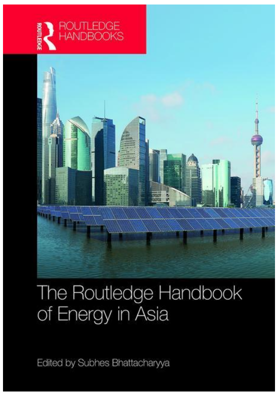

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9

NATURAL GAS TRADE AND MARKETS IN ASIA

Ronald D. Ripple

Introduction

This chapter aims to present a historical overview of the evolution of the natural gas markets in the Asian region and to provide a view to the future evolution given the expected changes in both demand and supply within and from outside the region.

The twenty-first century is frequently cast as the Asian Century. This is meant typically to address the region's rise in significance in geopolitical, economic, and military realms. However, such a label is also applicable to the expectations of the region's role, engagement, and influence on energy. And, within the broad definition of energy, the region's role in the developments of natural gas production, consumption, and trade will be no less influential.

Natural gas has played a relatively small role in Asia. Approximately 24 percent of the world primary energy mix is accounted for by natural gas, while the Asia Pacific region used natural gas to provide for only 11 percent of its energy needs in 2015. This compares to 32 percent for both North America and Europe/Eurasia. The Asia Pacific region relied on coal for 50 percent of its primary energy needs in 2015. BP and the International Energy Agency (IEA)[1] expect the share of natural gas to grow to 13 percent for the Asia Pacific region by 2035.

Asia shifted from near production-consumption balance for natural gas in the early 1980s to an imbalance of 144.5 Bcm (14 Bcf/d)[2] by 2015. The imbalance is expected to expand in the future, and this implies that the role of inter-regional trade in natural gas is expected to grow. It seems likely that most of the growth in inter-regional natural gas trade will be met via liquefied natural gas (LNG)[3] trade.

Asia is expected to continue its role as a key global driver of energy demand over the next several decades. The regional character of this demand is expected to change with China's role, while continuing to increase in absolute terms, diminishing relative to India's role. Much of this growth across the region is expected to focus on natural gas as a cleaner primary energy source and as a good substitute for coal in power generation and backup for intermittent renewables.

Numerous energy outlooks suggest that the Asian region will continue to rely on cross-border and inter-regional trade to meet demand growth, as internal supply growth, even from unconventional (e.g. shale and coal seam) natural gas, will be insufficient. Several natural gas pipelines are currently proposed, but the geography and geopolitics of the region make cross-border pipelines challenging. Hence, reliance on LNG-sourced gas trade is expected to continue to expand. Currently, 73 percent of global trade in LNG-sourced gas flows to Asian countries (with nearly half of this flowing to Japan), and only about 41 percent of these supplies originate within the region. Australia is expected to become the largest global exporter of LNG-sourced natural gas by 2018, but new players will also be entering the regional trade with natural gas sourced from the United States, as well as the potential for volumes from East Africa, Canada, and others. Asia is likely to be a prime target of nearly all of this capacity, especially if historical price differentials are a reasonable expectation for the future. The new entrants and volumes will change the regional and sub-regional market dynamics and potentially the underlying pricing structures that have persisted within the region for decades. All of this, as well as the potential complications of a persistence of the current low-price environment being faced around the globe will be addressed in the chapter.

The region

Asia is a very large and diverse region, and there are more than a few definitions of what constitutes the Asian region. Therefore, the region that is discussed in this chapter and the countries therein contained must be defined. If Asia is defined as continental Asia, it will include some 50 countries including those of the Middle East, the Russian Federation east of the Urals, the Caucasus, and Central Asia, along with all of the countries stretching across from Afghanistan and Pakistan south of the Himalayas to China and North and South Korea. The various sources of data and outlooks for energy supplies and demands employ a range of different country groupings, but none employs the continental definition with 50 countries. The discussion that follows will employ the regional definition used by BP in its Annual Statistical Review of World Energy and its Outlooks that is referred to as the Asia Pacific; this definition is quite consistent with the IEA when combining Organisation for Economic Co-operation and Development (OECD) Asia Oceania and Non-OECD Asia.

Reserves, production, and consumption of the region

The countries included in this regional definition that contain individually identified proved reserves of natural gas are Australia, Bangladesh, Brunei, China, India, Indonesia, Malaysia, Myanmar, Pakistan, Papua New Guinea, Thailand, and Vietnam; additional countries in the region contain proved reserves, but these are deemed too small to report separately; see Table 9.1 for reserves and Table 9.2 for production.

The largest proved reserves are in China, followed closely by Australia. Japan, South Korea, and Taiwan, traditional LNG-sourced natural gas importers, have no domestic natural gas resources. The largest producer of natural gas is China, and it has been since 2007. The reserves of the Asia Pacific region are 8.4 percent of the world total, and the region's production in 2015 represented 15.7 percent of global production. The driver for inter-regional trade is the fact that in 2015, the region's consumption accounted for 20.1 percent of global consumption.

Table 9.3 shows that China is the largest consumer of natural gas in the region, followed by Japan. Similar to its position with coal, China has the largest reserves, the highest production, and the largest consumption. However, since Japan must import all of its gas, China falls second to Japan for importing volumes; in 2015 China imported 59.8 Bcm via pipe and LNG, while Japan imported 118 Bcm via LNG.

Consumers of natural gas in the region, in addition to the 12 above, include Japan, New Zealand (which has its own reserves but too small to be separated out in the BP statistics), the Philippines (same situation as New Zealand), Singapore, South Korea, and Taiwan; see Table 9.3.

Table 9.1 Asia Pacific natural gas proved reserves

Country	*Proved reserves (Bcm)*							
	1980	*1985*	*1990*	*1995*	*2000*	*2005*	*2010*	*2015*
Australia	172.2	673.6	880.8	1200.9	2093.1	2236.2	3483.3	3471.4
Bangladesh	286.0	353.0	725.0	272.0	306.3	407.0	354.0	232.2
Brunei	207.0	238.0	331.0	400.0	366.0	340.0	301.2	276.0
China	726.1	900.9	1032.1	1725.1	1412.2	1585.5	2816.1	3841.3
India	343.0	480.0	700.0	676.1	759.8	1101.0	1148.6	1488.5
Indonesia	822.0	1982.2	2863.6	1950.0	2682.0	2478.0	2965.1	2839.0
Malaysia	850.0	1494.0	1640.0	2271.0	2337.0	2480.0	1081.6	1169.3
Myanmar	93.0	268.0	265.0	268.0	287.0	538.0	221.1	528.4
Pakistan	450.0	623.0	642.0	596.0	677.0	852.0	657.4	542.6
Papua New Guinea	–	0.1	1.7	3.0	3.0	2.4	155.3	141.3
Thailand	292.0	218.0	224.0	176.0	360.0	304.0	299.6	219.5
Vietnam	–	–	15.0	147.0	170.0	220.0	617.1	617.1
Other Asia Pacific	243.0	254.0	290.0	406.0	338.0	413.0	287.8	281.7
Total Asia Pacific	4484.3	7484.9	9610.2	10,091.2	11,791.2	12,957.1	14,388.0	15,648.1

Data source: BP (2016b).

Table 9.2 Asia Pacific natural gas production

Country	*Natural gas production (Bcm)*							
	1980	*1985*	*1990*	*1995*	*2000*	*2005*	*2010*	*2015*
Australia	11.1	13.0	19.7	28.3	32.1	39.2	52.6	67.1
Bangladesh	1.3	2.7	4.8	7.0	9.4	13.8	20.0	26.8
Brunei	8.6	8.6	8.9	11.8	11.3	12.0	12.3	12.7
China	14.7	13.4	15.8	18.5	28.1	51.0	99.1	138.0
India	1.2	4.5	12.0	18.8	26.4	29.6	49.3	29.2
Indonesia	18.5	32.3	43.9	60.0	69.6	75.1	85.7	75.0
Malaysia	2.5	10.7	17.2	26.8	46.6	63.8	60.9	68.2
Myanmar	0.4	0.9	0.9	1.6	3.4	12.2	12.4	19.6
Pakistan	7.2	8.8	12.2	15.6	21.5	39.1	42.3	41.9
Thailand	–	3.1	6.5	11.4	20.2	23.7	36.2	39.8
Vietnam	–	^	^	0.1	1.6	6.4	9.4	10.7
Other Asia Pacific	7.6	9.6	7.6	7.5	8.9	11.1	17.6	27.7
Total Asia Pacific	73.2	107.6	149.5	208.2	279.2	377.0	497.8	556.7

Data source: BP (2016b).

Note: ^ means less than 0.05 BCM. Totals may differ from column sums due to rounding.

Consumption of natural gas in the region has increased by 858 percent between 1980 and 2015, while total global consumption has increased by 142 percent.

The Asia Pacific region is expected to increase consumption by about 76 percent from its 2014 level. This will exceed that of all other regions, with the exception of Africa. However, Africa's growth is from a much lower initial base, and its 2035 consumption level is expected to reach 211 Bcm compared with 1073 Bcm for the Asia Pacific, placing it second only to North America.

Table 9.3 Asia Pacific natural gas consumption

Country	*Natural gas consumption (Bcm)*							
	1980	*1985*	*1990*	*1995*	*2000*	*2005*	*2010*	*2015*
Australia	10.4	13.0	16.0	18.5	22.0	24.9	33.2	34.3
Bangladesh	1.3	2.7	4.8	7.0	9.4	13.8	20.0	26.8
China	14.7	13.4	15.8	18.3	25.3	48.2	111.2	197.3
China Hong Kong SAR	–	–	–	^	3.0	2.7	3.8	3.2
India	1.2	4.5	12.0	18.8	26.4	35.7	61.5	50.6
Indonesia	7.0	12.4	16.9	28.1	32.5	35.9	43.4	39.7
Japan	24.1	38.3	48.1	57.9	72.3	78.6	94.5	113.4
Malaysia	2.5	4.4	7.6	12.9	26.6	34.9	34.5	39.8
New Zealand	0.9	3.3	4.3	4.3	5.6	3.6	4.3	4.5
Pakistan	7.2	8.8	12.2	15.6	21.5	39.1	42.3	43.4
Philippines	–	–	–	^	^	3.1	3.5	3.3
Singapore	–	–	–	1.5	1.7	6.5	8.8	11.3
South Korea	–	–	3.0	9.2	18.9	30.4	43.0	43.6
Taiwan	1.9	1.1	1.9	4.0	6.2	9.4	14.1	18.4
Thailand	–	3.1	6.5	11.4	21.9	32.5	45.1	52.9
Vietnam	–	^	^	0.1	1.6	6.4	9.4	10.7
Other Asia Pacific	1.9	2.9	2.5	3.4	3.5	5.2	5.8	7.8
Total Asia Pacific	73.2	107.9	151.6	211.0	298.5	410.8	578.4	701.1

Data source: BP (2016b).

Note: ^ means less than 0.05 BCM. Totals may differ from column sums due to rounding.

Figure 9.1 provides a graphical view of the regional growth in natural gas consumption since 2000. The three biggest players have been China, Japan, and India. By 2015 they accounted for over 50 percent of the region's total natural gas consumption, and they are expected to expand this role within the region.

Natural gas pricing and LNG shipping costs

Historically, natural gas pricing in the Asia region has been linked to the price of crude oil. Specifically, LNG-sourced natural gas has traded under long-term contracts with pricing clauses that link the price for the natural gas, in terms of MMBtu, to the price of a barrel of crude oil imported into Japan. This is the so-called JCC[4] pricing link.

Prior to the recent downturn in the price of crude oil, being mid-year 2014, the price of natural gas in Asia had been at a significant premium to that in the USA and Europe, reaching prices of US$18–US$19 per MMBtu, while prices in Europe were in the US$8–US$10 per MMBtu range and in the USA prices were in the US$2–US$4 per MMBtu range. Indeed, it was this large differential that motivated the large number of proposed natural gas export projects in the USA. The expectation was that such margins would lead to significant profits by liquefying USA natural gas and exporting it primarily to Asia. With the collapse of the crude oil price, the slowdown in the growth of energy demand, and the introduction of new export volumes from new LNG projects, the price of natural gas in Asia has fallen significantly leaving little if any margin for LNG shipments from the USA. Even the completion of the Panama Canal expansion,

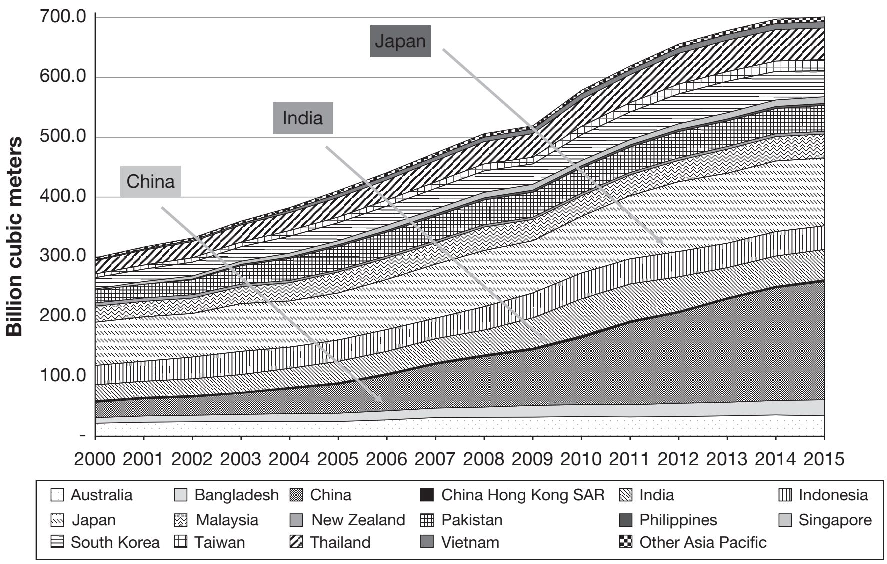

Figure 9.1 Asia Pacific natural gas consumption, 2000–2015

Data source: BP (2016b).

Table 9.4 LNG carrier shipping cost comparison

Port-to-port		*Approximate distance (nautical miles)*	*Fuel cost (US$)*	*18 knots*		*Day rate (US$40,000)*	*Cost/MMBtu*
				Days	*Hours*	*18 knots*	*US$*
Sabine Pass, USA	Zeebrugge	4861	340,248	13	6	1,060,000	0.46
	Tokyo (via South Africa)	15,825	1,107,755	36	12	2,920,000	1.34
	Tokyo (via Panama)	9149	640,440	21	8	1,706,667	0.96
Dampier, Australia	Tokyo	3762	263,319	8	12	680,000	0.31

Data source: Author's calculations.

Notes:

Assumptions: 160,000 m^3 tanker ⇒ ~3,500,000 MMBtu;

Accounts for round trip, includes two additional days for loading and unloading, US$35/nm fuel cost and US$0.18/MMBtu for Panama.

which shortens the voyage time between the USA and Japan by about 11 days, is not sufficient to produce the necessary margins to justify the construction of any additional capacity in the USA not already under contract and construction (see Table 9.4).

The delivered prices into Japan during 2016 have remained at or below US$7 per MMBtu, falling as low as US$4.1 in May. During this 2016 period, the price of natural gas in the USA, priced at Henry Hub, has been near US$3 per MMBtu, ranging a bit above and a bit below. When accounting for natural gas acquisition, liquefaction, and shipping costs, the natural gas from the USA cannot be delivered to Japan and produce a positive margin. To understand this, it is first necessary to understand the character of the business model for exports processed through the Cheniere Sabine Pass LNG project, based in Louisiana. An example follows.

A simple statement of the Cheniere business model is that Cheniere acquires the natural gas, processes it into LNG, and then delivers it to the contractual off-taker at shipside. Cheniere charges the Henry Hub price plus 15 percent for the gas, and adds the cost of processing that has been contractually agreed to with the off-takers,[5] which range from US$2.25 to US$3.00 per MMBtu. In September 2016, a typical price for natural gas at Henry Hub was US$3.12 per MMBtu. If we use BG's lowest cost processing agreement for our example, we find that the shipside delivered price, for full-cost recovery would have been US$5.84 per MMBtu. The September delivered price for spot trade into Japan was US$5.70 per MMBtu. So, even before accounting for shipping costs a negative margin will apply.

Table 9.4 provides an example of the shipping costs associated with transporting natural gas in the form of LNG from Sabine Pass to various delivery ports, with a comparison to the cost of shipping from the Northwest Shelf Project in Western Australia to Tokyo. For this example, the focus is on shipping via the expanded Panama Canal from Sabine Pass to Tokyo, and the spot day rate for the LNG tanker is set at US$40,000 per day.[6] The cost to ship the LNG in a 160,000-cubic meter tanker for the 9149 nautical mile voyage via Panama (and the return voyage for the ship) would be US$0.96 per MMBtu. When the natural gas cost, liquefaction fee, and shipping cost are totaled, the full-cost recovery delivered cost will be US$6.80 per MMBtu. Given the spot delivered price of US$5.70, this implies a loss of US$1.10 per MMBtu.

This suggests that in the current low-price environment there is little incentive to construct new LNG export projects in the USA to meet any shortfall in Asia. However, this does not mean that no volumes will flow from the USA Gulf Coast to Asia.[7]

Natural gas trade

Trade in natural gas has grown from 106.45 Bcm in 2001 (consisting of 4.25 Bcm imported via pipeline from within the region into Singapore and Thailand, and 102.2 Bcm imported in the form of LNG into Japan, South Korea, and Taiwan from both within and outside the region) to 299.8 Bcm in 2015 (consisting of 61.2 Bcm of pipeline trade and 238.6 Bcm of LNG-sourced gas trade). This represents a 182 percent increase.

Intra- and inter-regional trade

The trade of natural gas began within the region with LNG-sourced flows from Brunei in 1973. These followed the initial LNG-sourced trade between the USA (from the State of Alaska) and Japan beginning in 1969. Indonesia (1977) and Malaysia (1983) followed, and Australia joined the trade in 1989. With the exception of Brunei, each of these players expanded their export capacity, and from within the region were joined by Papua New Guinea in 2014. And while not included in the Asia Pacific region definition, Russia's Sakhalin 2 entered the LNG-sourced trade in 2009.

Pipeline trade within the region began with flows to Singapore from Malaysia (1992). Myanmar/Burma began pipeline exports to Thailand in 1998, and Indonesia began exports to Singapore in 2001. This form of movement within the region was further expanded with the completion of the Sino-Myanmar pipeline project in 2015 to move natural gas from offshore Myanmar to China.

China initiated pipeline imports from outside the region with the completion of the second west-to-east pipeline project in 2010, which carries natural gas sourced from Turkmenistan; the first west-to-east pipeline carried domestically produced gas from the Tarim Basin eastward to the major domestic consuming regions. The west-to-east capacity has been further expanded with the third west-to-east pipeline, and imports now come from Turkmenistan, Kazakhstan, and Uzbekistan. The second and third west-to-east pipelines each have a capacity of 30 Bcm per year.

The largest form of natural gas importation in the region is by way of LNG-sourced movements. This trade has grown from the initial small volumes moving from Alaska to Japan to 10 percent of total world consumption in 2015 [total world inter-regional trade accounted for 1042.4 Bcm, or 30 percent of total world consumption]. Total imports into the Asian region in 2015 amounted to just under 300 Bcm, which represented 29 percent of the world inter-regional trade flows. However, the Asian region accounted for 70 percent of the world trade in the form of LNG, including flows both within and from outside the region.

Table 9.5 shows the imbalance in production and consumption for the region since 1980. From near production-consumption balance, the region transitioned to a shortfall of 144.5 Bcm in 2015. The majority of this shortfall was met by LNG-sourced imports amounting to 125.4 Bcm from outside the region; the total LNG-sourced volumes for Asia Pacific amounted to 238.6 Bcm, with 47 percent of this produced within the region.

Japan, South Korea, and Taiwan have no domestic natural gas production. They also have no pipeline interconnections with any other country, so all of their natural gas is supplied via LNG-sourced imports. In the early period of LNG-sourced natural gas imports into the region only Japan, South Korea, and Taiwan imported. By 2015, they were joined by China, India, Malaysia, Pakistan, Singapore, and Thailand. Malaysia is actually an interesting example of energy economics at work. While Malaysia is now an importer of natural gas in the form of LNG (and via pipeline) it is also still an exporter of natural gas via LNG shipments. This reflects the fact that it is more economic for Malaysia to import to meet natural gas demand in parts of the country that are not nearby its natural gas production regions; it also has long-term contractual obligations that must be met from its existing production and liquefaction operations.

Tables 9.6a and 9.6b provide a view to the future while putting the Asia Pacific region imbalance into a global context; Table 9.6a is in Bcm and Table 9.6b is converted to Mtpa since much of the shortfall will be met by LNG-sourced trade, which will require both additional liquefaction and regasification capacity, which is typically stated in Mtpa. The projections are based on BP's Outlook to 2035, published in 2016 (BP, 2016a).

For this chapter, the key focus is on the row for Asia Pacific, which reports only negative values that are growing throughout the period from 1990 through 2035. Thus, as a region,

Table 9.5 Asia Pacific production: consumption imbalance (Bcm)

Items	*1980*	*1985*	*1990*	*1995*	*2000*	*2005*	*2010*	*2015*
Production	73.2	107.6	149.5	208.2	279.2	377.0	497.8	556.7
Consumption	73.2	107.9	151.6	211.0	298.5	410.8	578.4	701.1
Difference	0.01	(0.32)	(2.10)	(2.78)	(19.32)	(33.79)	(80.56)	(144.48)
BCF/day	0.00	(0.03)	(0.20)	(0.27)	(1.87)	(3.27)	(7.79)	(13.97)

Data source: BP (2016b).

Table 9.6a Regional imbalance (production minus consumption) in Bcm

Region	*1990*	*1995*	*2000*	*2005*	*2010*	*2014*	*2015*	*2020*	*2025*	*2030*	*2035*
North America	5.50	(24.62)	(29.56)	(31.63)	(27.56)	(0.03)	2.04	97.75	100.00	189.54	188.11
South and Central America	0.31	0.53	6.13	16.64	14.60	4.92	1.80	(7.48)	(16.26)	(29.87)	(40.58)
Europe and Eurasia	(12.39)	(37.74)	(50.86)	(69.68)	(99.66)	(7.24)	(30.21)	(24.98)	6.02	(0.10)	(14.79)
Middle East	7.24	7.03	20.70	41.73	93.16	135.91	126.64	123.45	121.36	115.81	119.63
Africa	29.14	37.81	71.86	91.79	106.17	82.57	75.21	72.03	61.70	81.38	125.52
Asia Pacific	(1.94)	(2.33)	(18.87)	(34.77)	(76.86)	(147.47)	(144.85)	(172.63)	(289.19)	(353.36)	(389.73)
Total natural gas imbalance	27.87	(19.32)	(0.58)	14.08	9.86	68.65	30.63	88.13	(16.37)	3.40	(11.83)

Data source: Author's calculations based on BP (2016b). Totals may differ from column sums due to rounding.

Table 9.6b Regional imbalance (production minus consumption) – Mtpa

Region	*1990*	*1995*	*2000*	*2005*	*2010*	*2014*	*2015*	*2020*	*2025*	*2030*	*2035*
North America	4.06	(18.16)	(21.80)	(23.33)	(20.33)	(0.02)	1.50	72.11	73.76	139.82	138.77
South and Central America	0.23	0.39	4.52	12.27	10.77	3.63	1.33	(5.52)	(11.99)	(22.04)	(29.93)
Europe and Eurasia	(9.14)	(27.84)	(37.52)	(51.40)	(73.52)	(5.34)	(22.28)	(18.43)	4.44	(0.07)	(10.91)
Middle East	5.34	5.19	15.27	30.78	68.72	100.26	93.42	91.06	89.52	85.43	88.25
Africa	21.50	27.89	53.01	67.71	78.32	60.91	55.48	53.13	45.52	60.03	92.59
Asia Pacific	(1.43)	(1.72)	(13.92)	(25.65)	(56.69)	(108.79)	(106.85)	(127.34)	(213.33)	(260.66)	(287.49)
Total natural gas imbalance	20.56	(14.25)	(0.43)	10.39	7.27	50.64	22.59	65.01	(12.08)	2.51	(8.73)

Data source: Author's calculations based on BP (2016b). Totals may differ from column sums due to rounding.

Asia Pacific has been and will continue to be net importer of natural gas to be able to meet the projected regional consumption given expected regional productive capacity.

The big players in demand and supply

Japan, China, and India are seen as continuing their role as the major consumers of natural gas in the region, and Australia is seen to be the largest player in terms trade in natural gas into the future.

The BP Outlook does not provide a country-by-country projection by fuel, so we will turn to the World Energy Outlook of the IEA. There is not complete agreement between the two Outlooks, but they are close enough to be able to make useful observations.

The Asia Pacific consumption of natural gas in 2013 equaled 630 Bcm,[8] which constituted 19.5 percent of total world consumption. According to BP statistics, the share of world natural gas consumption grew to just over 20 percent by 2015, at 701.1 Bcm. The BP Outlook 2016 has Asia Pacific natural gas consumption growing by 75 percent between 2014 and 2035, while the IEA has it growing by 84 percent between 2013 and 2035. BP's 2035 consumption level is 1073.3 Mtoe, whereas the IEA has it at 1046 Mtoe. If we adjust the IEA value for consumption in to 2013 to reflect the update in BP's Statistical Review, the projected IEA growth is the about 72 percent, so the two outlooks are in relatively close agreement as to both the future levels of consumption demand for natural gas in Asia and the growth from earlier observed consumption levels.

BP and the IEA see the future growth for natural gas in the region at similar levels. Per Table 9.7, the IEA projects 2035 natural gas component of TPED to be 1162.2 Bcm, while the BP Outlook to 2035 (2016a) has it at 1193 Bcm. The IEA projection has natural gas consumption doubling between 2013 and 2040. And over this period the share of the region accounted for by Japan, China, and India expands from 51 percent to 60 percent.

The share of natural gas in the energy mix is expected to increase significantly for the non-OECD Asian countries, and this can be seen for China (lifting from 5 percent to 11 percent) and India (lifting from 6 percent to 8 percent) by 2035.

Table 9.7 Natural gas total primary energy demand

	Natural gas demand (Bcm)						*Growth (%) 2013–2040*	*Share of mix*	
	2013	*2020*	*2025*	*2030*	*2035*	*2040*		*2013*	*2040*
OECD Asia Oceania	210.0	196.7	198.9	206.7	208.9	206.7	−1.6	22	21
Non-OECD Asia	420.0	588.9	710.0	830.0	953.3	1064.4	153.4	8	13
Japan	117.8	95.6	93.3	95.6	96.7	95.6	−18.9	23	22
China	157.8	280.0	352.2	416.7	468.9	506.7	221.1	5	11
India	50.0	64.4	90.0	114.4	140.0	165.6	231.1	6	8
OECD – Oceania less Japan	92.2	101.1	105.6	111.1	112.2	111.1	20.5		
Asia Pacific total	630.0	785.5	908.9	1036.7	1162.7	1271.1	101.8		
Japan's share (%)	18.7	12.2	10.3	9.2	8.3	7.5	− 59.8		
China's share (%)	25.0	35.6	38.8	40.2	40.3	39.9	59.2		
India's share (%)	7.9	8.2	9.9	11.0	12.0	13.0	64.1		
Total of Japan-China-India share	51.7	56.0	58.9	60.5	60.7	60.4	16.9		

Data source: BP (2016a).

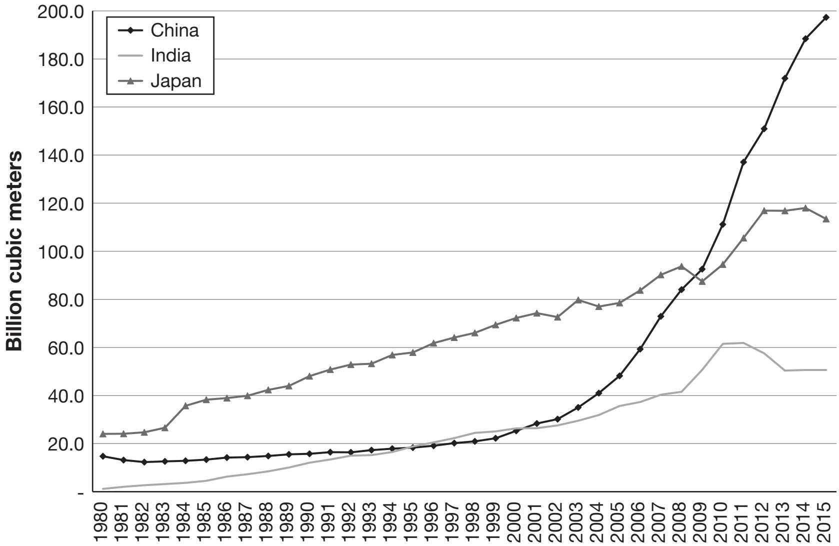

Figure 9.2 Natural gas consumption: Japan, China, and India

Data source: BP (2016b).

Figure 9.2 shows the dramatic increase in natural gas consumption in China, and the abrupt increase for Japan following the Fukushima Daiichi disaster.

The combination of Japan, China, and India accounts for 51 percent of the region's consumption in 2015. While the entire region is expected to continue to increase the absolute volumes of natural gas going forward, these three are expected to continue to dominate the region's consumption requirements, reaching 60 percent of the region by 2030 according to the IEA's New Policies Scenario projections. Growth in demand for natural gas will get a strong boost from China and India as they are expected to account for nearly half of the world's GDP growth through 2035, according to BP's Outlook to 2035.

India

India has announced its plan to expand its LNG import capacity to 50 Mtpa, up from 21 Mtpa currently. The timeline has not been specified, but given current expansions and new projects under development in 2015–2016, this target seems reasonable. In addition to the existing 21 Mtpa of regasification capacity an additional 20 Mtpa is under construction at four different locations (Dahej, Mundra, Kakinada, and Ennore, according to GIIGNL (2017)). All are expected to be operational by 2020. The additional 10 Mtpa needed to meet the 50 Mtpa target are not yet specified.

India has been in negotiations for many years to access Iranian natural gas via pipeline. However, this pipeline would have to transit Pakistan, and agreement has not been successfully brought to the final investment decision nor to the beginning of construction. As a result, India has turned its efforts in the direction of developing domestic resources and investing in LNG regasification terminals to meet its needs.

Like China, India is heavily reliant on coal for its energy requirements. It too would like to wean itself from coal to help satisfy international emissions reduction commitments and to clean its environment. The expectation of a less dramatic increase in the share of natural gas in the total country energy mix suggests that India's reliance on coal will continue more strongly into the future compared to China. Nevertheless, the IEA projection foresees a 231 percent increase in consumption, which will require substantial investment in natural gas import facilities and domestic transportation and distribution infrastructure. And this projected growth in natural gas consumption will propel India past Japan by 2030, but India will still be a distant second to China's natural gas consumption level.

Japan

Japan's natural gas consumption is not expected to increase from current levels. This is because it is expected that Japan will be bringing some, perhaps much, of its nuclear generation fleet back on line, and this will decrease the need for natural gas. While Japan's natural gas consumption had been on the rise throughout the 2000s, it showed a significant jump following the Fukushima Daiichi disaster in March 2011. Moving into 2012 Japan shut down all of it nuclear power plants, and natural gas was one of the main replacement fuels to help meet electricity generation needs. That surge in demand was a key driver behind the spike in regional natural gas prices to the US$18–US$19 per MMBtu range, with annual average prices nearing US$17 per MMBtu.

If we assume that simple cycle natural gas generation plants will be the first to shut down when nuclear power plants are brought back online, the reduction in demand for natural gas imports could be quite significant. For each 1000 MW nuclear power plant that is restarted, natural gas demand tied to simple cycle power plants could fall by as much as 1.5 Mtpa of LNG-sourced imports.[9]

Japan has 44 GWe of nuclear power capacity, comprising 42 reactors.[10] Of the 42, 24 reactors were in the process of restart approval in 2016, with two having restarted in the second half of 2015. Each reactor is roughly equivalent to the hypothetical 1000 MW plant in this example. So, if all 26 plants are operating by 2020, that could lead to a decrease in Japan's natural gas import demand by 39 Mtpa, or 43 Bcm. The IEA projections reported in Table 9.7 suggest a decrease of 22.2 Bcm between 2013 and 2020. The difference between these two may be due to the IEA assuming fewer nuclear reactors return to service or that the natural gas generation fleet in use is more thermally efficient, or both, and it may also assume that growth in other non-power generation uses for natural gas will offset some of the decline from the power sector. The decrease in demand of 22.2 Bcm implies 20 Mtpa, so there may be a range of 20–39 Mtpa of uncertainty for the demand for natural gas imports from Japan over just the next five or so years.

China

China's 13th Five Year Plan aims to have natural gas account for 10 percent of primary energy by 2020. This will be an increase from 5.9 percent in 2015. The IEA projection puts natural gas at 11 percent of primary energy for China by 2040; the IEA projection pre-dates the 13th Five Year Plan. BP expects China to contribute significantly to natural gas production, especially toward the end of its outlook to 2035. BP projects that China will contribute more to shale gas production growth than any other country in the world.

China appears to have significant shale resources that are deemed to be technically recoverable according to the 2013 study done for the IEA by Advanced Resources International. China's estimated technically recoverable shale gas resources amount to 1115 trillion cubic feet (31.6 trillion cubic meters), which is nearly double the estimated technically recoverable shale gas resources for the USA. However, there are significant questions about the commerciality of these technically recoverable resources. China has missed its production targets for coal seam gas consistently over the past five or so years, and many question the near future potential for China's large shale gas resource. This is further exasperated by the current low-price environment affecting investment viability around the world. This situation was exacerbated by the late-2014 decision of OPEC to maintain crude oil production levels to attempt to regain its market share. The decision sent negative signals across all energy sectors regarding the uncertainty of prices that may be earned on virtually any form of energy production.[11]

Nevertheless, BP expects China to import 40 percent of its natural gas requirements by 2035. This compares to their imports of 30 percent of consumption in 2015. If we accept the IEA projection for China's natural gas demand in 2035 at 468.9 Bcm, BP's expectation implies China's imports will reach 187 Bcm, compared to 59.8 Bcm in 2015. At the end of 2015, China had two import pipelines with combined capacity of 60 Bcm and 13 LNG regasification import facilities with combined capacity of about 46 Bcm (41.3 Mtpa). According to GIIGNL, there are eight additional regasification projects under construction with import capacity of 26 Bcm (24 Mtpa). This implies that existing and under-construction import capacity equals 132 Bcm. If we accept the BP–IEA-based projection of 187 Bcm imports for China in 2035, there must be additional investment in, and expansion of, import capacity equaling 55 Bcm. If all of this were to come in the form of LNG regasification, it would add just under 50 Mtpa of import capacity and increased demand.

There is much talk about pipeline imports to China from Russia, and there are two agreements between the countries and their respective national energy companies. Nevertheless, it is not likely that these projects will go forward any time soon. This is due at least in part to the current relatively low oil and natural gas prices and the negative effect this has had on Russia's export revenues that could be applied to natural gas field development and pipeline construction.

Australia

Australia has been part of the regional trade in natural gas since the Northwest Shelf Project (NWS) came online in 1989. The NWS is located in Western Australia about 1500 km north of Perth and has been expanded to five trains with a capacity of 16.3 Mtpa. The NWS project was followed by Darwin LNG, in the Northern Territory, and Pluto LNG, also in Western Australia, before several project consortia took final investment decision on seven new LNG export projects. The seven projects include Gorgon (15.6 Mtpa), Queensland Curtis LNG (QCLNG – 8.5 Mtpa), Gladstone LNG (GLNG – 7.8 Mtpa), Asia Pacific LNG (APLNG – 9.0 Mtpa), Wheatstone LNG (8.9 Mtpa), Ichthys LNG (8.4 Mtpa), and Prelude LNG (3.6 Mtpa).[12] When all projects are completed to planned full capacity, the ten LNG projects will constitute 85 Mtpa of export capacity. It was planned that all projects would be developed to full capacity by 2018, but several projects have announced slow-downs in the further development of trains in response to the low-price environment. Nevertheless, when all projects reach full capacity, Australia's LNG export capacity will exceed that for Qatar, the current largest exporter with 77 Mtpa.

Of the "new" seven, QCLNG, GLNG, APLNG, and Gorgon have all begun operation. QCLNG and GLNG began exports in 2015, and Gorgon and APLNG started operations in 2016. The three Queensland projects (QCLNG, GLNG, and APLNG) are each supplied with natural gas sourced from coal seams. These are the first LNG projects in the world to employ coal seam gas (also referred to as coal bed methane) as the feedstock for an LNG project. The Gorgon project, based in Western Australia is the largest LNG project in Australia history, with an estimated cost of US$54 billion.

The Prelude LNG project is led by Shell and will be a floating LNG (FLNG) liquefaction facility located offshore to the north of Western Australia. The floater is being constructed in South Korea.

Australia is already the largest exporter of natural gas within the Asia Pacific region, exporting 39.8 Bcm in 2015, all in the form of LNG. This represented nearly 60 percent of its production, and the share of production to be exported in the future is expected to increase. This is made possible by the relative size of its proved reserves to its domestic consumption. With a population of only about 24 million, there is not a large domestic draw on its resource base. From Tables 9.1 and 9.3, it is observed that Australia has a proved reserve base of natural gas equal to 3471.4 Bcm in 2015, with domestic consumption in that year of just 34.3 Bcm.

It is important to keep in mind, however, that Australia is a member of the Asia Pacific region being discussed. Thus, the imbalance identified between production and consumption in the region already includes all of these projects and their associated production, and it may include the assessment of BP and the IEA of potential expansions of existing projects and additions of new ones. So, while Australia will become the largest exporter of natural gas in the form of LNG, and most of the exports will be delivered within the Asia Pacific region, the shortfall identified will still have to be from outside the region via inter-regional trade.

Conclusion

The Asia Pacific region is a growing force in the markets for natural gas on a global scale. In the twenty-first century, it is expected to exhibit consumption growth at a higher rate than any other global region, with the exception of Africa. Asia Pacific's consumption will be second only to North America by then.

To meet this growth there will be a need for significant infrastructure investment both within and outside the region. This is because total global consumption of natural gas is expected to grow beyond just that in the Asia Pacific, and because the region is not capable of satisfying its own consumption demands with its own production. While the region is deemed to hold significant natural gas resources, which are identified as technically recoverable, there are concerns about the ability to produce these resources commercially.

The twenty-first century of natural gas is also likely to be the Asia Century. While virtually all member countries in the region will see substantial growth in consumption, and some with growth in production, the key players to watch appear to be Japan, China, and India for consumption, and Australia for production and exports.

Notes

1 Throughout this chapter the IEA projections discussed are drawn from the 2015 edition of the IEA's World Energy Outlook (International Energy Agency, 2015), and specifically the New Policies Scenario (NPS) outlook. The NPS projects are based on the assumption that all proposed energy policies will be implemented (albeit conservatively) and added to those policies officially in place as of mid-year 2015. BP also makes underlying assumption about the implementation of proposed energy policies beyond just those currently enacted in laws. These differ from outlooks by the Energy Information Administration in the USA, which is prohibited by law from assuming anything other than policies already enacted.

2 There are 35.3 cubic feet per cubic meter.

3 LNG (liquefied natural gas) is simply a transport phase for natural gas, and does not constitute a distinct commodity class. Natural gas (primarily methane) is cooled to −161 degrees Celsius, at which point it becomes a liquid. When liquefied in this manner the space required to contain the natural gas shrinks roughly 600 times while retaining it heat/energy content. It is this significant reduction in required space

that makes it economic to move natural gas in this form. Nevertheless, upon delivery the LNG is always re-gasified prior to use or injection into a pipeline system where it is comingled with other natural gas.

4 JCC is colloquially referred to as the Japanese Crude Cocktail, but it is actually Japanese Customs Cleared. The price of natural gas is linked to relative heat/energy content of natural gas to crude oil. An exact heat content linkage depends on the heat content of the average barrel of crude oil being imported into Japan. However, it is typically accepted that there are 5.8 million Btu (MMBtu) per barrel of crude oil. In this case, an exact conversion for the natural gas would call for multiplying the appropriate JCC price of crude oil by 0.1724 to arrive at the natural gas price per MMBtu. This multiple (as referred to as the slope factor) is an actively negotiated element of the long-term contracts, and it is typically assumed to be closer to 0.15, with some level of constant dollars and cents added. A version of this pricing formula that I estimated in the past is JCC × 0.1485 + 0.8, based on a regression analysis of Japanese crude oil prices and reported LNG delivered prices.

5 The contractual off-takers for the Sabine Pass LNG project are BG, GNF, GAIL, KOGAS, TOTAL, and Centrica. BG was first in the door, and has the lowest processing cost at US$2.25 per MMBtu.

6 The spot day rates vary according to the supply and demand for LNG tankers. The US$40,000 per day was in effect during September 2016. However, during a roughly five-year period the rate had been as high as US$130,000 and as low as US$30,000. At US$130,000 the shipping cost per MMBtu would be US$2.23 to Tokyo via Panama.

7 It is worth noting, however, that on a marginal cost recovery basis, which is relevant for already constructed and contracted facilities, there is still an incentive for off-takers to take delivery from Cheniere and ship even to Asia. In the example it is possible that the only marginal cost faced by, say BG, is the natural gas acquisition cost, which was US$3.59 per MMBtu. This is because the liquefaction fee is a demand charge (take-or-pay), which is a fixed cost. It is also potentially the case that the LNG tankers to be used will be on long-term contract, rather than spot terms, which is again a fixed cost. Under these conditions, there would then be a margin of US$2.11 per MMBtu, and this could then be allocated to cover at least a portion of the fixed costs.

8 The IEA World Energy Outlook 2015 reports TPED of natural gas as 567 Mtoe for the combined OECD Asia Oceania and Non-OECD Asia (International Energy Agency, 2015). Using BP conversion of 1.11 × Mtoe = Bcm results in 630 Bcm. The BP Statistical Review of World Energy for 2014 reports Asia Pacific consumption for 2013 at 575.2 Mtoe and 639.2 Bcm. However, BP updates these values in the 2016 Stat Review (BP, 2016b) to 610.5 Mtoe and 678.4 Bcm.

9 This assumes the 1000 MW nuclear plant runs at 90 percent of capacity over the year, and that simple cycle natural gas power plants are 38 percent thermally efficient. The 1.5 Mtpa of LNG equates to the 70,790,021 MMBtu of natural gas required to produce the comparable flow of electricity using simple cycle power plant.

10 www.world-nuclear.org/information-library/country-profiles/countries-g-n/japan-nuclear-power.aspx.

11 The more recent OPEC decision to constrain production is yet to send strong new investment signals to most of the world, so it is not clear how this may affect China's investment decisions regarding natural gas developments.

12 The capacities shown are planned full project capacities. Most of the projects are bringing on one a train at a time, and due to the relatively low-price environment some of the following trains are being delayed.

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