CHAPTER 5

Between the Old and New Worlds of Natural Gas Demand

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Introduction

Over the last 20 years, the natural gas industry landscape has been transforming from regional enclaves to a more global market. The long-distance transportation and storage of gas and the need to connect many customers via pipeline networks are not as straightforward as transporting, storing, and consuming liquids such as crude oil and refined products, or solids such as coal. Profitable investment in natural gas midstream and downstream infrastructure also benefits from a mix of customers (households, commercial and industrial facilities, and power plants) who can pay the full cost of delivering natural gas to their facilities.

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Hence, natural gas traditionally has been consumed within the region where it was produced, as long as someone invested in the gas infrastructure. That someone was often a state company dominating the gas value chain, that is, production and/or import of gas, pipeline networks, and delivery to end-users. Otherwise, private companies, mainly in the U.S., Canada, and Western Europe, were incentivized via regulatory constructs to build and operate midstream and downstream infrastructure. Many natural gas discoveries or even gas-heavy oil discoveries around the world were not developed because their monetization was very difficult, if not impossible, given the absence of state-owned or regulated private companies to develop the necessary—but very costly—midstream infrastructure (see Chap. 6 for a detailed discussion of commercial frameworks necessary for gas monetization).

The liberalization efforts in electricity and gas sectors across the world since the 1980s, albeit only partially successful in most cases, allowed for development of more gas resources and infrastructure, and induced competitive procurement of gas from competing producers but also via imports. Many countries became first-time producers, exporters, or importers of natural gas. In 2019, about 30 percent of global gas consumption was traded internationally as compared to about 23 percent in 2000 (BP 2020 Annual Statistical Review of Energy). There is a much larger number of exporters and importers across a wider geography. Although pipelines continue to account for more than half of global gas trade, the share of liquefied natural gas (LNG) has increased considerably in the twenty-first century; in 2019, the shares were roughly 62 percent pipeline and 38 percent LNG. Much LNG trade resolved regional dilemmas associated with pipelines (geopolitical or terrain). Longer pipelines can quickly become more expensive than LNG options. The growth in LNG trade has been at least partially driven by efforts to monetize "stranded" natural gas resources across the world, but most prominently in Qatar, Australia (coal-seam and conventional), and more recently the U.S. (shale gas). This strong supply-push has come at an opportune time: persistent high economic growth, especially in Asia-Pacific, led by China and followed by India and others.

High rates of economic growth driven by industrialization and the need to improve the standard of living of more than 3 billion low-income denizens of the world need strong support of reliable and affordable energy sources. While population growth, higher in lower-income countries, adds to this challenge constantly, energy needs of growing middle and upper classes are higher. After all, with more disposable income, people live in homes consuming more energy, travel more, and buy more energy-intensive products. Middle classes also demand lower pollution.

Natural gas has become an important option owing to several factors: (1) increased availability of abundant global natural gas resources via new discoveries and growth in LNG trade, (2) cleaner burning qualities of the fuel when compared to coal and some liquids, and (3) energy security enhancement of adding another fuel, from different providers than those supplying oil or coal to the energy portfolio of a growing economy. Still, the addition of natural gas to a country's energy portfolio and, in particular, growing its consumption has not been without issues.

This context inspired us to organize our chapter by pointing to a distinction between the Old World and New World of gas demand. The most obvious criterion is the evolution of gas demand centers. All analysts and observers expect most future demand for natural gas to come from faster growing economies in Asia-Pacific and, to a lesser extent but in aggregate potentially as significant, the Middle East, Africa, and Latin America (New World) rather than the U.S., Canada, and Western Europe (Old World) in the geographic sense. Obviously, this dichotomous approach is a simplification of the spectrum of countries that differ in terms of gas demand growth potential, gas market structures and liquidity, and role of government. Many fall in between the Old and New "extremes."[1] For example, while Russia can be easily classified as Old World in terms of established gas demand (since the 1960s) that is not expected to grow significantly, in terms of the dominant role of government and importance of gas exports to the Russian economy, it gravitates to our New World classification. In contrast, post-Soviet EU countries will likely see gas demand growth, and although the role of government will remain important, it will be tempered by EU membership requirements. In Asia-Pacific, Japan, and South Korea, although OECD members, will continue to have high government involvement to ensure energy security while decarbonizing. Accordingly, gas demand growth is still possible. Even in Australia, another OECD member, government policy may lead to gas demand growth to replace coal and as part of a pandemic-recovery stimulus program. To unravel our Old-New classification's multidimensional nature, we proceed in three distinct steps.

First, we look at the changes in geoeconomics of gas demand in recent years and in the future. We start with a comparison of major outlooks to identify commonalities and differences in assumptions that lead to significantly divergent scenarios. We then contrast historical and future policy and regulatory and infrastructure development trends across the world. This comparison highlights the rationale for our "Old World" versus "New World" classification. Within the latter, China is on its way to becoming the world's largest gas importer. India remains a laggard (only one-fifth of China's consumption), but it has large potential, somewhat supported by the growing investment in gas infrastructure. The post-Soviet bloc provides a great illustration of geopolitical implications of gas trade. The Middle East, a larger consumer of gas than Russia, will likely expand its consumption as part of industrial policies of key countries in the region, but perhaps at a much slower pace than the region experienced in the last decade. Latin America and Africa already consume nearly three times as much gas as India, but a few countries dominate consumption. In addition, there are significant differences across the countries in each region, including a variety of geopolitical and governance challenges. At the same time, gas demand growth everywhere—even in the Middle East—faces competition from renewable energy, coal, and nuclear. Finally, all of these considerations are influenced by the struggle for power among world's largest economies, which also present different visions of political organization and societal priorities.

Second, we look at changes in the commercial underpinnings of gas trade. We point to an increasing availability of LNG from a growing number of suppliers and rising interest of a growing number of countries in importing LNG, which has been made easier and cheaper by floating storage and regasification units (FSRUs). Contracts are more flexible in terms of length, ability to divert cargoes, pricing formulas, and more. Although these changes point to emergence of a global gas market, these conditions are not yet universal. A mix of practices coexists. In the New World, powerful state-owned enterprises (SOEs) and their governments are shaping these practices, raising questions about how liquid the global gas market really can become.

Third, we look at the importance of SOEs, which are instrumental to construction of sufficient natural gas infrastructure to support gas demand growth subject to energy security considerations. We see similarities between the role of SOEs and state in the New World and the beginnings of gas market development in North America and Western Europe where the state, if not SOEs, played an important role in developing the policy and regulatory conditions to facilitate gas infrastructure development. After all, a liquid gas market cannot exist in the absence of widespread gas pipeline and storage networks with sufficient spare capacity to balance regional and seasonal fluctuations in demand and supply. Although higher liquidity in the global LNG market has been inducing efforts to liberalize the gas sector in many countries, including China, India, and Central and Eastern European countries, SOEs remain important particularly where expensive domestic gas infrastructure still needs to be built to ensure sufficient and secure supply. Many of these markets are not attractive to private investors because the dominant role of SOEs and state's socioeconomic pricing policies undermine liberalization efforts.

In this sense, the trajectory of gas demand in the New World is likely to be a reflection of geoeconomic considerations on the part of both gas suppliers and consumers within the context of rising international competition for political power. This is why energy security and, in case of natural gas, security of supply have grown in importance. Countries will use different strategies to achieve their preferred energy mix. For natural gas, these strategies range from free-market alternatives to state-led, centrally planned undertakings and have a bearing on short- and long-term gas demand.

Where Are We and Where Are We Going: What Energy Outlooks Tell Us

Our distinction between the Old World and New World of gas demand lies at the intersection of energy consumption and access to gas resources. In the twenty-first century, the vast majority of economic growth has and will come from the New World. Natural gas has become an important part of the energy mix in many New World countries; and others are adding natural gas into their energy mix.

In Fig. 5.1, we graph future gas demand for different regions under a variety of scenarios produced by various entities. Our goal is to underline the trends and divergences across scenarios as inputs to our analysis. In particular, we want to question implicit assumptions behind some of these scenarios. Are countries capable of investing? Do they have sufficient access to funds? Do their SOEs have technical and managerial capabilities necessary to develop natural gas infrastructure? Can their market and institutional arrangements attract private investment? Can their consumers across various sectors pay the full cost of natural gas delivered to their premises? What are their energy security and environmental priorities? What alternatives do they have? Can renewables, coal, and/or nuclear meet their needs? What are their geopolitical considerations? And many more.

In recent years, there has been a transition in energy scenarios, including scenarios presented by oil and gas companies such as BP. It has become more common to see scenarios where global natural gas consumption peaks by 2030. The BP Energy Outlook released on September 15, 2020, is particularly interesting in terms of its significant shift from the company's 2019 Outlook. Most strikingly, the BP 2020 Net Zero scenario approaches the Greenpeace scenarios Stern describes in the Foreword to this book. Nevertheless, scenarios in Fig. 5.1, a mix of business-as-usual and climate scenarios, corroborate Stern's conclusions that natural gas demand will continue to rise in the New World, led by China and non-OECD Asia, while it remains flat (the U.S. and Russia) or declines in the Old World. In China and India, even BP 2020 and the Equinor Renewal scenarios call for higher gas consumption in 2050 than in 2020.

Still the difference between BP 2019 Rapid Transition and BP 2020 (Rapid) scenarios for India is striking. After all, India has been investing in long-term projects such as LNG import terminals and pipeline networks and pursuing policies to switch industries and cities to gas and to encourage domestic exploration and production (E&P). Importantly, scenarios such as the BP 2020 Net Zero represent what needs to happen in order to achieve a climate target rather than the lack of natural gas' cost competitiveness, which often drives reference scenarios. As such, the value various governments attach to their energy security and economic and human development versus the value they attach to complying with international climate agreements is a critical consideration.

In this context, of interest is the relatively more bullish outlook of the Institute for Energy Economics of Japan (IEEJ). Given Japan's dependence on imports for majority of its energy needs, it is instructive to observe this industrialized economy seeking its energy security in nuclear and imported gas and coal rather than relying on renewables exclusively. The IEEJ scenarios probably reflect this experience. IEEJ expects gas demand to rise significantly in Africa, the Middle East, and Latin America (not shown in Fig. 5.1) as well. Under certain scenarios, aggregate gas demand growth in the Middle East, Africa, Latin America, and Eastern Europe and Eurasia can be as high as demand growth in Asia-Pacific. We tend to lean toward these more bullish outlooks driven by energy-secure economic and human development goals of most New World countries. Importantly, there will be many willing suppliers of gas within the New

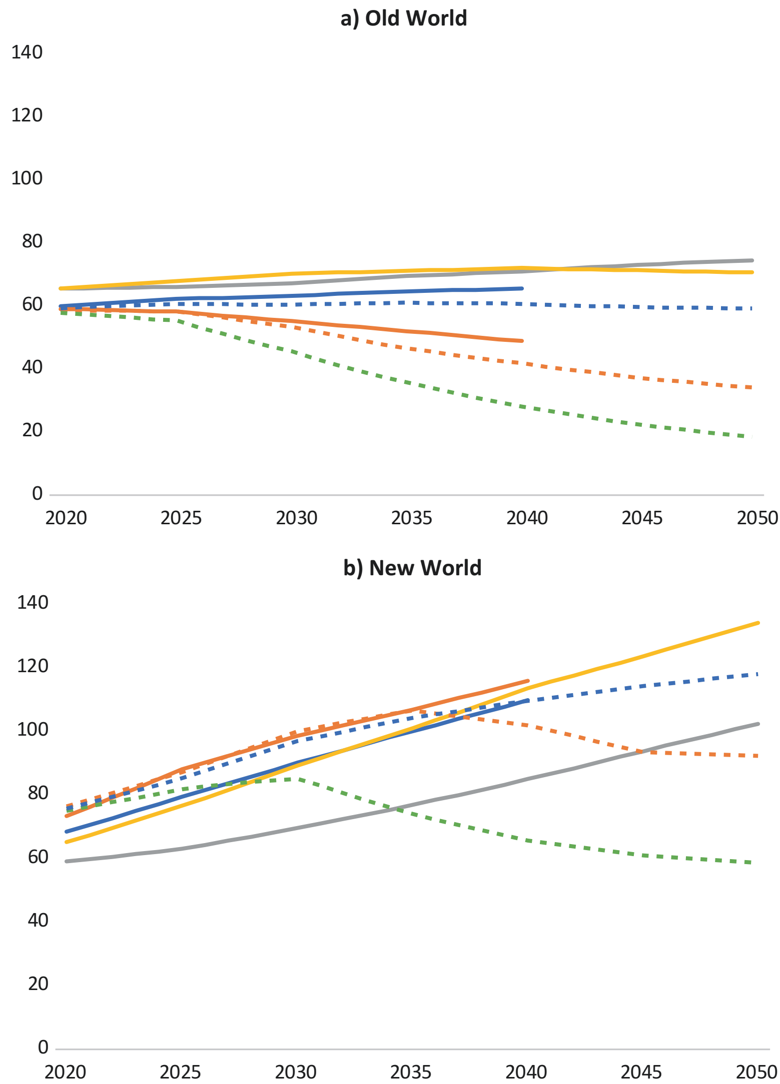
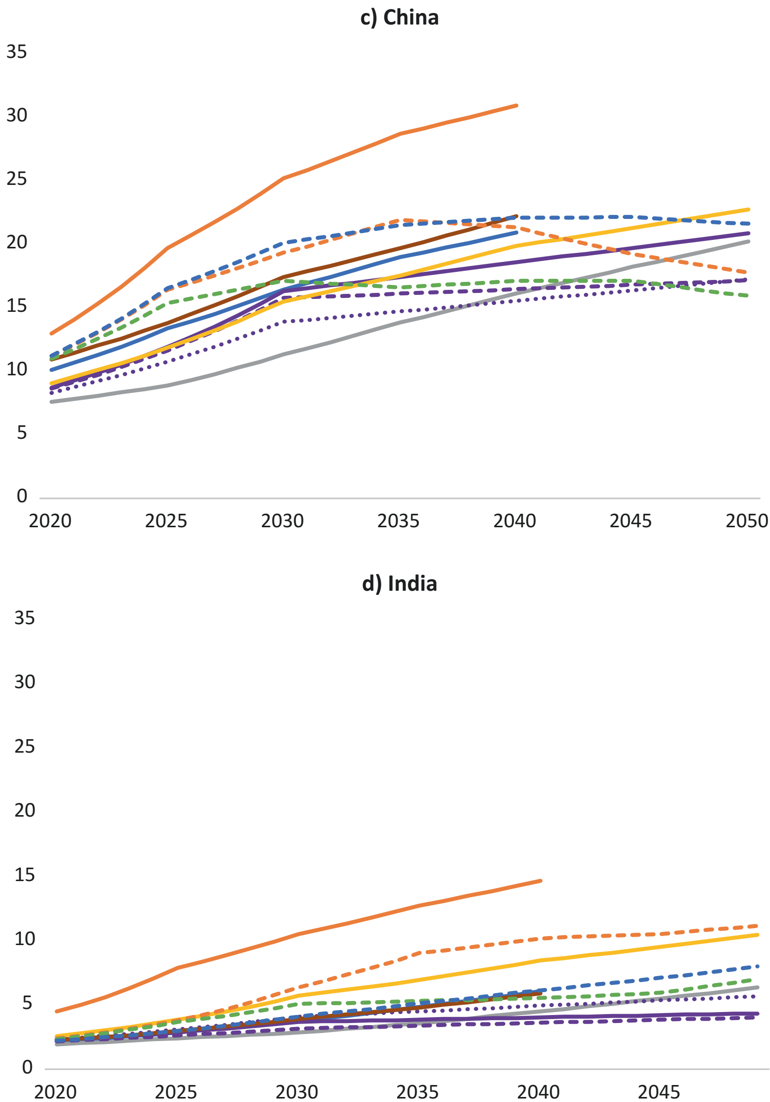


Fig. 5.1 Natural gas consumption scenarios (Quadrillion Btu, 2020–2050). (Sources: Compiled by the authors using data from RFF Global Energy Outlook 2020 and BP Energy Outlook 2020. Quadrillion Btu is roughly equivalent to a trillion cubic feet. The regional coverage of various outlooks varies and is not granular at a country level. Still, we are able to approximate our Old World as the U.S., Europe, and Eurasia/Russia and New World as the rest of the world). Since no scenario envisions gas demand growth in Russia, its inclusion in the Old World does not influence the contrast between Old and New Worlds. In addition to variation of regional definitions, 2020 values differ across scenarios also because different base years lead to different 2020 forecasts)

(*continued*)



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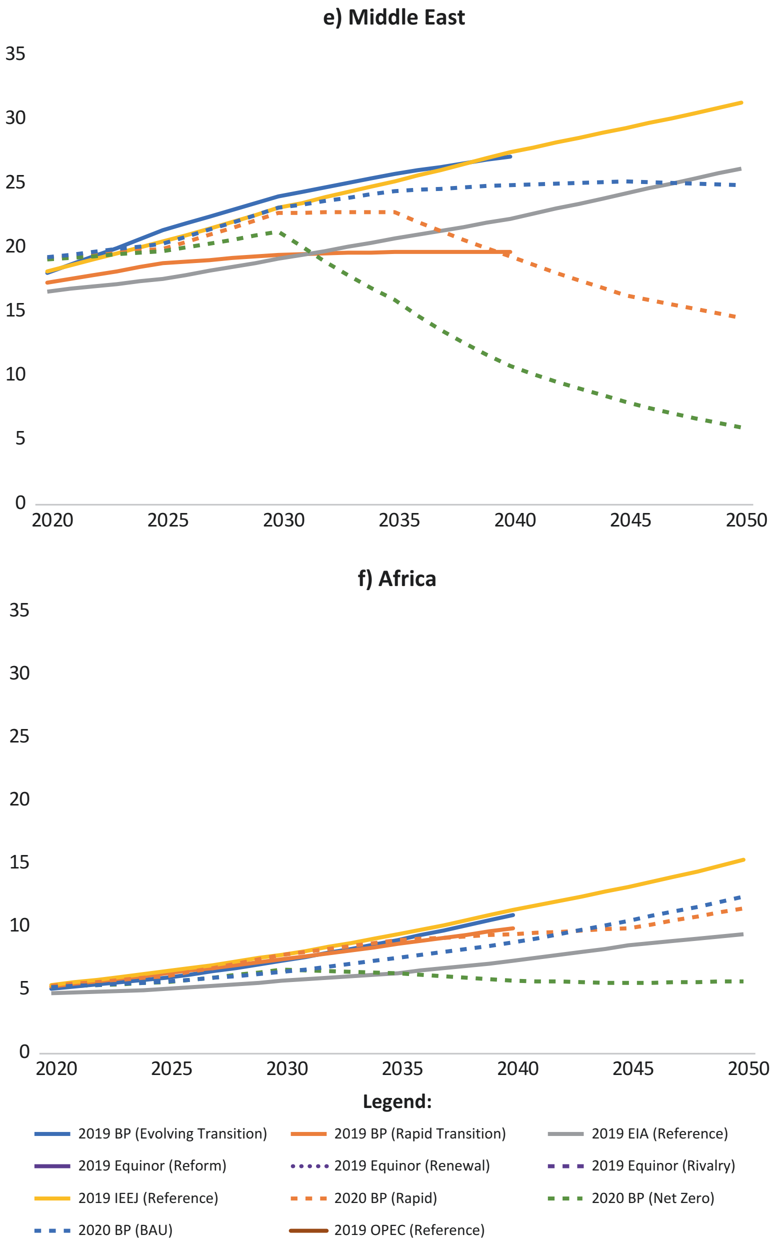

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World. Worth noting is also that gas demand growth will help reduce local pollution and greenhouse gas (GHG) emissions to the extent gas replaces coal, common in most of the New World countries. This view also is informed by the discussion of energy trends, to which we now turn.

Geoeconomics of Old and New Natural Gas Demand

The U.S. and the Soviet Union were the only major consumers of natural gas before the 1970s. Starting in the 1960s, Western Europe began to monetize its domestic gas discoveries and to increase imports. Japan started to consume natural gas, thanks to LNG imports from Alaska that started in 1969. Japan's goal was not only to support the country's economy but also to enhance energy security in this industrialized island nation that lacks domestic natural resources. LNG imports allowed Japan to diversify—mostly in power generation—away from Middle Eastern oil perceived as increasingly risky given the 1973 and 1979 oil shocks. Other countries such as South Korea, Taiwan, and some European countries joined Japan in importing LNG on similar premises. Today, the Old World and Russia still represent more than half of the global gas consumption, while China-dominated Asia-Pacific is responsible for about 22 percent of global consumption. Gas consumption has been shifting from the Old World to the New World and will continue to do so. Geoeconomics will influence the pace and nature of this transition.

North America

The U.S. has been consuming natural gas since the early nineteenth century and accounted for majority of demand growth up to the mid-twentieth century. Over time, the U.S. market has been joined by Canada, and later by Mexico, to form a North American demand center. Still, the U.S. has remained the largest consumer of natural gas globally by a wide margin. Domestic availability of gas helped create and sustain demand. Periodic shortages in supply deliverability, usually policy induced, provided impetus for imports mainly by pipeline from Canada and briefly via LNG. Growth in surplus associated methane from shale oil and liquids production and rapid conversion of existing LNG import facilities led to the U.S. taking a new position as a significant natural gas exporter. The Appendix and Chaps. 1–4 of this book provide details on the U.S. and North American gas marketplace, including the evolution of natural gas supply and impact of shale plays, gas use in power generation (40 percent of total gas delivered to consumers), industrial sector (30 percent), and LNG exports, as well as policy and regulatory shifts.

Russia and Two Europes

Russia (and earlier the Soviet Union) is world's second largest gas consumer with more than half as much consumption as the U.S. In 2019, gas constituted approximately 53 percent of total energy consumption in Russia, used mostly for power generation (46 percent share of total generation), space heating, and industry (BP Statistical Review of World Energy 2020). Given low, regulated prices, domestic gas has been competitive against coal.

As in the U.S., the origin of gas demand in Russia is rooted in the availability of domestic supply, initially as a byproduct of oil. However, for the Soviet Union, natural gas development did not start until the mid-twentieth century. Afterward, production soared, bringing natural gas to major Soviet cities, including Moscow and Leningrad. Just slightly later, gas reached Nizhniy Novgorod or Cherepovets as well as the Baltic Republics.

The centrally planned economy of the Soviet Union has not allowed for development of a gas market. Moreover, development of gas fields remained secondary to both development of crude oil and military goals of the Soviet Union. Despite high resource endowment, the natural gas industry lagged behind in its ability to provide sufficient supply until supported by a strong demand-pull from Western Europe associated with transfer of technology and pipelines. After the collapse of the Soviet Union, a newly created company, Gazprom, took over the role of the Soviet Gas Ministry. The close connection between Gazprom and the Russian state was formalized in 2005, when the Russian state became majority shareholder.

Gazprom still controls the majority of Russian gas reserves and the entire Russian gas pipeline infrastructure, known as Unified Gas Supply System (UGSS). Until recently, the company had monopoly over all gas exports. It still continues to control all Russian gas exports via pipeline. However, privileges rarely come without a price. In case of Gazprom, the price is in the company's domestic obligations, with gas considered a societal rather than a market good. Within this framework, Gazprom's role is to support Russia's economy and government's social policies rather than making a profit. The company has been obligated to sell gas to domestic consumers at regulated prices that only recently have become closer to export netback prices.[2] In addition, Gazprom is considered a supplier of last resort in situations where consumers (private, institutional, or industrial) are unable to pay their bills.[3] Take, for example, the 2009–2010 worldwide economic recession when many Russian natural gas users were unable to cover costs of gas use. Gazprom effectively financed these customers, which propped the Russian economy by contributing to ability of companies to survive the crisis (Loe 2019).

Attempts at liberalizing Russian gas market have not been successful due to strong pushback against deregulated prices (OIES 2020). Trading gas at the Saint Petersburg International Mercantile Exchange (SPIMEX) has had limited impact because there are significant limits to secondary trading of purchased gas (Henderson 2011). In addition, companies that fail to consume the volumes of gas they purchased on SPIMEX face contractual penalties from Gazprom. Importantly, the latter continues to own the UGSS with only limited third-party access.[4]

Given these constraints, domestic Russian gas consumption, while sizable, has not resulted in substantial monetization of gas within the domestic market. Moreover, while the track record on monetization via gas exports has been better, the history of trade with Europe points to important non-monetary goals of this trade.

Here it is useful to make a distinction related to European demand. We have become accustomed to treating most members of the European Union (EU) similarly. However, when it comes to natural gas demand and Russian gas imports, a significant distinction persists between Western European countries and their counterparts from the former Soviet bloc.

Western European demand has been incentivized by domestically available supplies (predominantly North Sea and the Groningen field) and expanded on the heels of the 1970s oil shocks and concerns about energy security. By that time, the Soviet gas industry already was invested in promoting Russian natural gas exports to Europe. This supply-push was predicated upon significant discoveries of gas in Western Siberia. In this case, however, the motivation for exports has been amplified by the shortcomings of the Soviet industrial system. To develop its gas and expand its reach (even domestically), the Soviet Union needed significant additions of high-quality pipeline and compression. As a result, the first Soviet gas exports were effectively structured as more or less a "barter deal" in which natural gas was exchanged for pipeline and technology. The gas price was oil-indexed to reflect gas value as a substitute for fuel oil in the European economy.

Despite the Cold War, Western Europe has seen gas trade with the Soviet Union as less of a danger to energy security than reliance on Middle East oil. The underlying reason: a gas pipeline between points A and B creates interdependency between the supplier and the consumer. As European gas development stagnated and fell behind demand growth, Soviet gas became an increasingly important part of the West European energy consumption. For the Soviet Union and later for Russia, Europe has become an important export market: oil and gas export revenues constituted just over 40 percent of Russia's federal budget revenues in 2019 and closer to 50 percent in years prior (Yermakov and Henderson 2020). Oil indexation of gas exports contributed to the growing importance of gas as a source of Russia's income but also exposed the risks associated with oil price collapses in 2015–16 and 2020.

Common dependency made for rather uneventful, commercially driven relationship where Western European gas and utility companies collaborated with Gazprom on a variety of projects. Significant geopolitical issues and breaks in gas supply have not occurred until after the Iron Curtain fell, exposing the rifts in policy goals between Russia and the post-Soviet world and underlining the differences in motivations behind Russian gas exports to Western Europe versus those flowing to the post-Soviet bloc.[5]

Only Ukraine and Romania have had significant domestic natural gas supply. Ukraine's reserves were exploited to a large degree during the Soviet era: Ukraine was the initial source of Soviet gas supply before the center of gas development moved to Western Siberia. As noted by Mikulska and Kosinski (2020), despite attempts to revive Ukrainian gas production to produce more gas, including for export, there is not much to show for it at this time. Domestic gas production in 2019 reached 20.7 billion cubic meters (bcm) supporting approximately 70 percent of Ukraine's total gas demand that year (29.8 bcm). Romanian gas still satisfies most of that country's domestic demand, and new developments are under way, though admittedly not without challenges (Visenesc and Bartelet 2017; Reuters 2020a). Gas demand in other post-Soviet states was developed because of their communist relationship with the Soviet Union. Russia would be a source of majority, if not entire, supply of gas to those territories. The gas was often provided as barter for other products (industrial, agricultural) or was supplied at a very low price (compared to gas exported to Western Europe) to reflect the communist bond.

As such, gas was a tool of geopolitics in the region from the beginning. Post-1990 Russia has used this tool to influence politics in Eastern Europe and the Caucasus region. The 2006 and 2009 spats with Ukraine were most severe and resulted in disruptions to gas supply to Western Europe. Gas also was important in Russia's relations with Armenia and Georgia, and the latter's support for oil and gas pipelines from Azerbaijan to Turkey to avoid Armenia as a transit country. The Trans-Anatolian pipeline plays an important role in diversifying gas supplies for Turkey but also Southeast Europe via the recent Trans-Adriatic pipeline.

Diversification has become an important element of gas market strategy in that region (Hinchey and Mikulska 2017; Swora and Mikulska 2017) as Gazprom has been known to take advantage of its dominant position in post-Soviet gas markets. Gazprom has done so both, in terms of geopolitical influence and economically (by setting high prices) (Michot Foss and Palmer-Huggins 2016; Collins 2017; Newnham 2011). Many countries, including but not limited to Poland, Lithuania, and Croatia, have been investing, with the help of the EU, considerable resources to build LNG import terminals and new pipelines to improve connectivity and allow for better balancing of the gas market domestically and at the regional level.

Changing realities of natural gas trade combined with diversification efforts and EU competition authorities looking into specific trade agreements also have caused Gazprom to take a more market-oriented stance in the region by amending many of its long-term contracts and introducing lower pricing, hub-indexing, and lower take-or-pay commitments. Given a troubled past and lack of mutual trust, energy security and geopolitical risk play important roles in post-Soviet calculus when it comes to Russian gas supplies. As a result, some countries seem to be willing to pay a premium for non-Russian gas, with Poland being an extreme example as it seeks to eliminate long-term contracts with Russia altogether.

These developments have implications for monetization of non-Russian gas. Many of the long-term contracts between Russia and post-Soviet countries are slated to expire in the 2020s. As such, these countries present an opportunity for non-Russian suppliers to enter the market where Russian gas would be otherwise too competitive to push out. In a way, this avenue signifies new and growing demand source for non-Russian supplies, even if gas demand in those countries holds steady or declines. On the other hand, Russian gas reaching the European market via existing and new pipelines such as the Turkish Stream and Nord Stream 2 (as this book was completed, Nord Stream 2 was still not finished) may still find its way to these markets. Landlocked countries such as Hungary, Slovakia, Serbia, and the Czech Republic cannot import LNG directly. Direct LNG imports are also difficult for Romania, Bulgaria, or Ukraine due to the need for LNG ships to go through the Turkish Straits, possibility of which has been keenly rejected by Turkey. But as long as Russian gas is pooled in a liquid European market with access to a wide range of global resources and well-connected pipeline network, energy security of importers will be enhanced as compared to sole dependence on Russian gas from a direct pipeline (Collins and Mikulska 2018; Collins and Mikulska 2020).

From the perspective of gas monetization, it is worth noting that many of the post-Soviet countries are experiencing high levels of economic growth relative to developed economies in Western Europe. This is likely to incentivize higher energy demand, including higher demand for natural gas. The latter, actually, could be a result of EU decarbonization policies. Even though in Western European countries those policies also target natural gas as a fossil fuel and source of greenhouse gas (GHG) emissions, in Eastern Europe the same policies can actually enable natural gas demand as the most viable alternative to coal, which supplies a good portion of domestic energy demand.[6]

Asia-Pacific

Japan used to dominate discussions about Asia-Pacific natural gas, even though in the 1970s, China consumed nearly as much. Unlike Japan, Chinese consumption was satisfied with domestically produced natural gas. During the 1980s, Australia, Indonesia, Pakistan, Malaysia, Thailand, and Bangladesh either increased or started producing and consuming significant amounts of natural gas, with some of these countries becoming large exporters. By the mid-1990s, Indonesia and Malaysia were responsible for half of global LNG exports, with Australia representing more than 10 percent. Around the same time, Japan accounted for about two-thirds of global LNG imports. At the time, global LNG trade was about one-fifth of what it is today.

Japan's initiation of LNG imports from Alaska, Brunei, and Indonesia in the 1970s was driven by that country's desire to improve its energy security and to reduce air pollution. Home to one of the world's largest economies, Japan has always depended on energy imports because the country lacks oil, natural gas, and coal resource endowments. Switching power generation from imported (mostly Middle Eastern) oil to natural gas (LNG) helped Japan's energy security by diversifying its energy portfolio in terms of both type of fuel used and countries of origin. LNG facilities were built mostly by Japanese utilities since the 1960s. Government policy, financial assistance (e.g., to power companies to switch to gas), and price regulation allowed for cost recovery.

Energy security considerations have also been important for Japan's decision to heavily invest in nuclear power. After the closure of nuclear plants following the Fukushima disaster, LNG imports, enabled by the existence of import terminals, prevented a major energy shortage. This demonstrated the option value of these assets. To increase its options further, Japan also increased subsidies for solar generation that reached 7.5 percent of total generation, roughly equal to hydropower. At the same time, coal-fired generation still provided about 30 percent of country's electricity needs, which underlines the importance of cost for global competitiveness, even for a highly developed economy. After Fukushima, coal often provided a cheaper alternative to nuclear power than LNG. To avoid potential overreliance on coal and/or LNG, Japan is in the process of restarting its nuclear power fleet, albeit slowly, as it continues to consider nuclear as the cheapest option to provide the reliable energy its industrial economy needs. Increasing nuclear generation also helps with lowering emissions and improving its trade balance. Nuclear is also central to new ambitions for hydrogen production. A recent pledge by Japan to be carbon neutral by 2050 may instigate early retirement of certain coal plants, which may benefit gas and renewables (e.g., McCracken 2020).

Today, Japan remains the world's largest LNG importer accounting for roughly 22 percent of LNG imports, followed by China (17 percent), South Korea (11 percent), India (7 percent), and Taiwan (5 percent). In other words, the Pacific Basin still dominates global LNG trade and is likely to do so, given the projections for gas demand growth in the region.

In South Korea, growth in gas demand will most likely come from phasing out coal-fired power plants, which currently generate more than 40 percent of electricity. In early 2019, the government reduced the LNG fuel tax by 75 percent while increasing the coal fuel tax 28 percent, resulting in the coal fuel tax being twice as large (Global Gas Report 2020). Assuming that LNG prices remain cheap relative to substitutes, this will encourage more coal-to-gas switching. However, long-term sustainability of switching will remain dependent on various factors, including (1) government policies on further taxation of pollution (coal), (2) the price of oil (to which most LNG coming to South Korea is indexed), and (3) LNG import arrangement (share of short-term and spot cargoes relative to long-term oil-indexed supply). Nuclear power could also be a significant competitor to natural gas, as South Korea is a leading nuclear technology developer and exporter. The share of nuclear generation has been increasing, supplying 26 percent of electricity in 2019. There are four plants under construction. In 2017, the new president announced plans to phase nuclear out by 2060 or so, which contributed to cancellation of plans for several new nuclear plants. Combined with policies to improve air quality, a moratorium on new nuclear capacity will likely increase LNG demand further over the next couple of decades.

As opposed to natural gas-poor Japan and South Korea, Indonesia and Malaysia used to be the major LNG exporters. Even today, they account for only about 16 percent of global LNG exports. More strikingly, they also import LNG due to declining reserves, increasing domestic demand, and difficulty of connecting different regions of these countries given the numerous islands and challenging terrain.[7] In these countries, power generation, industrial (fertilizer), and, to a lesser extent, transport sectors drive natural gas demand. Similar forces are pushing self-sufficient consumers of the past such as Pakistan, Bangladesh, and Thailand to become LNG importers. Power generation is often the key driver of demand, but fertilizer and light industries, as well as widespread use of compressed natural gas (CNG) in transport, also are important. Vietnam and other small economies in the region are following suit.

The single biggest player in Asia-Pacific is, of course, China. The country is currently consuming nearly 8 percent of global gas (compared to 22 percent for the U.S., 14 percent for Europe, and 11 percent for Russia) while producing more than 4 percent (still, more than Australia, the second largest producer in the region). China's natural gas infrastructure mostly has been shaped by long-term policies rooted primarily in energy security considerations. Industrial sector (mainly petrochemicals) drives demand growth, but power generation, city distribution networks to serve smaller customers, and the transport sector also contribute. Today, however, pressures from China's growing middle class to reduce urban air pollution are propelling coal-to-gas and liquids-to-gas switching. China has the world's largest LNG-fueled truck fleet, while the country prefers electric drive for smaller vehicles. Since 2010, Chinese gas demand grew at an annual average of 12 percent, while domestic production grew only at 7 percent. The expanding gap was balanced with pipeline and LNG imports, which grew at 34 percent per year since 2015 as compared to a steady 18 percent for pipelines.

China built a dual gas pipeline from Turkmenistan via Uzbekistan and Kazakhstan to the Chinese border (each about 1800 km) and then invested in pipelines for delivering that gas to the consumption centers in the east. Private companies could not commercially justify such a pipeline, especially given the geopolitical risks. Similarly, pipelines from Myanmar and Russia (Power of Siberia) would have not been built without state (SOE) involvement and public funds. China's national oil companies (NOCs) have built most of the 22 LNG terminals currently operating, and more are under construction, with private companies starting to play a more dominant role. Overall, the country has substantial capacity across the natural gas value chain, albeit still insufficient to balance growing demand and supply smoothly across the country throughout the year. Thus, investment in gas infrastructure continues to be needed. In essence, China, via its SOEs (some owned by local governments), has been investing in real options that give the country flexibility to switch between fuels and suppliers to meet its energy needs at lowest cost, essential for energy and economic security. Increasingly, private companies are entering the fray by building LNG import terminals and trading gas, encouraged by some reforms such as the creation of an independent midstream company that will provide open access to pipelines.

India has the potential to be a second China in terms of fast-growing natural gas demand. Growing population, hazardous air pollution in major cities, and increasing demands of a growing middle class for less pollution are pushing the country toward gas use in industry (India's largest consumer of gas in 2019), transportation, and buildings (commercial and residential). Unlike China, however, Indian public funding and SOEs are not as capable of building gas infrastructure capacity. Pricing and regulatory frameworks have not been conducive to private investment in domestic E&P or midstream. As such, insufficient domestic infrastructure has been more of a constraint on gas demand growth in India than in China. There are only six LNG import terminals and about 17,000 km of transmission pipelines. There also are external challenges to pipeline gas imports. The geography and geopolitics of the South Asian region has prevented several pipeline projects (from Iran and Turkmenistan via Pakistan and Afghanistan), and high cost has been a handicap for others (underwater pipeline from the Middle East).

Therefore, when it comes to gas as India's energy security enhancement, much will depend on LNG imports, which currently meet more than half of India's gas consumption. India's government plans to add more than ten LNG terminals (including FSRUs). It will also expand its pipeline infrastructure from 17,000 to approximately 32,000 km in the next few years, per India's oil minister Dharmendra Pradhan (Srivastava 2020). Most important, affordability of natural gas remains a major challenge in India, especially for the fertilizer industry and urban users, which historically used cheaper, often subsidized, fuels.

It is significant that gas-fired generation has not been able to reduce the role of coal in Indian power generation. In fact, gas-fired generation peaked at less than 120 terawatt-hours (TWh) in 2010 and has been stable at about 70 TWh since 2011. In contrast, coal-fired generation increased from 640 TWh in 2010 to 1170 TWh in 2018. India has plans to gasify 100 million tons of thermal coal (roughly 14 percent of 2019 production). Although details are unclear at this time, Coal India Ltd. is indicating up to $55 billion investment in gasification and liquefaction (for fertilizer production) by 2030. Given the importance of coal to local communities and Indian economy, these plans cannot be ruled out as too expensive or inconsistent with environmental goals. Still, gas is promoted by the Indian government among other alternatives, especially in fertilizer, city distribution networks, and transportation (CNG), with a goal of 15 percent share of the energy mix for gas in 2030. In November 2020, Prime Minister Modi increased this target to 25 percent. A great deal depends on the implementation of reforms the Indian government announced in 2020, which, besides development of midstream infrastructure, also promise market-driven gas pricing to encourage domestic and foreign investment along the gas supply chain (Srivastava 2020).

Middle East

Gas consumption in the Middle East has been increasing pursuant to a strategy of oil-to-gas switching and industrialization over the 2010s, but demand growth may slow within a decade. Mills (2020) predicts "improved efficiency, higher gas prices, slower economic growth and alternative generation" to drive this slowdown.

The region consumes about 14 percent of global gas (similar to Europe or Russia, and nearly ten times as much as India), but 40 percent of this consumption occurs in Iran and another 20 percent in Saudi Arabia. Due to years of sanctions, Iran has not been able to export much gas, except to Turkey and Iraq, via pipelines. The use of gas instead of oil or refined products also allows the country to export more liquids and generate more hard currency. Similar strategies are being followed by other major oil exporters in the region, including Saudi Arabia and UAE.

With significant gas reserves in the region (roughly 20 percent of global proved reserves) and demand expected to grow further (Fig. 5.1), more upstream, midstream, and downstream gas investment is already under way or planned to increase both domestic consumption and exports. That being said, difficult relations between Qatar, region's largest LNG exporters, and Saudi Arabia (and other Gulf Cooperation Council, or GCC, countries), have so far resulted in very sparse intraregional pipeline infrastructure. Indeed, regional tensions and rivalries have prevented pipeline gas trade in a region that should be one of the more conducive to cross-border exchanges (a similar pattern is in place in South America, as we note later). In addition, gas faces competition from renewable energy, nuclear, and coal. (The BP scenarios in Fig. 5.1 reflect the potential impact of this competition.) For example, the UAE, where gas used to provide all power generation in the past, plans to reduce the share of gas to 38 percent of installed capacity by 2050. Renewables are forecast to constitute 44 percent, nuclear 6 percent, and coal 12 percent of power generation. The first nuclear plant of nearly 6 GW of capacity in the UAE started generating from one completed unit in August 2020, while the construction of other units continues. Surprisingly, Dubai is building the second-largest coal-fired power plant in the region (3.6 GW of planned capacity). These choices reflect energy security concerns within the context of difficult relations with Qatar and Iran (Krane 2020).

Another challenge is the potential increase in the cost of gas. Historically, most gas in the region has been associated with oil (hence very low cost), and consumers have been paying very low prices set by governments. Low oil prices since 2015 have strained government budgets and subsidies have been cut, though not fully eliminated. Gas prices also have been rising partially to justify new gas resource development (e.g., see Mills 2020). Higher prices raise concerns about economic competitiveness, but governments seem to be focused on improving efficiency (e.g., switching to combined-cycle power generation from combustion turbines) rather than reinstating significant end-user subsidies. Instead, governments focus on developing major petrochemical and other industrial capabilities (e.g., see Benali and Al-Ashmawy 2020).

Latin America

Latin America is not a major consumer of natural gas (only 4 percent of global total). The region is home to significant resources that remain mostly underdeveloped. Long-standing regional tensions and rivalries, including territorial conflicts, have limited the growth of cross-border pipelines for natural gas trade. For example, Bolivia, a landlocked country with sizable reserves, has been exporting gas to Argentina and Brazil, but the volumes fluctuated, depending on the performance of the volatile economies of Argentina and, to a lesser extent, Brazil. More importantly, those countries' ability to meet their energy needs from alternative resources undermined Bolivian exports. For instance, high hydroelectricity (wet) years in Brazil reduce the need for gas-fired generation. Also, both Brazil and Argentina have their own gas resources and ability to import LNG. Argentina, already the largest consumer of gas in the region, likely will increase its self-sufficiency with the development of unconventional resources in Vaca Muerta, which is being targeted by the government as part of a stimulus plan (e.g., see Braga 2020), but high cost of production and transportation from remote location of resources remains a challenge.

Argentina resumed exports to Chile after cutting them during the economic crisis of the mid-2000s to provide subsidize gas to its citizens, which reduced upstream development. Today, domestic demand once again trumps exports to Chile, which is encouraged to expand its LNG import capacity to enhance its energy security. Brazil also could achieve self-sufficiency with associated gas from its giant pre-salt fields. With solutions to technical challenges, Brazil could satisfy domestic demand as well as export LNG.[8] The historical animosity between Bolivia and Chile prevented Bolivian gas exports to Chile as well as Bolivian gas being exported to other countries via a liquefaction facility in Chile. Peru LNG was the catalyst that allowed the development of the Camisea field and eliminated the Peru option for Bolivian exports. This long history of unstable exports to Brazil and Argentina and the lack of upstream investment in Bolivia due to unattractive fiscal regime, high political risk, and low domestic demand led to a decline in reserves and production in Bolivia.

Peru and Colombia, though smaller consumers, are the only two countries that have seen stable growth in gas demand since the Great Recession of 2008. In both countries, use of natural gas in vehicles has been significant. Bolivia, already doing the same, may increase gasification of its transport sector as its export volumes to Argentina and Brazil decline. Although there are many uncertainties in this historically volatile—politically and economically—region, availability of large natural gas resources and production history induces us to favor outlooks that foresee at least 50 percent increase in gas demand over the next 20 years.

Africa

Africa, as ever, is promising. With nearly a billion people, mostly in sub-Saharan Africa (SSA), the continent has the largest concentration of people without access to modern energy, which makes elimination of massive poverty with all the attendant ills even more difficult. This situation is paradoxical since many countries have large oil and gas resources: Nigeria, Angola, Egypt, and Algeria. Africa is also home to emerging producers such as Cameroon, Mauritania, Senegal, Mozambique, Tanzania, and Ghana. Only a few countries such as Algeria and Egypt have been able to monetize their resources via pipeline and LNG exports as well as domestic use, mainly for power generation.

In contrast, Nigeria has the largest gas reserves in Africa. However, the only monetization occurs through LNG exports, which is set to expand as *Nigeria LNG* decided to add a seventh liquefaction train and has plans to add more trains. Otherwise, the country has not been able to develop most of its gas. Notably, Nigeria has been unable to monetize associated gas, which ends up being flared. There are many reasons for this failure, including the terms of legacy upstream contracts that do not ban flaring, incumbent interests in the power generation sector, and other, mostly political, considerations. Importantly, the gas-power value chain is broken; electricity prices are set by the government, often below cost; and many customers do not pay their bills, which creates a domino effect: distribution utilities cannot pay the transmission company, which, in turn, cannot pay private generators, which, then, are unwilling to commit to long-term contracts with gas suppliers.

Ultimately, the inability to finance and develop domestic gas and electric power infrastructure has been a major impediment. Nigeria, with a population of roughly 200 million, has less than 15 GW of installed generation capacity and only a fraction of this capacity is able to dispatch consistently due to infrastructure bottlenecks. Over 80 percent of Nigeria's estimated peak electricity demand is met by off-grid electricity generation, often fueled by diesel. The long-awaited Petroleum Industry Bill, which was submitted to Nigeria's National Assembly at the end of September 2020, may address some of the legal and regulatory gaps when it is finally enacted. There are parallel initiatives in the power sector to increase generation and transmission capacity (Goodrich 2020). In the meantime, smaller-scale projects of delivering gas by private investors are moving forward despite the difficulties, driven by the desire to replace expensive diesel. They include expansion of local gas distribution systems, small-scale LNG distribution to business and industrial customers, and CNG projects. Although important, these initiatives only add up to several hundred miles of pipelines and several hundred million cubic feet a day of gas consumption. Much more is needed for Nigeria to use its natural gas to lift its population out of poverty.

Corruption has been the main culprit in SSA, causing massive deficiencies in institutional and governance infrastructure. Nevertheless, there is a renewed hope and homegrown movements to improve the politics and institutions to allow for better governance. A key target of these efforts is to develop continent's natural gas resources for domestic use in power generation and industry to create value added for the economies in the region. Many outlooks predict gas demand to double by 2040, but we must acknowledge significant upside and downside to this scenario, dependent on African countries' performance in eliminating institutional and governance inadequacies and both internal and regional political risks.

Between Coal and a Sunny Place

Given the growing focus on energy transition around the world, it is worth expanding on the energy mix considerations in various geographies and, in particular, how natural gas fits into this transition.

Coal has been prevalent in many of the New World countries. For example, coal consumption nearly tripled in China between the late 1990s and mid-2010s, before stabilizing. Similarly, coal consumption in India tripled between the late 1990s and 2019. Other countries, mostly in Asia-Pacific, also increased their coal consumption. As a result, despite the declining consumption in the Old World, world coal consumption has remained stable since the early 2010s. Coal is used primarily to generate electricity and in heat-intensive industries such as steel. Over the years, these heavy industries migrated to the New World. In particular, metallurgical coal is difficult to eliminate in heavy industries because of its high heat content. In contrast, very little coal is used for space heating, mostly in China, which is expanding gas distribution networks to eliminate household and commercial use of coal and, in doing so, improve urban air quality.

In general, two factors are responsible for coal's decline in the Old World: (1) increasing availability of natural gas and renewables, and (2) policy. The ability of people to pay for potentially more expensive but less polluting energy sources can affect both of these factors. Indeed, as discussed in Chap. 2, the retail cost of electricity has been rising across the U.S., most visibly in states with highest renewables mandates. Although the U.S. consumers, on average, have been able to afford more expensive electricity, millions of households receive assistance from the federal Low-Income Home Energy Assistance Program and many more from state or local programs. For some consumer groups, rising energy costs is a growing concern in the U.S. Other wealthy Old World countries also face the same issue. Per the European Commission, in 2018, approximately 34 million households in Europe were unable to afford indoor thermal comfort (EC 2020). Hence, even countries in the Old World may not be totally free to pursue their clean energy initiatives without consideration of lower-income populations. Lack of such consideration could result in societal dissatisfaction that can be reflected in either electoral results or protests. The "Yellow Jackets" protests in France in 2018, which started in response to additional fuel taxes, were reminiscent of many past protests in New World countries when their governments tried to eliminate their fuel subsidies. This affordability of energy provides important context to coal's resilience.

Coal often is more than a mere energy source in the New World. Where it is available domestically, coal also constitutes a major source of economic activity and employment, which makes weaning off coal more difficult. We know this phenomenon to be the case in the two largest consumers of coal, China and India, mining safety concerns notwithstanding. The economic dominance of coal exists elsewhere too. For example, in Poland, the strong political power of mining communities makes it extremely difficult for policy-makers across the political spectrum to move the country away from coal (Mikulska and Kosinski 2018). Such a shift would endanger livelihoods of thousands of miners and their families, who then, thanks to set of electoral factors, could effectively vote the entire government out of office.[9] Note that while coal-fired power generation in Poland has been falling, it has done so at much slower levels than what would be suggested by Poland's membership in the EU. In fact, Poland is the only EU member that has not signed the European Green Deal and, ironically, Poland is a target for new, energy-intense manufacturing of linchpin green deal technologies, such as lithium batteries for energy storage. While the EU can definitely express its disappointment and even impose fines on its members for not following EU rules, it cannot vote the Polish government out of office (Mikulska and Kosinski 2018).

That being said, advances in power generation have made natural gas a formidable competitor, particularly where prices are low and access is assured (Fig. 5.2). This has been the case in the U.S., where precipitous increase of gas production from low-permeability resources has knocked down prices from the 2005 high point and kept gas near or below $3 per million Btu (MMBtu) for several years (see Chap. 1 for extensive treatment). The U.S. LNG exports directly transmit the low Henry Hub price (see Chap. 4; coal exports transmit the Henry Hub price indirectly). The U.S. exports of light oil also have helped reduce the cost of oil-indexed

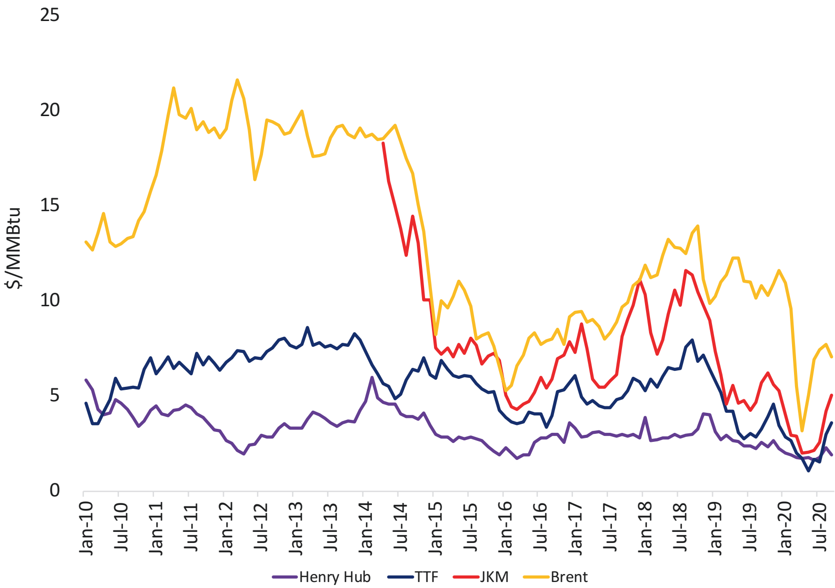

Fig. 5.2 Natural gas prices around the world. (Sources: U.S. EIA for Brent and Henry Hub, Bloomberg for JKM and TTF. Japan Ministry of Economy, Trade and Industry Spot LNG Prices to fill the gaps in Bloomberg JKM data)

LNG. Policy and regulatory actions have accelerated coal-to-gas switch as well. For example, several environmental regulations hastened the exit of many coal plants in an environment of low electricity prices, thanks to cheap natural gas (see Chap. 2). The EU's decarbonization policies have also been successful in pushing out coal to make space for less carbon-intensive fuels.[10]

Political pressure on fossil fuels, reflecting climate activism, increasingly targets drilling and, especially, midstream infrastructure such as pipelines and gas-fired power plants (see Chap. 2 for the U.S. case). Instead, activists promote renewable energy, especially in Old World countries and sub-jurisdictions characterized by wealthier populations. In these locations, government-incentivized investment in alternative energy capacity is almost purely for economic development and/or technology transition. In the New World, by contrast, new energy capacity is needed to meet the basic energy needs of billions of low-income people and new demand from growing populations with more disposable income. Concerns about air quality rather than GHG emissions typically drive the push for cleaner energy in the New World. This contrast between ***choice*** and ***necessity*** is crucial to understanding energy strategies of various countries and importance of their SOEs.

In the New World, renewables are an important option, but the push for them is not exclusive given the need for non-intermittent power to fuel industrial development. For example, New World countries, especially China and the Middle East, are pursuing nuclear power. India plans to expand its existing nuclear generation, but progress has been slow. Other countries are not as quick to follow given the capital intensity and technological requirements of building and operating nuclear power plants.

As a result of all these considerations, natural gas becomes a valuable option. Not only does it produce about half as much GHG as coal when combusted, but it also emits significantly less (or none) of the locally harmful mercury, sulfur dioxide, particulate matter, or nitrous oxides, and has no solid waste such as coal ash. These local environmental benefits are visible in improved air quality and, hence, are more valued by the emerging middle classes in growing urban areas. Gas-fired power generation can substitute for coal-fired generation. And while coal has been developed across more diverse geographies given its relative ease of transportation and use, increasing availability of gas via LNG can undermine this advantage. Additionally, conventional and shale gas resources are now understood to be available across wider geographies. For example, China has been growing its shale production, albeit slowly, given the difficult geology (e.g., see Jacobs 2019). If these resources can be developed at scale, they can provide an alternative to the domestic coal industry when it comes to employment and economic benefits. Nevertheless, the resilience of coal production in many countries around the world suggests that this substitution is not easy, and any movement away from coal and toward natural gas and renewables will be gradual.

New World Order?

A detailed discussion is beyond the scope of this chapter, but the realignment of world powers, which we can crudely simplify as Russia and China relative to the U.S., is a very relevant context for global gas trade. This realignment reveals itself in trade wars, new partnerships around the world, territorial claims, sanctions, and so on. For example, China's Belt and Road Initiative (BRI; or "Belt and Road Strategy" as the Chinese leadership views it) is part of China's expansion of its sphere of influence. China also launched the Asian Infrastructure Investment Bank (AIIB), an alternative to the World Bank and its affiliates such as the Asian Development Bank. The AIIB reports about $100 billion in commitments from its members.[11]

As part of BRI, or to pursue other strategic interests, China has invested more than $2 trillion ***outside of its borders*** since 2005, averaging $180 billion a year in the 2010s. More than $725 billion was invested in energy, averaging $60 billion in the 2010s (American Enterprise Institute). In contrast, total global energy investment averaged about $1.6 trillion a year in the 2010s according to IEA (2020a), with roughly 20–30 percent of investment taking place in China. In other words, China has been investing in other countries' energy sector an amount equivalent to about one-fifth of its domestic energy investment. Although much of the investment has been in resource-rich countries, significant investment has been in countries mostly ignored by Western lenders or donor agencies (e.g., nearly $106 billion in SSA). Notably, Chinese investment does not come with the same conditions with respect to democratic reforms, social norms, or climate change as Western donors often impose.

Without doubt, energy, without secure and affordable supply of which economic power cannot be established or manifest, is critical to this geostrategic game. Natural gas is certainly an important consideration. For example, Russia's "pivot to the east," which was exemplified in the Power of Siberia pipeline to China as well as Arctic LNG, can be seen as part of this realignment. It is also a reaction to energy transition themes in Western Europe. The U.S. LNG exports, although not controlled by the U.S. government, have become an influence tool in this new "cold war." In response to the U.S. trade war, China stopped importing the U.S. LNG, a decision made very easy given the availability of other low-cost LNG supplies. On the other hand, the U.S. LNG is providing Europeans, especially some post-Soviet countries, with an alternative to Russia being the sole supplier of gas. The U.S. sanctions on Nord Stream 2 should also be seen within the same cold war context, although they also strain relations between the U.S. and European allies such as Germany. Also, if anti-gas efforts around the U.S. (see Chaps. 1 and 2) continue to succeed in blocking gas development, the U.S. LNG may not be delivered to Europe in sufficient quantities, further straining the U.S.–EU relations. A market-based strategy could be a better way to support U.S. energy exports while building geoeconomic advantage (Collins and Mikulska 2020).

Old and New Commercial Arrangements

The U.S. gas market is the most liquid market in the world and has been so for a long time. The Canadian gas market is closely linked to the U.S. market with major pipeline connections. Since the 1990s, the Western European gas market has become more competitive as a result of a series of reforms and increased capability of procuring gas supplies from diverse sources. We refer readers to Chap. 1 and Appendix for a detailed discussion of the U.S. gas market.

Liquidity does not come easily. In fact, the dependence of a competitive and well-diversified natural gas market on expansive midstream and downstream infrastructure—somewhat counterintuitively—often requires significant government involvement as regulators in the Old World but often more prominently in the New World through their SOEs and non-market policies. We refer readers to the "Characteristics of Liquid Gas Markets" section in Chap. 6 for a more detailed discussion of gas market liquidity and cross-country comparisons.

The proclivity of New World countries to government-led gas sector regimes is strong, especially where gas imports are significant. In the early days of gas market development, local distribution companies (LDCs) were often part of the SOE that built the import pipelines or LNG facilities as well as the transmission backbone within the country. Alternatively, the

Electrification Versus Gasification

Electrification of all activity in the Old World targets reduction of fossil fuel use, whereas electrification in the New World targets fueling of economic and human development. In much of the New World, the cost of T&D and storage infrastructure needed for increasing natural gas demand can be a serious disadvantage against both coal and renewables. This is particularly visible for countries with a strong electrification agenda. Although Sustainable Development Goals, SDG 7, reporting (ESMAP 2020) suggests less than one billion people without access to electricity, mostly in South and Southeast Asia, Africa, and, to a lesser extent, Latin America, this number is misleading. This is because SDG 7 is a binary metric that defines access as having grid connection or some form of distributed energy source. Ayaburi et al. (2020), in contrast, report roughly 3.5 billion people without "reasonably reliable" access to electricity services. We find the latter number a more accurate depiction of energy poverty. In 2018, global average electricity consumption per person per year was about 3700 kWh. This number should not be confused with average residential consumption. It includes electricity consumed across the economy. After all, an economy cannot modernize without businesses and industries that provide the jobs and services the society needs. Our rough estimates of one-time capital investment necessary to increase electricity consumption of every global denizen to 3700 kWh ranges from \$4 trillion (all combined cycle gas) to \$12 trillion (all rooftop solar).

Electricity from sources other than gas-fired power plants can provide the modern energy needs for economic and human development, and the country can avoid constructing gas infrastructure. Utilizing the cheapest domestic fuel source, which is coal in India, China, and other Southeast Asian nations, for power generation and deploying renewables where feasible are indeed what has been going on in many countries with electrification goals. Midstream infrastructure investment in the coal-to-power supply chain is significantly less capital-intensive than the gas-to-power supply chain (40 percent of total costs for gas vs. 10 percent for coal according to IEA, 2016). The scenario is, perhaps, oversimplistic but without policy mandates (such as the legal requirement in China that resi-

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dential and designated industrial customers switch from coal to gas by a date certain) and/or financial penalties like effective carbon taxes, countries may well seek fuel alternatives that do not bear the transport cost which comes with gas usage. On the other hand, electrification can be pursued with gas-fired power as well. The need for gas infrastructure investment to fuel power plants can be kept to a minimum by placing power plants near gas transmission pipelines and LNG import terminals. Increasing utilization of gas-fired plants would reduce unit cost of electricity, rendering gas more competitive. And, in fact, investment in gas-fired power plants has been averaging about \$50 billion in recent years (IEA 2020a), roughly the same as coal-fired plants and about a fourth of solar and wind investments. Importantly, given the low capacity factor of wind and solar due to their intermittency and often lower capital cost of gas-fired plants, these investments result in equivalent or larger gas-fired generation capability than wind and solar.

state may not directly own LDCs, but establish them as monopolies with direct state backing and control. This has been the case in many European countries until privatization efforts in the energy industry began in the 1990s. The regulated, private, investor-owned LDC model adopted since the 2000s in Europe and elsewhere around the world (with some state ownership remaining in some cases) has been the norm in the U.S. since the late 19th century. Regulators of these naturally monopolistic companies are public servants, usually appointed, and thus not always free of influence.[12]

We must acknowledge the ability of consumers to pay mostly unsubsidized prices for competing fuels in developed economies of Western Europe as a key ingredient of the successful formula for developing a well-functioning, competitive natural gas market. Netback pricing, initiated in the Netherlands to monetize the Groningen discovery in 1959, set the price of gas delivered to various groups of customers (households, commercial businesses, industrial facilities) relative to other fuels (e.g., fuel oil) they were consuming. Luckily, the prices of those fuels were high enough to allow gas prices charged to customers to cover the full cost of producing and delivering natural gas, including an acceptable rate of return on capital invested in the transmission and distribution (T&D) infrastructure.

This ability to pay lacks in most countries that are trying to develop their internal gas markets. This is partially due to a history of consuming subsidized or domestically available cheap fuels. We also must note that the ability to pay and the willingness to pay are not always the same. The latter can be undermined if customers are used to paying subsidized prices for other fuels even if they can afford to pay the full cost of delivered gas. Building import infrastructure (pipelines or LNG), developing domestic resources, and using gas for power generation, methanol and fertilizer production are relatively straightforward, albeit costly, but they are insufficient to create a liquid market. Developing a deeper gas market requires a variety of customers that can afford the cost of gas plus the cost of new T&D infrastructure consisting of different diameter pipelines and storage (preferably some large underground capacity). This infrastructure must be geographically dispersed and must have sufficient capacity to balance demand and supply that vary across customer classes and different time frames (within a day, across days of the week, and, perhaps most importantly, seasons).

From these main points of risk inherent in natural gas value chain infrastructure, cultural preferences for balancing market and government strategies to manage and mitigate risk and affordability, we turn to four aspects of liquidity growth today and going forward: anchor customers for large capital projects, price formation patterns and trends, typical price-setting methodologies (traditional oil indexation and leanings toward gas), and the impact of LNG. We will funnel all of these through our Old/New World treatment in order to better understand future prospects for natural gas.

Anchor Customers

To initiate a gas market, power generation and feedstock use (e.g., fertilizer and methanol) have been anchor customers in many countries. These facilities can consume large volumes and be sited in proximity to gas-producing regions, LNG import terminals, or major pipelines. SOEs often develop these facilities. If developers are private, they often obtain state-guaranteed prices and volumes, through contracts with SOE buyers that are government-backed and/or contractual terms such as take-or-pay (TOP). Additional de-risking for private investors may come as part of financing (for instance, backing from multilateral institutions that supports obligations of SOE buyers). Some anchor customers can afford to pay the cost of gas and still be profitable.

The power and industrial sectors can create their own value chain challenges. For example, the ability of customers to pay for electricity from gas-fired plants is often questioned. Many countries that subsidize liquid fuels also subsidize electricity. Even if it is the state-owned utility (national or subnational) that buys the gas or the electricity from the gas-fired plant, its financial credit is often low and government guarantees on power purchase agreements (PPAs) are needed. There are many examples around the world demonstrating how the breakdown of the electric power value chain undermines financial viability of merchant power plants, which, in turn, risks cash flow waterfalls of gas suppliers (e.g., Nigeria, India, and Peru). We discuss these gas-power value chain issues in more detail in Chap. 6. Similar issues exist for fertilizer plants, which are preferred by governments because they can supply subsidized fertilizer to farmers. These subsidies to final products obtained from the use of natural gas necessitate some guarantees from the government for the gas supply agreement. Finally, the electrification trends in the Old and New Worlds have different meanings and, as such, will likely imply different outcomes for gas (see the "Electrification Versus Gasification" box).

Price Formation

There has been much hype about the globalization of natural gas. Prevailing argument is that increasing LNG trade will bring historically unrelated regional markets together. Indeed, LNG trade has been growing much faster than gas traded via pipelines, but it still only accounts for less than 15 percent of global gas consumption.

As compared to the 1990s, when four countries supplied more than 80 percent of LNG and Japan, Korea, and Taiwan purchased more than 70 percent of that supply, there are now a much larger number of LNG suppliers and importers (Fig. 5.3). Moreover, global gas consumption has doubled since 1990. A combination of supply-push and demand-pull encouraged the monetization of more gas resources via LNG. At the same time, growing economies, declining domestic gas production, energy security, and environmental drivers encouraged more countries to become importers. More recently, FSRUs made it easier for many countries to import LNG with shorter-term commitments. Finally, in recent years,

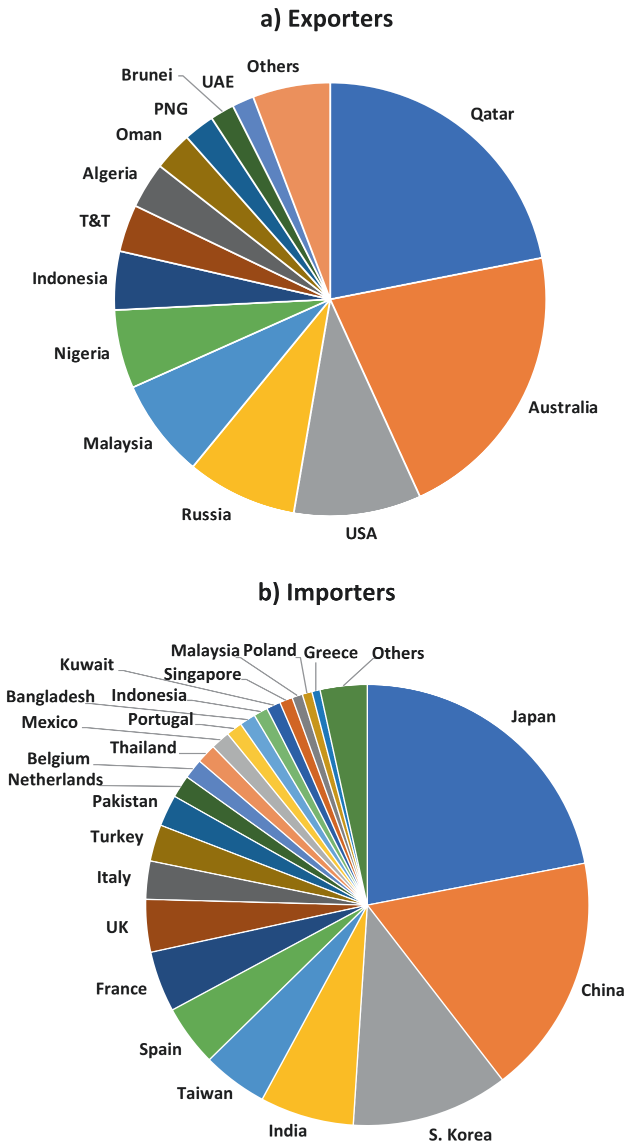

Fig. 5.3 LNG exporters and importers 2019. (Source: IGU (2020a))

liquefaction capacity has been in surplus of demand. All of these developments are contributing to a more flexible market where the share of short-term and spot trading has been increasing. The excess supply condition is probably temporary as more demand develops and production from existing fields and associated liquefaction plants declines (see Chap. 4). In the meantime, low prices encourage LNG imports and increased gas consumption.

Still, significant regional differences persist. Excluding the largest gas markets of the world, North America and Western Europe, gas pricing largely continues to reflect the fundamental reality of natural gas: the need for long-term contracts with prices that can justify large capital investments in upstream, long-distance pipeline infrastructure and the LNG value chains (Fig. 5.4).

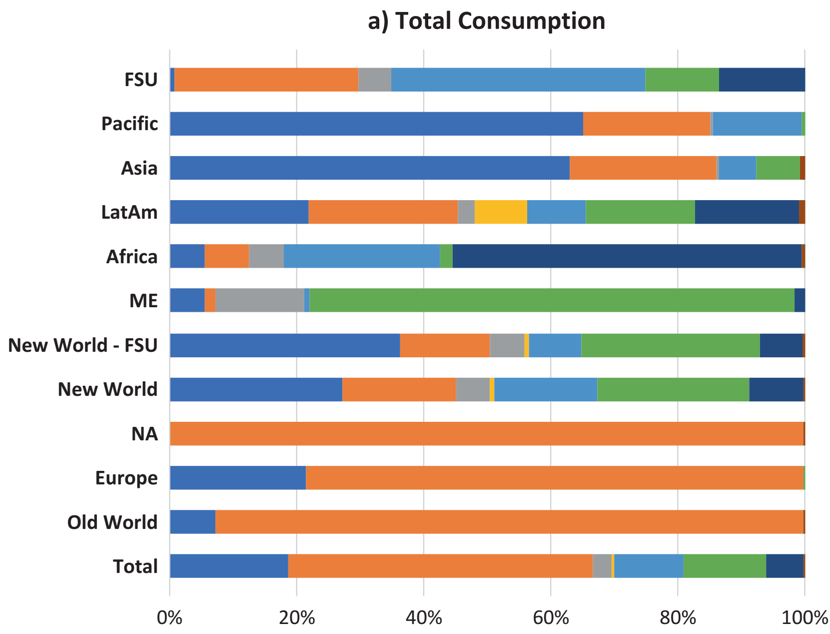

Fig. 5.4 Price formation 2019 (percentage share). (Source: IGU (2020b). OPE: oil price escalation; GOG: gas-on-gas competition; BIM: bilateral monopoly; NET: netback from final product; RCS: cost-of-service regulation; RSP: social and political regulation; RBC: below-cost regulation; NP: no price (free gas))

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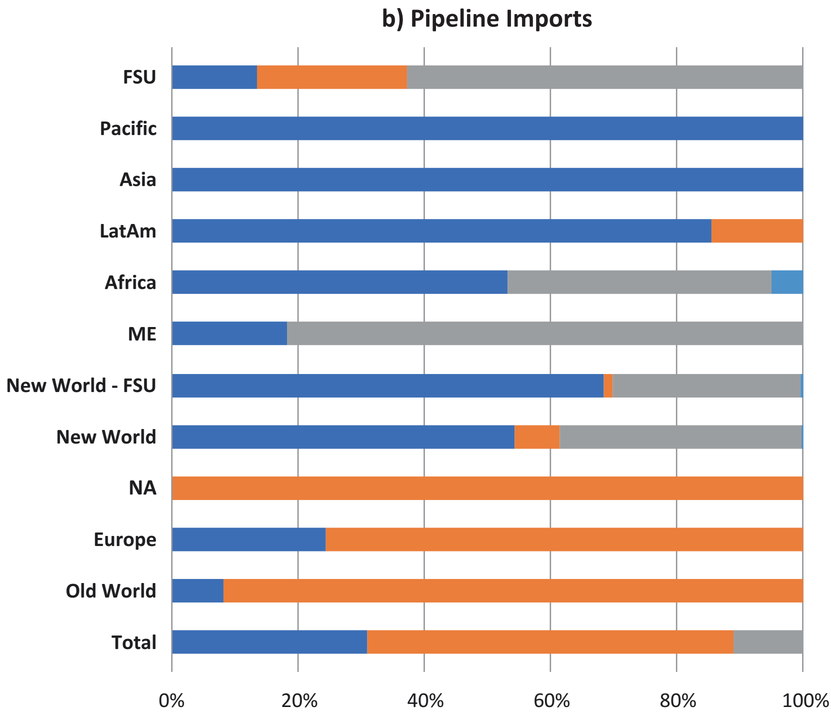

Fig. 5.4 (continued)

Western Europe and Central Europe are the main importing regions where there has been a shift from oil indexing, or oil price escalation (OPE), toward gas-on-gas (GOG) pricing within a regional gas hub. The trend has persisted since the 2000s as a result of declining domestic production, expiring oil-indexed pipeline import contracts, and development of a large number of LNG import terminals. Years of gas use and the push for liberalization of the EU gas market allowed for development of a competitive, relatively liquid market, with National Balancing Point (NBP) in the UK and Title Transfer Facility (TTF) in the Netherlands acting as hub prices. Today, TTF is the main pricing hub in Europe. TTF's share in over-the-counter (OTC) markets has been growing and accounted for more than 60 percent in 2019 according to S&P Platts. Increasing LNG imports and new or renegotiated pipeline contracts have used these hub prices.

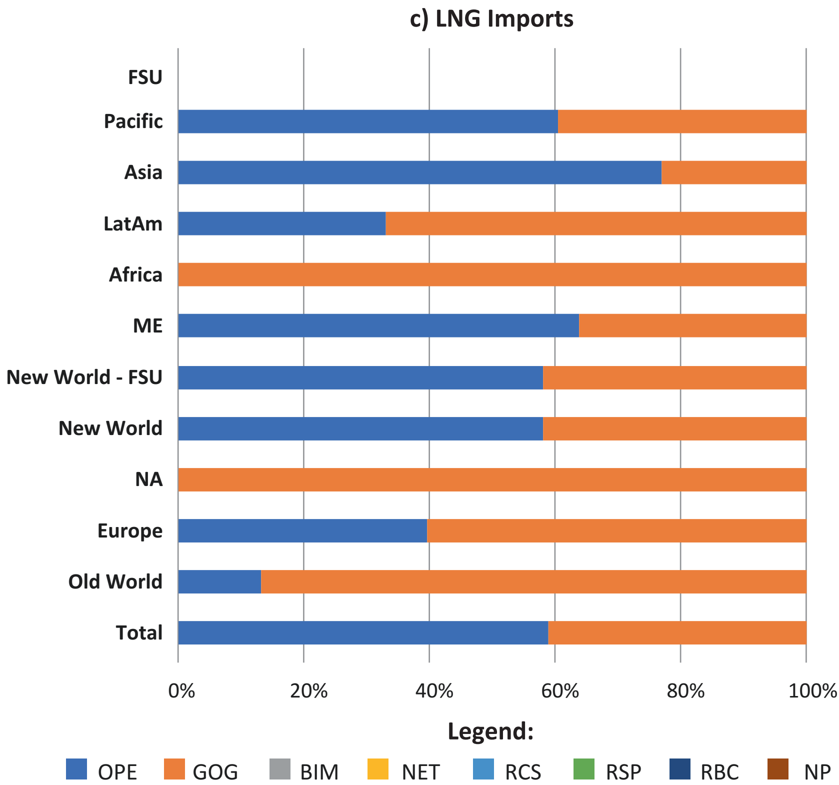

Fig. 5.4 (continued)

Details show that only "large" customers competing for suppliers were able to secure pure GOG pricing. In addition, some pricing reported as GOG in Fig. 5.4 had hybrid pricing: oil indexation within a band set often by hub prices.

In contrast, OPE gained ground and has persisted over the years in Asia-Pacific. In fact, prices set by governments for social and political reasons, often below the cost of service (RSP, or social and political regulation, and RBC, or below-cost regulation), accounted for more than 60 percent of volumes consumed in the 2000s. These have been mostly replaced by OPE and cost-of-service regulation (RCS) in the 2010s. Also, some contracts were switched from pricing based on bilateral negotiation (BIM) to OPE in the late 2000s.

Pricing policies in China are of particular importance. Historically, China's natural gas prices have been a hodgepodge of government-controlled prices for gas produced domestically and end-users. China's National Development and Reform Commission (NDRC) has set the prices with a cross-subsidy from power, industrial, and transport gas users to residential, agricultural, and fertilizer plant users. Domestic gas producers have been paid the city gate price less a pipeline transmission tariff, which is also determined by the NDRC based on construction and operating costs, distance from gas source to city gate, taxes, and an "appropriate margin." This approach often led to a gap between domestic prices and cost of imports based on global markets. Since the three major gas producers (PetroChina, Sinopec, and CNOOC) are also the major gas importers, the losses they incurred on imports reduced the capital available for gas exploration and production. In response, China has been reforming its gas pricing. LNG importers and producers of shale gas and coal bed methane are able to negotiate directly with large industries and power producers. The Turkmenistan–China pipeline started delivering OPE gas in the early 2010s. Chinese domestic production pricing also moved toward OPE. Overall, China has been moving away from RSP, first to RCS and later to OPE, for all sectors except fertilizer to prevent value leakage along the gas value chain and to encourage more investment along the gas supply chain. The unbundling of natural gas infrastructure and creation of an independent midstream company also are expected to encourage domestic production and market-based price creation.

India has been pursuing GOG pricing, but the formula that links the Indian gas price to a weighted average of prices from Henry Hub in the U.S., Alberta Hub in Canada, NBP in the UK, and Russian exports has been questioned by market observers. Since it was enacted, prices in hubs included in the formula have been lower than gas pricing mechanisms using the Japan Korea Marker (JKM) or Japanese Custom Clearing (JCC) that are common in LNG trade in closer geographic proximity to India. Although low prices in formula hubs kept Indian gas prices low and may have encouraged some gas demand in the country, they have been too low to encourage investment in exploration and production of domestic gas resources and have led to increasing LNG imports. India has a "Gas Utilization Policy" that governs the rationing of cheaper domestic gas. First-tier customer classes, in order of priority access to domestic gas, are city gas for households, fertilizer plants, LPG plants, and gas-fired power plants that provide power to distribution utilities. If there is any domestic gas left over after satisfying Tier 1 demand, it goes to steel mills, refineries, petrochemical plants, city gas for industrial and commercial customers, captive and merchant power plants, and others. If LNG has to be allocated to Tier 1 customers, subsidies are provided for them (Sen 2017). As a result, India is struggling with aligning prices of imported gas with delivered prices to end-users because LNG import prices are set based on OPE or increasingly in the spot market.

Resilience of Oil-Indexation in Asia

There are many reasons for the resilience of oil-indexed pricing in Asia. Fundamentally, they all contribute to a lack of liquid gas markets in importing countries. For example, Japan, still the largest LNG importer in the world, has historically used JCC almost exclusively. Other importers in the Pacific Basin have been using JCC as well. In recent years, rising imports from the spot market or based on short-term deals (especially after the Fukushima-induced shutdown of nuclear power plants) increased the share of non-JCC pricing. The JCC formulation still dominates in terms of volumes. The ability of Japanese utilities to pass any increase in LNG import prices to gas consumers via fuel-cost adjustment and customers' ability to pay higher prices undermine the incentive of utilities to seek cheaper supplies. Utilities' dominance in their franchise territories is a result of the lack of domestic competition, which is difficult to establish in the absence of supplies other than LNG imports.

Third-party access to LNG import terminals by competing businesses is an option. Such a strategy has been difficult to implement not only in Japan but also across the world because either SOEs or politically powerful utilities have built and operated import pipelines and LNG terminals, often carrying the responsibility of long-term commitments made to develop those facilities (e.g., Brazil, China, India, Japan, South Korea, and Turkey).[13] Often suppliers are not willing to renegotiate contracts in the absence of commercially viable options. Western Europe, as discussed, has been able to beat this impasse, thanks to a combination of (1) domestic production from the North Sea, (2) access to LNG imports from global sources and pipelines from North Africa, and (3) introduction of a legal regime progressively moving all EU countries toward gas market liberalization via subsequent Energy Packages. Other countries continue to struggle with developing sufficient infrastructure and liquidity, and, even if they are successful, they struggle with market reforms such as regulated third-party access (TPA) with cost-plus tariffs and trading hubs.

One obstacle in creating gas markets, absent in Japan and Western Europe for the most part but quite common in emerging economies, is preferential pricing of gas for specific customers. Governments often pursue these policies for socioeconomic reasons or industrial development purposes. They are necessary when gas replaces cheaper fuels, for example to reduce pollution associated with those fuels. Regardless of the rationale for administered pricing, the broken value chains across gas supply and end-users (including power and industrial sector) ultimately undermine cash flow and financial ability of companies to maintain and expand infrastructure. Specifically, these conditions deter private investment, which perpetuates the importance of public funds and SOEs to create and grow gas demand.

In short, outside of North America and Western Europe, countries are still struggling with meeting the conditions for creating liquid markets. There is no price transparency because geography often prevents sufficient diversity in terms of suppliers and consumers of natural gas in any given region. Sometimes, geopolitics prevents collaboration among the neighbors. In such an environment, energy security often drives natural gas (and other energy) procurement with governments and their SOEs, playing important roles in signing and guaranteeing sale and purchase agreements (SPAs), building and operating infrastructure, and internalizing the cost of administered pricing. These conditions prevent the establishment of physical or virtual pricing references such as Henry Hub in the U.S. and TTF in Europe, along with standardized contracts. Nevertheless, challenges to oil-indexation are emerging. And they are mostly due to growing LNG trade and changing commercial terms of that trade.

The Influence of Growing LNG Trade and Changing Commercial Terms

Large LNG projects for either import or export (including associated facilities for feed gas and upstream production) represent lumpy capacity that are imbued with risk and uncertainty. Thus, although LNG trade has grown, and grown in influence, we still see evidence of strategies forged to distribute risks that rest on government support in various forms, especially the involvement of some of the largest SOEs in existence. A distinct irony exists in that it is Old World, market-led, highly competitive U.S. incremental supply and pricing that are challenging traditions in global LNG trade. This raises a distinct question, as dealt with in Chap. 1, about the longevity of U.S. participation and impact.

In the past, the development of LNG supply projects has been underpinned by long-term SPAs (20–25 years, and some longer) with creditworthy buyers and large enough volumes for only one or two contracts sufficient to support the investment decision on a 4–5 million tons per annum (MTPA) liquefaction train. Today, contracts longer than 20 years are hard to find even for greenfield liquefaction plants. The average duration of LNG contracts has fallen from around 18 years in 2008 to 6 years in 2017, and the average contracted volume is down from 2.3 MTPA to 0.6 MTPA over the same period, though 2019 saw an increase to nearly 13 years and 1 MTPA (Fig. 5.5).

In recent years, long-term SPAs are being signed for terms of 15 years or longer. With more volumes, suppliers, ships, and liquefaction and

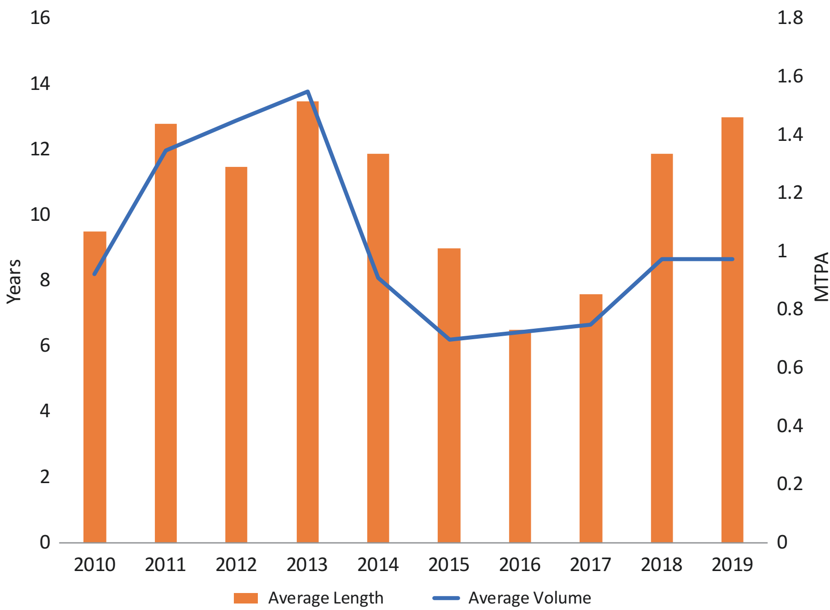

Fig. 5.5 LNG contract durations and volumes. (Source: Based on data from Shell LNG Outlook 2020)

regasification (including FSRUs) infrastructure available, the market also sees significant amount of short- (less than 5 years) and medium-term (5–15 years) trades because the needs of customers vary and shorter contract terms decrease the risk of stranded cargoes. In mid-2020, there were 24 FSRU terminals with more than 100 MTPA of capacity operating worldwide in diverse geographies, including Latin America, South Asia and the Mediterranean. Eight are expected to become operational by the end of 2020 or early 2021 (IGU 2020a).[14]

Spot cargoes, often defined as delivered within three months of transaction date, reached about 25 percent of total LNG volumes in 2018 (Fig. 5.6 reports more than 30 percent for 2019 while defining spot as one year). In 2019, China was the largest spot LNG buyer, closely followed by Japan. Together with India, Spain, South Korea, France, and Turkey, these seven countries accounted for 83 percent of spot LNG trade (IGU 2020a). Shorter-term contracts and spot volumes are based on GOG pricing,

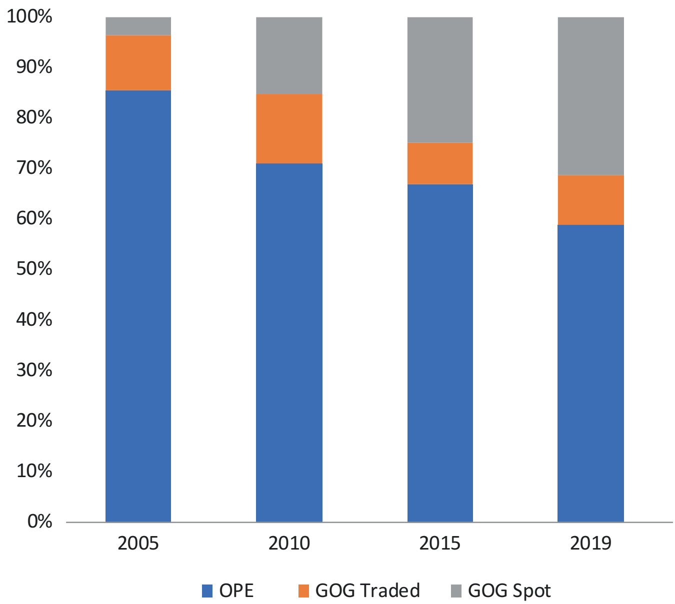

Fig. 5.6 LNG price formation. (Source: Based on data from IGU (2020b). Spot LNG is less than one year. In other studies, "spot" includes short-term contracts (1–4 years). In others, "spot" is defined as 90 days)

hastening the transition from OPE to GOG in LNG markets, although OPE still accounts for about 60 percent of LNG volumes traded (Fig. 5.6).

Legacy contracts for LNG and pipeline imports are starting to expire. Based on data from GIIGNL 2019 Annual Report, more than 115 (190) MTPA of contracts in force in 2018 will expire by the end of 2025 (2030). Asian and, gradually, other buyers are expected to follow the example of Western European importers that gradually switched to GOG pricing, albeit with hybrid formulations in some cases.

These trends suggest that there is differentiation between contracts for the output from new projects versus renewal of expiring contracts and sale of uncontracted LNG from operating facilities. Sellers in the latter group can accept shorter-term commitments because the investment in the facilities has been mostly, if not fully, amortized. Developers of new projects, however, need more traditional long-term contracts (20–25 years) to finance the investment.[15]

Aggregators, or portfolio companies (e.g., Shell, BP, and Total), and, to a lesser extent, traders (e.g., Glencore, Trafigura, and Vitol) are playing an important role in buying more of the supply from projects. The traders focus on smaller volumes to be traded quickly, perhaps at a lower margin. The aggregators, on the other hand, make larger commitments with longer terms to take advantage of arbitrage opportunities across seasons and geographies, using their large global portfolios and financial hedging programs. For example, BP will take the output from the Coral project in Mozambique and the Tortue project offshore Mauritania and Senegal into its supply portfolio, which it will market through a mix of spot, short-, medium-, and long-term contracts (Chap. 4 provides details on Tortue and commercial arrangements). BP and Shell are taking similar roles in Venture Global's Calcasieu Pass project in the U.S., with each committing to purchase 2 MTPA from the planned 10-MTPA plant in Louisiana (see Chap. 4 for details on Calcasieu Pass and commercial arrangements).

Tellurian—a company with many experienced officers formerly involved in Cheniere that developed Sabine Pass and Corpus Christi facilities in the U.S. Gulf Coast—is pursuing a different strategy. The company acquired producing assets in the Haynesville shale and has a subsidiary to develop a pipeline from Haynesville to its proposed Driftwood liquefaction facility. The company has been seeking equity partners (see Chap. 4 for details on Driftwood and commercial arrangements).

In other approaches, global oil majors and state-owned or controlled entities are using their own balance sheets to finance the investment and add the volumes to their supply portfolios, creating an alternative to traditional development approach of using project finance. Several projects—LNG Canada (a joint venture between Shell, Petronas, PetroChina, Mitsubishi, and KOGAS, which combines equity off-take and Shell's aggregator approach; see Chap. 4) and Golden Pass LNG (joint marketing by ExxonMobil and Qatar Petroleum; see Chap. 4)—went ahead without the support of long-term contracts.

Oil-Indexed LNG Pricing

$$P_{LNG} = A \cdot P_{Oil} + B$$

Where P_{LNG} is the price of LNG in \$/MMBtu; P_{Oil} is the price of reference oil in \$/barrel; A is the "slope" term; and B reflects the freight cost.

For most Asian trades, the reference price has been JCC, and for European cargoes, Brent. There is often a lag of one to three months in the oil price used to calculate LNG price. A is either negotiated or bid. Historically, it has been as high as 0.18 and as low as 0.05 (buyer's market of the early 2000s). For LNG price to be equivalent to oil price, A needs to be about 0.165 (based on energy content). The freight cost, B, is negotiated and can be FOB, DES/DAP. The price can be reviewed at regular intervals (e.g., five years).

Even oil indexation itself is undergoing changes (see box). Historically, the price of LNG was indexed to alternative fuels, mostly crude oil (JCC). As discussed before, JCC still dominates in Asia, but as old contracts expire, indexation to natural gas hub prices (Henry Hub, TTF) has been more common in spot and short-term trading. Henry Hub's importance grew with the shale-induced construction of liquefaction capacity in the United States. Although, with the exception of Sabine Pass contracts, the Henry Hub price is not explicit, the threat of cheap US exports indexed to Henry Hub influenced many renegotiations of pricing in existing contracts and new contract negotiations across the world. However, indexation of LNG trade in Asia to natural gas hub prices in North America or Western Europe can be a double-edged sword. On the one hand, such indexation will provide access to financial hedging via trading of futures and derivatives based on these hubs. On the other hand, it exposes buyers to the volatility of these hub prices that reflect demand-supply conditions of those hubs' home markets (i.e., the U.S. and Western Europe; see Chap. 1 for extensive treatment of Henry Hub price history) and, worse, vagaries of financial trading. These have very little to do with conditions in importing markets.

An alternative to gas hub pricing is indexation to Brent, a benchmark crude oil heavily traded at multiple exchanges (Intercontinental Exchange, ICE, and Chicago Mercantile Exchange, CME) and OTC markets. Brent has been popular in recent LNG contracts. Given the LNG surplus in the global market, made worse by the COVID pandemic, slopes of oil indexation formulas have been under pressure as well, staying below 11 percent. This has been the case in European pipeline contracts since 2010. The indexation to Brent also allows LNG importers to use a large portfolio of financial hedging tools. Since the oil market is global and buyers are familiar with oil price volatility from their oil-indexed contracts, indexation to Brent might be preferable to indexation to Henry Hub or TTF.

Lastly, there is the JKM LNG futures contract at ICE and CME offered by S&P Platts as an emerging pricing alternative for gas despite the failure of Asian gas markets to meet many of the traditional prerequisites for a liquid market. The trading of JKM derivatives increased from less than 10,000 lots in late 2017 to more than 70,000 lots in late 2019.[16] Total volume traded in 2019 was nearly 600,000 lots (Ang 2019).

Other changes have evolved in LNG commercial terms that help improve gas market liquidity. Historically, volume commitments were stringent with associated TOP clauses. Justifying billions of dollars in upstream and LNG supply chain development still requires commitments from buyers, but there is a great deal more flexibility in annual and short-term delivery programs, allowances for cargo diversion and less than 100-percent TOP. Both buyers and sellers feel more comfortable with new flexibility given the deeper market with many more buyers, traders, and aggregators. The spot market is an important option for diverted cargoes. Take-or-pay and deliver-or-pay (DOP) arrangements are tied to the spot market. This is especially true for short-term trading. With TOP, if the spot market price is less than the contract formula price, the buyer may compensate the seller for the difference (contract formula price–spot resale revenues–resale cost). With DOP, the seller pays the buyer the difference (cost of replacement–value of contracted cargo).

Increased flexibility is also seen in the transfer of title and risk, which shifts to the buyer when LNG loaded onto a ship free-on-board (FOB) but remains with the seller until LNG is unloaded with delivered ex-ship (DES).[17] Historically, diversion restrictions were the norm in LNG SPAs. The European Union in the 2000s and Japan in the late 2010s declared such restrictions anti-competitive. Destination flexibility is becoming more common. Buyers should be able to divert FOB cargoes with no restrictions. Since the seller carries the title and risk with DES cargoes until delivery, DES cargo diversions still require seller agreement.[18] If the seller agrees, any profits from diversion can be shared between the seller and buyer. Importantly, the U.S. LNG exports are FOB and add to the increased flexibility in the global market. The U.S. LNG contracts are also relatively easy to cancel by either party typically with a notice, two months in advance. The buyer has to pay the liquefaction fees ranging from $2.25 to $3.50/MMBtu (see Chap. 4 for more details on the U.S. LNG projects and key commercial terms).

Still, there are limits to the changes that increase liquidity. For example, LNG vessels are still very closely linked to projects, which reduces the availability of ships for spot trading. Tightness in the shipping market becomes visible during winter when demand rises and day rates for ships increase to over $100,000 per day, dipping in the spring to well below $50,000 a day (e.g., Wong 2019). Also, the reality of high cost of LNG supply chains and associated upstream development remains. And, as historical data demonstrate, when industry activity picks up, higher demand for services of a limited number of qualified EPC contractors and supply chain subcontractors raises costs.[19] For these reasons, as discussed, SPAs longer than 20 years may be making a comeback. Aggregators and traders are more likely to sign contracts than utilities, IOCs, or NOCs, which may become equity partners in some liquefaction projects. Importantly, although the LNG market is currently awash with supply, growing global demand, declining reserves, and aging liquefaction facilities will eventually necessitate new investments. In this environment, buyers that need certainty of supply will be more willing to sign contracts longer than 20 years. They will also have the opportunity to commit to smaller volumes from each project in large portfolios to enhance their energy security via diversified sources of supply.

Another wrinkle that needs to be ironed out for short-term trading to become truly liquid is contract standardization. There are a number of master SPAs with significant differences. Confirmation notices that set the commercial terms based on the master SPAs can therefore be different as well. Accordingly, several entities (BP, Trafigura, the International Group of Liquefied Natural Gas Importers or GIIGNL, the Association of International Petroleum Negotiators or AIPN) have developed model master SPAs.

Lastly, although the large increase in the number of LNG importers is welcome from the perspective of achieving a deeper market, many of the new importers have low credit ratings. In their World LNG Outlook 2018, Shell reported the share of non-investment-grade buyers (often SOEs and/or their governments) by volume was nearly 50 percent in 2017. Until 2010 or so, a great majority of all volumes under long-term contract were with A-rated buyers, with the remaining having a B-rating. This new mix of buyers raises the risk of long-term contracts, the mitigation of which may require government guarantees. Alternatively, companies willing to take and manage risks better in a portfolio (e.g., aggregators and traders) will fill the void.

Government Involvement: New World, Same Old?

As already discussed, regulated private sector entities dominate the natural gas industry in the Old World. Policy and regulation can boost or impede natural gas investments. This is least pronounced for the U.S. demand, which is mostly market-driven.[20] In Europe, however, governments are much more involved in shaping energy markets influencing demand for natural gas. For example, EU rules allow for third-party access (TPA) exemptions for new large investments such as LNG terminals or pipelines for imports.[21] That being said, project developers rarely need direct public funding—a good thing given that public support of the industry is waning in Western Europe.

However, state involvement continues to be the norm in other parts of the world, including post-Soviet EU countries. State-owned Gazprom exemplifies the dominant role of state in Russia. In South Korea, state-owned KOGAS imports all LNG. Japan's government plays a significant role in energy security via SOEs, regulation of private utilities, and international negotiations.

Several reasons exist for states' dominant role, including political context, need for large investments, and energy security. Hence, there is a wide variety of flavors when it comes to the role of state within the natural gas sector. In Fig. 5.7, we offer a spectrum with our interpretation of some

Fig. 5.7 Significance of market versus government across the world of gas

countries' relative positioning at the time of writing. Clearly, these positions can change as markets evolve and governments implement new policies such as deregulation.

The majority of Old World countries historically had been in relatively convenient situations where security of supply has been quite robust. The U.S. domestic supply and Canadian gas supply have been sufficient to meet regional demand, with periodic hiccups mainly due to policy or regulatory miscalculations. Western Europe's barter deal with the Soviet Union, availability of domestic production (North Sea), and access to pipelines from North Africa and to global LNG via numerous entry points into the continent allowed for a diversified supply portfolio. The Soviet Union's ample resources were also sufficient to meet its own and its peripheral countries' needs.

This has not been the case for industrialized economies such as Japan, South Korea, or Taiwan, which launched LNG imports in the 1970s and 1980s and had to rely exclusively on only a few LNG suppliers until the late 2000s. Accordingly, governments and/or SOEs have played, and many continue to play, roles that are more prominent. Similarly, today, governments of post-Soviet countries and, in some cases, their SOEs play important roles in securing a diverse supply of gas (to reduce dependence on Russia) as well as achieve other energy objectives. The dominant role of the state also reflects the historical political context in these countries. As a result, the integration of post-Soviet countries with the much more liberalized market system in Western Europe has been difficult.

In many cases, even if the ownership of natural gas and gas transmission belongs to separate companies, each of them is either controlled or owned by state. Large SOEs also discourage small, private competitors from entering the market. This trend is well visible in Poland, where state-controlled oil and gas enterprises currently are being consolidated into a large conglomerate with the goal of competing globally. The lack of a functioning market is another reason for keeping relatively centralized government control. Liberalization, if pursued before infrastructure can support liquidity, only creates advantage for the entity currently dominating the market (in the case of the post-Soviet region: Gazprom) without attracting private capital.

In the majority of New World countries, SOEs control or are dominant in all segments of the gas value chain. Often third-party participation is explicitly prohibited or limited. Where domestic production of oil and gas exists, NOCs control or dominate access. In countries that decided to import gas, new SOEs are formed for that purpose. Where TPA is permitted, investors are often confronted by frequent government interventions focused on achieving social or political goals unrelated to the economics of gas sector investments.

Government interventions often include below-market gas prices, which allow demand to increase without a corresponding increase in gas supplies and infrastructure unless SOEs and public funding fill the void. In many countries, the costs of below-market gas prices also are borne by SOEs that are the major gas suppliers resulting in decreased capital available for expanding gas infrastructure. Such broken value chains discourage private investment.

Below-cost gas pricing is sometimes necessitated by price subsidies provided to competing fuels if, for example, the government wants consumers to switch to gas or renewables from polluting fuels. For example, in China, gas industry participants complain about central government subsidies to renewables, which they claim have been much higher than any financial support provided to natural gas. While China had been reducing its renewable subsidies until 2020, a recent budget increase seemed to favor solar developers. While the impact of subsidy policy seems somewhat uncertain,[22] subsidies encourage more solar development. Even in the absence of subsidies, wherever renewable costs continue to decline, the price pressure on gas will persist. Subsidies to alternative heating fuels can also render gas less competitive, especially when infrastructure investment is needed to deliver gas (e.g., coal vs. gas in China). For example, China's coal-to-gas switching policy hit some roadblocks in the winter of 2017–18 because midstream bottlenecks created gas shortages and the government had to allow coal use.

Most New World countries need third-party investment because their energy SOEs and government budgets are already burdened with many subsidy programs, and due to low credit ratings (partially as a result of their poor balance of payments), their access to capital is limited. Even in China, there are constraints on the ability of both sovereign and provincial jurisdictions to continue investing in gas infrastructure as cash reserves are earmarked across a wide range of industries and social programs. During tough economic times, governments have fewer resources to allocate across various areas. Expanding gas infrastructure may not always rank high enough given the existence of alternative energy sources. Stimulus packages to help with the recovery from the COVID pandemic envision large infrastructure investments. In the Old World, the focus is on clean energy.[23] In the New World, stimulus packages are more modest and priorities often are different. These stimulus packages as well as legacy energy policies and subsidies cause energy sector investors to assess a variety of long-term risks (see "Investor's Dilemma" box).

Investor's Dilemma

At the risk of oversimplifying, companies investing in the energy industry have two choices:

1. Invest in clean energy in the Old World
2. Invest in gas in the New World

Both options need government support in various forms (tax credits, direct public funding). Where can shareholders expect the highest return? Where are market and political risks highest?

Low credit ratings of many New World countries and histories of subsidized energy pricing raise the risk of investing in those locations. Their need for energy to sustain their economic and human development often leads them to prioritize energy projects and offer guarantees for cost-recovery prices. In spite of these actions, guarantees have not always secured cash flow growth.

Growing debt burdens of Old World countries raise the likelihood that governments will cut subsidies to clean energy as they reprioritize needs such as health. Since wind and solar are now commonly presented as cheaper than conventional technologies, it may be easier to justify ending public support. Meanwhile, renewables' low operating cost and intermittency undermine their profitability. Also, even "clean" energy projects, especially if they are relatively new such as hydrogen infrastructure, may fall victim to "not-in-my-backyard" inclinations, or "NIMBYism" in the Old World.

(*continued*)

(continued)

To us, given the demand growth in growing economies of the New World and their ability to site projects relatively easier, risks for gas as well as other energy projects seem to be more manageable in the New World. Most outlooks agree on where demand growth will occur. Time will tell where profitable energy infrastructure will be developed …

Still, many New World countries may like to see gas play a bigger role in their fuel mix given its flexibility as a power plant fuel, importance as industrial feedstock, and immense local environmental benefits, especially as alternative to coal or diesel.[24] Many undertake efforts to improve gas sector commercial frameworks. However, untangling the knots in existing arrangements, including the dominant role of incumbent SOEs as well as price and subsidy policies for alternative fuels, is a lengthy process prone to bumps and unintended consequences along the way. The political difficulty of wresting power from SOEs that were tasked to build infrastructure and often secure supply (via production and/or imports) is made more difficult if the same SOEs also carry the burden of subsidies. For example, in China, the NDRC has been trying to transfer control of the gas pipeline network away from its NOCs to an independent entity since 2013. It made little progress until December 2019 when it finally launched the National Oil and Gas Pipeline Company (PipeChina). It took several more months to transfer control of major pipeline infrastructure and ten LNG import terminals to PipeChina from China's NOCs, including PetroChina and Sinopec. In May of 2020, PipeChina also announced that it started building another LNG import terminal in the Shandong province. In the meantime, other infrastructure transfers will likely be identified and TPA rules should be developed. These steps toward establishing a gas market are promising, but their success depends on PipeChina's performance and Chinese government's commitment to promoting competition (e.g., see Downs and Yan 2020).

Even in Japan, where regulated private utilities have been importing LNG, reforming the gas sector to allow for TPA has been challenging. Japan has been moving forward with price deregulation, unbundling, and TPA to LNG terminals and pipelines. Competitive suppliers now serve most of the customers in major markets, but TPA is not commonly available. In South Korea, Korea Gas Corporation is the exclusive wholesaler of gas to 34 retailers. Large consumers can arrange with LNG terminals to import LNG for self-use but only if KGC-committed volumes leave room.

These snapshots of global experience suggest that it is naïve to think that natural gas can become a significant part of any country's energy portfolio in relatively quick fashion solely based on private sector participation. At the same time, these experiences demonstrate the difficulties faced by most countries and their SOEs to develop the infrastructure necessary for a robust gas market. We now turn our attention to defining those difficulties.

The Critical Junction: Pipeline and Storage Infrastructure

The insufficiency of midstream and downstream gas infrastructure is a critical impediment to most New World countries introducing natural gas into their energy mix beyond anchor customers (Table 5.1). For example, the most successful so far, China, is about the same size as the U.S. in terms of land area, but its gas consumption is about a third of the U.S. gas consumption and its gas pipeline network is a fraction (about 4 percent) of the U.S. pipeline network. The deficits in storage infrastructure are even more striking. In the Old World, underground storage (UGS) capacity is critically important and typically accounts for 15–30 percent of annual consumption in a country. In addition, most countries have large tanks at LNG import terminals and small LNG storage near their distribution networks for balancing demand and supply during daily fluctuations, especially during winter. For example, the U.S. has about 110 small LNG storage and peak shaving facilities. India has no reported UGS capacity and relies on tank capacity at its LNG regasification terminals. China has been expanding its UGS capacity, but 26 facilities currently operating cover 4 percent of gas consumption. China has 17 UGS facilities under construction, and the country's 22 LNG terminals provide significant storage capacity, albeit only near where these facilities are located.

The lower energy density of gas increases transportation cost and, as such, is an inherent disadvantage for natural gas affordability, particularly in developing countries that have limited gas T&D infrastructure. The experience from more liquid gas markets demonstrates the need for all kinds of storage, including geologic, LNG, and linepack (to sustain pipeline throughput), to balance supply and demand. Imbalances derive from swings in gas demand (e.g., winter heating demand, summer air conditioning demand, the need to provide peaking and load balancing services

Table 5.1 Gas infrastructure density

	Pipelines (km)	*Km of pipe per km²*	*Km of pipe per million population*	*UGS*
United States	2,600,000	0.32	7,855	386/1/16%
Russia	177,700	0.01	1,217	28/4/17%
China	104,000	0.011	72	26/17/4%
Iran	20,794	0.014	248	3/3/3%
Canada	500,000	0.05	13,263	53/1/23%
Saudi Arabia	2,940	0.001	85	NA
Japan	4,456	0.01	35	5/–/<1%
Mexico	18,074	<0.01	140	NA
Germany	26,985	0.08	322	47/2/27%
UK	28,603	0.12	421	14/2/2%
UAE	3,277	0.04	331	NA
Italy	20,223	0.07	334	3/6/25%
India	16,800	<0.01	12	NA
Egypt	7,986	<0.01	78	NA
S. Korea	3,790	0.04	74	NA
Australia	30,054	<0.01	1,179	9/–/13%
Thailand	5,900	0.01	85	NA
Argentina	29,930	0.01	662	1/–/<1%
Pakistan	12,984	0.02	59	NA
Algeria	16,415	<0.01	374	NA
Indonesia	11,702	<0.01	43	NA
France	15,322	0.03	235	6/–/27%
Uzbekistan	10,341	0.02	308	2/1/9%
Turkey	14,666	0.02	174	4/3/8%
Malaysia	6,439	0.02	199	NA

Sources: Countries with a share of 2019 global gas consumption higher than 1 percent according to BP Statistical Review of Energy. Ranked from largest consumer down. UGS = underground storage. Numbers in the storage column represent UGS facilities operating, UGS facilities under construction, and operating UGS capacity as percentage of total annual gas consumption. Gas pipeline mileage is from CIA World Factbook, https://www.cia.gov/library/publications/the-world-factbook/ except for the U.S. (https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems), Canada (https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/pipelines/pipelines-across-canada/18856 and https://www.cer-rec.gc.ca/en/safety-environment/industry-performance/interactive-pipeline/index.html—~50,000 miles of gas transmission and ~450,000 km are gas distribution lines), and China and India (Global Gas Report 2020). Storage data are from CEDIGAZ UGS database (https://www.cedigaz.org/databases/)

to the power sector) as well as disruptions in supply (e.g., pipeline outages, cycles in upstream investment, and lags in drilling).

For now, in most of the New World, gas penetration in buildings (heating) sectors is low due to the widespread usage of traditional biomass, coal, or fuel oil. But if New World countries are to increase their natural gas consumption by expanding service to residential and commercial customers, not only pipeline but also storage infrastructure will become critical. This is especially true for inland areas; coastal regions may benefit from the storage tanks of LNG import terminals or FSRU access.

Who Is Investing in Energy Infrastructure and Where?[25]

Since many New World countries do not have an investment-grade credit rating (Table 5.2), there is less international capital available to them from traditional sources, and what is available is often more expensive. Others, in particular China, may fill the void in realignment of global power structure (see the section "New World Order?").

China stands out with a high credit rating. Assuming that China is willing to reduce the role of SOEs and allow international private investors, this rating should facilitate private investment once reforms under way at the time of this writing signal the opportunity to create value across the

Table 5.2 Sovereign credit ratings of selected New World countries

	Investment grade
China	High
India	Lowest investment grade
Egypt	Highly speculative
Thailand	Nearly upper medium
Argentina	In default
Pakistan	Highly speculative
Indonesia	Lower medium
Turkey	Highly speculative
Malaysia	Upper medium
Brazil	Speculative
Bangladesh	Highly speculative
Venezuela	In default
Colombia	Lower medium
Vietnam	Speculative
Peru	Lower/Upper
Chile	Upper medium

Source: https://countryeconomy.com/ratings gas supply chain. One of the reasons for China's high credit rating is its strong balance of payments, which allowed the country to undertake much gas infrastructure investment via public funds or SOEs' ability to borrow, which is positively influenced by China's sovereign rating. In contrast, India's barely investment-grade rating is a handicap for a country that needs international private investment to speed up the expansion of its gas and other energy infrastructure.

Many South and Southeast Asian countries have speculative (below investment-grade) ratings. It is very difficult for them to attract international capital without strong government guarantees in contracts. Even such guarantees may not be sufficient for internal pipeline or LDC projects. The ability to move FSRUs in case of non-payment is attractive to suppliers. SSA countries, though not included in Table 5.2 due to low levels of gas consumption at this time, have below investment-grade ratings as well and have faced the same challenges for years (e.g., see the discussion on Nigeria in the "Africa" section earlier).

In many of the same countries, domestic capital formation is also limited, and local financial institutions are not equipped to deal with large levels of funding and risk management capabilities required to develop the natural gas infrastructure. The natural gas sector must compete for scarce public funding (central or local governments, multilateral donor agencies) not only with other energy segments but also with a host of public services and infrastructure (health, education, transportation, water).

Often public funding comes from bilateral and multilateral donor agencies, including AIIB, or directly from China. The Organization of Petroleum Exporting Countries (OPEC) Fund, with $25 billion in commitments, is becoming another option especially in Africa. According to the Public-Private Infrastructure Advisory Facility (PPIAF) (2019), in 2017 about $250 billion was invested globally in electricity and gas infrastructure, nearly 80 percent of which was financed by SOEs or other public entities. Most of the investment was in electricity generation and grid. Gas grids received little funding. Private sector investors have pursued renewables projects because of their fast turnaround time and subsidies provided by governments. Importantly, most of their financing was also provided by public banks, bilateral or multilateral donor agencies. SOEs carried the burden of investing in thermal generation, electricity, and gas grids. The IEA (2019) estimates that only about $50 billion a year was invested in lower-middle-income and low-income countries (including many from Asia-Pacific).

It is possible to observe the manifestation of trends discussed so far in energy investment data (Table 5.3). Global investment in gas supply (including upstream, midstream, and downstream) has been consistently around 15 percent of total energy investment between 2015 and 2019 as

Table 5.3 Investment in gas supply, gas-fired power, oil and gas upstream, oil and gas midstream and downstream, billion of 2019 USD (percent share of global total)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*
North America	87, 17, 183, 64 (26, 23, 29, 24)	77, 19, 129, 78 (26, 24, 28, 28)	90, 17, 157, 84 (31, 23, 34, 29)	86, 15, 173, 73 (30, 21, 36, 26)	82, 13, 173, 61 (29, 18, 36, 22)	55, 10, 109, 44 (30, 17, 34, 23)
Latin America	11, 3, 51, 9 (3, 4, 8, 3)	10, 4, 38, 8 (3, 5, 8, 3)	9, 4, 38, 8 (3, 5, 8, 3)	8, 4, 43, 8 (3, 6, 9, 3)	8, 4, 45, 9 (3, 6, 9, 3)	7, 3, 29, 8 (4, 6, 9, 4)
Europe	43, 7, 66, 26 (13, 10, 11, 10)	37, 7, 46, 26 (13, 9, 10, 9)	31, 7, 40, 28 (11, 9, 9, 10)	24, 8, 38, 25 (8, 11, 8, 9)	26, 10, 42, 24 (9, 13, 9, 9)	18, 7, 30, 16 (10, 12, 9, 8)
Africa	18, 9, 68, 10 (5, 12, 11, 4)	17, 10, 55, 11 (6, 13, 12, 4)	15, 9, 57, 11 (5, 13, 12, 4)	13, 7, 54, 9 (5, 10, 11, 3)	14, 9, 50, 10 (5, 12, 10, 4)	10, 6, 33, 10 5, 10, 10, 5)
Middle East	26, 10, 74, 40 (8, 13, 12, 15)	21, 10, 54, 34 (7, 13, 12, 12)	19, 10, 48, 31 (6, 13, 10, 11)	13, 9, 45, 25 (5, 13, 9, 9)	13, 9, 47, 26 (5, 12, 10, 9)	10, 7, 36, 18 (5, 12, 11, 10)
Eurasia	62, 6, 90, 28 (18, 9, 14, 10)	55, 7, 70, 28 (19, 9, 15, 10)	53, 9, 65, 31 (18, 11, 14, 11)	46, 10, 61, 25 (16, 14, 13, 9)	44, 12, 61, 19 (15, 16, 13, 7)	23, 8, 36, 12 (12, 13, 11, 6)
Asia-Pacific	86, 22, 93, 69 (25, 29, 15, 26)	73, 21, 69, 71 (25, 27, 15, 26)	64, 19, 62, 71 (22, 26, 13, 24)	67, 17, 65, 78 (23, 25, 14, 27)	68, 18, 65, 79 (24, 24, 13, 29)	48, 19, 49, 52 (26, 31, 15, 28)

Author calculations based on data from IEA (2020a, b). The 2020 numbers are IEA estimates. Gas supply includes upstream, midstream, and downstream. Percentage is the share of gas supply in total energy investment in that region. Gas-fired power may include some oil-fired generation as IEA (2020a) reports them together. Oil and gas midstream includes refining and petrochemicals in addition to oil and gas pipelines and storage. It is provided as a comparison to total gas supply. LNG investment is part of the gas supply. LNG in Eurasia is Russia; LNG in Asia-Pacific is Australia; other LNG investments not included in the table add up to nearly $8 billion across the years.

reported by the IEA (2020a, b). This share has been only about 10 percent in Asia-Pacific, which is expected to see the largest gas demand growth in the coming decades. And, only 3 percent of total energy investment in Asia-Pacific has been in gas-fired power as compared to 4 percent worldwide. On the other hand, the region accounted for about 24 percent of global gas supply investment and 26 percent of global gas-fired power plant investment.[26] Although IEA data do not allow distinguishing between oil and gas, given that Asia-Pacific accounted for only 14 percent of upstream investment but 27 percent of oil and gas midstream and downstream investment, it seems safe to deduce that more of the gas supply investment in the region has been in midstream and downstream. In addition, upstream investment has been declining, while midstream and downstream investment has been rising. It is not hard to conclude that LNG terminals and pipeline developments, majority in China and some in India, have accounted for most of this investment. IEA (2019) reports that China and the rest of South and Southeast Asia accounted for about nearly 50 and 30 percent, respectively, of oil and gas downstream and infrastructure investment in Asia-Pacific.

Overall, however, gas does not seem to be central to energy policy in Asia-Pacific. Coal supply investment in the region has been relatively stable, with its share rising from 79 percent of world total in 2015 to 87 percent in 2019. Coal, renewables, and nuclear attracted significant investments and are alternatives to gas-fired power generation. Coal-fired power plant investment has been declining in dollars and share in total world coal-fired power plant investment (from 86 percent to 71 percent), while renewables investment increased their share of global investment (from 47 percent to 52 percent). Importantly, dollars invested in renewables have increased from 167 percent of coal and gas-fired generation investment in 2015 to 279 percent in 2019. Nuclear investment in the region (mainly China and South Korea) accounted for 41 percent of total global nuclear investment.

Among the other regions where gas demand is likely to grow, Middle Eastern countries have invested 16 percent of their total energy funding in gas supply. Slightly above the global average, this level of investment is driven by the continued policy of oil-to-gas switching in the region. Africa and Latin America are not seeing the investment levels necessary for high gas demand growth scenarios in Fig. 5.1. Investment shortfall also is visible in oil and gas upstream in these regions despite their abundant resource potential. Upstream investment is dominated by North America, hosting a third of global upstream investment, followed by Eurasia (about two-thirds in Russia) and Asia-Pacific (nearly half in China) accounting for 14 percent each.

The data in Table 5.3 and associated discussion provide a backdrop for a general story of gas pipeline and LDC investment, which seems very limited and mostly concentrated in China and India. Pipeline networks, albeit not as extensive as in the Old World, already exist in many countries with a history of domestic gas production, such as Indonesia, Malaysia, Bangladesh, Pakistan, and Thailand. For these countries and others (Vietnam, the Philippines), LNG imports seem to be sufficient to introduce or increase the share of gas-fired power generation in their energy mix as well as industrial and transport sector use. However, competition from coal remains a threat in some of these countries, including Indonesia, Malaysia, Thailand, Vietnam, and the Philippines. Outside Asia-Pacific, Turkey, Poland, Brazil, and smaller economies in Central America are also pursuing LNG imports, many via FSRUs, to enhance their energy security by diversifying their gas suppliers or introducing gas as a new fuel to their energy mix.

China

The winter of 2017–18 sharply exposed the shortcomings of the gas delivery system in China. China's gas consumption increased by 15 percent in 2017, and a large component of that growth has been attributed to a strong coal-to-gas switching program in the residential and industrial sectors (e.g., Lee 2018a) in order to meet 2017 deadlines for achieving air pollution goals. The gas demand resulting from this program and winter weather in northern China led to gas supply shortages in several regions. The government had to allow affected residential consumers as well as schools, hospitals, and other necessary public services to return to coal-fired heating. Gas deliveries to industries, many of whom had just converted from coal to gas-fired boilers, were cut causing production interruptions in some cases.

These shortages were mainly due to deliverability failures because of pipeline constraints between LNG terminals and northern demand centers and insufficient storage capacity to balance significant seasonal swing in gas demand in northern China. In Beijing alone, 2017–18 winter gas demand was 11 times higher than summer demand.[27] China used its LNG tanker truck fleet (largest in the world) to alleviate the shortages. In 2017, trucks delivered 12 percent of China's gas consumption (e.g., Graeber

2018). Trucking LNG may be a viable option when there is not enough time and/or it is too costly to build or expand pipelines to uncovered areas. It is also a way to build a market and customer base for future pipeline development to happen when critical customer mass is achieved. Nevertheless, the China National Petroleum Corporation's Economics and Technology Research Institute (ETRI) acknowledged that "inadequate gas peak shaving capacity is becoming a prominent problem" (e.g., Zhaofang 2017).

In April 2018, the NDRC "requested" that gas suppliers should boost storage to at least 10 percent of their supplies. This request does not have the force of law, but it shows the government's awareness of the natural gas storage challenge. However, despite several years of price reforms, prices to some consumers (e.g., residential) remain politically very sensitive and are administered by local governments that may not have agendas consistent with those of the central government. As Lee (2018b) reports, full deregulation of city gate gas prices has been delayed until 2020. If gas prices lack incentives to deliver, the government's environmental priorities could be undermined.

Currently, China has approximately 10 bcm of storage capacity that it expects to increase to 13 bcm in 2020, 20 bcm by 2023, and over 40 bcm in 2030.[28] It is hoped that seasonal arbitrage opportunities created by pricing reforms, if they are sustained, could spur investment in gas storage. In addition, there is a chance for PipeChina, newly established midstream company, to push for development of gas infrastructure. China hopes that this will incentivize not only domestic gas production but also investment in China's gas market (Shi 2020). Establishment of an independent midstream company is a step toward liberalizing the Chinese gas market via eventual TPA to the pipeline and storage infrastructure.

China was mostly self-sufficient in gas until the end of the 2000s. Since then, consumption grew much faster than domestic production. As discussed in the "Price Formation" section, a big challenge was that domestic producers (major NOCs) did not always receive a cost-recovery price for their production and transmission while they carried the higher cost of importing gas and delivering that gas to end-users at a price often lower than the cost. Pricing reforms partially targeted aligning the price received by domestic producers with import prices. As a result, domestic production growth picked up pace since 2016, although it is still growing less than demand. Nevertheless, some NOCs predict the majority of Chinese gas consumption to be supplied domestically by 2035, with significant volumes expected to come from coal bed methane (CBM) and coal-derived synthetic natural gas (SNG) (e.g., see Weijun 2020). Given the high economic and environmental cost of CBM and SNG and challenges such as access to water, these predictions appear suspect. In addition, geology of Chinese shale gas is “chaotic” as put by Jacobs (2019), who discusses difficulties with drilling and completion due to challenging geology. As such, Chinese shale gas production may not expand as much as expected nor would it be cost-effective. China does not seem to be putting all of its gas eggs in the domestic production basket as manifested in expanding import capacity. Accordingly, we would expect imports to increase their share as long as global LNG prices remain competitive.

India

India’s gas infrastructure is even less extensive than that of China. There is no pipeline network per se but rather long-distance transmission lines that connect production zones and LNG import terminals to major demand centers. The Indian government had a plan to spend $8 billion beginning in 2012 to develop a National Gas Grid and expand gas pipeline market delivery capacity to about 18 billion cubic feet per day (Bcf/d) by April 2017. However, there were only 16,800 kilometers of pipeline in India in early 2020, with another 14,200 under construction or proposed. India consumed less than 6 Bcf/d in 2019. Nevertheless, gas expansion is moving forward. India had its rounds 9 and 10 to award licenses for LDC development. Like in China, reducing urban air pollution has been a major driver for developing gas networks, with CNG as transportation fuel playing an important role. When all LDCs and connecting transmission pipeline capacity are developed, about 70 percent of India’s population will have access to gas (Global Gas Report 2020).

Today, the large regional imbalance in gas pipeline location remains, with the northwestern part of the country hosting most of the pipelines (40 percent in Gujarat and Maharashtra, home to first LNG import terminals and LDCs in major cities). With LNG import terminals and associated pipelines under construction or planned, gas is expected to reach most major cities in south and eastern half of the country. However, it is difficult to extend the gas delivery infrastructure in India and build new import terminals due to limited access to capital, dominance of SOEs, and significant land acquisition problems as well as the myriad of bureaucratic problems afflicting the expansion of any industrial activity in India. To address the issue and potentially inspire new demand growth, Shell, Petronet, and other companies are considering LNG trucking option in India, but it is highly unlikely for LNG trucking in India to reach the levels seen in China, given the constraints in road infrastructure and bureaucratic and sociopolitical dynamics of the country. The regulator is also pursuing to replace the existing distance-based transportation tariff with a unified tariff (postage stamp) to reduce the total cost of delivered gas at locations farther away from production or LNG import zones. Although gas demand may increase in those locations, it may decline in locations closer to supply zones since they would have to pay a higher transportation tariff than their current rate.[29]

The Gas Authority of India Ltd. (GAIL), an SOE, owns nearly three quarters of India's gas transmission capacity, imports about a fourth of the LNG, and sells about 55 percent of the gas consumed in the country. GAIL also owns about two-thirds of CNG stations in the country and has plans to expand its CNG and LNG capabilities to increase the use of gas in transport and industrial sectors. There is talk of unbundling the company, but until it is implemented with TPA, GAIL's dominance will continue.

India's domestic gas production declined 40 percent between 2010 and 2017 in part due to a lack of investment in the upstream sector. It increased but only slightly (by 2.3 percent) in the fiscal year 2017/18 and stabilized at that level for 2018/19 fiscal year, only to fall by almost 4 percent in 2019/20 according to the Petroleum Planning and Analysis (PPA) Cell of the Ministry of Petroleum and Natural Gas. The decline is partly due to a government-administered natural gas pricing which works directly against the 2016 reform (so-called HELP) that was supposed to attract domestic and foreign investors in the sector (IEA 2020b, p. 288). Domestic gas producers said they needed prices of at least $6–7/MMBtu and sometimes $10/MMBtu to revive gas production. In response, the central government approved a special pricing policy for existing but undeveloped discoveries and new discoveries in deepwater, ultra deepwater, and high pressure–high temperature fields in March 2016. Producers can negotiate prices for production from those fields subject to a price cap tied to the lowest of import prices for fuel oil, coal, naphtha, and LNG. The initial cap was $6.61/MMBtu but went as high as $9.32 in early 2019, before falling back to $5.61 in mid-2020 (Indian Oil & Gas 2020). In lower oil price periods, the special prices have been too low for upstream development. More importantly, volatility of this administered ceiling undermines investor confidence around future cash flows. The government has been promising freeing of domestic prices to induce domestic

E&P activity, but balancing consumer concerns seems to be preventing a final decision.

Energy Security

One overarching theme emanating from our survey of gas demand growth around the world is the importance of energy security in guiding energy strategy, including the role of natural gas, and investments. Of course, energy security has always been a key driver for all countries, but it gains further significance and some nuances in the New World where public funding and SOEs dominate the energy sector and new alignments among global powers are influenced by access to energy. So, it is worth discussing a bit further.

Energy security can be defined in the most basic form by a "4 As" approach: available, affordable, accessible, and acceptable access to energy supply.[30] In the past, the regional nature of natural gas put the suppliers and consumers of gas in a position of more or less equivalent dependency on each other. Today, natural gas is a more global commodity with a larger and growing number of producers, exporters, and consumers, mainly thanks to LNG.

A larger number of suppliers encourage competition and allow for supply diversification. Under competitive conditions, consumers can achieve lowest possible prices and possibly most advantageous contractual obligations. As Jonathan Stern notes in his Foreword to our book (and expanded relative to the role of competitive U.S. supply in Chap. 1), affordability is an important component of future of energy security and can determine the level of penetration gas can achieve in any given market. The consideration is particularly salient in less developed markets where governments may be constrained in ability to subsidize gas and hence may be more likely to keep coal as a major fuel. However, "lowest possible price" does not always mean lowest cost. For example, when countries want to avoid dependence on one supplier, they may invest in infrastructure necessary for supply diversification with redundancy. As we noted earlier, these expensive investments cannot always be achieved with purely commercial motive. We see a mix of market and government strategies and approaches worldwide.

For example, post-Soviet countries rejected at least some volumes of potentially lower-priced option (Russian gas) by investing in LNG import terminals and pipelines. This new infrastructure not only is able to bring gas from new supply sources like the U.S., Qatar, or Norway but also can efficiently distribute them within the region to better balance the market, preventing local shortages and/or price hikes. Much of the new infrastructure was not physically needed. The capacity of existing pipelines that bring Russian gas to Europe is large and could have been enhanced with compressors and interconnections. This investment would have been less than the cost of what has been built and/or is currently planned. Why the expense?

To begin, lack of competition from other suppliers in post-Soviet countries enabled Russia to charge higher prices than in Western Europe where Gazprom competes with other suppliers and interconnections exist to balance the market. In addition, gas has been a bargaining chip geopolitically as Russia used either price hikes or breaks in supply to influence policies of post-Soviet countries (Collins 2017). Availability of alternative supply (even simply as a credible threat of entry) prevents such behavior. For this availability, the marketplace needs large infrastructure investment. Thanks to this new capacity, Russia now is forced to price competitively. A good example here is Lithuania, where a new FSRU terminal pushed Russia to offer a 25 percent discount (Hinchey 2018). Access to LNG supplies via Greece has been a factor in 40 percent drop in prices of Russian gas in Bulgaria. Increasing bargaining power of post-Soviet countries also allowed them to secure more flexible terms in new Russian gas contracts.

China has been implementing a similar strategy of diversification that is visible in its gas import infrastructure that allows access to numerous LNG suppliers from around the world and pipeline gas from Russia as well as Central Asia (Turkmenistan, Kazakhstan, and Uzbekistan) (Pirani 2019). China is also making sure that its bargaining position vis-à-vis its suppliers is strong. Hence, when China negotiated the Power of Siberia pipeline to bring Russian gas, it made sure that the pipeline would not be directly connected to the same gas resources that currently serve the European market. Instead, an eastern route was designated. Though it needs new gas fields to be developed, it serves no other market but China. Such a situation precludes possible arbitrage opportunity on the side of Russia and hence makes the newly contracted deliveries more secure.

At the same time, Russia's own energy security considerations induce the country with the largest proved gas reserves in the world (19 percent of total; see Chap. 7) to diversify its export markets away from Europe. As such, the Power of Siberia appears to be a mutually beneficial project, although China may have the upper hand in terms of cost of gas at this time. It is suggested that Russia (Gazprom) built the pipeline as an incentive for China to agree on another pipeline Power of Siberia 2, which would bring Russian gas to China from Western Siberia, where gas is already developed and is currently supplying European demand (Pipeline & Gas Journal 2020). If the second pipeline is built, Russia could accrue substantial geopolitical influence as well as ability to arbitrage between European and Chinese demand.

To minimize situations where it needs to compete for natural gas with other centers of demand, China has been developing its own gas reserves, including in shale formations. Coal, nuclear, and renewable power are also attracting significant investment and are domestic alternatives to gas imports. Not only does China build coal-fired generation domestically, it also invests in coal power in other countries generating additional competition to natural gas demand there, including in Turkey, Vietnam, Indonesia, Bangladesh, Egypt, and the Philippines (NPR 2020; Li et al. 2020, pp. 1–9). "All of the above" seems to be the principle for ensuring China's energy security even if some options are more expensive than others (domestic gas, nuclear), less able to serve base, especially industrial, load (renewables), or more polluting (coal).[31]

The redundant infrastructure needed for energy security is suboptimal from a commercial perspective and may be a money-losing proposition, especially in many New World countries with illiquid markets distorted by administered pricing policies. Thus, state involvement becomes a needed element in developing that infrastructure. This is not unlike other public infrastructure that is beneficial for economic activity but not profitable enough to attract private investment, or for which a public interface is needed for assignment of property rights and coordinate common use (e.g., road, air, and water transportation infrastructure, water and sewage systems).

An important consideration for the scope and duration of state involvement is the political system. The more independent government is from the public, the more it can do, to support or hurt natural gas demand. In particular, governments with more central authority may have longer-term horizons in their strategic goals when compared to democracies, where election results often depend on economic performance and other public concerns. In democracies, executive branches (ministries and agencies) can develop long-range plans, but execution is subject to political cycles for appropriations. Short election cycles prevent politicians—often predominantly focused on getting reelected—from focusing on long-term priorities. A distinct question is how concerns about environment and climate figure into the complex picture of political systems and regimes, and with what implications for energy and economic priorities and development. In the Old World, public attitudes toward environment and climate deviate from those in the New World where economic development imperatives are stronger (Fig. 5.8). It is important to underscore that even in the Old World, 20–30 percent of randomly sampled respondents also consider the effects of climate change to be too far into the future to worry about, with another 10–15 percent not sure.

If a government with more central power sees natural gas as an important part of the country's energy mix, it could direct state-led investment toward gas infrastructure even if other societal needs have to be met at a

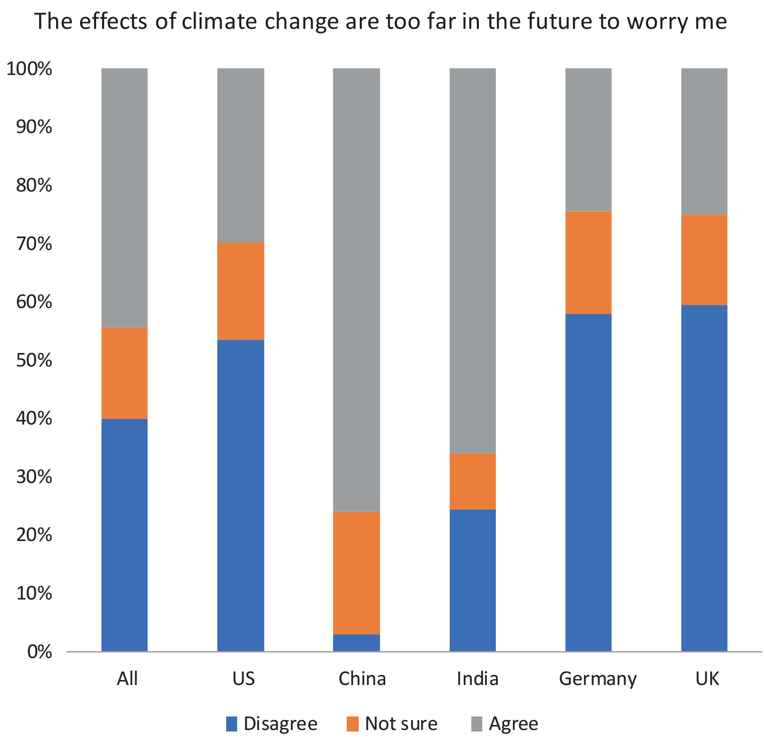

Fig. 5.8 Importance of climate change across the world. (Source: Khan 2020)

lower level. It can also direct investment to other energy infrastructure. China is an oft-quoted example of how a centrally planned economy could be a catalyst to rapid development in energy and other industrial imperatives, often via its SOEs. This includes building of LNG terminals, gas pipelines, and other gas infrastructure as well as coal, nuclear, wind, solar, and hydro facilities. In contrast, the politics in India (the largest democracy with a federal system, and which has to focus on immediate and complex needs of a multicultural society) might contribute to slower pace at which the country is able to move more decisively from coal to alternatives, including natural gas, and/or implement a long-term energy plan. Being a democracy does not mean SOEs are not important or corruption is not a problem. Indian SOEs are dominant in the energy sector, including the gas industry, as we discussed before. China and India have the same poor score in 2019 corruption perception index (Transparency International 2019). So, energy investments in both countries are likely to be inefficient from a commercial perspective.

Our goal is not to write a political thesis. Ultimately, how governments are organized and their ability to implement policies depend on a complex set of historical, cultural, and geographical factors that created today's legal and political systems. We do acknowledge, however, that the current political system in any country matters for gas suppliers and their ability to make decisions based on long-term goals such as energy security and climate change commitments, even under difficult times. From this perspective, China might instill more confidence in global gas suppliers than India, because it has been able to sustain investment in natural gas infrastructure and, of great importance, honor its long-term agreements. We must also acknowledge that, since the early 2000s, China has had significant current account surpluses, while India experienced large deficits. It is reasonable to see China's surplus as a result of country's consistent pursuit of its long-term economic and trade strategies. Ultimately, policy consistency and infrastructure built by public funds are expected to lay the foundation for private investors to develop projects by raising funding in global capital markets to the extent they reduce or eliminate various risks to projects. At the same time, we must follow closely the dynamic forces of global geopolitics, China's macroeconomic status, and the feedback loop between the two, which we discuss in some detail in Chap. 7.

A related observation concerns the investment decisions across the spectrum of countries in Fig. 5.7. For example, the U.S. companies hurt by difficult market conditions (see Chap. 1) were already consolidating or cutting back investment in the upstream, and new U.S. LNG projects were struggling to get financing. A convergence of factors was at play—slowing economic activity and energy demand in early 2019, which induced lower crude oil prices, and low U.S. natural gas prices with persistent surpluses, which induced lower LNG prices in receiving markets, squeezed LNG margins. Saturated buyers, who had rushed into LNG contracts following the Fukushima Daiichi accident in Japan in 2011, were under pressure to adjust. The pandemic exposed these weaknesses and sped up consolidation in the U.S. upstream and project deferments or cancellations in liquefaction.

By comparison, despite the pandemic, Russia and Qatar have been supporting their companies in strong natural gas development. These countries have few options for revenues and hard currency than to support their champion industries. For example, in Russia, Novatek, a nominally private company, continues with Arctic LNG expansion with significant support from the Russian government, including tax holidays and critical infrastructure buildup in the Arctic (e.g., Port of Sabetta). Gazprom has been benefiting from Russian government's support in building Power of Siberia (Mikulska and Jakubowski 2020). Qatar Petroleum has announced the expansion of its LNG fleet by up to 100 new vessels to support its aggressive liquefaction capacity expansion and signed preliminary agreements with Chinese and Korean shipbuilders. Qatar Petroleum is capable of financing these projects mostly from its equity, reducing the need for securing long-term contracts with creditworthy buyers (e.g., see Benali and Al-Ashmawy 2020).

Overall, in the New World, a convergence of energy security imperatives among resource-rich countries that have few other options for sustaining export revenues and those of emerging economies that see gas as a valuable alternative for their growing energy mix sustain and probably enlarge the role of governments. Also, the increasing regulatory burden in the Old World (especially Western Europe and possibly ahead for the U.S. and Canada) renders pragmatic New World countries more attractive markets for resource exporters. The fact that most of these suppliers and importers have political systems that concentrate power more centrally than democracies is an important determinant not only for natural gas but also for all energy investments and, indeed, many other aspects of economic and sociopolitical life.

Lessons Learned

1. In the Old World, primary energy consumption is decreasing, while it continues to increase in the New World. The challenges faced by gas in a declining energy demand world are much higher than in a growing one.
2. There seems to be little doubt that gas demand will grow in the New World, most significantly in Asia-Pacific led by China. Post-Soviet countries, including EU members, have been growing faster than Western Europe, and their energy transition favors coal-to-gas switching even when complying with EU targets. Although much hyped given its size, Indian gas demand growth may not be as significant as growth in the Middle East. Even the resource-rich SSA and Latin America may increase their gas consumption more than India if perennial governance problems of those continents can be solved.
3. Natural gas is facing competition from alternative fuels, most prominently from coal (New World) and renewables (Old World and New World). Coal is most competitive against gas in Asia-Pacific, mostly due to its reliability and affordability but also the long history of local coal-based economies. Alternative energy will be most competitive based on the criterion of acceptability (i.e., environmental benefits) as emerging middle classes want cleaner air, water, and land, especially in growing urban areas, and consider coal and most polluting liquid fuels unacceptable. We must allow for risk and uncertainty on this front as environmental and affordability impacts associated with alternative energy technologies come under greater scrutiny (true as well for Old World countries).
4. Given the limitations of intermittent and difficult-to-scale renewables, gas will likely benefit from the same socioeconomic trends related to local pollution in the New World. In the Old World, gas demand growth is at risk because of public's fear of climate change. Western Europe and parts of the U.S. will continue reducing their gas consumption.
5. Declining demand for gas in Old World countries that have been net importers could mean less competition for supply among New World buyers. To that extent, New World economies probably welcome declining gas consumption in the Old World. More gas, likely at lower

cost, especially from New World suppliers, could be available for their energy needs. Their bargaining power as importers might also increase.

6. The New World is characterized by strong roles for sovereigns, including regulation and involvement via state-owned or state-dependent companies. Even in the Old World, the role of government is potentially forceful and expanding in terms of energy policies, including mandates and subsidies, and regulations that favor alternative energy technologies over fossil fuels. In this sense, most "clean energy" companies are state-dependent in the Old World as well. As countries continue to fail to achieve climate-related targets based on economic calculus, there is a risk of some Old World countries' energy policies becoming more command-and-control than most New World countries.
7. The extent of state involvement may be related to the level of gas market development a country is currently exhibiting. Less developed markets may need more government intervention to help them grow to a point where they can be a host to competitive and liquid supply. Even in China, there are efforts to deregulate gas pricing and allow for private participation in gas delivery as the country continues to expand its gas infrastructure. In contrast, India exemplifies the fundamental challenge of most growing economies: balancing noble intentions to offer subsidized energy to the poor and their need for energy. Subsidy policies, however, are often quickly corrupted and undermine investment in energy supply chains. As such, expecting a gas market à la Western Europe (let alone the U.S.) in most New World countries is unwarranted.
8. State involvement also is related to the political system in a country. Most New World countries have political systems that do not follow Western models. Even democracies have different organization and style shaped by geography, historical and cultural underpinnings, and legal systems, among other factors.
9. Moreover, realignment of world powers with Russia and China as counterbalance to the U.S. also influences gas infrastructure development around the world.
10. Energy security is an important part of the calculus that fuels extensive government involvement. Historical policies of subsidizing cost of energy, and control of existing infrastructure by legacy SOEs, influence gas pricing and development of gas infrastructure.

Notes

1. Although imprecise and simple, to a great extent, our definition of Old and New World overlaps with OECD and non-OECD. Comparisons of the latter two have been the norm in most energy outlooks and similar discussions. As we discuss in this chapter, however, there are significant differences across OECD members, and some have more in common with the non-OECD countries when it comes to natural gas demand and markets.
2. Export netback prices relate to the price of gas exported by Gazprom minus transportation cost (usually taken from Moscow), minus export tax. For more see Henderson (2011) and OIES (2020).
3. For example, when prices of gas for industrial customers rose in 1997, Gazprom received only 29 percent of payments (only 12 percent in cash). For more, see Henderson (2011).
4. Since 2012, the company has to award access to third-party purchases via SPIMEX.
5. The post-Soviet-bloc designation relates to countries, which used to be either part of the Soviet Union or part of the Soviet influence sphere. For the purposes of this chapter, post-Soviet bloc includes Latvia, Lithuania, Estonia, Ukraine, Belarus, Poland, Czech Republic, Slovakia, Hungary, Romania, Bulgaria, Moldova, and republics of former Yugoslavia.
6. Even Poland, the EU country that has been highly dependent on coal for power generation and that has been persistent in allowing coal mining and coal power to operate, has now committed to eliminating coal from power generation by 2050–2060. See, for example, Reuters (2020b).
7. This issue is not limited to Asia. For example, several LNG import terminals have been under consideration in Australia—world's second largest LNG exporter—as the country struggles with uneven distribution of gas within its territory and opposition to development of new gas supplies and pipeline infrastructure. On issues around Australia's natural gas, see Maher and Mikulska (2017).
8. The dominant role of Petrobras (Brazilian NOC) across the gas supply chain and gas-fired power generation still handicaps gas market development in the most populous country in the continent.
9. Note that state initiatives to save some nuclear plants in the U.S. were also driven, at least partially, by political concerns around whole towns near a plant losing their economic raison d'être. Local economic and job impacts have also been key ingredients of successful renewable policies in the U.S. and elsewhere. Unsurprisingly, the stimulus packages to mitigate the impacts of the COVID pandemic focus on creating jobs, especially in the clean energy and general infrastructure sectors. It is useful to keep these

observations from the Old World in mind when we discuss the role of state in developing natural gas infrastructure in the "Government" section.

10. Important exception here is Germany. As the country expanded its push for renewables and banned nuclear power generation, it was unable to wean itself from coal. In fact, even recently a new coal-fired power plant was opened there, despite an almost concurrent stipulation to end coal use by 2038.
11. Members include major economies from Asia-Pacific, including Australia and South Korea (but not Japan), Central Asia, the Caucasus region, Russia, richest resource countries from the Middle East, Canada, and largest economies of Europe (including the UK, Germany, France, Italy). The U.S. opposed AIIB.
12. In the U.S. and Canada, LDCs are overseen by subnational, state, and provincial/territorial regulatory authorities, a reflection of constitutional norms that assign and protect the rights of these subjurisdictions. In the U.S., a handful of state regulators are elected.
13. In the U.S., an important ruling by the U.S. Federal Energy Regulatory Commission in 2002, the "Hackberry Decision," waived third-party open access requirements for LNG import terminals in order to encourage risk-taking development. In effect, the FERC agreed with the Hackberry receiving terminal developer, Dynegy, that LNG storage could be treated akin to producing fields, that is, regasified LNG would be dispatched into the U.S. pipeline system in competition with field production, alleviating the need for the FERC to set tariffs and rate schedules as part of certifying new facilities. See Hollis (2007).
14. We note that Chap. 4 mainly covers large-scale onshore LNG projects, which account for the overwhelming majority of LNG capacity.
15. For example, CPC and Cheniere signed a 25-year SPA (2 MTPA). Mozambique LNG has a 20-year SPA with Centrica LNG and Tokyo Gas (2.6 MTPA). Venture Global has 20-year SPAs with PGNiG (2.5 MTPA) and EDF Trading (1 MTPA) for its Plaquemines (Louisiana) project.
16. One lot = 10,000 MMBtu or ~195 metric tons.
17. Incoterms by the International Chamber of Commerce (ICC) now calls this delivered at place (DAP).
18. Re-exporting of a delivered cargo does not qualify as diversion.
19. According to Bresciani et al. (2020), the cost of liquefaction increased to about $2000 per ton in 2012, before declining to $900 in 2017. Some companies are pursuing smaller liquefaction trains and a modular approach to reduce and/or manage capital expenditure.
20. The main exception for market-driven natural gas demand in the U.S. derives from air quality actions that affected and reduced coal-fired power, stimulating increased use of methane.

21. This is equivalent to the Hackberry decision by the U.S. FERC, allowing the risk-taking LNG project developers to retain control over capacity in the same way they would control producing fields; see book Appendix.
22. However, the government has not been able to pay all the developers and is trying to reduce the number of projects eligible to receive subsidies. Most developers are SOEs, but publicly traded firms are hurt in the absence of subsidy cash flows from the government (e.g., Energy Voice 2020).
23. Australia is focusing on natural gas as part of its recovery (e.g., Kemp 2020).
24. For example, in South Asia, switching of smaller vehicles to CNG has been promoted since the 2000s to reduce urban air pollution. More recently, many Chinese cities have been switching from coal to natural gas in residential and industrial applications.
25. Portions of the text in this section were drawn from an earlier version of this chapter prepared by Miranda Wainberg, and reflect previous work.
26. IEA (2020a) reports gas and oil power generation investment together. Given that there is little investment in oil-fired power generation in most of the world, we treat the reported numbers as gas-fired power plants.
27. See Wainberg et al. (2017) for discussions of gas infrastructure bottlenecks.
28. China lifted underground gas storage capacity to 10.2 bcm in 2019 (Reuters 2020c).
29. For example, see https://www.spglobal.com/platts/en/market-insights/latest-news/oil/110320-interview-india-seeks-to-plug-energy-gap-though-gas-reforms-transition-fuels.
30. The traditional approach of 4 As has been recently challenged by some to include climate change and local pollution concerns (e.g., see Czerp and Jewell 2014).
31. As we were writing this chapter in September 2020, President Xi Jinping pledged net zero carbon by 2060. Like many such pledges, details are lacking. China's current energy mix and large investments in new coal-fired capacity and energy-intensive industries and infrastructure do not bode well for China meeting this pledge, but it does suggest a bigger role for gas along with renewables and nuclear to replace coal.

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