

Asian Insights SparX

2030 Energy Mix

Refer to important disclosures at the end of this report

DBS Group Research . Equity

5 Jul 2018

Fossil fuels need not fret

- We expect global energy demand to increase by 1.5% CAGR through to 2030 - a slowdown compared to the last two decades owing to energy efficiency gains
- We forecast a clear shift towards renewables in the global energy mix, from 15% in 2016 to 22% in 2030, as government policies are geared towards cleaner energy
- However, we believe demand for the three key fossil fuels – coal, oil, and natural gas – will not peak till 2030, instead growing at varying rates
- Strong demand for natural gas as the cleaner fossil fuel; demand for coal and oil will grow at a much slower pace
- In our region, Chinese gas players will benefit from volume gains from structural shift towards cleaner energy
- Chinese oil majors will look to boost gas production and will benefit from reforms in domestic gas pricing; oil prices are expected to remain robust despite muted demand outlook
- Indonesian coal miners still look attractive as they continue to prioritise high profitability over production growth
- Singapore rigbuilders are well positioned to meet emerging trends in the gas market through the provision of offshore gas facility solutions
- India is a bright spot for energy demand growth and we are positive on the gas distribution and oil downstream space

HSI Index: 28545.57

STI Index: 3,235.9

JCI Index: 5,633.94

Top Picks

Company	Price (LCY) 03-Jul	Mkt Cap (US$m)	12-mth Target Price (S$)	% Upside	Rcmd
China Gas Holdings	31.20	19,760	37.00	19%	BUY
China Tian Lun Gas Holdings	7.46	941	10.50	41%	BUY
ENN Energy Holdings Ltd	80.55	11,135	95.00	18%	BUY
Towngas China Co Ltd	7.70	2,718	9.00	17%	BUY
Huaneng Renewables Corp	2.67	3,596	4.00	50%	BUY
China Longyuan Power	6.25	6,402	7.85	26%	BUY
China Petroleum & Chem	6.90	106,486	9.00	30%	BUY
CNOOC Ltd	13.32	75,806	16.00	20%	BUY
PetroChina	5.88	137,177	7.60	29%	BUY
Indo Tambangraya Megah	21,300	1,676	35,000	64%	BUY
Adaro Energy	1,720	3,831	2,800	63%	BUY
Tambang Batubara Bukit Asam	4,000	3,209	4,500	13%	BUY
Sembcorp Marine	1.99	3,044	2.90	46%	BUY
Keppel Corporation	7.02	9,317	10.20	45%	BUY

Source: DBS Bank, DBS VI, Bloomberg Finance L.P.

The DBS Asian Insights SparX report is a deep dive look into thematic angles impacting the longer term investment thesis for a sector, country or the region. We view this as an ongoing conversation rather than a one off treatise on the topic, and invite feedback from our readers, and in particular welcome follow on questions worthy of closer examination.

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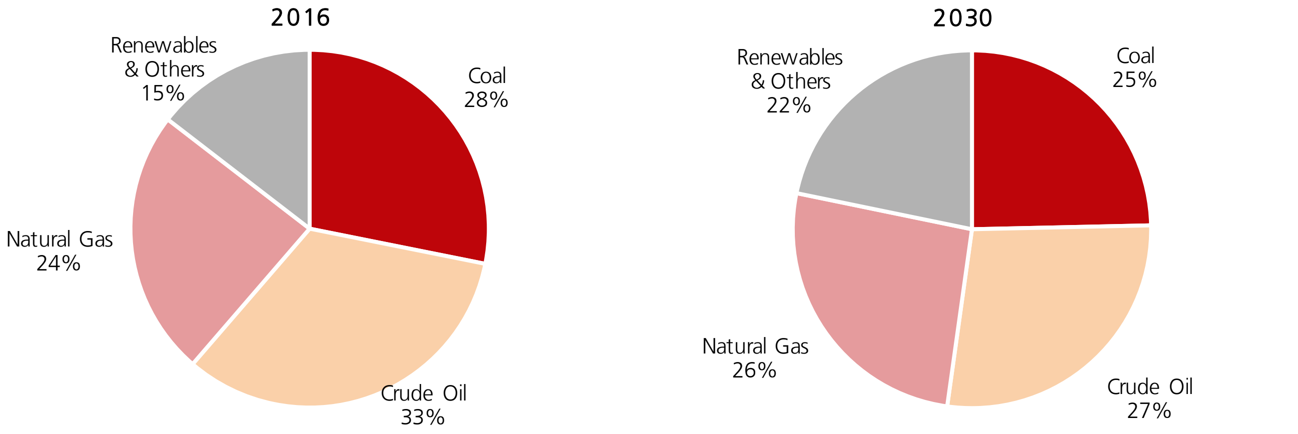
With special thanks to Anuj Upadhyay and Sabri Hazarika for their contributions to the report

INVESTMENT SUMMARY

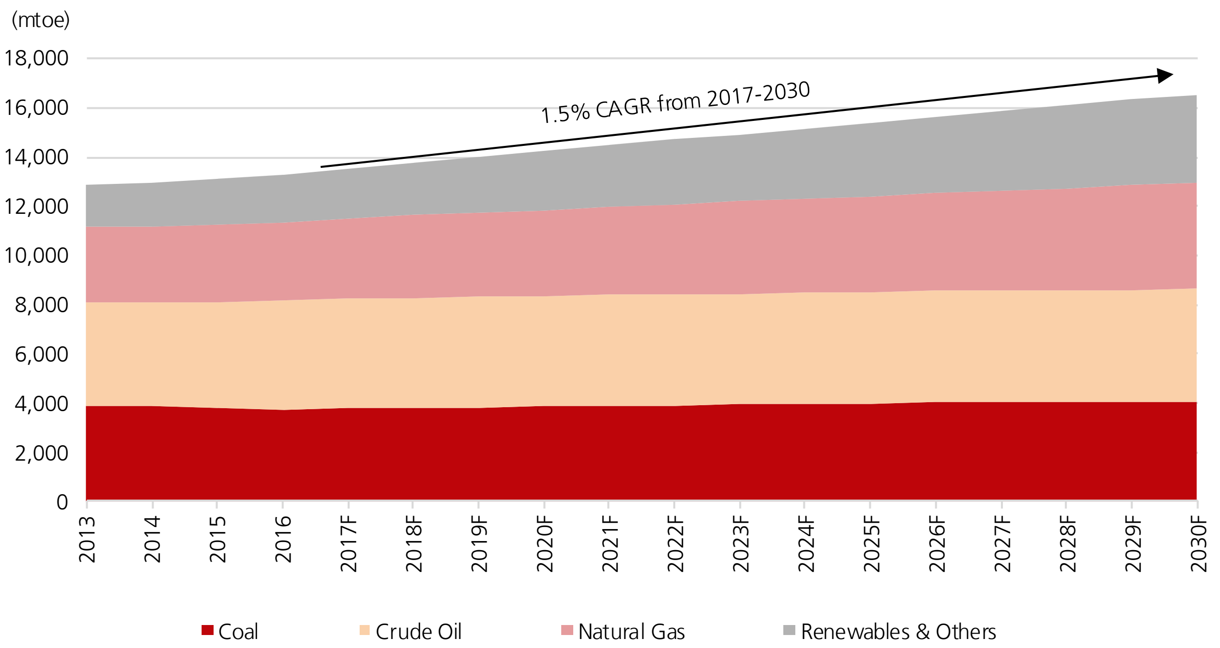
Clear trend towards renewables, but fossil fuel demand to grow on an absolute basis nonetheless. We expect global energy demand to increase at an average rate of about 1.5% p.a. from 2017-2030, premised on c.3.25% p.a. growth in global GDP, offset by improvements in energy efficiency (i.e. declines in energy intensity). Despite a clear shift towards renewables in the energy mix, from 15% in 2016 to 22% in 2030, we believe demand for the three key fossil fuels – coal, oil, and natural gas – will not peak till 2030, growing at varying rates. Natural gas demand will be strong and is expected to be c.33% higher by 2030 than 2016 levels, while demand for coal and oil will grow at a much slower pace.

Change in energy mix – 2016 vs. 2030 (DBS expectations)



Source: DBS Bank forecasts

Growth in energy demand (in million tons of oil equivalent)



Source: DBS Bank forecasts

We identify and elaborate on six major regional and global energy trends:

1) Increasing importance of gas in power production in China. Natural gas is greatly supported by the Chinese government as a type of fossil fuel that burns cleaner than oil or coal. China targets to increase the overall energy consumption proportion for natural gas from 5.9% in 2015 to 10% in 2020, and 15% in 2030. Natural gas consumption in 2017 had increased 15% y-o-y to 239.5bn cubic metres (m3). In order to reach the government's target, we expect natural gas consumption to be above 340bn cubic metres (m3) by 2020, representing a CAGR of 13% from 2016-2020. Growth will be driven by industrial coal boiler conversions, rural household coal-to-gas conversions for heating, and lower domestic gas prices following pipeline reforms, which will stimulate demand.

2) Increasing clean energy sources in China's electricity mix. In China, power supply is dominated by coal but fuel mix is changing to more wind and solar power. In 2017, coal power generation accounted for 73% of China's total power generation vs 80% in 2013. During the period, the proportion from renewable energy (RE) increased to 6.7% in 2017 vs 2.7% in 2013. We expect the ratio of RE to further increase to 9.3% in 2020 and 14.5% in 2030. From 2020 to 2030, we expect non-hydro RE to account for c.53% of the increase in China's power generation. Supportive government policies are still in place and tariff parity with coal could be earlier than expected, with advancements in technology driving down construction and operating costs of wind and solar power farms.

3) Rise of electric vehicles and impact on oil demand. Passenger transport accounts for c.20% of global oil consumption. Our auto analyst expects global electric vehicle sales to grow strongly from c.1.26m units in 2016 to over 26m units in 2030, representing an almost 15x increase in yearly sales volumes. Much of the increase in sales will come from Asia, in particular China. We estimate this will affect c.6% of oil demand by 2030, but a more important component of the demand picture is increasing fuel efficiency. Thus, oil demand growth from other sectors and emerging economies will be offset by the above factors and we are projecting global oil demand will grow quite slowly till 2030. Hence, supply will be the key determinant for oil prices in the medium to long term. We expect 2018 Brent crude oil price to average between US$70-75/barrel (bbl) and our 2019 average forecast for Brent is slightly lower at around US$65-70/bbl.

4) US as net energy exporter. Strong domestic production, thanks to technology breakthroughs that has more than halved the production cost of shale oil and gas, coupled with relatively flat energy demand has paved way for the US to become a new energy exporter. Last year, the US became a net natural gas exporter, with exports that quadrupled y-o-y to 1.94bn cubic feet. US LNG exports are set to quintuple by 2019 from 2017's level to 9.6 billion cubic feet per day. If this materialises, the US will become the world's third-largest natural gas exporter by 2020, after Australia and Qatar. For oil, US producers now export around 1.5-2.0 million barrels of oil per day (mmbpd), which could rise to 4.0 mmbpd over the next 5 years, as most of the incremental shale production is likely to be exported, due to lack of domestic refineries able to handle the light sweet oil. This is likely to have a moderating effect on oil & gas prices, and help Asian countries lower their import costs and diversify their sources of energy.

5) India as a leading energy consumption and reform story. India's energy consumption growth is healthy with oil consumption CAGR at ~5% in the last 5-10 years and expected to grow by 4% CAGR up to 2040 based on International Energy Agency (IEA) projections. There is a strong reform push in India's power sector and Government push towards renewables in the power mix, which should result in a much higher proportion of renewables in the power sector, with declining share of fossil fuels. The reforms in the oil & gas space – deregulation, pricing freedom, natural gas usage promotion – has improved prospects for gas distribution and downstream oil players, who will also benefit from attractive volume growth in the medium to long term.

6) Coal usage yet to peak in Asia. Coal accounts for around 50% of Asia's energy mix, and we believe that it will continue to be one of the most important energy components going forward given its affordability and availability. There is a need to ensure the availability of stable electricity supply to power industrial activities. We estimate global coal demand will still exhibit slow growth overall during FY17-30, with declining demand from Europe and flattish demand from China, offset by growing demand from India and also supported by ASEAN countries, mainly Thailand and Indonesia. We forecast coal price benchmark of US$75 per ton in FY18-20F, and US$70 per ton in FY21F and beyond, on the back of tight supplies.

Which players benefit from these trends?

Impact on subsectors and stocks

Subsectors	Impact / Outlook	Proxies
Chinese Gas Players	• Gas distributors will benefit from structural changes towards cleaner energy, enjoying strong volume growth that outweighs potential dollar margin compression • China gas distributors will benefit from rising import of energy from the US to China at competitive prices	• China Gas • China Tian Lun Gas • ENN Energy • Towngas China
Chinese Renewable Energy Players	• Near term adverse impact on solar supply chain players and wind turbine generator manufacturers as the business competition is set to intensify • Renewable energy set to reach grid parity with coal in China within 5 years with improving efficiencies and declining installation costs; thereby reduce subsidy burden and drive up demand for solar/wind power developers	• Huaneng Renewable • Longyuan Power
Chinese Oil Majors	• Shift towards natural gas will be a major point of interest for the Chinese oil majors in the long-term • Government has recently stepped up efforts in gas pricing reform, which is positive for gas producers	• Sinopec • CNOOC • PetroChina
Indonesian Coal Miners	• Healthy coal supply-demand outlook is positive for coal mining companies • Indonesian coal miners will continue to prioritise high profitability over production	• Indo Tambangraya Megah • Adaro Energy • Tambang Batubara Bukit Asam
Singapore Rigbuilders	• Singapore rigbuilders are well positioned to meet emerging trends in the gas market through the provision of gas solutions • We expect gas facility orders to account for half of orderbook in the medium term	• Sembcorp Marine • Keppel Corporation
India Energy Plays	• Positive on the gas distribution and oil downstream space • Execution of reforms continuous to be an issue in the power sector, only regulated entities preferred	• Petronet LNG • Gujarat Gas • Bharat Petroleum • Hindustan Petroleum • Indian Oil • Power Grid • National Thermal Power Corporation

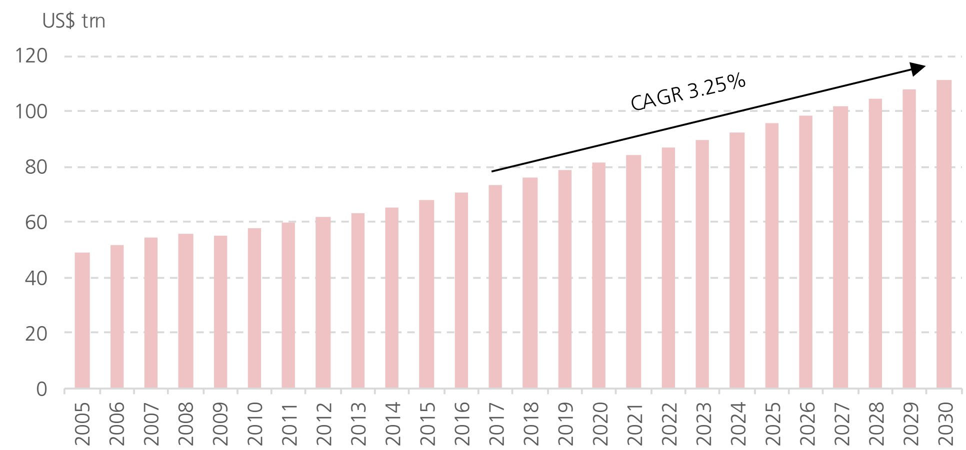
Source: DBS Bank

ENERGY MIX TRANSITION OVERVIEW

Global Energy Demand & Energy Mix Transition Forecast

Growth in global GDP will continue to boost demand for energy. The world economy continues to grow, driven by increasing prosperity in the developing world. Global GDP CAGR is projected to average around 3.25% to 2030, not too different from growth rates in the past two decades or so. Global output is partly supported by population growth, with the world population increasing by around 1.2 billion to reach nearly 8.5 billion people in 2030, a CAGR of just over 1%. But the main driver of economic growth is increasing productivity (i.e. GDP per person), which accounts for the majority of global expansion and is expected to lift more than 2.5 billion people from the low income strata. The increasing prosperity of the developing world is a key force shaping economic and energy trends over the next 25 years. Over 80% of the expansion in world output is driven by emerging economies, with China and India accounting for over half of that expansion. While African countries will likely account for nearly half of the increase in global population, contribution to world GDP growth will be less than 10%, weighed down by weak productivity.

Growth in world GDP (at 2010 PPP, US$, real GDP)



Source: OECD data

Growth rates will however, slow down, compared to previous decades. The expansion in global output and prosperity drives energy demand, with growth in energy consumption led by fast-growing developing economies. Global energy demand is forecast to grow at around 1.5% CAGR till 2030 as highlighted earlier, but this is a slowdown from over 2% CAGR in the previous 20 years. The slowing demand growth is largely due to deceleration in population growth trends, and better energy efficiency – that is energy intensity (energy used per unit of GDP) falling more quickly than in the past. Global GDP CAGR is projected to be 3.25% till 2030, but energy consumption is estimated to increase by only 1.5%. The other key trend contributing to lower energy intensity is increasing electrification of final end-user demand, especially in transport and heating.

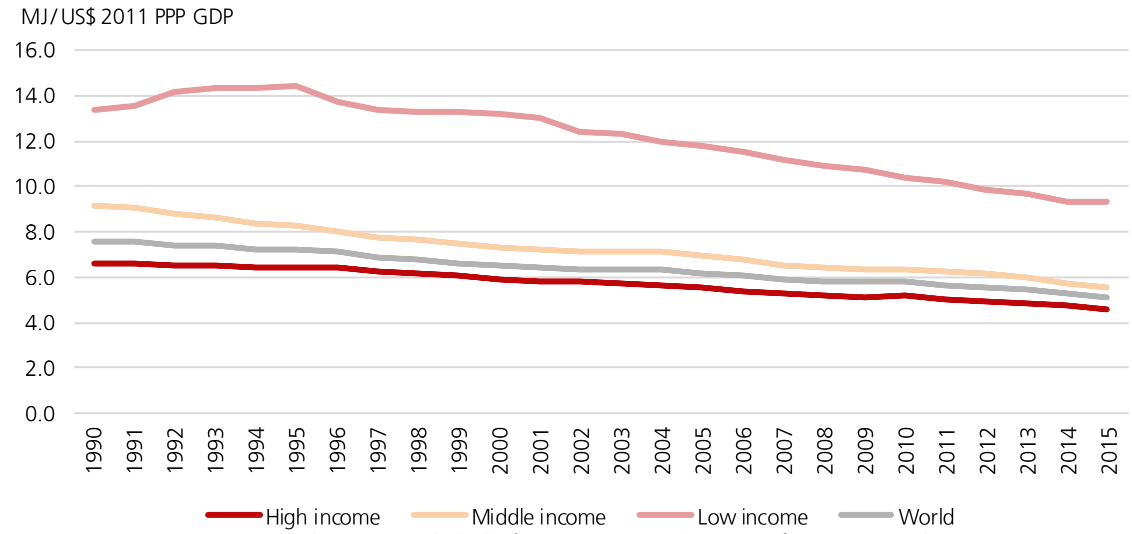
The world's energy system is highly sensitive to changes in energy efficiency. The world's energy intensity (units of energy per unit of GDP) has been declining on average by 1.4% per year for the last two decades. One of the main reasons for this is the accelerating electrification of the energy system, as electricity use is more efficient than burning fossil fuels directly owing to less heat loss. This effect is accentuated by the move towards renewables – as energy loss from solar and wind generation capacity is insignificant. The efficiency trend will be further boosted by the mainstreaming of electric vehicles, which typically consume less energy compared to liquid-fuel powered vehicles. There are lower efficiency improvements in aviation, maritime and rail transport sectors as internal combustion engines are likely to remain as the mainstay in these sectors in the medium to long term.

Energy losses will decline with rise of renewables. Fossil power plants convert only a portion of their input energy to electricity, as much of the input energy is lost as heat. Though combined heat and power plants capture some of this heat for other useful purposes, losses are still significant. In the case of renewable power generation, electricity is generated directly from wind, solar irradiance, and from running or elevated water. Although 100% of the input is not converted into electricity, the electricity generated is considered primary energy as the wind, sun or water not captured is not counted as part of the energy system. Hence, with a growing proportion of renewable power generation in the energy mix, heat loss in the production of energy will decline.

The overlooked driver of demand – energy intensity

Energy intensity plays a sizeable role in energy demand. Energy intensity is defined as the primary energy consumed per unit of GDP. A diverse number of factors can influence energy intensity, including a secular shift away from energy-intensive industries in certain countries, technology improvement and evolution (e.g. proliferatio`017, over 68% of the world's energy use is not covered by efficiency codes or standards (that number would be larger if China is excluded), which means there is still much policy headroom when it comes to driving energy intensity lower.

Global energy intensity trends over a 25-year period



Note: Energy intensity is measured in Mega Joule (MJ) of energy consumed per unit of GDP measured in 2011 constant currency US$ purchasing power parity terms

Source: World Bank

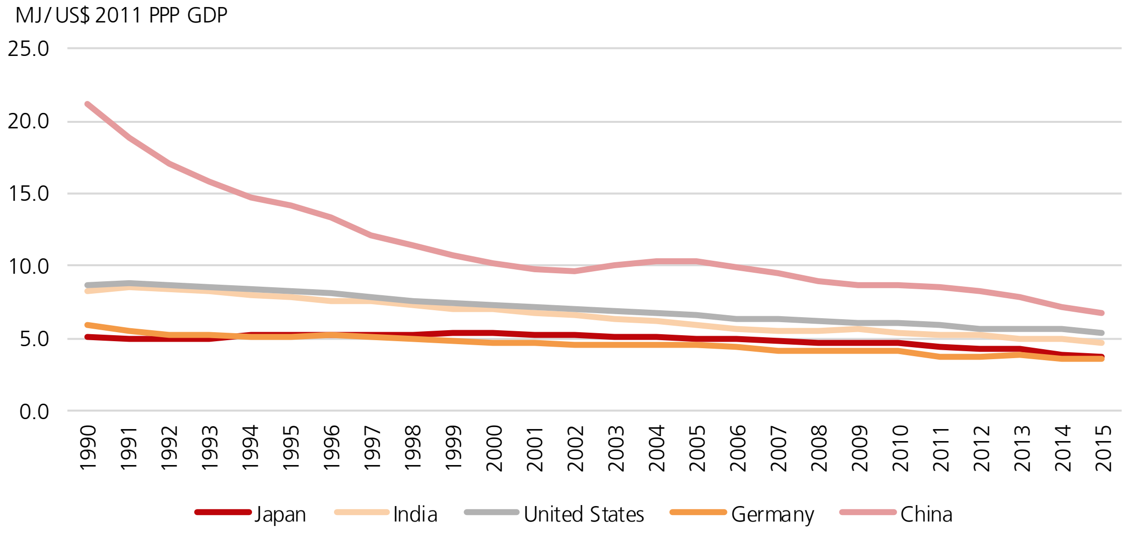
Energy intensity trends over different time periods

	CAGR 1990-2000	CAGR 2000-2010	CAGR 2010-2015
Country Groups			
High Income	-1.02%	-1.33%	-2.35%
Middle Income	-2.26%	-1.36%	-2.72%
Low Income	-0.12%	-2.33%	-2.15%
World	-1.54%	-1.13%	-2.40%
Key Countries			
Japan	0.54%	-1.14%	-4.60%
India	-1.75%	-2.58%	-2.44%
China	-7.02%	-1.63%	-5.07%
US	-1.65%	-1.87%	-2.29%
Germany	-2.35%	-1.18%	-2.62%

Source: World Bank data, DBS Bank calculations

Chinese energy efficiency declined during its high growth decade of 2000-10. As can be seen from the table above, the trend of energy efficiency improvements or declines in energy intensity are not uniform across time periods for various country groups as well as individual countries. For developed or high income countries, the trend is most secular with improving efficiency in every time period as we move forward in time. However, for middle and low income countries, periods of high growth may be associated with high energy intensity, which could slow down the overall improvement rate. This is most apparent for China in the 2000-10 timeframe, where very high GDP growth rates coincided with lower focus on energy efficiency. Energy efficiency has now picked up again in the current decade, where Chinese GDP growth has moderated and environment friendly energy practices have evolved. Move over to low income countries like India, and it seems that improvements in energy efficiency are lower in the current decade owing to higher economic growth. Thus the Chinese pattern could be repeated for emerging countries like India, which will likely moderate the pace of energy efficiency improvements to an extent as we move towards 2030.

Energy intensity trends for key high energy consuming countries



Source: World Bank

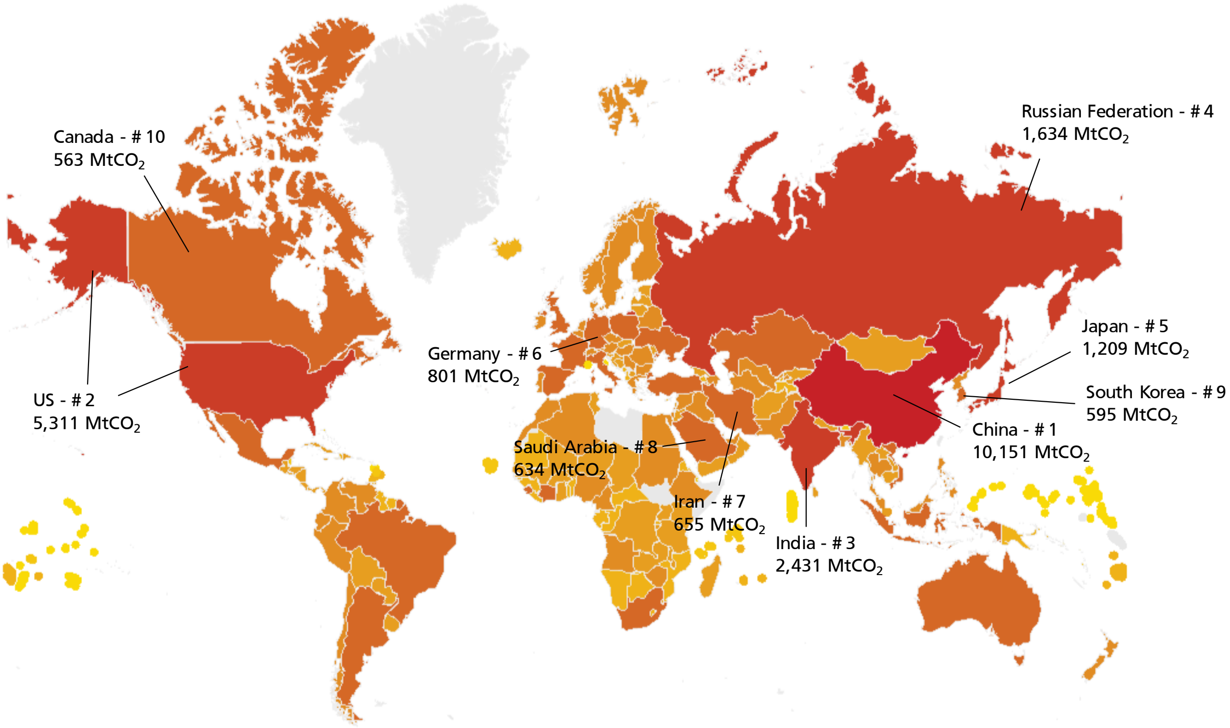
Energy mix changes as shift towards cleaner energy marches on

We forecast 2030 energy mix derived from bottom-up forecasts for countries based on government targets. We note that many governments now have formally stated policies on reducing emissions levels (especially post-Paris Agreement) and targeting more renewables in the energy mix to a 2030 horizon. Our forecasts are primarily based on these targets, working on a country-level basis and aggregating those numbers to reach our global forecast. While a country-by-country analysis of all 195 countries is beyond our scope, we note that the top 15 energy-consuming countries account for three-quarters of global energy demand (with China and the US as frontrunners, at 23% and 17% of global demand respectively, and India coming in a distant third at 5.5%), and therefore have focused on these countries as the cornerstone of our bottom-up methodology. While there might be concerns that targets may not be representative of the true trajectory, we believe that in general the targets set by the top 15 energy consuming governments are fairly achievable, and in fact, necessary to meet Paris Agreement pledges.

Paris Agreement a landmark deal – to drive lower emissions. While agreements and negotiations around emissions reductions have been taking place for the last three decades, the landmark Paris Agreement signed in 2015 and involving 197 nations representing more than 88% of global greenhouse gas (GHG) emissions was a game-changer. Each nation ratifying the agreement has submitted 'Nationally Determined Contributions' (NDCs) detailing their commitments, which aligns the capabilities and circumstances of each individual country with the goals of the global Paris Agreement framework.

Clean energy to take a larger role in global energy mix. The Paris Agreement helps in formalising some of the policy directions of the top GHG emitters, which is not only important from an environmental perspective, but also from a global energy mix perspective, as the top emitters are invariably also the largest consumers of energy in the world (barring Brazil and Saudi Arabia, who are in one 'top 10' list but not the other). China and the US alone account for c.40% of the world's energy consumption in 2017 (China 23%; US 17.1%). The next largest consumer – India – trails considerably behind at 5.5%. In general, there is a shift towards lower fossil fuel use, and a larger share of the mix going to renewables. Additionally, within the NDCs, we can see that some countries (e.g. China) have explicitly targeted a percentage of non-fossil fuels in the energy mix by a certain time period.

Heat map of the largest carbon emitters globally (darker = higher)



Note: MtCO2 is Metric Tons of Carbon Dioxide and is a measure of carbon emissions

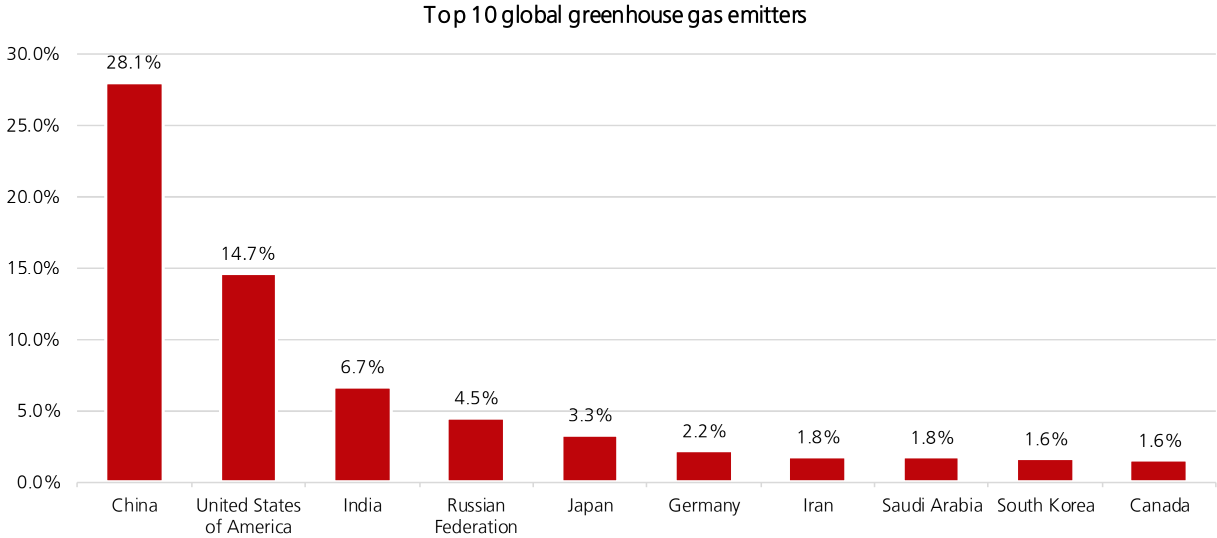
Source: Global Carbon Atlas

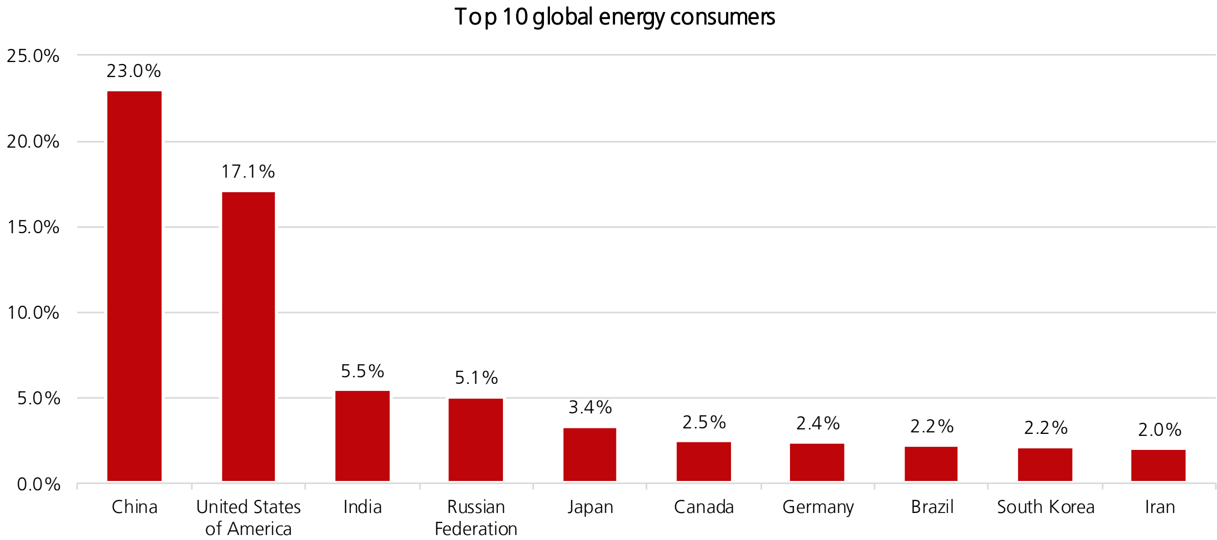
Summary of major global climate change agreements

Agreement	Year	Details
Kyoto Protocol	1997	• First signed in 1997, introducing legally binding emission reduction targets for developed countries • Second commitment period (Doha amendment) began on 1 Jan 2013 and ends in 2020. Participating countries to reduce emissions to 18% below 1990 levels • **Weakness of Kyoto Protocol: only requires developed countries to take action.** The US never signed up; various have pulled out. Thus, it **now only applies to 14% of the world's emissions**
Copenhagen and Cancun Agreements	2009/ 2010	• Copenhagen Accord in 2009 subsequently adopted by the Conference of the Parties (COP) (to the 1992 United Nations Framework Convention on Climate Change) in 2010 as the Cancun Agreement. Not legally binding. • **Regarded as an interim arrangement through 2020** until a legally binding successor to the Kyoto Protocol was put in place • Set a goal of limiting global temperature increase to 2 degrees Celsius • Called on all countries to put forward mitigation pledges • Established broad terms for reporting and verification of actions • Goal to mobilise US$100bn/year in public and private finance for developing countries • Establishment of a new Green Climate Fund
Paris Agreement	2015	• Landmark agreement with 197 nations having signed the agreement, with 176 parties currently having ratified, **representing more than 88% of global greenhouse gas emissions** • Aims to keep global temperature rise below 2 degrees Celsius above pre-industrial levels with an aspiration of 1.5 degrees Celsius • **Involves both developed and developing countries** • Calls on signatories to submit their 'Nationally Determined Contributions (NDC)', and make new pledges for deeper emission cuts every five years • Developed countries to provide US$100bn/year in funding to poorer countries to assist through 2025

Source: Climate Action Tracker, IEA, various government websites

Top 10 global greenhouse gas emitters vs. top 10 global energy consumers – mostly the same folk





Source: Global Carbon Atlas, BP Statistical Review

Climate change pledges – top 5 emitter/consumer countries

China		
Paris Agreement	2030 unconditional target(s)	Peak CO_2 emissions latest by 2030
		Non-fossil share of energy supply: 20% in 2030
		Forest stock: +4.5billion m^3 by 2030 compared to 2005
		Carbon intensity: -60% to -65% below 2005 by 2030
	Coverage	Economy-wide
	Land Use, Land-Use Change and Forestry (LULUCF)	Unclear how LULUCF is included
Copenhagen Accord	2020 target(s)	Carbon intensity: -40% to -45% below 2005 by 2020
		Non-fossil share of energy supply: 15% in 2020
		Forest cover: +40million ha by 2020 compared to 2005
		Forest stock: +1.3billion m^3 by 2020 compared to 2005
	Condition(s)	None
US		
Paris Agreement	Ratified?	Yes, but Trump has communicated intent to withdraw. Legally in place until Nov 2019
	2030 unconditional target(s)	Emissions levels 26-28% below 2005 by 2025
		Emissions levels 9-17% below 1990 by 2025 excl. LULUCF
	Coverage	Economy-wide, incl. LULUCF
	LULUCF	Included
Copenhagen Accord	2020 target(s)	17% below 2005 by 2020 incl. LULUCF
	Condition(s)	None
Kyoto Protocol	Member of KP CP1 (2008-2012)	Not ratified
	Member of KP CP2 (2013-2020)	No
	KP CP1 target (below base year)	7% below 1990
	KP CP2 target (below base year)	N/A
India		
Paris Agreement	Ratified?	Yes
	2030 unconditional target(s)	33% to 35% below 2005 emissions intensity of GDP by 2030
		Non-fossil share of cumulative power generation capacity 40% by 2030
	Coverage	Not specified
	LULUCF	Additional (cumulative) carbon sink of 2.5-3.0 Gigaton Carbon Dioxide Equivalent ($GtCO_2e$) by 2030
Copenhagen Accord	2020 target(s)	20-25% below 2005 emissions intensity of GDP by 2020
	Coverage	Excluding agriculture sector
	Condition(s)	None
Long-Term Goal(s)		Per-capita emissions never to exceed those of the developed world

16Russia		
Paris Agreement	Ratified?	No; ratification now looks to be delayed until 2019
	2030 unconditional target(s)	Emissions 25-30% below 1990 levels by 2030
	Coverage	Economy-wide, incl. LULUCF
	LULUCF	Target is subject to "the maximum possible account of absorbing capacity of forests"
Copenhagen Accord	2020 target(s)	Emissions 15-25% below 1990 levels by 2020
	Condition(s)	a) Appropriate accounting of the potential of Russia's forestry sector b) Undertaking by all major emitters of legally binding obligations to reduce emissions
Kyoto Protocol	Member of KP CP1 (2008-2012)	Yes
	Member of KP CP2 (2013-2020)	No
	KP CP1 target (below base year)	0% below 1990
Long-Term Goal(s)		None

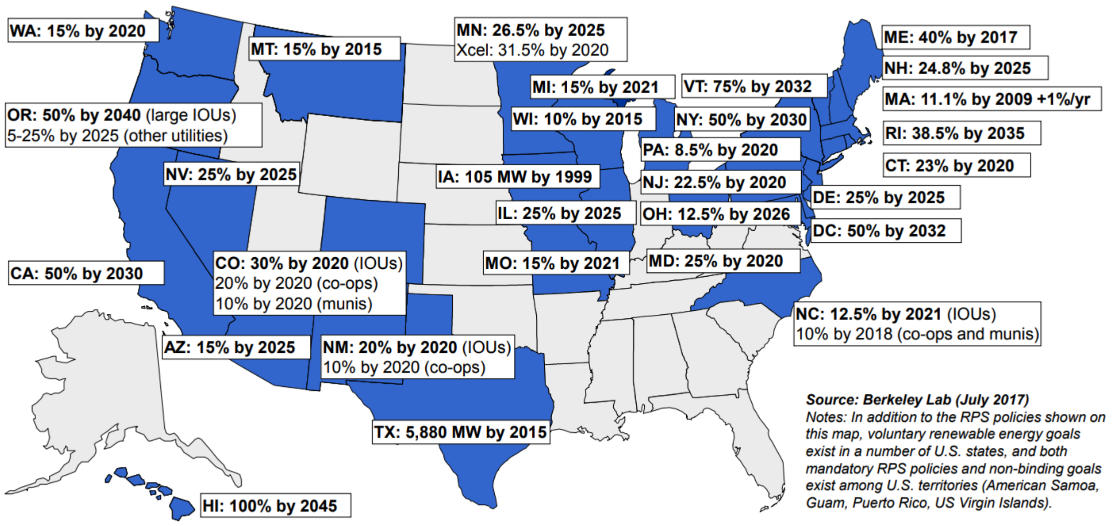
Japan		
Paris Agreement	Ratified?	Yes
	2030 unconditional target(s)	Emissions 26% below 2013 levels by 2030
	Coverage	Economy-wide, incl. LULUCF and overseas credits for 2030
	LULUCF	LULUCF credits considered
Copenhagen Accord	2020 target(s)	3.8% below 2005 emissions levels by 2020
	Condition(s)	LULUCF credits considered
Long-Term Goal(s)		Reduce greenhouse gas emissions by 80% by 2050 (base year not specified)

Source: Climate Action Tracker

Focus on the US – state-level targets driving emissions reductions

Renewable Portfolio Standards a key regulation in the US. While the US has not set a national-level target for its energy mix, the Renewable Portfolio Standards (RPS) is a major policy driver of the shift towards renewables in the energy mix. The RPS is a state-level requirement placed on retail electric suppliers to source a minimum percentage of their retail load from renewable energy sources. Currently 29 out of 50 US states and DC have RPS in place, though not in any standardised form – target proportions and timeframes vary considerably. Overall, RPS policies have accounted for roughly half of all US renewable electricity generation since 2000, so this is a key driver of the adoption of renewables in the US.

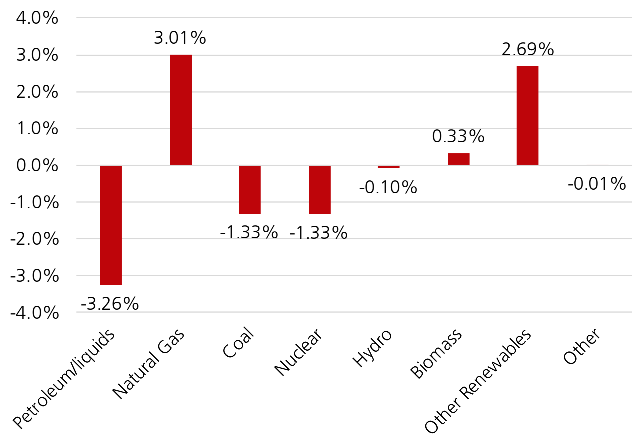
US Renewable Portfolio Standards by state



Source: Berkeley Lab 2017 Annual RPS Summary Report

Renewables requirements under RPS in 2030 will be 1.83x that of 2017 levels. Based on forecasts by the Berkeley Lab (the research arm of the Department of Energy), total RPS requirements are set to grow at a CAGR of 4.8% from 2017-2030, with 2030 RPS requirements representing around 1.83x of that in 2017. This matches the EIA's prediction of non-hydro renewable energy to grow by c.83% over that same time frame, with its proportion of the US' total energy mix increasing from 3.5% in 2017 to 6.2% in 2030. Natural gas is the other beneficiary, with its proportion in the energy mix climbing by c.3% owing to continued growth in shale gas volumes.

% change in energy source's proportion of total US consumption – 2030 vs. 2017



Source: US EIA forecast

Focus on China – towards bluer skies

With an objective to 'Make the skies blue again', China has embarked on various policies to reduce the proportion of dirtier fuels in its energy mix, while boosting the usage of cleaner fuels. In particular, as part of the 13th Five-Year Energy Development Plan issued in January 2017 by the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA), a mandatory target was introduced for the first time for coal, with the aim of reducing its proportion of the energy mix to below 58% in 2020 (compared to about 62% in 2016 and 60% in 2017, so China may very well overshoot the target if this trajectory continues). Meanwhile, China plans on ramping up usage of natural gas to above 10% by 2020 and above 15% by 2030.

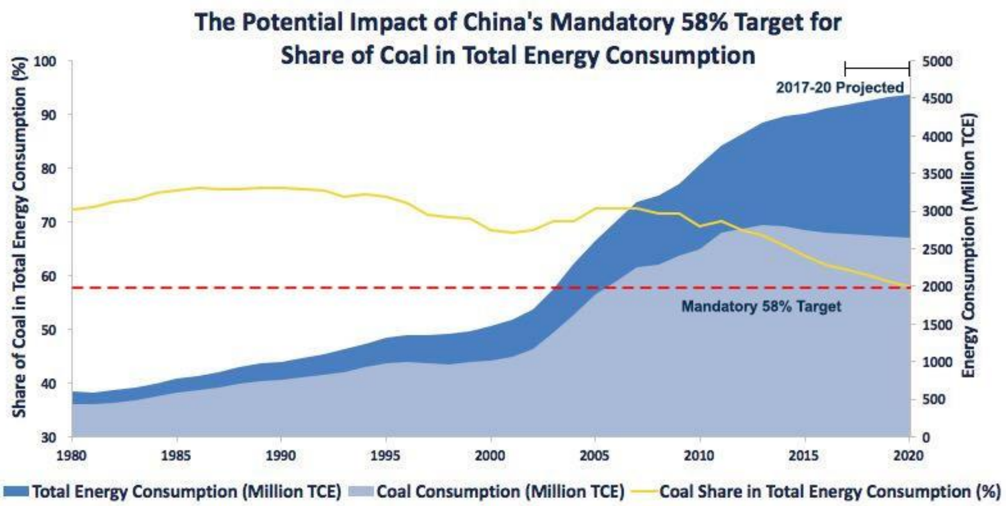
In terms of fossil fuel use, as SOEs dominate production of fuels in China, we can reasonably expect the high-level policy objectives to trickle down to the company level, giving credence to the targets set.

Summary of China's key energy mix targets from the various papers released by the government

	2020	2030	2050
Primary energy consumption (tonnes of coal equivalent)	5bn	6bn	
Non-fossil fuel proportion in energy mix	>15%	>20%	>50%
Non-fossil fuel proportion in power generation activities		>50%	
New Energy Demand		Should mostly be met by clean energy	
Coal share of energy mix	<58%		
Natural gas share of energy mix	>10%	>15%	
Energy consumption per unit of GDP	Down 15% compared to 2015		
Carbon emission per unit of GDP	Down 18% compared to 2015		
Energy self-sufficiency rate	>80%		

Source: NDRC

Coal as a proportion of China's energy mix should continue declining in the near-term

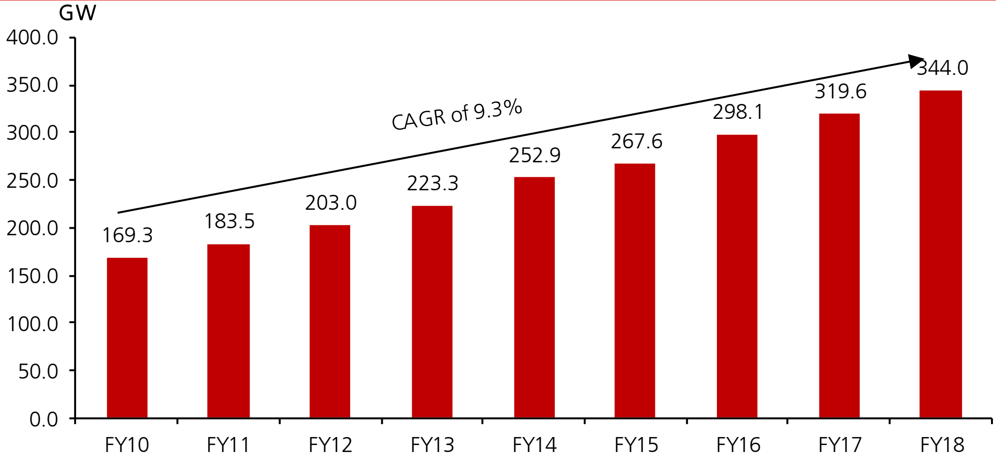


Source: National Resources Defense Council

Focus on India – 175GW renewable energy goal

Strong growth in power sector post reforms. The power sector in India is mainly governed by the Ministry of Power. The enactment of Electricity Act, 2003 has brought in revolutionary changes in almost all areas of the sector. Through this Act, a conducive environment has been created to promote private sector participation and competition in the sector by providing a level playing field. This has led to significant investments in generation, transmission and distribution areas. Over the years the installed capacity of Power Plants (Utilities) has increased to about 3,44,002 MW as of March 2018 from a meagre 1,713 MW in 1950. The per capita consumption of electricity in the country has also increased from 15 kWh in 1950 to about 1,075 kWh in 2015-16. The government has also achieved its target of 100% village electrification by electrifying entire 5,97,464 census villages. Regional grids have been integrated into a single national grid, thereby providing free flow of power from one corner of the country to another through strong inter-regional Alternating Current (AC) and High-Voltage Direct Current (HVDC) links. As a result, the all India peak demand (MW) as well as energy (MU) shortage have registered steady declines. The peak shortage and energy shortage have declined to 0.8% and 0.9% respectively during the year 2017-18 compared to 11.9% base deficit and 12.7% peak deficit during 2009-2010.

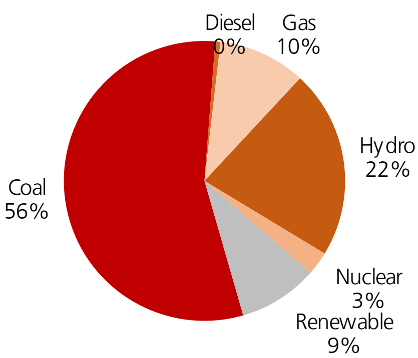
Total installed power generation capacity growth over FY10-18



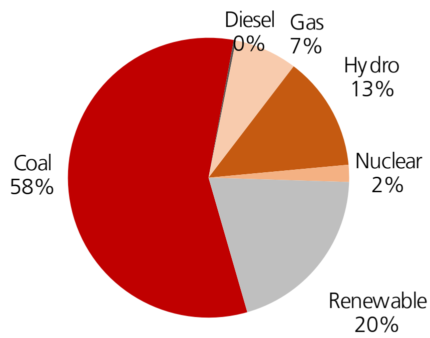
Source: CEA, Emkay Global Research

Capacity addition growth skewed towards renewables. Capacity has expanded significantly over the past 8 years, largely dominated by coal capacity additions. However, with a commitment to address environmental issues, the government has of late been focussing more on adding renewable energy capacities. The government targets to add 175 GW of renewable capacity by 2022 compared to only ~32GW of installed capacity as on FY15. The current installed renewable capacity as on Mar 2018 stands at 69GW which has already expanded more than 2x in the past three years.

Power sector fuel mix composition as of March 2010



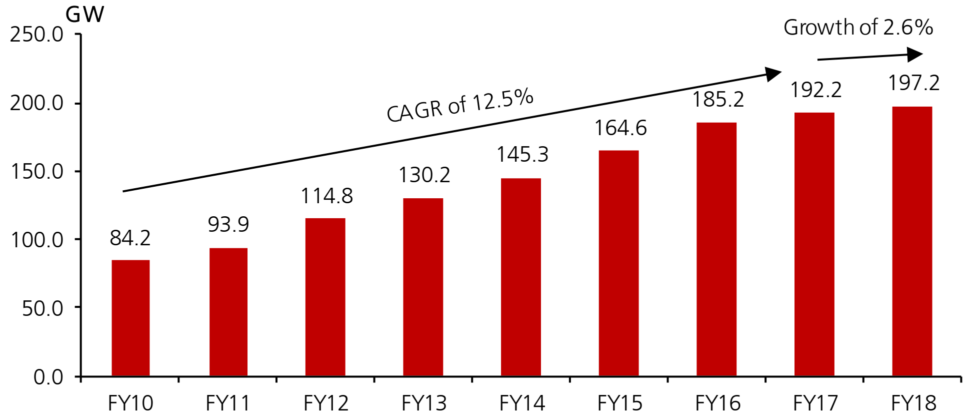
Power sector fuel mix composition as of March 2018



Source: CEA, Emkay Global Research

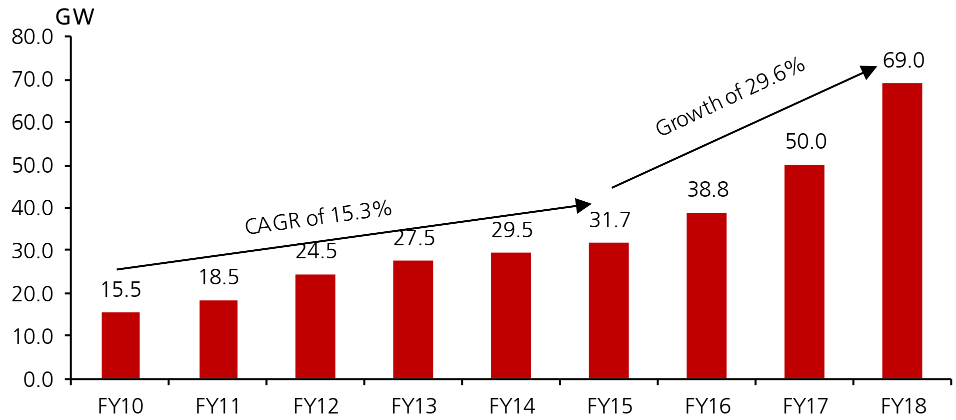
Capacity addition across the coal segment had witnessed a strong CAGR of 12.6% over FY10-FY17. However, growth in FY18 was very subdued at only 2.6% y-o-y, primarily due to an increased focus towards renewable capacity. On the other hand, renewable energy capacity grew at a CAGR of 15.3% over the FY10-FY15 period, and there was a significant jump of over 29.6% CAGR during FY15-FY18.

Total coal installed power generation capacity growth over FY10-18



Source: CEA, Emkay Global Research

Total renewable installed power generation capacity growth over FY10-18



Source: CEA, Emkay Global Research

Outlook of capacity additions – focus on renewables. While there is ~35-40 GW of thermal capacity under construction, the focus of the Government of India (GoI) is on setting up large scale renewable capacity as its commitment to the Paris Climate talks.

GoI's ambitious target to install 175GW of renewable capacity by 2021-2022. This comprises of 100 GW Solar, 60 GW Wind and 15 GW of Biomass, small hydro and Waste to power projects. The installed renewable capacity in India stands at 69GW as of March 2018. The year FY18 (fiscal year to March 2018) witnessed 38% y-o-y rise in renewable capacity additions (highest ever), dominated largely by new solar capacity (+140% rise y-o-y to 21.7GW in FY18 vs 9GW in FY17).

The ambitious target was set by the Indian government during the Paris Climate change talks as India's commitment for clean environment and ecology for future generation. India along with France has set up an International Solar Alliance (ISA), which is a treaty-based coalition of 121 solar resource rich countries located between the Tropic of Cancer and the Tropic of Capricorn. The ISA was created to address the special energy needs of these countries and provide a platform to collaborate on addressing identified gaps through a common, agreed approach.

India will contribute US$27 m to the ISA for creating the corpus, building infrastructure and recurring expenditure over a 5-year period from 2016-17 to 2020-21. In addition, public sector undertakings of the government – Solar Energy Corporation of India (SECI) and Indian Renewable Energy Development Agency (IREDA) – have contributed US$1 million each towards the ISA corpus fund.

Renewable installed capacity in India (Current vs Target)

Type of project	FY18 (MW)	Target FY22E (MW)
Small Hydro	4,486	5,000
Wind	34,046	60,000
Bio Power	8,839	10,000
Solar	21,652	100,000

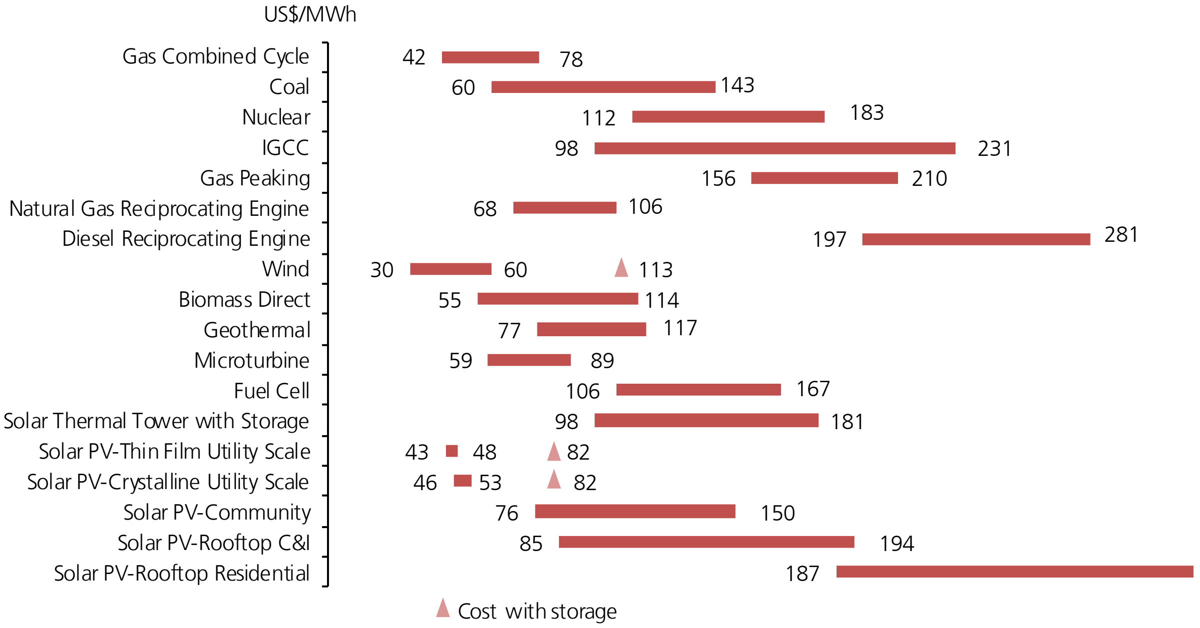
Source: CEA, Emkay Global Research

Government to focus on supportive infrastructure for renewables expansion. The setting up of renewable capacity will result in new challenges related to transmission of power as unlike thermal baseload capacities, power flow in solar and wind depends largely upon climatic conditions and are thus volatile in nature. This leads to major challenges for grid operators to maintain grid frequency, as high volatility can lead to collapsing of the same. Thus, GoI is also simultaneously working toward procuring large amount of batteries and inventories at affordable rates, and also on improving grid technology.

Cost of alternative/ renewable energy sources continue to fall

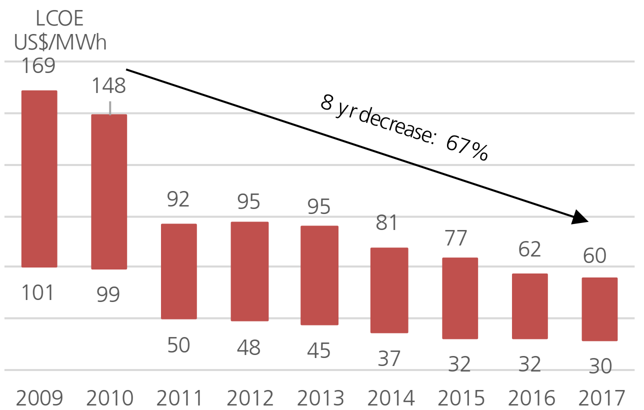
Renewable power generation costs and capital costs continue to decline, fuelling greater adoption. According to estimates from Lazard study as shown below, levelised cost of energy (LCOE) for wind and solar power have fallen by 67% and 86% respectively, over the last 8 years in the US market, and are quite competitive with fossil fuels like gas and coal, if we exclude storage requirements. Capital costs for a number of alternative energy generation technologies are currently in excess of some conventional technologies (e.g. gas), but costs are declining. Coupled with uncertain long-term fuel costs fossil fuel technologies, alternative/ renewable energy generation technologies are quickly closing the wide gaps in electricity costs. Of course, dispatch characteristics and grid infrastructure issues will ensure a mix of renewable and fossil fuel (both baseload and peaking) technologies will co-exist in future, albeit with a higher mix of renewable capacity in the system than currently.

Unsubsidised Levelised Cost of Energy (LCOE) Comparison in the US market (US$/ MWh basis)

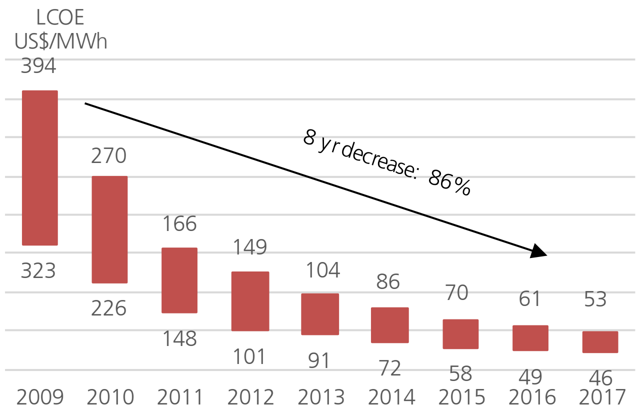


Source: Lazard's Levelised Cost of Energy Analysis Version 11.0, DBS Bank

Wind LCOE Trend in the US

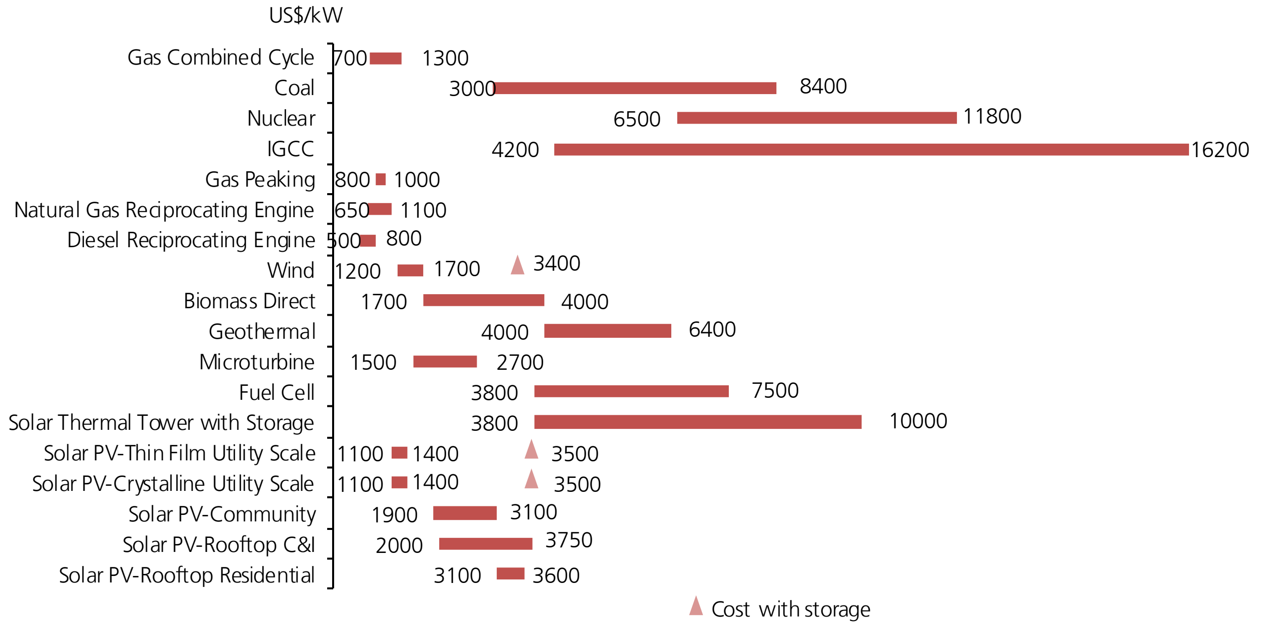


Solar PV LCOE Trend in the US



Source: Lazard's Levelised Cost of Energy Analysis Version 11.0, DBS Bank

Capital Cost Comparison in the US market (US$/ kW basis)

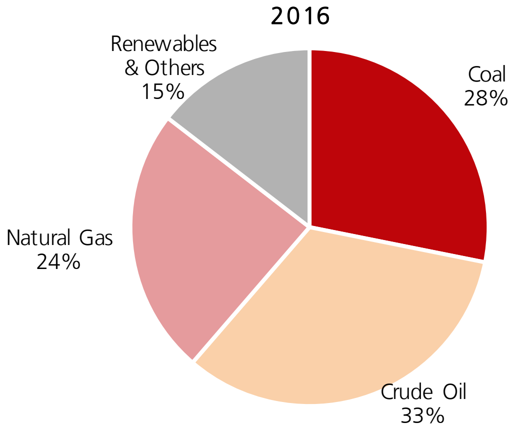


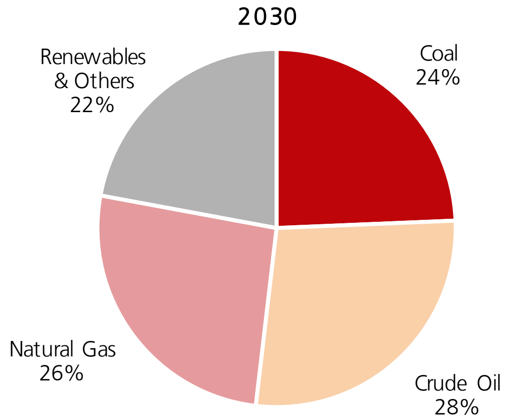
Source: Lazard's Levelised Cost of Energy Analysis Version 11.0, DBS Bank

Global Energy Mix Forecasts

Clear trend towards renewables, but fossil fuel demand to continue growing nonetheless. We expect global energy demand to increase at 1.5% CAGR from 2017-2030, premised on the back of c.3.25% CAGR in global GDP, offset by improvements in energy efficiency (i.e. declines in energy intensity). Despite a clear shift towards renewables in the energy mix, from 15% in 2016 to 22% in 2030, we believe demand for the three key fossil fuels – coal, oil, and natural gas – will not peak till 2030, albeit grow at differing rates. Natural gas demand will be strong and in 2030 is expected to be c.33% higher than 2016 levels, while demand for coal and oil will grow at a much slower pace.

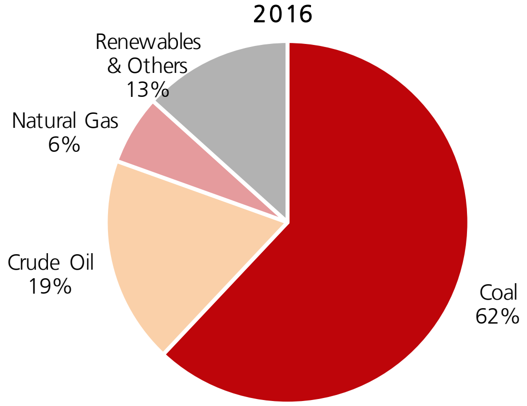
Change in global energy mix – 2016 vs. 2030 (DBS expectations)

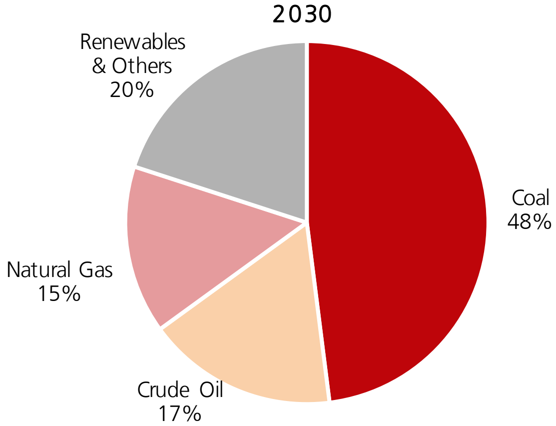




Source: BP data, DBS Bank forecasts

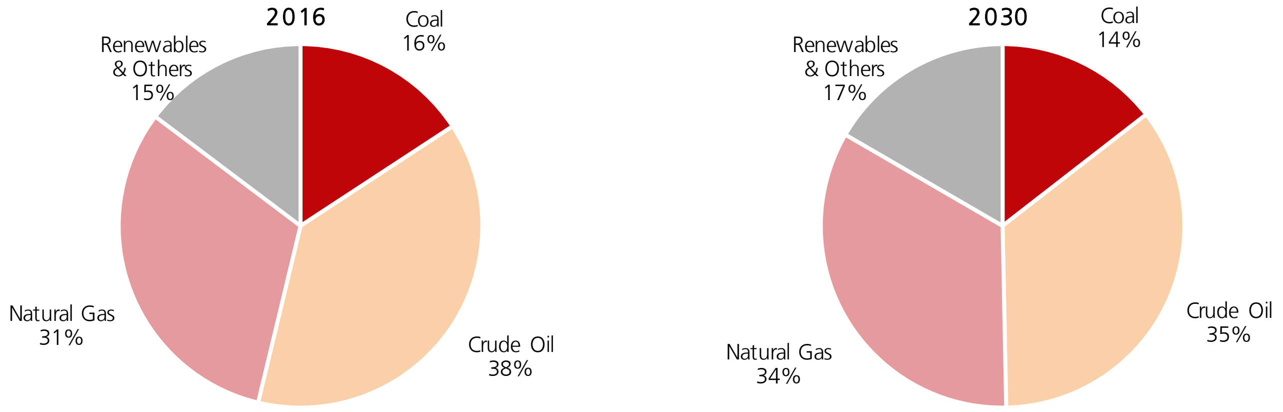
Change in China energy mix – 2016 vs. 2030 (DBS expectations)





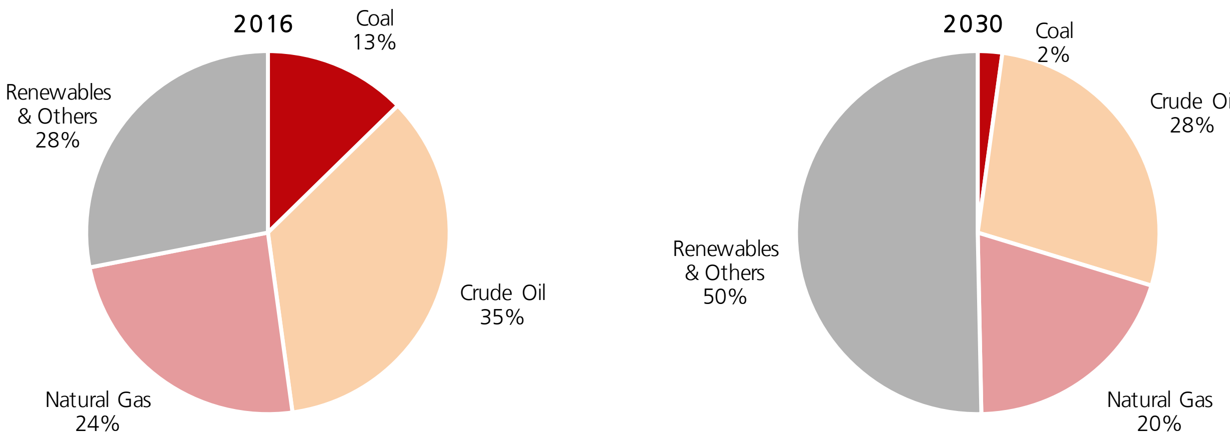
Source: BP data, DBS Bank forecasts

Change in US energy mix – 2016 vs. 2030 (DBS expectations)



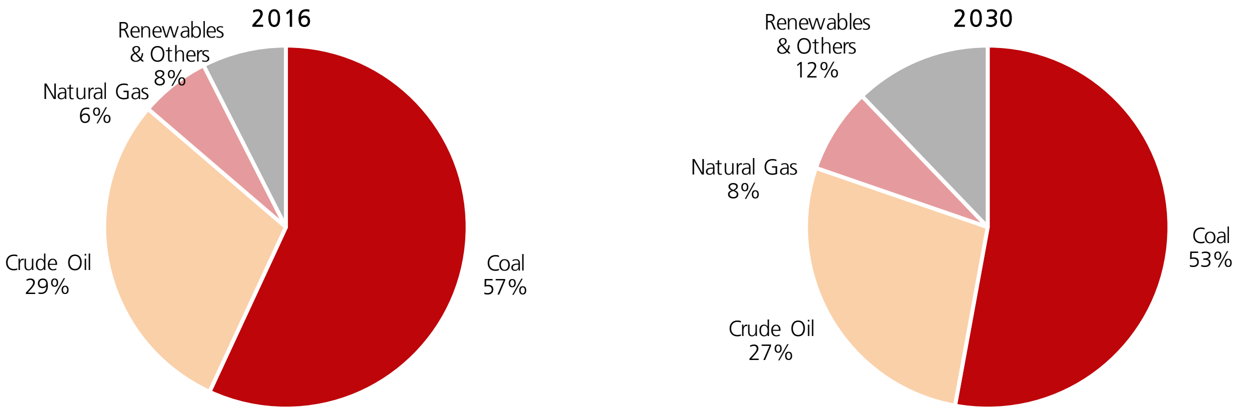
Source: BP data, EIA, IEA, DBS Bank forecasts

Change in EU-3 (Germany, France, UK) energy mix – 2016 vs. 2030 (DBS expectations)



Source: BP data, IEA, respective government data, DBS Bank forecasts

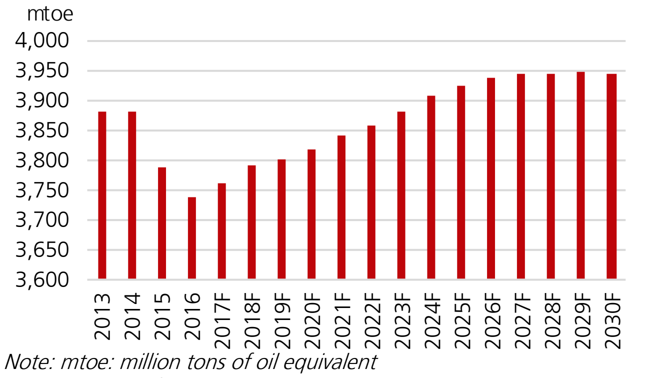
Change in India energy mix – 2016 vs. 2030 (DBS expectations)



Source: BP data, Government data, DBS Bank forecasts

Coal: New coal-fired power plant projects can be reduced, but scrapping existing operating capacity and capacity under construction is highly unlikely, as there remains a need to ensure the availability of stable electricity supply to power industrial activities. We estimate global coal demand will still exhibit slight growth over FY17-30, with declines in Europe and flattish growth in China offset by India and also supported by ASEAN countries, mainly Thailand and Indonesia.

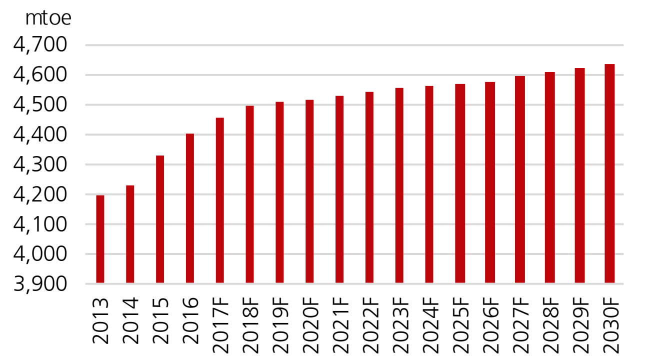
Global coal demand forecast



Note: mtoe: million tons of oil equivalent
Source: DBS Bank Forecasts

Crude oil: The biggest movers in the crude oil picture through 2030 are India and Japan. On one hand, we see significant additions to oil demand from India, on the back of strong growth in energy demand as its economy grows at a clip of close to 6% CAGR from 2017-2030, while efficiency gains remain modest. In addition, India's Draft National Energy Policy (2017) – which lays out the expected energy mix until 2040 – actually sees oil assuming an increasing role in the energy mix (from around 24.5% in 2012 to 27% by 2040). Meanwhile, Japan is expected to significantly lower its exposure to oil and is targeting 20-22% of its energy mix in 2030 to come from nuclear, and 22-24% from renewables, which is a significant change from 2016 levels where just 9.2% of primary energy demand was from nuclear and renewables.

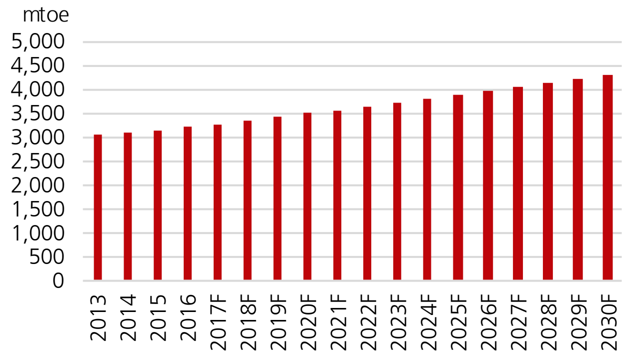
Global crude oil demand forecast



Source: DBS Bank Forecasts

Natural Gas: China is the single largest driver of natural gas demand through 2030, accounting for almost 40% of total incremental natural gas demand in 2030 as compared to 2016 levels, we estimate. This is driven by China's desire to combat domestic environmental pollution levels. China has set a target for natural gas to account for 15% of its energy mix by 2030 (up from 6-7% currently). Notably, out of the top 15 energy consuming countries, 12 of them are looking at growth in natural gas demand on a 2030 timeframe, mainly as an intermediate substitute between clean energy and dirtier fuels. Of the remaining 3 countries, Germany's natural gas demand could fall as it is replaced by renewables under its Energiewende policy, and Saudi Arabia and Mexico only see slight declines in gas demand.

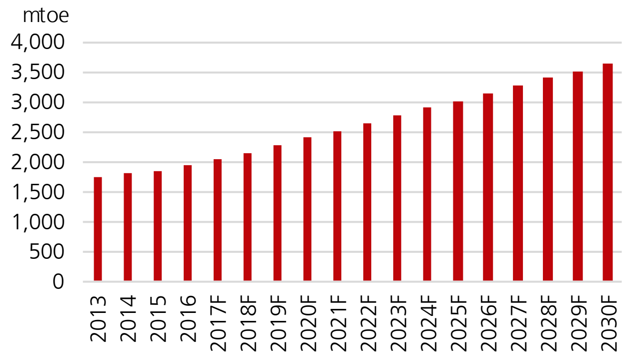
Global natural gas demand forecast



Source: DBS Bank Forecasts

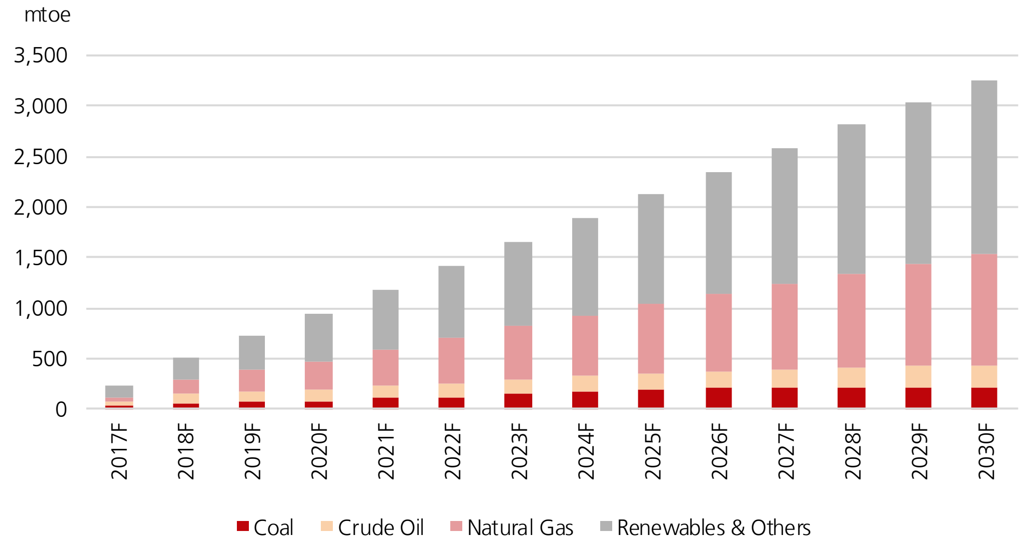
Renewables and Nuclear: Every country we have studied has policies in place targeting a higher proportion of renewables within the energy mix; the trend is clear. In aggregate, we expect demand for clean energy to grow at a CAGR of c.4.6% from 2017 to 2030, depressing the share of coal and oil in the global energy mix by 2030.

Global renewables and nuclear forecast



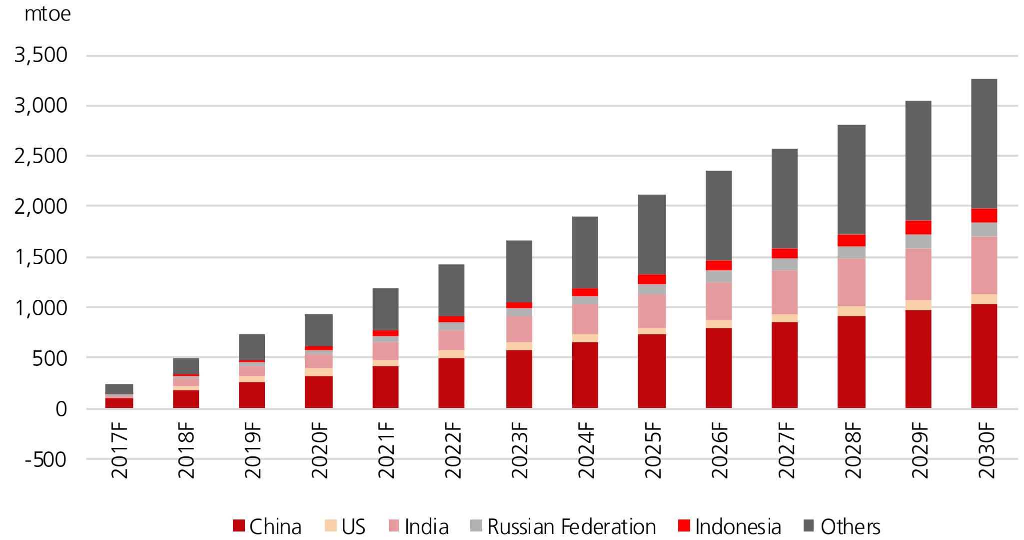
Source: DBS Bank Forecasts

Contribution to cumulative global energy demand by energy source



Source: DBS Bank Forecasts

Contribution to cumulative global energy demand by country



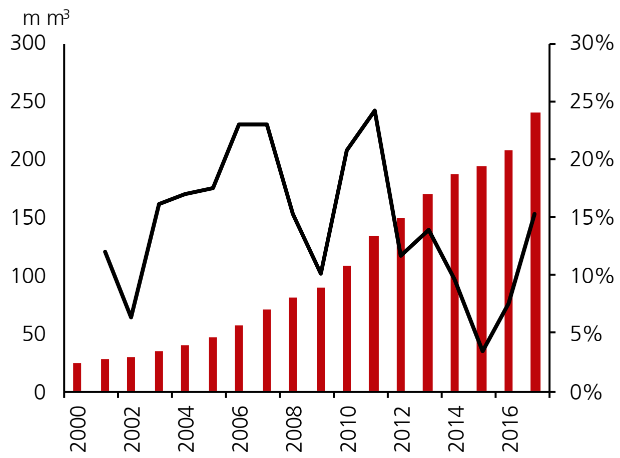
Source: DBS Bank Forecasts

KEY GLOBAL & REGIONAL ENERGY TRENDS

1. Increasing importance of gas in power production in China

Demand for natural gas in China enjoyed strong growth over the past years. The natural gas consumption CAGR was a robust 16% from 2005 to 2015. However, the proportion of natural gas in energy mix has lagged behind international peers' average of 23.7% of energy consumption. Moreover, demand for natural gas slowed down since the collapse of the oil price during 2014 and the gas consumption growth only recorded CAGR of 5% from 2014-2016.

Natural gas consumption



Source: CEIC, DBS HK

Main causes for China falling behind international peers is the lack of supportive government policies and law enforcement. There were not enough punitive and incentive measures in place for market participants. Also, the development of storage facilities and transmission pipeline network was slow, which is mainly due to the lack of a regulation on rate of returns.

The demand for natural gas has accelerated since 2H2016, as the Chinese government started to strictly enforce environmental regulations and issued favourable policies to stimulate clean energy usage. The NDRC issued the 13th Five Year Plan (FYP) for natural gas, which includes detailed targets for upstream, midstream and downstream segment of the value chain. By the end of 2020, natural gas as the proportion of primary energy consumption is targeted to increase from around 6% in 2015 to 10% in 2020. Moreover, the government also targets to further increase the proportion to above 15% by 2030. We believe the target is achievable given that the government is determined to boost clean energy consumption in China.

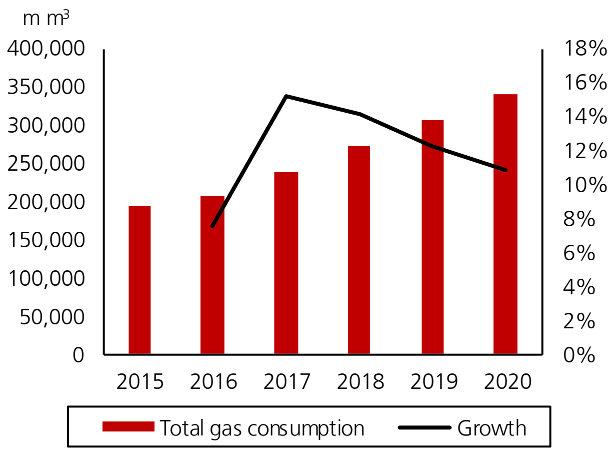
13th FYP main targets

	2015	2020	CAGR
Cumulative proven reserves (m m3)	13,000,000	16,000,000	4.2%
Production (m m3 / year)	135,000	207,000	8.9%
Proportion of energy consumption (%)	5.9%	10.0%	
Total population using gas (m)	330	470	7.3%
Proportion of population above town level using gas	42.8%	57.0%	
Pipeline length ('000 km)	64	104	10.2%
Pipeline transmission capacity (m m3)	280,000	400,000	7.4%
Underground storage capcaity (m m3)	5,500	14,800	21.9%

Source: NDRC

Good growth expected in natural gas volumes. By the end of 2017, the natural gas consumption increased 15% y-o-y to 239.5bn. In order to reach the government's target, we expect the natural gas consumption to reach above 340bn m3 by 2020, representing a CAGR of 13% from 2016-2020.

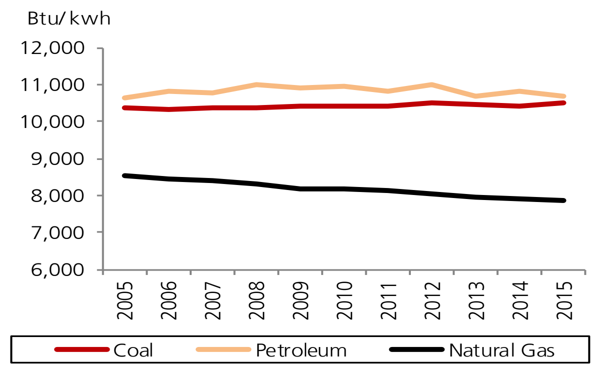
China natural gas consumption



Source: DBS HK

Natural gas is an attractive alternative fuel for China as it emits less pollutants and could act as base load energy source other than coal. Natural gas enjoys higher efficiency and lower carbon dioxide (CO2)/ nitrogen oxide (NO) / sulfur dioxide (SO2) emission compared to some of the traditional fossil fuels. Natural gas emits 50%/ 80%/99% less CO2/ NO/SO2 than coal, and 30%/80%/99% less than oil. In addition, natural gas power plants operate at c.25% lower heat rate (more efficient) than coal and petroleum power plants.

Average operating heat rate



Source: EIA

The conversion of industrial coal boilers to gas is one of the major growth drivers of natural gas consumption. The State Council targets to convert 189k steam ton/hour (t/h) of industrial coal-boilers by 2020, which is expected to boost natural gas demand by 42bn m3. The central government will penalise local governments if they cannot meet the target. Thus, in order to strengthen policy implementation, local governments have rolled out subsidies for ndustrial/commercial players to conduct the conversion. As a result, most targets to eliminate coal boilers below 10 steam t/h by 2017 were met. Looking forward into 2018-2020, we believe the pace of coal-fired boilers conversion will continue the momentum. In fact, many provinces have issued additional policies to eliminate coal boilers between 10-35 steam t/h.

Selective coal-boiler conversion subsidies

Province	City	Subsidy
Gansu (甘肃)	Lanzhou (兰州)	- Rmb100,000 per steam ton for coal boilers above 0.7MW - Rmb100 per m2 for coal boilers below 0.7MW used by public facilities (such as hospital, school, local government buildings)
Henan (河南)		- Finish conversion before Oct 2018: >Rmb60,000 per steam ton - Finish conversion after Oct 2018 but before Oct 2019 : >Rmb40,000 per steam ton
Hebei (河北)		- disposal only: Rmb30,000 per steam ton - replacement with clean energy : Rmb80,000 per steam ton
Jiangsu (江苏)	Suqian (宿迁)	- Rmb0.76 per m3 of gas consumption for two years
Jilin (吉林)	Changchun (长春)	- Rmb20,000 per steam ton for coal-boilers above 20 steam ton / hour
Shandong (山东)		- Rmb 35,000 / MW for coal-boilers below 100MW

Source: NDRC, DBS HK

Continued future growth from industrial coal boiler conversions. The "Action Plan on Prevention and Control of Air Pollution" promulgated by the State Council seeks to take measures to reduce air pollution in China. As stated earlier, one of the main targets is to shut small coal-fired boilers (<10 t/h) in cities above the prefecture-level by 2017 and replace these with cleaner sources including natural gas. There were strong efforts made to shut down or convert coal-fired boilers starting in 2H2016 and strong volume growth of 15% for natural gas was thus achieved in 2017.

After closing down the smaller boilers, the government started to tighten the policy to shut down or convert coal-fired boilers generating between 10 steam t/h to 35 steam t/h. Core cities such as Tianjin and Shijiazhuang have already implemented tighter policies. According to the General Administration of Quality Supervision, Inspection and Quarantine of the PRC, there were more than 460,000 industrial coal-fired boilers in the country in 2015. The proportion of small-medium industrial coal-fired boilers producing less than 35 steam t/h accounted for 91.7% of the total. Small industrial coal-fired boilers below 10t/h accounted for 46%, indicating that there is plenty of room for closing down medium sized boilers of between 10-35 steam t/h, which will further boost natural gas demand.

More natural gas for winter heating as well. Winter heating is believed to be one of the main contributors to air pollution in China. The Chinese government has issued multiple policies to tackle the use of scattered coal for heating purposes. The local governments have introduced subsidy schemes to subsidise gas usage and installation costs. Given increasing environmental and health awareness, we believe the subsidy schemes provide sufficient incentives to use natural gas, despite slightly higher costs for rural users. The subsidy scheme will last for three years to help users to reduce costs during the transition period. In addition, coal-free zones have been established to prevent companies from selling/using coal, which will push up local coal prices, and reduce the attractiveness of a possible switch back to coal.

The initial focus is on the Pan Beijing-Tianjin-Hebei area where the smog is the most severe. At the same time, the government issued the "Clean Winter Heating Plan for Northern China" ("北方地区冬季清洁取暖规划") to tackle winter heating in the northern parts of China, which has showed strong determination in shutting down coal usage.

Main targets – Clean Winter Heating in Northern China

	Year	Target
Overall Northern regions		
Clean energy coverage rate	2019	50%
	2021	70%
Replacement of scattered coal boilers	2019	74m tons
	2021	150m tons
2+26 core areas		
Clean energy coverage rate	2019	> 90% for core city > 70% for county > 40% for rural area
	2021	> 80% for county > 60% for rural area
Replacement of scattered coal boilers	2021	eliminate capacities < 35 steam t/h for city eliminate capacities < 20 steam t/h for county
Gas consumption	2017-2021	boost gas consumption by 23bn m3 from natural gas

Source: NDRC

Selective rural incentives set by local governments

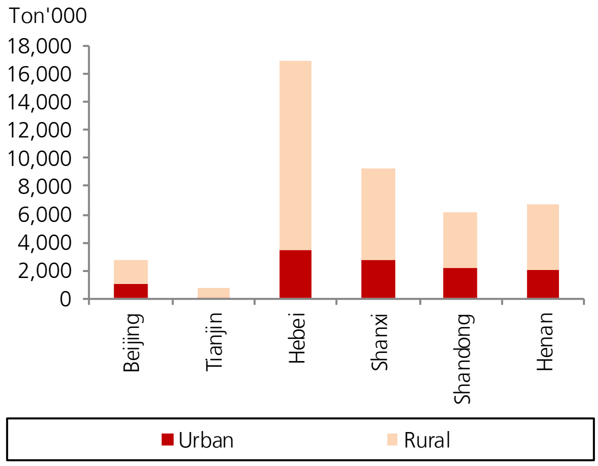
Province	City	Subsidy
	Beijing (北京)	- 30% equipment cost subsidy for maximum of Rmb12,000 (villages <500 households) and Rmb24,000 (villages > 500 households)
	Tianjin (天津)	- Municipal Ministry of Finance provided total subsidies of Rmb320m
Hebei	Handan (邯郸)	- Gas equipment: 70% cost subsidy up to a maximum of Rmb 2,700 - Gas pipeline: discounted installation fee of Rmb2,600 - Natural gas tariff (heating) subsidy : Rmb1 / m3 up to maximum of Rmb1,200
	Hengshui (衡水)	- Installation subsidy: Rmb2,600 - Natural gas tariff subsidy: Rmb1.5 / m3
	Xingtai (邢台)	- Natural gas tariff subsidy: Rmb1 /m3 up to maximum of Rmb900
	Shijiazhuang (石家庄)	- Installation and equipment: Rmb3,900 - Natural gas tariff subsidy: Rmb1 / m3 up to a maximum of Rmb900
	Baoding & Langfang (保定&廊坊)	- Gas equipment: 70% cost subsidy up to maximum of Rmb 2,700 - Coal-free zones will no longer adopt tiered pricing system - Natural gas tariff (heating) subsidy: Rmb1 / m3 for maximum of 1,200 m3 - Gas pipeline connection subsidy: Rmb4,000

Source: NDRC

Large market in rural coal-to-gas conversions. We are positive on rural coal-to-gas conversions as it will be one of the major drivers for the government to reach its gas consumption target in 2020. We expect rural coal-to-gas conversions to account for >8% of the increase in natural gas consumption during 2015-2020. Furthermore, we believe the implementation and expansion of coal-free zones are some of the measures to ensure that policies are successfully executed. The establishment of coal-free zones will prevent companies or residents from selling or using coal.

The government shifted its focus to tackle coal usage in rural areas starting from 2017 as rural residential coal consumption is believed to be one of the major contributors to air pollution. Beijing-Tianjin-Hebei region will be the focus as rural residents use scattered coal as a primary heat generation fuel. Scattered coal has the characteristics of low efficiency and high pollution. The emission intensity of scattered coal is 17.5 times more than coal for electricity generation. As a result, rural households accounted for >70% of the total residential coal consumption.

Household coal consumption



Source: CEIC

In 4Q2017, the government issued the "Clean Winter Heating Plan for Northern China" ("北方地区冬季清洁取暖规划"). The plan targets the clean energy heating rate to reach 70% by 2021, from c.17% in 2016. The plan targets coal-to-gas conversion for heating to boost gas demand by 23bn m3 from 2017-2021 in the core "2+26" cities in Pan Hebei-Tianjin-Beijing region.

Rural coal-to-gas conversion can greatly contribute to the increase in gas consumption as coal consumption for rural households is higher than urban households due to the lack of central heating systems. We estimate there are c.62m rural households in the Beijing-Tianjin-Hebei areas, which could boost natural gas demand by 31.2bn m3 assuming 40% of the households convert to gas heating.

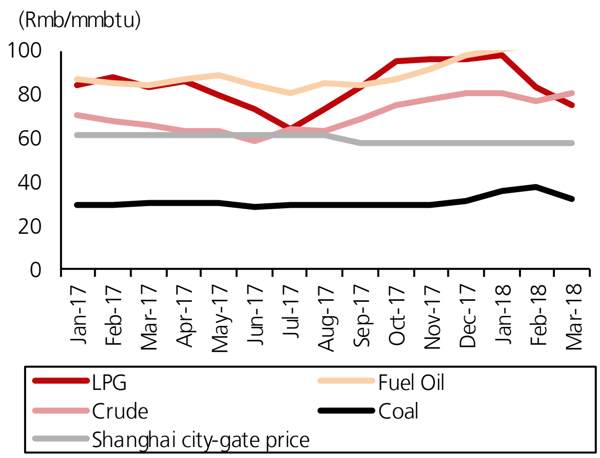
The government has also implemented policies to lower the end selling price to stimulate demand. As a result, intermediate costs including long/short distance pipeline transmission fees and distribution margins were lowered. In Oct 2016, the NDRC issued a document on the trial implementation of natural gas pipeline transmission pricing scheme. The return on asset for inter-provincial pipelines (long distance) is set at 8% based on a minimum utilisation rate of 75%, which means that a utilisation rate below 75% will have lower returns. The tariff mechanism is set for the pipeline company and it will be adjusted every three years. Local governments have recently started to limit the return on intra-provincial (medium to short) pipeline transmission, hence lowering the transmission fee.

The NDRC released regulatory guidance opinion on gas distribution prices in June 2016 to clarify its stance and removed industry concerns of a potential steep cut in distribution margin. According to the guidance opinion, the return on attributable asset (ROA) for city gas distribution business cannot exceed 7%. This will have a negative impact on projects with high dollar margin and ROA >7%, though there are not many projects with high returns. The average ROA for major gas distributors in China ranges from 3-5%.

Therefore, we do not expect a significant impact on the earnings growth for gas distributors

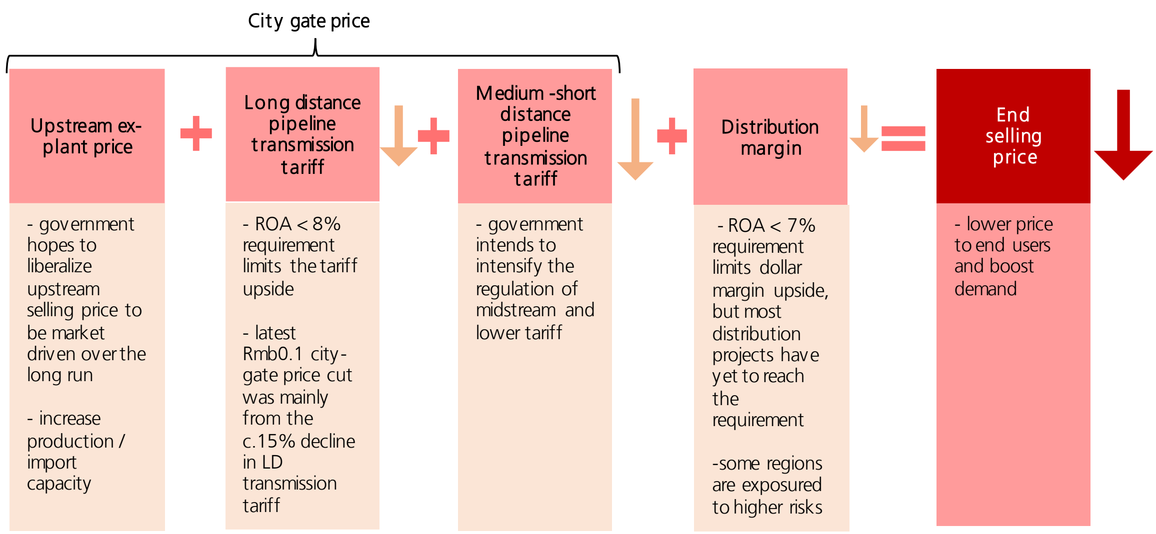
Lower gas price to stimulate demand. We expect end user gas price will be more competitive in the next few years as the government tackles intermediate costs, which is positive to demand growth. The lowering of end selling price for natural gas would be borne by a cut in pipeline transmission fees and distribution margins.

Alternative fuel vs natural gas price



Source: DBS HK

Natural gas price in China

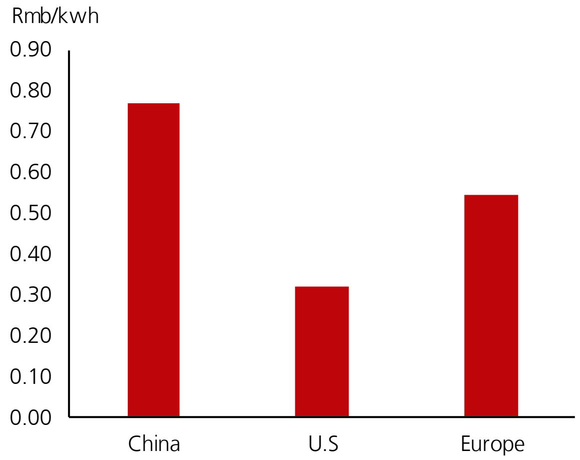


Source: NDRC, DBS HK

Gas power plants will also be more competitive. The LCOE for gas power plants in China consists of 62% fuel costs, 7% capex, 17% O&M costs, 7% finance costs and 7% tax. Therefore, LCOE is largely dependent on the upstream natural gas price. Since the natural gas price in China is relatively high compared to some of the international peers in the US and Europe, its LCOE is also comparatively higher.

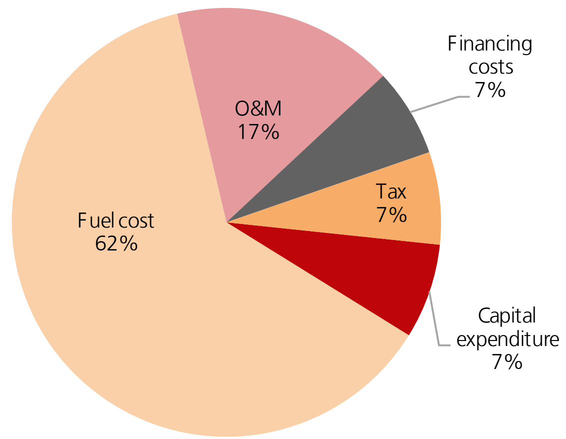
Prior to the plunge in oil prices in 2014 and the cut of city gas prices in 2015, the LCOE of gas power projects was very much less competitive compared to coal-fired plants. The city gate price was revised down by Rmb0.7/m3 in 2015 and another Rmb0.1/m3 in 2017, which has helped to drive down LCOE by c.Rmb0.1 / kwh to c.Rmb0.76/kwh. As the Chinese government seeks to lower gas prices by cutting midstream transmission fees and restricting distribution margin, the gas price is expected to remain at a low level, which is positive for the sector.

Levelised cost of energy (LCOE) of gas power plants - Global



Source: BNEF, DBS HK

LCOE structure



Source: DBS HK

We believe there is more downside to pipeline transmission tariffs. After the c.15% cut in long distance pipeline transmission tariff, we expect more provinces to announce a tightening of intra- provincial transmission tariffs, which would help to further reduce end user selling price, and boost gas sales volume growth. Pipeline transmission fees is one of the major cost components of gas distributors, and is estimated to account for c.30% of the selling price. We have seen a few provinces such as Shandong and Zhejiang starting to cut intra-provincial gas pipeline transmission tariffs, and we expect other provinces will follow suit. We expect the intra-provincial tariff to be cut by an average of 15% in FY18, implying c. Rmb0.03-0.06 reduction in city-gate price. This could help to alleviate distribution margin pressure, reduce end selling price, and stimulate demand in the long run.

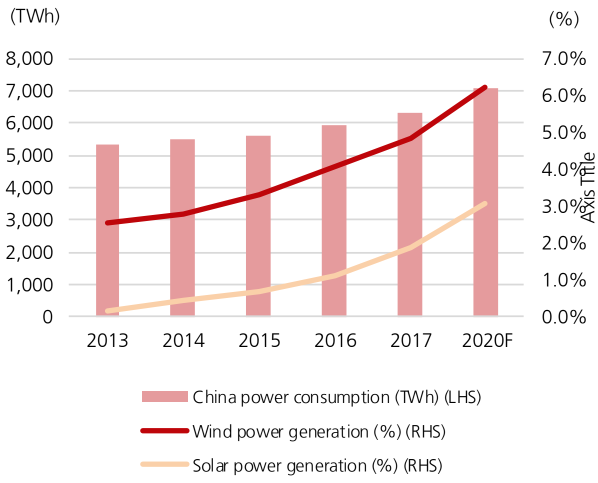
The provincial governments have issued local distribution return requirement guidelines riding on NDRC's distribution return guideline. We expect the local governments to start to conduct reviews on city gas projects in 2H18 and 1H19. This would lead a cut in distribution margin for projects with ROA <7% or high dollar margin, but we do not expect this to have significant impact on earnings for gas distributors as most projects are still operating at below the return requirement.

2. Increasing clean energy sources in China's electricity mix

Chinese investment in renewables a big chunk of global investment levels. According to statistics of BNEF (Bloomberg New Energy Finance), global investment in renewable energy edged up 2% y-o-y to US$279.8bn in 2017. Wind and solar power accounted for 38% and 58% of the total renewable energy (RE) investments respectively. According to BNEF, China's wind and solar power contributed 34% and 54% respectively of the world's total investment in RE.

A strong build-out of 53GW new solar capacity (+54% y-o-y) was fuelled by significant roll-out of distributed generation (DG) projects, which recorded a 3.6-fold y-o-y growth. This was underpinned by the government's favourable policy towards tariff subsidy for DG projects. China's solar DG development is benefiting high power tariff payers such as industrial and commercial customers to obtain a cheaper tariff rate against the backdrop that China is gradually liberalising its power market.

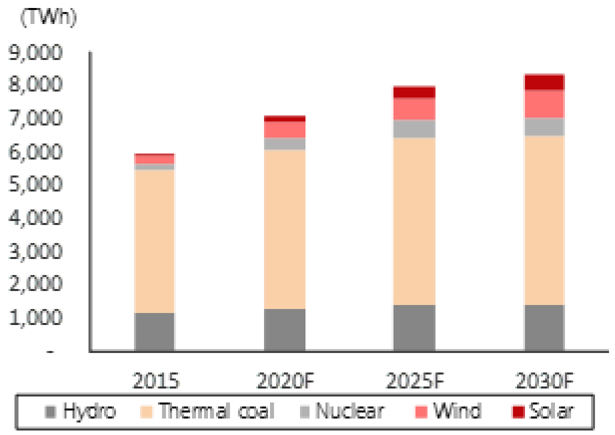
Renewable contribution in China's power generation sector and overall power consumption growth



Source: NEA, China Electricity Council, DBS HK

In China, energy supply is dominated by coal but fuel mix is shifting to more wind and solar. In 2017, coal power generation accounted for 73% of China's total power generation vs 80% in 2013. During the period, the proportion for RE (wind + solar) increased to 6.7% in 2017 vs 2.7% in 2013.

China power generation fuel mix



Note: TWh : Tera Watt hours
Source: GREENPEACE, CEWA, China Electricity Council, DBS HK

From 2020 to 2030, non-hydro renewable energy is to account for 53% of increase in China's power generation. We forecast national power generation to grow at 1.7% CAGR during 2020-30 to 8,366 TWh. In the context that China aims for non-fossil fuels to account for about 15% of total energy consumption by 2020 and 20% by 2030, the country has a target that the proportion of non-hydro renewable energy generation must not be less than 9% by 2020. We project aggregate wind and solar power generation to account for 9.3% (wind: 6.2%; solar: 3.1%) of the country's power generation in 2020 and expect the non-hydro renewable ratio may further rise to 14.5% (wind: 9.4%; solar: 5.1%) in 2030.

This assumes China's cumulative grid-connected capacity for wind power will expand to 220GW/415GW by 2020/2030 compared to 164GW in 2017. Also, China's cumulative grid-connected solar power is assumed to rise to 182GW/388GW by 2020/2030 compared to 100.6GW in 2017. We expect wind power industry's utilisation to range between 2,000 hours and 2,100 hours during 2020-2030. We forecast solar power industry's utilisation to be maintained at 1,200 hours on average during the period.

Supportive government policy for existing projects intact. China's cumulative installed wind power capacity increased to 188GW in 2017 vs 91GW in 2013, while cumulative installed solar capacity expanded to 130GW in 2017 vs 19GW in 2013. This is supported by the government's RE policies including feed-in-tariff (FiT), built-out of UHV (ultra-high voltage) transmission lines and guaranteed utilisation hours to promote usage of wind and solar power.

Feed-in-tariff policies. Earlier in 2009, the National Development and Reform Commission (NDRC) introduced 'on-grid tariff' policy for wind power, also known as FiT, based on project zonings. Solar power in China has also adopted the FiT policy. The FiT has a rate higher than coal-power tariff to help recover the cost of investment in RE generation. The FiT is fixed for 20 years from the start of commercial operations of wind and solar power projects. The payments of RE FiT are composed of two parts: i) provincial coal-fired tariff is paid by grid company monthly and ii) subsidy, representing difference between FiT and coal-fired tariff is paid by the National Renewable Energy Development Fund. China's wind power FiT has been cut three times since 2014. The latest tariff cut for wind power took place in December 2016 when the FiT for projects to be approved after 2018 was reduced by 15%/10%/9%/5% for Tier I, Tier II, Tier III and Tier IV resource zones respectively.

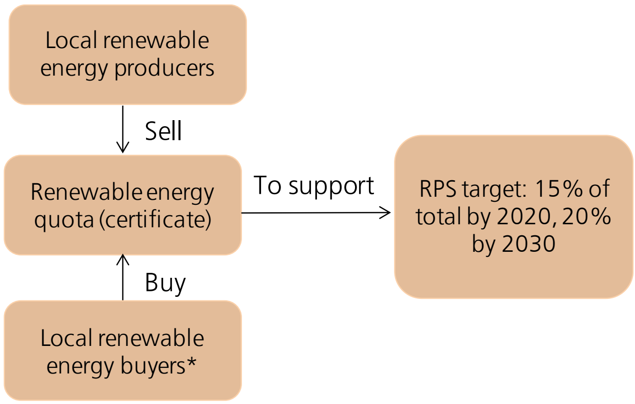
On 31 May 2018, the NEA announced a cut to solar FiT for projects connecting to the grid after 30 June 2018. The FiT for Tier I/II/III resource zones will be cut by Rmb0.05/kWh each to Rmb0.50/kWh, Rmb0.60/kWh and Rmb0.70/kWh respectively. Before this, China's solar power FiT had been reduced four times since 2011. The downward adjustment in RE FiT predominantly reflects reduction in construction costs and improvement in technologies (please see following pages for more information on RE construction cost and technologies).

Construction of UHV lines. China's roll-out of UHV transmission lines to a certain extent helps to increase usage of RE, by transmitting power from RE resource rich Northwest China to demand centres such as East, Central and North China. Since 2014, China has commenced commercial operations of at least seven f UHV lines (distinguished by alternating current), which is helping China to improve its high curtailment of wind power.

Guaranteed utilisation hour' policy. In response to high curtailment of wind and solar power during 2015-16, the Chinese government announced 'guaranteed purchase utilisation hour' policy in May 2016 to mandate a minimum power purchasing agreement between the grid company and RE producers. This has led to an improvement in RE utilisation since 2017 till now.

New policy - Renewable Portfolio Standard - prioritises RE usage. On 23 March 2018, the NEA announced "Renewable Portfolio Standard (RPS) and Assessment Methodology (Draft on Soliciting Opinions)". The target is that RE should form 15% of total power generation by 2020 and the ratio is expected to reach 20% by 2030. The mandatory target stipulates non-hydro RE must account for 3.5% to 25.5% of total power generation depending on the province. This is a long-awaited development for China's RPS since a previous proposal was announced in April 2016. The Chinese government is aggressively promoting RE use, we expect the RPS to be officially implemented no later than 2019.

Renewable Portfolio Standard (RPS) quota system



Source: NEA, DBS HK

**Note: Local renewable energy buyers (market participants) include: i) provincial and local grid companies (owned by either State Grid Corporation or China Southern Power Grid), ii) power sales companies, iii) industrial customers with captive power plants, and iv) customers of direct-power-supply (DPS). These power buyers are obliged to meet the RPS targets.*

China wind power sector: Renewable Portfolio Standard (RPS) - 2018 and 2020 targets by province

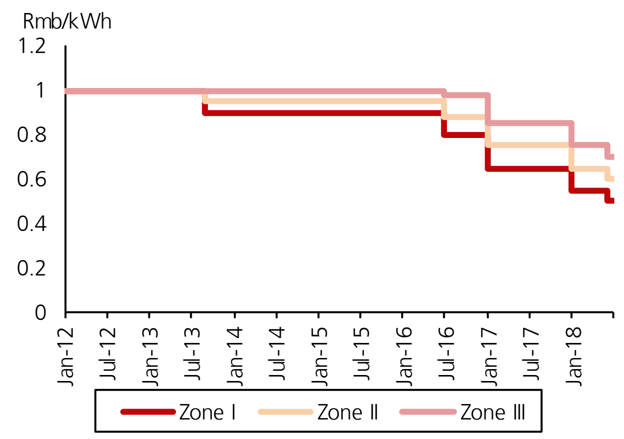
	Total RE (excluding Hydro)					
	2018 target	2020 target	Previous 2020 target announced in April 2017	*New 2020 target vs previous 2020 target (%)*	2016 Actual	*Gap between 2020 target and 2016 actual (%)*
Zhejiang	10.5%	13.0%	10.0%	*3.0%*	9.0%	*4%*
Tianjin	10.5%	13.0%	10.0%	*3.0%*	9.0%	*4%*
Hebei	10.5%	13.0%	10.0%	*3.0%*	9.0%	*4%*
Shanxi	13.0%	15.0%	10.0%	*5.0%*	10.0%	***5%***
Inner Mongolia	13.0%	13.0%	13.0%	*0.0%*	15.3%	*-2%*
Liaoning	9.0%	9.0%	13.0%	*-4.0%*	8.6%	*0%*
Jilin	16.5%	20.0%	13.0%	*7.0%*	13.7%	***6%***
Heilongjiang	15.5%	22.0%	13.0%	*9.0%*	12.4%	***10%***
Shanghai	2.5%	3.5%	5.0%	*-1.5%*	2.0%	*2%*
Jiangsu	5.5%	6.5%	7.0%	*-0.5%*	4.2%	*2%*
Zhejiang	5.0%	6.0%	7.0%	*-1.0%*	3.6%	*2%*
Anhui	11.5%	14.5%	7.0%	*7.5%*	6.1%	***8%***
Fujian	5.0%	7.0%	7.0%	*0.0%*	3.7%	*3%*
Jiangxi	6.5%	14.5%	5.0%	*9.5%*	3.8%	***11%***
Shandong	8.0%	10.5%	10.0%	*0.5%*	5.6%	*5%*
Henan	8.0%	13.5%	7.0%	*6.5%*	4.4%	***9%***
Hubei	7.5%	11.0%	7.0%	*4.0%*	4.7%	***6%***
Hunan	9.0%	19.0%	7.0%	*12.0%*	4.1%	***15%***
Guangdong	3.0%	3.8%	7.0%	*-3.2%*	1.9%	*2%*
Guangxi	3.0%	5.0%	5.0%	*0.0%*	1.3%	*4%*
Hainan	4.0%	5.0%	10.0%	*-5.0%*	4.5%	*1%*
Chongqing	3.0%	3.5%	5.0%	*-1.5%*	1.6%	*2%*
Sichuan	4.5%	4.5%	5.0%	*-0.5%*	2.3%	*2%*
Guizhou	4.0%	4.8%	5.0%	*-0.2%*	4.6%	*0%*
Yunan	10.0%	10.0%	10.0%	*0.0%*	12.5%	*-3%*
Tibet	13.5%	17.5%	13.0%	*4.5%*	10.1%	***7%***
Shaanxi	8.5%	11.5%	10.0%	*1.5%*	3.8%	***8%***
Gansu	15.0%	15.0%	13.0%	*2.0%*	12.5%	*3%*
Qinghai	21.0%	25.5%	10.0%	*15.5%*	18.3%	***7%***
Ningxia	21.0%	21.5%	13.0%	*8.5%*	19.1%	*2%*
Xinjiang	14.5%	14.5%	13.0%	*1.5%*	11.1%	*3%*

Source: NEA, DBS HK

RE tariff parity with coal power to come earlier. On 24 May 2018, the NEA released "Notice regarding 2018 requirement of wind power construction management" to stipulate that new quotas for wind power projects pending approval from 2018 onwards (including those 2018 provincial new quotas for wind projects not yet announced as of 18 May 2018 and onwards) will be awarded via electricity tariff auction rather than FiT. This is to accelerate the pace for wind power's prevalent tariff to have tariff parity with coal power. The Notice was announced to promote use of RE while rationalising installation of new wind power capacity. The policy is introduced against the backdrop that China's RE subsidy shortfall had extended to Rmb100bn by end-2017.

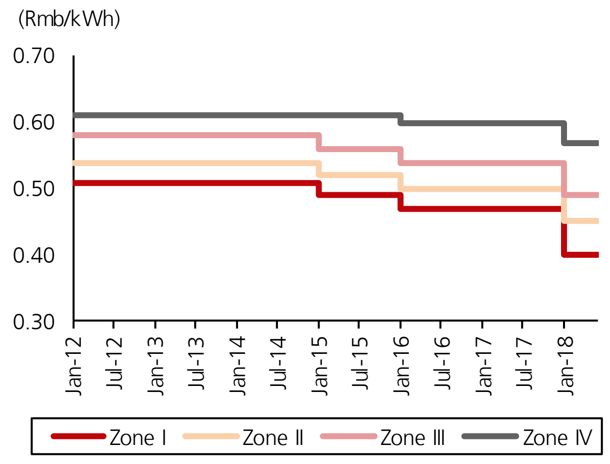
On 31 May 2018, NDRC, MOF and the NEA jointly published "the Notification on Photovoltaics power generation for 2018", which stipulated that in 2018: i) there will be no new installation quota for centralised solar power projects; ii) new installation of distributed generation projects is not to exceed 10GW; and iii) support for installation of photovoltaics poverty alleviation (PVPA). The Notification has reduced subsidies for distributed generation projects by Rmb0.05/kWh to Rmb0.32/kWh while feed-in-tariff for PVPA (village-level with unit project not exceeding 0.5MW) has remained unchanged.

China Solar Power: Feed-in-tariff



Source: NEA, NDRC, DBS HK

China Wind Power: Feed-in-tariff

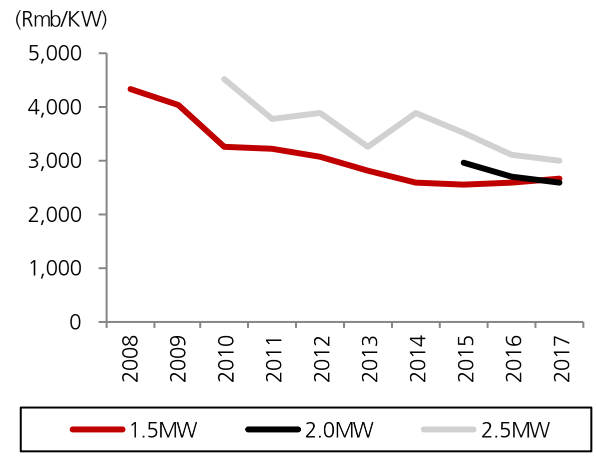


Source: NEA, NDRC, DBS HK

Advancement of technology to drive down RE construction costs – Wind Power. Advance in technologies for wind power primarily reflects a development towards larger rated-capacity wind turbine generators (WTG) with higher operational efficiency. A WTG unit usually accounts for around 70% of onshore wind farm's unit investment cost. Industry studies reveal that with every doubling in cumulative capacity of wind power, levelised cost of energy (LCOE) for wind power could come down by 10% due to fall in wind turbine equipment cost arising from economies of scale and more efficient technologies. For example, China's largest WTG manufacturer Xinjiang Goldwind (2208.HK)'s unit production cost of a 1.5MW WTG had decreased by 44% during 2007-2017, while that of 2.0MW had declined by 12% during 2015-17 and that of 2.5MW had dropped 33% during 2010-17.

As a result, in Tier I resource zones, unit capex of wind farms had declined to around Rmb6,000-6,500/kW in 2017 vs Rmb7,180/kW in 2016. In Tier III resource zones, unit capex had decline to around Rmb7,000/kW in 2017 vs Rmb7,950/kW.

China wind turbine generators (WTG) unit production cost

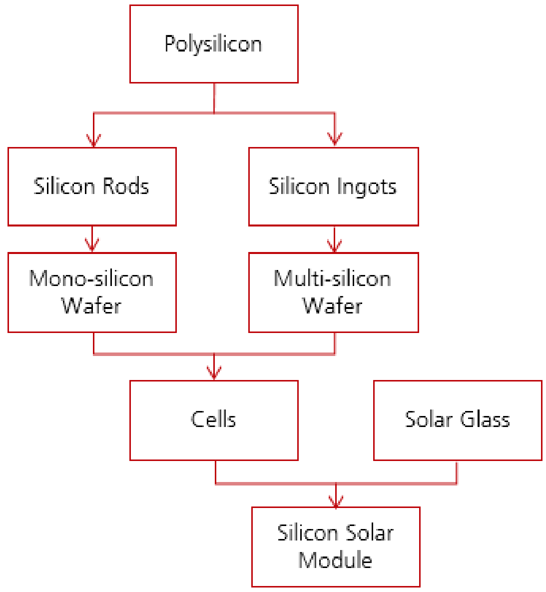


Source: Xinjiang Goldwind, DBS HK

Lower costs in Solar power. Solar power has witnessed substantial fall in unit construction cost in the past decade thanks to advancement of technology for the entire supply chain of photovoltaics (PV) modules, including poly-Si, wafers and cells. Industry studies reveal that every doubling in cumulative capacity of solar power, levelised cost of energy (LCOE) for solar power could come down by around 15%

Falling cost of modules, inverters and balance of system (BoS). These account for around 50%, 10% and 40% of unit capex respectively for a new solar farm in China. China's unit construction cost of solar farm had dropped substantially to around Rmb6.3-6.9/W in 2017 vs around Rmb15.9/W in 2010, representing a decline of 56%, mainly due to falling cost of modules. During 2010-2017, silicon solar module prices had fallen to US$0.33/W in 2017 vs US$1.75/W in 2010, representing a decrease rate of 81%, as poly silicon prices fell 74%.

Photovoltaics supply chain



Source: PV Tech, DBS HK

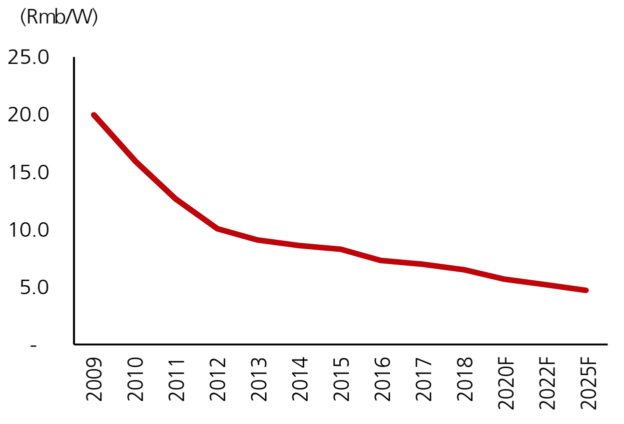
Looking forward to 2030, unit construction cost of PV system is expected to further decrease by at least 30%, attributed to an expected decline of 33% in modules and decrease of 50% in inverters, based on a study by ITRPV (International Technology Roadmap for Photovoltaic).

Advancement of technology in solar manufacturing. Wafers account for around 42% of production cost for PV modules, and the introduction of diamond wire cutting (or diamond wire saws) technology using "kerf' results in lower silicon waste and consumes less energy. We estimate the adoption of diamond wire cutting technology would reduce silicon waste by around 22%.

In 2017, in China, module efficiency of monocrystalline could have reached 20.0% (vs 17.5% in 2010) and that of polycrystalline at 18.7% (vs 16.5% in 2010).

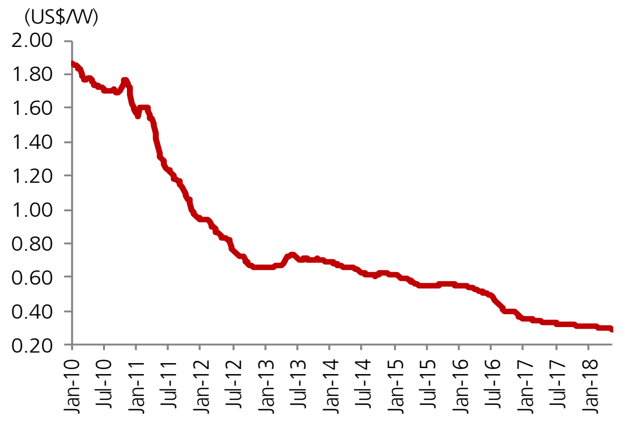
Cells account for around 62% production cost for PV modules, and the introduction of new processes to texture the surface of cells (also known as black cell) helps to improve module efficiency. The 'passivated emitter rear contact' design (PERC) results in higher efficiency cell designs. All-in, these two technologies could further improve module efficiency by 0.7%-0.9%.

China Solar Power: Unit construction cost of solar farms



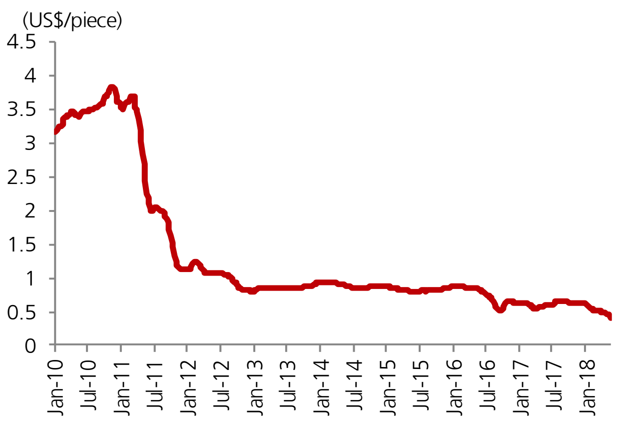
Source: China Photovoltaic Industry Association, DBS HK

China Solar Power: Average silicon solar module spot price



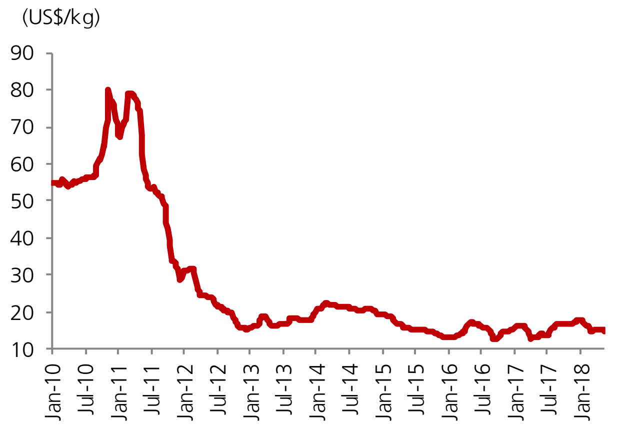
Source: Bloomberg Finance L.P., DBS HK

China Solar Power: Average 156MM multi solar wafer spot price



Source: Bloomberg Finance L.P., DBS HK

China Solar Power: Average PV grade poly silicon spot price

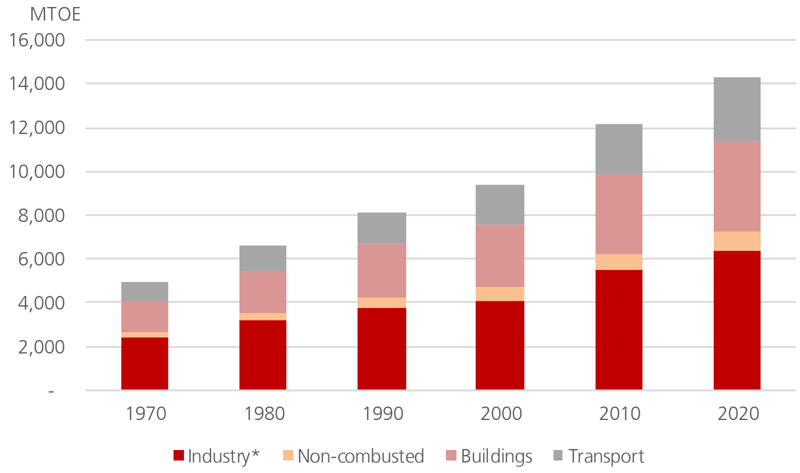


Source: Bloomberg Finance L.P., DBS HK

3. Rise of electric vehicles and impact on oil demand

Transport end-user sector is a major component of global energy demand. Industry has been the biggest consumer of energy over the last five decades as can be seen below, with a share of almost 50% to begin with, but the share of transport in the energy consumption pie has increased from about 17% in 1970 to around 20% currently. Increasing prosperity in developing economies has been the major driver for this, as the demand for transport has increased manifold. Demand for both passenger and freight services has driven an increase in energy demand of close to 2.5% CAGR since 1970 in the transport sector.

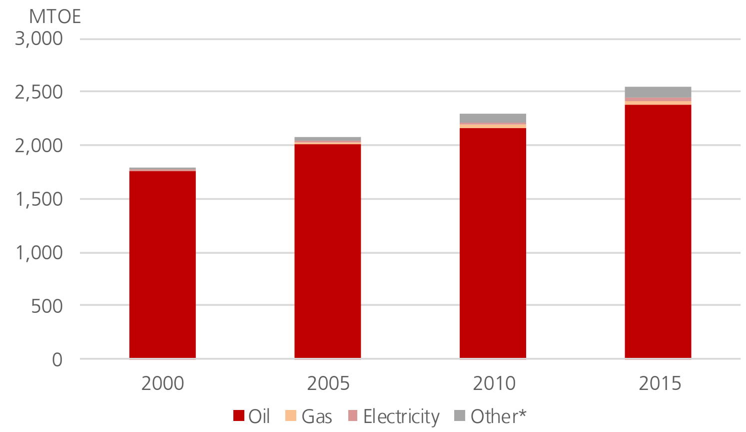
Primary Energy Consumption by end-use sector



** Industry excludes non-combusted use of fuels*
Source: BP Energy Outlook 2018, DBS Bank

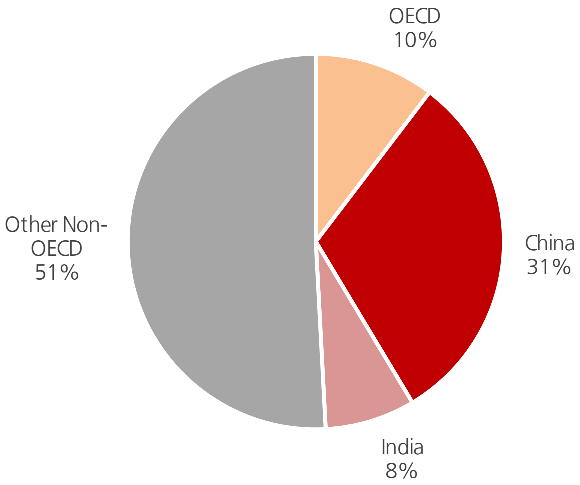
Transport sector energy demand has been dominated by oil. Demand from the transport sector, typically passenger vehicles, trucks, aviation, marine and rail, has been dominated by oil almost completely till the start of the 21st century, before concerns regarding emissions started a move towards cleaner options. However, while the proportion of oil as fuel has fallen from around 98% in 2000 to around 92% currently, it is still clearly the dominant fuel and electricity as a power source has not made much of a dent for now. The use of gas has picked up, though not presenting much of a challenge yet. As adoption of electric vehicles increases over the next 10-15 years, this graphic is likely to change, especially as much of the increase in electric vehicle adoption is likely to be in China, which has been one of the key drivers of transport energy demand over the last 15 years.

Transport energy consumption by fuel type



** includes bio-fuels, gas-to-liquids, coal-to-liquids, hydrogen*
Source: BP Energy Outlook 2018, DBS Bank

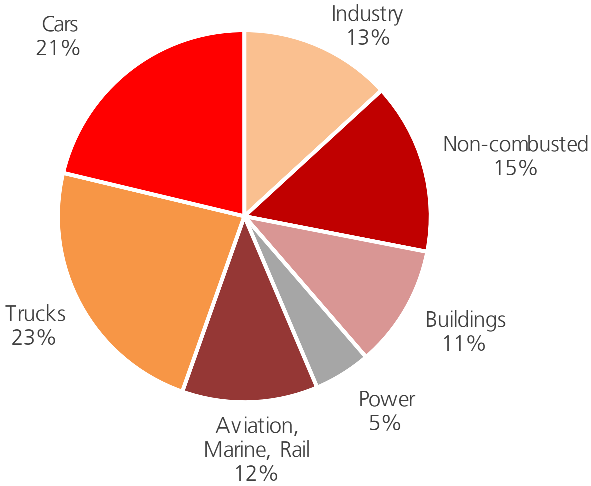
Contribution to incremental energy demand over 2000-2015



Source: BP Energy Outlook 2018, DBS Bank

Conversely, for oil, demand from transport sector makes up majority of demand. As of 2015, BP estimates that close to 56% of oil demand is driven by transportation – which includes cars, trucks, and non-road transport – aviation, marine and rail. Around 13% is used in industry, 15% as feedstock for petrochemicals, 11% for buildings (heating) and 5% for power generation. We do not expect demand from trucks or aviation, marine, rail segments to be significantly affected by electrification of vehicles, hence the cars segment representing around 20% of oil demand will be vulnerable to an impact from electric vehicles, in our opinion.

Contribution to demand for liquid fuels (oil and condensates)

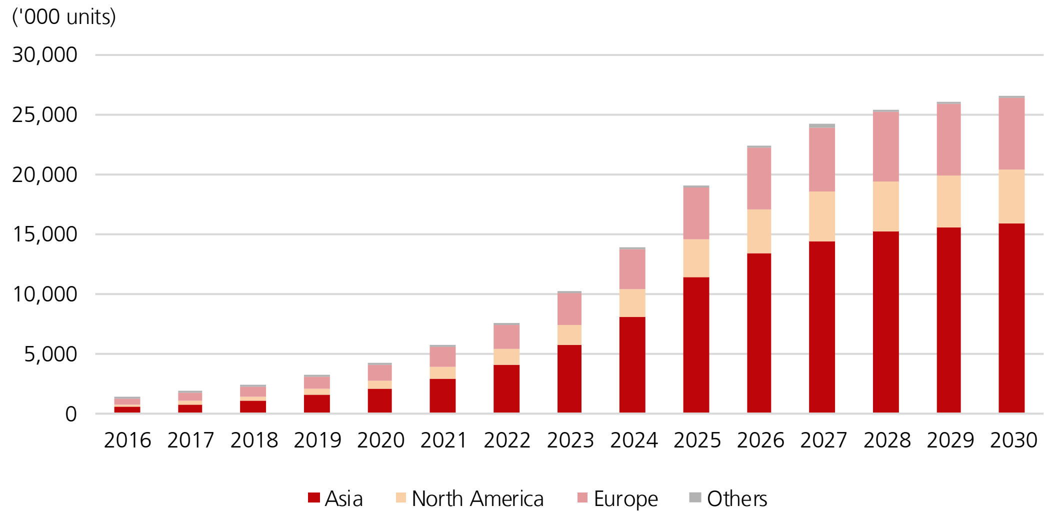


Source: BP Energy Outlook 2018, DBS Bank

Demand from cars and trucks the highest growth drivers for oil. While global oil demand has risen at a CAGR of around 1.4% over the last 15 years, demand from cars and trucks have been rising faster at 2.5% and 2.0% CAGR respectively, and hence, their share of the pie has been increasing. Demand from industry and buildings is largely flattish, while demand from power generation sector has been negative, owing to the high costs involved, and increasing use of natural gas.

Strong growth in EV unit sales expected. Our autos analyst Rachel Miu expects global EV unit sales to grow from c.1.26m units in 2016 to over 26m units in 2030, representing an almost 15x increase in yearly sales volumes. Much of the increase in sales will come from Asia, with China in particular being the dominant driving force, pun intended.

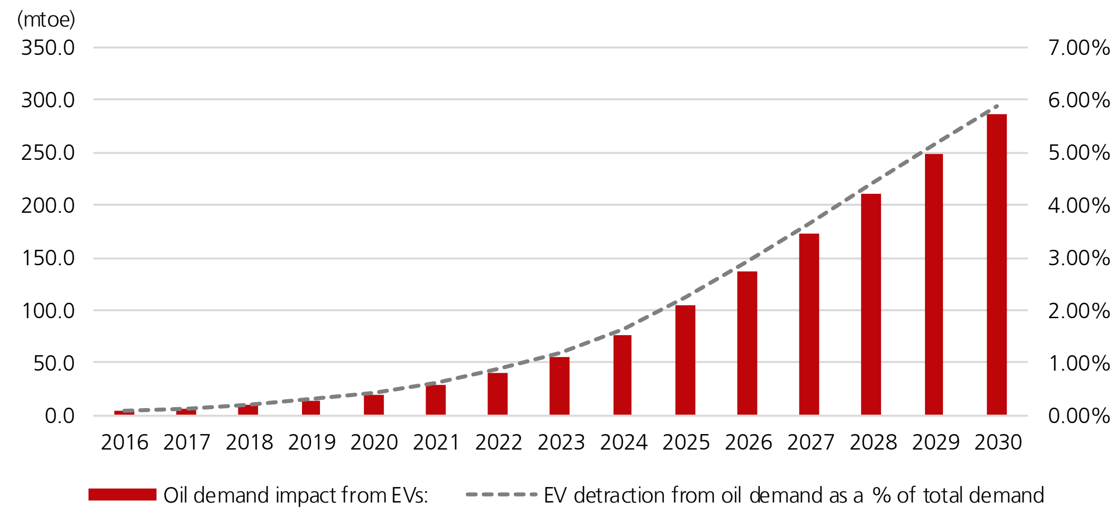
Forecast Electric Vehicle unit sales



Source: DBS Bank forecasts

EV impact on oil demand: 6% of annual oil demand could disappear by 2030. We estimate EVs will absorb c.285mtoe (million tons of oil equivalent) or around 5.3mmbpd (million barrels per day) of oil demand by 2030, which represents around 6% of the total demand for oil in that year, assuming that EVs are non-existent. That is not insignificant, but when you consider that global energy intensity is expected to improve every year from 2017 and 2030 – we expect global energy demand CAGR of 1.7% compared to global GDP growth of 3.2% over the above time period – we believe that changes in energy intensity trends and policies are as or more important than sales of EVs, which will tend to dominate headlines regarding future oil and energy demand.

Impact of Electric Vehicles on oil demand

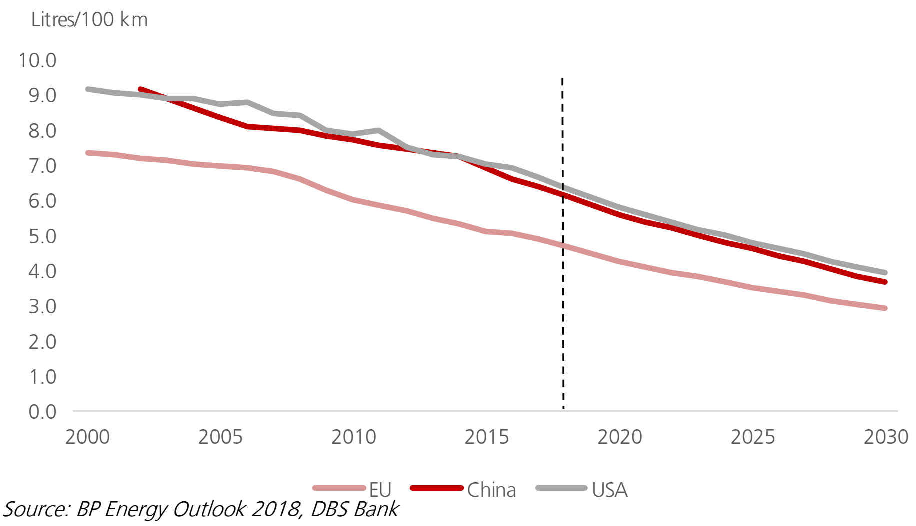


Source: DBS Bank forecasts

Energy intensity trends are very important in determining oil demand. Energy intensity is defined as the primary energy consumed per unit of GDP. A diverse number of factors can influence energy intensity, including a secular shift away from energy-intensive industries in certain countries, technology improvement and evolution (e.g. proliferation of smart meters, which enables more accurate control of consumption; or a shift to electric vehicles, which are more energy efficient), government policies and so on. Energy intensity has declined at a CAGR of 1.55% from 1990-2015 (based on World Bank Data), with that number accelerating to 2.4% from 2010-2015, led by the middle and high income countries, and notably China and Japan, which are two of the top 10 consumers of energy, which saw their energy intensity decline by 23% and 21% respectively over that 5-year period. Numbers by the IEA indicate 2016 saw a further 1.8% decline in energy intensity globally; that is US$2.2trillion when translated to dollar-savings – a sizeable figure. There is a similar trend in growth of consumption of oil vis-à-vis global economic growth, and this will increasingly be felt for oil consumption by passenger vehicles, which has been the key driver of oil demand in recent years as highlighted earlier.

Increasing fuel efficiencies of passenger vehicles will be a limiting factor for oil demand. Fuel efficiencies of cars have been improving in developed countries, especially the EU, with its tougher emission norms, as can be seen below. This trend is expected to continue in future and we believe will be a bigger factor for oil demand than the evolution of electric vehicles. According to our estimates, oil demand from passenger vehicles will be flattish or slightly lower in 2030 than reference 2016 levels of 18.7mmbpd (based on data from BP Energy Outlook).

Fuel economy of new cars



Source: BP Energy Outlook 2018, DBS Bank

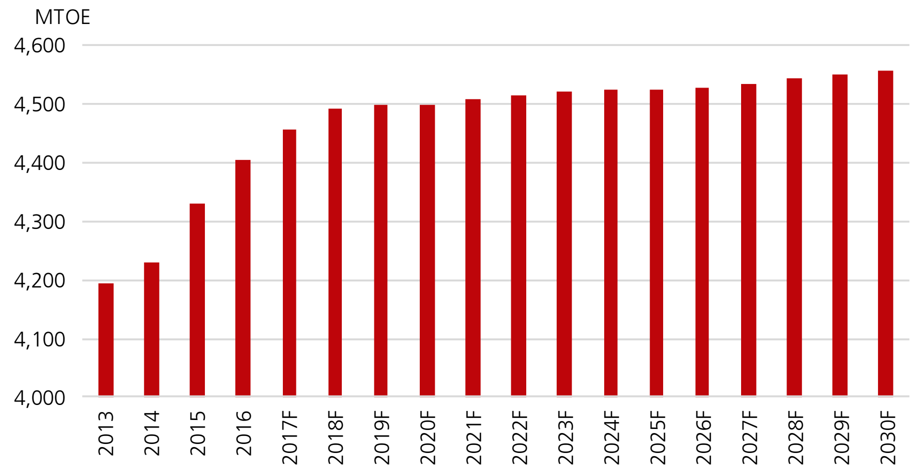
Oil demand from cars forecast to 2030 (mmbpd)

2016 oil demand from cars	Growth in demand for travel till 2030	Tightening in vehicle efficiency standards	Impact from switch to EVs	2030 oil demand from cars
18.7	10.8	6.1	5.3	18.1

Source: BP Energy Outlook 2018, DBS Bank estimates

Overall, we are projecting oil demand to be growing quite slowly till 2030. Despite the impact to oil demand from cars/ passenger vehicles from improving efficiencies, and shared mobility and electric vehicles, we highlight that this accounts for only 21% of global oil demand, and other drivers of oil demand – trucks, aviation, marine, rail and petrochemicals – will continue to grow as the global economy expands over time. India, for one, is a bright spot for oil demand, and we see significant additions to oil demand from India, on the back of strong growth in energy demand as its economy grows at a clip of close to 6% CAGR from 2017-2030, while efficiency gains remain modest. In addition, India's Draft National Energy Policy (2017) – which lays out the expected energy mix until 2040 – actually sees oil assuming an increasing role in the energy mix (from 24.5% in 2012 to 26.8% in 2040). Thus, we see slow growth in overall oil demand, and not a decline or plateauing up to the 2030 timeframe. Peak oil demand cannot be ruled out in the 2030-40 timeframe though.

Global crude oil demand forecast



Source: BP Energy Outlook 2018, DBS Bank Forecasts

Demand growth muted; supply will be the key determinant for oil prices in medium to long term. We do not expect a huge spurt in oil demand growth up to the 2030 timeframe as explained above. Neither do we expect any demand shocks from electric vehicles as the evolution and growth and adoption of electric vehicles is unlikely to be an overnight phenomenon which would suddenly wipe out a couple of million barrels of demand from the world. Thus, restraints or constraints in supply as a result of industry investment trends and geopolitics will be the major factor in guiding oil prices in future.

Near term, we expect 2018 Brent crude oil price to average between US$70-75/bbl and our 2019 average forecast for Brent is slightly lower at around US$65-70/bbl, as we expect some moderation from increasing US shale supplies as well as a gradual exit from the OPEC production cuts in 2019. OPEC and allies have recently agreed to raise production caps at the Vienna meeting to offset losses from Venezuela and Iran, but supply shortages could dominate newsflow in the near term, which could keep oil prices elevated and pose upside risks to our oil price estimates for 2018/19 .

Longer term forecasts remain sanguine owing to huge underinvestment during 2014-18. Capex budgets worldwide were cut substantially since the onset of the 2014 oil price collapse. Capex budgets for 2015 and 2016 declined by an average of about 25% each year across our sample of supermajors, and even 2017 eventually recorded 10% decline in capex though we were initially expecting 2017 capex to remain flat. In 2018, projections from global oil majors point to only a minor increase in capex – low single digit growth, which is not exciting. In any case, we do not expect oil capex levels to recover back to the highs seen in 2012-14 anytime soon. We have seen an unprecedented period of low capex compared to the years preceding 2014, when oil & gas capex grew at 12% CAGR between 2000-2014 representing an almost five-fold increase over the period.

As a result, industry consultant Wood Mackenzie believes close to US$1 trillion of capex meant for 2015-2020 timeline has been taken out of the system so far since the oil price crash in 2014. While project activity is picking up now, all the deferrals will mean that more than 3mmbpd of supply that was supposed to come onstream by 2020 will now only flow in the years after that. This will help the supply demand equation in the medium to long term. Also, the need to develop oil production in more expensive areas – and the cost of the most expensive last barrel needed to meet even steady demand – will continue to support oil prices. According to estimates from independent oil & gas consultancy Rystad Energy, the marginal sources of supply in 2020 will be currently non-producing shale fields (new shale) and oil sands, with a weighted average breakeven price of around US$63-66/bbl. Imputing some cost inflation to these numbers, we peg our longer term oil price forecast at around US$65-70/bbl.

Brent Crude oil price forecast – DBS' view

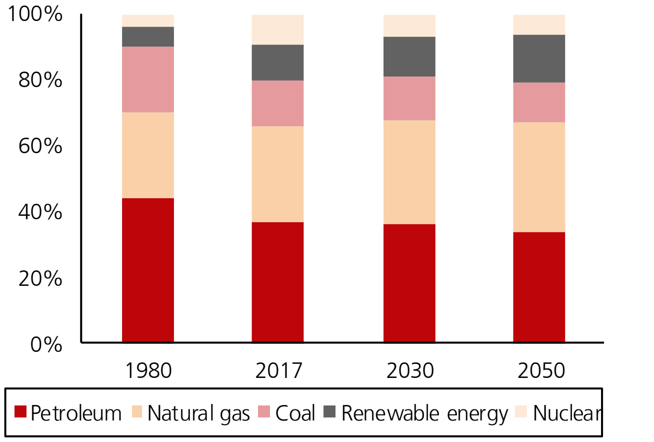
(US$ per barrel)	2013	2014	2015	2016	2017	2018F	2019F
Average Brent crude oil price	109	99	54	45	55	70-75	65-70
Long-term Brent crude oil price							65-70

Source: Bloomberg Finance L.P., DBS Bank Forecasts

4. US as net energy exporter

Petroleum will be less important to US energy basket over time. Although petroleum is still the largest primary energy source used for energy consumption, it has lost some market share to natural gas and renewable energy. Data from Energy Information Administration (EIA) showed that the percentage of petroleum in US' energy consumption declined from 44% in 1980 to 37% in 2016 while that of natural gas and renewable energy climbed from 26% and 6% to 29% and 10% respectively.

US energy consumption by primary energy source



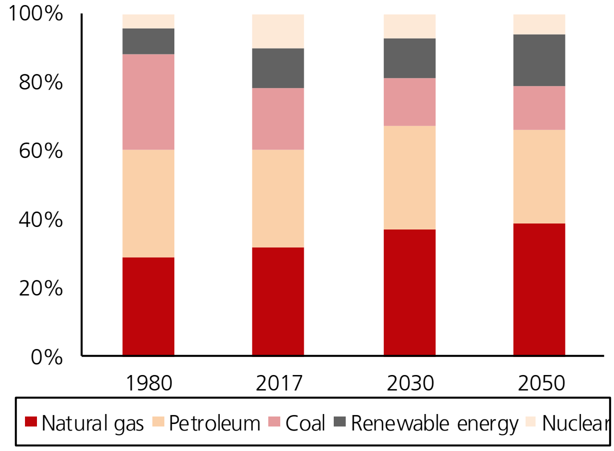
Source: US Energy Information Administration

The uptrend of natural gas and renewable energy in the primary energy mix is expected to continue. EIA estimated that petroleum and natural gas will each account for around one-third of energy consumption by 2050.

However, the picture of energy production mix is slightly different where natural gas has already recorded the highest percentage for total energy production in 2017. EIA estimates that the percentage of natural gas in the energy production mix will continue to climb in the next 20-30 years.

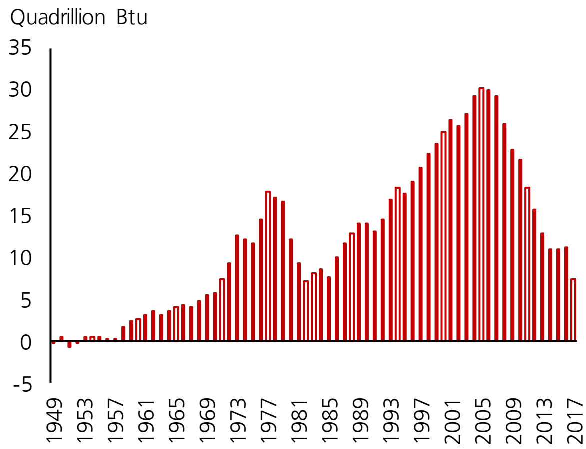
In addition, more cost-effective drilling and production technologies have helped to boost crude oil production, especially in Texas and North Dakota. Thus, strong domestic production coupled with relatively flat energy demand has allowed the US to become a new energy exporter.

US energy production by primary energy source



Source: US Energy Information Administration

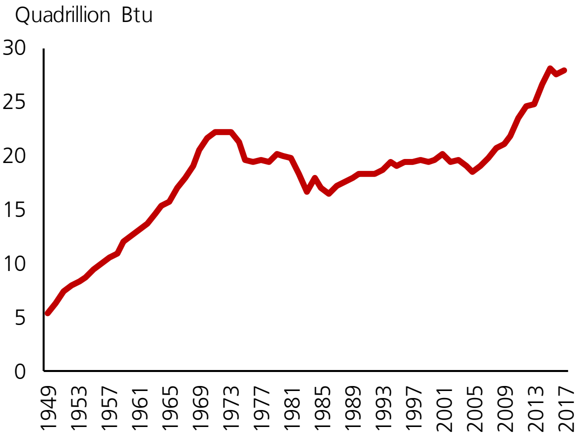
US primary energy net imports



Source: US Energy Information Administration

Excess supply of natural gas. Thanks to higher efficiency in hydraulic fracturing and horizontal drilling technologies, which make it possible to extract gas from shale formations, US natural gas supplies remains abundant and cheap. The US has one of the largest lowest cost gas resources in the world. In fact, proven reserves in the US were already up 5% last year to 341 trillion cubic feet, a 60% jump since 2006. According to CIA World Factbook 2017, the US is ranked fourth in proven natural gas reserves, after Russia, Iran and Qatar. Thus, production is expected to continue to outpace demand.

US natural gas production



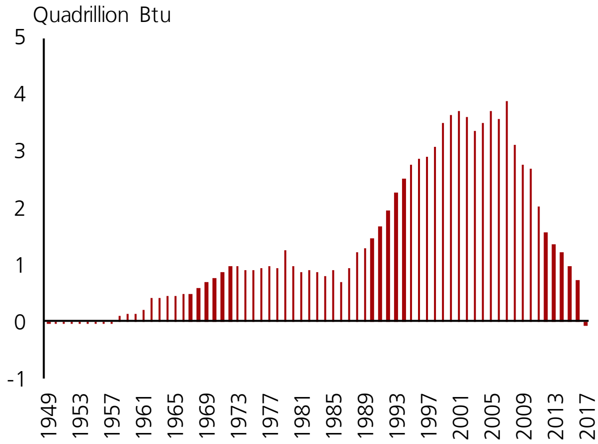
Source: US Energy Information Administration

Excess production is absorbed by strong demand from the export market. Last year, the US became a net natural gas exporter, with exports quadrupling from 0.5 billion cubic feet of gas per day in 2016 to 1.94 billion cubic feet per day in 2017. Around 53% of the exports went to Mexico, South Korea and China. In addition, an increasing share of US LNG exports are expected to go to Europe as EU member states look to diversify from their growing dependence on Russian gas.

With the consumption boost led by the global trend in shifting the energy mix towards natural gas to combat carbon emissions, US LNG exports are set to quintuple by 2019 from the 2017 level to 9.6 billion cubic feet per day. If this materialises, the US will become the world's third-largest natural gas exporter by 2020, after Australia and Qatar.

Robust growth in LNG exports is also underpinned by a wave of investments in infrastructure. The Kenai LNG export facility was the first and the only export plant in the US until it was shut down in 2016 due to depressed global LNG prices. But Sabine Pass LNG export terminal in Louisiana came on line the same year and has been expanding since. After a series of delays, Dominion Energy finally shipped out its first LNG cargo from Cove Point export terminal in Maryland in April 2018. A few more terminals are expected to come online within the next two years, such as Sempra Energy's Cameron LNG project in Louisiana, Elba Island LNG project in Georgia, Cheniere Energy's Corpus Christi project, etc.

US natural gas net imports



Source: US Energy Information Administration

Nevertheless, the booming LNG market is not without risk. Many industry players have been warning of a supply deficit in the medium to long term due to a lack of investments in the sector. There is no concern on supply in the short to medium term but shortage is likely to emerge by the mid-2020s, if investments in LNG facilities are inadequate.

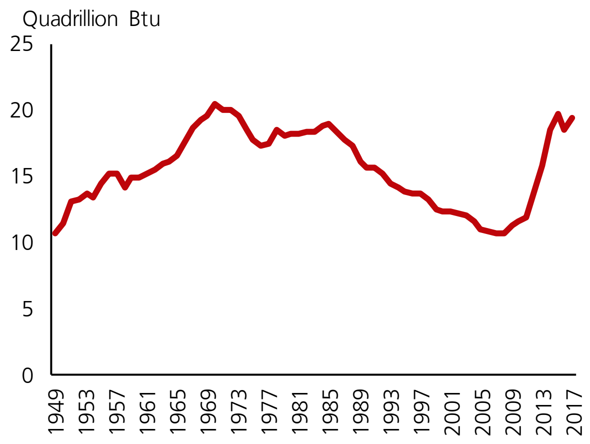
Some underinvestment due to a change in arrangements with customers. The traditional LNG export terminals have traditionally been massive with heavy investment in the tens of billions of dollars, and long term contracts are usually signed with customers to justify such heavy investment. But buyers from emerging markets now prefer smaller volumes on shorter and more flexible contracts. This new trend has prompted new LNG facilities to be smaller and in new modular-style designs where plants can be snapped together like Lego and expanded if and when demand grows. However, it has also deterred big players, who still favour the traditional set up, from making new investments.

US can be an oil exporter too. It has been a couple of years since Washington lifted a 40-year ban on oil exports, and US crude oil exports have taken off in the past year on the back of rising shale production, upgrade of export terminals, strong growth in global demand and geopolitical concerns in Saudi Arabia and Russia. In 2005, before the shale revolution, the United States had net imports of 12.5 million barrels per day (bpd) of crude and fuels - compared to just 4 million bpd today. Gross crude imports have dropped to 7.6mmbpd from a peak of 10.6mmbpd in 2006.

US is likely to be the world's largest oil producer soon. OPEC members have curtailed output since 2016 to support oil prices and eliminate extra inventories from the system. While they have recently agreed to boost supplies to an extent to counter the shortfall from Venezuela and export restrictions on Iran following the reintroduction of sanctions by the US, the level of spare capacity from these members is low. Saudi Arabia and Russia may be able to increase production by 200-300kbpd over the next few months.

In the meantime, US crude production has been reaching record highs, with production up about 27% since mid-2016 to 10.7m bpd currently. The gap between the top producer Russia, which pumps about 11m bpd, is getting closer. Rising production in the US is also supported by the rising number of rigs that US drillers have added. The only concern is the rise of pipeline bottlenecks in the Permian Basin, which could restrict production in coming months from this prolific area. Otherwise, the US is very likely to take over the number one producer spot from Russia by the end of the year or in 2019 at the latest.

US crude production



Source: US Energy Information Administration

US oil will find new customers and keep pricing and competition in check. US producers now export around 1.5-2.0mmbpd, which could rise to 4.0mmbpd over the next 5 years, as most of the incremental shale production in likely to be exported, owing to lack of domestic refineries able to handle the light sweet oil and demand for these grades from countries like China and India. While global demand for oil will slow down until 2030 and likely peak out in the 2030s, growth in the next 15-20 years undoubtedly will come from fast-growing developing economies. In particular, China and India alone are estimated to account for half of the total growth in global energy demand through 2030. For Asian buyers, the main attraction of US oil has been the price. Thanks to the shale boom, US crude is more price competitive, with WTI trading at significant discount to Brent currently, allowing the US to gain market share from OPEC and Russia.

Infrastructure providers will play a big role in boosting exports. In February, the Louisiana Offshore Oil Port started export operations, and it is the only terminal that can handle supertankers on the US Gulf Coast. In April, Nave Quasar arrived at the Port of Texas City to test the super tanker capability for crude exports. Corpus Christi port is also exploring the possibility of receiving very large crude carriers at its port. Pipeline and logistics firms in the US Gulf Coast will be big beneficiaries of this export boom, with demand for both storage and export infrastructure rising.

5. India – energy consumption and reforms story

Policies aimed at incentivising investment in generation capacity. A host of power sector related reforms and schemes have been carried out over the years in order to encourage private sector participation and thus enhance more investment in the capital intensive power sector. The key ones include Electricity Act, Village Electrification, Discom Bailout plans, UDAY scheme, 24x7 Affordable 'Power for All', Deen Dayal Upadhyay Gram Jyoti Yojana (DDUGJY), Integrated Power Development Scheme (IPDS), Gas Pooling Mechanism, SHAKTI scheme, SAUBHAGYA scheme, competitive bidding for PPAs, emphasis on renewable sector, coal block auction etc. Key highlights of some of these policies are tabulated below.

Power sector policies aimed to increase generation

Policy	Details
Electricity Act, 2003	• This watershed Act delicensed generation, facilitated open access, introduced power trading and encouraged private participation with an aim to enhance competition in the sector. The Act also laid more emphasis on promoting renewable technology-based generation and also mandated the electricity distribution companies of India (discoms) to purchase the same. • The Act also allows industries to set up captive generation plants for their own consumption and also gave them an option to select their own power supplier through open access mechanism. • The Act provides flexibility to the discoms to enter into PPAs with generators and procure power through either competitive bidding or through Cost-Plus regime under which the regulatory commission will approve and evaluate the prudence of capital cost and determine tariffs on annual basis with fixed RoE. • Capacity additions got a major boost especially across the coal segment which witnessed more than a two-fold jump over FY10-FY16.
Deen Dayal Upadhyay Gram Jyoti Yojana (DDUGJY)	• The scheme is designed to provide continuous power supply to rural India. • The government plans to invest Rs756 billion (US$11 billion) for rural electrification under this scheme. • Focus on feeder separation (rural households & agricultural) and strengthening of sub-transmission & distribution infrastructure including metering at all levels in rural areas. This will help in providing round the clock power to rural households and adequate power to agricultural consumers.
Integrated Power Development Scheme (IPDS)	• IPDS is basically a new avatar of the Restructured Accelerated Power Development and Reforms Program (R-APDRP) scheme in which funds are provided for reduction of aggregate technical and commercial (AT&C) losses, upgrade of infrastructure, IT-based billing and auditing system, and collection efficiency. • Under this scheme, all discoms including private ones are eligible to get government support. Power Finance Corporation is the nodal agency for this scheme.
SAUBHAGYA Scheme	• The Indian government announced this scheme in September 2017 with an aim to provide electricity to each and every household in the country. • The deadline for the same is to be completed in December 2018 and the total outlay of the project is Rs163 bn while the Gross Budgetary Support (GBS) is Rs. 123.2 bn.

Source: Relevant Government Ministries, Emkay Global Research

Challenges exist on the ground. While the above schemes have led to significant capacity additions in the generation side, the negligence and improper management across the distribution and fuel supply segment has led to various cost and viability issues across the sector. Much of the gas-based capacity is idle for want of fuel and many of the competitively bid coal-based projects are seeking post-facto revision of the tariffs on various grounds. Concern on ecological imbalance and delays in project execution has stalled the growth of hydro projects and those under construction are witnessing huge cost over-runs, making it economically unviable for the electricity distribution companies of India (discoms) to enter into PPAs.

Thus, while the last decade saw huge interest and investments by the private and public financial institutions companies in the capital-intensive power sector, the past few years have become challenging for all stakeholders in the sector. Power projects are turning into Non-Performing Assets (NPAs) based on a multitude of reasons plaguing the sector including policy paralysis, delay in project execution, deteriorating financials of discoms and lack of revival in industrial power demand. Absence of long term PPAs, lack of gas supply, poor coal inventories, policy paralysis, delay in reforms execution and cost over runs have led to almost 60GW of thermal projects stranded. In order to address these issues, the Government has introduced various other key reforms and schemes as listed in the following table.

Power sector policies aimed to address distribution and other challenges

Policy	Details

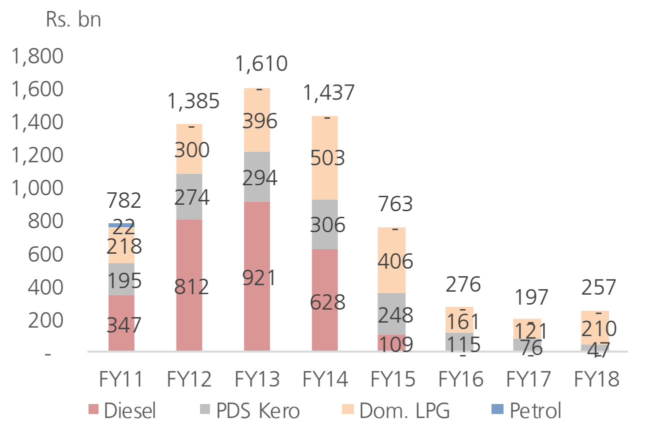
Ujwal Dliscom Assurance Yojana (UDAY Scheme)	• Financial Turnaround - States will take over 75% of the discom debt as on Sept 30, 2015 - 50% in FY 2015-16 and 25% in FY 2016-17.
	• States to issue non-SLR including SDL bonds, to take over debt and transfer the proceeds to DISCOMs in a mix of grant, loan, equity.
	• Borrowing is not to be included for calculating fiscal deficit of the State
	• The balance 25% of debt to remain with discoms and would be renegotiated with the lenders at rates not more than bank base rate +0.10%
	• States to take over future losses of discoms in case efficiencies fail to improve.
	• Targets to be achieved under UDAY:
	  • To bring down AT&C loss to 15% by 2019 vs 24% nationwide as in 2015.
	  • 100% Feeder and Distribution metering
	  • Elimination of ACS-ARR gap by FY19
	• Impact of the scheme: Financially & Operationally sound discoms, increased demand for power, improvement in load factor of generating plants, reduction in stressed assets and availability of cheaper funds

Shakti Policy	• Objective: To auction long-term coal linkages to power companies which will ensure adequate fuel supply to plants facing supply constraints. • The move will improve the plant utilisation and also lower the power tariffs due to access to domestic coals, coupled with better plant utilisation. • The move will also help banks exposed to the power sector to cut down on NPAs.

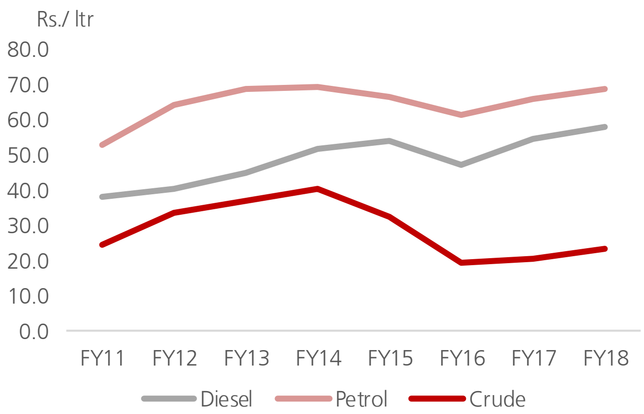
Source: Relevant Government Ministries, Emkay Global Research

The overall Indian landscape for energy and fuels also witnessed sea changes in the last 3-5 years with major reforms initiated by the Government which was supported by decline in oil prices. The pricing for petrol and diesel has been deregulated while kerosene usage was discouraged through reduced allocation and small monthly price hikes. LPG was brought under a targeted subsidy system where the subsidy was channelled through bank accounts with customer verification, thereby stemming leakages. Small monthly hikes in LPG was also initiated though due to Government's thrust of promoting cooking gas among the lower income group, but this was suspended in order to encourage LPG adoption. Consequently, under-recoveries/subsidy losses which peaked at Rs 1.6trn in FY13 fell to Rs 200-300bn p.a. during FY16-18. The oil marketing companies were given autonomy in petrol and diesel pricing and barring a few political event based instances, rates were in line with international prices.

Under-recoveries have fallen significantly

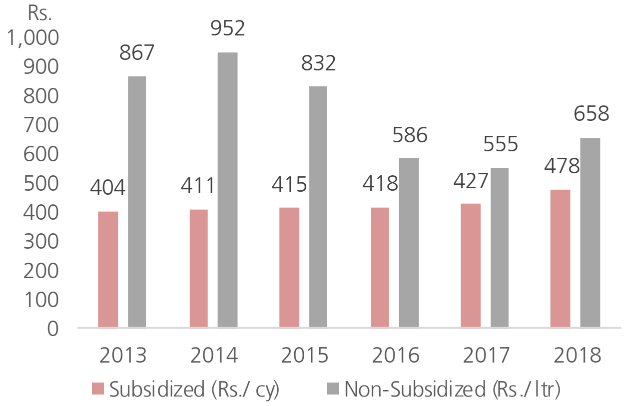


Petrol-diesel and global crude prices largely in tandem



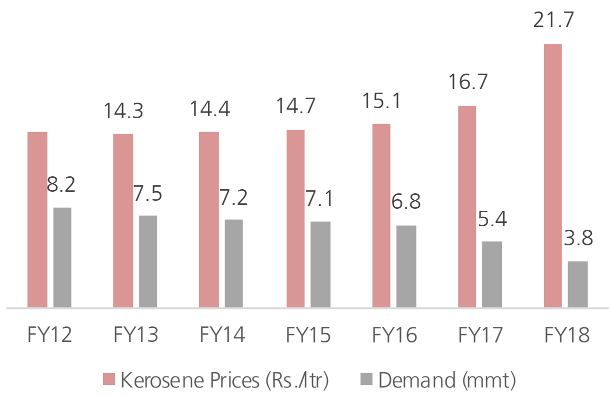
Source Government data, Emkay Global Research

Subsidised LPG prices rising



Source Government data, Emkay Global Research

Kerosene prices hiked to discourage demand



Host of upstream related reforms were also carried out to enhance E&P activities and domestic oil and gas output. These include new initiatives like Discovered Small Fields (DSF) and Hydrocarbon Exploration Licensing Policy (HELP) where complete pricing and marketing freedom is given for all kind of hydrocarbons with perennial bidding and a simpler revenue sharing mechanism. The gas pricing reforms include linking conventional natural gas pricing to global hubs like Henry Hub, NBP, Alberta and Russian domestic gas while for difficult to access fields, the pricing mechanism has a ceiling linked to alternate fuels like LNG, FO, coal etc. This has renewed interest in the fledgling deepwater reservoirs and local majors like Reliance and ONGC have expedited development of their acreages in the KG basin.

The upstream reforms are:

1. Discovered Small Fields auction (DSF) in 2016
2. Hydrocarbon Exploration Licensing Policy (HELP) in 2017
3. Domestic Natural Gas Pricing Guidelines in November 2014
4. Deepwater, high pressure high temperature, difficult gas price ceiling in 2016.

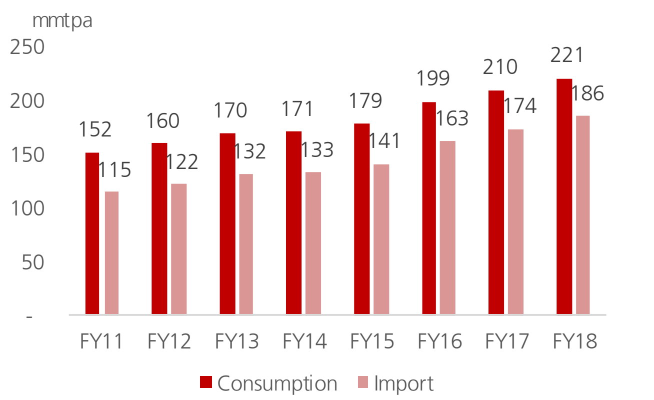
The gas midstream-downstream sector has also been a focus area as the Government aims to promote gas usage in order to meet pollution control commitments as well as save on energy costs as gas is comparatively cheaper than liquid hydrocarbons. This includes grid development, expansion of city gas distribution (CGD) and policy measures to restrict polluting fuels where Courts have also played an important role. Already taxation is lower in gas.

Gas downstream measures are:

1. Promoting gas grid development with target to double pipeline network to 30,000km.
2. Viability gap funding is done for frontier pipelines like the newly developed eastern grid.
3. Allocation of cheap domestic gas for CNG and domestic PNG sector which are prioritised and are alternatives to petrol/diesel and LPG where import dependency is high.
4. Expansion of CGD through new area allocation. The Government along with sector regulator has put cities/areas up for CGD bidding. The latest round covers 86 clubbed areas. The eastern grid development was also accompanied by complementary CGD area allocation to the developer GAIL along the pipeline network.
5. Courts and tribunals have promoted gas usage in high pollution areas by banning liquid and solid fuels.

Policies are also in place regarding fuel mix. In this regard, the Government's prime targets are to reduce oil import dependency by 10% in the next 5 years and increase share of natural gas in the primary energy basket to 15% from current mix of less than 7%. Thus, policy and reform measures are aimed at boosting domestic hydrocarbon output, promoting gas usage and reducing subsidies to achieve above objectives, which in turn are based on broader objectives like foreign exchange savings and energy security along with environmental protection.

India's oil import dependency is high at 80%

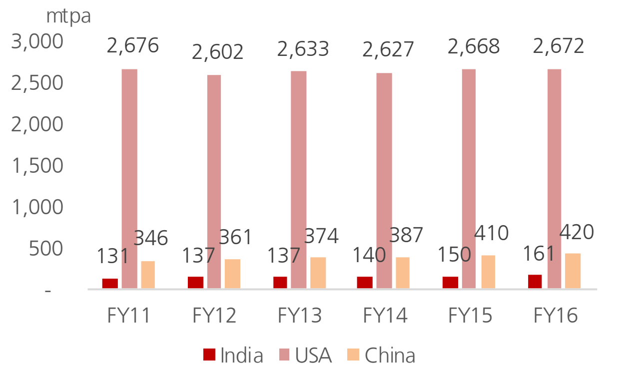


Source: Government data, Emkay Global Research

India's energy consumption growth is healthy with oil consumption CAGR at ~5% in the last 5-10 years. The oil demand to GDP growth multiplier has gone up in the last few years driven by rapid urbanisation, LPG cooking gas penetration and driving populace. Vehicle sales growth has picked up and India's per capita oil consumption is much lower than developed countries and even emerging country peers like China. Overall India is one of the fastest growing major economies and with higher income levels, industrialisation and freight activity, oil demand growth is likely to be in a similar range.

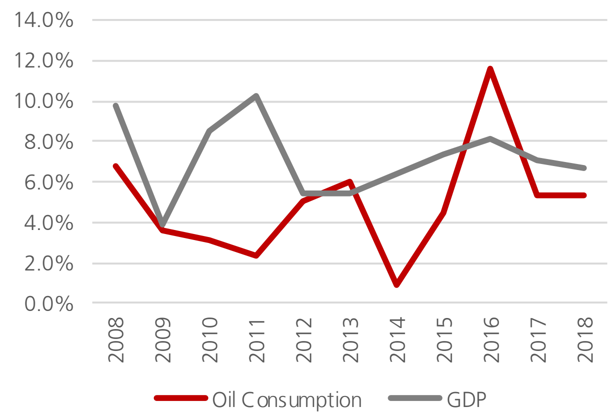
The IEA estimates Indian oil demand to grow by 4% CAGR up to 2040 which would lead to absorption of the planned refining capacity expansion. This could be challenging for the Government to achieve its target to lower import dependency unless there are major oil discoveries or aggressive adoption of gas as an alternate fuel.

India's per capita oil consumption is very low



Source: Government data, Company statements, Emkay Global Research

Oil demand to GDP multiplier is up



Source: Government data, Company statements, Emkay Global Research

Refining capacity growth in the works. Refining capacity addition targets are in place by domestic companies - particularly Public Sector Undertakings (PSUs), who are experiencing a shortfall compared to their marketing volumes, hence their reliance on private refiners and imports. With demand outlook healthy and private players also getting into marketing, the PSUs are aggressively protecting their market share and have captive capacity available. Against 250mmtpa (million metric tonnes per annum) of refining capacity presently, the target is to achieve 440mmtpa by 2030. Capacity expansion of 15mmtpa is currently underway which is expected to be commissioned by 2021.

Refinery capacity addition plans

mmtpa	Current	CY30E	CY21E UC	Current projects
IOCL Group	80.7	116.6	85.0	Koyali underway
BPCL Group	36.5	56.0	38.3	Bina refinery expansion
ONGC HPCL Group	42.2	62.9	50.9	Vizag and Mumbai expansion underway
Reliance	68.2	98.2	68.2	
Essar/Nayara	20.0	45.0	20.0	
Others	0.0	60.0	0.0	
Total	247.6	438.7	262.4	

Source: Media reports, Government data, Emkay Global Research

Indian refiners are also integrating petrochemicals as a diversification move particularly due to perceived threat on transportation fuels in the long term from use of gas and adoption of electric vehicles. Of course, India being a strong growth economy will generate robust petchem demand. Petchem being a high value product would also enhance refining margins. Already refiners like Reliance Industries Limited (RIL) and Indian Oil Corporation Limited (IOCL) have sizeable petchem exposure though new projects are being developed by other players which are expected to be commissioned during 2018-21.

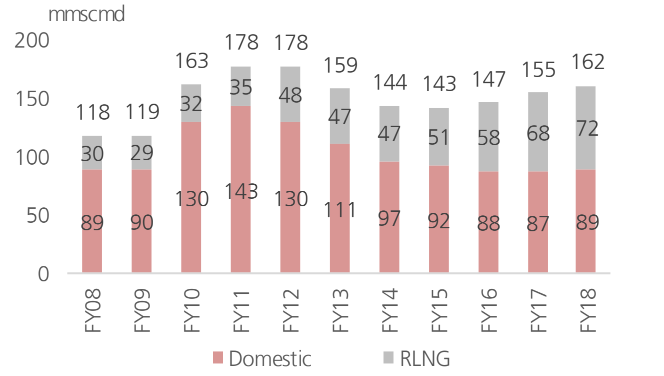
Petrochemical exposure of refiners

RIL Jamnagar	Petchem integrated within the complex, high exposure, to further increase with new projects
IOCL Koyali	Already has LAB facility, expansion project to include PPU
IOCL Panipat	Already has PX/PTA and naphtha cracker/polymer-glycol unit
IOCL Paradip	PPU under construction, has plans to set up MEG & PTA plants
BPCL Kochi	Niche propylene derivative project under construction
HPCL Barmer	New refinery to include integrated petchem/naphtha cracker complex
HMEL Bhatinda	Work has started on an ethylene/polymer unit
MRPL	Already has PPU and has a PX/benzene subsidiary next door
Mega West Coast	New refinery to include a 18mmtpa integrated petchem complex

Source: Media reports, Company statements, Emkay Global Research

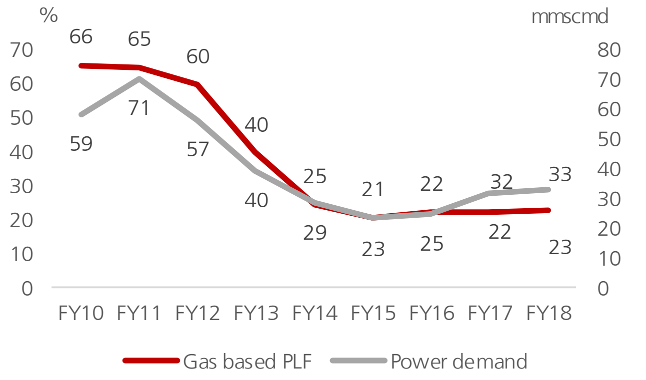
Gas demand has been affected by domestic production issues, which led to a sharp fall in power sector demand as low prevailing spot electricity tariffs restricted the utilisation of gas based power plants using the pricier LNG. The 10-year gas output CAGR has been 3% while for 5-year CAGR was flat. Against the decline in domestic output, LNG supplies have grown as sectors other than power have switched to using it. Overall gas volumes consumedbottomed in FY15 even as LNG imports grew significantly, while in FY18, domestic gas output also rose, led by ONGC, despite output at Reliance fields continuing to decline.

Gas consumption volumes bottomed out in FY15



Note: mmscmd : Million Metric Standard Cubic Meter Per Day
Source: Government data, Company statements, Emkay Global Research

Entire gas demand destruction from power sector



Note: PLF refers to plant load factor for power plants
Source: Government data, Company statements, Emkay Global Research

Future outlook for gas is better though. In FY18, volumes grew by 4% y-o-y and going forward, we believe the outlook is better with sectors like fertilisers, refineries, industries and city gas off-taking more gas. We expect gas demand to grow by 5-6% under our base case scenario, though success of large number of new City Gas Distribution (CGD) areas and any revival in power sector could boost it further.

Sources of gas looking up, could help boost consumption. Against current domestic gas production of ~90mmscmd (million metric standard cubic ceter per day), players like Reliance and ONGC are targeting almost 50mmsmcd of new output from deepwater fields by fiscal year 2023. With such a large quantity of local gas, demand can grow significantly. New LNG terminals are also planned. Against 25-30mmtpa (100mmscmd) of LNG capacities currently, another 30-35mmtpa of capacities are likely to come from 6-7 new terminals over the next 5 years. Hence, with higher available supply, infrastructure expansion and policy measures, gas demand growth can be stronger. If we assume the 50mmscmd of additional domestic gas output target is met with full domestic absorption and new LNG terminals operating at 50% capacity utilisation, gas demand CAGR in next 5 years would be closer to 9% under a blue sky scenario.

New LNG terminals on the radar

	Commissioning	Capacity (mmtpa)
Dahej	Existing	15.0
Kochi	Existing	5.0
Hazira	Existing	5.0
Dabhol	Existing	5.0
Mundra	FY19	5.0
Jaigarh	FY19	4.0
Ennore	FY19	5.0
Dahej Expansion	FY20	2.5
Jafrabad	FY21	5.0
Dhamra	FY22	5.0
Chhara	FY22	5.0

Source: Company statements, Emkay Global Research

New supplies can lead to almost 10% demand CAGR over next 5 years

mmscmd	Domestic	LNG	Total
Current Supply	90	70	160
New Gas	50	36	86
FY23 Supply	140	106	246
CAGR	9%	9%	9%

Source: Company statements, Emkay Global Research

Gas is still unlikely to cause a major shift in energy mix in near term; oil will decline slightly. At 5-6%CAGR expected for gas demand, the share of gas in the primary energy basket would grow by less than 1% in the next 5 years, while the Government's target is to double the share of gas in the energy basket from xx% currently. This seems unrealistic as it would require 20-25% demand CAGR for gas. At our best case of 9% CAGR, the share of gas in the energy mix would be better at 10%, thus aggressive policies can make a difference. The energy mix would otherwise not change by very much. Oil's share is also expected to reduce by 1% assuming 10% CAGR in renewables and 4% in coal, yet import dependency would continue to remain high.

Primary energy basket and energy mix for India

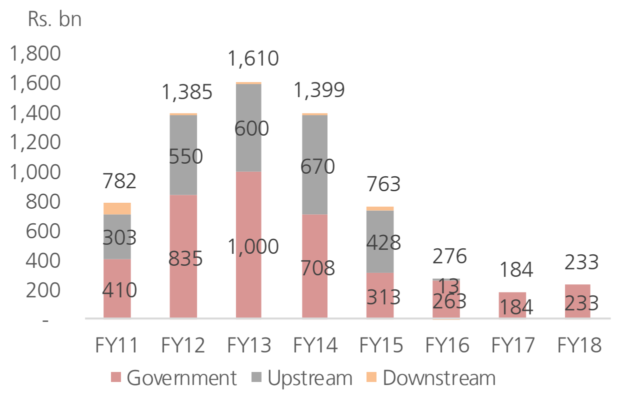
mmtoe	CY16	CY22E
Oil	213	269
Gas	45	64
Coal	412	521
Others	54	96
Total	**724**	**950**
Share in Primary Energy Basket		
Oil	29%	28%
Gas	6%	7%
Coal	57%	55%
Renewables	7%	10%
Total	100%	100%

Source: BP, Emkay Global Research

Challenges to growth. The oil and gas/energy space has certain challenges owing to import price and subsidy risks, fiscal challenges and land acquisition difficulties.

Oil & Gas price risks. Being an import dependent economy (80%+ oil import share/ 50%+ gas import share), India is impacted by volatile crude and imported gas (LNG) prices, more so due to socio political sensitivity and controlled pricing in sectors such as cooking gas, electricity, fertilisers etc. This leads to significant subsidy burden which may be too much for companies to bear and also exerts pressure on the fiscal deficit. Hence a prudent formulaic subsidy sharing mechanism needs to be in place besides eventual decontrol of all these items.

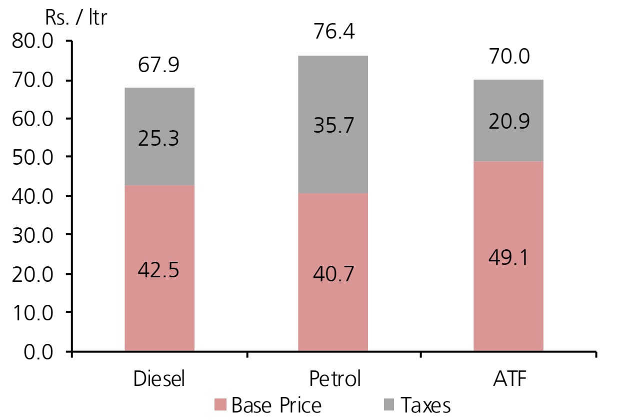
Petroleum subsidy burden sharing



Source: Government data, Company statements, Emkay Global Research

Fiscal challenges. The sector is heavily taxed and even post implementation of GST, certain items like crude oil, natural gas, petrol (gasoline), diesel and jet fuel are kept out of the ambit of the GST, as they are significant revenue drivers for both centre and states. This has led to dual regimes for industry players, resulting in input tax credits not being available, in addition to high prices. Additionally, fiscal overtures like the Cairn Energy Income Tax demand are also dampeners which makes foreign and private players cautious to invest in India.

Taxation is very high in major fuels like petrol, diesel and jet fuel



Source: Government data, Company statements, Emkay Global Research

Land acquisition issues. Local protests have impacted land acquisitions for projects such as pipelines, refineries, terminals etc leading to considerable time and cost overruns. Farmers are unwilling to part with their lands, while political elements also play a part.

6. Coal: Usage yet to peak in Asia

Coal will continue to be in demand in the Asian region. Coal accounts for around 50% of Asia's energy mix, and we believe that it will continue to be one of the most important energy components going forward given its affordability and availability. As coal has one of the lowest costs of production (US$ per MWh) in the conventional and renewable energy space, replacing coal means that governments need to brace for higher energy cost across the board, which may entail wide implications for the macroeconomics of the respective countries.

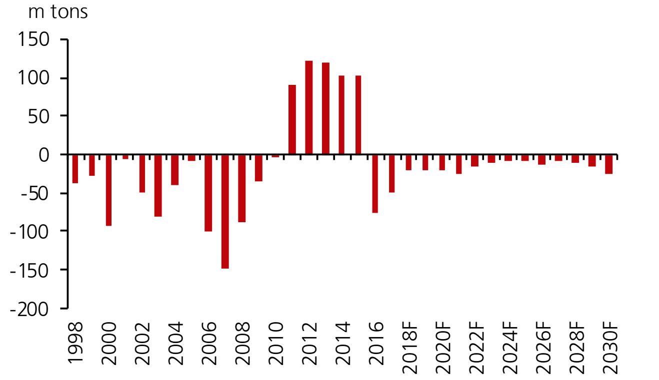
The relatively close proximity of Indonesia and Australia to the main purchasers of coal such as China and India also reinforces the popularity of this energy source among Asian countries. Besides Indonesia, Thailand's plans to shift its energy mix to higher coal content will boost demand for coal in the ASEAN space. ASEAN will be one of the largest markets for coal beyond China and India, which we believe is sufficient to offset any potential demand deceleration from the EU countries.

Energy security is another factor. Moreover, replacing coal entirely may require multi-decade efforts, as it currently comprises half of the region's energy mix. Energy security is another factor that will ensure that coal demand does not disappear anytime soon. As electricity generation is crucial for maintaining the growth of industrial activities, replacing coal's position in the energy mix requires careful planning and execution in the long term to avoid unpleasant economic disruptions.

Renewable and alternative energy comes with reliability and scalability issues, in our view. Such energy sources have yet to enter the phase of large-scale operations, especially in Asian countries, given their still developing infrastructure. Natural gas, which is cleaner vs. coal, also requires additional investment in piping facilities, storage tanks, regasification facilities and power plant upgrades for gas-enabled power plants.

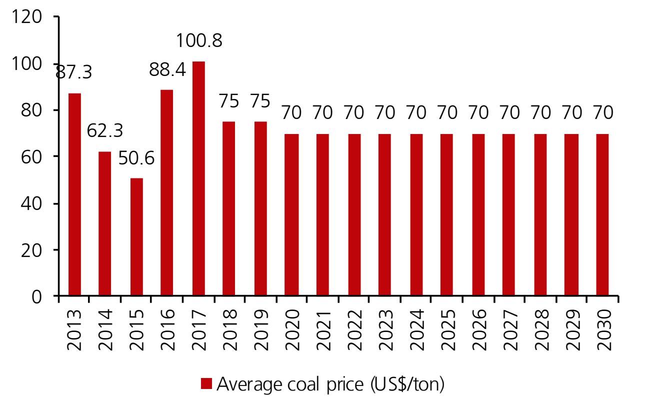
Coupled with a rational supply outlook, we reiterate our coal price benchmark of US$75 per ton in FY18-20F, and US$70 per ton in FY21F and beyond. We are expecting the supply and demand dynamics to remain tight, thus providing the impetus for coal prices to stay above US$70 per ton – which we believe is a win-win level for both coal miners and users (mainly power plant operators).

Coal supply/demand surplus/ deficit summary and forecast



Source: BP Statistics, DBS Bank

DBS Newcastle coal price estimate (US$/ton)



Source: Bloomberg Finance L.P., DBS Bank

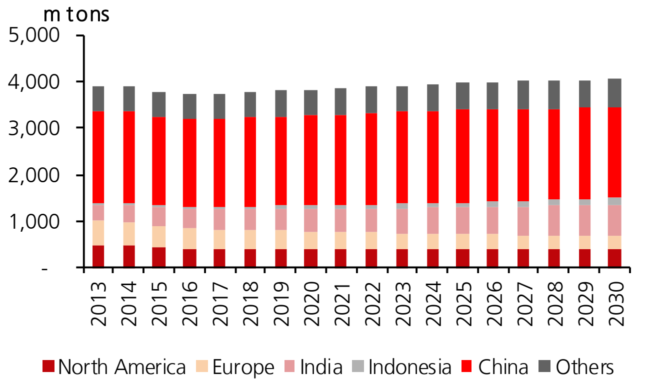
Demand outlook: Replacing coal is challenging

Despite the pressure to embrace a cleaner energy mix, which may cause developed countries to continue limiting or even cutting their coal-fired power plant generation capacity, we believe replacing coal entirely could bring about huge challenges. Looking at the global project pipeline, coal still plays an important role in ensuring energy security. There is also a need to ensure the availability of stable electricity supply to power industrial activities

We expect there will be a reduction in the number of new coal-fired power plant projects, but scrapping existing operating capacity and capacity under construction is highly unlikely, as doing so will have a massive impact on economic and industrial activities.

We estimate global coal demand will still exhibit slow growth in FY17-30, with declining demand from Europe and flattish demand from China offset by growing demand from India and also supported by ASEAN countries, mainly Thailand and Indonesia.

Global coal demand outlook (m tons)

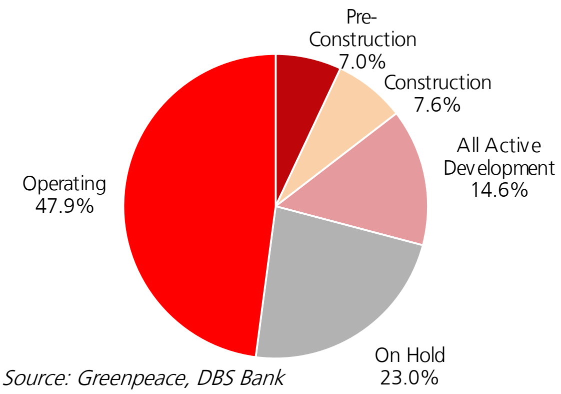


Source: DBS Bank estimates

China coal demand expected to be flattish at worst. China will continue to have to rely on coal, in our view, despite its intention to reduce pollution. China has 921k MW of coal-fired power plants in operation, with another 280k MW still in active development and 145k MW under construction, not to mention 134.4k MW in the pre-construction stage. Despite the capacity additions, 441.8k MW of coal-fired power plant projects are on hold to prevent power oversupply conditions and comply with environmental rules.

Looking at the additional 50% of total installed capacity, we believe China's coal consumption will remain healthy. We expect flattish coal consumption growth in China over FY17-30F, which we believe is fairly conservative, as coal-fired power plant projects under construction come online gradually. We assume the use of cleaner technology and more efficiency being achieved for the new power plant projects.

China's coal power plant project status

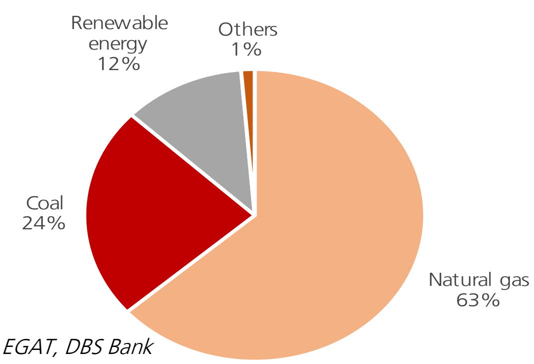


Source: Greenpeace, DBS Bank

Beyond China, we see strong demand coming from ASEAN countries such as Indonesia and Thailand, as both countries rely on affordable and reliable energy to grow their economies.

Thailand's shift to coal for energy security. Thailand is expected to increase the share of coal in its energy mix to diversify its fuel mix for power generation. Currently, coal accounts for around 24% of Thailand's energy mix. Thailand relies mainly on natural gas to generate power, but its domestic gas supply growth is expected to slow down in the face of depleting reserves.

Thailand's 2016 energy mix

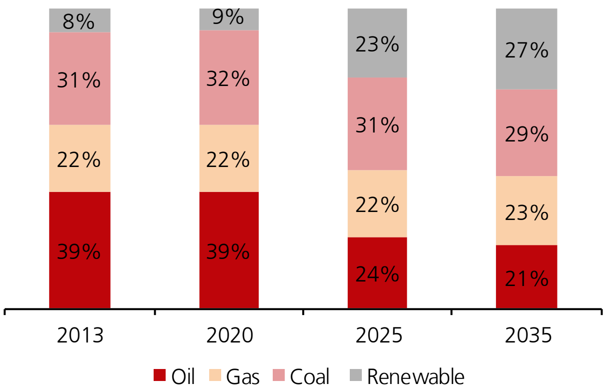


Source: EGAT, DBS Bank

Importing gas from Myanmar may be a short-term solution but this entails higher cost vs. domestically produced natural gas. Moreover, renewable energy in Thailand also has not reached meaningful economies of scale to make it cost competitive vs. conventional energy. While the Thailand government seems to be heading towards cleaner renewable energy sources by launching several pilot project initiatives, the Electricity Generating Authority of Thailand (EGAT) has signed a long-term contract of 25 years with Adaro Energy to secure Thailand's long-term coal supply. The intention to diversify beyond natural gas presents the opportunity for coal consumption to grow in the country.

Over in Indonesia, despite the plan to add more renewable energy to its 2025 energy mix target, Indonesia still relies on coal to a large extent. Its upcoming power plant projects are dominated by coal-fired capacity, followed by gas and diesel. Since Indonesia is one of the world's largest coal producers, tilting towards coal power is also wise in its attempt to maximise the country's electrification ratio going forward.

Indonesia's energy mix blue print

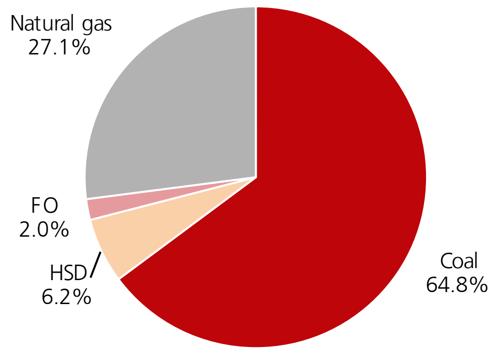


Source: Ministry of Energy and Mineral Resources, DBS Bank

Coal currently accounts for close to two-thirds of current energy consumption in Indonesia. Indonesia's National Electricity Company (PLN) relies on coal to fulfil the nation's electricity demand and we believe the trend will not change drastically going forward. In 2016, coal accounted for 64% of PLN's total energy consumption.

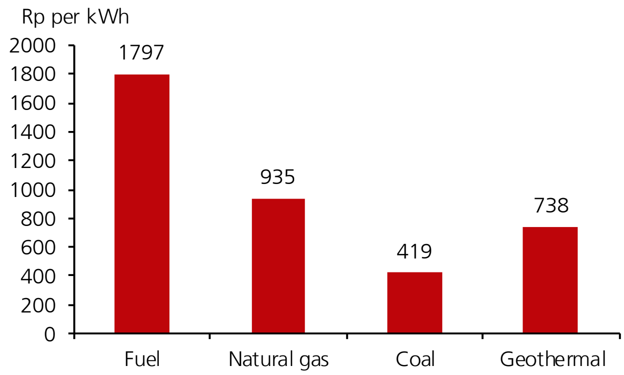
PLN needs to harness the cheapest energy sources to stay profitable and financially sound. PLN is able to generate power at the lowest cost per kWh using coal as its primary energy source vs. other energy sources.

PLN's energy consumption (2017)



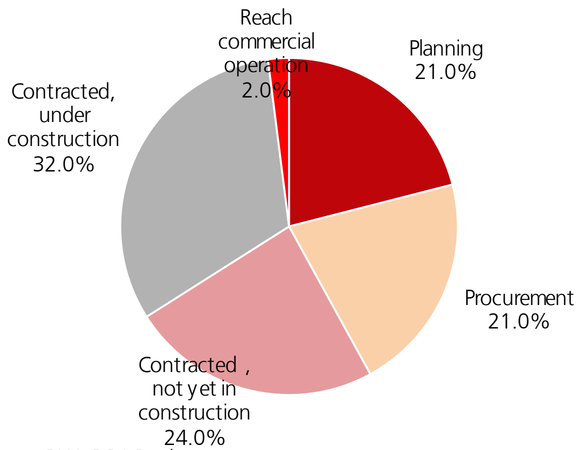
Source: PLN, DBS Bank

PLN's power generation cost (Rp per kWh, 2016)



Source: PLN, DBS Bank

Progress of 35,000MW new capacity addition as at March 2017



Source: PLN, DBS Bank

New power projects of 35,000MW under planning in Indonesia, other coal powered plants under construction globally as well. The well-planned execution and gradual delivery of 35,000MW new power capacity is the key critical factor that will determine how well Indonesia can boost its domestic coal demand. There could be upside risks to our coal demand forecast for Indonesia and long-term coal price projection, as we have assumed only 60% completion of the 35,000MW new capacity in 2030.

Coal fired power plant project list – global (2016)

Countries	Pre-Construction (MW)	Construction (MW)	All Active Development (MW)	On Hold (MW)	Operating (MW)
China	134,480	145,573	280,053	441,749	921,227
India	128,715	48,168	176,883	82,495	211,562
Turkey	66,852	2,640	69,492	17,654	16,362
Indonesia	38,450	7,820	46,270	8,385	27,399
Vietnam	29,580	15,177	44,757	2,800	13,394
Japan	17,343	4,256	21,599	-	44,078
Egypt	17,240	-	17,240	-	-
Bangladesh	15,685	275	15,960	3,935	250
Pakistan	10,418	4,860	15,278	5,310	190
South Korea	8,760	5,917	14,677	1,160	33,417
South Africa	6,290	7,940	14,230	1,500	40,513
Philippines	9,293	4,476	13,769	926	7,282
Poland	5,820	4,245	10,065	1,500	27,761
Russia	8,706	180	8,886	700	48,435
Thailand	7,306	600	7,906	600	5,457
Mongolia	5,700	1,400	7,100	250	706
Zimbabwe	6,480	-	6,480	1,200	980
Myanmar	5,130	-	5,130	6,455	160
Taiwan	800	4,000	4,800	7,600	17,407
Botswana	3,904	432	4,336	-	600
United Arab Emirates	1,470	2,400	3,870	-	-
Malaysia	-	3,600	3,600	-	10,008
Malawi	3,520	-	3,520	-	-
Bosnia & Herzegovina	3,500	-	3,500	500	2,065
Cambodia	3,040	135	3,175	1,200	370
Germany	2,020	1,100	3,120	660	53,060
Serbia	2,900	-	2,900	320	4,294
Chile	2,272	375	2,647	375	5,101
Mozambique	2,600	-	2,600	1,620	-
Nigeria	2,200	-	2,200	1,000	-
Rest of the World	19,127	7,371	26,498	17,473	472,382
Total	**569,601**	**272,940**	**842,541**	**607,367**	**1,964,460**

Source: Greenpeace, DBS Bank

Supply outlook: Rational global output will support prices

Global output is heading towards the phase of consolidation, led by China. The Chinese government's plans to scrap inefficient national capacity, and merge and put its coal capacity into the hands of several super-large coal miners are also positive – thus enabling the government to keep domestic supply in check and prevent coal price from slumping again.

Seaborne coal miners, mainly those from Indonesia, also do not plan to expand their capacity to elevated levels in the face of heavy equipment supply constraints and limited access to financing. We expect global coal supply to grow only at 1% CAGR in FY18-30.

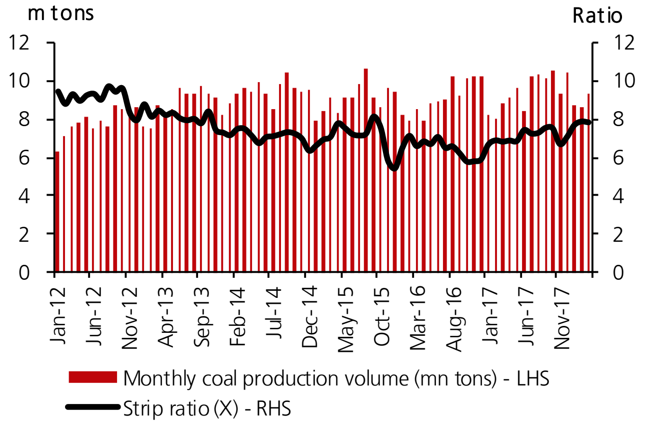
Other than China and Indonesia, coal supply growth elsewhere will be muted due to supply rationalisation efforts and the phasing out of mining concessions. Investments in the coal sector will remain tepid due to the cyclical factor, coupled with limited demand expansion potential in the future.

Output behind schedule in Indonesia. Though we have not seen any consolidation among coal miners in Indonesia, we believe the government's warning that Indonesia's coal production could only reach 400m tons by 2020 vs. the 2018 output target of 420m tons, indicates that Indonesia's coal production landscape is changing structurally. The efficiency-boosting efforts among the coal miners back in 2012-2015 have led to idle coal reserves, which put their profitability and mineable coal at risk. Raising production involves more than just restarting the machineries and digging the soil for coal. The miners need to reorder divested machineries, rehabilitate the unused soil and regain the confidence of bankers to finance the aforementioned activities. We reckon that returning to the productivity levels of the 2008-2012 era will be a tall order.

On the other hand, we also detect a still cautious stance among miners due to their reduced appetite to ramp up their operations aggressively (unlike four years ago). This means that the coal miners will not significantly increase their output to potentially cause a slump in coal prices. United Tractor's (UNTR)'s monthly Pamapersada (the mining contractor subsidiary's statistics) also does not point to any behavioural changes among its clients.

We believe the same trend will also persist globally. One example is China, the largest coal producer in the world, which intends to keep its output pretty much flat until 2020. China plans to maintain its supply rationalisation programme by actively controlling the working days of miners. Its consolidation plan is positive for the long-term coal supply-demand balance.

UNTR's overburden removal and coal production volume



Source: UNTR, DBS Bank

Output consolidation taking place in China. The output consolidation that is happening in China is positive for coal supply-demand dynamics. As China accounted for 46% of global thermal coal output of 3.6bn tons in 2016, the domestic coal miners' consolidation plan (which will allow the government to have more control over coal output going ahead) will have a positive effect on global coal prices. Such output consolidation is also part of the plan to cope with the downside potential that may come with declining coal-fired power plant capacity, as it can prevent an excessive decline in coal prices that can hurt the coal miners.

The consolidation plan mainly revolves around merging the coal mines into several super-large coal mines with an annual production capacity of 100m tons. This will eliminate any excess capacity and improve the operational efficiency of the coal miners via mergers and acquisitions. The Chinese government is aiming for a coal production capacity of 3.9bn tons vs. 2017's total coal output of 3.4bn tons. So far, China's coal sector reform has reduced the total number of coal mines to 7,000 from 10,800 in 2015. China's Shanxi province has already set output and total capacity targets of 1bn and 1.2bn tons by 2020, respectively, which are similar to its 2016 output of 1bn tons. Shanxi province accounts for more than half of China's total production capacity and we believe such a capacity cap will prevent the recurrence of excess supply conditions, especially when coal demand growth is expected to be flat until 2022, according to EIA forecast.

IMPACT TO SUB SECTORS & STOCKS

IMPACT ON SUB-SECTORS

Implications on Chinese gas players

Gas distributors will benefit from structural changes. Amid ongoing changes in the government policies in China, the global trend of reducing carbon emissions through the use of cleaner energy is unquestionable and all gas distributors will benefit. They will enjoy strong volume growth despite the suppressed dollar margin over the long term. In fact, major gas distributors are expected to achieve above industry average volume growth of c.20% from FY17-20 from strict implementation of coal-to-gas conversions and a more competitive selling price. Thus, we expect the overall impact to earnings is positive to the major gas distributors.

In addition, China gas distributors will benefit from rising import of energy from the US to China. With more LNG from the US, not only is the source of gas supply broadened but is also obtained at competitive prices as the US is one of the lowest cost natural gas producers globally. China Gas has already signed a MOU for long term supply of 3m tons of LNG per year from the US. ENN and Towngas China will also benefit as we believe they can ride on their parent's plan of constructing LNG receiving terminals in China.

China Gas is the major beneficiary of coal-to-gas conversion initiative among the major gas distributors. China Gas gained first mover advantage by aggressively developing rural coal-to-gas projects starting 2016. We expect the company to achieve 1.1m and 2.2m new rural household connections in FY18 and FY19 respectively. We estimate city gas sales volume for China Gas to expand at 31% CAGR from FY17-FY20, which is the highest among the major gas distributors since it has a higher proportion of projects located in inland areas and lower tier cities, which is less prone to dollar margin pressures. The dollar margin is expected to slightly decline from Rmb0.63 / m3 in FY18 to Rmb0.61 / m3 in FY20. We estimate the company to post earnings CAGR of 31% from FY17-20.

China Tian Lun Gas is a regional gas distributor with projects mainly located in Henan and Northeastern part of China. The company is aggressively penetrating into rural coal-to-gas conversion market in Henan by setting up Rmb10bn fund with the Henan government. We expect 300k and 600k of new rural connections in FY18 and FY19 respectively. This supports the revenue from new connections to grow 147% and 60% y-o-y in FY18 and FY19 respectively. Due to the higher commercial and industrial mix and coal-to-gas conversion, its city gas sales volume growth is expected to reach 40% y-o-y during 1Q18, ahead of our full year estimate of 33%. We expect dollar margins will remain stable at c.Rmb0.44 / m3 during FY17-FY19 as a majority of the projects are located in tier 3/4 cities which generate lower dollar margins. We estimate the company to deliver earnings CAGR of 41% from FY17-FY20.

China Resources Gas receives solid support from its parent company, allowing it to obtain attractive large city projects. However, we believe it would be negatively impacted by the dollar margin pressure from the government's review on distribution margin and the gas shortage during winter as a result of the lack of midstream infrastructure in the near term. We expect its dollar margin to decline from Rmb0.58/m3 in FY17 to Rmb0.53/m3 in FY20. Despite the decent mid-teens growth in sales volume, the decline in dollar margin will likely be a drag on earnings. Its FY17-20 earnings CAGR of 8% is less exciting than other major peers.

ENN Energy has shifted its focus to developing its Integrated Energy business in recent years, which is expected to be another growth driver in the medium term. It targets to increase gas related consumption from 500 m m3 in FY18 to 2bn m3 in FY20, and this will account for 8% of its city gas volume in FY20. As a result, we expect FY17-20 sales volume to grow at 20% CAGR. In addition, its parent's LNG receiving terminal will commence operations this year, which will help to ease dollar margin pressure during the winter peak season going forward. We expect its earnings CAGR to be 15% in FY17-20.

Towngas China differs from other gas distributors in its determination to invest in midstream infrastructure. Its parent company started to invest in underground storage facilities few years ago, and phase 1 of Jintan underground storage facility with capacity of 140m m3 will commence operations this year. This will help to support its dollar margin and underpin gas sales stability during the winter peak season. Its dollar margin is expected to remain stable at Rmb0.63 / m3 this year with volume growth expected to reach 17% in FY18. We are projecting FY17-20 earnings CAGR of 14%.

Implications to Chinese renewables players

Short term pain, long term gains on solar power. We think the recently announced "Notification on Photovoltaics power generation for 2018" caught the market by surprise and have negative impact on new solar power installation in 2018. We expect solar newly installed capacity to decrease 40% y-o-y to 31.9GW in 2018. Expected pull-back in new installation is to have adverse impact on solar supply chain players as the business competition is set to intensify. These include poly/mono-Si producers such as **GCL Poly (3800.HK)** and **Longi Green Energy Technology (601012.CH)**, and solar glass players such as **Xinyi Solar (968.HK)** and **Flat Glass (6865.HK)**. Nevertheless, intensified upstream competition will accelerate the decline in installation costs, which will be beneficial for long term development of solar power sector.

Steady growth in wind power. As the government increases the proportion of wind power generation, the installation capacity is expected to ramp up steadily from 164GW in 2017 to >210GW in 2020. Also, the gradual reduction in curtailment rate can increase the return and attractiveness of wind power projects over the long run. In our view, recently announced "Notice regarding 2018 requirement of wind power construction management" should have limited impact to wind farm developers, and have slight adverse impact on Wind Turbine Generator (WTG) manufacturer.

As of note, China's wind farm developers including **Huaneng Renewables (958.HK)** has wind power projects approved but not yet starting construction amounted 3.8GW and projects approved under construction of 1.7GW. This is to support the company's new capacity installation for next 3-5 years. **Longyuan Power (916.HK)** has wind power projects approved but not yet starting construction amounted 7.9GW, which is abundant to support the company's new wind power capacity installation in the next 3-5 years.

However, as the policy targets to promote consumption of RE while rationalising installation of new wind power capacity, we think it could have slight adverse impact on China's total wind power installation, and thus have adverse impact on WTG manufacturers as competition is set to intensify.

Renewable Portfolio Standards to drive grid-parity. China's RE subsidy deficit is widening, primarily driven by strong installation of solar power capacity over the past two years. China's newly installed solar power capacity were 53.1GW and 34.5GW in 2016 and 2017 respectively. These had exceeded new wind power installation of 19.6GW in 2017 and 23.3GW in 2016. Given high feed-in-tariff (FIT) of solar power, it requires high subsidy (representing difference between FIT and local coal-fired tariff). China's RE subsidy shortfall had extended to Rmb100bn by end-2017 from Rmb70bn as at end-2016.

In March 2018, China announced Drafts on Soliciting Opinions for Renewable Energy Portfolio Standard (RPS) and Operation of Coal-fired Captive Power Plants (CPPs) respectively. Based on these two policies, coal-fired CPPs would likely shoulder a higher proportion of procurement of RE going forward and to pay their arrears of government funds. We think this can alleviate significant delays in subsidy collection and improve cash flow.

Furthermore, the implementation of RPS is expected to accelerate the process of grid-parity for solar and wind power projects. Along with improving efficiencies and declining installation costs, we expect RE to reach grid-parity within five years. No reliance on subsidies and more competitive pricing than coal power in the long run will drive up demand for RE and help to achieve China's target to increase non-fossil fuel energy consumption from 12% in 2015, to 15% in 2020 and 20% in 2030. This is positive for solar/wind power developers such as **GCL New Energy (451.HK)**, **Beijing Enterprises Clean Energy (1250.HK)**, **Huaneng Renewable (958.HK)**, and **Longyuan Power (916.HK)**.

Implication on Chinese oil majors

The shift towards natural gas will be a major point of interest for the Chinese oil majors (PetroChina, Sinopec, CNOOC) in the long-term, with China now targeting 15% of its energy mix to come from natural gas. Already we are seeing all three oil majors guiding for growth in domestic natural gas production over the next two years.

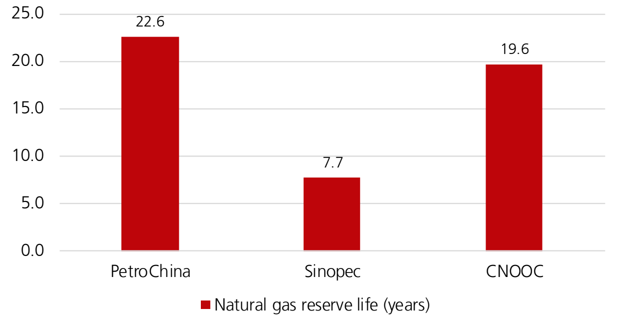
We think Sinopec (386 HK) and CNOOC (883 HK) are the main beneficiaries – with caveats.

PetroChina: In the near term, PetroChina (857 HK) will continue to be bogged down by loss-making gas imports as the country's dependence on natural gas grows before the market-based gas pricing reform comes into play full-swing. To recap, China is a net gas importer, with PetroChina importing the majority of the gas required for domestic consumption. It does so under loss-making long-term contracts, predominantly via pipeline. Additionally, domestic gas consumption growth has outpaced growth in natural gas production thus far, and this trajectory is unlikely to change in the near-term. This makes PetroChina a net loser when it comes to higher natural gas volumes expected at this juncture. On a positive note, China's NDRC has recently implemented the long-awaited unification of residential and non-residential gas pricing and newswires suggest possibility of pipeline nationalisation by winter. These seem to be paving the way for the gas pricing reform to better reflect gas cost and reverse the losses of imported gas situation.

Sinopec: Sinopec's (386 HK) natural gas production is a relatively high percentage of its overall upstream output at c.36.5% in FY17. Growth in demand therefore has a relatively larger impact on its revenues. However, Sinopec has a low gas reserve life of 7.7 years. Thus, the caveat is that Sinopec needs to boost its gas reserve life either via domestic exploration (but that has not produced stellar results) or purchase of assets overseas, which would make sense given Sinopec's low net gearing of just 0.07x as of 1Q18.

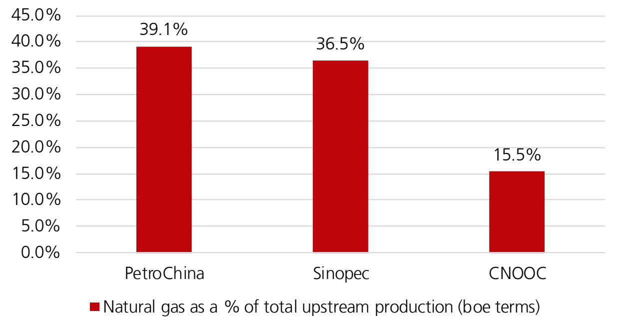
CNOOC (883 HK) has a relatively high gas reserve life at 19.6 years, but the caveat is that its natural gas production currently accounts for just 15.5% of total production on a barrels of oil equivalent basis; this should increase as natural gas production and demand rise, which makes CNOOC an obvious beneficiary, though the impact depends on how aggressively gas output can be boosted.

Chinese oil majors' reserve life (years)



Source: Company, DBS Bank

Chinese oil majors' gas output as a proportion of total upstream production (in boe terms)



Source: Company, DBS Bank

Implication on Indonesian coal miners and power generators

Healthy coal supply and demand is positive for coal mining companies. Coal miners' strong profitability will sustain on the back of a stable coal price outlook and improving mining practices that keep operating costs low. We believe coal companies such as Indo Tambangraya Megah (ITMG), Adaro Energy (ADRO) and Tambang Batubara Bukit Asam (PTBA) will be the best plays in the long term. **Our top picks are ITMG and ADRO given their strong exposure to the global export coal market.**

We do not have coverage of any companies in the power generation sector in Indonesia. We believe that high coal prices could be challenging for end users such as power generators if they are unable to pass on higher fuel cost to electricity prices. We believe that coal price of US$70 per tonne is the win-win level for both buyers and sellers.

Indonesian coal miners will continue to prioritise high profitability over production as part of their strategy to preserve long term coal reserves. Sustaining high profitability will drive earnings and share prices. A conservative coal output target will also keep market supply and demand in check.

Valuations are undemanding. Indonesian coal miners' current valuations reflect the market's lack of confidence in the sustainability of coal prices. Such undemanding valuations reflect the market's fairly low expectations on earnings due to market expectations of weak long term coal price outlook. However, we are more positive on the coal price outlook and believe coal miners deserve a valuation of 10.0x-11.0x FY18F PE.

Current valuation also reflects market sentiment that it will be difficult for coal price to be sustained at the current level of US$100 per tonne. Higher than expected coal price will also be capped by supply and demand strategies of large producers such as China, as well as government regulations such as Indonesia's domestic market obligation (DMO) coal pricing mechanism of US$70 per tonne.

We believe the market is underestimating the potential earnings growth of coal companies. Despite moderate coal price expansion in the long term, we believe profitability and earnings will drive the share prices of coal players. Coal stocks are also poised to pay handsome dividends on modest capital expenditure, and investments to enhance productivity performance.

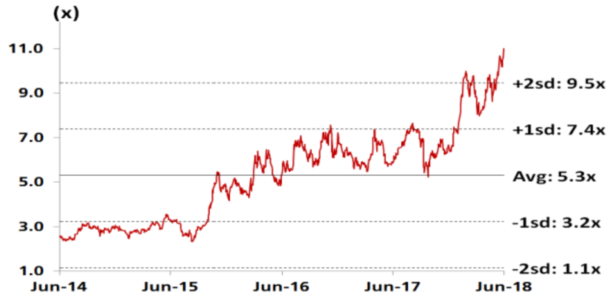
ADRO forward P/E Band

Source: Bloomberg Finance L.P., DBS Bank

ITMG forward P/E Band

Source: Bloomberg Finance L.P., DBS Bank

PTBA forward P/E Band



Source: Bloomberg Finance L.P., DBS Bank

Implication on Singapore rigbuilders

Strategic move towards gas solutions. The Singapore rigbuilders – Keppel Corporation (Keppel) and Sembcorp Marine (SMM) - have been proactively developing their capability in the gas value chain over the past 5-10 years. The move comes on the back of changing energy mix towards cleaner energy, strategy to broaden product offering and rising competition from China on their once bread-and-butter product – drilling rigs.

To become mainstream product, contributing half of orderbook. During 2005-2013, Singapore rigbuilders accounted for nearly two-thirds of global jackup deliveries. By 2014, Chinese players' market share had risen to 40% by orderbook, on par with Singapore rigbuilders, though >90% of Chinese's orders are speculative by nature. Since the oil crisis, there has been a dearth of rig orders and we do not expect rig orders to make a comeback any time soon given the rig oversupply situation.

Moving forward, gas solutions are set to become the mainstream products of Keppel and SMM, accounting for nearly half of orderbook in the medium term.

Singapore rigbuilders are well positioned to meet emerging trends in the gas market with a suite of innovative solutions catering to the entire value chain to bring LNG from producers to consumers. They are the global leaders in Floating Storage Regasification Units (FSRU), and Floating Storage Unit (FSU) conversions.

Keppel has successfully delivered the world's first Floating Liquefied Natural Gas (FLNG) conversion vessel – the only viable solution for stranded gas that constitutes 40-60% of global gas resources.

Meanwhile, in addition to conventional gas solutions, SMM acquired a new technology in 2014 – Gravifloat, a re-deployable, gravity-based, modularised LNG and LPG Terminals for installation in shallow waters. Gravifloat technology can also be deployed to other applications such as i) Integrated LNG to Power – an integrated 3-in-1 solution for receiving near-shore LNG; LNG storage and regasification; and power generation for 30-400MW capacity; and ii) LNG bunkering modules that can be installed in the open sea with multiple quay sides, away from the busy port traffic. SMM could work with its parent, Sembcorp Industries on these solutions for gas-fuelled power facilities.

Keppel's gas value chain - providing gas solutions for the seamless delivery of LNG from producers to consumers

Source: Keppel Corporation, July 2017

Implications on Indian energy space

Execution of reforms is an ongoing issue in the power sector. Any positive results from the UDAY scheme is still not visible even after 2.5 years since its launch. Progress on cutting AT&C losses (either by opting for franchisee route or discoms) has also been slow. The various states are unwilling to enter into any fresh long-term PPAs and commit themselves to fixed payment charges. Coal supply issue continues to impact plant utilisation with over 24 plants facing sub-critical inventory levels.

Lack of PPAs is now turning a majority of the stranded projects into Non-Performing Assets (NPAs) for the banking sector and with the Reserve Bank of India's new guidelines, the power sector faces the threat of witnessing 40-50GW capacity turning into NPAs. Also, the expected pace of consolidation in the sector has been disappointing.

We continue to prefer regulated return entities Power Grid and National Thermal Power Corporation (NTPC) besides CESC Limited as a demerger play (demerger likely to be completed by Aug 2018). Except for these three companies, the power sector in India offers event-specific trading opportunities rather than any serious long-term investment options.

Reforms in the Indian oil & gas space has improved prospects for players. The last five years has seen significant reforms in the Indian Oil & Gas space from fuel price deregulation and targeted subsidies to upstream pricing freedom and promotion of natural gas usage. Implementation was aided by sharp fall in oil and gas prices which provided a cushion to consumers. Although current oil price uptick has pressured the petro-economy, the situation is much better than what it was in the past.

More reforms will be welcome. Among pending reforms, a transparent and formulaic subsidy sharing mechanism and eventual deregulation of cooking fuel prices are sought. The proper inclusion of the petroleum sector under the GST regime is also much needed as the current partial system with dual regimes has created a burden on oil and gas companies as well as consumers.

Volume growth is of course, attractive. The Government wants to reduce the country's dependence on oil imports by 10%, double the share of natural gas in the energy basket to 15% and protect the exchequer from price shocks, hence focus is on domestic upstream development and increase in gas consumption. India remains an attractive growth economy with oil and gas consumption expected to grow at 4-6% CAGR in the medium to longer term, hence volume outlook is attractive while a transition to market based industry would improve pricing power and margins.

We remain positive on the gas distribution and oil downstream space with Petronet LNG (PLNG IN), Gujarat Gas (GUJGA IN), Bharat Petroleum (BPCL IN), Hindustan Petroleum (HPCL IN) and Indian Oil (IOCL IN) being our preferred picks. With Union Elections approaching, Indian markets would witness volatility due to political risks which would impact the majorly Government promoted Oil & Gas sector. Valuations nevertheless are undemanding and any improvement in macros is expected to provide a re-rating catalyst for the sector.

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BUY (>15% total return over the next 12 months for small caps, >10% for large caps)
HOLD (-10% to +15% total return over the next 12 months for small caps, -10% to +10% for large caps)
FULLY VALUED (negative total return i.e. > -10% over the next 12 months)
SELL (negative total return of > -20% over the next 3 months, with identifiable catalysts within this time frame)

** Share price appreciation + dividends*

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