrels per day in 2004. Since then, however, Cantarell's oil production has declined to 558,000 barrels per day (in 2010) as has total oil production in Mexico. With declining oil production, Mexico has begun to shift more of its domestic energy consumption to natural gas, particularly in the electricity and industrial sectors.

While Mexico's natural gas production has grown in recent years, consumption has grown even faster. Mexico is a significant producer of natural gas with annual production in 2011 of 52.5 Bcm or 5.1 Bcfd from proven reserves of 350 Bcm (12.5 Tcf).[32] However, with consumption of 68.9 Bcm or 6.7 Bcfd in 2011, Mexico has become a net importer of natural gas, Table 1-3-1.[33] Last year (2011), Mexico imported 16.4 Bcm or 1.6 Bcf of natural gas, primarily by pipeline from the U.S. but also via LNG from Qatar, Nigeria and Peru.

Table 1-3-1. Mexico Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		67.9	2,400	6.6	68.9	2,430	6.7
Supply							
▪	Marketed Production (Dry)	55.1	1,950	5.4	52.5	1,850	5.1
▪	Net Exports/Imports	12.8	450	1.2	16.4	580	1.6

Source: BP Statistical Review of World Energy, June 2012.

32 U.S. Energy Information Administration. Country Analysis Brief: Mexico. Accessed July 24, 2012.
33 BP Statistical Review of World Energy, June 2012.

Domestic natural gas consumption has been and is projected to continue to grow annually by 2.4%. By 2025, the Secretaria de Energia (SENER) predicts Mexico will require an additional 52 Bcm (5 Bcfd) of supply over today's production to satisfy growing demand.[34]

Recent resource appraisal work by PEMEX indicates that Mexico has recoverable shale gas resources of 8,410 Bcm (297 Tcf) ranging from 4,250 to 13,000 Bcm (150 to 459 Tcf), Table 1-3-2.[35] These resources are distributed across a host of Cretaceous- and Jurassic-age basins, Figure 1-3-1. As such, developing unconventional gas, particularly shale gas, is becoming a high priority as Mexico seeks to meet its growing demand for natural gas.

Table 1-3-2. Mexico Unconventional Gas Resources

		Resource Estimates				Current Production	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	8,410	297	-	-
▪	CBM	n/a	n/a	110	4	-	-
▪	Tight Gas	n/a	n/a	n/a	n/a	Not defined	Not defined
	TOTAL	**n/a**	**n/a**	**8,520**	**301**		

B. Governmental Authorities Engaged with Unconventional Gas Development

The three main governmental agencies involved with the assessment, regulation, and development of natural gas in Mexico are the Ministry of Energy (SENER), the National Commission of Hydrocarbons (CNH or Commission), and Petroleos Mexicanos (PEMEX).

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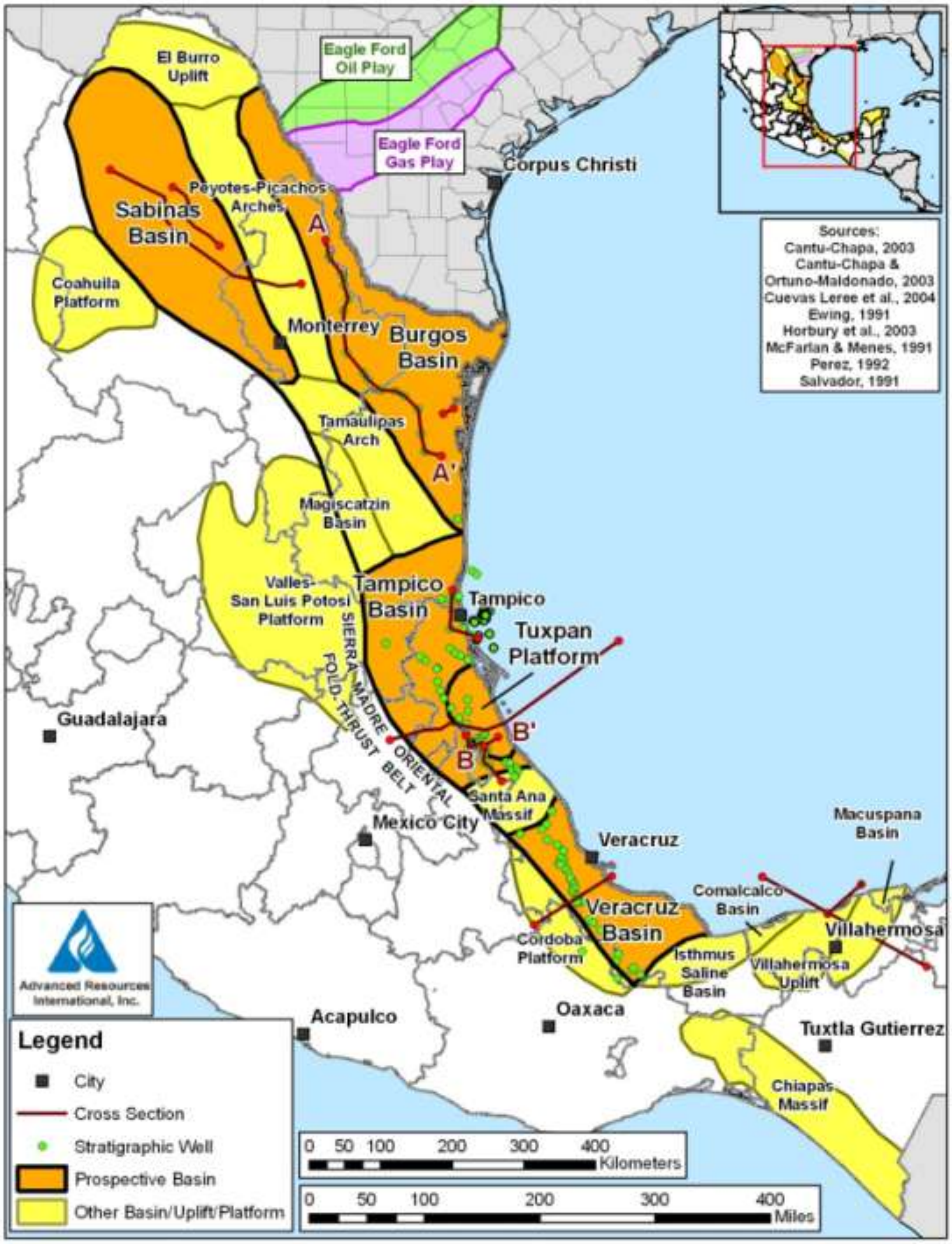
34 Unconventional Gas in Mexico: Economic Considerations and Regulatory Issues. Presentation. Comision Nacional de Hidrocarburos. Adopted from SENER. August 2011

35 Investor Presentation from PEMEX, March 2012

Figure 1-3-1. Onshore Shale Gas Basins of Eastern Mexico's Gulf of Mexico Basin.



(Source ARI, 2011)

- *Ministry of Energy (Secretaria De Energia) (SENER)*. The Mexican Ministry of Energy is the official government agency in charge of energy production and regulation in Mexico. All of Mexico's hydrocarbon resources are owned by the state, as set forth by the Mexican Constitution. SENER also plays an important role in Mexico's economic policies and the head of SENER is a member of the Executive Cabinet of Mexico.

- *National Commission of Hydrocarbons (Comision Nacional de Hidrocarburos or CNH)*: The CNH is a technically oriented, independent organization charged with supporting SENER in the regulation of PEMEX and its subsidiaries. The CNH was created to support and evaluate PEMEX operations by establishing technical guidelines, designing performance evaluation mechanisms, and creating guidelines for the approval and allocation of budgets for future energy projects.

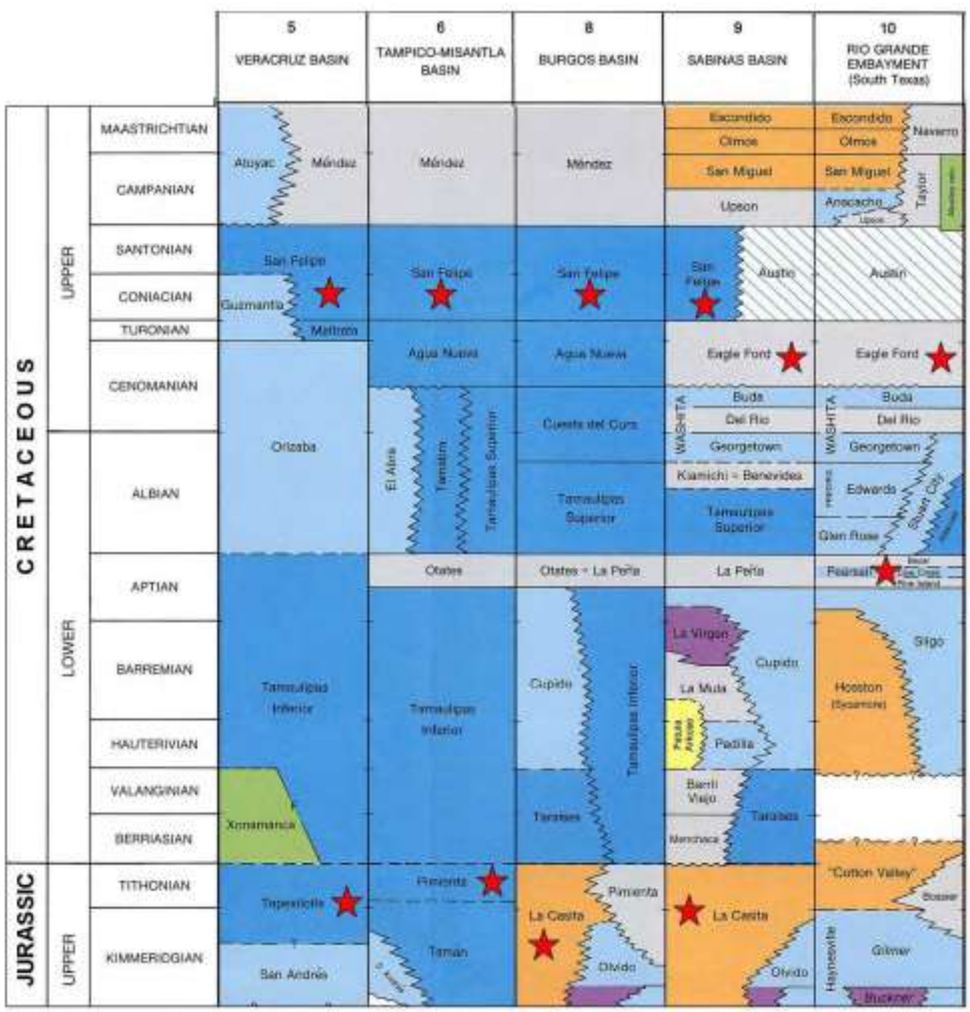
- Petroleos Mexicanos (PEMEX). Petroleos Mexicanos (PEMEX), Mexico's state-owned, vertically integrated petroleum company, is responsible for Mexico's hydrocarbon production and marketing. It is also the largest contributor to government treasuries, providing over a third of the government's tax revenue, paying out about 60% of its revenue in royalties and taxes.[36] PEMEX has sole control of Mexican hydrocarbon resources, including exploration, production and sale. The company operates through its main corporate office and its four subsidiaries, PEMEX Exploration and Production, PEMEX Refining, PEMEX Gas and Basic Petrochemicals, and PEMEX Petrochemical. PEMEX is a high profile organization in Mexico due to its status as the largest contributor of government revenues.

[36] Hartley, Peter H., Ph.D, Medlock, Kenneth B. III., Ph.D. The Future of Oil in Mexico: The Revenue Efficiency of PEMEX: A Comparative Approach. The James A. Baker III Institute for Public Policy. Rice University, Houston, TX. April, 2011

C. Unconventional Gas Resource Assessments

The Jurassic- and Cretaceous-age shales deposited in Mexico's onshore Gulf of Mexico basins have potential for holding significant volumes of gas in place. Figure 1-3-2 provides a correlative stratigraphic column of shale gas intervals for four major basins of Mexico and for the Rio Grande Embayment in South Texas. The stratigraphic column highlights the San Felipe (Austin equivalent), Aqua Nueva (Eagle Ford equivalent), Yates/La Pena (Pearsall equivalent) and La Casita (Haynesville equivalent) shale sequences.

Figure 1-3-2. Stratigraphy of Jurassic and Cretaceous rocks in the Gulf of Mexico Basin and USA. (Shale gas targets are highlighted.)



Source: EIA/ARI Modified from Salvador, A. and Quezada-Muneton, J.M., 1989

In addition to shale gas, a series of tight sands formations also exist in several of Mexico's eastern basins, equivalent to the Cotton Valley, Hosston and other formations productive in Texas. Coalbed methane resources have been identified in the Sabinas Basin of northern Mexico.

Shale Gas. PEMEX Exploration and Production recently estimated that Mexico has 8,410 Bcm (297 Tcf) of technically recoverable shale gas resources, primarily in the basins of eastern Mexico. The PEMEX study also provides a range in estimates of 4,250 to 13,000 Bcm (150 to 459 Tcf).

- The Burgos Basin's Eagle Ford and Agua Nueva shales are estimated to hold 760 to 2,460 Bcm (27 to 87 Tcf) of recoverable resources.
- The shales in the Sabinas-Burro Picachos area are estimated to hold 1,560 to 4,590 Bcm (55 to 162 Tcf) of recoverable resources.
- The Tampico – Mizatlan region has an estimated 570 to 1,700 Bcm (20 to 60 Tcf) of recoverable shale gas resources.
- Additional shale gas resources exist in the deep (3,000 to 5,000 m) formations in Chihuahua and Veracruz.

In 2011, the EIA/ARI study of worldwide shale gas resources estimated that Mexico has 19,290 Bcm (681 Tcf) of technically recoverable shale gas resource.[37] The comparison of the EIA/ARI and PEMEX E&P studies is provided in Table 1-3-3.[38]

The two studies arrived at similar estimates for the recoverable shale gas resource for Late Jurassic formations. However, the two studies differed significantly on the shale resource in Upper Cretaceous formations, particularly for the Eagle Ford Shale in the Burgos and Sabinas basins. The Eagle Ford Shale and other Upper

[37] Energy Information Administration. (2011) World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States

[38] CNH 2011, Presentation: What Place for Unconventional Gas in Mexico? – Economic Considerations and Regulatory Issues.

Cretaceous shale recoverable gas resources were estimated at 14,360 Bcm (507 Tcf) by the EIA/ARI study compared to 3,000 Bcm (106 Tcf) in the PEMEX study.

Table 1-3-3. (Mexico) EIA/ARI and PEMEX Shale Gas Resource Assessments

Shale Gas Play	US-EIA: World Shale Gas Resources: Mexico Assessment	PEMEX E&P Ranges (lower, central and upper)
Upper Cretaceous	507	54-106-171
Mid-Cretaceous	8	0
Late Jurassic	166	95-190-285
TOTAL	**681**	**150-297-459**

Source: CNH 2011, Presentation: What Place for Unconventional Gas in Mexico? – Economic Considerations and Regulatory Issues

Tight Gas. PEMEX does not identify its tight gas reserves or report tight gas production. However, based on information in the technical literature, tight gas is known to be present in the Burgos and Sabinas basins. PEMEX has recently engaged U.S. drilling and services companies and other technical support providers to enable the company to extract its tight gas resources more efficiently.

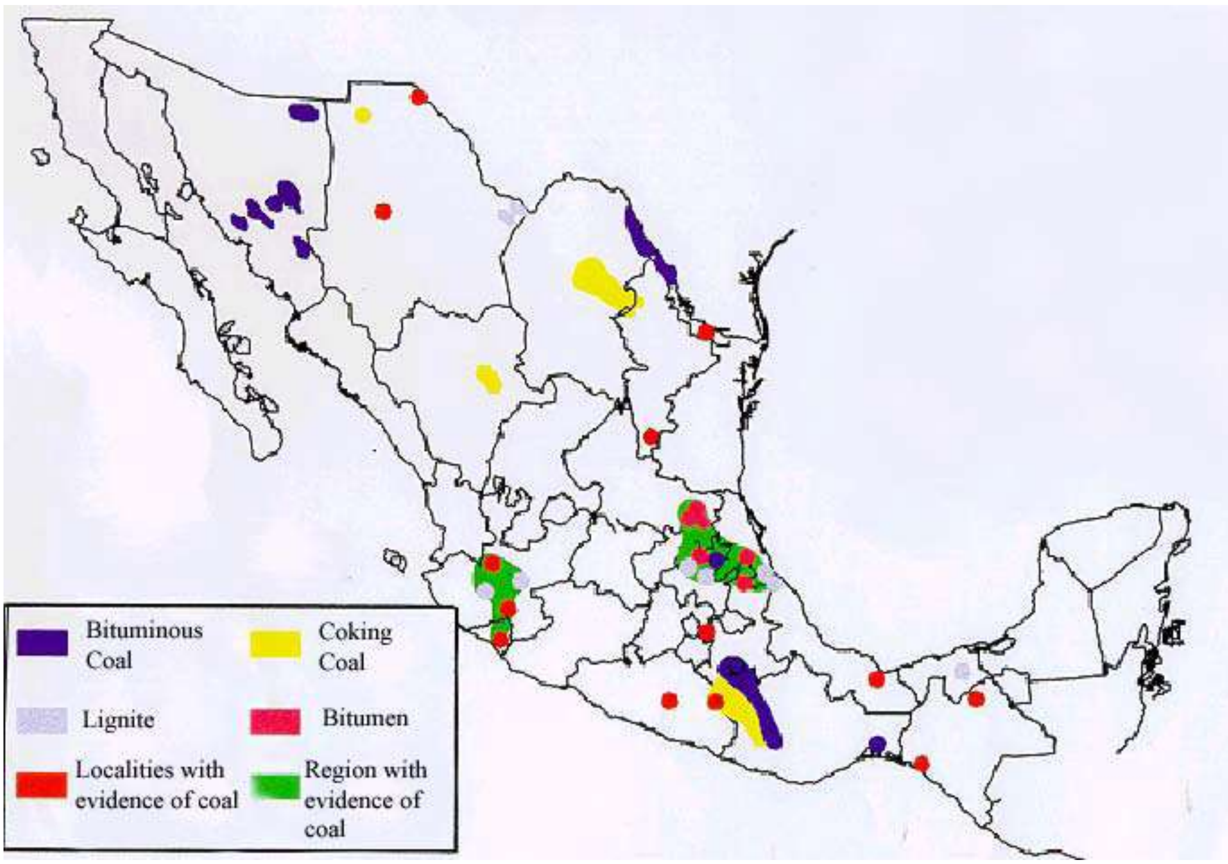
Coalbed Methane. The CNH has set forth an official government estimate for coalbed methane resources of 110 Bcm (4 Tcf). In addition, the U.S. Environmental Protection Agency's Coalbed Methane Outreach Program (CMOP) estimates that Mexico has 119 to 212 Bcm (4.2 to 7.5 Tcf) of CBM resources.[39] These CBM reserves are concentrated in northern Mexico, mainly in Coahuila state in the Sabinas Basin region with additional resources in Sonora and Oaxaca states, Figure 1-3-3. The Sabinas Basin alone is estimated to hold 70 Bcm (2 Tcf) of CBM resource as estimated by Netherland Sewell for the Comision Nacional de Hidrocarburos.[34]

Additional potential for CBM production exists in the deep Mexican coal mines with high methane concentrations, evidenced by Mexican CMM emissions which are currently about 200 MMcm/year (7 Bcf/year).[39] A major roadblock to CBM/CMM

[39] Kelafant, J. Outlook for CMM in Mexico and Colombia. US EPA/ARI. October 2011

development in Mexico is uncertainty regarding coalbed methane production and CBM ownership rights.

Figure 1-3-3. Mexico's Coal Fields



Source: ARI Outlook for CMM in Mexico and Colombia (2011), Adapted from Santillan (2006)

D. Unconventional Gas Activity and Production

Currently, shale gas exploration in Mexico is in its very early stages. In 2011, PEMEX completed its first shale gas well, Emergente #1, into the Eagle Ford Shale in Coahuila state. The well was drilled to a depth of 8,250 feet with a 4,500 ft lateral and then completed with 17 frac stages at a cost of $20 million (USD). The well had an initial production (IP) rate of 2.9 million cubic feet per day (MMcf/d). While gas production from this well began in May, 2012, no additional public data has been released on production volume.

According to PEMEX, the Emergente #1 well is the first in a 10-well shale exploration project to evaluate the Eagle Ford Shale's potential on the Mexico side of this active U.S. shale gas trend. In 2011 PEMEX disclosed that the company plans to invest $8 billion USD to drill 4,000 wells toward a goal of producing 1 Bcf of shale gas per day within the next decade.[34]

For the longer term, PEMEX announced that it plans to pursue five main shale gas areas of Mexico: Sabinas / Burro Picachos; Chihuahua; Burgos; Tampico / Mizantla; and Veracruz. In November of 2011, the company stated that it intends to explore 175 shale gas sites across the economy by 2015 and 6,500 sites by 2050.

Mexican Energy Secretary Jordy Herrera said, "With the shale gas potential and reserves, and the gas associated with crude, we should become a country with sufficient energy resources, both fossil and renewable, to achieve independence, and we could eventually export, all we need to do is make decisions in favor of the Mexican people. Developing gas production is urgent, the country cannot be subjected to the political times." According to Herrera, "government officials have been working with state-owned oil giant Petroleos Mexicanos, or PEMEX, to determine the size of the country's natural gas fields and have contacted Congress to discuss the development of the country's indigenous natural gas reserves."[40]

The challenge to the rapid development of the shale gas resources of Mexico include limited experience with unconventional drilling and completions, lack of a comprehensive gas pipeline infrastructure, PEMEX's priority on oil development, and limits on water resources for hydraulic fracturing in certain of the shale gas basins. However, with a concerted investment and development program directed to shale gas, these challenges will likely be overcome.

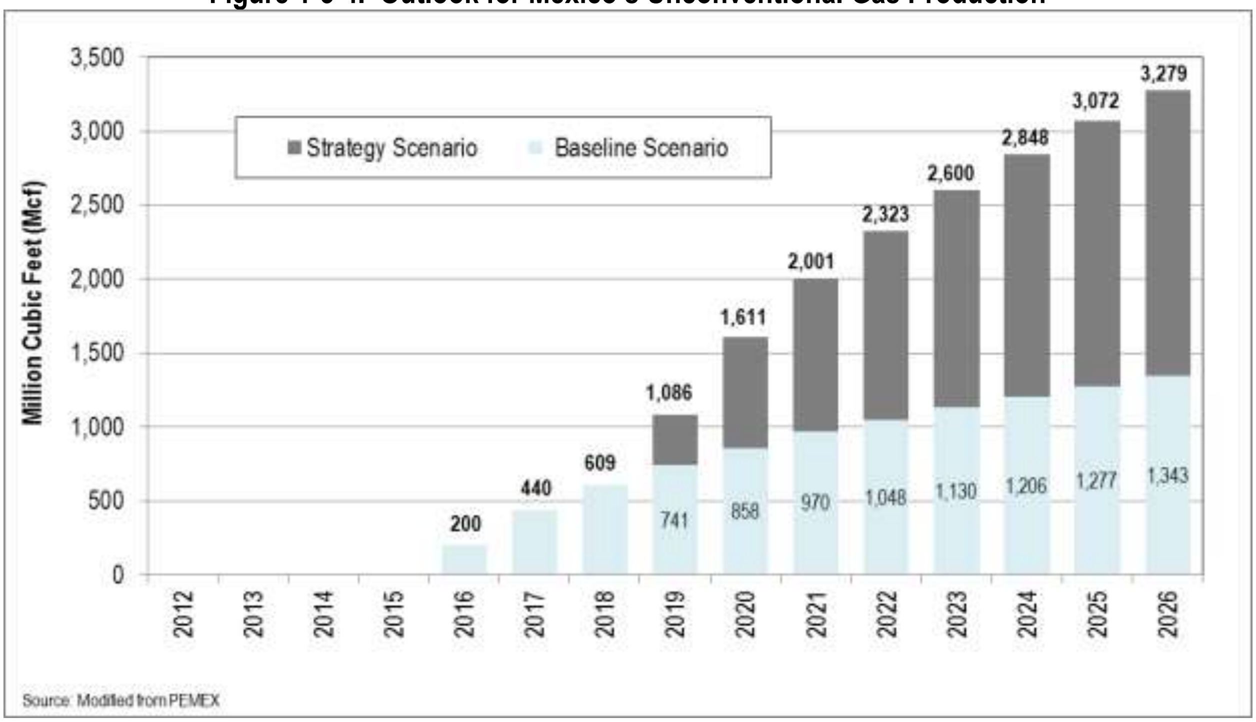
As a measure of Mexico's expectations for its abundant shale gas resources, Energy Minister Herrera announced, in November 2011, that Mexico is scrapping

[40] Mexico - Rising Natural Gas Superstate?, John Daly, 05 December 2011, www.oilprice.com.

construction plans for 10 new nuclear plants and looking "to replace the use of other fuels with natural gas."[41]

The Mexican Ministry of Energy has included two scenarios for the development of shale gas, Figure 1-3-4: (1) the baseline scenario has production of 2 Bcm (0.2 Bcfd) from the Eagle Ford shale play in 2016, reaching 14 Bcm (1.3 Bcfd) in 2026 and (2) the "strategy scenario" which assumes the development of both the Eagle Ford and the La Casita shale/tight sand plays, providing gas production of 34 Bcm (3.3 Bcfd) in 2026.[42,43]

Figure 1-3-4. Outlook for Mexico's Unconventional Gas Production



[41] Mexico Reorients Energy Strategies on Shale Gas, Gregg Hass, December 2, 2011, www.ugcenter.com.
[42] Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas, International Energy Agency, OECD/IEA, 2012, 29 May 2012.
[43] Secretaria de Energia, 2012 Estrategia Nacional de Energia (National Energy Strategy) 2012-2026, Secretaria de Energia, Mexico City.

Appendix 1. Geological Studies of Unconventional Gas Formations in Mexico

The following are a sample of key geological studies prepared by the various federal and state agencies involved with assessing the size and characteristics of the unconventional gas resources of Mexico.

1. Guzman-Vega, M.A., Castro Ortiz, L., Roman-Ramos, J.R., Medrano-Morales, L., Valdez, L.C., Vazquez-Covarrrubias, E., and Ziga-Rodriguez, G., 2001. “Classification and Origin of Petroleum in the Mexican Gulf Coast Basin: an Overview.” In Bartolini, C., Buffler, R.T., Cantú-Chapa, A. (Eds.), The Western Gulf of Mexico Basin: Tectonics, Sedimentary Basins and Petroleum Systems. American Association of Petroleum Geologists, Memoir 75, pp. 127-142.

2. Perez Cruz, G.A., 1993. “Geologic Evolution of the Burgos Basin, Northeastern Mexico.” Ph.D. thesis, Rice University, 577 p.

3. Eguiluz de Antuñano, S., 2001. “Geologic Evolution and Gas Resources of the Sabinas in Northeastern Mexico.” In: Bartolini, C., Buffler, R.T., Cantú-Chapa, A. (Eds.), The Western Gulf of Mexico Basin: Tectonics, Sedimentary Basins and Petroleum Systems. American Association of Petroleum Geologists, Memoir 75, pp. 241–270.

4. Prost, G. and Aranda, M., 2001. “Tectonics and Hydrocarbon Systems of the Veracruz Basin, Mexico.” In C. Bartolini, R.T. Buffler, and A. Cantu-Chapa, eds., The Western Gulf of Mexico Basin: Tectonics, Sedimentary Basins, and Petroleum Systems. American Association of Petroleum Geologists, Memoir 75, p. 271-291.

APEC Unconventional Natural Gas Census

Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 2. SOUTH AMERICAN UNCONVENTIONAL GAS

SECTION 2.
SOUTH AMERICAN APEC ECONOMIES UNCONVENTIONAL GAS

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SECTION 2. OVERVIEW: SOUTH AMERICAN APEC ECONOMIES UNCONVENTIONAL GAS

A. Introduction

The two South American APEC Economies - - Chile and Peru - - have distinctly different natural gas endowments and consumption patterns, Table 2-1.[1,2,3] Both economies have seen their natural gas consumption increase, with Chile consuming 5.3 Bcm or 0.5 Bcfd and Peru consuming 6.2 Bcm or 0.6 Bcfd in 2011. However, Chile's natural gas production is small at 1.4 Bcm or 0.1 Bcfd and declining, while Peru's natural gas production is substantial at 11.4 Bcm or 1.1 Bcfd and increasing. As a result, in 2011 Chile was a net importer of natural gas via LNG (3.9 Bcm, 0.4 Bcfd), while Peru was a net exporter of natural gas via LNG (5.2 Bcm, 0.5 Bcfd).

B. Unconventional Gas Resources and Production

No official estimates exist for unconventional gas reserves or resources for Chile or Peru. Chile has an estimated 96 Bcm (3.4 Tcf) of conventional gas resources plus potential for coalbed methane and shale gas resources in the Magallanes Basin, which adjoins Argentina's Austral Basin and also hosts Chile's conventional gas production.[4,5,6] Peru has the "world-scale" Camisea conventional gas field and 350 Bcm (12.5 Tcf) of proved natural gas reserves. In addition, a private study by Drilling Info estimates 2,070 Bcm (73 Tcf) of potentially recoverable shale gas resources for Peru, Table 2-2. [7]

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1 BP Statistical Review of World Energy, 2012.
2 U.S. Department of Energy, Energy Information Administration, Peru Country Analysis Brief, May, 2012
3 U.S. Department of Energy, Energy Information Administration, Chile Country Analysis Brief, May, 2012
4 Legarreta, L. and Villar, H.J., "Geological and Geochemical Keys of the Potential Shale Resources, Argentina Basins." AAPG Search and Discovery Article #80196, Posted November 7, 2011, Adapted from presentation at AAPG Geoscience Technology Workshop, "Unconventional Resources: Basics, Challenges, and Opportunities for New Frontier Plays," Buenos Aires, Argentina, June 26-28, 2011.
5 Urien, C.M. and Schiefelbein, C.F., "Sedimentary Sequences and Petroleum Systems in the Austral Foreland Basin." AAPG Search and Discovery Article #90039, AAPG Calgary, Alberta, June 16-19, 2005.
6 Collao, S., Oyarzun, R., Palma, S. and Pineda, V., "Stratigraphy, Palynology, and Geochemistry of the Lower Eocene Coals of Arauco, Chile." International Journal of Coal Geology, v. 7, p. 195-208, 1987.
7 "Opportunities for Unconventional Resources in Latin America", Drilling Info, 2010

Table 2-1. South American Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
1. Chile							
Consumption		4.7	170	0.5	5.3	200	0.5
Supply							
▪	Marketed Production (Dry)	1.7	60	0.2	1.4	50	0.1
▪	Net Exports/Imports	3.0	110	0.3	3.9	150	0.4
2. Peru							
Consumption		5.4	190	0.5	6.2	220	0.6
Supply							
▪	Marketed Production (Dry)	7.2	260	0.7	11.4	400	1.1
▪	Net Exports/Imports	(1.8)	(70)	(0.2)	(5.2)	(180)	(0.5)
3. Total							
Consumption		10.1	360	1.0	11.5	420	1.1
Supply							
▪	Marketed Production (Dry)	8.9	320	0.9	12.8	450	1.2
▪	Net Exports/Imports	1.2	40	0.1	(1.3)	(30)	(0.1)

Sources: BP Statistical Review of World Energy (2012); EIA Country Analysis Briefs, (2012). JAF2012_064.XLS

Table 2-2. Estimates of South American APEC Economies Unconventional Gas Resources

Resource		Technically Recoverable		Annual Production (2011)	
		(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
1. Chile					
▪	Shale Gas	n/a	n/a	n/a	n/a
▪	CBM	n/a	n/a	n/a	n/a
▪	Tight Gas	n/a	n/a	n/a	n/a
	TOTAL	**n/a**	**n/a**	**n/a**	**n/a**
2. Peru					
▪	Shale Gas	2,070	73	-	-
▪	CBM	n/a	n/a	-	-
▪	Tight Gas	n/a	n/a	-	-
	TOTAL	**2,070**	**73**	**-**	**-**

JAF2012_064.XLS

C. Notable Recent Unconventional Gas Activity

Chile. In June 2012 ENAP reported plans to drill two shale appraisal wells in the Magallanes Basin. One well will be drilled in the Lenga block with Canadian partner and methanol producer Methanex, which obtained the stake from Apache after the latter decided to suspend exploration activities in southern Chile. Methanex' Cabo Negro methanol plant has been operating at 30% of its 2.8-million t/a, 365-MMcfd capacity due to local gas shortages.

Several years ago GeoPark conducted an internal CBM evaluation of its conventional oil and gas blocks in the Magallanes Basin but has not discussed this unconventional resource in recent months. The company is currently evaluating shale gas and oil potential in the Estratos con Favrella Shale formation, which it reported has previously tested and produced oil. In June 2012 GeoPark initiated a program of diagnostic fracture injection tests on 6 to 8 wells on their Fell Block to determine fracability and reservoir properties of the shale. Preliminary results of this program are expected in 4Q-2012.[8]

Peru. Peru's unconventional gas resource potential is poorly defined. There might be a Devonian-age shale gas resource opportunity in the Ucayali Basin. In addition, there is an industry report of hydrocarbon tests (and a potential discovery) in Devonian-age sedimentary rocks of the Solimoes Basin (Jurua Formation) straddling the Peru-Brazil border.

8 Geopark Holdings Ltd., Second Quarter 2012 Operations Update, July 23, 2012.

2.1 CHILE UNCONVENTIONAL GAS

A. Introduction

Chile has become a significant LNG importer as the economy's domestic conventional gas supplies have not kept pace with growing demand. Argentina had supplied Chile with most of its gas imports via pipeline until a serious supply shortage occurred in 2005. Chile then decided to construct LNG import facilities -- the first in South America -- to diversify its supply options and satisfy the bulk of its natural gas import needs.

In 2010 Chile produced a modest average 170 MMcfd of natural gas from about 3.4 Tcf of conventional proved reserves, a level which has remained fairly constant for the past three decades. Gas production is concentrated in the Magallanes Basin, in Chile's far southern province Tierra del Fuego, and is almost entirely from conventional sandstone reservoirs.

Chile's domestic natural gas consumption peaked in 2005 at nearly 700 MMcfd, after which the import shortage dramatically curtailed supplies. More recently, natural gas consumption, particularly by Chile's electric power sector, and natural gas imports have started to rebound, albeit gradually, reaching 330 MMcfd in 2010. Today, only about 10% of Chile's gas imports are delivered via pipeline from Argentina, the former main supplier, with the remainder imported as LNG, Table 2-1-1.[9]

In 2009 Chile completed construction of two LNG terminals. The Quintero plant, located in central Chile with 380-MMcfd capacity, is operated by BG Group (40%), with partners ENAP (20%), Endesa Chile (20%) and Metrogas (20%). The regasified fuel is sent by Electrogas about 28 km to the city of Quillota. The Quintero LNG plant was shut down as a precaution during the great earthquake of 2010, but suffered only minimal damage as the LNG storage tanks are seismically isolated. A second smaller (190-MMcfd) LNG import terminal is located at Mejillones in northern Chile.

[9] U.S. Energy Information Administration, website accessed August 22, 2012.

Because Chile depends so heavily on LNG imports, its natural gas prices are several times higher than in neighboring gas-rich countries, such as Argentina and Bolivia, averaging about $10/Mcf.

Table 2-1-1. Chile Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		4.7	170	0.5	5.3	200	0.5
Supply							
▪	Marketed Production (Dry)	1.7	60	0.2	1.4	50	0.1
▪	Net Exports/Imports/Other	3.0	110	0.3	3.9	150	0.4

No official resource estimates exist in Chile for unconventional gas, Table 2-1-2. However, the Magallanes Basin in Southern Chile likely has prospective shale gas formations, as well as promising CBM prospects and possibly tight gas resources, Figures 2-1-11 and 2-1-2.[10,11] Following initial CBM and shale well tests, further testing and appraisal of Chile's prospective unconventional gas resources appears warranted.

Table 2-1-2. Chile Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		Gas In-Place		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	-	-
▪	CBM	n/a	n/a	n/a	n/a	-	-
▪	Tight Gas	n/a	n/a	n/a	n/a	-	-
	TOTAL	-	-			**-**	**-**

10 U.S. Energy Information Administration. (2011) World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States.
11 Methanex, Investor Presentation, August 8, 2012.

Figure 2-1-1. Arauco CBM Region and Magallanes Basin are Chile's Main Unconventional Gas Areas

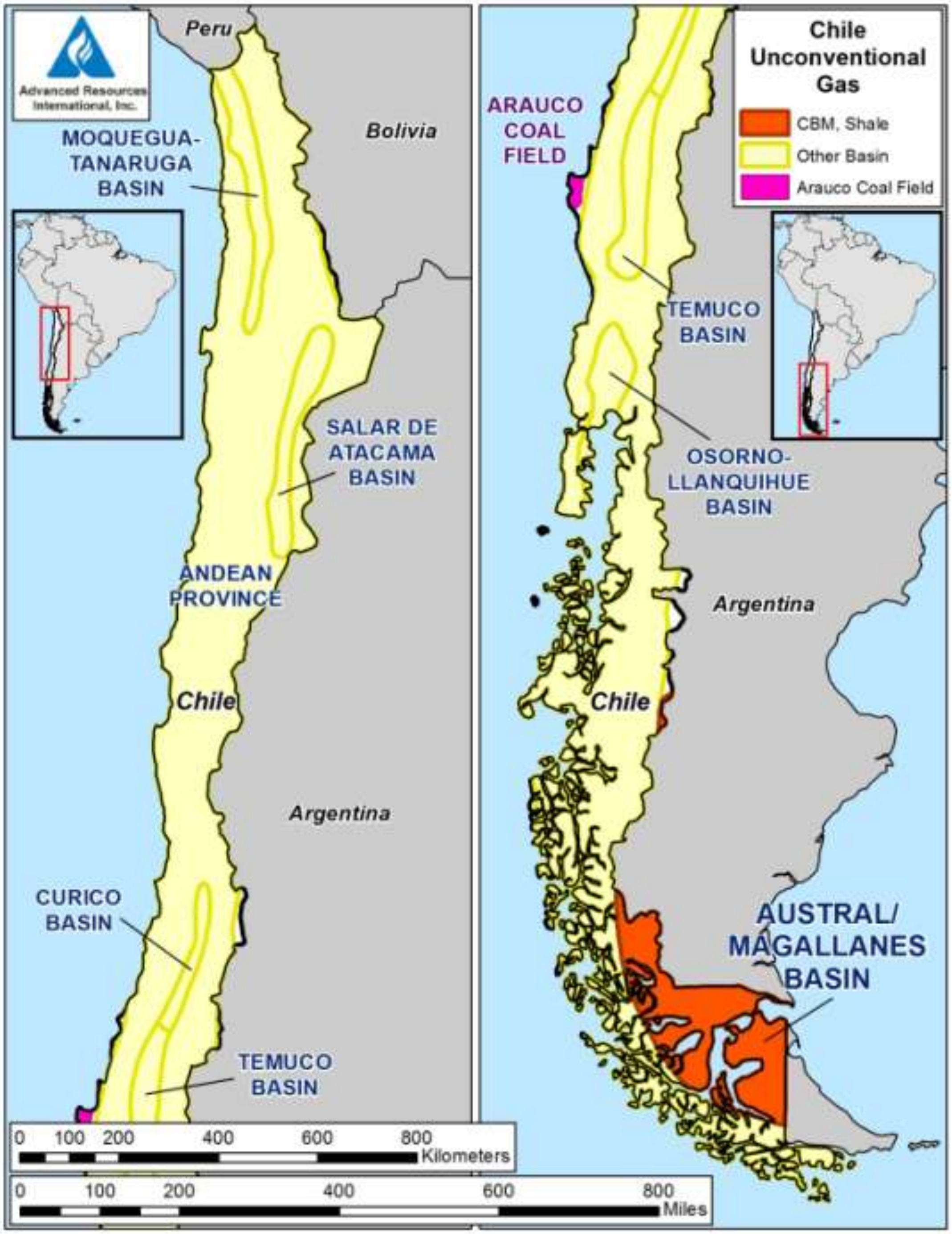

Figure 2-1-2. The Magallanes Basin Has Chile's Best Unconventional Gas Resource Potential

B. Governmental Authorities Engaged with Unconventional Gas Development

Oil & gas exploration and development in Chile is governed by the Political Constitution of the Republic of Chile and Decree Law 1089, on Special Contracts for Exploration and Exploitation of Hydrocarbons of 1975 and subsequent amendments. The right to explore and develop fields is granted for each area under a special operation contract between the State of Chile and the contractor.

The main governmental agencies involved with the assessment, regulation and development of natural gas resources in Chile are the Ministry of Energy (Ministerio de

Energia), the National Commission of Energy (Comision Nacional de Energia or CNE), and the state-controlled oil company Empresa Nacional de Petroleo (ENAP).

- ***Ministry of Energy*:** Chile's Ministry of Energy develops the overall policy for energy development and supply, while regulating the energy industry and the other governmental organizations involved with the energy sector. The ministry is tasked with projecting supply and demand and formulating policies to effectively remedy Chile's current energy shortage.

- ***National Commission of Energy*:** The CNE is the independent technical body charged with establishing the technical standards and laws by which energy sector participants must abide. The CNE also monitors markets, collects data and analyzes energy prices and tariffs.

- ***Empresa Nacional de Petroleo (ENAP)*:** ENAP, the state-owned oil and gas monopoly engages in every step of the hydrocarbon supply chain from exploration to refining and marketing. ENAP also operates overseas exploration and production assets through its subsidiaries. The company currently is engaged in operations in the Magallenes Basin, Chile's only oil and gas producing region. ENAP also joint ventures with foreign producers to promote investment and boost oil and gas output in Chile.

ENAP announced in March 2011 that it will require companies bidding for oil and gas exploration tenders in the southern Magallanes region to also explore for shale gas. Companies granted the tenders reportedly will sign special operating contracts, known in Chile as CEOPs, which will require that they allocate part of their budget for shale-gas exploration. ENAP will have a 30% to 50% stake in the CEOPs.

The only specific unconventional gas contract awarded by Chile to date was for Layne Energy's 780,000-acre Arauco CBM concession. This contract has a 35-year period; no other fiscal terms have been released. Oil and gas royalties in Chile typically amount to about 12% to15% of production.

C. Unconventional Gas Resource Assessments

No rigorous assessments have been performed yet on Chile's unconventional natural gas resources. Consequently, ARI evaluated company reports and data on Chile's conventional petroleum geology for insights into its unconventional gas potential.

C.1 Shale Gas. The Magallanes Basin has prospective shale gas potential that is just now beginning to be evaluated and tested. The Mid-Lower Jurassic Inoceramus Formation and the U. Cretaceous Palermo Aike Formation shales, which formed under lacustrine (non-marine) depositional conditions, are the main source rocks in this basin. The shales range from 50 to 400 m thick and are organic-rich (TOC: 0.5-2%; kerogen type II-III). The basin's simple structure and depth to shale (1-5 km) are favorable. Well-defined oil-prone and gas-prone thermal maturity windows occur in the basin,[12] somewhat similar to those in the Texas Eagle Ford Shale play.

With recognition of the risk posed as to whether these lacustrine shales are sufficiently low in clay and thus brittle to be efficiently stimulated, ARI perspective is that the shale gas resources in the Magallanes Basin offer Chile a viable unconventional gas supply alternative to costly natural gas imports . Further evaluation of Chile's shale gas potential appears warranted.

GeoPark Energy reports that it currently is testing the Estratos con Favrella Shale in the Magallanes Basin, which overlies the Lower Inoceramus Fm.[13]

C.2 Coalbed Methane. Chile's best defined unconventional gas resource is its coalbed methane deposits, which have been explored intermittently for two decades. There are two main CBM areas in Chile : the high-rank Arauco Coal Field in central coastal Chile, and in the low-rank Magallanes Basin in the Tierra del Fuego region of southern Chile. Although only general information is available on these prospective

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[12] Legarreta, L. and Villar, H.J., "Geological and Geochemical Keys of the Potential Shale Resources, Argentina Basins." AAPG Search and Discovery Article #80196, Posted November 7, 2011, Adapted from presentation at AAPG Geoscience Technology Workshop, "Unconventional Resources: Basics, Challenges, and Opportunities for New Frontier Plays," Buenos Aires, Argentina, June 26-28, 2011.
[13] Urien, C.M. and Schiefelbein, C.F., "Sedimentary Sequences and Petroleum Systems in the Austral Foreland Basin." AAPG Search and Discovery Article #90039, AAPG Calgary, Alberta, June 16-19, 2005.

areas, in ARI's view these prospects could have development potential under Chile's relatively high $10/Mcf gas price environment.

The Arauco Coal Field near the coastal port of Conception is Chile's traditional coal mining region. Coal seams totaling about 5 m thick occur in the Lower Eocene Lota Member of the Curanilahue Formation,[14] which is roughly time-equivalent to the coal deposits in the Powder River Basin, Wyoming. The coal reserves at Arauco are estimated at 500 million metric tons and are primarily bituminous grade (13,500 kcal/lb heat content),[15] placing the Arauco coal slightly more mature than Appalachian Basin coal.

The underground coal mines at Arauco are considered gas-prone and well known for methane hazards. Six deep conventional oil and gas wells have penetrated the coal formation at depths of 500 to 1,000 m in the Arauco region. However, the Arauco Coal Field is structurally complex with numerous faults, including many that are still seismically active. US-based Layne Energy holds a 780,000-acre CBM concession at Arauco but has not released drilling results.

The Magallanes Basin in southern Chile appears to be Chile's most promising CBM prospect. Coal deposits occur over a much larger area than at Arauco and the structure is a simple syncline with few faults. About 30 m of total coal is present in the Late Eocene to Miocene Loreto Formation, sub-bituminous in rank (7,500 kcal/lb). In addition, the overlying Miocene-age El Salto Formation has additional coal deposits, albeit of slightly lower rank.

C.3 Tight Gas. The Magallanes Basin in southern Chile, also known as the Austral Basin in Argentina, may have low-permeability tight gas resources but they have not yet been assessed or tested.

[14] Collao, S., Oyarzun, R., Palma, S. and Pineda, V., "Stratigraphy, Palynology, and Geochemistry of the Lower Eocene Coals of Arauco, Chile." International Journal of Coal Geology, v. 7, p. 195-208, 1987.
[15] Hackley, P.C., et al., "Coal Quality Characteristics of Tertiary Coals from Chile: A GIS-Based Approach." Geological Society of America, Annual Meeting November 2–5, 2003.

D. Unconventional Gas Activity and Production

Chile has experienced preliminary coalbed methane drilling, but its tight gas and shale gas resources have yet to be tested and evaluated. ENAP has been the main explorer, along with several small operators based in North America.

- ENAP: Chile's national oil and gas company has drilled several coalbed methane appraisal wells in the Magallanes Basin and is currently planning to drill two shale gas appraisal wells in the basin. Since 2011, the company has required that contractors devote a portion of their exploration commitment in the Magallanes Basin to shale gas appraisal.

  As early as 1991-2, ENAP drilled two vertical wells in the Magallanes Basin to test coal seam gas content and permeability. In 2008-10, the company drilled two additional vertical production wells, hydraulically fracturing and testing the Loreto Fm coal at depths of 800 to 1,200 m. ARI provided design and supervision support to ENAP for this project. However, ENAP scaled back the CBM project due to the 2008 fiscal crisis.

  In June 2012, ENAP reported that it plans to drill two shale appraisal wells in the Magallanes Basin. One well will be drilled in the Lenga block with Canadian partner and methanol producer Methanex, which obtained the stake from Apache after the latter decided to suspend exploration activities in southern Chile. Methanex' Cabo Negro methanol plant has been operating at 30% of its 2.8 million t/a, 365 MMcfd capacity due to local gas shortages.

- ***Layne Energy:*** This company, a subsidiary of US-based drilling contractor Layne Christenson, obtained Chile's first CBM concession, for a 780,000-acre area in the Arauco Coal Field of central Chile. Layne holds a 100% working interest in the 35-year CBM contract, which is with the Ministry of Mines and Energy. The company conducted initial coring in 2007 but has not reported activity since. (Layne was the company that rescued the 33 Chilean miners trapped underground for two months in 2010).

- ***GeoPark Holdings***, based in the UK, holds three conventional oil and gas exploration blocks in Chile, with three more blocks under application, totaling 3.9 million acres. GeoPark produced an average 26 MMcfd from its lease blocks during Q2-2012, all from conventional formations. This year the company plans to invest $125 million to drill 22 wells and collect seismic data.[16]

  Several years ago GeoPark conducted an internal CBM evaluation of the Magallanes Basin but has not discussed this unconventional resource in recent months. GeoPark is currently evaluating shale gas/oil potential in the Estratos con Favrella Shale, a formation which the company reported has previously tested and produced oil. In June 2012 GeoPark initiated a program of diagnostic fracture injection tests on 6 to 8 wells on their Fell Block to determine the fracability and reservoir properties of the shale. Preliminary results of this program are expected in 4Q-2012.[17]

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16 GeoPark Holdings Ltd., Investor Presentation, April 2012.
17 GeoPark Holdings Ltd., Second Quarter 2012 Operations Update, July 23, 2012.

2.2 PERU UNCONVENTIONAL GAS

A. Introduction

With its prospective but lightly explored hydrocarbon basins and the installation of the first LNG export terminal in South America, Peru has the potential for becoming an important new source of natural gas supplies. New government policies have been instituted to attract foreign investment in the oil and gas sector supporting Peru's interest in increasing natural gas development for both domestic use and exports.

Peru currently is self-sufficient in natural gas, producing 11.4 Bcm or 1.1 Bcfd of natural gas in 2010 while consuming 6.2 Bcm (220 Bcf) or 0.6 Bcfd domestically, Table 2-2-1.[18,19] The excess of marketed natural gas production over consumption of 5.2 Bcm or 0.5 Bcfd was exported as LNG to Spain and the Asia Pacific. Peru's natural gas production is mostly sourced from the Camisea project in southeast Peru, which came on stream in 2004. The discovery and development of this "world-scale" conventional gas field has enabled Peru to increase its domestic consumption of natural gas by 15-fold over the past decade, providing a clean, affordable source of domestic energy for Peru.

Table 2-2-1. Peru Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		5.4	190	0.5	6.2	220	0.6
Supply							
▪	Marketed Production (Dry)*	7.2	260	0.7	11.4	400	1.1
▪	Net Exports/Imports/Other	(1.8)	(70)	(0.2)	(5.2)	(180)	(0.5)

*In 2010, Peru had gross natural gas production of 393 Bcf. Of this, 130 Bcf was re-injected or used in the field and 8 Bcf was vented and flared, leaving dry marketed production of 255 Bcf. Sources EIA Peru CAB, May, 2012 and BP Statistical Review of World Energy, 2012.

18 U.S. Department of Energy, Energy Information Administration, Peru Country Analysis Brief, May, 2012.
19 BP Statistical Review of World Energy, 2012.

Drawing on a proved reserve base of about 350 Bcm (12.5 Tcf), Peru's marketed natural gas production has increased steadily in recent years as increased domestic consumption and the initiation of LNG exports provided market outlets for Peru's natural gas production.

Currently, unconventional gas development is in its infancy in Peru. While there have been reported gas shows and flow tests in prospective shale formations, no commercial production exists. A private study by Drilling Info estimated Peru's shale gas resources at 2,070 Bcm (73 Tcf), Table 2-2-2.[20]

Table 2-2-2. Peru Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	2,070	73	-	-
▪	CBM	n/a	n/a	n/a	n/a	-	-
▪	Tight Gas	n/a	n/a	n/a	n/a	-	-
	TOTAL	-	-	**2,070**	**73**	**-**	**-**

Source: Drilling Info, 2010

Peru's government has been aggressively pursuing foreign investment and exploration, bidding out many of its onshore exploration blocks. With an estimated 2,070 Bcm (73 Tcf) of technically recoverable shale gas, unconventional resources have the potential to play a large role in Peru's push to expand natural gas production, increase exports and provide energy for its growing energy-intensive metallurgy industry. However, this potential is still many years in the future as much of the Peru's basins have yet to be rigorously explored for hydrocarbons.

[20] "Opportunities for Unconventional Resources in Latin America", Drilling Info, 2010

B. Governmental Authorities Engaged with Unconventional Gas Development

The main governmental agencies involved with the assessment, regulation and development of natural gas activities in Peru are the Ministry of Energy and Mines, Perupetro, and Petroperu.

- *Ministerio de Energia y Minas (Ministry of Energy and Mines)*: The Ministry of Energy and Mines is part of the executive government and formulates plans and policies for the sustainable development of Peru's hydrocarbon resources in accordance with the government's overall energy policy. The Instituto de Geologico Minero y Metalurgico (INGEMMET) is an autonomous division within the Ministry of Energy and Mines that provides geological information on Peru's natural resources.

- *Perupetro*: Perupetro, the National Agency of Hydrocarbons, is responsible for promoting, negotiating and monitoring contracts for the exploration and production of hydrocarbons in Peru. Perupetro promotes investment in Peru's hydrocarbon industry and manages the Peru's hydrocarbon endowment. Perupetro also provides statistical information on Peru's hydrocarbon reserves and production.

- Petroperu: Petroperu is a state-owned energy company engaged in midstream and downstream oil and gas operations, including pipelines, refining, petroleum distribution and gasoline marketing. The company owns the majority of Peru's refineries. Petroperu has stated that it plans to begin participating in upstream oil and gas development. PetroPeru's gross revenues of about 5.17 billion USD in 2011 made it the largest company in Peru.

C. Unconventional Gas Resource Assessments

While no official government estimates have been published for the size of Peru's unconventional gas, a private study by Drilling Info (DI) published in 2010 estimates that Peru has 2,070 Bcm (73 Tcf) of shale gas resources, primarily in the Ucayali Basin, Figure 2-2-1. The study also identifies six prospective shale gas formations in three key basins, Table 2-2-3.[20]

Figure 2-2-1. Prospective Shale Gas Basins of Peru

Source: Drilling Info, 2010.

Table 2-2-3. Prospective Shale Gas Basins and Formations of Peru

Basin Name	Formation	Age	Maximum Thickness (m)	Average TOC
Madre de Dios	Cabanillas Group	Late Devonian	600	2-3%
Maranon Basin	Chonta	Late Cretaceous	500	2-5%
Maranon Basin	Pucara	Early Jurassic	2,800	2-5%
Ucayali Basin	Ambo	Mississippian	813	2-5%
Ucayali Basin	Copacabana-Tarma	Early Permian	900	2%
Ucayali Basin	Shinai	Middle Permian	70	2-3%

Source: Database DI International February 2010

In addition to its shale gas potential, Perupetro estimates Peru has an estimated 1,950 to 2,100 Bcm (69 to 74 Tcf) of conventional gas resources, in basins that have been largely unexplored. Figure 2-2-2 provides the stratigraphic column for the hydrocarbon basins of Peru, highlighting the Ucayali Basin and its Devonian-age Cabanillas Group with reported shows of shale gas.[21]

Figure 2-2-2. Stratigraphic Column for the Sub-Andean Basins of Peru

AGE	Santiago Parsep	PARSEP NE Peru	Marañon Oxy	Marañon Petroperu	Huallaga	Ucayali	PARSEP Ucayali North and Ene	PARSEP Ucayali South
Q		Corrientes		Corrientes				
TERTIARY	Nieva	Marañon	Upper Red Beds	Marañon	Capas Rojas Superiores			
		Pebas		Pebas		Ipururo	Ipururo	
	Upper Puca	Chambira		Chambira		Chambira	Chambira	
	Pozo: Pozo Shale	Pozo: Pozo Shale	Pozo Shale	Pozo Shale		Pozo Shale	Pozo Shale	
	Pozo Sand	Pozo Sand	Pozo Sand	Pozo Sand	Pozo	Pozo Sand	Pozo Sand	
	Lower Puca: Santiago SS	Yahuarango	Lower Red Beds	Yahuarango	Capas Rojas Inferiores	Yahuarango	Yahuarango	Yahuarango
CRETACEOUS	Cachiyacu	Vivian: Upper Vivian	Basal Tertiary	Upper Vivian	Cachiyacu	Casa Blanca	Upper Vivian	Upper Vivian
		Huchpayacu	Cachiyacu	Huchpayacu		Huchpayacu	Cachiyacu	Cachiyacu
		Cachiyacu		Cachiyacu		Cachiyacu		Lower Vivian
	Vivian	Lower Vivian	Vivian	Lower Vivian	Vivian	Vivian	Lower Vivian	
	Chonta	Chonta:		Pona	Chonta	Chonta	Chonta	Chonta
				Lupuna				
		Upper Chonta	Chonta shale	Upper Cetico				
		Chonta Lmst	Chonta Lmst	Caliza				
			Chonta Sand					
			Low ChontaSd					
		Lower Chonta	BasalChontaSd	Lower Cetico				
		Agua Caliente	Agua Caliente	Agua Caliente	Agua Caliente	Agua Caliente	Agua Caliente	Agua Caliente (1)
		Raya	Raya	Raya	Raya	Raya	Raya	Absent
	Cushabatay	Cushabatay	Cushabatay	Cushabatay	Cushabatay	Cushabatay	Cushabatay	
JURAS	Sarayaquill: Red Beds	Sarayaquill: Red Beds	Sarayaquillo	Sarayaquillo	Sarayaquillo	Sarayaquillo	Sarayaquill: Red Beds	
	Evaporitic Unit	Evaporitic Unit					Evaporitic Unit	
	Pucará: Condorsinga	Pucará: Condorsinga	Pucará	Pucará	Pucará	Pucará	Pucará: Condorsinga	
TRIAS	Aramachay	Aramachay					Aramachay	
	Chambara	Chambara					Chambara	Pucará (Pongo Mainique)
PERM	Mitu	Mitu	Mitu	Mitu	Mitu	Mitu	Mitu	Red Bed Group: Upper SS Fm
								Mid Mudstone Fm
								Lower SS Fm (2)
	Ene	Ene	Ene	Ene	Ene	Ene	Ene	Ene: Shinai Member
								Noipatsite Mbr
								Ene SS Mbr
	Copacabana	Copacabana	Copacabana	Copacabana	Copacabana	Copacabana /Tarma	Copacabana /Tarma Green Sandstone	Copacabana /Tarma Green Sandstone
CARB	?	Tarma	Tarma	Tarma				
		Ambo	Ambo	Ambo	Ambo	Ambo	Ambo	Ambo
DEV		Cabanillas	Cabanillas	Cabanillas		Cabanillas	Cabanillas	Cabanillas
ORD		Contaya	Contaya	Contaya	Contaya	Contaya	Contaya	
Basement								

(1) Basal Chonta + Upper Nia Kaatsirinkari (2) Lower Nia Kaatsirinkari

Source: Peurpetro Ucayali and Ene Basin report, 2002

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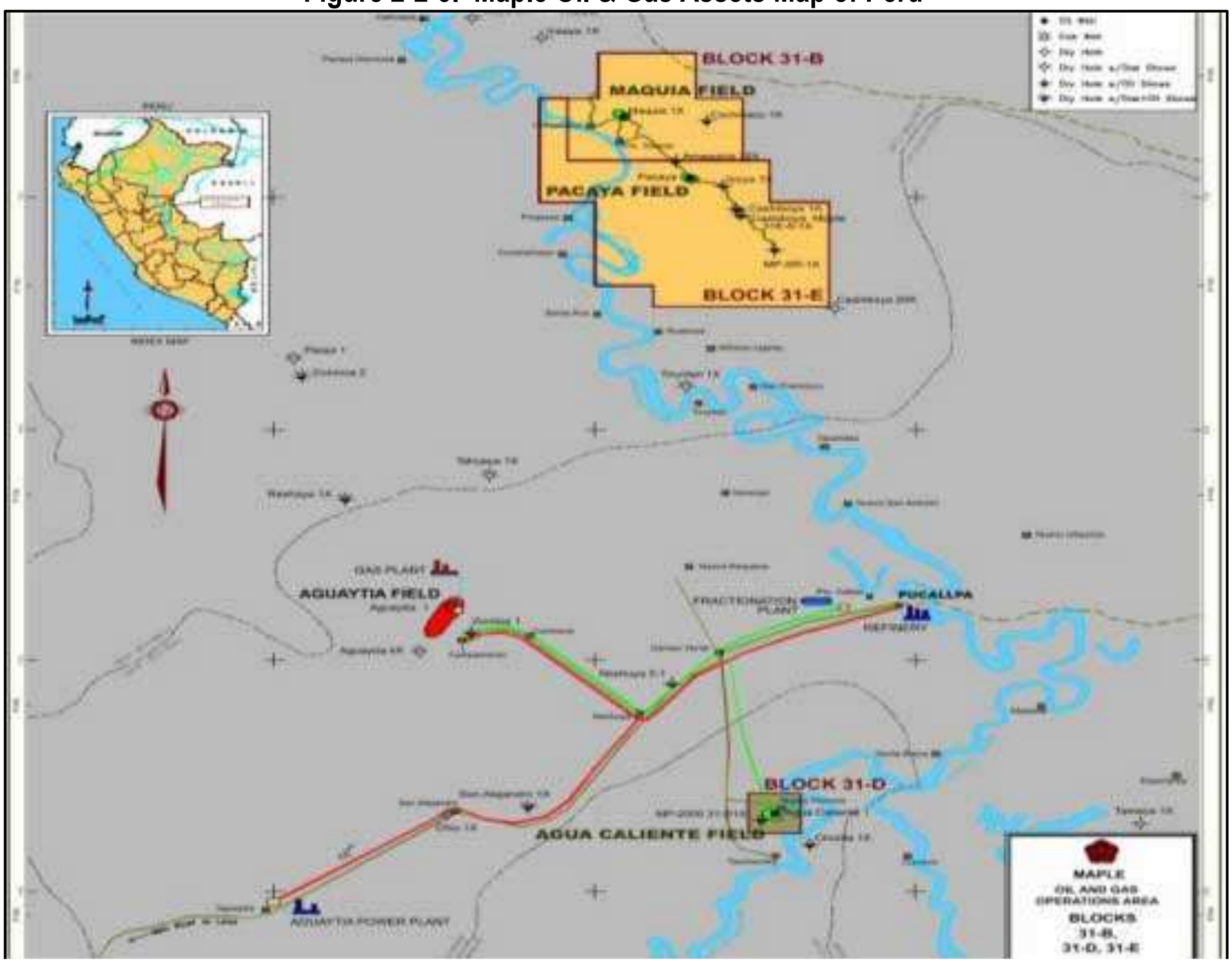
21 Ucayali and Ene Basin Technical, part of the Hydrocarbon Potential of the Southern Sub-Andean Basins Project, Ucayali, Ene and Madre de Dios Basins, PARSEP, Proyecto de Asistencia para la Reglamentación del Sector Energético del Perú, December 2002.

D. Unconventional Gas Activity and Production

Spain's Reposol and Canada's Talisman are two international E&P companies active in Peru, although their activities, so far, has been targeted on exploration for oil, not unconventional gas. However, shale gas potential has been recently reported as part of the exploration program by two smaller companies operating in Peru.

- UK-listed Maple Energy has identified a potential Devonian-age shale gas opportunity with its Santa Rosa 1-X well in Block 31-E in the Ucayali Basin, Figure 2-2-3.[22]

Figure 2-2-3. Maple Oil & Gas Assets Map of Peru



Source: Maple Energy, 2012

[22] Maple Energy Corporate Presentation, May 2012.

- More recently, HRT S.A. announced the discovery of hydrocarbons in the Devonian sedimentary rocks of the Solimoes Basin that straddles Peru and Brazil. The new well (1-HRT-8-AM), drilled to a depth of 3,345 meters, tested gas in the Jurua Formation and provides confirmation of a natural gas trend in the Jurua Field previously identified by wells 1-HRT-5-AM and 1-HRT-2-AM.

Although active Andean tectonics have structurally deformed many of Peru's petroleum-bearing basins, potentially faulting up the shale targets, in the longer-term unconventional gas is expected to play a role in Peru's natural gas industry. For example, the International Energy Agency's recent "Special Report on Unconventional Gas" (2012) forecasts that about 0.5 Bcfd (5 Bcm) of unconventional gas could be produced in Peru by 2035.[23]

Appendix A. Other Data and Resource Sources

Numerous geological studies of conventional formations in Peru's oil and gas basins have been undertaken by the Ministerio de Energia y Minas, the Instituto Geologico Minero Metalurgico (Ingemmet), or Perupetro. These studies help build the foundation for assessing the size and characteristics of Peru's unconventional gas resources.

The following are a sample of key geological studies prepared by Ingemmet:

1. "Atlas de Mineria y Energia en el Peru 2001" (Atlas of Minerals and Energy in Peru) – Includes information and maps on the sedimentary basins and petroleum geology of Peru.
2. Ucayali and Ene Basins Technical Report (2002) PARSEP (Proyecto de Asistencia para La Reglamentacion del Sector Energetico del Peru) - Joint Venture between Canada and Peru (Perupetro).
3. Huallaga Basin Final Report (2001) PARSEP - Joint Venture between Canada and Peru.
4. Madre Dios Basin Technical Report (2002) PARSEP - Joint Venture between Canada and Peru.

[23] "Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas", International Energy Agency, OECD/IEA, 2012.

5. Maranon Basin Report (2002) PARSEP - Joint Venture between Canada and Peru.

6. Salaverry Basin Report (2001) PARSEP - Joint Venture between Canada and Peru.

7. Santiago Basin Report (2001) PARSEP - Joint Venture between Canada and Peru.

8. Titicaca Basin Report (2008) Perupetro.

9. Trujillo Basin Report (2001) PARSEP - Joint Venture between Canada and Peru.

10. Tumbes and Talares Basin Report (2005) Perupetro.

APEC Unconventional Natural Gas Census
Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 3. AUSTRALIA/NEW ZEALAND UNCONVENTIONAL GAS

SECTION 3.
AUSTRALIA/NEW ZEALAND APEC ECONOMIES
UNCONVENTIONAL GAS

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SECTION 3. OVERVIEW: AUSTRALIA/NEW ZEALAND UNCONVENTIONAL GAS

A. Introduction

Australia and New Zealand hold significant unconventional gas (and oil) resources, particularly in shales and in coals. These resources have enabled Australia to expand its role as a major LNG exporter and provide the base for much of New Zealand's future natural gas production.

Last year (2011), these two economies consumed 30 Bcm or 2.9 Bcfd of natural gas. While New Zealand's natural gas consumption and production of 4 Bcm or 0.4 Bcfd were in balance, Australia's natural gas production of 45 Bcm or 4.4 Bcfd enabled it to export 19 Bcm or 1.9 Bcfd last year (2011), Table 3-1.[1,2]

Table 3-1. Australia/New Zealand Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		30	1,060	2.9	30	1,040	2.9
Supply							
▪	Marketed Production (Dry)*	50	1,760	4.8	49	1,730	4.8
▪	Net Exports/Imports/Other	(20)	(700)	(1.9)	(19)	(690)	(1.9)

Sources: U.S. EIA, 2012; BP Statistical Review of World Energy, 2012.

1 U.S. Energy Information Administration, Australia Country Analysis Brief, May, 2012.
2 BP Statistical Review of World Energy, May, 2012.

B. Unconventional Gas Resource Assessments

Together, the two economies hold 24,350 Bcm (859 Tcf) of technically recoverable unconventional gas resources, including large established coalbed methane reserves and preliminary assessed shale gas resources, Table 3-2. [3,4] Australia, with its significant investment in developing its coalbed methane resources (called coal seam methane (CSM) or coal seam gas (CSG) in Australia and New Zealand), dominates the resource estimates with 12,400 Bcm (439 Tcf); recent exploration and testing has raised New Zealand's coalbed methane estimate to 50 Bcm (2 Tcf). Only Australia currently has resource estimates for shale gas and tight gas.

Table 3-2. Australia's/New Zealand's Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	11,300	398	-	-
▪	CBM	n/a	n/a	12,450	441	6	0.6
▪	Tight Gas	n/a	n/a	600	20	-	-
	TOTAL	**-**	**-**	**24,350**	**859**	**6**	**0.6**

Source: Geoscience Australia/BREE Gas Resource Assessment, 2012 and "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", U.S. EIA/ARI, 2011

An estimated 6 Bcm/yr (0.6 Bcfd) of coalbed methane (CBM) was produced in Australia last year (2011) and small volumes of CBM have been produced in New Zealand. With the pending completion of several LNG export facilities in Australia (Queensland), Australia's CBM production is expected to climb dramatically.

[3] BREE 2011, Australian energy projections to 2034–35, BREE report prepared for the Department of Resources, Energy and Tourism, Canberra, December.
[4] "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", sponsored by the U.S. Energy Information Administration (April, 2011) prepared by Advanced Resources International.

3.1 AUSTRALIA UNCONVENTIONAL GAS

C. Introduction

With large conventional natural gas resources on the Northwest Shelf and even larger deposits of coalbed methane in Queensland and New South Wales, Australia is poised to challenge Qatar as the world's dominant LNG exporter.

Last year (2011) Australia consumed 26 Bcm or 2.5 Bcfd of natural gas, with consumption remaining essentially flat for the past five years, Table 3-3-1.[5,6] In contrast, Australia produced 45 Bcm or 4.4 Bcfd of natural gas, enabling Australia to export 19 Bcm or 1.9 Bcfd in 2011 to nearby Asia-Pacific markets. (Coalbed methane contributed about 6 Bcm or 0.6 Bcfd of Australia's 2011 natural gas production.)

Natural gas production has been growing in recent years and is projected to rise dramatically as a series of new LNG export terminals supplied by coalbed methane are scheduled to come on stream in 2014-2015.

Table 3-1-1. Australia Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		26	910	2.5	26	900	2.5
Supply							
▪	Marketed Production (Dry)*	46	1,610	4.4	45	1,590	4.4
▪	Net Exports/Imports/Other	(20)	(700)	(1.9)	(19)	(690)	(1.9)

Sources: U.S. EIA, 2012; BP Statistical Review of World Energy, 2012.

5 U.S. Energy Information Administration, Australia Country Analysis Brief, May, 2012.
6 BP Statistical Review of World Energy, May, 2012.

Australia has a significant volume of proved conventional and unconventional natural gas reserves, estimated at 3,760 Bcm (133 Tcf).[2] The bulk of the conventional natural gas reserves are located in the offshore Northwest Shelf of Australia. Additional natural gas reserves (and resources) are available from the large coalbed methane deposits in the Bowen, Surat and Sydney coal basins and tight gas in the Cooper Basin. The shale gas reserves of Australia, while potentially quite large, have yet to be rigorously assessed.

In 2012, the Bureau of Resources and Energy Economics' economic research unit (BREE) provided updated resource assessments for Australia's unconventional gas resources.[7] This resource assessment study estimated that Australia had 12,400 Bcm (439 Tcf) of technically recoverable coalbed methane, 11,300 Bcm (398 Tcf) of technically recoverable shale gas (using the EIA/ARI World Shale Gas Resource Assessment of 2011),[8] and 600 Bcm (20 Tcf) of technically recoverable tight gas, Table 3-1-2 and Figure 3-1-1.

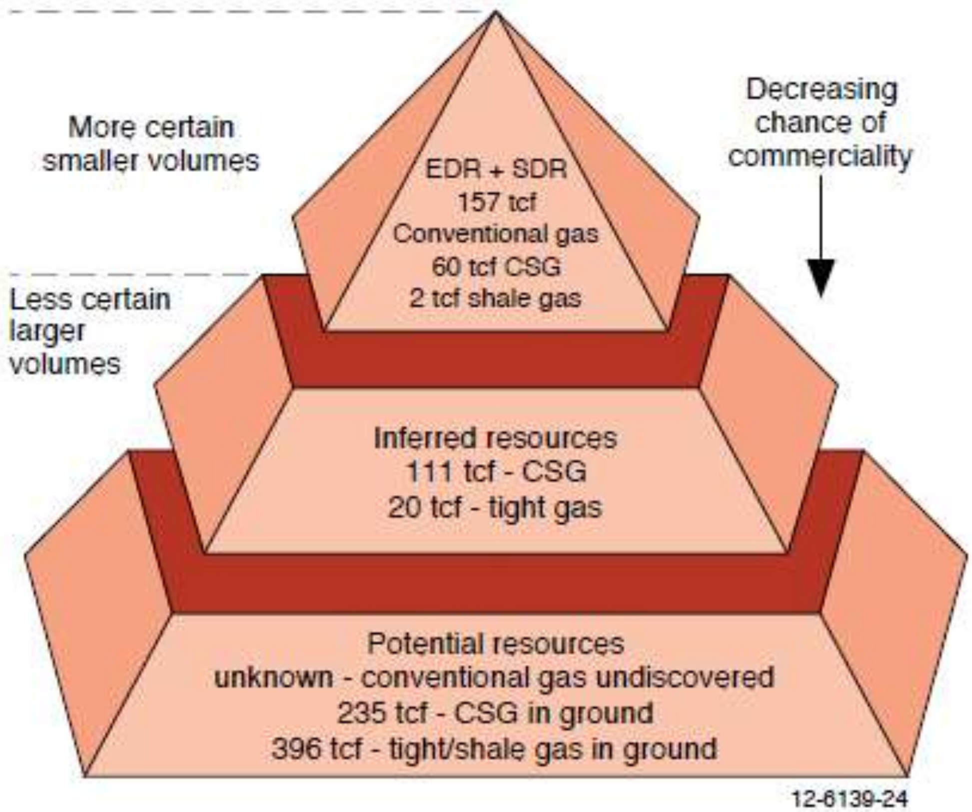
Table 3-1-2. Australia's Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	11,300	398	-	-
▪	CBM	n/a	n/a	12,400	439	6	0.6
▪	Tight Gas	n/a	n/a	600	20	-	-
	TOTAL	**-**	**-**	**24,300**	**857**	**6**	**0.6**

Source: Geoscience Australia/BREE Gas Resource Assessment, 2012 and "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", U.S. EIA/ARI, 2011

[7] BREE 2011, Australian energy projections to 2034–35, BREE report prepared for the Department of Resources, Energy and Tourism, Canberra, December.
[8] "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", sponsored by the U.S. Energy Information Administration (April, 2011) prepared by Advanced Resources International.

Figure 3-1-1. Australia's Natural Gas Resources



Source: Geoscience Australia/BREE Gas Resource Assessment, 2012

LNG exports have become a major and growing industrial enterprise in Australia. Last year (fiscal 2010-2011) LNG exports of 28 Bcm or 2.7 Bcfd generated $10.4 billion of revenues.[9] Currently a series of large LNG export terminals, involving US$170 billion of capital expenditure and supplied by Australia's large coalbed methane reserves and resources, are being constructed in on the east coast of Queensland. Looking forward Australia projects that its LNG exports will grow to nearly 140 Bcm or 14 Bcfd by 2035.[3]

D. Governmental Agencies Engaged with Hydrocarbon Industry

The main governmental agencies involved with the assessment, regulation and development of natural gas activities are the Department of Resources, Energy, and Tourism, the Bureau of Resources and Energy Economics, and Geoscience Australia. The federal National Offshore Petroleum Safety Authority (NOPSA) regulates activity from 3 to 2000 miles off Australia's coast. In addition, each individual Australian state

[9] BREE 2012, Energy in Australia 2012, Canberra, ISBN 978-1-921812-98-9, February

and territory is responsible for regulating natural gas activities within its state/territory. More information regarding the various governmental agencies involved in the states and territories of Australia is provided in Appendix A.

- *Department of Resources, Energy, and Tourism (RET).* The RET develops policies for Australia's energy development with the ultimate goal of increasing Australia's international competitiveness in an environmentally responsible, secure and sustainable manner. The RET is composed of a series of agencies responsible for various aspects of Australia's energy planning and oversight. The RET publishes monthly and annual statistical information on Australia's oil and natural gas development.

- *Bureau of Resources and Energy Economics (BREE).* The BREE is an economic research unit within the RET that provides data, analysis and advice to government and industry on Australia's energy resources. The BREE conducts resource assessments and provides short, medium and long-term projections of Australia's hydrocarbon production. In 2012, the BREE published *Australian Gas Resource Assessment* as a more in-depth natural gas focused follow-up to Geoscience Australia's 2010 energy resource assessment.

- *Geoscience Australia (GA).* Geoscience Australia is Australia's national geoscience and geospatial information agency supporting Australian government and industry on resource development, environmental policy, energy infrastructure and public safety. GA published *Australian Energy Resource Assessment* in 2010 that provided one of the first comprehensive examinations of Australia's existing and potential unconventional gas resources.

E. Unconventional Gas Resource Assessments

C. 1 Geological Studies of Unconventional Gas Formations in Australia. Australia's unconventional gas resource assessments have benefitted from a foundation of earlier geologic studies. The following are a sample of three studies prepared by Australia's federal and state agencies on the geology and reservoir properties of the unconventional gas resources of Australia.

1. "Unconventional Gas Plays in Cooper Basin, South Australia: Unconventional Gas" The Government of South Australia: Department of Primary Industries and Resources (2012).

2. "Sydney-Gunnedah Basin Coal Seam Methane Exploration Fairways and Sweetspots" New South Wales Government: Division of Resources and Energy (2006).

3. "Queensland's Petroleum Exploration and Development Potential 2010–11" Queensland Government: Department of Natural Resources and Mines, Geological Survey of Queensland (2012).

C. 2 Unconventional Gas Resource Studies. According to BREE/Geoscience Australia, Australia's total unconventional gas resources are estimated at 24,300 Bcm (857 Tcf), Table 3-1-3. Coalbed methane (referred to by Australians as coal seam gas or CSG) economically demonstrated resources (EDR) were 930 Bcm (33 Tcf) with another 1,700 Bcm (60 Tcf) of sub-economic demonstrated resources (SDR), and 3,140 Bcm (111 Tcf) of inferred resources. The identified CBM resource base is expected to grow given the 6,660 Bcm (235 Tcf) of potential "in ground" CBM resources waiting to be defined. For tight gas, the BREE/Geoscience Australia study estimated 570 Bcm (20 Tcf) of inferred resources.

For shale gas, the BREE/Geoscience Australia study used the recently published EIA/ARI estimate of 11,220 Bcm (396 Tcf) of potential "in ground" resources plus 60 Bcm (2 Tcf) of inferred resources for shale gas.[4]

Table 3-1-3. Australia's Total Unconventional Gas Resources

Resource Category	Coalbed Methane (CSG) (Tcf)	Tight Gas (Tcf)	Shale Gas (Tcf)	Total Gas (Tcf)
1. Identified Resources				
Economically Demonstrated Resources	33	-	-	33
Sub-Economic Demonstrated Resources	60	-	2	62
Inferred Resources	111	20	-	131
Sub-Total	204	20	2	226
2. Potential In-Ground Resources	235	Unknown	396	631
Total Resources	**439**	**20***	**398**	**857**

JAF2012_055.XLS

Note: CSG demonstrated resources as of January 2012. Source: Geoscience Australia/BREE Gas Resource Assessment 2012*The IEA's World Energy Outlook special report on Unconventional Gas "Golden Rules for a Golden Age of Gas" (2012) estimated remaining recoverable resources of tight gas in Australia at 8 Tcm (282 Tcf).

Table 3-1-4 provides a listing of the sedimentary basins of Queensland with potential for unconventional gas. Little information is available on tight gas resources in Australia, but exploration is underway to determine the size and accessibility of these resources.

Table 3-1-4. Ages of Sedimentary Basins with Unconventional Resource Potential

Basin	Age
Laura Basin	Middle Jurassic to Early Cretaceous
Maryborough Basin	Late Triassic to Cenozoic
Eromanga Basin	Early Jurassic to Late Cretaceous
Surat Basin	Late Triassic to Middle Cretaceous
Cooper Basin	Late Carboniferous to Middle Triassic
Bowen Basin	Early Permian to Middle Triassic
Galilee Basin	Carboniferous to Triassic
Adavale Basin	Early Devonian to Late Carboniferous
Georgina Basin	Neoproterozoic to Ordovician
Mount Isa Superbasin	Mesoproterozoic

Source: Queensland's Petroleum Exploration and Development Potential 2010–11, May 2012

Overall, Australia has 6,400 Bcm (226 Tcf) of demonstrated (economic and sub-economic) and inferred unconventional gas resources. An additional 17,900 Bcm (631 Tcf) of potential in ground resources round out Australia's unconventional gas resource base, leading to a total estimate of 24,300 Bcm (857 Tcf). As such, the size of the unconventional gas resource dwarfs Australia's demonstrated remaining undiscovered conventional gas resource base of 4,450 Bcm (157 Tcf).[9]

Shale Gas. Cooper Basin shale gas accounts for 6,490 Bcm (229 Tcf) of Australia's total recoverable shale gas resource of 11,270 Bcm (398 Tcf). As of mid-2012, multiple successful test wells have been drilled into the Nappamerri Trough portion of this basin. Beach Energy, one of the most active shale explorers in the Cooper Basin, reported a contingent shale gas resource of 2 Tcf in its South Australian portion of the Nappamerri Trough in 2011. Santos reported commercially productive shale gas potential based on a handful of test wells.

Coalbed Methane (CBM). Queensland accounts for 92% of current Australian CBM resources; New South Wales provides the remainder. The majority of CBM reserves and resources are from just two Queensland coal basins - - the Surat (69%) and Bowen (23%).[10]

Tight Gas. BREE/Geoscience Australia sets forth 570 Bcm (20 Tcf) for Australia's tight gas resources, located as follows: Perth Basin – 280 Bcm (10 Tcf), Cooper Basin – 230 Bcm (8 Tcf), and Gippsland Basin 50 Bcm (1.7 Tcf).[10]

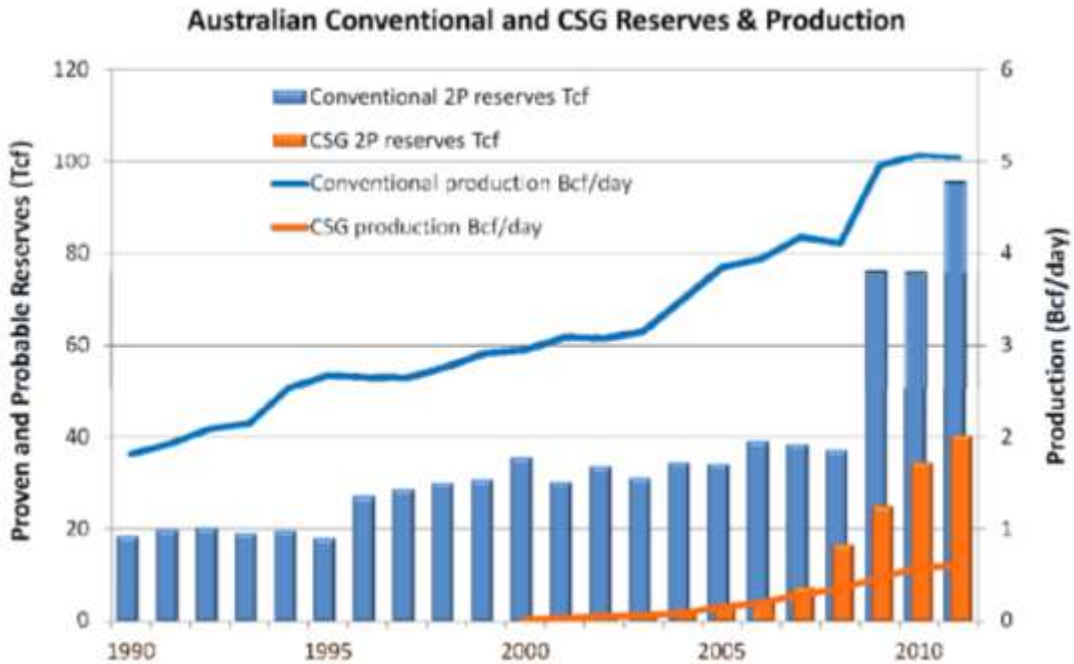
F. Unconventional Gas Activity and Production

In the near-term, growth in unconventional gas production is expected to depend on major opportunities for LNG exports as well as modest increases in domestic demand. Australia currently relies on coal-fired power generation for about three quarters of its electricity. However, governmental policies aim to significantly decrease this high reliance.[10] To replace lost coal-fired power, Australia plans to increase gas-

[10] Australian Gas Resource Assessment 2012, Australian Government, Department of Resources, Energy and Tourism, Geoscience Australia, Bureau of Resources and Energy Economics, ISBN 978-1-92210327-7, GeoCat # 74032.

fired electricity from 16 percent to 36 percent by 2035. Coalbed methane, which is located in close proximity to Australia's eastern population centers, is expected to serve as the major source of new gas supplies, Figure 3-1-2.[3,11]

Figure 3-1-2. Australia's World-Class Gas Reserves



Source: EnergyQuest, WA Dept. Mines and Petroleum, Geoscience Australia, APPEA

In the medium to longer-term, tight gas and shale gas resources have the potential to further increase Australia's natural gas productive capacity, assuming exploration is successful. Table 3-1-5 provides a listing of unconventional gas resource targets available in Queensland basins.[10] However, there will most likely be delays before wide-scale increases in production will occur due to limitations on deep rigs and hydraulic fracturing infrastructure. Also, a more comprehensive gas pipeline infrastructure needs to be built to connect tight and shale gas basins to markets, Figure 3-1-3.[10]

[11] EnergyQuest, WA Dept. Mines and Petroleum, Geoscience Australia, APPEA

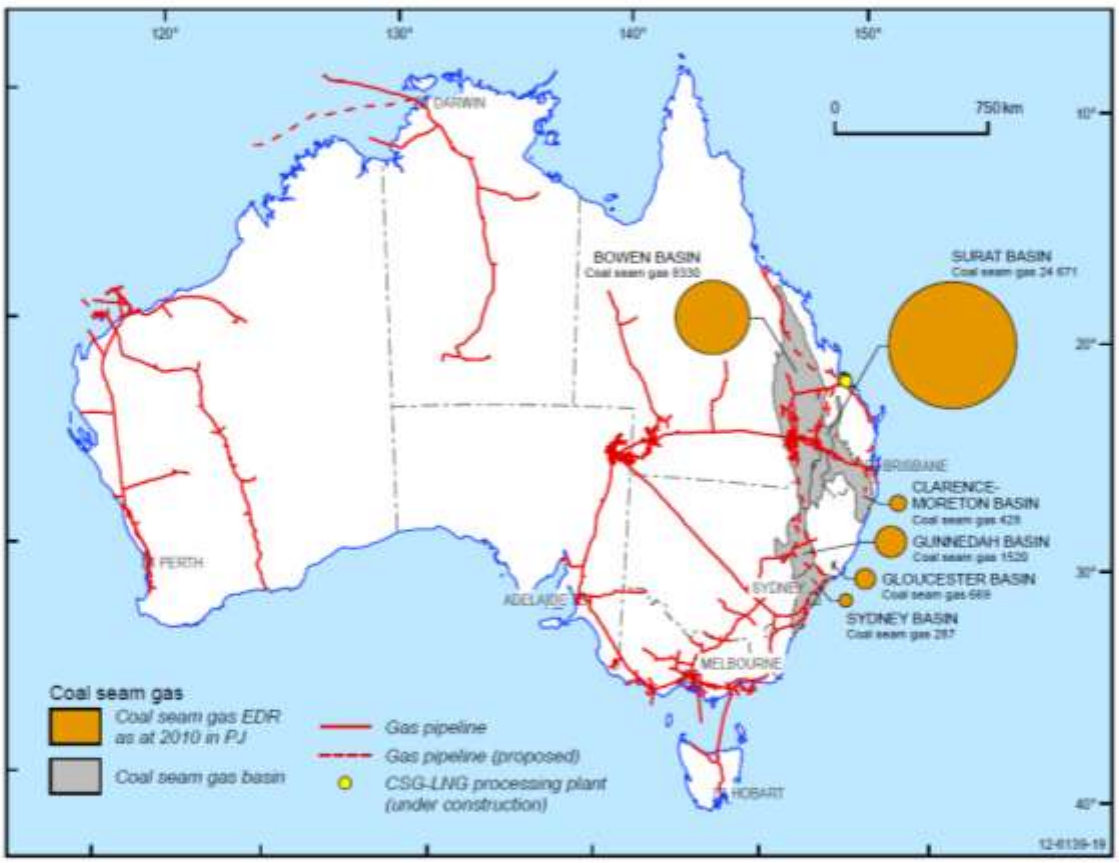
Table 3-1-5. Unconventional Gas Resource Targets in Queensland Basins

Basin	Formation	Environment	Thickness (m)	Top Depth	TOC	Ro	Resource Target
1. Laura	Dalrymple Sandstone	Fluvio-deltaic	329 to 527 m	442 to 592 m	0.91 to 12.90%	0.81%	Shale gas or tight gas
2. Maryborough	Maryborough Formation	Marginal Marine to Estaurine	up to 2245 m	Outcrop to 865 m	approx 1.5%	up to 2.88%	Shale gas or tight gas
	Tiaro Coal Measures	Fluvio-lacustrine	6 to >430 m	Outcrop to 592 m	Coal	up to 3.02%	CSG or shale gas
3. Eromanga	Winton Formation	Fluvio-lacustrine	400 to 1000 m	Outcrop to 1060 m	Coal	0.3 to 0.5%	CSG
	Toolebuc Formation	Restricted Marine	20 to 45 m	Outcrop to 1640 m	0.2 to 26.1%	0.35 to 0.55%	Shale gas
	Birkhead Formation	Fluvio-deltaic to lacustrine	up to 580 m	Outcrop to 2180 m	0.75 to 6.3%	up to 1%	Shale gas
	Westbourne Formation	Fluvio-lacustrine	70 to 130 m	Outcrop to 2046 m	0.51 to 2.18%	0.7 to 0.87%	Shale gas
	Poolowanna Formation	Fluvio-lacustrine	up to 165 m	370 to 2450 m	0.6 to 17.9%	up to 1.2%	Shale gas
4. Surat	Walloon Coal Measures	Fluvio-lacustrine	up to 507 m	Outcrop to 1660 m	Coal	0.44 to 0.7%	CSG
5. Cooper	Roseneath Shale	Lacustrine	20 to 80 m	1360 to 2530 m	1.0%	1 to 4%	Shale gas
	Epsilon Formation	Prograding delta	30 to >60 m	1370 to 2625 m	3.7 to 7.5%	0.6 to 1.6%	Tight gas
	Murteree Shale	Deep, freshwater lacustrine	Average of 50 m, up to 80 m	1370 to 2680 m	2.50%	1 to 4%	Shale gas
	Patchawarra Formation	Fluvio-lacustrine	up to 550 m	1375 to 2990 m	Coal	up to 3.6%	Shale gas or tight gas
	Toolachee Formation	Fluvio-lacustrine	20 to 50 m	1360 to 2950 m	up to 7.2%	up to 2.4%	Shale gas or tight gas
6. Bowen	Black Alley Shale	Marine to lacustrine	up to 350 m	45 to 2030 m	0.29 to 10.18%	0.52 to 0.98%	Shale gas
	Tinowon Formation	Deltaic	50 to 70 m	890 to 2830 m	•	0.52 to 0.98%	Tight gas
7. Galilee	Aramac Coal Measures	Fluvial and peat swamp	31 to 272 m	757 to 1600 m	Coal	0.39 to 5.2%	CSG or shale gas
	Betts Creek Beds	Fluvial and peat swamp	50 to 210 m	approx. 900 m	Coal	0.70 to 8.75%	CSG or shale gas
	Lake Galilee Sandstone	Fluvial	85 to 287 m	1055 to 2734 m	•	up to 1.77%	Tight gas
8. Adavale	Log Creek Formation	Marine shelf sediments	up to >755 m	approx. 3100 m	up to 1.55%	1.4 to 1.6%	Shale gas or tight gas
	Lissoy Sandstone	Nearshore, shallow marine to restricted marine	up to 470 m	approx. 2760 m	•	1.4 to 1.6%	Shale gas or tight gas
	Cooladdi Dolomite	Lagoonal to back reef	up to 85 m	approx. 2500 m	•	1.4 to 1.6%	Shale gas or tight gas
9. Georgina	Arrinthrunga Formation	Carbonate and siliciclastic shelf	138 to 835 m	64 to 726 m	up to 9.6%	up to 0.6%§	Shale gas or tight gas

	Inca Shale	Marine	up to >133 m	Outcrop to 3216 m	up to 2.82%	CCAI* of 1 to 1.5	Shale gas or tight gas
	Thorntonia Limestone	Peritidal to restricted shallow marine	13 to 104 m	Outcrop to 1960 m	up to 8.7% in NT wells	•	Shale gas or tight gas
	Beetle Creek Formation	Marine	27 to >172 m	Outcrop to 1018 m	0.19 to 1.51%	CCAI* of 1 to 1.5	Shale gas
	Georgina Limestone	Tidal shallow marine	>33.2 to 759 m	Outcrop to 2457 m	EOM† up to 2000 ppm	TAI‡ of 2.25 to 2.50	Shale gas or tight gas
10. Mount Isa Superbasin	Lawn Hill Formation	Mid to outer shelf	up to 2200 m	Outcrop to 2000 m	up to 7%	•	Shale gas
	Termite Range Formation	Turbidite fan	up to 1300 m	Outcrop to 2500 m	up to 8%	•	Shale gas
Mount Isa Superbasin	Riversleigh Siltstone	Mid to outer shelf	up to 2900 m	Outcrop to 4500 m	up to 8%	•	Shale gas

*Conodont Colouration Alteration Index † Extractable organic matter ‡ Thermal Alteration Index
§ Analysis only from PGA Bradley 1 Source: Geological Survey of Queensland, 2012

Figure 3-1-3. Location of Australia's Coal Seam 2P Gas Reserves and Gas Infrastructure



Source: DEEDI 2012, Geoscience Australia

Shale Gas. Early exploratory shale wells have been drilled in the Cooper Basin of South Australia and the Canning Basin of Western Australia. Limited exploration is also present in the Georgina, McArthur, Amadeus, Galilee-Eromanga and Perth basins.[10]

- Recently, Norway's Statoil entered into a partnership with Canada's PetroFrontier to pursue four shale gas exploration projects in the Southern Georgina Basin, Northern Territory. The partnership plans to drill 10 to 20 exploratory wells in the next five years.

- In mid-2011, QGC (BG Group's Australian subsidiary), acquired a 60% interest in the 500,000 acres ATP 940 in the Central Cooper Basin Nappamerri Trough shale fairway. The farm-in agreement includes a five year, $130 million exploration program.

- Norwest Energy is proposing to fracture stimulate the Arrowsmith-2 well in the Perth Basin that penetrated three shale horizons and one tight gas horizon.

  - Kockatea Shale - - 450 m
  - Caryngia Formation - - 250 m
  - Irvin Coal Measures - - 330 m
  - High Cliff Sandstone - - 22m

- Beach Energy completed a second phase fracture stimulation of the Epsilon Formation and Murteree Shale (REM) sections of the Encounter-1 shale and basin-centered gas well. The first fracture stimulation stage delivered a gas flow rate of 750 Mcfd from the Patchawarra Formation. The second phase, involving five frac stages, delivered a gas flow rate of 1.3 MMcfd. Three additional deep vertical wells have been drilled to test the deeper Patchawarra Formation at 13,000 feet.

- Holloman Energy Corp. is conducting seismic data acquisition on PEL 112 along the southwestern margin of the Cooper-Eromanga Basin in South Australia. The survey is targeting the multi-zone Namur, Hutton and Birkhead shale zones to a depth of 7,000 feet.

- Exoma Energy Limited is testing the Toolebuc Shale (and CSG) in ATP 999P, at a depth of 4,200 feet with the Culloden-1 and Sancho-1 wells, in the Galilee Basin. The operator has gathered chip samples from an 85 foot section of the shale.

- Senex Energy has a 12 well exploration and appraisal program underway in the Cooper Basin (PELs 516 and 115) targeting the Roseneath-Epsilon-Murteree (REM) package of shale and tight gas sands at about 10,000 feet. Following completion of the initial three wells, Senex has undertaken a large-scale stimulation program in each well. The first stimulation in the Sasanof-1 well led to a peak gas flow rate of 178 Mcfd.

Coalbed Methane. In 2010-2011, CBM production of nearly 0.5 Bcfd accounted for roughly 11% of Australia's natural gas production, primarily from the Bowen and Surat Basins of Queensland, with small additions from the Sydney Basin in New South Wales.

The recent boom in LNG export terminal construction has led to increased investments in CBM operations in New South Wales and Queensland. Three large CBM-sourced LNG projects are under construction in Queensland and one project, Arrow Energy LNG, has a FEED study underway. One additional smaller-scale LNG project, Fisherman's Landing LNG, also has a FEED study underway, Table 3-1-6.[10]

Table 3-1-6. CSG-Based LNG Projects at Various Stages of Development, as of April 2012

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Australia Pacific LNG	APLNG (Origin/ ConocoPhillips/ Sinopec)	Gladstone	under construction	2015	Two trains, each with 4.5 Mt LNG	US$14 b (A$13.6 b)
Gladstone LNG project	Santos/Petronas / Total/Kogas	Gladstone	under construction	2015	7.8 Mt LNG	US$16 b (A$15.5 b) (includes production wells and 435 km pipeline)
Queensland Curtis LNG project	BG Group	Gladstone	under construction	2014	8.5 Mt LNG (12 Mt ultimately)	US$15 b
Arrow Energy LNG	Shell/Petro China	Gladstone	FEED studies under way	2017	8 Mt of LNG	na
Fisherman's Landing LNG project (train 1)	LNG Ltd	Gladstone	FEED studies underway, environ. approval received	na	1.5 Mt LNG	US$1.1 b (A$1.1 b)
Fisherman's Landing LNG project (train 2)	LNG Ltd	Gladstone	FEED studies underway, environ. approval received	na	1.5 Mt LNG	US$1.1 b

Source: BREE 2012c

Coalbed methane (CSG) development in Australia which began in 1976 has increased greatly in the past ten years, particularly in Queensland and New South Wales. While the initial CSG exploration wells were drilled into high rank Permian coals of the Bowen Basin, much of the recent activity has targeted the lower rank Jurassic coals in the Surat Basin. Additional CSG exploration is underway in South Australia, Tasmania, Victoria and Western Australia. These intensive CBM exploration efforts have led to the identification of productive Permian-age coal measures in the Bowen, Gunnedah, Sydney and Gloucester basins and productive Jurassic-age Walloon Coal Measures in the Surat and Clarence-Moreton basins.

Last year (2010-2011), nearly 600 CSG exploration and production wells were drilled in Queensland. Annual production of CSG reached 6 Bcm (0.6 Bcfd), up three fold from five years earlier. Queensland's Bowen Basin, with 3 Bcm (0.3 Bcf) and Surat Basin, with 3 Bcm (0.3 Bcf), provided the bulk of CSG production, with the Sydney Basin providing only modest volumes of 0.2 Bcm (0.02 Bcfd).

Origin Energy, the CSG supplier to the Australia Pacific LNG (APLNG) project, has assigned 12,810 PJ of 2P (16,022 PJ of 3P) CSG reserves to APLNG, primarily from the Bowen Basin's Spring Gully and the Surat Basin's Central Walloon Fairway CSG fields. Origin claims to have an additional 10,614 PJ of contingent (3C) CSG resources available.

Santos Limited, the CSG supplier to the Gladstone LNG (GLNG) project, has drilled 440 CSG wells, with another 300 CSG wells scheduled by 2015, primarily in the Fairview, Arcadia and Scotia area coals of the Bowen Basin.

BG Group (and its Queensland gas subsidiary) is the CSG supplier to the Queensland Curtis LNG (QCLNG) project, expecting to begin annual LNG exports of 8.5 Mt in 2014 and 12 Mt ultimately.

In addition to active CSG development associated with the three CSG-LNG projects in the Bowen and Surat basins of Queensland, a number of other CSG projects are in various planning stages as of mid-2012, Table 3-1-7.[10] Five of these projects, including AGL's Camden Gas and Gloucester's Coal Seam projects, are in the Sydney Basin. Arrow's Surat gas project, looking to develop 180 to 360 PJ of annual CSG production would provide gas supply for the Arrow Energy LNG project expecting start-up in 2017.

Table 3-1-7. CSG Projects at Various Stages of Development, as of April 2012

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Blackwater/Norwich Park CSG project	Bow Energy	Bowen Basin	EIS under way	2015	na	na
Camden Gas Project (stage 2)	AGL	Camden	on hold	na	12 PJ pa	$35 m
Camden Gas Project (stage 3)	AGL	Camden	on hold	na	na	$100 m
Casino project	Metgasco	Casino	on hold	na	18 PJ pa	na
Gloucester Coal Seam gas project	AGL	Hunter Valley	on hold	na	15–25 PJ pa	$200 m
Narrabri coal seam gas project	Eastern Star Gas/Santos	Narrabri	on hold	na	20 PJ pa (initally) (150 PJ pa ultimately)	$1.3 b
Surat Gas Project	Arrow Energy	Surat Basin	EIS under way	2016–18	180–360 PJ pa	na

Source: BREE 2012C

Tight Gas. Although Australian federal and state-level energy agencies do not specify tight gas volumes in production reports, small scale hydraulic fracturing has been occurring since 1968 in low permeability plays in the Cooper and Amadeus basins including the Moomba and Big Lake gas fields in the Cooper Basin's Nappamerri Trough. Also, it is known that tight gas is currently produced from various fields in the Perth Basin, in Warro, Whicker Range and West Erregulla fields.[12] There are several planned projects to expand tight gas production, particularly in the Perth Basin of Western Australia. [10]

[12] Geological Survey of Western Australia 2011, Summary of petroleum prospectivity, Western Australia 2011: Geological Survey of Western Australia, 42p., National Library of Australia Card Number and ISBN 978--1-74168-357-8

Appendix 1. Key Agencies Involved with Unconventional Gas in Australia's States and Territories

Queensland. The Department of Natural Resources and Mines is responsible for the regulation and approval of hydrocarbon projects in Queensland. The Department is also responsible for land sales and providing reports on natural gas production and drilling statistics. The Geological Survey of Queensland provides geoscience and resource potential information for Queensland and publishes geoscientific and exploration data to attract investment to the state.

New South Wales (NSW). The Minerals and Petroleum Sector of the New South Wales Department of Trade and Investment, Regional Infrastructure and Services, Division of Resources and Energy, is responsible for facilitating, regulating and taxing hydrocarbon development. The Geological Survey of NSW is a component of the Division of Resources and Energy and is charged with providing information and advice to the government and industry on NSW's geology, resources and land development. The Division of Resources and Energy has a database containing exploration reports and development plans related to the hydrocarbon industry.

Victoria. The Department of Primary Industries (DPI) regulates and promotes the development of Victoria's hydrocarbon industry. The DPI provides annual statistics on petroleum exploration, production activity, and reserves.

South Australia. The Energy Resources Division of the Department for Manufacturing, Innovation, Trade, Resources, and Energy (DMITRE) regulates hydrocarbon activities and provides geoscientific data to support hydrocarbon exploration and development in South Australia. The Petroleum Sector of the Energy Resources Division provides a database with production, well drilling and completion information.

Western Australia. The Department of Mines and Petroleum (DMP) is responsible for regulating the hydrocarbon industry in Western Australia and encouraging hydrocarbon development in the state by providing geoscientific information on energy resources and maintaining a stable investment environment. The Geological Survey of Western Australia is a component of the DMP.

Northern Territory. The Department of Resources (DoR) is responsible for administering petroleum E&P activities within the territory. The Northern Territory Geological Survey is a component of the DoR and provides industry and government officials with geoscientific information concerning the Northern Territory's resources. The DoR provides hydrocarbon production and drilling statistics on its website.

3.2 NEW ZEALAND UNCONVENTIONAL GAS

A. Introduction

The discovery of the giant Maui gas-condensate field in the offshore Taranaki Basin established New Zealand's natural gas industry. Placed on production in 1979, Maui's original gas reserves of 96 Bcm (3.4 Tcf) have been the mainstay of New Zealand's natural gas supply. However, the Maui field is now mature and in decline, with more than half of its reserves already produced. While a series of smaller fields have helped maintain natural gas supply, overall natural gas production (and thus consumption) is on decline.

Last year (2011), New Zealand consumed and produced 3.9 Bcm (140 Bcf) equal to 0.4 Bcfd of natural gas supply, Table 3-2-1.[13,14] With no current access to pipelines or LNG imports, new internal sources of natural gas would need to be developed to support growth in demand.

Table 3-2-1. New Zealand Natural Gas Consumption and Supply

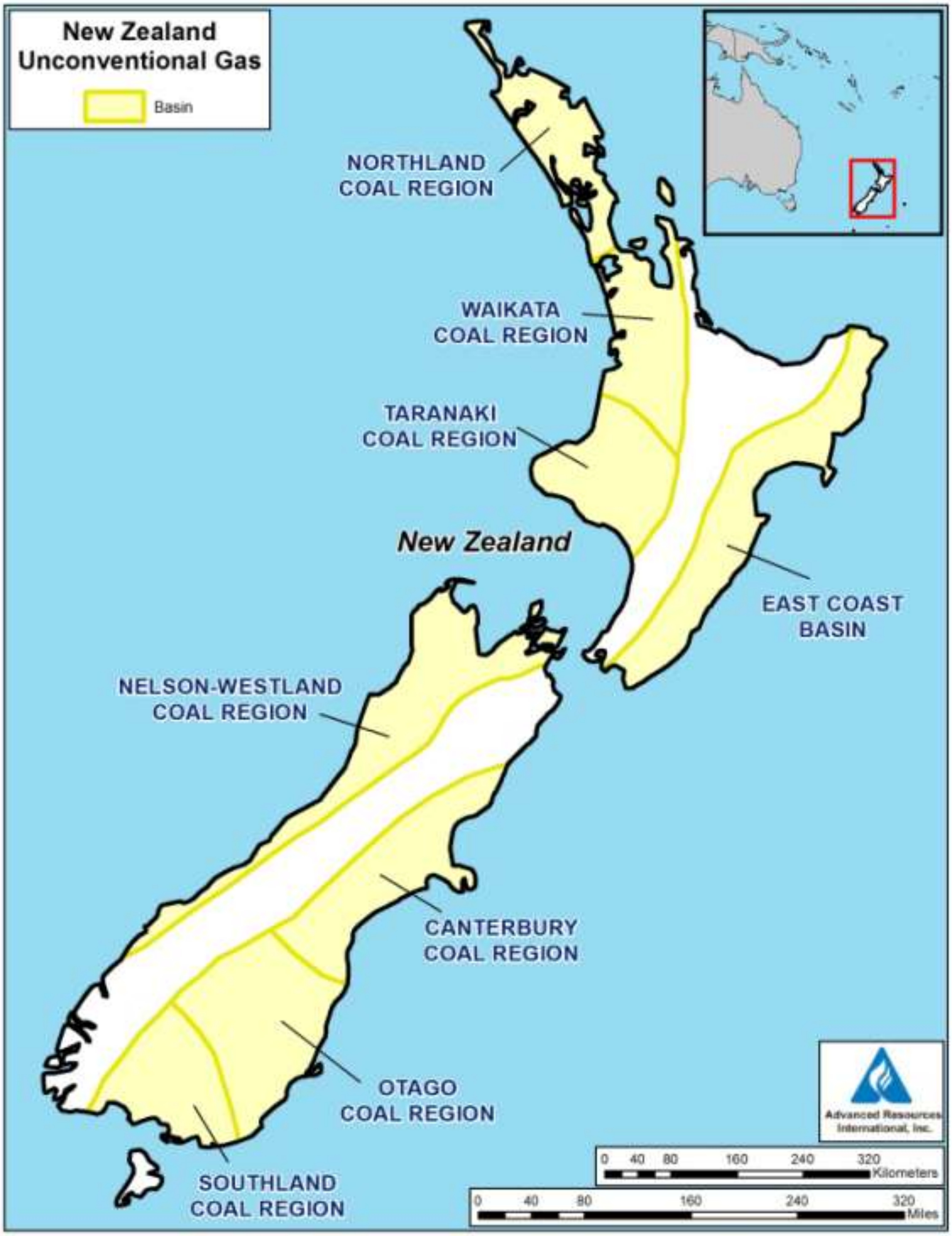
		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		4	150	0.4	4	140	0.4
Supply							
▪	Marketed Production (Dry)	4	150	0.4	4	140	0.4
▪	Net Exports/Imports/Other	-	-	-	-	-	-

Sources: U.S. EIA, 2012; BP Statistical Review of World Energy, 2012.

An initial appraisal of New Zealand's petroleum systems indicates promise for the presence and potential of unconventional gas resources, although the bulk of this potential is likely located in offshore basins, Figure 3-2-1.

13 U.S. Energy Information Administration, New Zealand Country Analysis Brief, 2012.
14 BP Statistical Review of World Energy, 2012.

Figure 3-2-1. New Zealand's Unconventional Gas Basins



Source: Modified by Advanced Resources International from Ministry of Economic Development, "New Zealand's Petroleum Basins", 2010.

- Much of New Zealand's natural gas (and oil) accumulation are geochemically typed to Late Cretaceous and Paleogene coaly rocks as well as Early Cretaceous and Paleocene marine shales.

- One high potential source rock is the marine black shale in the Late Paleocene Waipawa Formation in the northern Taranaki and East Coast basins, where it has been penetrated by several wells. The shale has an average thickness of about 30 m (100 feet) with TOC values of 2% to 6% (up to 12%). Based on measured thermal maturity (Ro) and hydrocarbon index (HI) values, the Waipawa Shale contains oil- to gas-prone kerogen.[15]

Some limited initial appraisals have been conducted by the private sector on the size of New Zealand's CSG resources, estimated at 54 Bcm (~2 Tcf), Table 2.[15] Of this, 24 Bcm (860 Bcf) is estimated to be in Solid Energy's coal seam gas leases in the Taranaki region and an additional 30 Bcm (1,050 Bcf) may exist on L&M Energy's leases in several onshore coalfields.[16,17] However, no publically or privately available estimates exist for New Zealand's shale gas or tight gas resources, Table 3-2-2.[17,18]

Table 3-2-2. New Zealand's Unconventional Gas Resources

		Resource Estimates				**Production (2011)**	
		GIP		**Technically Recoverable**			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	-	-
▪	CBM	n/a*	n/a	54	2	small	small
▪	Tight Gas	n/a	n/a	n/a	n/a	-	-
	TOTAL	-	-	**54**	**2**	**small**	**small**

Source: Ministry of Economic Development, "New Zealand's Petroleum Basins", 2010.
*As part of an earlier resource assessment, Advanced Resources Int'l. estimated a CBM resource in-place of about 400 Bcm (14 Tcf).

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15 Ministry of Economic Development, "New Zealand's Petroleum Basins", 2010.
16 Solid Energy website, www.coalnz.com, 2012
17 D.A. Manhire and S. Hayton, Coal Seam Gas in New Zealand: Perspective from New Zealand's Most Active CSG Explorers.
18 L&M Energy website, www.lmenergy.co.nz, 2012

B. Governmental Authorities Engaged with Unconventional Gas Development

The main governmental agencies involved with the assessment, regulation and development of natural gas activities in New Zealand are the Ministry of Economic Development (MED), New Zealand Petroleum and Minerals, and Gas Industry Company.

- *Ministry of Economic Development (MED).* The Ministry of Economic Development (MED) has a lead role for establishing the regulatory framework for the gas industry, including actions to secure gas supplies for existing and prospective gas-fired electricity generation and for the administration of the Gas Act of 1992. In addition, MED conducts periodic studies and projections of the supply and demand of natural gas in New Zealand and provides historical information on oil and natural gas reserves.

- *New Zealand Petroleum and Minerals.* This agency manages the government's oil and gas resources and promotes investment in these resources.

- *Gas Industry Company.* This entity is the co-regulator of the gas market in New Zealand and has the goal of optimizing the contribution of natural gas to the New Zealand economy.

C. Unconventional Gas Resource Assessments

New Zealand's Early Cretaceous marine source rocks, deposited during global anoxic events, have high organic content. However, thermal maturity modeling indicates that most marine Type II source rock shales in New Zealand only began to generate oil and gas at depths (current) of about 13,000 feet, with the Great South Basin reaching thermal maturity (for oil generation) at 10,000 feet.

Shale Gas. One of the most prospective areas for shale gas (and oil) resources appears to be the East Coast Basin. This basin covers an area of 30,000 mi^2 (12,000 mi^2 onshore), with over 30,000 feet of sedimentary rock, including organic-rich marine and lacustrine deposited shales. The prospective rocks, deposited during the Late

Cretaceous are mudstones and fine-grained marine sediments, with the black shale deposited corresponding to maximum transgression at the beginning of the Paleocene.

Shale gas exploration and resource assessments are underway in the onshore portion of the East Coast Basin, Figure 3-2-1. The exploration targets are the Whangai and Waipawa organically-rich mudstones, with reservoir properties somewhat similar to the Bakken Shale in the U.S., Table 3-2-3. Based on thermal maturity, the Waipawa Shale is immature while the deeper Whangai Shale appears to be in the oil and gas window.

Table 3-2-3. Comparison of New Zealand's Waipawa and Whangai Shales w/the U.S. Bakken Shale

Unit	Bakken	Waipawa	Whangai
Depth (m)	2700-3500	0-5000	0-5000
Net Thick (m)	10-50	10-60	300-600+
Primary Perm (microdarcies)	40-50	10-200	10-110
Tmax (C)	420-450	430-445	420-445
Quartz Content %	20-68	40-80	40-80
TOC %	1.1-12	3-12	0.2-1.7
Vit Refl Ro	0.3-1.2	0.3-0.4	0.4-1.4
Total Porosity %	8-12	9-23	16-31
Source Rock/Oil Gravity (API)	Type II/42	Type II/50	Type II/50

Source: Tag Oil website, August 2012.
Bakken Data: Flannery, Jack; Kraus, Jeff; 2006 Search and Discovery Article #10105; Integrated Bakken Data: Flannery, Jack; Kraus, Jeff; 2006 Search and Discovery Article #10105; Integrated Analysis of the Bakken Petroleum System, US Williston Basin; Waipawa, Whangai Data; GNS, NZ Gov't; Francis, David; 2007 Reservoir Analysis of Whangai and Waipawa; PEP's 34348 & 38349, onshore East Coast Basin, Core Labs report 2007-12-18

Coalbed Methane. The New Zealand Ministry of Economy Development's CSG investigations to date indicate a CSG resource equivalent to about 2,000 PJ, equal to about 54 Bcm (1,900 Bcf). This estimate combines a series of individual company reserve and resource estimates, as follows:

- Solid Energy, the state-owned coal miner, recently announced (May, 2012) a contingent resource (2C) of coal seam gas in the Taranaki Coal Region of 24 Bcm (858 Bcf), up four-fold from its previous contingent resource (2C) estimate of 5 Bcm (180 Bcf). The company is seeking a five-year extension of its Taranaki permit to pursue the appraisal and discovery phase of the project. The sub-bituminous coal resource in the Taranaki region exists in multiple thin coal seams, requiring innovative solution for effectively linking the full coal resource to a production well.

- Solid Energy's work at the North Huntly Coalfield, in the Waikato Coal Region, established a coalbed methane resource of 1 to 5 Bcm (24 to 190 Bcf). CSG production from exploration wells in the Huntly Coalfield was used to power a 1 MW electricity generator. The company terminated its demonstration project given the expected higher cost of CSG production at Huntly and the now lower short- to medium-term outlook for natural gas prices.

- L&M Energy announced CSG reserves (proven, probable and possible) of over 7 Bcm (260 Bcf) within its Southland Permit (PEP 38220, Ohai). In addition, the company's most recent (September, 2012) assessment indicates that the larger Ohai (PEP 38220) and Waiou (PEP 38226) permits, covering a combined area of 600 km^2, "have the potential to contain an energy resource (3P) on the order of 30 Bcm (1,050 Bcf). To date L&M Energy has drilled over 50 exploration wells, conducted multiple 2D seismic surveys and undertaken production testing on its numerous CSG permit areas. (Previously, the company had announced a CSG resource estimate of up to 14 Bcm (500 Bcf)).

Tight Gas. No publically available resource estimates exist for the tight gas resources of New Zealand.

D. Unconventional Gas Activity and Production

Shale Gas. TAG Oil is actively pursuing the East Coast Basin's shale formations, primarily for oil which likely also holds associated shale gas (or free shale gas in the deeper portions of the basin). The company estimates an undiscovered resource potential (P50) of over 12 billion barrels of original oil in-place on its 1.7 million acre East Coast Basin lease area, with reservoir properties and oil recovery potential expected to be similar to the Bakken Shale, Table 3-2-3. Recently Apache Energy acquired an interest in TAG Oil's East Coast Basin lease in exchange for funding a phased exploration program. The planned exploration program will be conducted over four years, with seismic operations starting in 2011 and well drilling in 2012.

A smaller company, New Zealand Energy Company (NZEC), holds three permits totaling 7,450 km^2 in basins with prospects for shale oil and gas. NZEC recently drilled three stratigraphic wells in the East Coast Basin shale formations, looking to launch an exploration program for shales in 2013. NZEC estimates that its East Cape permit of 1.8 million acres has a resource potential of 20.9 billion barrels of original shale oil in-place (OOIP), with 478 million barrels prospectively recoverable (assuming a 2% recovery factor).

More recently, numerous applications for new petroleum exploration permits specifically targeting shale gas have been submitted for the onshore Canterbury Basin as well as in Marlborough and in Southland. It appears that, for a variety of geological reasons, New Zealand's eastern onshore basins may be more prospective for shale gas than its western onshore basins.

Coalbed Methane. Coalbed methane (called coal seam gas (CSG) in New Zealand) exploration began in the 1980s in the Ohai Coalfield and at Greymouth Coalfield on the South Island. (Advanced Resources provided reservoir engineering and on-site technical assistance to this pioneering effort.) Currently, eight companies are active in CSG exploration, holding 17 petroleum permits. CSG permits covering 13,640 km^2 have been granted in the past two years, with a further 9,049 km^2 awaiting approval. One of these is a commercial CSG development permit granted for the Greymouth Coalfield on South Island. On North Island, while commercial CSG production has yet to be achieved, the gas produced from the exploration wells in the Huntly Coalfield (Waikato Coal Region) has been used to power a 1 MW generator.

Resource assessment and exploration of coal seams in Maramarua, Huntly, Waikare and some southern Waikato coal fields indicate CSG potential, but with gas yields relatively low by world standards. Preliminary investigations in Taranaki have targeted the thin multiple seams of the southern Mokau and Tangarakau coal fields.

CSG exploration is underway in New Zealand, with 16 of the 45 petroleum wells drilled in 2010 being CSG wells. Eight of these wells were drilled by L&M Energy in the Waikata and Southland coal basins. For 2012, L&M has announced plans to drill eight wells in the South Canterbury area. L&M currently has a CSG pilot project underway at Ohai (Southland coal region of the South Island), including the drilling of a 750m deep production well and a 1,035 m long lateral development well. The pilot project's goals are to establish the gas production profile, to provide data for estimating 2P (probable) reserves, and to optimize completion and development design.

L&M Energy reported that a previous CSG exploration wells in the Ohai area, well OM #4 drilled in 2010 to 1,034m, intersected 40m of gassy (11 m^3/t) Cretaceous Marley coals and shallower Eocene Beaumont coal measures. Prior exploration by L&M Energy in the adjoining larger Waiau Permit involved three CSG wells that encountered 6 to 9 meters of Beaumont coal measures at 350m to 450m, with gas contents of 2.3 to 4.4 m^3/t (dry, ash-free). A short flow test in one of the wells (Mt. Linton-2) indicated a low-moderate permeability of 3.4 md.

After completing an initial appraisal and its drilling program on the West Coast, Comet Ridge NZ Pty Ltd announced the certification of nearly 7 Bcm (230 bcf) of contingent (2C) CSG resource near Greymouth (Nelson-Westland Coal Region). Inclusion of this recent information would increase the CSG resource estimate for New Zealand.

Tight Gas. No tight gas development activity has been reported to date for New Zealand.

APEC Unconventional Natural Gas Census Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 4. CHINA UNCONVENTIONAL GAS

SECTION 4.
CHINA APEC ECONOMIES
UNCONVENTIONAL GAS

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SECTION 4. CHINA UNCONVENTIONAL GAS

A. Introduction

China, currently highly dependent on coal, is undergoing a structural shift towards increased use of natural gas. While this cleaner-burning fuel today accounts for only 3% of China's primary energy consumption, natural gas is expected to reach 10% of primary energy use by 2030. With limited conventional natural gas resources, China is looking to LNG imports and domestic unconventional gas production as its main sources of future natural gas supplies.

Last year (2011) China consumed nearly 131 Bcm or 12.6 Bcfd of natural gas, up substantially from 2010, Table 4-1.[1] Even though domestic natural gas production increased in 2011, reaching 103 Bcm or 10.0 Bcfd, the significant growth in gas use led to a sharp jump in natural gas imports (net), reaching 28 Bcm or 2.6 Bcfd (China transports natural gas to Hong Kong, China). Approximately half of China's natural gas imports are by pipeline from Turkmenistan, with the remaining by LNG primarily from Australia, Qatar, Indonesia and Malaysia.

Table 4-1. China Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		108	3,800	10.4	131	4,610	12.6
Supply							
▪	Marketed Production (Dry)	95	3,350	9.2	103	3,630	10.0
▪	Net Exports/Imports/Other	13	450	1.2	28	980	2.6

Source: BP Statistical Review of World Energy, 2012.

[1] BP Statistical Review of World Energy, May, 2012.

China's proved reserves of natural gas are estimated at 3,800 Bcm (134 Tcf), including significant (though un-quantified) reserves of tight gas in the Ordos Basin. China's undiscovered unconventional gas resources, though still uncertain, are judged to be much larger, Table 4-2. Recoverable unconventional gas resources total an estimated 36,000 Bcm (1,271 Tcf); (not including recoverable tight gas) out of 201,300 Bcm (7,107 Tcf) of gas in-place.

Tight gas and coalbed methane already contribute 38 Bcm/yr (3.7 Bcfd), equal to one-third of China's natural gas production, mainly from tight gas reservoirs (estimated by Advanced Resources International), Table 4-2. In addition, China has vast and still untested shale gas resources, distributed in multiple basins, Figure 4-1. With higher market-based natural gas prices, a large and growing land rig fleet, and nascent hydraulic stimulation capability, China has the potential to become a major unconventional gas producer.

Table 4-2. China's Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	134,500	4,747	25,100	886	-	-
▪	CBM	36,800	1,300	10,900	385	2	0.2
▪	Tight Gas	30,000	1,060	n/a*	n/a*	36	3.5
	TOTAL	**201,300**	**7,107**	**36,000**	**1,271**	**38**	**3.7**

Sources: Ministry of Land and Resources, 2012. "Results of the National Shale Gas Geologic Assessment and Favorable Locations." March 2.
Zou, C.N, Tao, S.Z., Gao, X.H., Li, Y., Gong, Y.J., Jia, J.H., Dong, D.Z., and Li, X.J., 2010. "Concepts, Geological Characteristics and Evaluation Techniques for Continuous Petroleum Accumulations in China." AAPG Convention, New Orleans, Louisiana, April 11-14, 27 p.
Qiu, H.J., 2008. "Coalbed Methane Exploration in China." AAPG Annual Convention, San Antonio, Texas, April 20-23, 36 p.
*The IEA's "World Energy Outlook: Special Report on Unconventional Gas, Golden Rules for a Golden Age of Gas", (2012), estimated that the remaining technically recoverable tight gas resource was 3,000 Bcm (106 Tcf).

Figure 4-1. Unconventional Gas Basins of China

China's most commercially developed unconventional gas resource is tight gas, with large-scale production from the Ordos and Sichuan basins. Coalbed methane, while considered highly promising in the 1990's, has lagged behind its expected development pace due to geologic and reservoir challenges. Shale gas, currently in the earliest phases of exploration, has potential to become a major gas supply source for China. However, shale gas output likely will grow more slowly than anticipated as industry adapts gas extraction technology to China's complex reservoir settings and gains operating experience from its overseas joint ventures.

B. Governmental Authorities Engaged with Unconventional Gas Development

The government authorities involved with unconventional gas development in China are distinct from those for conventional oil and gas resources. Indeed, each individual unconventional resource type (CBM, shale, tight gas) has its own unique set of investment and leasing policies, regulations, and procedures that have evolved over the past two decades. In this sense, China differs from other economies (e.g., USA, Australia) where conventional and unconventional gas resources are administered under a unified system with minor differences in policy and taxation.

Traditionally, China's central government, rather than the provincial government, owns the mineral rights for unconventional gas resources. China's central Ministry of Land and Resources (MLR) provides policies and oversight on leasing for unconventional gas development.[2] Provincial-level governments (e.g., Shanxi) may obtain local mineral rights but are not permitted to lease them to foreign entities.

Administration of each unconventional resources type is discussed below.

Shale Gas. China is still formulating its investment regimes for domestic and foreign shale gas operators. Contracts will be competitively bid and implemented by MLR, although PetroChina and Sinopec have inherent advantages because they control much of the land and data. It is likely that fiscal terms will be a combination of tight gas and CBM terms. A price subsidy of RMB 0.26 to 0.3 per m^3 (\$0.04 to 0.05/m^3) is reportedly under consideration. Earlier this year Shell signed China's first foreign PSC for shale gas development at the Fushun block in the Sichuan Basin. The contract period is 30 years but other terms remain confidential.

Coalbed Methane. Administration of this new gas resource was uncertain until the government created the China United Coalbed Methane Corporation (CUCBM) in 1996. By 1998 China developed fiscal policy and leasing procedures for CBM resource development and the first PSC's were signed.

[2] Che, C.B., 2011. "The Present Situation of China's Unconventional Gas." Ministry of Land and Resources. September 25, 27 p.

In late 2010 the Chinese government relaxed the former monopoly held by CUCBM on coalbed methane investment, allowing three additional companies to joint venture with foreign partners. The CBM contract allows production to be sold at the market price, which is higher than the controlled pricing for conventional gas. There is also a modest subsidy for CBM production (0.2 RMB/m^3), which may be increased to promote investment.

Tight Gas. Administration of tight gas resources is similar to that of conventional, except that the investment terms may be adjusted in favor of the operator to promote development. While the Ministry of Land and Resources (MLR) has ultimate authority over tight gas resources, in practice CNPC (PetroChina) has been the dominant operator and administrator.

Foreign companies need to joint venture with PetroChina (or other lease holders) to obtain access to its existing tight gas PSC's. For example, Chevron "farmed into" PetroChina's Chuandongbei gas project in the Sichuan Basin in 2005 and is developing its tight gas potential. Another potential avenue (e.g., Sino Gas & Energy in the northeast Ordos Basin) is to develop tight gas along with stratigraphically inter-bedded CBM resources, which is permitted under China's CBM contract.

Geologic and Reservoir Data. Unlike North America, Europe, and Australia, China does not make well log and production data available to the public in a systematic way. Although these data are freely available in the West, they ordinarily are considered proprietary commercial or even confidential state secrets (note that a Chinese-American geologist is currently serving an 8-year prison term for selling well location data). Sporadic data on unconventional gas formations are published in technical journals, mainly in Chinese language, requiring time consuming interpretation and integration of the data into usable formats for geologic mapping and analysis. The lack of ready access to geological and reservoir data is a significant factor slowing investment in unconventional gas resources by both Chinese and foreign companies.

China has four main groups that collect and analyze unconventional natural gas data:

- ***Ministry of Land and Mineral Resources.*** China's central government maintains a land registry data base and has ultimate authority on leasing oil and gas rights to operators. In 2011 the MLR established a shale gas research group in Beijing with drilling and analysis capabilities. In particular, in early 2010 the MLR set a target for China to identify 50 to 80 shale gas prospects and 20 to 30 exploration and development blocks by 2020. MLR also set a goal for China to define 1 Tcm (35 Tcf) of recoverable shale gas reserves and to produce 8 to 12% China's natural gas by 2020. More recently (March 2, 2012), the MLR raised this target to as much as 100 Bcm/yr or 9.7 Bcfd by 2020.

- ***Individual Province Petroleum Geology and Coal Geology Bureaus.*** Each province in China maintains a central geologic data collection system cataloguing well log, seismic and laboratory data on conventional and unconventional resources. The information is owned by the province and may be sold to private or government companies. Only limited portions of this geological data are published.

- ***PetroChina, Sinopec, CUCBM and other government-controlled petroleum companies.*** Each of these major industry firms has its own internal data collection and aggregation system which is considered proprietary and generally not available for purchase, although joint-venture partners may gain access to some data. These groups have the best data sets and conduct the most sophisticated analyses of unconventional gas in China.

- ***Universities such as China University of Geology in Wuhan and Beijing.*** These organizations tend to have limited subsurface data on unconventional resources and are less influential in China's unconventional gas industry.

C. Unconventional Gas Resource Assessments

Preliminary national-level unconventional gas resource assessment studies have been performed individually by Chinese and foreign authors on shale gas, coalbed methane and tight gas.

Shale Gas. China has extensive organic-rich shale source rocks that are prospective for shale gas development. The main targets include Paleozoic black shales of marine origin located in southern and western China, which are mainly gas prone. Other targets included Mesozoic organic-rich shales of lacustrine origin located in northwestern and northeastern China that are mostly oil-prone. Industry has focused mainly on the dry-gas-prone marine shales in the Sichuan Basin of southern China, although the thermally less mature, oil-prone Junggar and Songliao basins in north China are beginning to attract interest.

CNPC's E&P research center (RIPED) conducted the first scoping evaluation of potential shale gas resources in China, which they estimated at 21.7 to 45.0 Tcm (766 to 1,589 Tcf),[3] based on analogs with American shale basins. Most of the shale targets identified by the study have high TOC and high thermal maturity. However, a number of the shale formations are rich in clay and low in more brittle minerals (quartz, carbonate) important for successful shale stimulation and recovery.

More recently (March 2, 2012), the MLR published a separate preliminary evaluation that estimated China's recoverable shale gas resources at approximately 25.1 Tcm (886 Tcf), out of 134.4 Tcm (4,747 Tcf) of shale gas in-place.[4] Based on the work of 420 staff, the assessment surveyed 41 basins and regions but excluded the Qinghai and Tibet areas. The MLR further projected that shale gas production in China would reach 100 billion m^3 (3.5 Tcf) in 2020, or about 9.7 Bcfd, which seems very ambitious.

Finally, the EIA/ARI study, which is the most transparent and explicit of the publically available shale resource studies, estimated China's technically recoverable shale gas resources (risked) at 36 Tcm (1,275 Tcf.)[5] The study noted that the Sichuan and Tarim basins are likely China's most prospective shale areas, containing organic-

[3] Liu, H.L., Wang H.Y., Liu R.H., Zhao, Qun Lin Y.J., 2009. "Shale Gas in China : New Important Role of Energy in 21st Century." International Coalbed and Shale Gas Symposium, University of Alabama, Tuscaloosa, USA.
[4] Ministry of Land and Resources, 2012. "Results of the National Shale Gas Geologic Assessment and Favorable Locations." March 2. Website accessed September 6, 2012, http://www.mlr.gov.cn/xwdt/jrxw/201203/t20120302_1069466.htm (in Chinese)
[5] "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside of the United States", sponsored by the U.S. Energy Information Administration (April, 2011) prepared by Advanced Resources International.

rich shales deposited under marine conditions, similar to the depositional origin of commercial North American shales. Lacustrine-deposited organic-rich shales were identified in the Junggar, Songliao, and other northern basins but were not assessed due to their likely high clay content and lack of data.

- ***Sichuan Basin.*** The Sichuan Basin and adjacent Yangtze Platform are China's most active shale gas regions. Paleozoic black shales (within the Cambrian Qiongzhusi and Silurian Longmaxi formations) are thick and laterally extensive, and characterized by suitable depth, thermal maturity, and brittle mineralogical composition (rich in quartz).[6]

  The Sichuan Basin is an active conventional and tight gas development area, with horizontal drilling and hydraulic stimulation capability that is being upgraded for horizontal shale requirements. The nearby major cities of Chengdu, Chongqing, Guiyang and Wuhan provide ready markets for natural gas. However, geologic challenges include significant and tectonically active faulting as well as sour gas contamination across much of the Sichuan basin.

- **Tarim Basin.** This remote and logistically challenging area in western China's Xinjiang region also has large prospective shale gas resources. Thick Paleozoic-age (Cambrian, Ordovician) marine shale source rocks are present. However, these formations are deep (4-5 km), even on the structural uplifts, and thus wil be expensive to access. Furthermore, absent local markets, the shale gas production from the Tarim would need to be transported to eastern China via a west-to-east Pipeline. Perhaps due to these challenges, shale gas exploration activity has not yet been reported in the Tarim Basin.

Coalbed Methane. China has large coalbed methane resources estimated by the Ministry of Land and Resources at approximately 37 Tcm (1,300 Tcf) of gas in-place, of which 10.9 Tcm (385 Tcf) is shallower than 1.5 km and considered technically

[6] Sun, S.S., 2011. "Resource Prospect and Advancement in Shale Gas in China." PetroChina Research Institute Petroleum Exploration & Development, 36 p.

recoverable.[7] An earlier, independent assessment of China's CBM resources, published in the Encyclopedia of Energy, estimated 10 Tcm to 33 Tcm (350 to 1,150 Tcf) of gas in-place, with 2 Tcm (70 Tcf) technically recoverable.[8]

Much of the resource is located in the Ordos and Qinshui basins of Shaanxi, Inner Mongolia and Shanxi, close to eastern gas markets and existing pipeline infrastructure. The principal coal seam targets occur within the Permian-Carboniferous Shanxi and Taiyuan formations.

Coal seam gas content varies with rank and depth, from about 3 m^3/t in sub-bituminous coals to over 20 m^3/t in anthracites. However, the coal reservoirs often are under-saturated due to uplift, erosion and cooling. Permeability is usually low (about 1 mD), although some areas with higher permeability have been located. Coal basins in China are structurally more complex, with steep dips and faults that compartmentalize the reservoirs into isolated blocks that are harder to develop. These geologic challenges are a principal reason for China's slow level of CBM development and production, about 2.1 Bcm/yr (200 MMcfd) as of mid-2012 despite 20 years of increasingly intense exploration.

Tight Gas. China has significant tight gas in-place resources in sandstone and carbonate formations, estimated by PetroChina at approximately 30 Tcm (1,060 Tcf).[9] However, no estimates exist as to how much of this in-place resource is neither technically nor economically recoverable. Only two areas (Ordos and Sichuan basins) have been exploited to date, but China likely has vast additional still uncharacterized tight gas potential in other basins.

- ***Ordos Basin***. Tight sandstones in the Paleozoic Shanxi Formation are being developed at Sulige gas field in the deep central Ordos Basin. Porosity averages 8.5% while permeability is moderately low at around 1 mD. These sandstones

[7] Qiu, H.J., 2008. "Coalbed Methane Exploration in China." AAPG Annual Convention, San Antonio, Texas, April 20-23, 36 p.
[8] Encyclopedia of Energy, Volume 4, 2004 Elsevier, Inc., pp. 257-272.
[9] Zou, C.N, Tao, S.Z., Gao, X.H., Li, Y., Gong, Y.J., Jia, J.H., Dong, D.Z., and Li, X.J., 2010. "Concepts, Geological Characteristics and Evaluation Techniques for Continuous Petroleum Accumulations in China." AAPG Convention, New Orleans, Louisiana, April 11-14, 27 p.

thin towards the basin's shallow eastern edge, where exploration drilling continues.

- ***Sichuan Basin.*** The Sichuan Basin has tight gas resources in the sandstones and carbonates of the Upper Triassic Xujiahe Formation. These deposits average 7% porosity with permeability under 1 mD. Extremely high H_2S makes these resources hazardous to produce and costly to develop.

D. Unconventional Gas Activity and Production

Last year (2011), China produced approximately 38 Bcm/yr (3.65 Bcfd) from unconventional gas reservoirs, out of a total 103 Bcm/yr (9.9 Bcfd) of natural gas production, Table 4-2, with tight gas providing the bulk of output. Shale gas production is expected to start soon and may grow rapidly, although probably much more slowly than official government targets due to numerous geologic, operational and infrastructure challenges, as well as time for technology adaptation.

China's Twelfth Five-Year Plan envisions rapid, near-term growth in unconventional gas production, including 10 Bcm to 15 Bcm per year (1.0 to 1.5 Bcfd) of coalbed methane, 21 Bcm/yr (2 Bcfd) of shale gas, and 31 Bcm/yr (3 Bcfd) of tight gas.

Shale Gas. It appears likely that shale gas eventually will provide the greatest volume of unconventional gas production in China. Early-stage drilling and testing is underway in the Sichuan Basin by PetroChina and Shell.

While present volumes of shale gas production are negligible, these volumes could increase rapidly assuming geologic and operational issues can be overcome. However, the Chinese government's long-term production target for shale gas is 60 to 100 Bcm/yr (5.8 to 9.7 Bcfd) by 2020 will undoubtedly be challenging to achieve.

While shale gas exploration is in the early stage, well testing has yielded mixed but fairly encouraging results to date. China's first horizontal shale well was drilled in 2010-11 by PetroChina in the southern Sichuan Basin. This well, which required 11 months to drill, placed a 1,079-m long lateral within the Lower Silurian Longmaxi

Formation. After an 11-stage slickwater frac simulation, the well averaged 460 Mcfd over a 44-day period. Nearby, Shell flowed a significantly higher 2.1 MMcfd from a vertical test frac well.[10] Given the US experience with shale gas development, future wells in China are likely to continue to show improvement.

With potentially the world's largest undeveloped shale gas resource as well as bountiful tight gas and CBM deposits, the prospects for increased production of unconventional gas in China are promising. However, China's unconventional gas industry faces numerous and quite challenging geologic, infrastructure, and policy hurdles.

Coalbed Methane. Chinese and foreign companies have been active in CBM exploration and development since about 1990.[11] The first wave of CBM exploration (1990-2000), including testing by six major foreign oil companies, laid the groundwork for China's CBM industry. CBM production began to increase in 2000, after local Chinese companies focused on reducing their drilling costs and benefited from higher gas prices.

As of October 2011, China CBM production stood at about 2 Bcm/yr (0.15 Bcfd), below the government's revised target of 5 Bcm/yr (0.5 Bcfd) by 2010[12] and far below the long-term (2020) production target of 41 Bcm/yr (4 Bcfd). (Official government targets for CBM production have changed frequently.) As of mid-2012, CBM production is estimated to have increased to 200 MMcfd, from some 10,000 vertical and a few dozen horizontal wells drilled in the Qinshui and Ordos basins in Shanxi and Shaanxi provinces. CBM drilling has intensified in recent years to about 2,000 to 3,000 vertical wells per year.

However, CBM productivity per well is still quite low (typically less than 20 Mcfd/well), due to significant geologic challenges including faulting, low permeability,

[10] Hackbarth, C.J., Soo, D., and Singh, N., 2012. "Sichuan Basin Shale Gas, China: Exploring the Lower Silurian Longmaxi Shale." International Petroleum Technology Conference, Bangkok, Thailand, 7-9 February, IPTC 14487.
[11] China United Coalbed Methane Corporation Ltd., 2009. "Achievements of the International Cooperation in the Past 10 Years and the Progress of Science and Technology." Ninth Sino-US Oil and Gas Industry Forum, October, 19 p.
[12] China Oil and Gas Conference, Beijing, October, 2011, subsequently revised.

and low gas saturations. Recently, horizontal multi-lateral drilling, adapted from the USA and Australia, has been used to achieve higher productivity wells (0.3 to 1 MMcfd/well) in limited sweet spot locations such as the southern Qinshui and eastern Ordos basins.

Many CBM operators note that another factor slowing CBM development has been the slow pace of approval under China's Overall Development Plan (ODP) process, which is still geared towards conventional resources and its discrete exploration and development phases. Shell announced in August 2012 that it planned to move its global CBM business unit to China this year.

Current foreign CBM operators in China include Dart Energy, Far East Energy, Fortune Oil, Green Dragon Gas, and Sino Gas and Energy. Green Dragon, the furthest along of this group, recently announced that its production had increased to about 5 MMcfd during the first half of 2012.

In August 2012 CNOOC announced that it would invest $1.56 billion in CBM development over the next five years. CNOOC had previously taken control of CUBM, the government company set up in 1996 to regulate and invest in the coalbed methane industry. Given the continuing challenges facing the CBM industry in China, this increased investment may result in only modest production increases.

In addition to CBM, a much larger volume of coal mine methane (CMM), a mixture of CBM and ventilation air, is being drained for mine safety and productivity purposes from within China's deep underground coal mines. Short (100-m long) boreholes are drilled into the coal seams from within underground coal mine workings and used to collect and produce the gas. CMM production in China is mostly low in purity (10-50% methane) due to mixing with ventilation air and thus is used locally for small-scale power generation or boiler fuel. China's coal mines drained a total 7.35 Bcm (0.7 Bcfd) of CMM (recalculated at 100% methane) in 2010. Of this total drained, approximately 2.5 Bcm/yr (0.24 Bcfd) was utilized while the remainder was vented.[13]

[13] China Coal Information Institute, 2011. "Progress of China Coalbed Methane."

Tight Gas. The dominant source of unconventional gas production in China is tight gas, already providing about 36 Bcm/yr (3.5 Bcfd); (higher than target), mainly from low-permeability sandstone and carbonate reservoirs in the Ordos and Sichuan basins. Development of tight gas resources helped China advance its horizontal drilling and hydraulic fracturing capabilities. Tight gas output is expected to continue to grow, albeit at a moderate pace as industry focuses increasingly on shale gas projects.

In the Sichuan Basin, PetroChina has been drilling mainly vertical, hydraulically fractured wells that average about 700 Mcfd/well. Other operators are drilling experimental horizontal wells with higher flow potential. In the Ordos Basin, PetroChina is the dominant producer, drilling vertical, hydraulically fractured wells that flow about 400 Mcfd/well (average for 1,760 wells). Recently drilled multi-lateral horizontal wells in the Ordos Basin, such as at Shell's Changbei project, indicate flow potential in excess of 20 MMcfd.

In August 2012 Shell announced that it plans to invest a minimum $1 billion annually in China unconventional gas production. Most of the investment is targeted to tight gas development in the Ordos Basin, with some investment in the company's early-stage Sichuan shale gas and Ordos CBM projects.

APEC Unconventional Natural Gas Census
Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 5. RUSSIA UNCONVENTIONAL GAS

SECTION 5.
RUSSIA APEC ECONOMIES
UNCONVENTIONAL GAS

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SECTION 5. RUSSIA UNCONVENTIONAL GAS

A. Introduction

Russia is a giant in terms of natural gas reserves, production and undiscovered resources. The government of Russia relies on its natural gas exports, by pipeline to Europe and by LNG to Asia-Pacific, for a significant portion of its revenues. Russia also relies on natural gas for more than half of its domestic energy needs.

Last year (2011), Russia's natural gas consumption was 425 Bcm equal to 41.1 Bcfd, Table 5-1. [1] At the same time, Russia produced 607 Bcm or 58.7 Bcfd of marketed natural gas from a proved reserves base of 44,600 Bcm (1,575 Tcf). After a sharp drop in 2009, natural gas production rebounded in 2010 and 2011. Publically reported natural gas proved reserves of 44.6 Bcm (1,575 Tcf) have been level for the past 10 years.

Table 5-1. Russia Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		414	14,610	40.0	425	15,000	4.1
Supply							
▪	Marketed Production (Dry)	589	20,790	56.9	607	21,430	58.7
▪	Net Exports/Imports/Other	(175)	(6,180)	(16.9)	(182)	(6,430)	(17.6)

Source: BP Statistical Review of World Energy, 2012

The difference between its natural gas production and consumption of 182 Bcm or 17.6 Bcfd has been exported, primarily to Eastern and Western Europe. A series of new natural gas pipeline systems to Europe (and potentially to China) are being constructed or proposed, including the recently completed Nord Stream Pipeline. Completion of the Yamal-Europe II and South Stream pipelines would significantly increase Russia's natural gas export capacity to Europe.

[1] BP Statistical Review of World Energy, 2012

Three large Western Siberian gas fields (Yamburg, Urengoy and Medvezhye) hold nearly half of Russia's proved natural gas reserves. With recent declines of production from these "big three" fields, Russia launched the Yamal Megaproject in 2008 to develop new areas for natural gas production. By year 2020, Gazprom expects the Yamal Peninsula and adjacent offshore areas to provide 135 to 175 Bcm or 13 to 17 Bcfd of natural gas production.

In the past, Russia has flared a portion of its natural gas production, particularly associated gas from remote oil fields. According to NOAA, Russia flared an estimated 40 Bcm or 3.9 Bcfd of natural gas in 2008, equal to 6% of its marketed production.[2] Since then, the Russian government has taken steps to reduce natural gas venting and flaring.

Until recently, the development of unconventional hydrocarbon resources has not been a priority for the Russian oil and gas industry due to the existence of large conventional resources. However, recently considerable interest has been expressed for evaluating the potentially large shale oil and gas formations in the Timan-Pechora and Western Siberia (Bazhenov) basins, Figure 5-1. In addition, Gazprom has recently undertaken CBM development in the Kuznets Basin.

In 2012, Gazprom published an estimate of 83.7 Tcm (2,950 Tcf) for Russia's coalbed methane resource in-place, with 13.1 Tcm (460 Tcf) in the Kuznets Coal Basin (Kuzbass) for CBM resources at a depth of 1,800 to 2,000 meters. Deeper coal deposits in the Kuzbass would add to the volume of CBM resource in-place. Until recently, CBM was extracted in Russia as part of coal mine degasification. In recent years, this approach has yielded 5 million cubic meters (0.2 Bcf) of methane per year in the Pechorsky and Kuznets basins, Table 5-2.

[2] U.S. Energy Information Administration, Country Analysis Brief, 2012

Figure 5-1. Timan-Pechora and Western Siberia Shale Oil and Gas Basins

Table 5-2. Russia's Unconventional Gas Resources

		Resource Estimates				Production (2011)*	
		Gas In-Place		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	**	**	n/a	n/a
▪	CBM	83,700	2,950	**	**	Small	Small
▪	Tight Gas	n/a	n/a	**	**	n/a	n/a
	TOTAL	**83,700**	**2,950**	**	**	**Small**	**Small**

*Gazpom, 2012. **From Gazprom website "Production of Coalbed Methane" page "In the recent years coalbed methane operations have produced 5 million cubic meters per annum in the Pechorsky and Kuznetsky basins."
**The IEA special study on unconventional gas estimated 8 Tcm (280 Tcf) of recoverable shale gas, 20 Tcm (700 Tcf) of recoverable CBM and 7 Tcm (250 Tcf) of recoverable tight gas.

Russia is in the process of developing procedures for inclusion of coalbed methane (CBM) into the Russian classified Index of Natural Resources and Underground Waters, which will make it possible to obtain subsurface use licenses for CBM. In addition, the Ministry is considering Gazprom's proposal for a zero production tax rate for CBM, as well as zero import duties on CBM production equipment not manufactured in Russia.

After several years of dismissing the importance of unconventional gas, and particularly shale gas, Russia has begun to more seriously evaluate the domestic potential and worldwide impact of this resource.

- In 2010, the Russian Federal Legislature (Duma) recommended that the government evaluate Russia's potential in shale gas and study new technologies for producing shale gas in Russia.
- At the end of August 2012, Russia "pulled the plug" on Gazprom's $US15 billion Shtokman (3,800 Bcm (134 Tcf)) flagship energy project in the Russian Arctic due to falling European demand and the demonstrated pressure of cheap, bountiful shale gas in the U.S., reducing America's need for LNG imports.[3]
- In early September, 2012, Russia's gas giant Gazprom entered into an agreement with Argentina's state-controlled YPF energy company to pursue shale oil and gas in Argentina.

B. Governmental Agencies Engaged with Unconventional Gas Development

The Russian Ministry of Energy, Gazprom and a series of non-state companies (such as LUKOIL) comprise the internal oil and gas sector of Russia.

- *Ministry of Energy.* The Russian Ministry of Energy was created in 2008 when it was split from the former Ministry of Industry and Energy. The Ministry of Energy also includes the former Federal Agency for Energy. Alexander Novak is currently the Minister. The Ministry of Energy is responsible for energy policy

[3] Macalister, T., "Plug Pulled on Russia's Flagship Shtokman Energy Project", The Guardian 29 August 2012.

and regulation of Russia's energy complex, including oil and gas production, refining, pipelines and petrochemicals.

Recently, the Russian Ministry of Energy proposed a new set of tax policies designed to attract investment into challenging new oil and gas provinces, particularly for the Arctic offshore. (Russia's oil industry is currently taxed at a marginal rate of around 90% per barrel of crude oil exported, among the heaviest in the global oil industry, (Reuters, 2012).[4] With expected adoption of these new tax policies, international major ExxonMobil entered into a partnership with Russia's state oil firm, Rosneft, making an initial commitment of $3.2 billion of investment, with development of the massive Bazhenov Shale a priority. Mr. Tillerson, Chairman and CEO of Exxon, stated, "The in-place potential (in the Bazhenov) is enormous - - billions of barrels. The real issue is can we develop it in a cost effective way?"

- *Gazprom.* OAO Gazprom is Russia's largest company and the single largest producer of natural gas in the world. The company was created in 1989 when the Ministry of Gas Industry became a corporation, with the Russian government holding most of the control. Alexey Miller is CEO of Gazprom and Viktor Zubkov is Chairman of the Board. In addition to production of natural gas of 509 Bcm equal to 48.2 Bcfd (in 2010),[5] as well as substantial volumes of crude oil and gas condensate. Gaszprom owns and operates the Russian natural gas pipeline system with nearly 160,000 kilometers (98,000 miles) of gas trunk lines.

- *LUKOIL,* the third largest non-state, publically traded oil company worldwide (in terms of proven reserves of hydrocarbons) accounts for about 17% of Russia's oil production and refining. Last year (2011) LUKOIL's natural gas production was about 22.0 Bcm equal to 2.1 Bcfd. After internal use, re-injection and transportation losses, marketed natural gas was 18.6 Bcm equal to 1.8 Bcfd. The company has announced plans for accelerated growth in gas production (in Russia and abroad) with a goal of natural gas providing a third of the company's

[4] Reuters, 2012
[5] Gazprom website, 2012.

hydrocarbon production. (A number of smaller private oil and natural gas companies also operate in Russia.)

C. Unconventional Gas Resource Assessments

C.1 Geological Studies of Oil and Gas Resources of Russia. Four in-depth studies of Russia's oil and gas geology and hydrocarbon resources provide valuable information on the potential for unconventional gas in this economy.

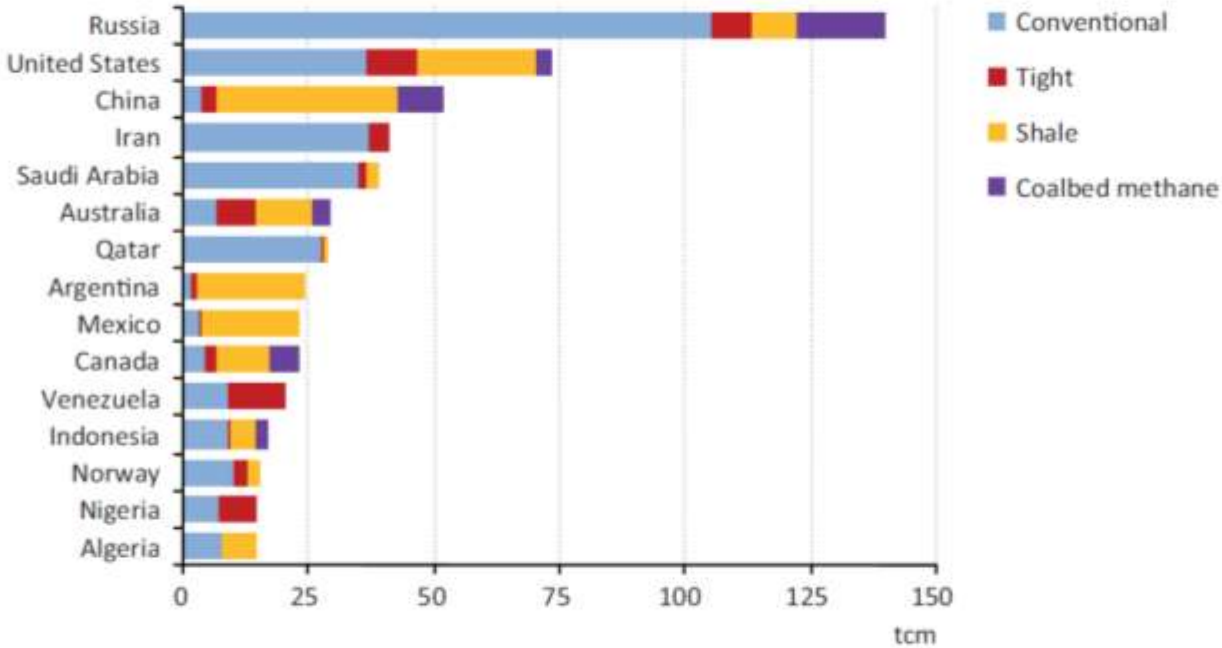
1. Geology and Natural Gas Production of Deep Sedimentary Basin in the Former Soviet union by Dyman, Litinsky and Ulmishek (2001).
2. Mineral Systems of Siberia, Mongolia, Northeastern China, Republic of Korea, and Japan (Northeast Asia), A Collaborative Project by Russian Academy of Sciences, Mongolian Academy of Sciences, Changchun University of Earth Sciences, the Geological Survey of Japan, and the U.S. Geological Survey.
3. The Fourth All-Russia Conference "Cretaceous System of Russia and CIS Countries: Problems of Stratigraphy and Paleogeography", E.Yu. Baraboshkin, V.A. Zakharov, B.N. Shurygin, O.S. Dzyuba, A.E. Igol'nikov, 2009, published in Stratigrafiya. Geologicheskaya Korrelyatsiya, 2009, Vol. 17, No. 3, pp. 125–128.
4. Russian Oil Supply, Performance and Prospects, John D. Grace, Oxford University Press Aug 2005.

C.2. Unconventional Gas Resources Studies.

. ***Shale Gas.*** No official publically available estimates exist for the shale gas resources of Russia. However, the IEA, in their recent special publication on unconventional gas, has an estimate of about 8 Tcm (280 Tcf) of recoverable shale gas resource for Russia, Figure 5-2.[6]

[6] International Energy Agency, "Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas", OECD/IEA, 2012.

Figure 5-2. Remaining Recoverable Gas Resources in the Top Fifteen Countries, End-2011

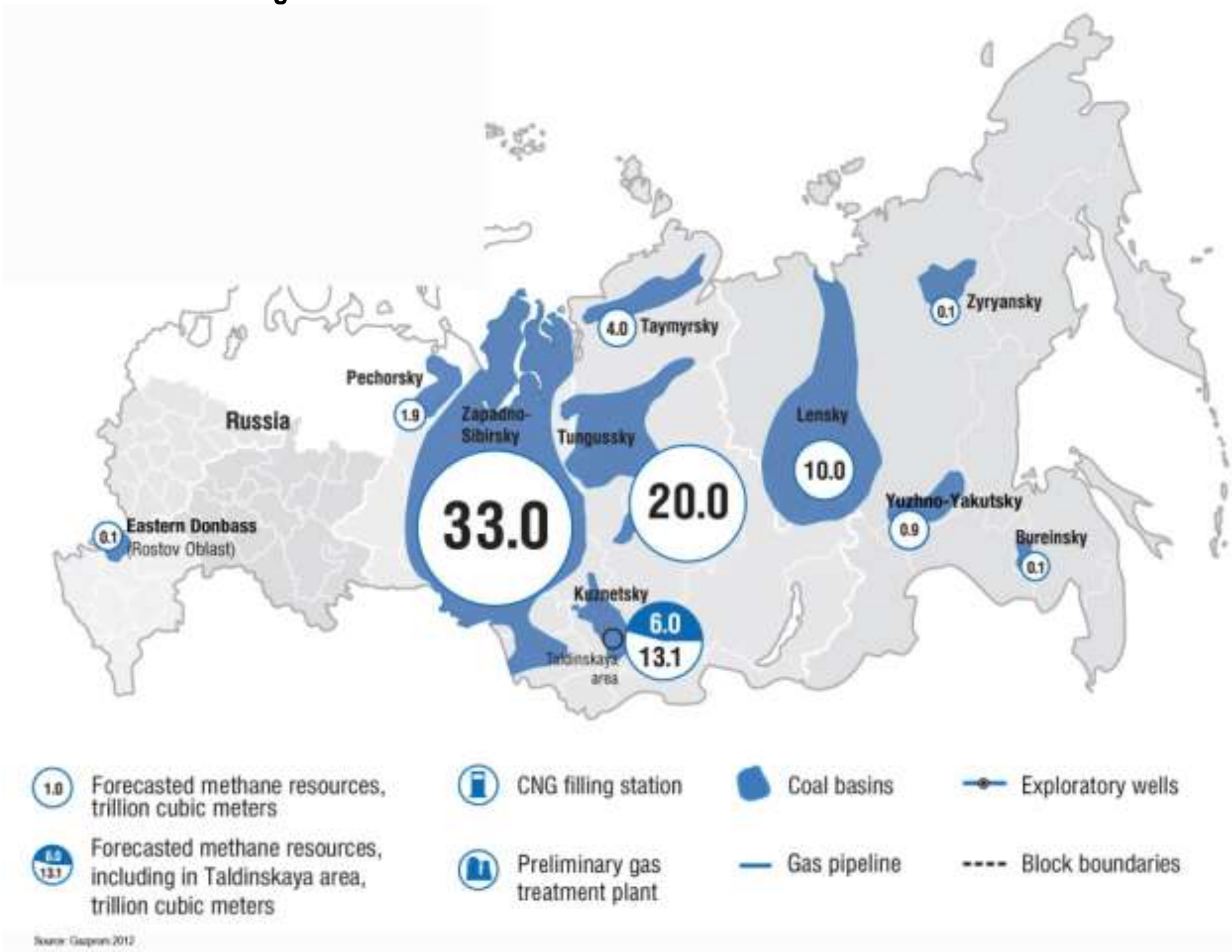


Source: IEA (2012)

Coalbed Methane (CBM). Gazprom states that Russia's coal basins are estimated to contain up to 83,700 billion cubic meters (nearly 3,000 Tcf) of CBM resources in-place, with a significant portion of this in-place resource located in the Kuznetsky Basin (Kuzbass) with 13,100 Bcm (460 Tcf), Figure 5-3. Additional Russian CBM resources are estimated to exist in the following basins: Zapadno-Sibirsky (33 Tcm), Tungussky (20 Tcm), Lensky and Taimyrsky (14 Tcm); Pechorsky (1.9 Tcm) and Yuzhno-Yakutsky, Eastern Donbass and other basins (1.2 Tcm).[7]

[7] Gazprom press release Feb 12, 2010 Russia's Resource Base Ensures Commercial CBM Production; GazProm website, 2012.

Figure 5-3. Potential Coalbed Methane Resources in Russia



The Kuznetsky Coal Basin, covering an area of 10,000 square miles on the southern slopes of the west-central Siberian plain, contains numerous coal seams that extend below 5,000 feet in the basin center. In 1991, Advanced Resources estimated 12,750 Bcm (450 Tcf) of CBM resource in-place for the Kuzbass to a depth of 5,000 feet. This estimate is similar to the current Russian estimate of 13,100 Bcm (462 Tcf) of CBM resources to a depth of about 6,000 feet in the Kuzbass by Gazprom. ARI's previous assessment also included an estimate of 2,800 Bcm (100 Tcf) of CBM resource in-place for the Timan-Pechora (Pechorsky) basin, compared with Gazprom's current estimate of 1,942 Bcm (68 Tcf).

The IEA, in their special publication on unconventional gas, has an estimate of about 20 Tcf (700 Tcf) of recoverable CBM resources for Russia, Figure 5-2.[6]

Tight Gas. Similar to shale gas, no official publically available estimates exist for the tight gas resource of Russia. However, the IEA, in their recent special publication on unconventional gas, has an estimate of about 7 Tcm (250 Tcf) of recoverable tight gas resources for Russia, Figure 5-2.[6]

D. Unconventional Gas Activity and Production

Shale Gas. No shale gas exploration or production exists in Russia, but Gazprom recently assigned technicians to work in partnership with China National Petroleum Corp. in Chinese shale gas fields.[8]

Coalbed Methane. Gazprom stated that "CBM production is destined to become one of the cornerstones for Gazprom's resource base expansion strategy and will essentially lead to the creation of a new industry in Russia - - CBM production industry."[5]

CBM development is underway Kemerovo Oblast in the Taldinskaya Field of the Kuznetsk Coal Basin (Kuzbass). The licensed exploration area in the south central region of Kuzbass contains an estimated 6 Tcm (212 Tcf) of CBM resource, spread across four prospective fields, Figure 5-4.

CBM exploration was initiated in Kuzbass in 2003. In 2008, Gazprom bought complete control of the project with the intent to expand CBM operations in the area. Seven exploratory wells were drilled by Gazprom in 2008-2009 leading to coalbed methane production last year of 5 million cubic meters (0.2 Bcf).

With subsequent development, CBM production is projected to reach 4 Bcm per year (0.4 Bcfd) by 2020 and in the longer–term reach 20 Bcm/yr or 2 Bcfd.[5] Currently, the produced CBM is used to generate electricity for local population centers in the Kuznets region which are far from Russia's traditional gas producing areas. Gazprom hopes this CBM project will serve as a blue print for implementation in Russia's other coal basins.

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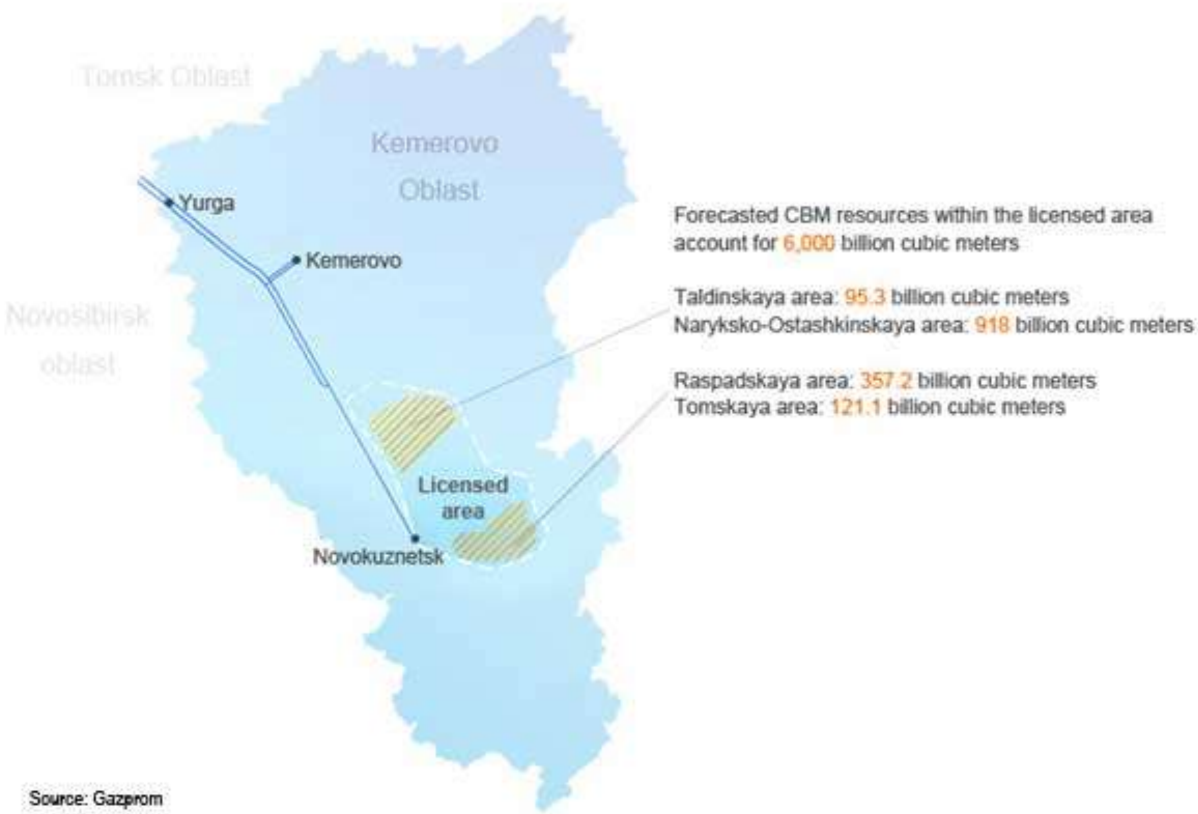
[8] Oil and Gas Journal, www.ogj.com, July 2012, "Gazprom, CNPC Add Shale Gas to Cooperation"

Figure 5-4. Feedstock Base for CBM Production in Kuzbass



Tight Gas. No tight gas activity is currently reported for Russia, although Russia has begun to increasingly rely on hydraulic fracturing to accelerate the production of its "conventional" oil and gas resources.

APEC Unconventional Natural Gas Census Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 6. ASIA PRODUCING UNCONVENTIONAL GAS

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ASIAN APEC ECONOMIES
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SECTION 6. OVERVIEW: ASIAN NATURAL GAS PRODUCING APEC ECONOMIES UNCONVENTIONAL GAS

A. Introduction

Seven of the Asian APEC Economies - - Brunei, Indonesia, Malaysia, Papua New Guinea (PNG), Philippines, Thailand and Viet Nam - - are significant producers as well as consumers of natural gas. A major portion of their excess natural gas production is sent, via LNG and/or pipeline, to the geographically proximate Asian Natural Gas Non-Producing APEC Economies consisting of Japan, Republic of Korea, Chinese Taipei, Singapore and Hong Kong, China.

Table 6-1 provides an economy-by-economy summary of the natural gas consumption, marketed production and net export/import balance for these seven APEC Economies.

The seven Asian Natural Gas Producing APEC Economies fall into three distinct groups, namely: natural gas exporters, natural gas importers, and natural gas balanced economies.

- Three Asian APEC Natural Gas Producing Economies - - Brunei, Indonesia and Malaysia - - comprise the natural gas exporters, providing 81 Bcm (2,830 Bcf) or 7.7 Bcfd of natural gas exports, primarily via LNG. Brunei, with its relatively small volumes of natural gas consumption, exports about three-quarters of its natural gas production. Indonesia and Malaysia, each significant consumers of natural gas, export about half of their natural gas production. With declining domestic natural gas production in Indonesia and Malaysia and growing consumption (plus unmet demand), new sources of natural gas supply, particularly from unconventional gas, are a high priority if Indonesia and Malaysia are to remain as significant natural gas exporters in the Asian region.

Table 6-1. Asian Natural Gas Producing APEC Economies - - Natural Gas Consumption and Supply

	2010			2011		
	(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
1. Brunei						
Consumption	3	110	0.3	3	120	0.3
Supply						
▪ Marketed Production (Dry)	12	430	1.2	13	450	1.2
▪ Net Exports/Imports	(9)	(320)	(0.9)	(10)	(330)	(0.9)
2. Indonesia						
Consumption	40	1,420	3.9	38	1,340	3.7
Supply						
▪ Marketed Production (Dry)	82	2,890	7.9	76	2,670	7.3
▪ Net Exports/Imports	(42)	(1,470)	(4.0)	(38)	(1,330)	(3.6)
3. Malaysia						
Consumption	32	1,130	3.1	29	1,010	2.8
Supply						
▪ Marketed Production (Dry)	63	2,210	6.1	62	2,180	6.0
▪ Net Exports/Imports	(31)	(1,080)	(3.0)	(33)	(1,170)	(3.2)
4. PNG						
Consumption	Small	Small	Small	Small	Small	Small
Supply						
▪ Marketed Production (Dry)	Small	Small	Small	Small	Small	Small
▪ Net Exports/Imports	-	-	-	-	-	-
5. Philippines						
Consumption	3	110	0.3	4	130	0.4
Supply						
▪ Marketed Production (Dry)	3	110	0.3	4	130	0.4
▪ Net Exports/Imports	-	-	-	-	-	-
6. Thailand						
Consumption	45	1,590	4.4	47	1,650	4.5
Supply						
▪ Marketed Production (Dry)	36	1,280	3.5	37	1,310	3.6
▪ Net Exports/Imports	9	310	0.9	10	340	0.9
7. Viet Nam						
Consumption	9	330	0.9	8	300	0.8
Supply						
▪ Marketed Production (Dry)	9	330	0.9	8	300	0.8
▪ Net Exports/Imports	-	-	-	-	-	-
Total						
Consumption	**132**	**4,690**	**12.9**	**129**	**4,550**	**12.5**
Supply						
▪ Marketed Production (Dry)	**205**	**7,250**	**19.9**	**200**	**7,040**	**19.3**
▪ Net Exports/Imports	**(73)**	**(2,560)**	**(7.0)**	**(71)**	**(2,490)**	**(6.8)**

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- One Asia APEC Natural Gas Producing Economy - - Thailand - - is a net natural gas importer. While it still produces important volumes of natural gas, 37 Bcm or 3.6 Bcfd in 2011, Thailand has been a natural gas importer for some time. However, Thailand's volume of natural gas imports has doubled in the past decade as increases in natural gas consumption have outstripped increases in natural gas production. Pursuit of unconventional gas could help stabilize or reduce future natural gas imports in Thailand.

- Three Asia APEC Natural Gas Producing Economies - - PNG, Philippines, and Viet Nam - - currently have a balanced situation of natural gas consumption and production. However, two of the economies, Philippines and Viet Nam, have considerable internal unmet demand, particularly from power generation, and thus may shortly join the ranks of the natural gas importers. Development of unconventional gas would delay (or even forestall) this situation. The third economy, PNG has significant proved reserves (440 Bcm, 15.6 Tcf) plus undeveloped natural gas resources but little internal natural gas demand. It will soon (in 2014) join the ranks of the natural gas exporters. As such, PNG may place lower priority on pursuing unconventional gas.

Table 6-2 provides summary information on the natural gas consumption, production and export/import situation of these three groups of Asian APEC Natural Gas Producing Economies.

Table 6-2. Asian Natural Gas Producing Economies - - Natural Gas Consumption and Supply (2011)

	Bcm			Bcf			Bcfd		
	Consumption	Production	Exports/ Imports	Consumption	Production	Exports/ Imports	Consumption	Production	Exports/ Imports
1. Exporters									
▪ Brunei	3	13	(10)	120	450	(330)	0.3	1.2	(0.9)
▪ Indonesia	38	76	(38)	1,340	2,670	(1,330)	3.7	7.3	(3.6)
▪ Malaysia	29	62	(33)	1,010	2,180	(1,170)	2.8	6.0	(3.2)
Subtotal	**70**	**151**	**(81)**	**2,470**	**5,300**	**(2,830)**	**6.8**	**14.5**	**(7.7)**
2. Importers									
▪ Thailand	**47**	**37**	**10**	**1650**	**1,310**	**340**	**4.5**	**3.6**	**0.9**
3. Balanced									
▪ PNG	-	-	-	-	-	-	-	-	-
▪ Phillipines	4	4	-	130	130	-	0.4	0.4	-
▪ Viet Nam	8	8	-	300	300	-	0.8	0.8	-
Subtotal	**12**	**12**	**-**	**430**	**430**	**-**	**1.2**	**1.2**	**-**
4. Total	**129**	**200**	**(71)**	**4,550**	**7,040**	**(2,490)**	**12.5**	**19.3**	**(6.8)**

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B. Unconventional Gas Resource Assessments

To date, only a handful of resource assessments have been conducted for in-place or technically recoverable unconventional gas in the seven Asian Natural Gas Producing APEC Economies.

The most rigorous resource assessment is for the CBM resource in-place, followed by a preliminary estimate of the shale gas resource in-place for Indonesia, Tables 6-3 and 6-4. Small volumes of in-place CBM resources have also been defined in the Philippines, Thailand and Viet Nam.

Based on the numerous notations of n/a (no data available) on Tables 6-3 and 6-4, additional efforts toward assessing shale gas, CBM and tight gas resources in the Asian APEC Economies is warranted.

Table 6-3. Asian Natural Gas Producing APEC Economies – Unconventional Gas Resources (Metric Units)

	Gas In-Place			Technically Recoverable		
	Shale Gas	CBM	Tight Gas	Shale Gas	CBM	Tight Gas
	(Bcm)	(Bcm)	(Bcm)	(Bcm)	(Bcm)	(Bcm)
Brunei	n/a	n/a	n/a	n/a	n/a	n/a
Indonesia	28,000	12,800	n/a	n/a	n/a	n/a
Malaysia	n/a	n/a	n/a	n/a	n/a	n/a
PNG	n/a	n/a	n/a	n/a	n/a	n/a
Philippines	n/a	150	n/a	n/a	n/a	n/a
Thailand	n/a	17	n/a	n/a	n/a	n/a
Viet Nam	n/a	30	n/a	n/a	10	n/a

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Table 6-4. Asian Natural Gas Producing APEC Economies – Unconventional Gas Resources (English Units)

	Gas In-Place			Technically Recoverable		
	Shale Gas	CBM	Tight Gas	Shale Gas	CBM	Tight Gas
	(Tcf)	(Tcf)	(Tcf)	(Tcf)	(Tcf)	(Tcf)
Brunei	n/a	n/a	n/a	n/a	n/a	n/a
Indonesia	1,000	453	n/a	n/a	n/a	n/a
Malaysia	n/a	n/a	n/a	n/a	n/a	n/a
PNG	n/a	n/a	n/a	n/a	n/a	n/a
Philippines	n/a	5	n/a	n/a	n/a	n/a
Thailand	n/a	1	n/a	n/a	n/a	n/a
Viet Nam	n/a	1	n/a	n/a	0.3	n/a

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6.1 BRUNEI DARUSSALAM UNCONVENTIONAL GAS

A. Introduction

Brunei Darussalam ("Brunei") is a small (5,765-km^2), petroleum-rich economy located in Southeast Asia on the northern portion of Borneo Island, surrounded on three sides by Malaysia. Commercial oil was first discovered in 1929 by Shell at the onshore Seria field, while Brunei's first offshore exploration well was drilled in 1957. Today, offshore fields account for nearly all of Brunei's oil and gas production.

In 2011, Brunei produced 12.8 Bcm or 1.2 Bcfd of natural gas from 13 fields, Table 6-6-1.[1] Brunei's reported proved natural gas reserves are estimated at about 0.3 Tcm (10 Tcf).[2]

Table 6-6-1. Brunei Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		3.0	110	0.3	3.4	120	0.3
Supply							
▪	Marketed Production (Dry)	12.3	430	1.2	12.8	450	1.2
▪	Net Exports/Imports	(9.3)	(320)	(0.9)	(9.4)	(330)	(0.9)

Source: U.S. Energy Information Administration

Brunei consumed 3.4 Bcm equal to about 0.3 Bcfd of natural gas in 2011 and exported the remainder as LNG to Japan and Republic of Korea. A 5-train LNG facility with a production capacity of 7.2 Mt/year is supplied with 0.9 Bcfd of gas from offshore conventional gas reservoirs. Ownership of the LNG facility is the Brunei government 50%, Shell 25%, and Mitsubishi 25%. Brunei may have unconventional gas resources, but no publicly available resource assessment studies have been performed to date, Table 6-1-2.

[1] U.S.Energy Information Administration, website accessed August 7, 2012
[2] BP Statistical Review of World Energy, 2012

Table 6-1-2. Brunei's Unconventional Gas Resources

		Resource Estimates				Current Production	
		Gas In-Place		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	n/a	n/a
▪	CBM	n/a	n/a	n/a	n/a	n/a	n/a
▪	Tight Gas	n/a	n/a	n/a	n/a	n/a	n/a
	TOTAL	**-**	**-**	**-**	**-**	**-**	**-**

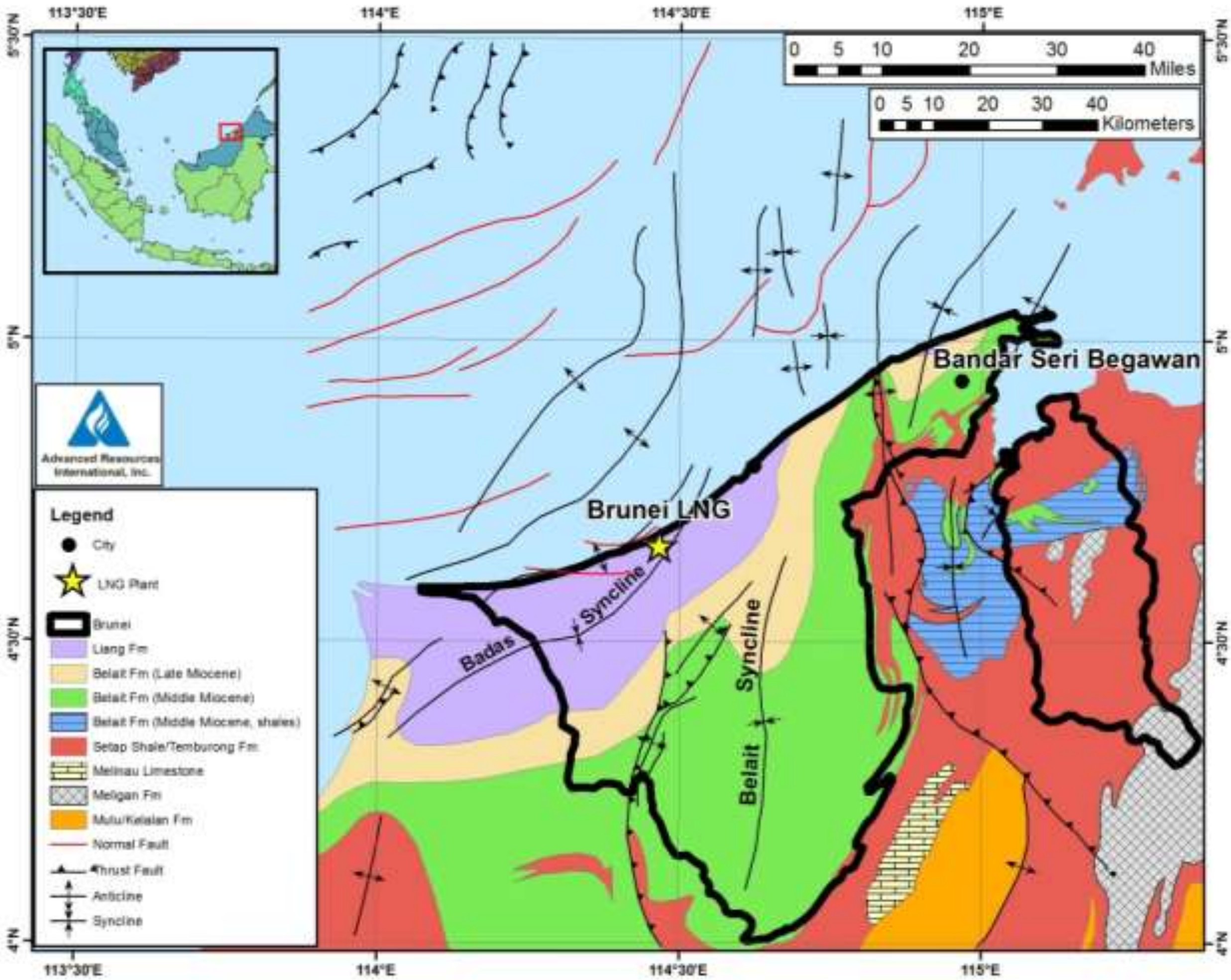
While the technical literature has reported that Shell has been developing tight gas deposits offshore Brunei, including using hydraulic fracturing, no information is available on the size of this resource.[3,4] A brief geological review (conducted by ARI) suggests that there may be thick tight gas deposits in the Badas and Belait synclines, located onshore close to the existing Brunei LNG export facility, Figure 6-1-1. Unconventional gas deposits could help extend the life of Brunei's LNG export plants should conventional gas production decline.

B. Governmental Authorities Engaged with Unconventional Gas Development

The Government of Brunei's Petroleum Unit oversees the development of the Brunei's natural gas and oil resources. Brunei National Petroleum Co. Sdn. Bhd. (PetroleumBRUNEI), a limited-liability company that is wholly owned by the Government, controls the economy's commercial interests in the oil and gas sector. Another company, Brunei Shell Petroleum Co. Sdn. Bhd. (BSP), is the dominant oil and gas production company in Brunei, jointly owned by the Government and Shell.

[3] Tucker, C.F. IV, Dean, M.C., Pahmiyer, R., Bate, K., Omotosho, P., Walli, F., Ahmad, Z., and Brittingham, P., "Developing Offshore Tight Gas Sands and Navigating Subsurface Uncertainty." SPE 132273, CPS/SPE International Oil & Gas Conference and Exhibition, Beijing, China, 8-10 June, 2010.
[4] Talib, N. and Omar, A.S., "Hydraulic Fracturing Stimulation Executions in Brunei." IPTC 15463, International Petroleum Conference, Bangkok,, Thailand, 7-9 February 2012.

Figure 6-1-1. Unconventional Gas Basins of Brunei and North Borneo (Source ARI 2012)



Apart from Shell's tight gas developments offshore, ARI is not aware of any unconventional gas research or drilling activity taking place onshore in Brunei. In late 2006, ARI visited Brunei to discuss CBM technology with PetroleumBRUNEI, as well as the methodology for evaluating its CBM resources. (It is possible that research on unconventional gas resources has progressed in Brunei since then.)

PetroleumBRUNEI maintains a comprehensive geologic and reservoir data base for all petroleum wells and seismic in Brunei. This data base may be made available to potential investors for a fee. The data base does not specifically identify or assess unconventional gas resources but may provide a good platform for such a study.

C. Unconventional Gas Resource Assessments

C.1. Government Resource Assessments. There are no publicly available reports of the unconventional gas geology or resource potential in Brunei, although Shell has published several articles about hydraulic fracturing of offshore tight sandstones.

C.2. Private Resource Assessments. The unconventional gas resource assessment presented in this section of the report is based on ARI's evaluation of Brunei's oil and gas geology and technical literature. (More detailed analyses may have been conducted by industry (PetroleumBRUNEI, Shell, etc.) but remain proprietary.) ARI's initial review of Brunei's onshore geology indicates that the its unconventional gas potential is relatively small but may be prospective, particularly should declining conventional gas production result in a future shortfall at Brunei's LNG export facility.

Brunei's coal deposits are minor, thinly bedded and thermally immature lignite. Brunei's shales are young, tectonically mobile (likely not rigid), low in TOC and thermally immature. However, thick sandstone sequences are present in Brunei, including some low-permeability reservoirs that Shell is completing with hydraulic fracturing. It appears that tight gas offers the best potential, particularly in onshore troughs.

Brunei's petroleum resources are contained within a 10-km thick deltaic sequence.[5] The deltaic sequence comprises three separate delta systems: the Paleogene to early Miocene Meligan, the early-late Miocene Champion, and the Late Miocene to present-day Baram Deltas. Each generally consists of pro-delta shales overlain by a deltaic sand/shale sequence. The structural style is complex, with syn- and post-depositional deformation and uplift.[6] The main structural elements are a series of wide synclines and narrow anticlines, mainly N-S trending. Faults are syn-

[5] Curiale, J., Morelos, J., Lambiase, J., and Mueller, W., "Brunei Darussalam: Characteristics of Selected Petroleums and Source Rocks." Organic Geochemistry, v. 31, p. 1475-1493, 2000.
[6] Schreurs, J., "Geology of Brunei's Deltas, Exploration Status Updated." Oil and Gas Journal, August 1997.

sedimentary, down-to-basin growth faults. Mobile shales commonly intrude along fault and other weak planes.[7]

Most of the conventional oil and gas deposits are at 2 to 3 km depth and are located within the Champion Delta strata, represented by the Setap, Belait, Lambir, Miri and Seria Formations.

- Setap Formation consists of up to 3 km of shale with thin interbedded sandstones. It ranges from early to middle Miocene and becomes progressively younger to the northwest. The Setap Shales were deposited in an open marine, relatively distal environment and represent basinal equivalents of the more sandy, deltaic facies.

- Belait Formation, a dominantly sandstone sequence with interbedded shales and coals, spans the early to late Miocene and comprises the entire Champion Delta depositional system in much of Brunei. The Belait Formation has been interpreted as coastal and coastal plain deposits from a range of sedimentary environments associated with a relatively large delta. The sandstones have been described as mostly fluvial. Exposed coals are closely associated with tidal deposits.

- Lambir, Miri and Seria formations are lithologically similar to the Belait Formation but are considered to have been deposited mostly in marine rather than in deltaic environments.

Shale Gas. There has been no comprehensive public study of the shale gas resources of Brunei. Literature on Brunei's conventional shale source rocks suggests that they are young (Miocene), deposited quite rapidly, low in TOC, thermally immature, mobile (ductile), and thus possibly not brittle enough for hydraulic stimulation.

[7] Gartrell, A., Torres, J., and Hoggmascall, N., "A Regional Approach to Understanding Basin Evolution and Play Systematic in Brunei – Unearthing New Opportunities in a Mature Basin." IPTC 15171, International Petroleum Conference, Bangkok,, Thailand, 7-9 February 2012.

Geochemical oil and gas typing indicates that land plant organic material is the source of most of Brunei's hydrocarbons. However, the mature hydrocarbon kitchen areas of offshore fields are mainly deep marine sediments, suggesting a significant charge contribution from deep sediments as well. Source rock studies indicate that the shales in Brunei, regardless of depositional setting, have relatively low organic contents (~1%) and are gas-prone. Data for the coaly shales suggest a similar conclusion.

Over-pressuring occurs deeper than about 2 km throughout Brunei, reflecting continued kerogen-to-gas maturation, and is related to shaliness of the sediments and high sedimentation rates. A widespread and variable regional distribution of overpressures appears to exist across Brunei.[8] Mobile shale features related to overpressuring -- such as active mud volcanoes, shale diapirs, and shale dikes -- are common throughout Brunei. The mud extruded from mud volcanoes in the Baram Delta province is sourced from highly overpressured shale formations, most likely the pro-delta shales.

Coalbed Methane. Brunei's identified onshore coal deposits are relatively thin, aerially limited, and low-rank lignite. There is no significant coal mining activity. The coal deposits in Brunei are of Miocene age and interbedded with shales and sandstones. It is possible that thicker coals are present within the onshore troughs, such as the 15-km wide Berakas Syncline, where they may be buried at CBM-prospective depths of 100-1500 m.[9]

Tight Gas. Brunei's best unconventional gas resource appears to be tight gas sandstones. While no public study of this resource has been performed, Shell has published several SPE articles about hydraulic fracturing in tight sandstones offshore. For example, starting in 2007, Shell successfully stimulated tight sand reservoirs (permeability 0.01 to 1 mD) in the offshore Danau-Bubut field. Three of the zones, which were deposited in thin-bedded, lower shoreface facies and at current sub-sea

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[8] Tingay, M.R.P., Hillis, R.R., Swarbrick, R.E., Morley, C.K., and Abdul Razak Damit. "Origin of Overpressure and Pore-Pressure Prediction in the Baram Province, Brunei." AAPG Bulletin, vol. 83, no. 1, p. 51-74, January 2009.

[9] Morley, C.K., Back, S., Van Rensbergen, P., Crevello, P., and Lambiase, J.J., "Characteristics of Repeated, Detached, Miocene–Pliocene Tectonic Inversion Events, in a Large Delta Province on an Active Margin, Brunei Darussalam, Borneo." Journal of Structural Geology, vol. 25, p. 1147-1169, 2003.

depths of 4,800 to 9,800 feet, produced at over 10 MMscf/day each. However, long-term production is unknown. While the reported log quality is poor, porosity is estimated at 8 to 12%. The field, located in very shallow water (50 feet) and near the shore line, is undergoing further development.[10]

In addition, Shell's West Asset in the offshore of Brunei has deep, fine-grained, shoreface tight sandstone reservoirs with low to moderate (0.1 to 10 mD) permeability. The sandstone targets have 9 to 13% porosity at depths of 9,000 to 11,000 feet below sea level. Hydraulic fracturing has been used by Shell to remediate several prematurely declining wells, overcome skin damage, and maintain gas production.[11]

Similar tight sandstones likely exist onshore in Brunei, given the thick deltaic depositional facies. The most prospective locations would be in the onshore troughs, such as the Berakas, Badas and Belait Synclines. The sandstones could be over-pressured below a depth of 2 to 3 km onshore, which would increase their storage potential and the likelihood of locating "dry" gas-saturated reservoirs. Further study of Brunei's onshore tight gas potential could help extend the life of the LNG facility in this economy, which is important for supplying North Asian markets.

D. Unconventional Gas Activity and Production

To date, only Shell has reported engaging in unconventional gas development in Brunei, namely in tight sand reservoirs of the offshore Danau-Bubut field. Although PetroleumBrunei has studied unconventional gas potential in the economy, there are no reports of unconventional gas exploration activity in Brunei. Upstream activity in Brunei is dominated by Shell and PetroleumBrunei. Several smaller companies also are active.

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[10] Tucker, C.F. IV, Dean, M.C., Pahmiyer, R., Bate, K., Omotosho, P., Walli, F., Ahmad, Z., and Brittingham, P., "Developing Offshore Tight Gas Sands and Navigating Subsurface Uncertainty." SPE 132273, CPS/SPE International Oil & Gas Conference and Exhibition, Beijing, China, 8-10 June, 2010.

[11] Talib, N. and Omar, A.S., "Hydraulic Fracturing Stimulation Executions in Brunei." IPTC 15463, International Petroleum Conference, Bangkok, Thailand, 7-9 February 2012.

6.2 INDONESIA UNCONVENTIONAL GAS

A. Introduction

Indonesia, the world's fourth largest country with a population of 250 million, has significant conventional gas production and is a major source of LNG exports.[1] However, Indonesia's economy is rapidly growing and expected to reach the 1 trillion dollar GDP level by late 2012. While still a major LNG exporter, Indonesia's increasing domestic consumption is placing challenges to meeting its natural gas export commitments.

Natural gas consumption in 2011 was 37.9 Bcm equal to 3.7 Bcfd. While gas consumption declined in 2011, it is still up significantly from five years ago, Table 6-2-1.[1] With natural gas production of 75.6 Bcm equal to 7.3 Bcfd, Indonesia exported the balance of 37.7 Bcm equal to 3.6 Bcfd using a combination of LNG and pipelines. Indonesia's reported proved reserves of approximately 3.0 Tcm (105 Tcf) have been flat for the past several years.

Table 6-2-1. Indonesia Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		40.3	1,420	3.9	37.9	1,340	3.7
Supply							
▪	Marketed Production (Dry)	82.0	2,890	7.9	75.6	2,670	7.3
▪	Net Exports/Imports	(41.7)	(1,470)	(4.0)	(37.7)	(1,330)	(3.6)

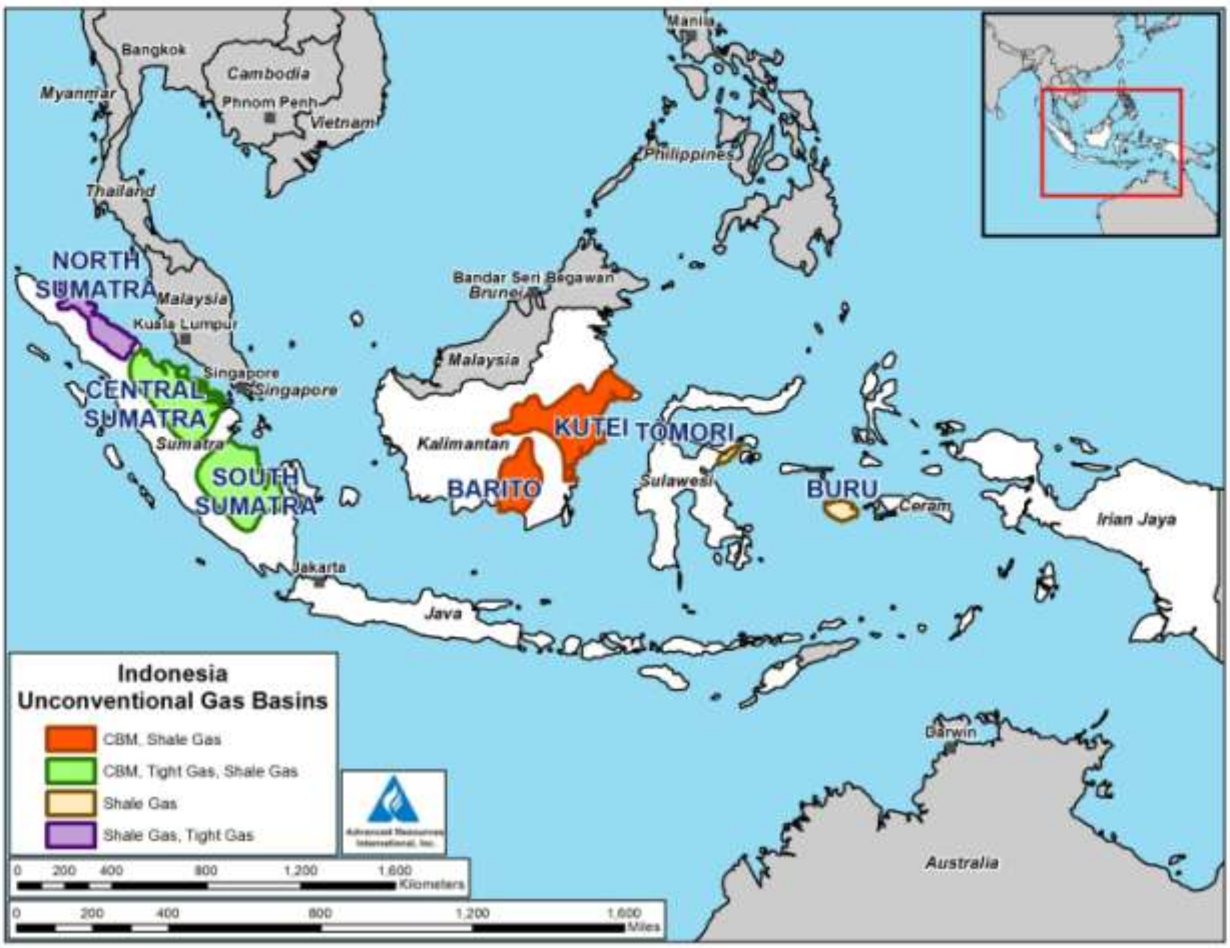
Source: EIA's CAB Indonesia, 2012

[1] U.S. Energy Information Administration, 2011. "Country Analysis Briefs : Indonesia."

After peaking in 2010 at 82.0 Bcm or 7.9 Bcfd, Indonesia's natural gas production declined in 2011, resulting in reduced LNG exports. As a result, the government has begun to promote unconventional natural gas development, particularly coalbed methane, to help maintain or grow its natural gas production and exports.

Indonesia has significant onshore unconventional gas resources, located mainly in sedimentary basins on the islands of Sumatra and Borneo, close to existing natural gas infrastructure, Figure 6-2-1.

Figure 6-2-1. Map of Indonesia Unconventional Gas Basins (Source: ARI 2012).



- Coalbed methane (CBM) by far is the best defined of Indonesia's unconventional gas resources, with an estimated 12,800 Bcm (453 Tcf) of prospective gas in-place located in five main coal basins, Table 6-2-2.[2] Early-stage exploration and initial commercial CBM production is underway by VICO (BP/ENI), ExxonMobil, TOTAL and other companies, stimulated by the Indonesia's recently enacted CBM investment policy framework.

- Apart from CBM, roughly 28,000 Bcm (1,000 Tcf) of additional shale gas plus additional still un-assessed tight gas resources also may be present, based on early scoping studies. However, commercial scale drilling for shale and tight gas resources has not yet begun, as the government is developing its fiscal regimes to accommodate industry investment.

Table 6-2-2. Indonesia's Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		Gas In-Place		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	28,000	1,000	n/a	n/a	-	-
▪	CBM	12,800	453	n/a	n/a	Small	Small
▪	Tight Gas	n/a	n/a	n/a	n/a	-	-
	TOTAL	**40,800**	**1,453**	n/a	n/a	**Small**	**Small**

Source: Stevens and Hadiyanto, 2004 and an unpublished study reported by Lemigas (2010)

Indonesia has constructed long-distance gas pipelines which connect Sumatra and Java, but Kalimantan remains isolated with a relatively limited gas pipeline infrastructure. Indonesia also has a large onshore drilling rig fleet that may be suitable for unconventional gas development (e.g., Chevron has drilled over 6,000 relatively shallow oil production wells at Duri Field). However, horizontal drilling and hydraulic fracturing capabilities in Indonesia still are quite limited.

[2] Stevens, S.H. and Hadiyanto, 2004. ""Indonesia: Coalbed Methane Indicators and Basin Evaluation." SPE 88630, SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Australia, 18-20 October.

Indonesia's natural gas prices have risen sharply in recent years, from about US$1 to $3/Mcf a decade ago to US$6 to $14/Mcf today. Chevron's Duri thermal enhanced oil recovery operation in Central Sumatra consumes 400 MMcfd as fuel for steam injectant, paying an average 2011 delivered price of $11/Mcf.[3] The Bontang LNG facility in East Kalimantan exports natural gas to North Asia at mid-2012 FOB price averaging US$12.80/Mcf. In addition, Indonesia currently exports 1 Bcfd of natural gas from South Sumatra to Singapore via pipeline at an average 2011 price of $US14.05/Mcf.[4] On the island of Java, however, the gas shortage is now so severe that two LNG re-gasification terminals are currently being constructed with contracts being negotiated at oil-linked prices of US$10 to $12/Mcf.

These higher gas prices and rapidly growing gas markets should help support unconventional gas development in Indonesia in the coming decade.

B. Governmental Authorities Engaged with Unconventional Gas Development

Indonesia has a single energy ministry which regulates the economy's oil and gas exploration and production industry, including conventional and unconventional resources - - the Ministry of Energy and Mineral Resources (MIGAS). This centralized administration simplifies and facilitates investment for unconventional natural gas development compared with other countries where authority is dispersed. Once a production sharing license has been awarded by MIGAS, a company's work program is then overseen by a separate government organization called BPMIGAS.

PT Pertamina, the government-owned state oil and gas company, lost its energy policy and regulatory authority to MIGAS a decade ago. However, Pertamina still controls large areas within Indonesia that may be prospective for unconventional gas exploration. PGN (Perusahaan Gas Negara), a listed mostly government-controlled pipeline company, owns and operates most of the Indonesia's natural gas pipelines. PGN is gradually moving into the upstream business as well, including pursuing unconventional gas development. Other operators with significant unconventional gas

[3] Talisman Energy, 2012. "Management Discussion and Analysis for the Period Ending March 31, 2012.
[4] Central Bank of Indonesia, July 27, 2012.

activities in Indonesia include local private companies (Medco), international majors (BP, ExxonMobil, TOTAL, others), and smaller independent E&P's (Santos, Dart Energy, others).

B.1 Regulation of Unconventional Gas Development. The regulation of each unconventional resources type in Indonesia is discussed below.

- ***Shale Gas.*** Although Indonesia recently approved four joint studies for shale gas exploration, it is still formulating its investment regime for shale gas exploration and development. Most likely the contract will be a modified standard PSC, with more favorable terms such as provided in the CBM PSC.

- ***Coalbed Methane.*** Although commercial of production of CBM only just began in 2011, this emerging resource is the most advanced unconventional gas type in terms of established government regulation and private investment. Indonesia's large CBM resources were first quantified by ARI in 1996-98, but ownership and regulation remained uncertain for several more years as both the Ministry of Oil and Gas and the Coal Directorate made competing claims. This uncertainty was resolved in 2001 when MIGAS was granted overall authority. (During 2002-4 ARI further assisted MIGAS develop Indonesia's CBM fiscal policy and contract terms under an Asian Development Bank consulting project.)

  The new oil and gas law -- including CBM regulation -- was passed in 2006, with the first CBM-specific PSC awarded in 2008 (to Medco). Since then about 40 CBM PSC's have been awarded, with additional applications under review.

  CBM leasing is by direct negotiation, with an initial 6-month geologic study period followed by a nominally competitive bid, during which the applicant can match other competing bids for the block (if any). Signature bonus, minimum work commitments, and a 25% domestic market obligation on gas sales apply. Typically, the contract provides for a 3-year exploration period, which is extendable, followed by a 27-year production period. The government is considering whether to extend the entire contract period to 50 years, because of the additional time typically needed for CBM production and development compared with conventional resources. In areas that overlap existing conventional oil and gas or coal mining licenses, those other rights owners are given a 2-year “grandfathered” period to apply for an exclusive CBM license, after which other companies are permitted to apply.

- ***Tight Gas.*** Indonesia does not presently have an investment regime specifically for tight gas resources but MIGAS is in the early phases of developing one. Terms and administration very likely will be similar to those for conventional oil and gas, perhaps improved slightly to promote development. To date no local or foreign companies have invested in tight gas development in Indonesia.

B.2 Geologic and Reservoir Data. In recent years MIGAS has developed a systematic GIS data base (Patra Nusa Data) that catalogues most of the conventional well log and seismic data within Indonesia. This data base is made available to potential investors for a fee. However, the data, once purchased, are not permitted to leave Indonesia, consequently the analysis must be performed in-country. The data base does not specifically identify or assess unconventional gas resources but provides a good platform for such a study. Indonesia has four main organizations which collect and analyze data on unconventional natural gas resources:

- ***MIGAS.*** MIGAS maintains Indonesia’s GIS data base comprising (conventional) oil and gas well logs, seismic data, and laboratory analyses. There is no specific data base on unconventional resources, apart from the 2002-2004 ADB study on coalbed methane performed by Advanced Resources International. Note that MIGAS regulates the unconventional gas industry and awards licenses but does not conduct or publish resource analyses studies for public use.

- ***Lemigas.*** Lemigas is a government organization with an upstream oil and gas R&D and service company division. Lemigas has a small team dedicated to studying unconventional natural gas resources and is Indonesia’s leading group on the subject. Reportedly, Lemigas has assessed shale gas, CBM and tight gas resources but has not made these studies available to the public.

- ***BP, ExxonMobil and other petroleum companies.*** Each of these major industry firms has its own internal data collection system for unconventional natural gas in Indonesia. However, these data and studies remain proprietary and are not available the public.

- ***Universities such as Bandung Institute of Technology (ITB) and Gaja Mada University (Jakarta).*** These universities have students and researchers who study unconventional natural gas resources. However, their capability and data access are limited compared with the above three organizations.

C. Unconventional Gas Resource Assessments

A comprehensive geologic assessment (in need of update with new drilling) is only available for Indonesia's coalbed methane resources in Indonesia. Shale gas and tight gas resource assessments have not been provided as public reports. Further, the more detailed analyses conducted by industry remain company confidential.

C.1. Shale Gas. Indonesia's shale gas and shale oil resources are starting to attract industry attention but there is no public study of the potential. A still unpublished scoping resource study conducted by Lemigas estimated roughly 28,000 (1,000 Tcf) of shale gas in-place. However, much of the shale gas is stored in lacustrine-formed shales that may not be suitably brittle due to high clay content. Due to its generally low thermal maturity, much of the shale resource may be in liquid form (crude oil and NGLs).

Indonesia has widespread but structurally complex and poorly characterized shale gas potential in several regions. Kalimantan's Barito, Kutei, and North Tarakan basins have thick, liquids-prone lacustrine source rock shales within the Eocene Tanjung Formation. Tectonically active eastern Indonesia (Sulawesi, Seram, Buru) has marine source rock shales that are gas-prone but are also structurally complex. Sumatra's North, Central and South Sumatra basins have oil-prone source rocks in the deep troughs adjacent to anticlinal conventional oil and gas fields. MIGAS is considering undertaking a detailed shale gas resource assessment study, along the lines of the 2004 ADB/ARI CBM study.

- **Barito Basin.** The 25,000-mi^2 Barito Basin, in sparsely populated and swampy South Kalimantan province, contains 3,000-foot thick, organic-rich, but mostly non-marine shales within the Eocene Tanjung Fm, considered the basin's main source rock. The Tanjung Formation is 3,000 to 12,000 feet deep and in the oil window throughout much of the basin, possibly reaching dry gas maturity in its deepest interval.

- **Kutei Basin.** The 40,000-mi^2 onshore portion of the Kutei Basin of eastern Kalimantan contains Mid-Late Miocene mudstones and carbonaceous shale source rocks. The deepwater-deposited shales may have 1 to 2% TOC.[5] The interbedded shale, sand and coal sequence is over 3,000 feet thick in many areas. The depth to the top of the oil generative zone (0.7% R_o) averages 9,000 feet, while the Miocene shales become dry gas mature (1.3% R_o) below about 15,000 feet of depth.

- **Tomori and Buru Basins**. Located on the east coast of Central Sulawesi, the Tomori contains thick marine-deposited source rock shales within the Lower Miocene Tomori Formation. TOC is fairly high in the upper portion of the formation, averaging 2 to 4% and consisting of Type II/III kerogen.[6] The Tomori Fm becomes gas prone (> 1.0% Ro) below a depth of about 11,300 ft. Also in eastern Indonesia, the Bula Basin extends across part of the island of Seram and contains Mesozoic and Middle Tertiary deposits of primarily marine origin.

[5] Saller, A., Lin, R., Dunham, J., 2006. "Leaves in Turbidite Sands: The Main Source of Oil and Gas in the Deep-Water Kutei Basin, Indonesia." American Association of Petroleum Geologists, v. 90, no. 10, p. 1585-1608.
[6] Hasanusi, D., Abimanyu, R., Artono, E., and Baasir, A., 2004. "Prominent Senoro Gas Field Discovery in Central Sulawesi." In Noble, R.A. et al. (eds.), Proceedings Deepwater & Frontier Exploration in Asia & Australasia, Jakarta, Indonesia Petroleum Association, p. 177-197.

- **Central and South Sumatra Basins.** The Brown Shale Formation within the Paleocene-age Pematang Group is an important lacustrine oil source rock in the Central Sumatra Basin, with 3.7% mean TOC.[7] In the South Sumatra Basin, petroleum source rock shales include lacustrine sediments in the Eocene-Oligocene Lahat Formation, which has TOC ranging from 1.7 to 8.5% and thermal maturity of 0.64-1.4% R_o.[8] These source rocks appear to reach gas maturity in the deep central partitions of the basins.

C.2. Tight Gas. No comprehensive public study of tight gas resources is available but there is information on certain tight gas deposits. (Note that Indonesia's standard for "tight gas" is less than 5-10 mD, which is much higher than the standard used in the USA of <0.1 mD.) For example, in the Central Sumatra Basin, a coarse-grained sandstone within the non-marine Sihapas and Pematang formations with relatively low permeability (7-13 mD) has been identified as a tight gas candidate.[9]

In the North Sumatra basin, Pertamina has reported a tight gas prospect in the Serang field, where the unspecified formation is 60 m thick, 2300 m deep, and has strong gas shows. Pressure and temperature conditions are extreme - - 9,000 psi (equivalent to 1.2 psi/foot gradient) and 350ºF. The formation will need to be hydraulically stimulated to produce but Pertamina has not yet attempted such a completion. The South Sumatra Basin also likely has tight gas resources.

C.3. Coalbed Methane. During 1996-1998 ARI conducted the first comprehensive assessments of Indonesia's CBM resources for Chevron, MIGAS and the Asian Development Bank. ARI updated this assessment in 2004.[10,2] Indonesia has significant and highly prospective coalbed methane resources estimated at about 12,800 Bcm (453 Tcf) of gas in-place. The estimate was based on ARI's systematic

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[7] Hwanga, R.J., Heidrick, T., Mertanib, B., and Qivayantib, M., 2002. "Correlation and Migration Studies of North Central Sumatra Oils." Organic Geochemistry, v. 33, p. 1361-1379.
[8] Bishop, M.G., "South Sumatra Basin Province, Indonesia: The Lahat / Talang Akar – Cenozoic Total Petroleum System." U.S. Geological Survey, Open-File Report 99-50-S, 2001.
[9] Rahmat, J., Irawan, C., and Saputra, S., 2007. "Exploring Siliciclastic Tight Gas Reservoir." AAPG European Region Conference, Athens, Greece.
[10] Stevens, S.H., "Coalbed Methane in Indonesia: an Overlooked Resource." American Association of Petroleum Geologists, 2000 AAPG/IPA International Conference and Exhibition in Bali, Indonesia, 15-18 October, 2000.

collection of deep well drilling and seismic data from the coal mining and petroleum industries, along with laboratory analysis of coal rank and methane adsorption capacity.

Thick, economically important coal deposits occur in Indonesia, mostly on Sumatra and Borneo (Kalimantan province). The thickest and most prospective for CBM development are Miocene-age coals, particularly the Muara Enim Formation and its equivalents. Some 20 to 30 individual coal seams are present, totaling over 30 m of net coal. The Miocene coal is low in rank (lignite to sub-bituminous with R_o of 0.3 to 0.5%) and relatively shallow (outcrop to 1,500 m). Gas content ranges from 100 to 200 scf/ton (dry, ash-free basis) and the coals appear to be nearly to fully gas saturated. Permeability of 20 to 500 mD has been reported. Overall, Indonesia's Miocene coal deposits are thicker, deeper, thermally more mature, and contain higher gas content compared to the Powder River Basin (Wyoming) coalbed methane, often considered its closest geologic analog.

D. Unconventional Gas Activity and Production

Indonesia has initial commercial CBM production along with numerous CBM exploration programs underway across the country. There is no tight gas or shale gas drilling or production in Indonesia, although interest is increasing.

D.1. Coalbed Methane. To date some 50 production sharing contracts have been awarded by MIGAS, representing investment commitments of over $200 million, with additional applications under consideration. The most commercially advanced CBM project is the Sanga-Sanga PSC in East Kalimantan, where BP, ENI and partners (VICO Indonesia) initiated commercial CBM production in March 2011. Production was reported at 1.3 MMcfd in June 2011 and is likely higher today (~5 MMcfd). The produced CBM is being transported north to the existing, underutilized Bontang LNG facility, where it is processed and then exported by tanker to North Asia. VICO plans to move in a second drilling rig to drill 40 new CBM production wells this year. Last year VICO partner ENI estimated CBM resources at Sanga-Sanga at approximately 370 Bcm (13 Tcf) and announced a 400-MMcfd production target for 2020.

Other companies pursuing CBM exploration and development in Indonesia (Dart Energy, ExxonMobil, Medco, Santos, TOTAL, etc.) are in the early corehole drilling phase of exploration, with some targeting small-scale commercial production for power generation by year end.

D.2. Shale Gas. The government reportedly has approved four initial joint studies of shale gas potential but has not yet granted any PSC's. The only publicly reported activity is that AWE Limited, an Australian unconventional gas operator, is conducting a joint study of shale gas potential within a 5,000-km^2 area of the Central Sumatra Basin. Additional activity is likely once the government develops regulations for shale gas investment.

6.3 MALAYSIA UNCONVENTIONAL GAS

A. Introduction

Malaysia is an important Southeast Asian oil and gas producer and exporter, with the strategic petroleum sector controlled by state-owned Petronas, currently one of Asia's most profitable companies. Essentially all of Malaysia's oil production comes from conventional reservoirs in the offshore Gulf of Thailand and the South China Sea.

Oil production averaged 630,000 B/D in 2010, more than half of which was sourced from the Tapis field in the offshore Malay Basin. Malaysia's proved oil reserves stand at about 4 billion barrels. Malaysia exported 234,000 B/D in 2010, while importing 204,000 B/D for its refineries, for net exports of 30,000 B/D.

Malaysia's natural gas development is offshore, primarily in the Sarawak Basin in the east near Brunei. Gas production, entirely from conventional reservoirs, averaged 62 Bcm or 6 Bcfd in 2011, from approximately 2,400 Bcm (86 Tcf) of proved reserves, Table 6-3-1.[1] Annual domestic natural gas consumption has been relatively stable at 29 Bcm or 2.8 Bcfd, equal to 46% of production in 2011, enabling 33 Bcm or 3.2 Bcfd to be exported. There are several important ongoing projects that would expand natural gas production in the near term.[2]

Table 6-3-1. Malaysia Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		31.9	1,730	3.1	28.5	1,010	2.8
Supply							
▪	Marketed Production (Dry)	62.6	2,210	6.1	61.8	2,180	6.0
▪	Net Exports/Imports	30.7	1,080	3.0	33.3	1,170	3.2

Source: BP Statistical Review of World Energy, May 2012

[1] BP Statistical Review of World Energy, May 2012.
[2] Energy Information Administration, Malaysia Country Analysis Brief, December 14, 2011.

In 2011, Malaysia ranked as the world's second largest LNG provider, exporting primarily to China, Japan, Republic of Korea, and Chinese Taipei. The Bintulu LNG complex on Sarawak, comprising eight trains in three plants with total annual capacity of 48 Bcm (1.7 Tcf), is the main hub for Malaysia's natural gas export industry. Petronas owns majority interests in Bintulu, which is supplied by conventional reservoirs in offshore natural gas fields. LNG is transported by Malaysia International Shipping Corporation (MISC), majority owned by Petronas (62%), which operates a fleet of 27 LNG tankers. JGC and others have studied the feasibility of capturing CO_2 at the Bintulu LNG plant and sequestering it in geologic formations.[3] (Shell's technologically advanced 14,700 B/D gas-to-liquids (GTL) plant also is located in Bintulu.)

In 2011, Petronas initiated construction on the Sabah Oil and Gas Terminal (SOGT), an important new gas complex slated for completion by the end of 2013. SOGT will process 13 Bcm/yr (1.3 Bcfd) from the offshore Gumusat-Kakap, Malikai, and Knabalu fields, mainly for domestic use in Sabah as well as supplying 5 Bcm/yr (0.5 Bcfd) to the Bintulu LNG export facility.

Onshore western Malaysia consists of crystalline igneous and metamorphic rocks which appear to lack any conventional or unconventional oil and gas potential. However, prolific sedimentary basins are present in eastern Malaysia, mostly offshore north of the Borneo coastline, Figure 6-3-1. These basins continue into the onshore areas of Sarawak and Sabah states, where they may have limited albeit undefined unconventional gas potential within multiple coalbed methane, shale gas, and tight gas formations, Table 6-3-2.

[3] JGC Corporation, "CO_2 Underground Storage at the LNG Plant." CTI/Industry Joint Seminar on Technology Diffusion, Jakarta, Indonesia, February 2004.

Figure 6-3-1. Unconventional Gas Basins of Malaysia (Source: ARI 2012)

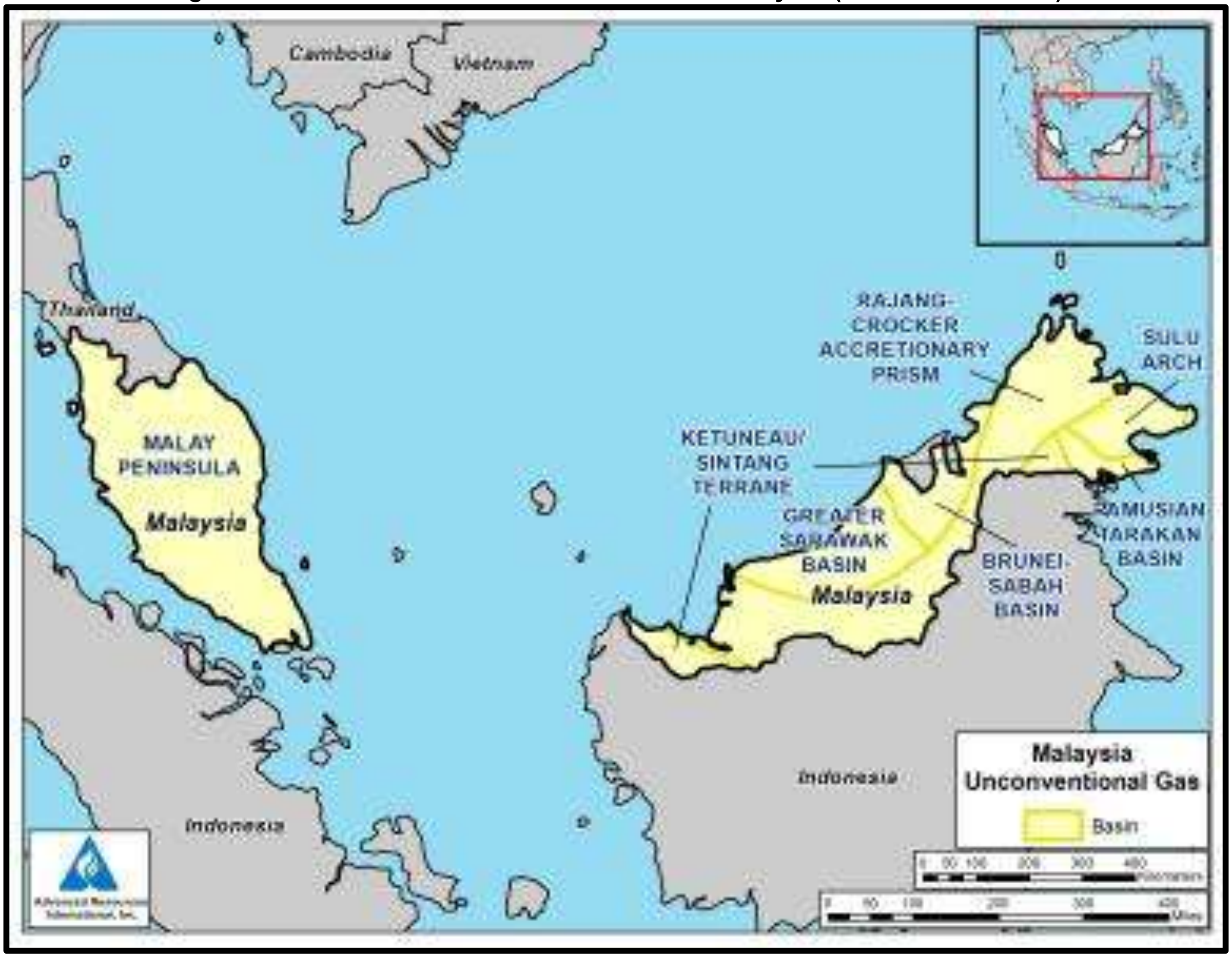

Table 6-3-2. Malaysia's Unconventional Gas Resources

		Resource Estimates				Current Production	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	n/a	n/a
▪	CBM	n/a	n/a	n/a	n/a	n/a	n/a
▪	Tight Gas	n/a	n/a	n/a	n/a	n/a	n/a
	TOTAL	**-**	**-**	**-**	**-**	**-**	**-**

B. Governmental Authorities Engaged with Unconventional Gas Development

State-owned Petronas controls the oil and natural gas sectors in Malaysia. The company has a monopoly on upstream natural gas development and also plays a leading role in downstream activities and LNG. Most of Malaysia's natural gas production is from production-sharing agreements operated by foreign companies in conjunction with Petronas. The company earned profits of nearly US$21 billion in 2010, with *Fortune* ranking Petronas as the most profitable company of any type in Asia.

At present approximately 70 PSC's are active in Malaysia. Petronas, Shell, and ExxonMobil dominate oil and gas leasing activity and account for a combined 80% of Malaysia's hydrocarbon output. Other active companies include ConocoPhillips, Hess, Japex, Lundin Malaysia, Mitsubishi Corporation, Murphy Oil, Newfield Energy, Nippon Oil, Statoil and Talisman.

Current fiscal terms provide Petronas with a carried interest ranging from 15% to 25% in any exploration block in Malaysia. There are four distinct PSC contract types, based on water depth, for offshore exploration and development. Contractors provide all financing and bear all risks of exploration, development and production in exchange for a share of the total production. Following a commercial discovery, Petronas has the right to become a working partner in development.

Petronas maintains a comprehensive geologic and reservoir data base from all petroleum wells and seismic in Malaysia. This data base may be made available to potential investors for a fee. The data base does not specifically identify or assess unconventional gas resources but may provide the basis for such a study.

C. Unconventional Gas Resource Assessments

C.1 Conventional Gas Resource Studies. Nearly all studies of conventional oil and gas resources in Malaysia focus on its prolific offshore basins. However, there are several petroleum geology studies which assess northern Borneo in eastern Malaysia and may provide insight into Malaysia's unconventional gas potential with one report particularly relevant.

- **Assessment of Undiscovered Oil and Gas Resources of Southeast Asia (2010).** Schenk, C., Brownfield, M., Charpentier, R.R., Cook, T.A., Klett, T., Kirschbaum, M.A., Pitman, J.K., and Pollastro, R.M., U.S. Geological Survey.

C.2 Unconventional Gas Resource Studies. As discussed above, no public studies are available on Malaysia's unconventional gas formations or resources. Peninsular Malaysia is underlain by crystalline basement, comprising igneous and metamorphic rocks with limited oil and gas potential of any type, whether conventional or unconventional. However, eastern Malaysia in northern Borneo has the onshore (but thinner) portions of the prolific offshore sedimentary basins. To date, no unconventional gas testing or evaluation has been reported in Malaysia.

The following section provides a preliminary assessment of Malaysia's unconventional gas potential, based on ARI's analysis of the conventional petroleum geology literature. More detailed study is needed, preferably using primary data sources (logs, seismic, lab data).

Shale Gas. No data or public studies are available on Malaysia's shale gas potential. Carbonaceous shales present in onshore Sarawak are low-rank, poorly lithified, and unlikely to be brittle enough to respond favorably to hydraulic stimulation. In West Sabah, the Miocene-age Temburong Formation has black mudstones and carbonaceous shales with low carbon content (TOC average 0.3%) that also appear non-prospective. Malaysia's gas shale potential appears to be negligible but still warrants further study.

Coalbed Methane. The Oligocene-Miocene Nyalau Formation contains small but locally significant coal deposits in onshore Sarawak, including some close to the Bintulu LNG plant. The Nyalau Fm is an onshore extension of the important offshore petroleum source rocks and reservoirs of the Balingian Province. Occasional coal seams are present, mainly in the middle and upper portions of the Nyalau Fm, but these are generally thin (0.2-0.3 m) and rarely exceed 1 m. Coal rank in the area south of Bintulu is sub-bituminous C, although R_o occasionally reaches as high as 0.7%, which suggests a coal rank of high-volatile bituminous B.[4] There are no known direct measurements of the gas content of the coals.

The coal resources of Sarawak in the Nyalau Fm are estimated at about 700 million tons. The primary coal field in this region of Malaysia is the Miocene-age Merit Pila coal field, a small (170 million tons proved reserve), low-rank deposit located about 75 km south of Bintulu. Produced coal from this mine is used at the Sejingkat Power Corporation power plant at Kuching.[5]

Tight Gas. There are no public studies of Malaysia's tight gas potential, nor have there been specific reports of testing for this unconventional resource. However, extensive low-permeability sandstones occur within the Oligo-Miocene Nyalau Formation, although the individual sandstone beds appear to be fairly thin (1 m). Nearly all geologic efforts in Sarawak have been directed towards high-quality conventional reservoir sandstones, thus data on low-permeability sandstones are limited. Future analysis is needed to assess well log, test and seismic data to more rigorously evaluate the tight gas sandstone potential of Sarawak.

Shell and Petronas have discussed the concept of hydraulic fracturing of tight gas formations in an undisclosed (probably offshore) location of Malaysia. The unnamed formation is a tight gas/condensate deposit consisting of 11 stacked sandstone layers interbedded with shale. Core data showed permeability ranging from 0.1 mD to 10 mD. The shallow layers are normally pressured, while the deeper sandstones are overpressured by up to 2,000 psi. Other reservoir characteristics or results were not disclosed.[6]

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[4] Hasiah, A.W., "Oil-Generating Potential of Tertiary Coals and Other Organic-Rich Sediments of the Nyalau Formation, Onshore Sarawak." Journal of Asian Earth Sciences, vol. 17, p. 255-267, 1999.

[5] Osvald, P. and Sýkorová, I., " Merit Pila Coal Basin, Malaysia –Geology and Coal Petrology."

[6] Altaei, A., Hui, W.T., Chan, K.S., Lau, R., and Yeap, M.E., "Numerical Simulation of Hydraulic Fracturing in a Stacked Tight Gas Condensate Reservoir." International Petroleum Technology Conference,IPTC 15336, 8 p.

D. Unconventional Gas Development Activity and Production

Whereas numerous companies are actively developing conventional reservoirs in Malaysia, none have tested or appear to be planning to assess the unconventional gas resource potential.

- ***Petronas***, Malaysia's largest oil and gas producer, has not reported any unconventional gas interest or activity.

- ***Newfield Exploration*** is Malaysia's fourth largest oil producer (30,400 B/D during Q2-2012), operating multiple offshore conventional fields in the South China Sea. Newfield is an important shale gas/oil producer in the United States, notably in the Woodford Shale and Granite Wash plays. However, Newfield has not announced any unconventional gas activity in Malaysia.

- ***Murphy Oil Corp.*** announced in September 2009 the startup of several smaller new gas fields offshore Sarawak that will supply the Bintulu LNG Terminal. Murphy's gas production reached 350 MMcfd during Q4-2010 and is expected to remain at that level for about five years. Murphy is an active shale developer in North America but has not announced any unconventional gas activity in Malaysia.

- ***Shell*** is developing a 90 MMcfd conventional gas field offshore Sarawak with Petronas. Although an active shale developer in North America, Shell has not announced any unconventional gas activity in Malaysia.

6.4 PAPUA NEW GUINEA UNCONVENTIONAL GAS

A. Introduction

Endowed with abundant but scarcely developed conventional oil and gas resources, Papua New Guinea (PNG) very likely also has extensive unconventional gas potential that has yet to be assessed. Located on the eastern half of Papua Island, PNG is challenged by rugged topography, underdeveloped infrastructure, and the structurally complex geology of the Papuan fold and thrust belt. However, oil and gas development has progressed gradually since 1986-7, when the first commercial oil and gas fields were discovered. Today with 440 Bcm (15.6 Tcf) of proved reserves, PNG is poised to become a major LNG exporter.[1]

Oil production in PNG peaked in 1992 at over 120,000 B/D but has since declined steadily to 30,000 B/D in 2011. PNG currently imports about 6,000 B/D to meet its growing domestic demand. Natural gas production is currently also quite small, just 0.1 Bcm (4 Bcf) or 11 MMcfd in 2010, sufficient to balance its equally modest domestic demand for gas, Table 6-4-1.[2]

Table 6-4-1. PNG Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		0.1	4	0.01	n/a	n/a	n/a
Supply							
▪	Marketed Production (Dry)	0.1	4	0.01	n/a	n/a	n/a
▪	Net Exports/Imports	-	-	-	n/a	n/a	n/a

Source: U.S. EIA, Country Analysis Brief, 2011

1 BP Statistical Review of World Energy, May 2012.
2 U.S. Energy Information Administration, Country Analysis Brief, 2011

After lengthy delays, the 6.6 million t/year Papua New Guinea LNG Project is being constructed by ExxonMobil and its partners at total investment costs of US$15.7 billion, making it the largest ever private sector investment in the PNG economy. Natural gas will be supplied by conventional oil and gas fields in the Southern Highlands and Western provinces, transported by pipeline to the LNG plant located approximately 20 km northwest of Port Moresby. Scheduled for completion in 2014, the PNG LNG project is expected to process over 250 Bcm (9 Tcf) of gas and 200 million barrels of NGL's during its 30-year life, making PNG a significant gas exporter in the Pacific Basin.

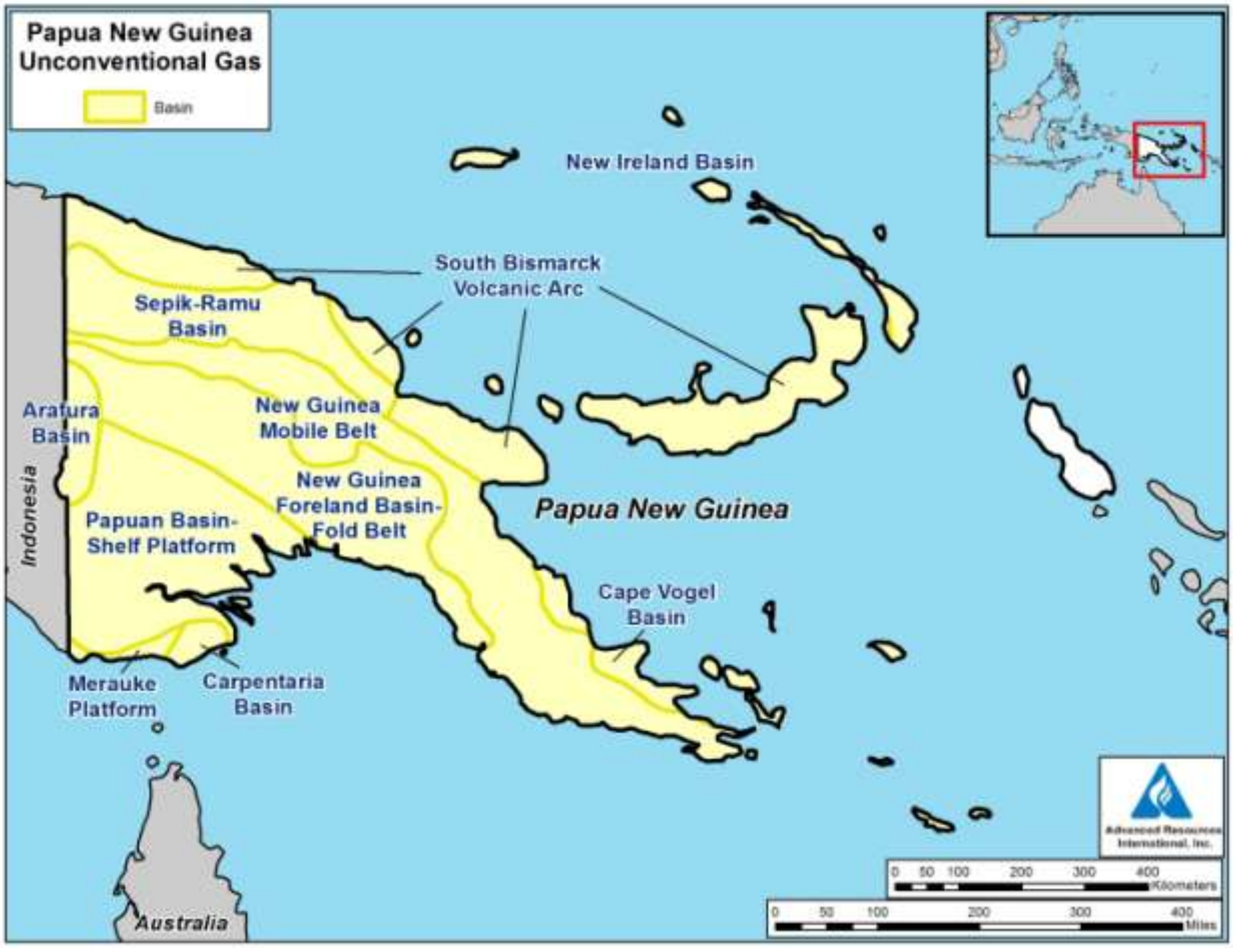
Unconventional gas resources have not yet been defined in Papua New Guinea, Table 6-4-2.

Table 6-4-2. PNG's Unconventional Gas Resources

		Resource Estimates				Current Production	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	n/a	n/a
▪	CBM	n/a	n/a	n/a	n/a	n/a	n/a
▪	Tight Gas	n/a	n/a	n/a	n/a	n/a	n/a
	TOTAL	**-**	**-**	**-**	**-**	**-**	**-**

A series of onshore (as well as offshore) hydrocarbon basins exist in PNG, with source rocks that may be prospective for shale gas or CBM, Figure 6-4-1. However, considerable further study is required to establish the size and commercial viability of these resources.

Figure 6-4-1. Unconventional Gas Basins of Papua New Guinea (source ARI 2012)



B. Governmental Authorities Engaged with Unconventional Gas Development

The Papua New Guinea Department of Petroleum and Energy administers overall energy production and consumption policy in the economy. In 1992, the formerly-named Petroleum Division of Papua New Guinea's Department of Minerals and Energy commissioned a study which concluded that natural gas from recent discoveries in the Papuan Fold Belt could be aggregated to supply an LNG plant on the northern coast. In 1995, the government devised a Natural Gas Policy setting forth fiscal and administrative policies for natural gas development.

BP and ExxonMobil undertook steps within this policy framework to cite an LNG plant at Madang on Papua's north coast. However, the 1997 Asian financial crisis, a damaging tsunami that occurred near the proposed site, and the onset of low-cost

Australian coalbed methane delayed construction of the LNG export plant for a decade. Finally, in August 2007 a new plan was developed for an LNG plant on the seismically more quiescent southern coast. ExxonMobil and its partners have initiated construction of a LNG export facility. Completion is planned for 2014, with LNG sales contracted to Japan, China and Chinese Taipei.

Currently, there are no special fiscal terms in place for exploration development of unconventional gas deposits in PNG.

Geologic and Reservoir Data. The Papua New Guinea Department of Petroleum and Energy is believed to maintain a comprehensive geologic and reservoir data base from all petroleum wells and seismic in PNG. This data base may be made available to potential investors. Very likely the data base does not specifically identify or assess unconventional gas resources but it may provide the basis for such a study.

C. Unconventional Gas Resource Assessments

C.1 Conventional Gas Resource Studies. Papua New Guinea has five major sedimentary basins. The first significant oil discovery came in 1986, at the Kutubu field in the remote Southern Highlands of the onshore Papuan Basin.[3] At the time of discovery, the field was accessible only by helicopter, but a highway was later constructed to facilitate access. Today, the Papuan Basin is the most explored and still the most active in PNG, with over 300 wells drilled.

In 1987 British Petroleum discovered the large Hides gas field located about 75 km east of Kutubu oil field. Both fields produce from high-quality Toro sandstone, with inter-well communication reportedly of up to 12.5 km. The Hides gas field contains about 200 Bcm (7.1 Tcf) of original gas in-place, making it PNG's largest gas field discovered to date.

[3] McWalter, M., 2011. "PNG Gas Finds Push LNG Plans." AAPG Explorer, July.

The conventional reservoirs are mainly Cretaceous sandstones and carbonates (Darai, Ieru, Toro and Imburu formations), with good porosity and permeability. Many wells are capable of producing 10,000 barrels of oil per day. The Darai Limestone is a karsted marine shelf carbonate of Miocene age, highly fractured and varying in thickness from 1.0 to 1.5 km. The Ieru Formation is an Upper Cretaceous shaly unit which underlays the Darai Limestone. The Lower Cretaceous Toro sandstone underlays the Ieru Formation and is the primary reservoir unit in Kutubu and Moran Project oil fields. Finally, the Upper Jurassic Imburu Formation hosts high-quality reservoir sandstones, in the Kutubu and Moran fields.

C.2 Unconventional Gas Resource Studies. Given PNG's abundant conventional oil and gas deposits, it is likely that considerable unconventional gas resources also are present. However, no study has been performed to identify and assess the unconventional gas potential.

The following section provides a preliminary assessment of PNG's unconventional gas potential based on ARI's analysis of the conventional petroleum, geology literature. More detailed study is still needed, preferably using primary data sources (logs, seismic, lab data).

Shale Gas. No data or public studies are available on shale gas resources in Papua New Guinea. The primary oil source rocks in the Papuan Fold Belt are believed to be marine-deposited Jurassic shales, although these are considered clay-rich. Recent geochemical work suggests that Late Cretaceous shales or perhaps lacustrine, gypsum-rich shales embedded in Oligocene-Miocene carbonates have also acted as important source rocks.[4]

[4] Volk, H., George, S.C., Middleton, H., and Shofield, S., 2005. "Geochemical Comparison of Fluid Inclusion and Present-Day Oil Accumulations in the Papuan Foreland – Evidence for Previously Unrecognised Petroleum Source Rocks." Organic Geochemistry, vol. 36, p. 29-51.

Coalbed Methane. PNG has coal deposits but they are still poorly defined.[5] There may be CBM resources in deep coal seams but this is still speculative.

Tight Gas. There are no public studies of tight gas resources in the PNG. There may be tight gas potential in onshore sedimentary basins, but this remains speculative at this point.

D. Unconventional Gas Development Activity and Production

A small group of companies are actively developing conventional oil and gas reservoirs in Papua New Guinea, but none have tested or appear to be planning to test unconventional gas formations.

- **ExxonMobil** is heading up the consortium to construct and operate the PNG LNG facility. The company has not discussed the unconventional gas potential in PNG.

- ***Oil Search Ltd***, based in Australia, is the largest oil and gas producer in PNG, having produced gas there since 1992. Oil Search has not announced any unconventional gas activity in Papua New Guinea.

- ***Drill Search Energy***, also based in Australia, helped to discovered the Elk and Antelope gas fields, with estimated 240 Bcm (8.6 Tcf) of contingent resources. The company is proposing a second LNG facility but is still negotiating with prospective partners. Drill Search has not announced any unconventional gas activity.

- ***Interoil Inc.,*** a small Canadian independent company, recently discovered the Elk-Antelope oil and gas field in the eastern Papuan Fold and Thrust Belt. The field, which is productive from a Miocene carbonate reef reservoir, may support a separate LNG project. Interoil has not announced any unconventional gas activity.

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[5] Belkin, H.E., Tewalt, S.J., Hower, J.C., Stucker, J.D., and O'Keefe, J.M.K., 2009. "Geochemistry and Petrology of Selected Coal Samples from Sumatra, Kalimantan, Sulawesi, and Papua, Indonesia." International Journal of Coal Geology, vol. 77, p. 260-268.

APEC Unconventional Natural Gas Census
Part I

Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions

SECTION 7. ASIA NON-PRODUCING UNCONVENTIONAL GAS

6.5 PHILIPPINES UNCONVENTIONAL GAS

A. Introduction

Philippines has limited conventional and unconventional oil and gas resources, nearly all of which are located offshore. Oil production averaged just 27,000 B/D in 2011, satisfying less than 10% of this economy's growing oil demand. Natural gas consumption of 3.6 Bcm or 0.35 Bcfd in 2011 has increased steadily in recent years, Table 6-5-1.[1] All of the Philippines' natural gas use is from domestic sources, from an estimated 85 Bcm (3 Tcf) of proved reserves, mainly from offshore fields. By far the largest gas field is Malaympaya in the Palawan Basin, offshore western Philippines. A 423-km natural gas pipeline network linked to the Palawan Basin exists in southern Luzon, the most populous island in the Philippines.

Table 6-5-1. Philippines Natural Gas Consumption and Supply

	2010			2011		
	(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption	3.1	110	0.3	3.6	130	0.4
Supply						
▪ Marketed Production (Dry)	3.1	110	0.3	3.6	130	0.4
▪ Net Exports/Imports	-	-	-	-	-	-

Source: BP Statistical Review of World Energy, 2012

Domestic natural gas production and demand currently are in balance, but there is considerable pent-up demand in the economy. While the Philippines does not currently have an LNG import terminal, Shell is evaluating the construction of a floating LNG import facility at its Batangas refinery in southern Luzon, which would be the first of its type in Southeast Asia. Similar floating LNG facilities could help provide natural gas to the many small islands in the Philippines. If approved, the "first-gas" target arrival date would be 2016.

[1] BP Statistical Review of World Energy, May 2012.

Table 6-5-2 summarizes the currently documented estimates for unconventional gas resources in the Philippines. No tight gas or shale gas resources have been defined, but a small coalbed methane resource of 150 Bcm (5.2 Tcf) may be present. Figure 1 shows onshore sedimentary basins in the Philippines which may hold promise for undiscovered unconventional gas resources.

Table 6-5-2. Philippines' Unconventional Gas Resources

		Resource Estimates				**Current Production**	
		GIP		**Technically Recoverable**			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	-	-
▪	CBM	150	5.2	n/a	n/a	-	-
▪	Tight Gas	n/a	n/a	n/a	n/a	-	-
	TOTAL	**150**	**5.2**	**n/a**	**n/a**	**-**	**-**

Figure 6-5-1. Onshore Sedimentary Basins of the Philippines (Source ARI 2012)

B. Governmental Authorities Engaged with Unconventional Gas Development

The Philippines Department of Energy (DOE) administers overall energy production and consumption policy for the economy. In 1973, the current Service Contract System took effect with the enactment of Presidential Decree No. 87, better known as the "Oil Exploration and Development Act of 1972". This fiscal regime promotes offshore exploration, the focus of oil and gas industry activity in the Philippines.[2]

The Philippine National Oil Company (PNOC), also created during the oil crisis of 1973, is a government-owned energy exploration and development company. PNOC is an integrated petroleum company with exploration and production, refining and marketing capabilities. It also operates smaller coal and geothermal divisions. PNOC participates in Shell's Malampaya Deepwater Gas-to-Power Project, holding a 10% non-operated interest.

The current Philippines oil and gas investment contract is geared towards conventional reservoirs and has the following terms:

- Service fee of up to 40% of net production.
- Cost reimbursement of up to 70% gross production with carry-forward of unrecovered costs.
- FPIA grants of up to 7.5% of the gross proceeds for service contract with minimum Filipino company participation of 15%.
- Exemption from all taxes except income tax; income tax obligation paid out of government's share.
- Exemption from all taxes and duties for importation of materials and equipment for petroleum operations.

[2] Tamang, J.T., 2011. "Current Issues: Philippine Natural Gas Industry." 2nd Pacific Energy Summit, Jakarta, Indonesia, February 21-23, 12 p.

- Easy repatriation of investments and profits.
- Free market determination of crude oil prices, i.e., prices realized in a transaction between independent persons dealing at arms-length.
- Special income tax of 8% of gross Philippine income for subcontractors.
- Special income tax of 15% of Philippine income for foreign employees of service contractors and subcontractors.

Currently, there are no special fiscal incentives or terms in place for the development of unconventional oil and gas deposits in the Philippines.

Geologic and Reservoir Data. PNOC and the PDOE maintain comprehensive geologic and reservoir data bases from all petroleum wells and seismic in the Philippines. These data bases may be made available to potential investors for a fee. They do not specifically identify or assess unconventional gas resources but may provide the basis for such a study.

C. Unconventional Gas Resource Assessments

C.1 Conventional Gas Resource Studies. In June 2011, the Philippines Department of Energy (DOE) estimated that potential petroleum resources totaled 28 billion barrels of oil initially in-place and 1,530 Bcm (54 Tcf) of gas in-place. The DOE's estimated recoverable discovered and undiscovered resources from conventional reservoirs are approximately 1.9 billion barrels of oil, 164 million barrels of condensate, and 290 Bcm (10.4 Tcf) of natural gas. This estimate is based on analysis of 16 onshore and offshore sedimentary basins, from the Cagayan Valley Basin in the north to the Agusan-Davao Basin in the south, as well as the prolific Northwest Palawan and the Sulu Sea basins along the western flank of the archipelago.

Oil and gas development in the Philippines is overwhelmingly focused offshore and entirely focused on conventional reservoirs. Starting in 1989, significant oil and natural gas fields were discovered offshore Northwest Palawan Shelf in western Philippines. These include the Malampaya gas field, discovered by Shell in 1990, which is by far the largest gas discovery to date. Commercial production started in 2002, with gas transported to a modern combined cycle gas turbine complex in southern Luzon which accounts for one-fifth of total power generation capacity in the Philippines.

The small onshore Libertad gas field, discovered in 2006, holds 0.02 Bcm (0.6 Bcf) of recoverable natural gas. The smaller San Antonio gas field, located onshore in northern Luzon and developed starting 1994, supplies natural gas as fuel to the local electric cooperative in the Province of Isabela.

C. 2 Unconventional Gas Resource Studies. As discussed above, no public studies are available on unconventional gas formations or resources in the Philippines. Most of the onshore territory of the Philippines is underlain by crystalline basement, comprising igneous and metamorphic rocks with scant oil and gas potential of any type, whether conventional or unconventional. There are several sedimentary basins onshore but they contain mainly carbonate and tuffaceous deposits, with limited petroleum source rocks. To date, no unconventional gas testing or evaluation has been reported in the Philippines.

The following section is a highly preliminary assessment of the Philippines's unconventional gas potential prepared by Advanced Resources for this APEC report. More detailed study is still needed, preferably using primary data sources (logs, seismic, lab data).

Shale Gas. No data or public studies are available on the shale gas resources of the Philippines. There may be some shale gas potential in certain onshore sedimentary basins, such as the Central Luzon Basin, Visayon Basin in Cebu, and Cotabato and Agusan-Davao basins in Mindanao. However, the quality of the hydrocarbon source rock shales is not documented and the shale gas potential appears to be limited.

Coalbed Methane. The best defined unconventional gas resource in the Philippines is coalbed methane. The Philippines has relatively small coal deposits of Miocene age in the central and southern coal fields. These narrow, fault-bounded grabens -- such as the Mindoro, Visayan, and Zamboanga-Sibugay basins -- may have modest CBM resources, but the CBM resource in these grabens have not yet been production tested. The coal-bearing strata total up to 2 km thick, with as much as 70 m of total coal thickness including individual coal beds up to 25 m thick. Coal rank ranges from sub-bituminous to semi-anthracite. The coal fields are structurally complex with many faults and often steep dips.

Sorption isotherm measurements indicate storage capacity ranging from 3 to 7 m^3/t in sub-bituminous coal from the Mindoro Basin, to 16 to 21 m^3/t for bituminous coal in the Visayan Basin, to as high as 23 m^3/t in semi-anthracite coal from the Zamboanga-Sibugay Basinram. However, measured desorbed gas content reportedly ranges from 1.4 m^3/t for subbituminous coal up to 4.4 m^3/t for semi-anthracite and bituminous coals.[3] This indicates that the coal reservoirs may be seriously undersaturated and may not be economic to develop.

CBM resources of sub-bituminous coal in the Mindoro Basin on Semirara Island were preliminarily estimated at 150 Bcm (5.2 Tcf) of gas in-place, although this estimate assumed 100% methane saturation.[4] Additional CBM resources may be present in the Visayan and Zamboanga basins. These resources have not yet been production tested, but they could be the focus of additional more detailed commercial studies.

Tight Gas. There are no public studies of tight gas resources in the Philippines. There may be some tight gas potential in certain onshore sedimentary basins, such as the Central Luzon Basin, Visayon Basin in Cebu, and Cotabato and Agusan-Davao basins in Mindanao. Whereas up to 14 km of Miocene sedimentary rocks are present,

[3] Flores, R.M., Stricker, G.D., Papasin , R.F., Pendon, R.R., del Rosario, R.A., Malapitan, R.T., Pastor, M.S., Altomea, E.A., Cuaresma, R., Malapitan, A.S., Mortos, B.R., and Tilos, E.N., 2006. "The Republic of the Philippines Coalbed Methane Assessment: Based on Seventeen High Pressure Methane Adsorption Isotherms." U.S. Geological Survey, Open-File Report 2006-1063, 70 p.
[4] Flores, R.M., Pendon, R.R., Stricker, G.D., and Rasdas, A.R., 2008. "Untapped Coalbed Methane Resources in the Philippines." Abstract, 33rd International Geological Congress, Oslo, Norway, August 6-14.

these are dominated by marine carbonates and volcanic tuffs, with little hydrocarbon source rock.[5] Reservoir quality is reported to be quite poor.[6]

D. Unconventional Gas Development Activity and Production

A small group of companies are actively developing conventional oil and gas reservoirs offshore Philippines, but none have tested or appear to be planning to test unconventional gas formations.

- ***Shell*** is the largest gas producer in the Philippines, operating the Malaympaya gas field. Although an active shale developer in North America, Shell has not announced any unconventional gas activity in the Philippines.

- ***Nido Petroleum Limited*** is a small Australia-based independent E&P which produces about 500 B/D of oil from several small mature fields offshore of Palawan Island. Nido has not announced any unconventional gas activity in the Philippines.

- ***PetroEnergy Resources Corp.***, a small Philippines-based independent E&P, has several exploration blocks offshore which have no production currently. The company has not discussed unconventional resources in the Philippines.

[5] Bachman, S.B., Lewis, S.D., Schweller, W.J., 1983. "Evolution of a Fore-Arc Basin: Central Luzon Valley, Philippines." AAPG Bulletin, vol. 67, p. 1143-1162.
[6] Durkee, E.F., Peterson, S.L., 1961, "Geology of Northern Luzon, Philippines." AAPG Bulletin, vol. 45, p. 137-168.

6.6 THAILAND UNCONVENTIONAL GAS

A. Introduction

Thailand was one of the first economies in Southeast Asia to build a sizeable natural gas production industry, starting in the 1980s when Unocal (now Chevron) and other foreign operators began to develop offshore natural gas fields in the Gulf of Thailand. With availability of supply, natural gas consumption has doubled over the past decade in Thailand and currently accounts for about 40% of primary energy consumption. Much of Thailand's power is generated with natural gas, and natural gas fueled vehicle use is growing.[1]

Thailand exported natural gas for a decade (1999-2009), but by 2010 rapidly growing domestic demand outstripped more gradually rising natural gas production. In 2011, Thailand produced an average of 37 Bcm or 3.6 Bcfd from 280 Bcm (9.9 Tcf) of proved reserves, all from conventional reservoirs. With domestic consumption 47 Bcm or 4.5 Bcfd, Thailand imported nearly 10 Bcm or 0.9 Bcfd last year, Table 6-6-1.[2,3] The government recently projected that Thailand's annual natural gas consumption would grow to 72 Bcm or 7 Bcfd by 2030, requiring a sharp increase in natural gas imports.

Table 6-6-1. Thailand Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		45.1	1,590	4.4	46.6	1,650	4.5
Supply							
▪	Marketed Production (Dry)	36.3	1,280	3.5	37.0	1,310	3.6
▪	Net Exports/Imports	8.8	310	0.9	9.6	340	0.9

Source: BP Statistical Review of World Energy, 2012

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1 Deunden Nikomborirak, "Gas in Thailand." In The impacts and benefits of structural reforms in the transport, energy and telecommunications sectors, APEC#211-SE-01.1, Chapter 18, p. 385-424, January, 2011.
2 Energy Information Administration, Country Analysis Brief, Thailand, website accessed August 13, 2012.
3 BP Statistical Review of World Energy, 2012

Gas supplies via pipeline from Myanmar currently provide the bulk of Thailand's natural gas imports. However, incremental production from newly developed gas fields in Myanmar is now expected to be exported to China under long-term contracts. As a result, Thailand commissioned its first LNG import facility in May 2011 and is planning to build additional facilities to meet its rapidly growing natural gas consumption and import needs.

Few official, publicly available studies of unconventional gas have been conducted to date by Thailand authorities. However, two very limited in scope assessments of coalbed methane have estimated a gas in-place of 17 Bcm (600 Bcf) for the Mae Tha coal field in Northern Thailand, Table 6-6-2.[4]

Table 6-6-2. Thailand Unconventional Gas Resources

		Resource Estimates				Production (2011)	
		GIP		Technically Recoverable			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	0	0
▪	CBM*	17	0.6	n/a	n/a	0	0
▪	Tight Gas	n/a	n/a	n/a	n/a	0	0
	TOTAL	**17**	**0.6**	**-**	**-**	**0**	**0**

*Based on very limited resource appraisal for the Mae Tha coal field.

Based on ARI's internal studies, Thailand may have significant onshore unconventional gas resources, particularly in the Khorat Plateau and the Central Plains regions. Unconventional gas development could help dampen Thailand's rapidly growing natural gas imports and fill its extensive existing natural gas transportation infrastructure.

[4] Wuttipong, K., Thawee, J., and Sungkom, B., "Assessment of Coalbed Methane Potential in Thailand: A New Project in the Mae La Mao, Mae Sod, and Khiansa Basins." In 43rd CCOP Annual Session, New Energy Resources in the CCOP Region – Gas Hydrates and Coalbed Methane, p. 129-142, September, 2007.

B. Governmental Authorities Engaged with Unconventional Gas Development

Thailand's upstream natural gas exploration and production industry is controlled by the Petroleum Authority of Thailand (PTT), a government organization under the Ministry of Finance. The Petroleum Authority of Thailand operates its own production company (PTT Exploration & Production or PTTEP). PTT also regulates investment by private companies active in Thailand, such as Chevron and Hess, taking a minority position in natural gas fields that generally ranges from 5% to 40%. PTT operates a 3,100-km gas pipeline network transporting gas from offshore fields to power generation facilities owned by the Electricity Generating Authority of Thailand (EGAT), which accounts for half of Thailand's natural gas consumption, as well as to a variety of other industrial users.

Thailand's natural gas industry is regulated by the Petroleum Act of 1971 and Energy Industry Act of 2007, while foreign investment is regulated by the Foreign Business Act of 1999.

Wellhead natural gas prices typically are linked with the price of fuel oil and have risen sharply in recent years, from about US$2/Mcf in 2005 to PTTEP's average US$7.41/Mcf reported for offshore natural gas production from the Gulf of Thailand (Q2-2012).[5] Wellhead gas prices in the onshore Khorat Plateau, which may have promising unconventional gas resources, appear to be significantly higher. Gulfport Energy Corp. reported an average sales price of US$9.43/Mcf during Q2-2012.[6]

PTT maintains a comprehensive geologic and reservoir data base from all petroleum wells and seismic in Thailand. This data base may be made available to potential investors for a fee. The data base does not specifically identify or assess unconventional gas resources but might provide a good platform for such a study. In addition, the Department of Mineral Fuels (DMF) has data from five coalbed methane exploration wells that were drilled during 2004 to 2006.

[5] PTT Exploration & Production Plc., Analyst Meeting, Q2-2012, Bangkok, Thailand, August, 2012, p. 9.
[6] Gulfport Energy Corp., Corporate Investor Presentation, August, 2012, p. 32.

C. Unconventional Gas Resource Assessments

C.1. Government Resource Assessments. Thailand's government has not yet evaluated its tight gas or shale gas resources but has initiated preliminary resource assessments for coalbed methane. Two separate studies of CBM resources in northern Thailand were funded by the Thai government in 2004, conducted by the Suranaree University of Technology (Mae Tha Basin, Lampang Province) and by Chiang Mai University (Mae Lamao Basin, Tak Province).[4] Although some limited CBM results have been published, full release of these studies could provide the basis for a better assessment of Thailand's CBM potential.

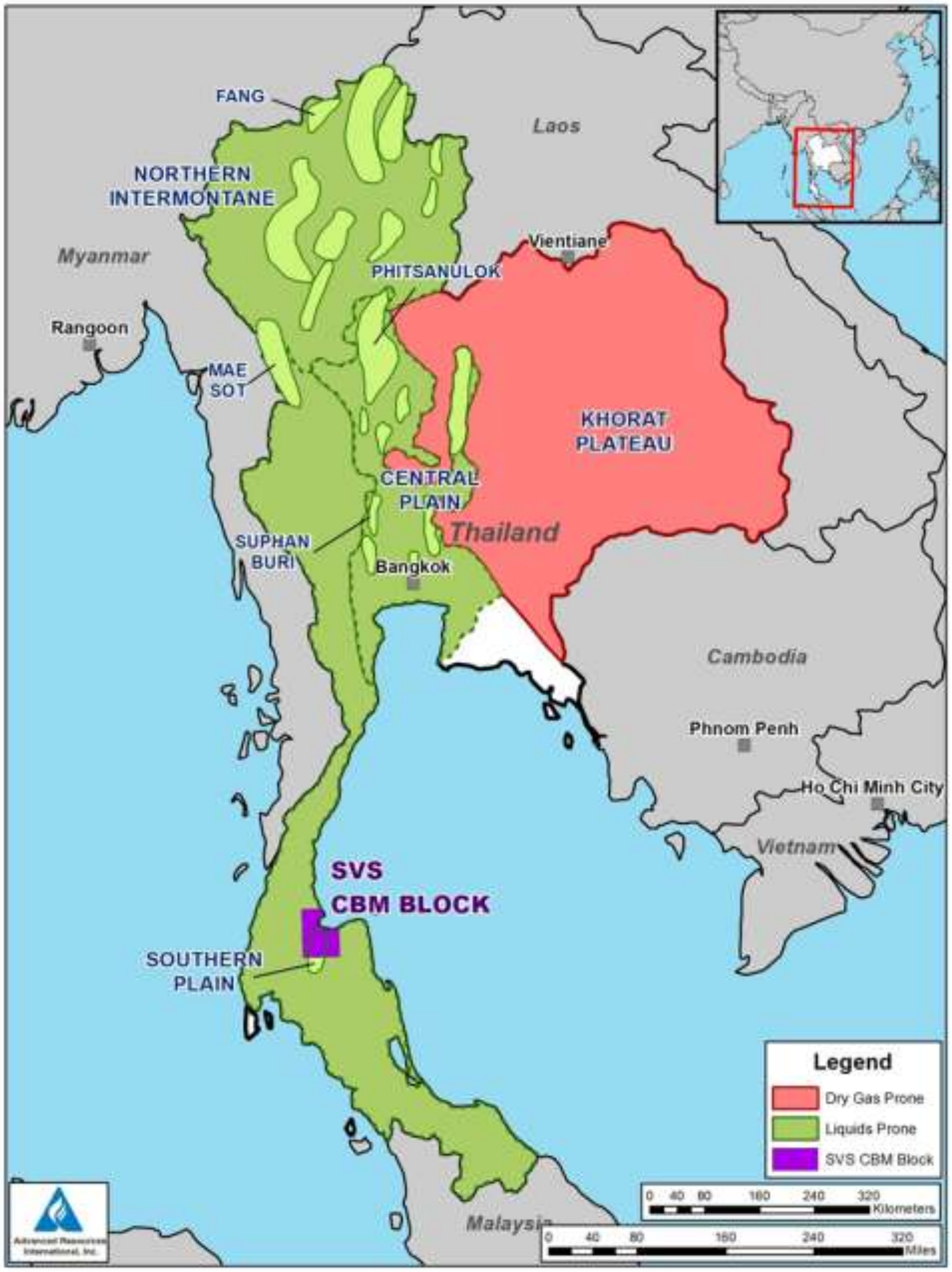
In 2004, three CBM test coreholes were drilled on close (30-m) spacing at Mae Tha coal field in Lampang Province, and another four coreholes were drilled at Mae Lamao coal field in Tak Province, both in northern Thailand. The estimated gas content of the coals was measured at only 1.4 ft^3/ton and the recovered gas consisted mainly of nitrogen. Making allowance for improper gas content measurement methodology and using an assumed 35 ft^3/ton gas content, the DMF estimated an in-place CBM resource for the entire Mae Tha coal field at about 600 Bcf.

In 2006, the DMF drilled one additional CBM exploration well and two observation wells at the Mae Lamao coal field. The measured gas content was still low (7 to 11 ft^3/ton and possibly contaminated by leaked air), consisting of 60% methane, 28% nitrogen, and 12% CO_2. The coal seams, which totaled about 15 m thick, were of sub-bituminous rank (R_o of 0.41%). A submersible pump was inserted for production testing, with reported low water flow rates (only 1 m^3/day or 6 barrels/day) and minimal gas production.

C.2. Private Resource Assessments. As a supplement to the Thailand government's unconventional gas resource assessments, ARI prepared an assessment of Thailand's unconventional gas resource potential based on a literature review of Thailand's oil and gas geology. In addition, the US Geological Survey recently published a short abstract discussing hypothetical unconventional gas concepts for

Thailand.[7] In ARI's view, considerable (albeit still undefined) unconventional gas resource potential exists in the Khorat Plateau and Central/Southern Plains regions, particularly for shale gas and tight gas, Figure 6-6-1.

Figure 6-6-1. Unconventional Gas Basins of Thailand (source ARI 2012)



[7] Schenk, C.J., "Potential Unconventional Oil and Gas Resource Accumulations, Onshore Thailand (Abstract)." International Petroleum Technology Conference, IPTC-14922-Abstract, 15-17 November, 2011.

Thailand has four main onshore sedimentary basins with unconventional gas potential:

- ***Khorat Plateau.*** Northeast Thailand's Khorat Basin has thick, organic-rich source rocks of Permian and Triassic age that occur at prospective depth. These marine-deposited shales sourced the Permian carbonate and Triassic conventional clastic reservoirs of this region, including two significant producing conventional gas fields. Furthermore, these shales are thermally mature, having attained dry gas to over-mature conditions. Shale gas deposits in the Khorat Plateau appear to be Thailand's most promising unconventional gas resource.

- ***Northern Inter-montane Basins.*** Small pull-apart basins such as the Fang Basin produce oil from conventional sandstone reservoirs, sourced by Miocene lacustrine shales. However, these shales are quite shallow, most likely clay-rich and ductile, and do not appear to reach gas-prone thermal maturity. Local coal deposits also occur, some actively mined, but the coal seams are relatively shallow, low-rank and laterally limited in extent. As such, the coals in this region appear to have limited CBM potential.

- ***Central Plain.*** In the Central Plain, oil is produced mostly from conventional Miocene sandstone reservoirs as well as pre-Tertiary fractured granites. Miocene lacustrine shales, considered the primary oil source rocks in this region, may become gas-prone at depth.

- ***Southern Plain.*** The under-explored Southern Plain contains the smaller Khien Sa Basin where early conventional exploration efforts were unsuccessful. While data are scarce, this area does not appear to have good unconventional gas potential. Two CBM exploration wells in this basin failed to locate thick coal.

Based on Thailand's regional petroleum geology, ARI considers that shale gas deposits in the Khorat Plateau to be the most promising unconventional gas target, followed by tight gas sandstones and carbonates in the Khorat and Central/Southern

Plains. Thailand also has coalbed methane potential in its northern inter-montane basins which may be locally important.

Shale Gas. There has been no comprehensive public study of shale gas resources in Thailand. Literature on Thailand's conventional shale source rocks in the Khorat Plateau indicates that the Permian and Triassic shales are thermally mature, moderately high in TOC, and of marine origin, thus possibly brittle and responsive to hydraulic fracturing. As such, the Khorat Plateau shale gas potential appears to be promising. Because the data on the shale gas resource in this area is so limited, a rigorous appraisal, using primary log, core, and seismic data, should be a priority undertaking for Thailand.

Coalbed Methane. Thailand has conducted selected CBM testing during the past decade and some limited public information is available. Although Thailand's CBM potential appears to be minor, it may be locally useful as a fuel source as well as most valuable for degasification ahead of coal mining. CBM well testing performed in Thailand to date has indicated low permeability and low gas content. However, these measurements were not conducted by CBM-experienced crews and were considered "inconclusive" by the Department of Mineral Fuels.

Moderately thick, early Tertiary-age coal deposits (Oligocene-Miocene) occur in western and northern Thailand within inter-montane rift basins. These coals total about 2 to 8 m thick, with individual seams 1 to 3 m thick. Burial depth is relatively shallow (120-300 m), and the coals reach sub-bituminous C to high-volatile rank (Ro 0.5% to 0.77%). Based on this data, Thailand's deep coal deposits could be prospective for CBM development. The best CBM potential appears to be in Chiang Mai, Lampang, Tak, Phetch Buri, Krabi, and Trang provinces.[8] However, individual coal fields are small in area, thus multiple regions likely would need to be developed to achieve a critical volume of gas production.

[8] Benjavun Ratanasthien, "Coalbed Methane Potential in Thailand." Unpublished abstract, Department of Geological Sciences, Chiangmai University, Thailand, 2 p.

Tight Gas. Although no public study of the tight gas resource has been performed in Thailand, sandstone and carbonate reservoirs with low permeability are likely to be present in the Khorat Plateau and the Central/Southern Plains regions. These tight formations may be inter-bedded with conventional gas reservoirs and, apart from the need to introduce hydraulic fracturing, could be jointly developed with existing infrastructure.

D. Unconventional Gas Activity and Production

In 2003-2004, a private company, SVS Energy Resources Limited Company, received a CBM exploration license for onshore block L71/43, within the Khiansa Basin of southern Thailand. The exploration block was located in Pun Pin and Khian Sa districts near the Kantang and Sabayoi coal fields in Surat Thani Province. SVS drilled two CBM test wells, one of which penetrated several thin, low-rank coal beds (R_o 0.27-0.44%), while the other well failed to locate significant coal.

Conventional upstream activity in Thailand is dominated by Chevron, Hess, and PTTEP, with a group of other smaller companies also active.

- Chevron, Hess and PTTEP have not reported any unconventional gas activity in Thailand.
- Statoil signed an MOU with PTTEP in January 2011 covering joint studies of conventional and unconventional resources in Thailand and elsewhere.[9] No further information is available.

[9] PTTEP, news release, March 18, 2011.

6.7 VIET NAM UNCONVENTIONAL GAS

A. Introduction

Viet Nam has a thriving oil and gas production industry focused on offshore development of conventional reservoirs in the South China Sea. Oil production averaged 326,000 B/D in 2011 from about 4 billion barrels of proved reserves. With its economy expanding at a rapid pace, domestic demand overtook production in 2010 and Viet Nam became a net, as well as growing oil importer.

Viet Nam's natural gas consumption of 8.5 Bcm or 0.8 Bcfd in 2011 is up by more than four fold in the past decade, Table 6-7-1.[1,2] Viet Nam's natural gas production, entirely from conventional reservoirs, was 8.5 Bcm or 0.8 Bcfd in 2011, from a reported 620 Bcm (21.8 Tcf) of proved reserves. Viet Nam's natural gas development is primarily offshore, mainly in the Cuu Long, Nam Con Son, and Malay basins.

Table 6-7-1. Viet Nam Natural Gas Consumption and Supply

		2010			2011		
		(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
Consumption		9.4	330	0.9	8.5	300	0.8
Supply							
▪	Marketed Production (Dry)	9.4	330	0.9	8.5	300	0.8
▪	Net Exports/Imports	-	-	-	-	-	-

Source: U.S. EIA CAB Viet Nam, 2012 and BP Statistical Review of World Energy

[1] U.S. Energy Information Administration, Viet Nam Country Analysis Brief, May 9, 2012.
[2] BP Statistical Review of World Energy, May 2012

Currently, Viet Nam's natural gas demand and supply are in balance. Even though natural gas production is projected to grow, the government expects that faster growth in natural gas demand will overtake supply. Unmet demand may reach 13 Bcm or 1.3 Bcfd by 2025, necessitating large-scale LNG imports or the development of new sources of natural gas supply.[1]

Viet Nam has announced plans to construct LNG import facilities to meet its rising demand for gas. Its first LNG import project, in Vung Tau province, would import 2 to 4 Bcm/yr (50 to 150 Bcf/yr) by 2015, expanding to 11 Bcm/yr (380 Bcf/yr) by 2025. A second LNG import facility with 4 Bcm/yr (150 Bcf/yr) of capacity is scheduled to commence operation in Binh Thuan Province by 2018, while a third smaller, floating LNG import terminal is planned for Vung Tau by 2013.

Viet Nam is bordered on the east by prolific offshore sedimentary basins, but most of its onshore land mass is underlain by crystalline rocks that have little conventional or unconventional hydrocarbon potential. However, there are several small Tertiary-age "pull-apart" basins located onshore, notably the Hanoi Basin in the north, which may have limited, but strategically located, unconventional gas resource potential, Figure 6-7-1.

In particular, CBM resources were tested in the Hanoi Basin under a recent commercial exploration project. The operator, Australian E&P Dart Energy, estimated 10 Bcm (0.3 Tcf) of technically recoverable CBM resources within its concession, out of nearly 30 Bcm (0.8 Tcf) of total gas in-place, Table 6-7-2. Apart from this limited CBM resource study, there are no publically available evaluations of tight gas or shale gas potential in Viet Nam. While the CBM and other unconventional resources appear to be relatively limited, their close proximity of the Hanoi Basin to the capital of Viet Nam may still make them economically significant.

Figure 6-7-1. Hydrocarbon Basins of Viet Nam (source ARI 2012)

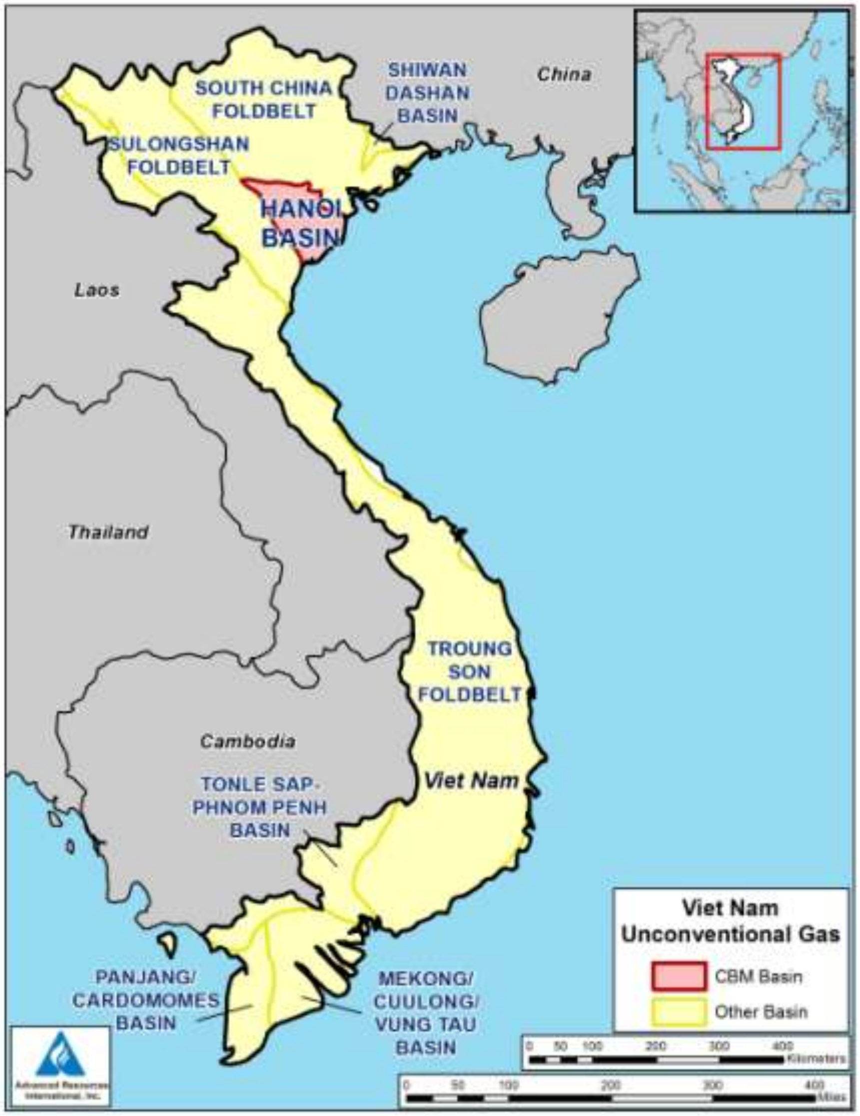


Table 6-7-2. Viet Nam's Unconventional Gas Resources

		Resource Estimates				**Production (2011)**	
		Gas In-Place		**Technically Recoverable**			
Resource		(Bcm)	(Tcf)	(Bcm)	(Tcf)	(Bcm/yr)	(Bcfd)
▪	Shale Gas	n/a	n/a	n/a	n/a	0	0
▪	CBM*	30	1	10	0.3	0	0
▪	Tight Gas	n/a	n/a	n/a	n/a	0	0
	TOTAL	**30**	**1**	**10**	**0.3**	**0**	**0**

*For the Dart Energy concession area in the Hanoi Basin.

B. Governmental Authorities Engaged with Unconventional Gas Development

PetroVietnam, which is controlled by the Ministry of Industry and Trade, has administrative authority over oil and gas activity in Viet Nam. PetroVietnam operates an upstream subsidiary, PetroVietnam Exploration and Production (PVEP), which develops its own projects and joint ventures with foreign companies. PetroVietnam also has upstream oil and gas investments in about 15 countries, focused mainly in South America and the former Soviet Union.

Foreign leasing may take place by direct negotiation or competitive bidding. The standard 30-year production sharing contract (PSC) comprises a 7-year exploration period and a 23-year development period. PetroVietnam reserves a minimum 20% equity interest in all PSC's in Viet Nam. Royalty rates for natural gas are low, ranging from 0% to 10%. There is a 0 to 10% VAT and a 32% Enterprise (profit) Tax. Cost recovery ranges up to 70%. Petroleum exploration and production activity is currently restricted to conventional formations in Viet Nam's offshore sedimentary basins.

Viet Nam has limited onshore gas pipeline infrastructure, but operates three large offshore gas pipeline systems which connect the southern gas fields with power plants and onshore gas distribution systems. These include the 250-mile Nam Con Son pipeline, which transports a majority of Viet Nam's gas supply and has a capacity of 680 MMcfd. The Bach Ho pipeline (150 MMcfd capacity) transmits associated gas from the Bach Ho field to the Phu My power complex. A third pipeline (200 MMcfd capacity) runs from the PM-3 Commercial Arrangement Area between Viet Nam and Malaysia to the Ca Mau combined-cycle power plant.

Viet Nam controls domestic electricity and natural gas prices at low levels compared with international market rates. For example, natural gas delivered to PetroVietnam from the Cuu Long Basin sold for as low as $1.68/MMBtu in 2010, while natural gas from the Nam Con Son Basin sold for US$3.32/MMBtu. However, the PM3-CCA field gas sold for over US$7/MMBtu[3] and natural gas prices are rising as Viet Nam evolves into a net gas importer. With Asian LNG prices of US$10 to US$15/Mcf, the

[3] Petroleum Economist, March 9, 2011.

price environment in Viet Nam may soon become much more supportive for unconventional gas development.

PetroVietnam maintains a comprehensive geologic and reservoir data base from all petroleum wells and seismic in Viet Nam. This data base may be made available to potential investors for a fee. The data base does not specifically identify or assess unconventional gas resources but may provide the basis for such a study.

C. Unconventional Gas Resource Assessment

C.1. Conventional Gas Resource Studies. Recent studies of Viet Nam's conventional petroleum geology provide insight into its unconventional gas potential. These studies estimate that the remaining natural gas reserves and resources of Viet Nam range from 2,100 to 2,800 Bcm (74 to 100 Tcf).

About 50 oil and gas fields have been discovered to date in Viet Nam. Oil has been discovered and produced in Cuu Long, Nam Con Son and Malay-Tho Chu basins, while natural gas is being produced in Song Hong and developed in Nam Con Son and Malay-Tho Chu basins. The Cuu Long Basin is now considered mature from an exploration perspective. Less explored regions include the Song Hong, Nam Con Son, Malay-Tho Chu and Khanh basins.

Several recent studies have assessed Viet Nam's conventional petroleum geology and oil & gas potential, with focus on the offshore. These include:

- **Viet Nam Petroleum Geology and Potential (2012).** Coordinating Committee for Geoscience Programmes in East and Southeast Asia (CCOP), Vietnam Oil and Gas Corporation (PetroVietnam).

- **Vietnamese Sedimentary Basins: Geological Evolution and Petroleum Potential (2010).** Michael B.W. Fyhn, Henrik I. Petersen, Anders Mathiesen, Lars H. Nielsen, Stig A.S. Pedersen,Sofie Lindström, Jørgen A. Bojesen-Koefoed, Ioannis Abatzis and Lars O. Boldreel. ENRECA project funded by the

Danish Ministry of Foreign Affairs. Vietnam Petroleum Institute (PetroVietnam) provided data and permission to publish this study.

- **Assessment of Undiscovered Oil and Gas Resources of Southeast Asia (2010).** Schenk, C., Brownfield, M., Charpentier, R.R., Cook, T.A., Klett, T., Kirschbaum, M.A., Pitman, J.K., and Pollastro, R.M., U.S. Geological Survey.

C.2 Unconventional Gas Resource Studies. Much of Viet Nam is underlain by crystalline basement, comprising igneous and metamorphic rocks with limited oil and gas potential of any type, whether conventional or unconventional. However, there are several small, structurally complex Tertiary-age pull-apart basins located onshore, the largest being the Hanoi Basin, which have sedimentary sequences that could be prospective for unconventional gas exploration. To date, limited CBM testing has occurred in the Hanoi Basin. There is minimal data on the shale gas or tight gas deposits of Viet Nam.

Shale Gas. Prospective shale source rock formations are present in Viet Nam's small onshore Tertiary sedimentary basins, notably the Hanoi Basin in the north. Petroleum exploration wells drilled in this basin encountered hydrocarbons, including the Tien Hai gas field discovered in 1975. The source rocks for these fields are believed to be organic-rich mudstone (TOC of 6.5% to 17%) and coal seams of Paleogene to Oligocene age that contain mostly Type 1 kerogen.[4] These source rocks were deposited under freshwater lacustrine, anoxic conditions. Whereas the mudstones are thermally immature (Ro 0.4%) near the surface, they have generated oil and may reach gas-prone thermal maturity at depth.[5] Unfortunately, the lacustrine mudstone may be clay-rich and ductile, rather than brittle, limiting stimulation effectiveness and gas recovery efficiency.

[4] H.I. Petersen,, C. Andersen, P.H. Anh, J.A. Bojesen-Koefoed, L.H. Nielsen, H.P. Nytoft, P. Rosenberg, L. Thanh. "Petroleum Potential of Oligocene Lacustrine Mudstones and Coals at Dong Ho, Vietnam: an Outcrop Analogue to Terrestrial Source Rocks in the Greater Song Hong Basin." Journal of Asian Earth Sciences, vol. 19, p. 135-154, 2001.

[5] Petersen, H.I., Nytoft, H.P., and Nielsen, L.H., "Characterisation of Oil and Potential Source Rocks in the Northeastern Song Hong Basin, Vietnam: Indications of a Lacustrine-Coal Sourced Petroleum System." Organic Geochemistry, vol. 35, p. 493-515, 2004.

Although current data suggest that the Hanoi Basin has limited potential for shale gas development, the close proximity of this clean energy resource to Hanoi City warrants further detailed investigation.

Coalbed Methane. The Hanoi (Red River) Basin in the north is Viet Nam's largest coal basin (3,500 km^2), with thick sub-bituminous rank coal at depths of 250 to 1,200 m.[6] Gas content was estimated by a CBM developer (prior to drilling) to be around 40 scf/ton, with possibly 170 to 280 Bcm (6 to 10 Tcf) of gas in place.[7]

Dart Energy and Keeper Resources have conducted CBM projects in Viet Nam, with Dart drilling 8 wells before relinquishing the project. In addition, the 5,000-km^2 Quang Yen Basin in northeast Viet Nam may have CBM potential but has not been assessed. Even though the few CBM test wells drilled to date in Viet Nam were not commercially successful, the close proximity of these unconventional gas resources to key markets justifies further more detailed evaluation of their potential.

Tight Gas. No data but prospective low-permeability formations may occur in onshore Tertiary sedimentary basins, such as the Hanoi Basin in the north.

D. Unconventional Gas Activity and Production

Several years ago Viet Nam awarded the first two production sharing contracts (PSC) for coalbed methane development. The model PSC for CBM has a 30-year term, comprising two 3-year exploration period and a 24-year development period. Relatively high foreign ownership of up to 70% is permitted, with PetroVietnam typically owning the remaining 30% of the project. Other contract terms are confidential. No shale gas or tight gas concessions have been awarded to date.

Whereas numerous companies are actively developing conventional reservoirs in Viet Nam, only two firms have attempted unconventional gas exploration, thus the

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6 Böhme,M.,Prieto, J., Schneider, S., Hung, N.V., Quang, D.D., Tran, D.N., "The Cenozoic Onshore basins of Northern Viet Nam: Biostratigraphy, Vertebrate and Invertebrate Faunas." Journal of Asian Earth Sciences, in press, 16 p., 2012.

7 Thai, S.D., "Coal Bed Methane in Viet Nam is Hot." Energy & Power Systems Practice, Frost & Sullivan. August 7, 2008.

potential remains at an early stage of delineation and appraisal. The only report of actual unconventional gas drilling activity has been Dart Energy's CBM project in the Hanoi Basin.

- Following three years of negotiation, the small independent E&P ***Keeper Resources*** obtained a CBM production sharing contract in early 2010, granted by PetroVietnam and PetroVietnam Exploration Production Corporation (PVEP) for a 3,600-km^2 area of the Red River Basin southeast of Hanoi. The project proceeded with the signing of drill site construction and preparation contracts, after acquiring land access approvals, but Keeper did not actually drill. This project appears to be dormant.

- In January ***2008 Dart Energy*** acquired a 70% interest in the 2,601-km^2 Hanoi Trough PSC, also located close to the capitol city of Hanoi. The company tested eight CBM exploration wells to assess the block's CBM potential. These indicated limited shallow CBM resources (estimated 0.3 Tcf of gross prospective resources out of 0.8 Tcf gas in place), with further untested promise below 1,000-m depth.[8] Dart's application to withdraw from the Hanoi Trough PSC is currently being reviewed by the government.

- Chevron, KNOC, Gazprom, Petronas, Talisman, ExxonMobil, Total and TNK-BP conduct conventional gas companies in Viet Nam. None of these companies have reported any unconventional gas activity in Viet Nam.

[8] Dart Energy, Quarterly Report, Quarter Ending March 31, 2011.

SECTION 7.
ASIAN NATURAL GAS NON-PRODUCING APEC ECONOMIES UNCONVENTIONAL GAS

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SECTION 7. OVERVIEW: ASIAN NATURAL GAS NON-PRODUCING APEC ECONOMIES UNCONVENTIONAL GAS

A. Introduction

Five of the Asian APEC economics - Hong Kong, China; Japan; Republic of Korea; Singapore and Chinese Taipei - are significant consumers of natural gas with little to no indigenous natural gas production. As shown on Table 7-1, these five APEC economies consumed an estimated 180 Bcm or 17.4 Bcfd of natural gas last year (2011).[1,2] Natural gas consumption is up substantially, from 164 Bcm or 15.8 Bcfd in the prior year (2010).

Table 7-1. Asian Natural Gas Non-Producing APEC Economies - Natural Gas Consumption, by size

	2010			2011		
	(Bcm)	(Bcf)	(Bcfd)	(Bcm)	(Bcf)	(Bcfd)
1. Japan*	94	3,340	9.1	106	3,720	10.2
2. Republic of Korea**	43	1,520	4.2	47	1,640	4.5
3. Chinese Taipei***	14	500	1.4	16	550	1.5
4. Singapore	8	300	0.8	9	310	0.8
5. Hong Kong, China	4	130	0.4	3	110	0.3
Total	**163**	**5,790**	**15.9**	**181**	**6,330**	**17.3**

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*Japan produced about 3 Bcm (120 Bcf) or 0.3 Bcfd of natural gas in 2011 from remaining proved reserves of 21 Bcm (740 Bcf), primarily in the mature Minomi-Nagoda field on the western coast of Honshu.

**Republic of Korea produced less than 1 Bcm (11 Bcf) of natural gas in 2011 from its only operating domestic gas field, Donghoe-1 in the Ulleung Basin.

***Chinese Taipei produced less than 1 Bcm (9 Bcf) of natural gas in 2011.

Source: BP Statistical Review of Work Energy, 2012 and U.S. EIA Country Analysis Briefs, 2012

1 BP Statistical Review of World Energy, May 2012
2 U.S. Energy Information Administration Country Analysis Briefs, 2012.

Two of these APEC economies, Japan and Republic of Korea, accounted for the bulk of the natural gas consumption and imports. Japan consumed 106 Bcm or 10.2 Bcfd in 2011, up nearly 12% from 2010 due largely to increased imports of LNG as substitute for loss of electric power from the accident at the Fukushima nuclear plant. Republic of Korea consumed 47 Bcm or 4.6 Bcfd of natural gas in 2011, up moderately from 2010 but up significantly (34%) from its average rate of natural gas consumption in the prior three years.

Currently, the bulk of Japan's natural gas imports are via LNG from Malaysia, Australia and Qatar. The bulk of Republic of Korea's natural gas imports are via LNG from Qatar and Indonesia.

The remaining three APEC economies - Hong Kong, China; Singapore; and Chinese Taipei - together consumed 27 Bcm or 2.6 Bcfd natural gas in 2011. A natural gas pipeline from mainland China provided 3.1 Bcm or 0.3 Bcfd to Hong Kong, China last year to meet its annual natural gas demand. A natural gas pipeline from Indonesia provided the bulk of Singapore's annual natural gas consumption of 9.1 Bcm or 0.8 Bcfd. Chinese Taipei obtained its year 2011 natural gas supply of 16.1 Bcm or 1.5 Bcfd via LNG from numerous sources, with Qatar, Malaysia and Indonesia providing three quarters of the LNG import volume.

B. Government Agencies and Private Entities Engaged With Natural Gas Development

B.1 Hong Kong, China. The Natural Energy Commission (NEC) in the People's Republic of China coordinates its overall energy policy, including the energy policies for Hong Kong, China (replacing the Hong Kong Ministry of Energy and Mining Resources). See Chapters on China Unconventional Gas for a more comprehensive discussion of government agencies engaged with unconventional gas development.

B.2 Japan. The Ministry of Economy, Trade and Industry (METI), with its Agency for Natural Resources and Energy and its Petroleum and Natural Gas Division (within the Natural Resources and Fuel Department) sets national policies for natural gas development and imports. The implementation of these policies is by a series of state-run and private companies, discussed below.

Japan's dominant natural oil and gas company, JNOC, was reorganized in 2004 to form a series of new competitors, including state-run Japan Oil, Gas and Metals Corporation (JOGMEC) and numerous stand-alone oil and gas companies such as INPEX, Japan's largest oil and gas company, and Japan Petroleum Exploration Company (JAPEX). Osaka Gas, Tokyo Gas and Tiho Gas are Japan's largest retail natural gas companies, accounting for about three-fourths of the retail market.

B.3 Republic of Korea. The Ministry of Knowledge Economy (MKE) sets the energy policies for the Republic of Korea including assuring steady and stable energy supplies to meet its growing energy demand. The Korean National Oil Company (KNOC) is responsible for exploration and production of oil and gas in the Republic of Korea. The Korea Gas Corporation (KOGAS) is the primary organization in the Republic of Korea's natural gas sector, focusing primarily on LNG imports and overseas liquefaction facilities. KOGAS operates three of the Republic of Korea's four LNG receiving terminals, owns and operates its 1,726-mile pipeline system, and operates a series of private natural gas distribution companies.

B.4 Singapore. The Ministry of Trade and Industry (MTI) and its Energy Division develop and manage Singapore's overall energy policy, including addressing energy security, economic competitiveness and environmental sustainability. The Energy Policy Group, led by MTI, provides energy policy coordination among other energy related divisions of MTI, such as Energy Market Authority (responsible for regulating the pipeline natural gas industry) and the Economic Development Board.

B.5 Chinese Taipei. The Bureau of Energy within the Ministry of Economic Affairs establishes and oversees Chinese Taipei's energy policies. To attain energy security and reduce its dependence on nuclear power, the Ministry, as a part of its recent position paper, "will promote renewable energy at full scale" and "will also promote reasonable use of natural gas."

C. Importance of Unconventional Gas Resources

The five Asian Natural Gas Non-Producing APEC Economies obtain the great bulk of their natural gas supplies via imports from other Asian Natural Gas Producing APEC Economies such as Brunei, Indonesia and Malaysia.

Given the limited remaining conventional natural gas resources available in the region, the presence and active pursuit of unconventional gas - - shale gas, coalbed methane and tight gas - - would support the continued availability of geographically favorably located sources of natural gas supply for these five APEC Economies.

APEC Unconventional Natural Gas Census
Part II

Suggested Framework, Scope, and Content for an APEC Unconventional Gas Census and Recommended Follow-on Supporting Activities

Asia-Pacific Economic Cooperation's Energy Working Group

January 2013

APEC Unconventional Natural Gas Census

PART II

Suggested Framework, Scope, and Content for an APEC Unconventional Gas Census and Recommended Follow-on Supporting Activities

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I. APEC UNCONVENTIONAL GAS CENSUS REPORT – PART II

I.A Purpose of Report

The purpose of Part II of the report, *"APEC Unconventional Gas Census: Evaluating the Potential for Unconventional Gas Resources to Increase Gas Production and Contribute to Reduced CO_2 Emissions",* is to provide APEC's Energy Working Group with two products:

- Suggested framework, scope and content of an APEC unconventional census, and its relationship to other international and national activities, and
- Recommendations for setting up an APEC Unconventional Gas Census, including scope, content, timing and management responsibility.

Part II of the APEC Unconventional Gas Census report is a complementary document to Part I of the report (provided separately).

Part I of the report documents the information on surveys of unconventional gas resources completed, underway or planned by the various APEC economies, including a discussion of relevant information on unconventional gas captured by international agencies. Part I of the report also provides our projections of the potential amounts of unconventional gas, by type, that would be practically and economically produced in each APEC economy, including a time frame for their availability.

I.B The Need For and Value of an APEC Unconventional Gas Census

Unconventional gas resources and industrial activities have long been closely tracked and documented by government and industry in North America and Australia. These two regions have seen steady increases in unconventional gas exploration and production during the past several decades, to the extent that unconventional gas resources now supply a sizeable or even dominant share of overall natural gas production compared with the conventional reservoirs. Today, the USA, Canada, and Australia all export (or will soon) large quantities of excess unconventional gas production, a remarkable turnabout for economies which not long ago were viewed to be depleting their gas resources and constructing LNG import facilities to meet future natural gas demand.

Simultaneously, over the past few decades, government agencies, industry, and supporting oilfield service and consulting firms in the USA, Canada, and Australia have gradually developed an array of analytical and data base development skills needed to track and assess these unconventional gas resources and activities. The most important components within this unconventional gas "tool kit" include:

- Geologic identification, mapping and characterization of existing and emerging unconventional gas plays;
- Appraisal of unconventional gas resource potential and reservoir quality;
- Developing and refining fit-for-purpose drilling and completion technologies; and
- Constructing the geologic and well data bases needed to track industrial and research activities.

Policy makers in certain of the economies have come to depend on these specialized unconventional gas analytical and data tracking capabilities to develop and fine-tune fiscal terms that are most suitable for attracting unconventional gas resource investment. In addition, private oil and gas companies now rely on these capabilities in formulating their quite diverse individual corporate strategies targeting development of unconventional gas deposits. Over time, a virtuous cycle of unconventional gas information, insight, and investment has gradually taken shape in the USA, Canada and Australia, with rather spectacular results.

Outside North America and Australia, however, the tools and skill sets needed to track and characterize unconventional gas resources and production generally remain at a nascent state or simply do not exist, in spite of heightened industry interest in unconventional gas resources and the looming shortages of natural gas in many rapidly growing economies. Key institutional challenges and gaps confronting unconventional gas researchers and prospective investors, previously highlighted in many of the individual APEC economy chapters in Part I of the report, include:

- ***Overlooked Resources***: For certain of the APEC economies, unconventional gas geology and resources have been completely overlooked or poorly characterized by existing technical literature in the public domain. As such, there is a widespread lack of understanding (or confidence) in their true potential. A good example is the lack of recognition of the extent and quality of the coalbed methane resources in Indonesia prior to ARI's appraisal for ADB/MIGAS published in 2004. Simulated by this resource appraisal, Indonesia established fiscal terms for allocating investment in CBM development and now exports, via LNG, a portion of its CBM production.

- ***Under-Reporting***: In other APEC economies, unconventional gas drilling and production activities may be taking place "under the radar", perhaps in conjunction with conventional production, but are not being separately recorded due to the lack of a formal unconventional gas reporting system. To some extent the lack of data on tight gas production and applied technology may be constraining the introduction of more efficient, appropriate recovery technology. This may be the case for Mexico tight gas resources and coalbed methane.

- ***Pigeon Holing:*** Finally, in some APEC economies, selected aspects of unconventional gas activity may be recorded by a particular government agency but not be widely shared with other relevant agencies or with an industry which could benefit from this information. This may be the case in several of the APEC economies.

In fact, many of these challenges and gaps plagued North America and Australia during the early days of unconventional gas exploration (1970's and '80), resulting in unwarranted initial skepticism concerning the size and quality of the unconventional natural gas resource base; today, these issues have largely been rectified. Similarly, such institutional gaps and inefficiencies tend to obscure recognition by policy makers of the true contribution that unconventional gas resources could provide in the APEC economies, while also hindering needed industry investment.

To overcome these hurdles, there is need for a systematic program to transfer the specialized unconventional gas analytical capabilities and practices from a few of the economies to all APEC economies, even to those with modestly promising resource potential.

In our subsequent chapter, we set forth a suggested framework for building the foundation and framework for a comprehensive APEC Unconventional Gas Census. We also provide recommendations for the scope, timing, and management responsibility for two APEC-supported follow-on projects to facilitate this goal - - the APEC Unconventional Gas Census Workshop and the implementation, in each relevant APEC economy of a permanent, comprehensive Unconventional Gas Census.

II. SUGGESTED FRAMEWORK, SCOPE AND CONTENT OF A SYSTEMATIC APEC UNCONVENTIONAL GAS CENSUS

Three steps are essential for establishing the framework, scope and content of a systematic APEC Unconventional Gas Census, namely: (1) designating a lead ministry; (2) establishing the Unconventional Gas Census Team; and (3) installing the unconventional gas resource appraisal and data system.

II.A Designation of Lead Ministry

The first step of the systematic APEC Unconventional Gas Census should be for the individual geologically prospective economies to designate a ministry or other government agency (a lead ministry) with the lead role for assessing unconventional gas resources and tracking activity. Most commonly, this would be the Ministry of Energy, Ministry of Mineral Resources or Natural Resources, or a similar body which already may have oversight and responsibility for conventional oil and gas development. In the case of APEC economies with significant coal mining activity, it also may be advantageous to involve the Coal Ministry or Department, with its vast coal data base potentially useful for evaluating coalbed methane resources.

The Lead Ministry should then appoint a permanent Unconventional Gas (UG) Team, comprising a full complement of technical, economic, and policy specialists. Team members should have strong backgrounds in the conventional oil and gas industry at the very least (and perhaps coal mining as well for coalbed methane). While they needn't be established unconventional gas experts, they should be readily trainable in unconventional gas technology and best practices to be provided by international consulting experts. Such specialized training and technology transfer in individual disciplines, outlined below, likely would be needed for most APEC economies outside of North America.

II.B Establishing the Unconventional Gas Team

The overall composition of a typical Unconventional Gas Census Team within the APEC economy could be as follows:

- ***Team Leader:*** Responsible for overall strategy and management of the Unconventional Gas Census within a given APEC economy, including oversight of the technical, economic, and policy specialists. This individual should have a diverse background in the fiscal, financial, technical, and policy aspects of oil and gas development, along with willingness to adapt to the peculiarities of unconventional gas resource exploration and development.

- ***Petroleum Geologists:*** One or more individuals experienced in various aspects of geologic evaluation of petroleum deposits, including stratigraphy, sedimentology, structure, geophysics, petrophysics, and geomechanics, as well as the use of seismic reflection, remote imagery, computer mapping software, well logging, and laboratory rock analysis. Unconventional gas background is preferred but not necessary, assuming the availability of suitable training.

- ***Petroleum Engineers:*** One or more individuals experienced in various aspects of petroleum engineering, including the disciplines of reservoir engineering, well drilling, testing, completion, production operations, surface facilities, and transportation analysis. Again, the essential unconventional gas background and skills may be acquired from specialized training.

- ***Economist:*** The Team should include at least one economist familiar with the financial evaluation of oil and gas projects, including the estimation of capital and operating costs, investment schedules, cash-flow evaluation, and fiscal systems including production sharing contracts. (Note that there is relatively little variation in the evaluation of unconventional vis-a-vis conventional natural gas projects.)

- ***Environmental Specialist:*** Onshore unconventional gas projects can have a significant surface footprint and may generate voluminous oilfield waste that requires safe disposal. Consequently, the Team requires a specialist in environmental engineering or mitigation of oil and gas projects, including mitigation of surface impacts, air and noise emissions, plus produced water treatment and disposal.

- ***Energy Policy Specialist:*** Balancing the need for unconventional gas development with the impacts on other sectors of the economy and land use will require sensitive policy solutions. The policy specialist should understand these competing needs and how unconventional gas fits into the overall energy requirements and investments of a given economy.

- ***Data Base Specialists*****:** Responsible for developing, operating, and updating geologic and well drilling/production data bases for unconventional gas development. These data bases will need to be compatible with other petroleum data systems as well as be readily accessible to the various sectors of government and industry.

II.C Installing the Unconventional Gas Resource Appraisal and Data System

One of the two main objectives for the Unconventional Gas Team is to appraise the geologic and development potential of the diverse unconventional gas resources that may exist within an economy, whether tight gas, shale gas, or coalbed methane. Properly conducted, a comprehensive appraisal can be of profound utility to policy makers, providing a sophisticated understanding of the location, magnitude, quality, and development potential/challenges of an economy's unconventional gas resource base in all its diversity.

The appraisal may influence an economy's energy strategy at the very highest levels, such as appears to be the situation in Mexico following the shale gas resource studies prepared first by the U.S. EIA and subsequently by PEMEX. Policy implications may include energy trade (aim for self-sufficiency, export, or import), infrastructure (construction of pipelines, storage, LNG terminals), industrial mix and policy (including the degree of energy intensity), as well as the fiscal regime for investment (taxation rates, foreign vs domestic investment, etc.). The appraisal also may help to attract industry investment. For example, Indonesia's current boom in coalbed methane exploration and Mexico's recent national priorities for shale gas development are two positive examples of the importance of rigorous resource appraisals.

A proper unconventional gas appraisal will require an inter-disciplinary approach drawing on the Team's full complement of geology, petroleum engineering, economics, fiscal analysis, and data base development skills. International consultants with global unconventional gas industry experience would be needed to assist the Team during key phases of the appraisal, as discussed below.

Data for the appraisal would come principally from existing seismic, well log, and laboratory data that has been collected from conventional oil and gas projects. These data could be supplemented by newly collected, specialized data relating to unconventional gas resources (e.g., well and outcrop sampling programs, laboratory measurements). Additional data obtained from the coal mining industry also may help support coalbed methane studies.

The specific approach, manpower and budget for the unconventional gas appraisal will depend on each economy's circumstances, but the individual components of study generally should include the following:

- ***Initial Geologic Data Gathering and Synthesis:*** Most APEC economies already possess a vast array of geologic data collected in previous years/decades from conventional oil and gas fields as well as from coal deposits. These existing data sets -- which should cost little to access -- provide the raw foundation for the unconventional gas resource appraisal. However, these data sets tend to be located in various repositories, where they are mixed together with and often obscured by voluminous less-useful conventional reservoir data. Consequently, the first step of the appraisal is to locate and flag the particular geologic data sets which may be useful for an unconventional gas appraisal.

- ***The next step is to transfer and synthesize these diverse and unconnected data points into a coherent set of unconventional gas data bases that are compatible and readily usable for analysis.*** Data formats may include Excel-type spreadsheets, ArcView-type GIS computer mapping systems, and GeoSEIS-type seismic reflection data bases. Note that this task is non-trivial, typically requiring a significant portion of the overall appraisal budget. International consulting experts likely will be needed to assist the Team during this effort, particularly for identifying the most useful data signatures as well as designing the data base systems.

- ***Identification and Mapping of Key Unconventional Gas Plays:*** Once the geologic data bases have been synthesized into a coherent and usable format, they should be assessed at a relatively high level to identify the broad unconventional gas resource plays types within each economy. These play types may include tight gas, shale gas, and coalbed methane deposits of varying geologic age and tectonic setting. The stratigraphy, tectonics, structural geology, geochemistry, thermal evolution, and petroleum generation and migration history of each play needs to be unraveled, depending on data availability. This stage of the appraisal is quite important because distinguishing large, high-quality resource plays from the less promising “time-wasting” candidates with little development potential can greatly improve the study’s efficiency and impact. International consultants drawing on the experience in North America and Australia could play a key role here.

- ***Define the Potential Sweet Spots Within Each Play:*** Each of the unconventional plays will likely have geologically favorable, mediocre, and poor areas. Consequently, the next step of the appraisal is to map out the various geologic and reservoir characteristics of each play to help define the distribution of quality attributes, again data permitting. Typically, these include formation thickness, burial depth, thermal maturity and organic content. Geohazards such as the extent of faulting or contamination by inert gases (CO2, N2, H2S) also needs to be defined. Although not yet conducted at the detailed “prospect” scale, this process will identify the relatively superior parts of the play for further analysis, which may include exploration drilling, sampling and testing. Experienced consultants can help guide this process.

- ***Estimate Technically Recoverable Resources:*** Once the plays have been mapped and partitioned, the reservoir properties within each area may be characterized. This enables estimation of technically recoverable unconventional gas resources, a key step, using rigorous appraisal methodologies that have been developed by geologists in selected countries in recent years. Experienced consultants will be crucial to this step as well.

- ***Assess Suitable Unconventional Gas Drilling and Completion Technologies.*** Each unconventional gas play will have its particular set of well drilling and completion technologies which optimize production and recovery, depending on the local geologic, reservoir, and surface conditions as well as on the capabilities of the service sector within the host economy. Consequently, the next step of the appraisal process is to examine the applicability of existing or adaptations of “off-the-shelf” technologies from proven unconventional gas basins, versus the need to develop completely new recovery methods. Key aspects of this analysis will include surface access, well site construction, drilling rig capabilities, the use of vertical vs horizontal drilling, well completion strategies, hydraulic or chemical stimulation of the formation, overall field design, and long-term production operations. Environmentally safe disposal of produced water, CO2, or other wastes also should be assessed.

- ***Economic Evaluation of Unconventional Gas Development.*** Having gained a solid understanding of the geologic potential and the most suitable drilling and completion techniques, it may now be possible to estimate capital and operating costs for unconventional gas development by play. Standard economic evaluation should be conducted, centered on cash-flow analysis, to identify the indicative cost/supply curves for unconventional gas within a given economy.

Sensitivity analysis should be performed to define the key economic variables and parameters (gas prices, capex and opex, timing of investment, taxation, etc.). For planning purposes, alternative forecasts of potential unconventional gas production also should be conducted. The use of a resource based unconventional gas model and annual projections have provided industrial firms as well as government policy makers in North America with critical information for investment and policy decisions.

- ***Fiscal Policies Suitable for Unconventional Gas Resource Development.*** Existing fiscal policies designed for conventional oil and gas may be inappropriate for unconventional gas development. For example, a 50-well offshore deepwater platform project has entirely different risk and investment profiles compared with a 1,000-well onshore coalbed methane development project. Fiscal policies will need to be internationally competitive to attract investment in unconventional gas resource development, but also appropriate for an individual economy's government and energy policy objectives. The fiscal analysis will draw on all previous steps of the appraisal while adding these political and policy realities.

- ***Access to Natural Gas Transportation Systems.*** Large-scale commercial development of unconventional natural gas requires a mix of residential, commercial, and industrial users; natural gas pipelines; LNG processing plants, as well as other transportation and utilization infrastructure. The capability of the existing infrastructure system within each economy should be evaluated based on the projected future volume of unconventional gas output. Gaps and deficiencies should be noted.

III. RELATIONSHIP OF THE SUGGESTED APEC CENSUS TO OTHER ACTIVITIES

III.A International Activities

A small group of international agencies, such as the International Energy Agency[1] and the World Energy Council (plus the U.S. Energy Information Administration as part of their International Energy Outlook) provide projections on natural gas.

However, in general, this information combines conventional and unconventional gas (or excludes much of the unconventional gas resource). In addition, these reports often only provide this information on a regional-, rather than a country-specific, basis for natural gas supplies and production. An APEC Unconventional Gas Census would provide valuable input to these international outlooks for natural gas.

III.B National Activities

Certain of the APEC economies, namely the U.S. and Canada (as discussed above), have already instituted formal, annual unconventional gas census frameworks, data collection systems and supply projections. Our proposed framework for a comprehensive APEC Unconventional Gas Census has drawn heavily on the experiences of these two economies.

[1] Recently, the International Energy Agency published a special report on unconventional gas as a supplement to their World Energy Outlook. This report, entitled "Golden Rules for a Golden Age of Gas", provided some preliminary estimates for the size and productivity of unconventional gas for a handful of the APEC economies. However, the IEA study acknowledged that the resource data base for their production and reserve projections was limited and often relied on judgmental allocations from older, high level resource studies.

In addition, Australia has recently taken some initial steps for establishing the size of its coalbed methane resource and has provided preliminary information on its tight gas resource. Also, PEMEX recently undertook an appraisal of its domestic shale gas resources, enabling the Ministry of Energy to provide both a “base scenario” and a “strategy scenario” for the development and targeted production of its shale gas. Finally, Indonesia (with support from the Asian Development Bank) has undertaken an assessment of its in-place CBM resources. These are some of the important “first steps” toward an unconventional gas census.

IV. APEC WORKSHOP ON THE UNCONVENTIONAL GAS CENSUS

An important next step is to convene a 2 to 3 day APEC workshop on the Unconventional Gas Census, located in a significant APEC region. The workshop would allow APEC economies to hear and discuss the state-of-the-art in unconventional gas resource assessment and production technologies. To improve communication, the workshop should be limited to one or two representatives per economy, for total attendance of approximately 40 to 50. Possible topics for the workshop could be:

- Modern Unconventional Gas Industry in USA, Canada, and Australia: current status, where it's heading, and lessons learned.
- Geologic Appraisal of Unconventional Gas Resources: data interpretation and methodologies.
- Key Technologies for Unconventional Gas E&P: exploration, drilling, completion, production.
- Economic and Fiscal Aspects of Unconventional Gas Development
- Establishing a Uniform Methodology for Unconventional Gas Reporting

Possible speakers and unconventional gas experts that would provide the presentation materials and "lessons-learned" at the workshop could be:

- APEC officials to "kick off" the workshop; providing the objectives and agenda for the workshop
- APEC member officials to discuss the status of unconventional gas activities within their economy
- Industry consultants with international unconventional gas expertise
- Selected E&P and service company officials and experts

Several possible locations for the Unconventional Gas Census workshop could be considered, such as:

- Singapore is a leading candidate, being centrally located in Southeast Asia and also convenient to China, Australia, New Zealand and Russia.
- China, has major under-developed unconventional resources and rapidly growing demand and significant interests in supporting unconventional gas development.
- Houston, USA, is a major center for unconventional gas production and service companies and also convenient for Latin American economies.

V. INTERNATIONAL CONSULTING TEAM TO SUPPORT THE APEC UNCONVENTIONAL GAS CENSUS

The APEC Unconventional Gas Census, proposed above, would require the analytical and advisory support of a team of international consultants possessing strong unconventional gas industry experience in all key aspects of the project. The consulting team would visit the principal economies with unconventional gas resource potential at key stages during the Census to provide critical technical expertise and guidance. The twelve economies with unconventional gas resources proposed to be supported by international consultants during the Census are: Brunei, Chile, China, Indonesia, Malaysia, Mexico, New Zealand, Peru, Philippines, Thailand, and Vietnam. A more selected technical assistance effort could be provided to Australia, which has already established a number of the key foundation blocks for an Unconventional Gas Census. Canada and the U.S. will not require the services of the consulting team.

V.A International Consultant Team Composition and Qualifications

A strong and experienced consulting team is vital to the success of the proposed APEC Unconventional Gas Census. All members should have significant experience on unconventional gas resource appraisal and development in the U.S. and Canada, as well as relevant resource development and appraisal expertise in the other APEC economies. Knowledge of advanced unconventional gas extraction technologies will be critical, including demonstrated experience and applying that knowledge in the developing economies. There are five key functional areas of expertise; two or more of which may be handled by a single individual, depending on qualifications.

- ***Team Leader:*** At least 15 years of management experience on comparable unconventional gas projects in advanced and developing economies. Requires broad multi-disciplinary supervisory experience covering geology, reservoir engineering, drilling and completion technology, economic appraisal, fiscal policy, and environmental technologies.

- ***Unconventional Gas Geologist:*** At least 10 years of experience in geologic exploration and development of unconventional gas resources in advanced and developing economies.

- ***Unconventional Gas Engineer:*** At least 10 years of experience in unconventional gas development in advanced and developing economies including reservoir, production, drilling, and completions technology and engineering.

- ***Unconventional Gas Data Base Expert:*** At least 5 years of experience working with geologic and engineering data on unconventional gas projects in advanced and developing economies, including log and production analysis, computer GIS mapping, and data base development.

- ***Unconventional Gas Economist:*** At least 10 years of experience working on economic evaluation of unconventional gas projects in advanced and developing countries, including estimation of capital and operating costs, cash-flow analysis, and international fiscal regimes including production sharing contracts.

V.B International Consultant Tasks

The international consultant team would prepare an initial study design document and then visit participating economies at three stages over the course of the 2-year project to conduct the following work tasks:

- ***Study Design & Methodology***: Provide an overall generic design and methodology document (i.e., not specific to a given economy) for evaluating the unconventional gas resources (tight gas, shale gas, coalbed methane). This would include geologic data gathering, synthesis, evaluation methodology, and data base design. Play characterization and resource estimation. Well drilling, completion, production, and environmental technologies. Cost estimation and economic appraisal including fiscal regimes. Infrastructure requirements and policy development. Work with APEC Singapore to contact and schedule visits to unconventional gas teams in the ten economies.

- ***Kickoff Meeting and Technology Transfer Seminar:*** Travel to each of the ten economies to meet with their designated Unconventional Gas Teams. Discuss project objectives, expectations, work items, and schedules. Conduct a 1-day seminar on unconventional gas technologies, focusing on transfer of developments in advanced economies and the challenges confronting developing economies. Review the Teams' plans for implementing the Appraisal and offer technical guidance and support.

- ***Midpoint Meeting and Progress Assessment:*** Return to each of the ten economies to evaluate their progress in developing institutions, personnel, and procedures to support unconventional gas development. Evaluate progress in data base development, geologic evaluation, and technology assessment. Provide guidance to small groups as needed.

- **Final Meeting and Report:** Visit each of the ten economies for a final time to assess their Appraisals. Offer final technical guidance and support. Prepare brief final report on each economy evaluating the effectiveness of their unconventional gas systems, including gaps and weaknesses.