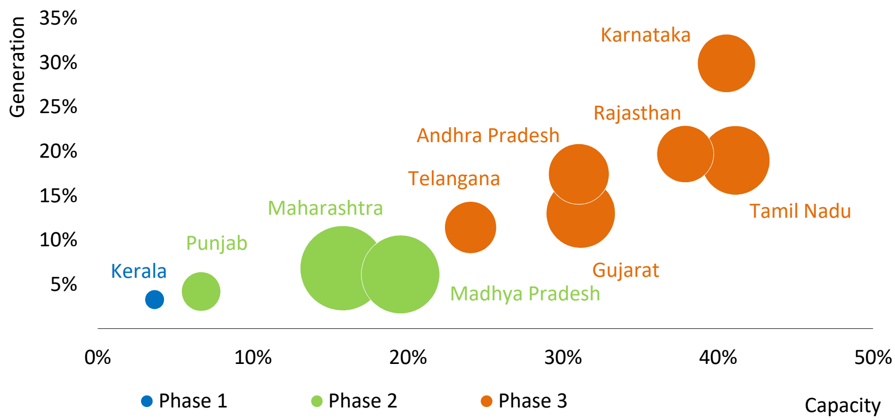
S P O T L I G H T

Insights from the state-level integration of renewables

The share of solar and wind in India's 10 renewable-rich states is significantly higher than the national average, and these states are already redefining how their power systems are operated. The most significant renewables integration challenges are in Karnataka (where solar and wind meet around 30% of annual electricity demand), Tamil Nadu (19%) and Gujarat (13%) (Figure 3.9). These states are in Phase 3 of the IEA renewables integration framework, described above, and with ambitious targets they will move to Phase 4, putting them ahead of most countries.

Figure 3.9 ▷ Solar and wind generation by state, as a share of annual generation and capacity, 2019



Several Indian states are leading the way in increasing the share of VRE in electricity demand, providing useful case studies for integration challenges.

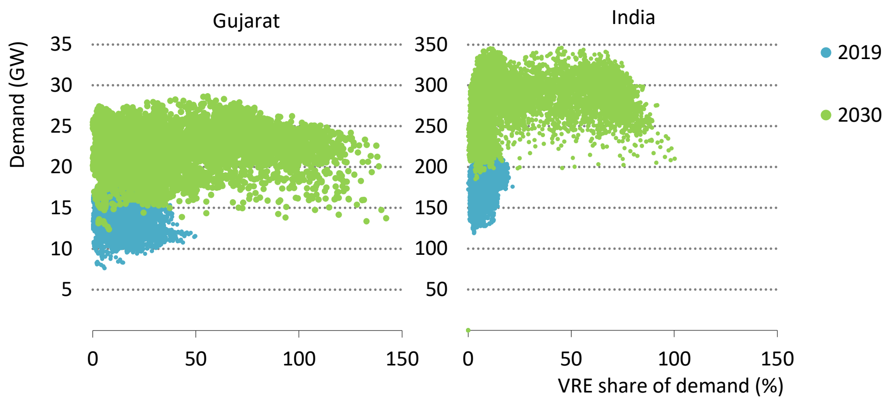
Note: Bubble size corresponds to percentage of electricity generated by VRE in each state relative to total electricity generation in India.

The state of Gujarat is among the most advanced in its power market development, with significant renewables potential and robust deployment targets, financially stable discoms, and a statewide commitment to stop the commissioning of new coal projects from 2021. Gujarat is likely to face renewable integration challenges sooner than other states, and we have explored these challenges through a detailed Gujarat power system model. The model includes separate nodes for each of the discom areas as well as out-of-state trade, and contrasts system operation today with the way it might look in 2030 based on state government targets.

Gujarat's 2030 targets include over 44 GW of solar and wind capacity to satisfy the state's power requirements, along with an additional 20 GW to be contracted to other states.

These ambitions would increase the annual share of solar and wind generation to almost 40% of total generation, from around 13% today. On an hourly basis, it is expected that solar and wind will meet up to 77% of demand at certain times of the day by 2022; by 2030, output exceeds total demand in many hours of the year, posing significant system challenges and dramatically increasing the likelihood of curtailment (Figure 3.10).

Figure 3.10 ▷ Hourly share of available solar and wind generation as percentage of demand in Gujarat versus India as a whole



Renewables-rich states such as Gujarat are already coping with higher hourly shares than the rest of India, and are now facing future integration challenges.

Today Gujarat still has negligible levels of solar and wind curtailment. However, without an increase in flexibility, 44 GW of solar and wind by 2030 would lead to annual curtailment of around 7% of solar and wind generation in 2030 – a significant level of lost output. Avoiding high levels of curtailment, and the additional system costs this may entail, will require action on a broad number of fronts. The results of our modelling exercise show that Gujarat is well-placed to develop three key flexibility resources:

- DSR: agricultural pumping accounts for more than 20% of the state's electricity demand, and shifting this load to the daytime would go some way towards aligning peak demand with solar output. This is achievable in Gujarat because it has a dedicated agricultural feeder system that allows the interruption of agricultural supply without impacting other consumers; this system is already used to manage the timing of agricultural supply today. Adjusting today's predominantly night-time scheduling to the day would reduce the baseline level of curtailment down to 3%, reduce the start-up needs from thermal generation sources by around 40%, and cut operating costs by around 10%.
- Thermal plant flexibility: coal power plants could be operated more flexibly if technical minimum plant load factors were to be reduced from 75% to 55% for older

units and to 40% for newer units. The next decade will see a significant change to the operating practices of coal and gas plants: relatively minor changes in capacity factors will lead to much larger changes in the operating patterns of coal generators, which look set to spend more time at very high or very low output in 2030 relative to today. More flexible operation of coal would allow the power system to cope with higher levels of renewables generation, but depends on the value of increased thermal plant flexibility being recognised and adequately compensated.

- Investment in batteries: a four-hour duration battery storage addition of 4 GW would allow high solar output during the day to be stored for later use to meet evening demand. As dispatchable thermal capacity declines relative to peak demand, battery storage would also help reduce short-term energy purchases and reduce import dependency.

Operational and market design challenges

As India adds a greater share of wind and solar to its energy mix and as its demand profile becomes more variable, it will face new kinds of operational and market-related challenges. This section explores the wider, structural features of India's power system and looks at where reforms could help India meet these challenges.

India has one of the world's largest synchronous power grids, with most of the scheduling and unit commitment carried out at the intra-state level by discoms. Long-term bilateral PPAs are the main way of buying and selling electricity in India, covering 90% of generation in 2019. The remainder is either bilateral trading or transactions on India's power exchange. This means that generators, for the most part, are scheduled by discoms within a limited contractual pool. Hopes are high that India's power exchange will organise more efficient trades in the future, but liquidity is currently fragmented across different products and trading platforms, and the wholesale market currently accounts for less than 5% of all power transactions.

India currently has 40 GW to 50 GW of generation capacity that is financially unviable. This is largely the result of a mismatch in demand and supply which has arisen because the pace of capacity additions has far exceeded demand growth. There is also a mismatch in incentives between generators which develop government- or state-auctioned capacity under attractive payment guarantees, and the discoms that are the primary off-takers for this new capacity. Both face difficulties in fulfilling their roles. Discoms struggle to collect revenue from consumers and face low regulated tariffs (often below the cost of metering), while generators have been unable to sell excess power to the relatively small wholesale market. The result of all this is renewable energy curtailment, asset underperformance, a general mismatch between the costs of producing electricity and the available returns, and a high level of technical and commercial losses, which average around 20% (compared with a global average of 7%).

The Indian power system also has a history of outages, resulting in part from the difficulties faced by the discoms discussed above, which have constrained investment in infrastructure and contributed to the current high level of technical losses. This history has led many consumers to install diesel-fired back-up power, and encouraged larger-scale industrial users to opt out of buying higher-priced grid electricity.

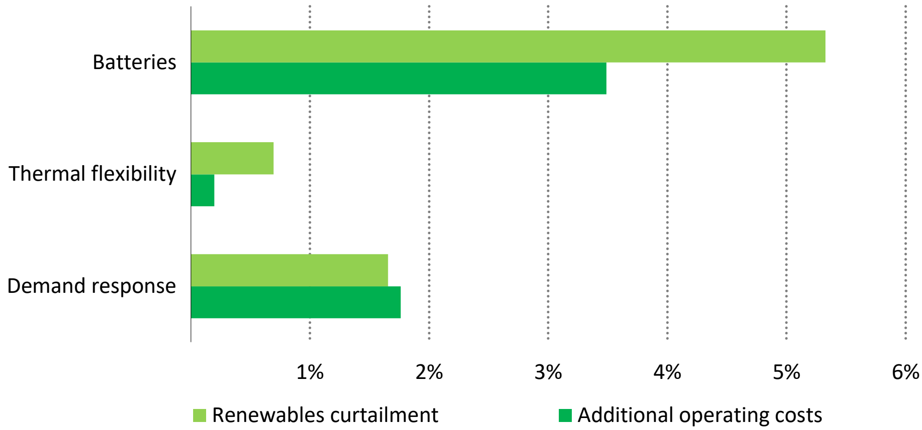
These are well-recognised issues, and the Indian government is pursuing a number of reforms. A key objective is a centralised market for day-ahead scheduling and real-time dispatch with gate closure. There were several developments in 2020: in June, the real-time power market was launched, filling an important gap by providing real-time corrections for intermittent and variable generation such as solar and wind, as well as for demand. This was followed by the launch of the Green Term-Ahead Market, allowing renewable electricity to be traded at a premium (compared with the regular day-ahead market) for buyers looking to fulfil their renewables purchase obligations (RPOs).

Further regional and, eventually, countrywide integration of the power system is crucial to managing the growing share of renewables. Co-ordination between a strong federal structure and supporting states is a central component of system integration, especially since India's power system has a diversified ownership structure, which means that reconciling different interests is a key part of effective regulation and governance. Greater integration and co-ordination are key objectives in the roll-out of renewable management centres and "green energy corridors" across eight renewable-rich states in order to facilitate the transmission of solar and wind to high demand centres.

However, there are several aspects that require further development. The necessary network upgrades rely on the ability of consumers to pay fixed charges and on grid companies to pay for bottleneck management services. Market liberalisation is hindered by a general unwillingness by generators to cancel or renegotiate existing contracts and submit to market-based pricing. Moreover, the business model for utility-scale battery storage in India remains uncertain, in the absence of efficient price signals that would enable batteries to arbitrage between periods of scarce and abundant supply. Far-reaching electricity sector reform would be needed to accommodate the scale of battery deployment required in *WEO* scenarios.

Sensitivity cases were run to explore the implications of slower progress on market reforms and rates of deployment of flexibility resources. In the first sensitivity, India is prevented from fully leveraging its thermal plant flexibility: in this case, there is a continued restriction on older coal plants to maintain a minimum stable operating level of 75% instead of 55%, while new coal plants operate at a minimum of 50%, rather than at 45%. Sensitivities were also run on batteries and DSR, assuming that no further investments would be made in these sources of flexibility after 2020.

Figure 3.11 ▷ Impacts of limiting flexibility options in India in the STEPS in 2030



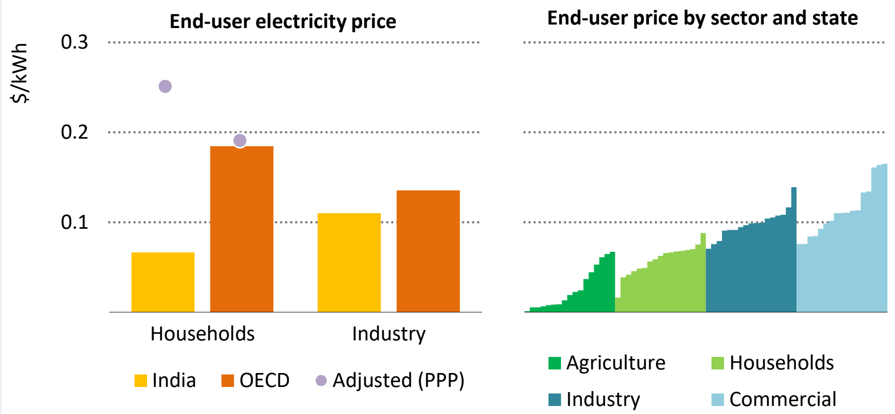
Reduced flexibility from batteries, thermal power plants or demand response in 2030 would lead to increased renewables curtailment and additional operating costs.

A lack of development in any of these three flexibility options would result in increased renewables curtailment and in increased operating costs relative to STEPS; this is particularly the case for batteries, which play a strong role in integrating the increasing share of solar generation (Figure 3.11). However, further cost-benefit analysis would be required to determine whether the value of curtailed renewable energy would exceed the investments required to reduce their curtailment.

Box 3.3 ▷ How cheap is India's electricity?

Electricity prices in India in nominal terms are lower than the average among member countries of the Organisation for Economic Co-operation and Development (OECD). However, after adjusting for purchasing power, so as to reflect spending on electricity as a share of Indian household income, prices are higher than the OECD average. This is despite the fact that India – like some other emerging and developing economies – has higher end-user prices for more energy-intensive industrial consumers in order to cross-subsidise the lower tariffs paid by vulnerable users in the household and agricultural segment. Prices also vary not just among end users, but also between states, where a complex patchwork of different taxes and subsidy regimes can leave consumers in some states paying five times more for their electricity than their counterparts in neighbouring states (Figure 3.12).

Figure 3.12 ▷ Comparison of electricity prices paid by different end users in India, 2018



Households' electricity tariffs in India are higher than the OECD average, adjusted for purchasing power, despite being subsidised by commercial and industrial consumers.

Note: End-user prices (stacked by state) calculate each state's discom revenue per megawatt-hour for each category of consumer.

The degree to which electricity becomes affordable is primarily a consequence of macroeconomic conditions, particularly the purchasing power of wages and the level of wage growth, but there are also issues endemic to the power sector that create additional challenges, such as high levels of technical and commercial losses and poor billing practices and collection rates. Tariffs sometimes end up four times higher than the purchase cost of power, and some low-income households pay a significant portion of their monthly income to meet electricity bills.

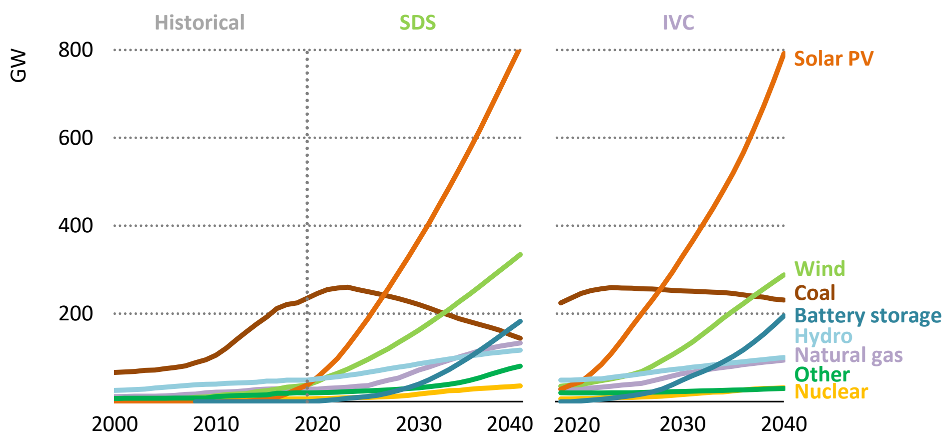
Looking ahead, the rise of renewables is likely to add to the complexity of electricity tariffs because it is likely to lead to billing based on the time of use becoming a more important part of cost-effective system balancing. There is already a case for ensuring that the complex and varied tariffs in place do not disadvantage low-income households, and this further projected increase in the variation in tariffs adds to it.

3.2.3 The power system in the India Vision Case and Sustainable Development Scenario: Charging ahead

The IVC shows a smarter transformation of the electricity sector that more fully exploits the flexibility from thermal power plants, as well as storage, DSR and cross-sector integration, in order to accommodate rising shares of renewable energy. There is also a notable shift to an India-wide, cost-reflective dispatch of generation assets. Timely implementation of market reforms underpins a significant scaling up of investment, as electricity demand is nearly 10% higher in 2030 compared with the STEPS.

The power system of the IVC makes the transition to renewables and away from coal at a faster pace than in the STEPS. By 2030, renewables make up around 60% of total generation capacity and provide 450 GW of non-hydro renewable capacity. Utility-scale solar PV passes the 60 GW mark in 2022, while close to 30 GW of agricultural load is met by solar in the next five years. By 2030, solar PV alone is responsible for meeting 75% of India's 2030 renewable target, and is on track to provide almost 800 GW in 2040. Offshore wind deployment also accelerates in the IVC, with the industry gaining a foothold in the 2020s and capacity eventually expanding to 30 GW in 2040 (Figure 3.13).

Figure 3.13 ▷ Power capacity in India by source in the SDS and IVC, 2000-2040



The ramp-up in renewable capacity in the IVC is almost as rapid as in the SDS.

The development of battery storage systems in India also picks up in the IVC, with greater deployment and deeper cost reductions: at $120/kWh, the cost of a four-hour storage system is 40% lower than in the STEPS in 2040. Batteries are an essential means to integrate additional solar and wind capacity in this case, and reach almost 200 GW of capacity in 2040, 36% higher than in the STEPS. The expansion of battery capacity also serves to limit the amount of coal-fired capacity needed to ensure power system adequacy. The IVC sees in addition a lifting of many of the barriers to DSR: aggregation of loads and access to wholesale and balancing markets for demand-side resources allows DSR to mitigate the increase in peak demand in the IVC, and to facilitate the integration of higher shares of solar PV. Agricultural pumping sees a major transition to solar PV powered pumping solutions, and remaining grid-connected pumping is aligned with power-system needs in the IVC thanks to tariff design and smart controls. Meanwhile more of India's rapidly growing fleet of air conditioners are equipped with smart controls in the IVC, allowing for modulation of electricity demand in line with system flexibility needs.

On the thermal side, captive coal generation capacity is gradually replaced by gas-fired and (to a lesser extent) renewables capacity. Coal-fired capacity peaks in the mid-2020s and then declines steadily. This leads to improvements in air quality in cities in India, while also cutting energy-related CO_2 emissions. The emphasis on gas-fired power also gives a boost to the overall use of natural gas in India.

Overall, the IVC gets India's power system much closer to the trajectory required in the SDS, where renewable capacity additions reach 1 330 GW by 2040 (compared with 1 200 GW in the IVC). However, emissions outcomes remain far apart: in the SDS, total power sector emissions fall by 80% compared with 2019 levels by 2040, and are on course to reach net zero by 2050, whereas in the IVC they remain largely unchanged. This difference is primarily a consequence of existing coal-fired capacity continuing to play a relatively prominent role in India's power system in the IVC, where the rapid growth in renewables avoids new emissions from rising electricity demand but does not displace existing coal-fired capacity. In the SDS, by contrast, a wide range of technologies and measures are deployed to reduce emissions from existing coal assets that would otherwise continue to operate, as in the IVC. They include, for example, measures to reduce the amount of output from existing coal-fired power plants by repurposing them to focus on providing flexibility, by equipping existing plants with CCUS or co-firing with biomass, or by retiring them early if these options are not viable (section 3.4.2).

3.3 Exploring prospects for a gas-based economy

India has long-standing plans to expand the use of gas in its energy mix, and the level of current ambition is high: the government is targeting a 15% share of gas in the energy mix by 2030, up from 6% today and 8% in 2010. Achieving this ambition would still leave the share of gas below today's global average of 23%, but this shift would nonetheless be a momentous one for the Indian energy economy. It would require significant investment and policy support all the way along the value chain to incentivise new upstream activity and gas import capacity, to underpin the construction of new transmission and distribution pipelines, and to install new end-user equipment.

There are reasons to believe that the gas market can grow rapidly, provided that current policies promoting its use are effectively implemented. International gas market conditions are propitious for India: ample supply at low prices helped to avoid a reduction in gas demand in 2020 despite the effects of the Covid-19 pandemic, and is now giving price-sensitive Indian buyers incentives to contract new volumes. Efforts are also under way to enact market reforms that encourage gas trading, and to rationalise the taxes and tariffs applied to different end users across the states of India.

Nonetheless, significant challenges lie ahead. India's gas market today is a complex patchwork of different pricing mechanisms, gas allocation schemes and types of gas (Box 3.4), and there are some distressed gas-fired assets in the power sector as well as some underperforming and underutilised infrastructure. This complexity represents one challenge. It will also not be easy to encourage growth in a market that is likely to be based, in large part, on imported gas, or to find ways of overcoming the persistent competitiveness gap at the end-use level between gas and cheaper local energy sources such as coal and renewables. Ultimately, concerted policy efforts, backed by robust implementation, are key to creating the incentives necessary for gas in India to grow.

Box 3.4 ▷ A gas by any other name

Gas has multiple identities in India, with different terms used to distinguish its origin or end use. Pipeline natural gas, or PNG, mostly consists of domestically produced natural gas. Imported gas is known as r-LNG, or regasified liquefied natural gas. CNG, or compressed natural gas, is natural gas that is bottled and sold at filling stations as a transport fuel. Biomethane, which is biogas upgraded to reach pipeline quality specifications, is a relatively new addition to the gas lexicon, and is being marketed in India as a sustainable variant of CNG, called either CBG or bio-CNG.

All of the above gases are ultimately methane, the primary constituent of natural gas. The exception is biogas, which also consists of CO_2 and other gases such as nitrogen, and when not upgraded to biomethane is used primarily as a source of local heat and power and clean cooking in rural areas. Although often assumed to be in the same category as these gases, liquefied petroleum gas – LPG – is a natural gas liquid and in IEA accounting is classified as a liquid fuel.

The prospect of increased Indian reliance on natural gas provokes a range of views as to the implications for India's economy, its environmental performance and its energy security. Our intention in this section is to untangle these various strands and explore in more detail what a gas-based economy could mean for India, and the extent to which it might meet India's designated policy objectives – notably to diversify the fuel mix towards cleaner alternatives, tackle poor urban air quality and reduce dependence on oil.[1]

3.3.1 Can India afford gas?

The prospects for gas in India hinge on its affordability, and whether there is a way to adequately remunerate gas producers and suppliers while still having a delivered product that is consistently and affordably priced for Indian consumers. There are parts of India, notably in Gujarat, that have been relatively successful in finding this balance, but the overall record – despite numerous reforms and administrative solutions – has been mixed. There is also a very wide variation across different Indian states in terms of today's gas infrastructure and consumption (Table 3.3), although there are ambitious plans to expand pipeline connections and CNG filling stations almost everywhere.

[1] The idea of a "gas-based economy" is often understood to refer to fossil natural gas, but this is not necessarily the case, and we examine also the prospects for low-carbon gases such as biogas, biomethane and hydrogen.

Table 3.3 ▷ Indicators of gas supply, consumption and infrastructure in selected states and union territories of India, 2019

	Prod. (bcm)	TFC (bcm)	Gas-fired power (GW)	LNG regasification capacity (bcm/y)		PNG connections (thousands)		CNG stations	
			Existing	Existing	Planned	Existing	Planned	Existing	Planned
Gujarat	1.4	14.9	7.6	37.4	13.6	2 065	1 018	548	236
Uttar Pradesh	-	10.4	1.5	-	-	159	2 037	128	845
Maharashtra	-	8.5	3.2	6.8	17.7	1 457	1 590	313	303
Madhya Pradesh	-	2.1	-	-	-	56	2 009	43	361
Assam	3.3	2.0	0.6	-	-	34	416	-	72
Delhi	-	1.9	2.2	-	-	1 097	-	482	-
Haryana	-	1.9	0.4	-	-	100	1 185	66	327
Kerala	-	1.9	0.5	6.8	-	1	3 394	4	826
Rajasthan	1.5	1.7	1	-	-	2.2	4 246	5	603
Rest of India	3.8	5.2	7.6	6.8	25.8	109.1	26 513	141	4612
Total	**10**	**50**	**25**	**58**	**57**	**5 100**	**42 400**	**1 730**	**8 190**

Note: Prod. = Production (onshore only), TFC = total final consumption.

Sources: IEA analysis based on Cedigaz (2020); GAIL (2020); MPNG (2020); PNGRB (2020); PPAC (2020).

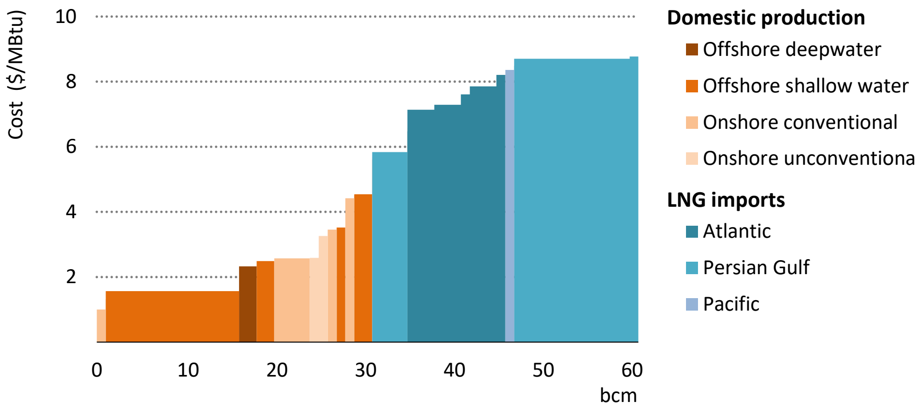
Wholesale gas pricing

On the wholesale side, pricing is split between domestically produced gas and more costly LNG imports (Figure 3.14). Since 2014, the price of domestically produced gas has been set by a formula linked to a basket of international reference prices. This means it is not necessarily reflective of the cost to producers of domestic extraction, nor the affordability – or willingness to pay – of gas to different consumer categories in India. In 2019, this administered price averaged \$3.2/MBtu,[2] while the weighted average wholesale price of all sources of gas in India in 2019 was around \$6/MBtu once more expensive imports were factored in.

Around half of India's gas supply is imported and, with around 30 bcm of LNG imports in 2019, India is already the world's fourth-largest importer of LNG. The majority of LNG delivered in 2019 was priced either via oil-linked formulas, typically at a premium of 11-15% to crude oil markers, such as Brent or the Japanese Crude Cocktail (JCC), or as hub-indexed spot US LNG delivered under long-term contracts. The remainder was purchased on the spot market, where prices are often determined on the basis of gas-to-gas competition. In recent years, these spot prices have been well below the cost of oil-indexed gas supply, resulting in pressure from the main Indian buyers of LNG – Petronet and GAIL – to renegotiate the terms of these long-term supply contracts. In parallel, the practice of tendering for spot LNG cargoes has strengthened price discovery, which has been bolstered by the creation of the IGX, India's nascent gas market hub. This allows buyers and sellers to trade in both spot and forward contracts across three physical hubs (Box 3.5).

[2] A higher ceiling price averaging \$8/MBtu has been set for gas developed in more challenging deepwater or ultra-deepwater zones. To encourage foreign direct investment, the Indian government has also offered pricing and marketing freedom for so-called "non-regulated" fields as part of HELP.

Figure 3.14 ▷ Weighted average cost of natural gas in India by source, 2019



A significant cost gap exists between domestically produced gas, which has been unable to keep pace with demand, and imported LNG, the price of which is mostly linked to oil.

Notes: Domestic costs refer to the break-even costs of developing resources. LNG imports refer to landed costs.

Box 3.5 ▷ India's emerging gas exchange

India took an important step in its gas market evolution in June 2020 with the opening of the IGX. This is a digital trading platform linking three physical LNG-importing "hubs": Dahej and Hazira in Gujarat, and Kakinada in Andhra Pradesh. For the moment, only regasified LNG is tradeable, but over time this platform could become a way to introduce more transparent, cost-reflective and uniform pricing arrangements across the entire Indian gas market.

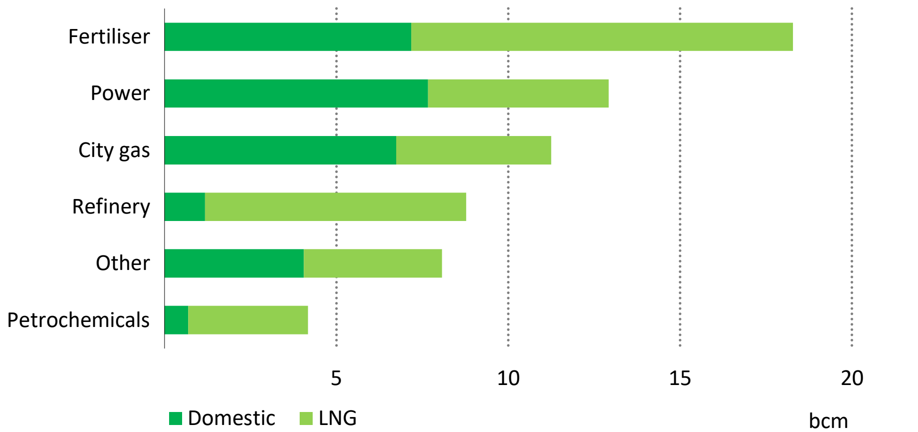
To become a successful reference point for price, a trading hub requires a number of enabling conditions, notably an unbundled gas value chain with third-party access to infrastructure and the presence of several buyers and sellers of wholesale gas. It also needs a certain amount of liquidity, meaning that gas might be bought and sold multiple times before being physically delivered and consumed. It must also have depth, meaning that gas has to be available on spot terms, e.g. on a day-ahead basis, and as a futures product, e.g. deliveries agreed for the next month, season or year. Market participants can use these traded products to undertake risk management, for example by hedging their future production or consumption.

These conditions are not yet met in India. As in many other emerging gas markets, there is only a limited set of gas supply sources in India, while infrastructure (including storage) is still insufficient, and domestic supply is dominated by long-term bilateral contracts, often with strict conditions about delivery and resale. Unbundling the gas value chain, ensuring transparent third-party access and bringing greater competitive pressures to bear on the Indian gas market (thereby curbing the market power of incumbents) is a process that is likely to take time. The most well-known gas hubs in the United States (Henry Hub) and in Europe (the National Balancing Point [NBP] in the United Kingdom and the Title Transfer Facility [TTF] in the Netherlands) all took several years after their inception to reach maturity. The Indian power sector provides a further useful point of comparison: an exchange was created in 2008, and has since seen significant growth in the number of transactions, but the current traded volume still represents only 5% of total power supplied in the country.

End-user prices

There are a multitude of gas prices in India, which vary depending on the origin of the gas, the distance it travels and the taxes applicable in the state in which it is consumed. An important factor determining the end-use price of natural gas is the mix between domestic gas and imported LNG. A government-administered allocation policy reserves the cheaper domestically produced volumes of gas for specific consumer categories (Figure 3.15). The order of allocation has undergone frequent revisions over the past several years; power plants, until recently a high priority, have now been removed from the list altogether. Fertiliser plants were also initially given preferential access to reduce the need for more expensive urea imports. However, later revisions gave city gas distribution (CGD) top billing to free up LPG for use in rural areas in place of more polluting fuels, while fertiliser plants transitioned to a "pooled pricing" system to help them to manage the transition to greater imports.

Figure 3.15 ▷ Split of domestically produced gas and LNG consumed by sector, 2019



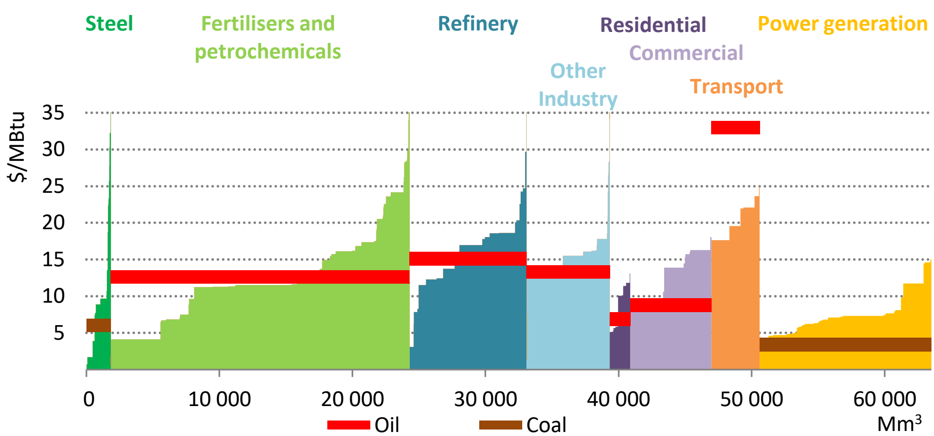
The power sector has received the highest share of cheaper domestically produced gas in recent years, although the most recent rule changes now prioritise CGD.

Notes: IEA analysis based on PPAC (2020).

Commentary about the affordability of gas on India's gas market typically focuses on the sensitivity of consumption to landed LNG costs; a recurring narrative is that LNG prices lying above a \$5/MBtu to \$6/MBtu range preclude the large-scale adoption of gas in the face of competing fuels. However, pipeline tariffs and taxes are very important elements in the final cost to consumers, and they vary widely in a complex patchwork across the country, depending on the category of consumer and the state in which they reside.[3] In the case of India, tariff reform and a streamlining of applicable taxes are important policy levers that could potentially reduce the prices charged to end consumers and therefore make higher imported gas prices more tolerable.

For this report, we conducted a bottom-up analysis of prices actually paid by different end users, using facility and state-level data in key gas-consuming industries and states. This has yielded a first-of-a-kind estimate of the range of prices paid in different states and sectors in India, making possible a more detailed assessment of the competitiveness of gas compared with competing fuels (Figure 3.16).

Figure 3.16 ▷ Range of natural gas prices paid in selected end-use sectors in India and average price of the main competing fuels, 2019



There is an affordability gap between natural gas and competing fuels in several sectors, although a small subset of consumers benefit from access to lower-cost domestic gas.

Notes: Mm^3 = million cubic metres. Energy sector own use not included. Many industries are not viable for competitive fuel switching, e.g. a relatively small amount of gas is used as process heat in the petrochemicals sector, while 90% of fertiliser production already comes from natural gas. Competing fuels are naphtha and, potentially, coal gasification.

Sources: IEA estimates based on data from GAIL (2020); MPGN (2020); MoSPI (2018); PPAC (2020).

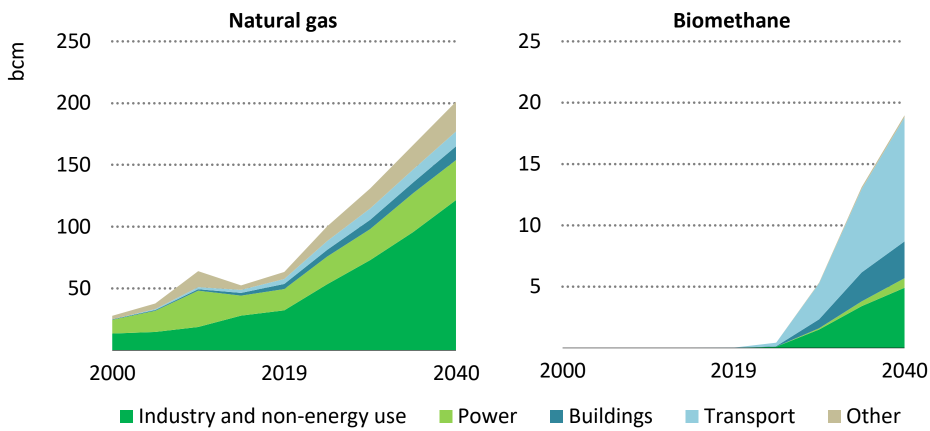
[3] In Ahmedabad, for example, residential consumers pay about 40% less than commercial and industrial consumers for an equivalent amount of natural gas. However, the tax rate in Ahmedabad is double that of Bangalore. The government is now planning to include gas into the GST, which would mean that gas is taxed at a standard rate across India; the implications for the competitiveness of gas would vary, depending on the present arrangements in each state.

As noted above, the weighted average price of domestic and imported gas in India in 2019 was around $6/MBtu. With the additions of different state taxes, transport tariffs and corporate margins, the final cost to consumers is usually considerably higher, however, and the weighted average end user price in 2019 was $12/MBtu. The range is very large, with most gas consumers paying somewhere between $6/MBtu and $18/MBtu. This is comparable in absolute terms to prices paid in Europe, but is much higher after adjusting for relative purchasing power in India. A further difference between end-user prices in India and elsewhere is that most large-scale users of gas in India, such as industrial facilities, pay higher prices than smaller-scale consumers.

As things stand, the main sector where gas is clearly competitive is transport; CNG prices are around 40-50% lower than petrol and diesel prices, which also have a high tax component. Natural gas is also well placed to compete in smaller-scale industries that require consistent levels of adjustable process heat but must, suboptimally, resort to using coal, biomass or furnace oil today. However, in many other parts of the Indian economy – including some key industrial sectors – the case for gas on straight cost grounds is much less compelling. With today's regulatory framework, economics alone do not make the case for gas in India.

3.3.2 Gas demand in the STEPS

Figure 3.17 ▷ Natural gas and biomethane demand by sector in India in the STEPS



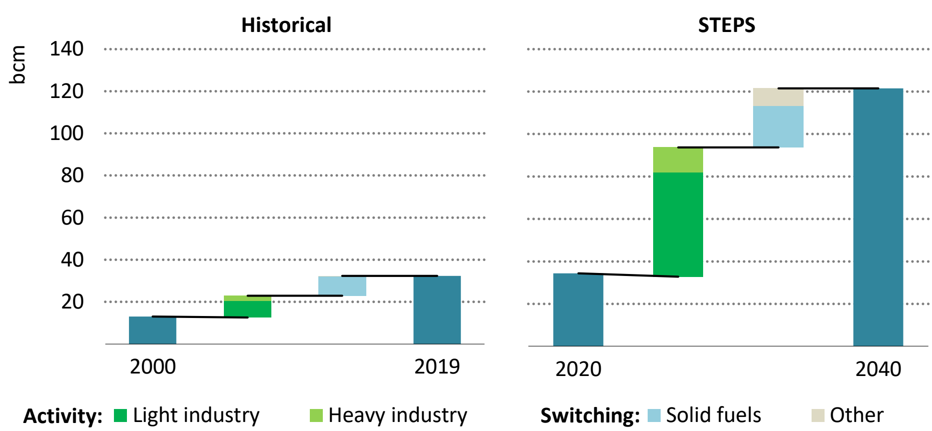
Industry is the key driver of natural gas demand growth, while transport demand underpins the growth of biomethane, which reaches a 10% share of total gas demand by 2040.

Overcoming affordability challenges for natural gas requires a range of supportive policies. The Indian government, as well as some states, has put in place a number of policies promoting gas use, including a wide-scale roll-out of CNG and bio-CNG, and the expansion of gas infrastructure including LNG terminals, long-distance transmission pipelines and CGD networks. These policy ambitions translate into rapid growth of gas demand in the STEPS over the next decade (Figure 3.17). On average, gas grows nearly 7% each year to 2030, more than double the rate of overall energy demand growth. The share of gas in India's energy mix (both natural gas and biomethane) doubles from 6% to 12% by 2040, largely at the expense of coal and traditional solid biomass. However, this share remains the lowest among the countries and regions modelled in the *WEO*.

Gas use in industry

In the STEPS, industrial gas demand – including the use of gas as a feedstock for petrochemical and fertiliser production – is the primary source of demand growth (Figure 3.18), and the share of gas in total industry energy demand nearly doubles to reach 20% by 2040. Most of the growth comes from lighter industrial sectors and small- and medium-scale industrial customers, who gain gas connections as transmission and distribution infrastructure is rolled out. This means that the share in industrial gas demand of energy-intensive industries such as refineries, fertiliser plants and some gas-based steel producers declines from around 40% today to around a fifth in 2040.

Figure 3.18 ▷ Drivers of industrial gas demand in India in the STEPS, 2000-2040



Industrial gas demand is poised to rise rapidly, with infrastructure supporting market growth and encouraging existing end users to switch away from other fuels.

Gas, where it is available, is well suited to the needs of lighter industrial sectors such as textiles, manufacturing, and food and beverages. These tend to be located in or close to large population centres, where air quality becomes an increasingly important consideration; providing policy incentives for such clusters of MSMEs to switch to gas-burning equipment is therefore key to unlocking further growth. For many such industries, the convenience of being able to adjust process heat temperatures and the opportunity to make efficiency gains are added advantages of using gas instead of liquid or solid fuels, although electricity provides competition for some lower-heat applications. For some industries currently using liquid fuels, switching to gas can be commercially attractive, particularly in cases where fuel costs are relatively low in terms of total added value, or where there is a relatively short payback period associated with the upfront investment costs to switch to gas-burning equipment.

Policies will play a critical role in determining the speed and scope of growth in natural gas. Most of the 30 bcm of demand growth attributable to fuel switching in the STEPS is driven by policy-led efforts to reduce the level of coal and oil use in industries which are located near urban areas and contribute to poor air quality. To take one example, the possibility of using CNG in place of coal in India's massive brick industry is attracting interest in some jurisdictions.

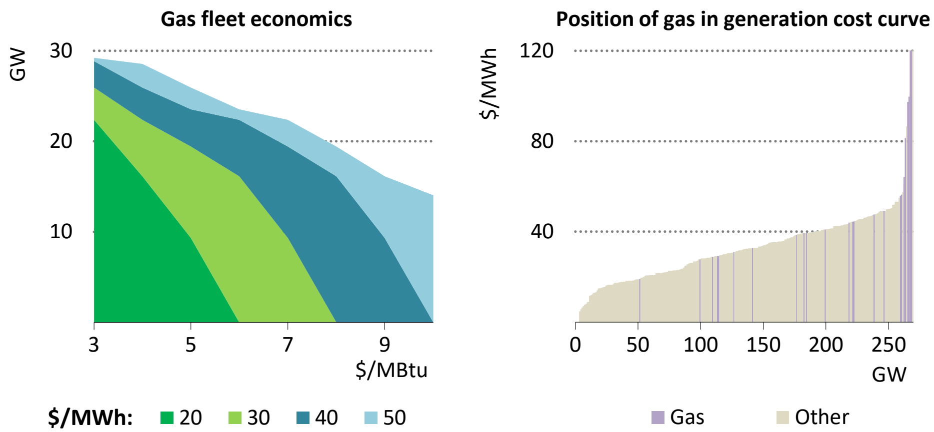
Gas use in power

Natural gas has been facing a perfect storm in India's power sector in recent years. A wave of new power plants was commissioned in the late 2000s in anticipation of a large increase in supply from India's offshore gas resources. However, production from the much-awaited KG-D6 field in the Krishna Godavari Basin off India's east coast did not match expectations and fell away quickly. Gas-fired power plants were left short of gas or became reliant on more expensive LNG. The situation was compounded by revisions to the gas allocation policy, which left power plants lower on the priority list. Lower-than-anticipated electricity demand, along with ample thermal coal capacity, has meanwhile left very little space for gas to contribute to marginal power generation. In 2018, 60% of gas-fired power plants were deemed by the government to have become stranded assets (Ministry of Power, 2018).

Recent market developments have seen mixed fortunes for gas; LNG spot prices in summer 2020 hit record lows of around $2/MBtu, causing an uptick in gas used for power generation. However, a tighter Asian market caused spot prices in December 2020 to surge to multi-year highs, dampening the economics of gas plants. Moreover, supply-side economics are only one determinant of a plant's operations; actual scheduling depends foremost on the level of electricity demand, while the electricity tariffs received by gas are fixed by long-term PPAs, with dispatch determined within a limited contractual pool of generators. Even if this were to change, less than a third of capacity would be competitive at tariffs below $30/MWh (Figure 3.19), given the level of gas import prices reached in *WEO* scenarios ($7/MBtu to $9/MBtu). With cheap solar providing the main competition for the incumbent coal-fired generators, natural gas is looking at a range of walk-on parts in India's power scene rather than a central role.

With plant economics likely to remain challenging, the outlook for gas in India's power sector – as elsewhere – is highly contingent on policy, and on the implications of policy for coal-fired power. Ideas that have been explored to revive stranded gas plants include the possibility of pooling tariffs from gas-based power plants with those of renewable facilities in order to enhance their affordability for consumers. Reforms in the midstream, such as allowing power plants to contract pipeline capacity on a more flexible basis, could reduce operational costs. Using natural gas plants to provide flexibility, and then remunerating their ancillary services to the electricity grid, is another possible option. However, for the moment, most of the tariffs do not reflect the additional costs of meeting peak demand and operating only when renewable energy generation is at seasonal or diurnal lows, and some cash-poor discoms have been reluctant to dispatch relatively expensive gas even when it is required for system reliability.

Figure 3.19 ▷ Gas-fired power generation economics under different delivered gas costs and power tariffs, and generating costs in mid-2020



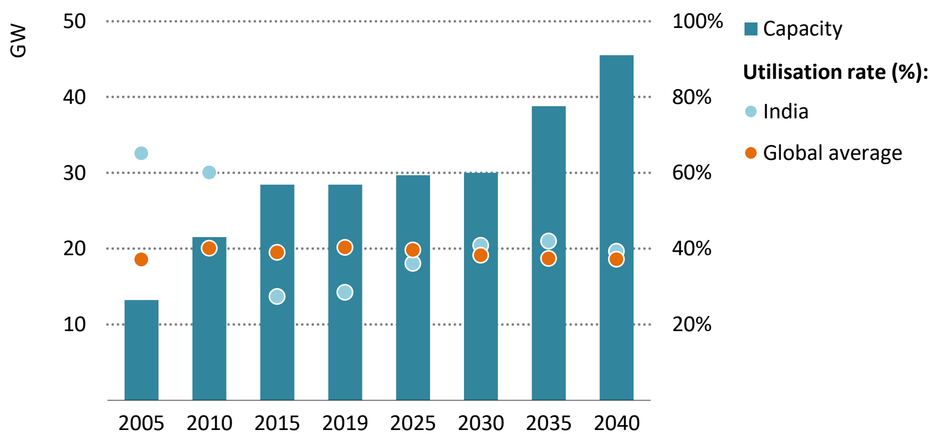
Even with a supportive tariff rate and low delivered gas prices, gas-fired power plants struggle to compete in the Indian power sector.

Notes: Right-hand chart is IEA analysis based on Ministry of Power (2020), covering the period March-August 2020, during which spot gas prices were at record lows. Other refers to generation sources covered by Ministry of Power reporting, primarily thermal coal plants. The delivered cost of gas in the left-hand chart includes the energy component (50-60%) and taxes, tariffs and corporate margins (40-50%).

As discussed in the deep dive on the power sector above, India has an increasing need for flexibility, and this creates some opportunities for natural gas in the future. However, most of India's flexibility needs are relatively short term, even intraday, and these are areas where gas faces some fierce competition from other technology options. Recent auctions for round-the-clock power have primarily been won by renewables linked to utility-scale batteries. In the STEPS, coal plants are the major source of flexibility to balance the growing share of VRE to 2030. In later years gas is used alongside a broad range of other flexibility options, including greater interconnections, battery storage and DSR.

As a result of the difficult environment it faces in the fast-growing power generation sector, only around 10% of additional gas demand to 2040 comes from that sector in the STEPS. Most of that increase over the next decade is due to a revival of existing gas power plants rather than investment in new plant capacity (Figure 3.20). Despite the increase, moreover, the contribution of gas to overall power generation remains static, at around 4%, as solar and wind make up the majority of new generation.

Figure 3.20 ▷ Gas-fired capacity and average utilisation rate in India in the STEPS, 2005-2040



India's gas-based power assets slowly recover from today's low utilisation rates; capacity growth after 2030 is underpinned by flexibility rather than baseload requirements.

One opportunity for new gas-fired power generation is in the captive power sector, i.e. with companies that choose to generate their own power or use diesel as back-up generators. This is a significant element in the Indian power mix, accounting for around 40% of industrial power needs. At present, more than half of India's 75 GW of installed captive capacity is coal-fired, followed by diesel generators with a 20% share. Gas has a 10% share of the captive power sector, and around a quarter of gas-fired generation in 2019 was from captive power units, with petrochemical and fertiliser plants the main users. The scope for growth is linked to two main variables: the roll-out of gas infrastructure and the reliability and affordability of electricity from the centralised grid. We estimate that 1.5 bcm to 4.5 bcm of additional gas demand could arise in the captive power segment, with the upper range depending on industries with existing captive capacity deciding to switch their generation to gas.

City gas distribution

CGD is a category encompassing a number of different uses – gas for residential cooking and hot water, CNG for transport, and a wide variety of commercial and small-scale industrial uses. The rise in gas use in urban households over the last decade has largely been policy-driven, underpinned by efforts to free up LPG for use in rural areas. As of September 2018, 18 states and union territories (covering 96 cities, towns and districts) in India had city gas networks, with the majority of residential gas demand consumed in the urban agglomerations of Delhi, Mumbai and Ahmedabad.

In the transport sector, India is one of the largest CNG markets in the world, with nearly 3 million CNG vehicles and half a million CNG buses on the roads. There are ambitious plans to expand the use of biomethane in transport, with targets to add bio-CNG cylinders to the product line of 5 000 CNG stations by 2025. There are also emerging plans to develop LNG as a heavy-duty transport fuel. This degree of policy ambition translates into an average growth rate of nearly 6% in the STEPS; by 2040, around 5% of total gas demand is used in road transport, more than double the global average.

The uptake of gas by more urban consumers depends on the development of gas infrastructure, especially distribution pipelines and CNG stations. A total of 10 bidding rounds have taken place that awarded tenders to build gas distribution networks, but the scale of the 9th (in 2018) and 10th (in 2019) bidding rounds underlined India's ambitions to extend the gas grid. If all the proposed infrastructure were to be built, this would give potential coverage to 70% of India's population, compared with 2% who are connected today (around 5 million households). GAIL, the main transmission system operator in India, is expanding its gas transmission network by around 80% over the next three years to develop a backbone for this roll-out of distribution infrastructure (PNGRB, 2020). The main trunk line under construction is the Jagdishpur-Haldia-Bokaro-Dhamra Pipeline, nearly 4 000 km in length, to bring gas to the eastern and northeastern parts of the country. There are also plans to develop small-scale LNG supply chains, loading them onto specialised containers for transport through road, rail and barge networks, prior to developing pipeline infrastructure.

A host of permitting and financing challenges remain before these plans can be realised. Moreover, the ambition to scale up urban gas consumption is significantly greater than the projected rise in domestic output, so although the CGD sector as a whole stands to benefit from priority access to cheaper domestic gas resources, it also faces the prospect of increased reliance on imported sources of gas. As the balance of domestic and LNG consumed in CGD tilts towards the latter, prices are likely to increase. The extent to which this might be matched by rising household incomes and industry margins is a key uncertainty.

The affordability of gas also hinges on efforts to reform gas transport tariffs in order to prevent consumers farther away from gas sources from being penalised (while avoiding problems with CGD utilities' cost recovery of the kind experienced by electricity distribution companies in the electricity sector). Unbundling supply from transport and ensuring third-party access are crucial prerequisites for the cost-effective utilisation of the grid. The Petroleum and Natural Gas Regulatory Board has recently enacted a series of supportive regulatory actions aimed at rolling out a uniform transmission tariff, standardising gas purchase agreements and launching an electronic bulletin board.

In the absence of significant winter heating loads, the quantity of gas demanded by CGD consumers does not vary much over the course of the year; seasonal variation is of the order of 10%, compared with over 250% in Northwest Europe. This limits the need to oversize parts of the system, including storage, meaning the marginal investment costs per household connection are relatively lower.

Aggregate demand in the CGD sector is likely to be far lower than in the power generation and industrial sectors, where bulk quantities are contracted by power plants and large-scale industrial users, many of which are directly connected to the high-volume transmission network. As a result, the business model underpinning the expansion of gas distribution networks relies less on securing a few big anchor customers than on building pipelines in conjunction with CNG stations, which are currently the most profitable end users.

3.3.3 Gas supply and security in the STEPS

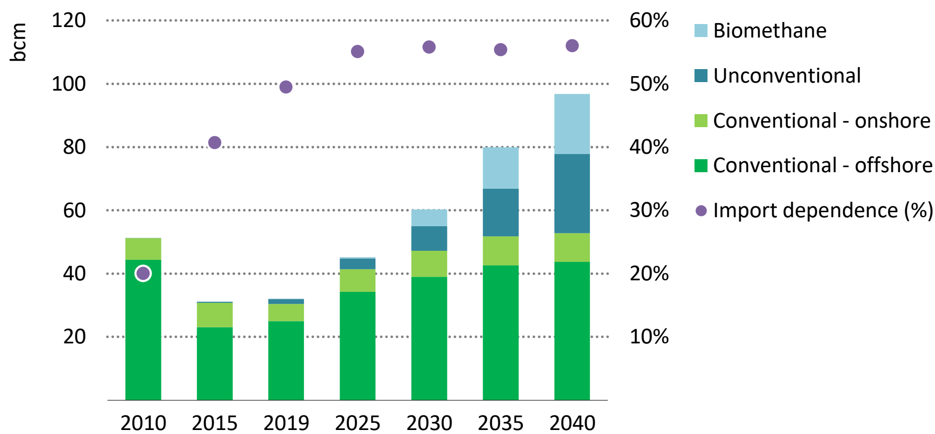
A key uncertainty in India's movement towards a "gas-based economy" is whether it can take place without a vibrant upstream gas sector. Gas production has fallen since reaching a high point in 2010, and has flattened out at around 32 bcm in recent years. Lower-than-expected domestic production has had several knock-on effects on India's energy sector as a whole, leaving distressed assets in the power sector, increasing the cost of fertiliser subsidies, and reshaping the market distortions that stem from the complex allocation regime of cheap domestic gas. The government wants to revitalise investment in India's own gas resources, but the pandemic and its aftermath weigh heavily on prospects for a durable recovery in regional gas prices, particularly as the LNG market appears well-supplied over the next five years; while this is good news for Indian importers, it does not bode well for the government's ambitions for domestic gas production.

Estimates of India's recoverable gas resources stand at around 8 trillion cubic metres (tcm), the majority of which are situated in India's eastern offshore block, Krishna Godavari. The Indian government has taken steps to incentivise development of technically challenging natural gas fields, including deepwater resources, by reforming licensing requirements and allowing companies to market the resulting production at higher prices. This has spurred some new offshore developments by ONGC and Reliance, as well as some spending on smaller fields onshore. The government is also looking to encourage production of coalbed methane, where resources are estimated at some 1.2 tcm and current production is around 1.3 bcm per year. India also has some potential for shale gas, although challenges related to land and water access make large-scale production unlikely.

The major dilemma facing the Indian upstream is the flip side of the "affordability" issue discussed above: prices on the domestic market are at present not adequate to trigger larger investment, especially at a time when company finances are under strain from the pandemic and when there is ample supply of international LNG. In the STEPS, however, the market begins to rebalance in the mid-2020s; domestic natural gas production gradually picks up as prices rise and a hospitable regulatory framework supports additional investment in new offshore fields, and overall output more than doubles to reach 78 bcm by 2040 (Figure 3.21).

An additional, sometimes overlooked, source of domestic gas supply for India is biomethane. India has ample supplies of sustainable feedstock for biogas and biomethane production, mainly from sugar cane, rice and wheat crop residues. Increased urbanisation and improvements in waste management and collection also create significant potential for gas production from municipal solid waste. In an environment where most natural gas is imported, and long-distance pipelines face difficulties with permitting and financing, these local sources of domestic supply represent a potentially attractive option from both a commercial and an environmental perspective. Biomethane production, primarily for use in the transport sector, reaches nearly 20 bcm by 2040 in the STEPS (see section 3.4.2).

Figure 3.21 ▷ Domestic gas production in India in the STEPS, 2010-2040



A revival in offshore gas fields over the next decade helps bring production back to its historic 2010 peak; unconventional gas and biomethane lead growth in the 2030s.

The growing gap between India's domestic output and its projected demand means an increasing reliance on imports. In the STEPS, these are met entirely by LNG; we do not assume any new pipeline connections over the period to 2040. Although the economics could work, the practical and political challenges of bringing gas to India overland from Iran or from Turkmenistan weigh heavily against these options, especially in an environment where LNG is readily available for direct delivery to Indian ports.[4]

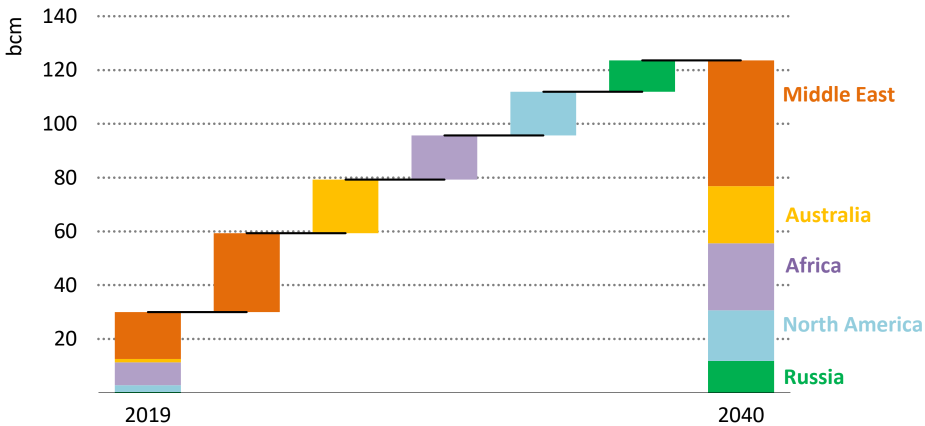
As noted above, India is already a major LNG importer and has several long-term gas contracts in place for around 35 bcm per year of deliveries. The largest source of LNG for the Indian market is Qatar, although its share of the total has declined in recent years as Indian buyers have contracted shipments from a more diverse set of exporters. In 2019, these included African exporters (Nigeria and Angola), other Middle Eastern countries (United Arab Emirates and Oman), the United States and Australia. The range of potential sources of LNG and the increasing flexibility of contractual terms provide some comfort in terms of gas security, although India does face the prospect of a rising bill over time for imported gas.

In the STEPS, India sees a quadrupling of LNG imports from around 30 bcm in 2019 to more than 120 bcm in 2040, and continues to source LNG from a range of international suppliers (Figure 3.22). The annual cost of imported gas rises from $12 billion to $43 billion over this

[4] This represents a change from the previous *India Energy Outlook* (IEA, 2015), in which LNG represented the bulk of India's imports but pipeline imports in the corresponding scenario began in the late 2020s.

period, though this remains relatively small compared with the cost of imported oil ($250 billion in 2040).

Figure 3.22 ▷ Indian LNG imports by exporting region in the STEPS, 2019-2040



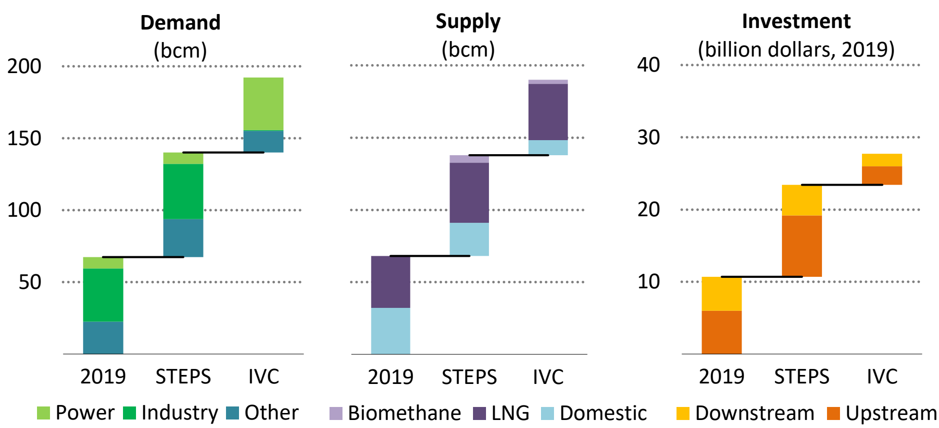
India is a primary market for LNG, accounting for nearly 30% of global growth to 2040 in the STEPS, and is well positioned geographically to develop a balanced portfolio of supply.

Rising LNG imports in the STEPS means that the gap between already-contracted LNG supply and projected LNG demand widens to around 40 bcm by 2030. We assume that this is filled with a mixed portfolio of fixed-term contracts and spot volumes. This does not, as is sometimes assumed, imply a choice between long-term, inflexible, oil-indexed supply and market-responsive spot purchases. While it is true that long-term contracts have "take-or-pay" clauses that oblige buyers to import a minimum contracted quantity of gas, there are several provisions allowing for flexibility. For example, in 2018 GAIL exercised its right to resell US LNG volumes that were uncompetitive in the Indian market by agreeing "swap contracts" with Shell. Moreover, volumes agreed in long-term contracts need not necessarily be oil-indexed, and in recent years sellers have accepted a variety of pricing terms, agreeing to reduced "slopes" dictating the strength of the oil-gas price link, netback to Henry Hub prices or linkages to emerging Asian spot benchmarks. Contracting a spot cargo, by contrast, is by definition "take-or-pay", and short-term contracts underpinning spot deliveries can still be indexed to oil. India's need for reliable baseload supplies of LNG implies that long-term contracts will remain part of the mix, even as the country seeks to benefit from the growing commoditisation of LNG.

3.3.4 Realising the India vision for gas in 2030

The outcomes in the STEPS move India towards the government's aim of becoming a much more gas-based economy, but do not meet its aspirations in full. We explore the additional upside potential for gas in the IVC, in which gas achieves an 11% share in the overall energy mix by 2030 (compared with 9% by the same year in the STEPS). In the IVC, gas use grows at an average annual rate of 8% to 2030, or around eight times the average rate of growth over the last decade. All sectors share in this additional growth, with around 40% coming from industry, especially manufacturing, steel and petrochemicals, and half from the power sector. CNG is also more widely used as a transport fuel (Figure 3.23).

Figure 3.23 ▹ Growth in key indicators for gas in India in the STEPS compared with the IVC, 2019-2030

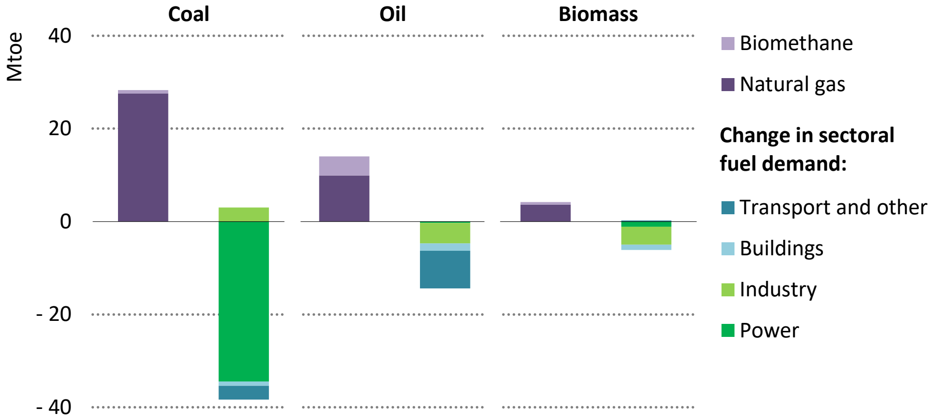


The IVC sees a more than doubling of gas demand in the next decade, sustained by market reforms and policy support.

The IVC is based on higher economic growth than the STEPS, so some of the additional gas demand is due to higher activity levels. But in order to increase substantially its share of overall energy demand, gas needs to *replace* other sources of energy to a much greater extent than is seen in the STEPS. Given its dominance in India's energy system, coal is the main target for substitution, and around 40 Mtoe is displaced in the IVC (or around 10% of total coal demand in 2019) (Figure 3.24).

Part of the switching in the IVC also takes place in the industry sector, where gas displaces some oil, as well as some biomass which is used in traditional industrial furnaces. However, the main change in relation to the STEPS comes in power generation. In the STEPS, installed gas-fired capacity remains roughly level through to 2030 (albeit with a steady rise in utilisation rates); in the IVC, 35 GW of gas-fired capacity is added over this period.

Figure 3.24 ▷ Change in gas demand in the IVC due to fuel switching from coal, oil and biomass, 2019-2030



To achieve a gas-based economy in the IVC, gas must displace other fuels to a much greater extent than in the STEPS, especially in power.

Non-fossil gases also grow more strongly in the IVC. Some 4 Mtoe of biomethane is deployed as bio-CNG by 2030, decreasing the size of the projected fleet of petrol and diesel vehicles by around 4%, and helping to reduce oil import dependence and import bills. The wider penetration of gas in urban areas in the IVC meanwhile reduces demand in urban areas for LPG; this facilitates greater uptake of LPG in rural areas, aiding in the total displacement of around 50 Mtoe of biomass by 2030.

There is no visible trade-off in the IVC between stronger growth of natural gas and the rise of renewables. Both enjoy robust growth at the expense of incumbent fuels, and the increased share of solar PV in power generation is complemented by the flexibility that natural gas provides.

In order to support the significant level of gas demand growth in the IVC, a number of changes are needed that go beyond those assumed in the STEPS. They can be grouped into four broad categories:

- **Accelerated pace of infrastructure growth.** In the IVC, annual investment in gas infrastructure doubles compared with historical average rates, reaching $5 billion per year on average from 2019-30, or a quarter more than in the STEPS. As a result, the number of CNG stations expands further, resulting in more comprehensive coverage and reduced congestion at stations; LNG terminals, which currently have limited connectivity with potential consumers, are better connected to an expanded grid. The flexibility and reliability of the gas grid is enhanced by more efficient use of capacity, with an independent transmission system operator supporting the roll-out of flexible pipeline nomination schedules, and a balancing code which allows a secondary market for spare pipeline and LNG capacity.

- **Faster transition to a competitive and transparent gas market**. The IVC implies a rapid transition that involves consistent implementation of market-based reforms, a rationalisation of applicable taxes and more robust implementation of existing policies, such as those related to unbundling. This is key to rationalising end-user prices and thereby widening the consumer base.
- **More favourable investment climate for domestic producers of various gases.** In the IVC, annual upstream spending is 60% higher than in the STEPS, and it reaches over $5 billion by 2030, as continued regulatory and licensing reforms generate greater interest in a faster-growing gas market. This spending includes greater investment in waste-to-gas and other biomethane projects, as well as investments that accelerate progress with low-carbon hydrogen (via electrolysis). Higher incomes in the IVC help to support affordability.
- **Stronger policy recognition of positive externalities.** Gases produced and transported in a responsible way can bring environmental benefits when replacing more polluting fuels. The IVC would reduce the carbon intensity of the economy considerably compared with the STEPS. An economy that is 14% larger than in the STEPS in 2040 would be associated with emissions that are 12% lower (see also next section). In addition, more rapid development of biomethane would bring rural co-benefits, reducing stubble burning and methane emissions and underpinning rural business development.

In the IVC, India imports around 90 bcm of gas from international markets by 2030. It takes advantage of today's gas glut, but it also underpins new upstream and midstream developments. India's import requirements in the IVC mean that it becomes a linchpin in the global LNG balance; those requirements open up a global supply gap in the mid-2020s that call for an additional 10 bcm of new projects.

As LNG requirements grow in the IVC, India's importers are able to play a more active role in international gas markets, building a portfolio of supply, shipping and regasification stretching beyond India's own territory. This increases their purchasing power and ability to optimise supply and demand, bringing greater contractual flexibility on volumes as well as the ability to hedge using a diverse set of pricing mechanisms. Regasification capacity reaches 170 bcm by 2030, nearly a quarter more than in the STEPS.

3.3.5 The environmental implications of gas use in India

The contribution of natural gas to reaching environmental goals varies widely across different countries, between sectors and over time. Where it replaces more polluting fuels, it reduces both air pollution and CO_2 emissions. But natural gas is not in itself a solution to climate change: it is a source of emissions in its own right, and new gas infrastructure can lock in these emissions for the future. Our analysis examines these divergent opportunities and risks.

The IVC and the SDS highlight these dynamics in different ways. Gas demand is higher in both cases than in the STEPS, but the effect of that additional gas use is to bring down emissions