

**LNG trade flows in the case of oversupplied markets and its consequent impact on prices**

Alexander Apokin, Energy Economics Analyst

Energy Economics and Forecasting Department (EEFD)

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# Executive summary

This report reviews “LNG glut” scenario to estimate the impact of new liquefaction capacity coming to the LNG market up to 2025. Between 2012 and 2017, over 250 mtpa of gas liquefaction projects have been announced and most of those are still not shelved and have completion dates before 2025. With latest IEA WEO (IEA, 2018) seeing over 500 mt LNG trade by 2025 compared to 300 mt in 2017, it is plausible to doubt if there would be a demand in place for such a rapid market growth.

As the new wave of LNG projects started entering the market from 2016, there has been a long-standing anticipation of the “LNG glut” – oversupply of LNG that would induce the “great reconfiguration” of global LNG trade (Corbeau et al, 2016). So far, 150 extra mtpa of LNG capacity from Qatar, the US, Australia and Russia are widely expected before 2025, and it is unclear how the market will react. Gas consumers in the EU and Japan also prepare for the “LNG revolution” (Seko, 2017), a term similar to “shale revolution” of 2009-2011, changing market design, regulation and adding infrastructure.

The effect of this “LNG glut” and corresponding market transformation has long been a focus of market analysts, but did not get enough attention as a research topic in the energy economics. Also, effects of the new market design and trade flow reconfiguration in Asia were reviewed before (Aguilera et al., 2014; Shi et al 2016; Corbeau et al, 2016) but existing studies did not model the LNG capacity oversupply, only the market structure changes.

We build on a vast literature on energy modelling and forecasting, as well as on the body of LNG market research, to run the model with LNG capacities coming on schedule. The main modelling tool is the in-house model of the GECF Secretariat, Global Gas Model, based on the database on network of liquefaction, regas, LNG routes, pipelines and LNG carrier fleets. The infrastructure database of the GGM that is used for the modelling exercise contains: 240 liquefaction plants, 400 regasification plants, more than 5000 gas pipeline and shipping routes, and the trade gas contracts database contains annual contracted and delivered volumes, including 600 contracts (country-to-country and non-dedicated), based on more than 1000 company-to-company contracts.

We use a global modelling tool GGM to see how the LNG trade flows change based on the timing of the project schedules and capacity going as planned. We implement the project schedules announced, assume no bottlenecks in feedgas or upstream production and natural gas transportation, and solve the trade flows model to get the market distribution of flows and the market-specific LNG prices for Asian, European, and Latin American markets. We benchmark the results to the Reference case of 2018 edition of GECF Global Gas Outlook 2040.

There are three main outtakes from the modelling. First, gas market design and pricing mechanisms matter, especially in how the Asian customers behave. By 2025, some of them will have access to the piped gas from Russia, as well as to an increasing indigenous production of natural gas. Secondly, the impact of “LNG glut” for Latin American and European markets is often overlooked, as those markets are price-sensitive and could absorb up to extra 40 mtpa annually, even as the pipeline gas consumption is flat or growing. Thirdly, the policy drivers of natural gas demand should not be overlooked. The gas use in China as per Chinese 13th Five-year plan was undercut in 2017-2018 by the lack of infrastructure and affordability challenges vis-à-vis coal, but the demand is also price-elastic and might ramp up quickly (Wanga and Xue, 2017).

# Background for developing LNG oversupply scenario: market overview 2016-2018

The notions of looming LNG oversupply (“LNG glut”) have been in place since 2014, when the oil market collapse met a mountain of megatrain facility FIDs and announcements, including then Sabine Pass, Gorgon, Yamal, Prelude, Cove Point, and several others. From 2015 to H2 2018, no major project took FID, although there have been several major non-binding announcements (such as Qatari announcemnent for the LNG capacity export growth from the North Field). The long-term price decline that originated only on American market in 2010 was followed by a slump in global prices that lasted 2013 to 2016.

#### Figure 1. LNG historical prices, $/mmbtu

Source: GECF Secretariat based on data from GECF GGM

During 2016-2018, over 20 gas production and LNG projects were shelved, while others rescheduled due to adverse market conditions. The projects that took FID earlier focused on capital and operating cost minimization, and many projects arrived on the market 1 or 2 years later than originally planned. After natural gas prices recovered in H2 2017, and peaked in 2018 due to Chinese emergence as a dominant LNG importer, the shelved project pipeline was refreshed. While LNG Canada in October 2018 was the first major FID since 2015, the financing and offtake arrangements for this project were unlikely to be replicated by other market players. However, according to a consultant Wood Mackenzie, 2019 will see FIDs for least five major LNG projects. Together with both LNG and pipeline projects coming online in the next years, and some “guaranteed” FIDs pending after announcements, this wave of LNG projects could create oversupply in the markets after 2020.

#### Table 1: Announced and upcoming LNG projects

|  |  |  |  |
| --- | --- | --- | --- |
| **Name** | **Country** | **Capacity (mtpa)** | **Status** |
| *Under construction (post-FID), “First wave” assumed to be online before 2021* |
| Prelude FLNG | Australia | 3.6 | Under construction |
| Darwin LNG Train 2 | Australia | 4.45 | Under construction |
| Kribi LNG | Cameroon | 1.5 | Under construction |
| LNG Canada | Canada | 17 | Under construction |
| Tortue LNG | Mauritania/Senegal | 2.5 | Under construction |
| Coral FLNG | Mozambique | 3.4 | Under construction |
| Yamal LNG Train 3 | Russia | 5.5 | Under construction |
| Golden Pass LNG Train 1-3 | US | 15 | Under construction |
| Freeport LNG Train 1-3 | US | 15 | Under construction |
| Cameron LNG Trains 1-3 | US | 12 | Under construction |
| Corpus Christi Train 2-3 | US | 9 | Under construction |
| *Pre-FID (Announced/FEED) assumed to be online before 2030, “Second wave”* |
| Goldboro LNG | Canada | 10 | Approved |
| Bear Head LNG | Canada | 12 | Approved |
| Costa Azul LNG | Mexico | 2.4 | Announced |
| Rovuma LNG | Mozambique | 15.2 | Announced |
| Mozambique LNG | Mozambique | 10 | Announced |
| Qatar LNG+ | Qatar | 30 | Announced |
| Arctic LNG 2 | Russia | 20 | Announced |
| Jordan Cove | US | 6 | Announced |
| Sabine Pass LNG Train 6 | US | 4.5 | Announced |
| Calcasieu LNG | US | 10 | Announced |
| Freeport LNG Train 4 | US | 4.5 | Announced |
| Driftwood LNG | US | 12.6 | Approved |
| Magnolia LNG | US | 8 | Approved |
| Delfin LNG | US | 7.6 | Approved |
| Baltic LNG | Russia | 1.3 | Pre-FEED |

Source: GECF Secretariat based on data from GECF GGM

The total amout of LNG from these projects that could hit the market by 2025 is estimated at 300 mtpa. It is far off any demand growth estimates for LNG, thus some market adjustment is inevitable.

# Mode of natural gas exports and the new business models

Given the favourable logistics, the owners of conveniently situated gas reserves have plenty of reasons to enter the LNG market as compared to pipeline, despite generally higher unit costs (see Table 1). The main reasons are the LNG price premium, lack of stringent supply regulation, better seaborne reach for the long-distance (over 5000 km) markets, lower capital requirements compared to pipeline (and lower still in case of FLNG) and lack of geopolitical hurdles for shipment.

#### Table 2: Options for monetizing gas reserves

|  |  |  |  |
| --- | --- | --- | --- |
|  | **Domestic market** | **Pipeline exports** | **LNG exports** |
| *Starting investment* | Depends on domestic infrastructure in place | High | High |
| *Liquidity* | Varies | Zero, except Europe | Maximum |
| *Geopolitical hurdles* | Absent | Very likely | Unlikely |
| *Margin* | Low and regulated | Market price, premium to domestic market | Market price, premium to domestic market |

Source: Author’s analysis

As per industry practice, the lenders required the project company to accumulate offtake commitments before providing the financing to the LNG facility. The situation began to change in the recent years as there emerge two new approaches to the financing:

1. Offtakers provide equity financing for the project, as in cases of LNG Canada (FID) and Rovuma LNG (pre-FID), or project goes for the equity participation (some North American LNG facilities such as Driftwood LNG) and intends to market undedicated volumes afterwards. Those are not widespread, but there is ongoing experience accumulation and practices building.
2. The different pricing model is used as the LNG and feed gas providers are not integrated. Most North American projects take a fixed liquefaction fee from the exporters, under long-term arrangements of liquefy-or-pay.
3. Offtakers are portfolio players that sign up for the undedicated volume intending to market it as part of their global portfolio.

With the LNF projects that utilize new business models, the risks are divided between gas reserve holders, LNG services providers and the consumers so that some projects are not mothballed even as cash inflows barely cover cash costs. This innovation is a part of new oversupply scenario, as business model might lead to market clearing with such projects being ready for significantly lower prices for longer before mothballing the projects.

# Gas market forecast benchmarking for 2019-2040

**GECF GGO 2018** in the Reference case projects that natural gas trade will add 100 bcm by 2025 and another 350 bcm by 2040, with LNG trade seen adding 110 mtpa (150 bcm) by 2025 and another 130 mtpa (180 bcm) by 2040. This LNG growth is underpinned by strong pipeline trade growth, and also by strong national priorities for gas reserve holders to develop those reserves.

#### Table 3: GECF’s GGO Ref. Case gas trade projection (bcm)

|  |  |  |  |
| --- | --- | --- | --- |
|  | **2017** | **2025** | **2040** |
| World natural gas production | 3696 | 4317 | 5417 |
| World natural gas trade | 1166 | 1265 | 1616 |
| Share of trade % | 32 | 29 | 30 |
| Pipeline | 706 | 717 | 876 |
| LNG | 388 | 536 | 719 |
| Asian spot price | 6.7 | 8.5 | 9.9 |
| European spot price | 5.4 | 7.6 | 9.5 |
| Henry Hub price ($2017/MBtu) | 3.0 | 3.5 | 4.8 |

Source: GECF Secretariat based on data from GECF GGM

The pipeline growth described by GECF project-wise includes the completion of Central Asia-China gas pipeline D, the Turkmenistan-Afghanistan-Pakistan-India pipeline (TAPI), the Iran-Pakistan pipeline, and both routes for the Power of Siberia pipelines.

For European supplies, pipeline capacity is to be expanded with completion of the Southern Gas Corridor (via Transadriatic pipeline or TAP), Nord Stream 2 and 3, and the Turkish Stream pipelines, as well as several intra-EU gas pipeline interconnectors to be built in Europe. While LNG infrastructure will see a much faster build-up than pipelines, the cost of LNG shipments will force many projects (such as most Gulf of Mexico LNG) to take cash losses or mothball the capacity.

**IEA WEO 2018** projects growth in natural gas trade to add 230 bcm by 2025 and another 290 bcm by 2040, with LNG trade adding 140 mtpa (186 bcm) to 2025 and another 180 mtpa (250 bcm) to 2040. The main growth markets are emerging Asia Pacific importers, with extra 186 and 221 mtpa in 2025 and 2040 respectively to offset the effect of fluctuations in both mature Asian markets and in the European market.

#### Table 4: IEA WEO gas trade projection (bcm)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **2017** | NPS | CPS | SD |
| **2025** | **2040** | **2025** | **2040** | **2025** | **2040** |
| World natural gas production | 3769 | 4293 | 5399 | 4386 | 5847 | 4189 | 4184 |
| World natural gas trade | 771 | 1000 | 1289 | 1019 | 1464 | 985 | 1080 |
| Share of trade % | 20 | 23 | 24 | 23 | 25 | 24 | 26 |
| Pipeline | 447 | 491 | 532 | 500 | 657 | 458 | 452 |
| LNG | 323 | 509 | 757 | 518 | 807 | 527 | 627 |
| Japan price ($2017/MBtu) | 8.1 | 9.8 | 10.1 | 9.9 | 10.5 | 9.0 | 8.8 |
| EU price ($2017/MBtu) | 5.8 | 7.8 | 9.0 | 7.9 | 9.4 | 7.5 | 7.7 |
| Henry Hub price ($2017/MBtu) | 3.0 | 3.3 | 4.9 | 3.4 | 5.3 | 3.3 | 3.6 |

Source: IEA WEO 2018

The **Wood Mackenzie**’s H2 2018 Global Gas Service highlights that in 2018, 20 mtpa took FID and 2019 will be a record year for FIDs, with over 60 mtpa of projects. Together with another 30 mtpa of FIDs expected in 2020 (including Qatari LNG expansion FID), this could form a supply overhang for the years to come. It is worth noting that methodology that Wood Mackenzie uses is different from IEA’s in that market clearance is not assumed. As a result, the numbers are not directly comparable. LNG supply to 2025 is expected by Wood Mackenzie to be at extra 170 mtpa (230 bcm) and 240 mtpa (320 bcm) by 2040. Most of those volumes are to be absorbed by emerging Asia demand, but due to fast ramp-up of supply through new projects, extra 75 mtpa (100 bcm) are projected to land in Europe by 2025, in a competition with pipeline gas.

#### Table 6: Wood Mackenzie’s gas trade projection (bcm)

|  |  |  |  |
| --- | --- | --- | --- |
|  | **2018** | **2025** | **2040** |
| Total trade | 891 | 1039 | 1382 |
| LNG capacity |  | 463 | 410 |
| LNG supply | 426 | 629 | 947 |
| Japan spot price ($2017/MBtu) | 7.6  | 8.5 | 12.5 |
| (TTF+NBP)\*0.5 price ($2017/MBtu) | 6.0 | 7.3 | 10.7 |
| Henry Hub price ($2017/MBtu) | 3.2 | 2.6 | 5.1 |

Source: Wood Mackenzie’s Global Gas Service Base Case H2 2018

The conversion factors (in this case, gas temperature) that GECF and IEA use are comparable, while for WoodMac the calorific equivalent is used instead. Also, pipeline figures are not fully comparable as GECF forecast is at the country level, while IEA forecast considers only inter-regional pipeline trade. Comparing the three LNG trade scenarios, one can get a wide range of estimates of volumes even as the Henry Hub prices stay within $3/mmbtu. Even as IEA projects less natural gas traded in the long-term than GECF, it is more aggressive on LNG post-2025. On the other hand, both GECF and WoodMac project less LNG activity post-2025, but more (extra 45 bcm) in 2018-2025. However, it should be noted that GECF model is balanced, while WoodMac’s model indicates demand-supply gap that is not yet filled up with new LNG projects.

#### Table 5: Benchmarking global gas trade projections (bcm)

|  |  |  |  |
| --- | --- | --- | --- |
| 2025 | GECF | IEA | WoodMac |
| Total gas trade | 1265 | 1000 | 1039 |
| Pipeline | 717 | 491 | 423 |
| LNG | 536 | 509 | 554 |
| Asian price ($2017/MBtu) | 8.5 | 9.8 | 8.5 |
| European price ($2017/MBtu) | 7.6 | 7.8 | 7.3 |
| Henry Hub price ($2017/MBtu) | 3.5 | 3.3 | 2.6 |
| 2040 | 1616 | 1289 | 1382 |
| Pipeline | 876 | 532 | 695 |
| LNG | 719 | 757 | 661 |
| Asian price ($2017/MBtu) | 9.9 | 10.1 | 12.5 |
| European price ($2017/MBtu) | 9.5 | 9.0 | 10.7 |
| Henry Hub price ($2017/MBtu) | 4.8 | 4.9 | 5.1 |

Source: GECF Secretariat based on data from GECF GGM, IEA WEO 2018, Wood Mackenzie’s Global Gas Service Base Case H2 2018

It is worth noting that despite the difference between trade flows, the price projections remain almost at the same levels. Moreover, along with all description for “oversupply” that is provided by IEA and WoodMac, the prices are resilient in 2025, being on a rising trend as compared to 2017. The difference in the LNG outlooks can be attributed to different methodologies, but also to very different perception of LNG facility financing models implemented in the last wave of projects, and national priorities.

Concerning the methodological differences, estimates of pipeline trade for 2017 are 706 bcm at the GECF and 447 bcm at the IEA. This 260 bcm difference is due to the fact that IEA only measures inter-regional trade flows, while GECF measures trade flows on a country basis. For LNG trade, which is dominantly inter-regional, the difference is mere 65 bcm, 388 bcm at the GECF vs 323 bcm at the IEA. Still, this difference is compressed to 230 bcm for pipeline and 27 bcm for LNG by 2025, as IEA envisions more rapid natural gas trade expansion, especially for pipeline.

Concerning the assumptions on national gas policies, for GECF forecast, national priorities for maximizing indigenous production are paramount, even in case some obvious hurdles exist. This gives a different outlook for market configuration. In developing Asia, the case in point, Chinese production is estimated at extra 30 bcm higher by 2025 and by 60 bcm higher by 2040 compared to IEA forecast, even as demand is about 90 bcm and 40 bcm lower, respectively. Also, in the EU, the production forecast is 25 bcm higher in 2025 and 20 bcm higher by 2040 as the demand is higher. European market favours supplies over pipeline infrastructure, both in place and planned, thus the tilt to the pipeline as compared to the IEA projection.

However, given the new business models for LNG facilities promoted in the North America, the risks to “oversupply” the market are mounting. Thus, there is a need to develop the separate scenario that will allow to assess the impact of this situation on the market.

# Developing the oversupply scenario

In the LNG market, the concept of “oversupply” itself needs more accurate definition, as the literal oversupply is possible only in a limited way. Natural gas storage worldwide as of now can only hold less than 10% of the gas produced each year, and this share is projected to reach 10% by 2040. This storage is used for offsetting seasonal demand fluctuations, and is not large enough to accommodate excess natural gas in case of oversupply.

As physical storage is limited, so is physical oversupply, and it is not possible to deliver more LNG than can be consumed. Thus, for the LNG market it is more pertinent to define the “capacity oversupply” than physical oversupply, i.e. the situation where capacity growth largely outstrips consumption growth. In this case, part of the already capacity is not . As a result, natural gas supply (extraction and processing) facilities could be partially reduced or mothballed (put in conservation) in case of insufficient offtake.

There are technical limits to partial reduction of output, that differ from plant to plant and could be as flexible as 0 to 100% of supply or only 10% of supply. Most LNG facilities could operate at more than two thirds of capacity due to technical reasons. If offtake is not sufficient for this capacity, mothballing of LNG facility becomes the only economical option.

For the natural gas market, this “capacity oversupply” will compress liquefaction fee (which currently is estimated at $3/mmbtu), making the natural gas more affordable. Along with the policy efforts to promote natural gas, the affordability is the major driver for coal-to-gas switching, which is estimated to happen at a price band of $3-6/mmbtu. This can create additional demand for natural gas where coal generation can be substituted, which might total up to mtpa by 2025 and mtpa in 2040.

The nameplate capacity of US and Canada LNG facilities is projected to reach 127.7 mtpa by 2022, compared to 38 mtpa in 2018, and most of those are not on the marginal cost curve at the market prices both for Asian and European market. However, due to an alternative business models used by some of those projects, there is a perspective that the supply will not be idled. This means the LNG supply from those plants could be offered at a lower marginal cost. As per the concept of “supply overcapacity”, this means supply from the other facilities globally is at risk. We can outline the cost curve for European (based on Germany), Latin American (based on Brazil) and Asian (based on Japan) markets to identify the LNG volumes at risk.

|  |  |
| --- | --- |
| Figure 2. Demand and cost curves for Japan in 2018, 2025 and 2040 | Figure 3. Demand and cost curves for Germany in 2018, 2025 and 2040 |
| Figure 4. Demand and cost curves for Brazil in 2018, 2025 and 2040 |

Source: GECF Secretariat based on data from GECF GGM

Basically, these curves outline the cost range for the “contestable market” (in other words, price-elastic segment of the curve) at 3-7 $/mbtu band for Japan in 2025, while being inelastic in Germany (because of Russian piped gas supply being available) and Brazil around 3.5 and 2.5 $/mbtu, respectively. This means there is a potential for balancing demand from Latin American market almost at Henry Hub price levels ($2.5-3/mbtu), and balancing European market at well below $5/mbtu. However, these are the minimum price levels for those markets which entail the risk of significant reorientation of supply and/or will cause total supply reduction in the longer term. It is still unclear how large is the market space for price-inelastic supplies of LNG, though typically it is the whole volume of demand that is not covered by either domestic supply of cheap pipeline gas.

# Modelling oversupply with GGM

The LNG oversupply scenario is quantified through the use of the GECF Global Gas Model (GGM), which is a unique energy model developed in-house at the GECF Secretariat, and which includes different sub-models with each one focused on one segment of the gas value chain (production, pipelines, LNG, shipping, regasification, contracts and demand).

The GGM is a unique long-term energy forecasting model developed in-house at the GECF Secretariat. GGM has the most comprehensive and granular view on the natural gas market while producing forecasts of the whole range of national and regional energy balances. The GGM is characterized by its uniquely high granularity for natural gas market, encompassing:

* 113 country-level forecasts, with 60 regional aggregates and a global projection
* Complete energy balance estimates, covering 29 sectors and 34 fuels annually, from 1990 to 2040
* 4300 gas supply entities representing gas supply potential at the global scale, divided into:
* 740 existing and operational production facilities (including aggregates)
* 2120 new projects based on existing reserves
* 1300 yet-to-find (YTF) entities
* 160 unconventional resources (existing and YTF), generating the most comprehensive database available of global shale and tight gas, coalbed methane (CBM) and methane hydrates.

The infrastructure database contains:

* 240 liquefaction plants
* 400 regasification plants
* more than 5000 gas pipeline and shipping routes

The gas contracts database contains:

* Annual contracted and delivered volumes, including 600 contracts (country-to-country and non-dedicated), based on more than 1000 company-to-company contracts

Energy and natural gas demand forecasts are derived based on a set of scenario assumptions fed with over 100 indicators on macro and energy price data, utilizing econometric modelling techniques with the time-series dating back to 1990. Policy measures are taken into consideration at each stage of this process. Solving for the demand produces the gas demand curve for each country. All of the sub-models have been calibrated and based on 2017 as the last available year of historical data.

**GGM natural gas supply and trade module**

The GECF GGM prioritizes to the delivery of all volumes of natural gas that are already contracted (called “obligated trade”), using contract and infrastructure databases, although prioritization does not necessarily guarantee there is enough feed gas or transport capacity to deliver.

The remaining volumes of natural gas, if any, are offered on the free market, and priced to each possible delivery point according to a cost curve of production and shipping components. The costs are the cumulative productions capital costs depreciation, operating expenses, plus the transport costs either via pipeline (charged per mcf per km) or LNG (charged per mcf for capital costs depreciation, operating expenses and shipping freight rates per day) for every point to point connection on the network.

The market clearing process establishes natural gas flows that form the actual cost curve, and the natural gas prices for gas-to-gas competition volumes, while considering all the imposed technical, financial and market restrictions. Re-export flows are not evaluated separately, and in this sense all trade flows reported are final destination flows.

# Quantifying scenario assumptions

To model oversupply, the model inputs are modified as such:

* Liquefaction facility schedules
	+ Russia: Arctic LNG II moved from 2030 to 2025, Pechora LNG – cancelled (moved 2019 to 2041)
	+ US: all plants’ cost is assumed to depreciate over 30 years, for Alaska plant the tax rate is cancelled
	+ Qatar: Assumed to come online in 2022, not 2025
	+ Australia: all plants’ cost is assumed to depreciate over 30 years
* Contracts:
	+ Removed destination clauses from all Asian contracts starting 2020, and from all shipments starting 2022.
	+ Ceased contracts with Japan and South Korea, and also all Russian contracts with Europe
	+ Increased depreciation time to 30 years for US and Canada plants

All the other parameters retain the Ref.Case scenario values, so that the scenario could be easily benchmarked.

The special case of modelling included disabling all the contract structure for the forecast, so that the effect of gas market liberalization would be fully accounted for. This models the renegotiation of most contracts as the capacity oversupply takes place.

# Scenario modelling results

The results confirm that the market design is central to the structure of LNG flows. Specifically, the role of contract obligations matter in situations the market is hit with the oversupply. As Asian and Latin American contracts are currently largely oil-indexed, the supply and demand fluctuations in the oil and gas markets create frictions that are removed via renegotiations only after some time (Agerton, 2016). While those contracts are necessary to make LNG and upstream projects bankable, there is a strong policy-directed trend towards greater flexibility of the gas market, especially in Asia (Stern, 2016; Niyazmuradov and Heo, 2018).

The assumptions for LNG supply overcapacity allow us to reduce the price to the new level of the marginal costs, as there is a certain level of required capacity utilization for liquefaction facilities. The demand reaction is characteristic depending on the flexibility of the market.

#### Table 7: Natural gas demand and trade, total and by region, bcm

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|   | Bcm | 2017 | 2040 - Ref. case | 2040 - LNG oversupply case | 2040 - LNG oversupplcase + full gas-to-gas competititon |
| World | Demand | 3709 | 5427 | 5618 | 5851 |
| Imports | 1094 | 1595 | 1709 | 1849 |
| Pipeline | 706 | 876 | 893 | 914 |
| LNG | 388 | 719 | 817 | 936 |
| Europe | Demand | 538 | 573 | 609 | 615 |
| Imports | 499 | 502 | 538 | 544 |
| Pipeline | 436 | 383 | 376 | 381 |
| LNG | 63 | 119 | 161 | 163 |
| Asia | Demand | 794 | 1422 | 1541 | 1761 |
| Imports | 369 | 756 | 847 | 969 |
| Pipeline | 89 | 205 | 224 | 345 |
| LNG | 280 | 551 | 624 | 624 |
| Latin America | Demand | 178 | 291 | 309 | 343 |
| Imports | 29 | 48 | 62 | 69 |
| Pipeline | 15 | 15 | 18 | 18 |
| LNG | 14 | 33 | 44 | 51 |

Source: GECF Secretariat based on data from GECF GGM

While there is projected extra market of around 115 bcm globally given somewhat lower LNG prices, without price flexibility there is extra 14% global LNG demand as the price is rigid. Given the price flexibility, the figure for additional trade tops 250 bcm compared to the Reference case scenario, including additional demand for 160 mtpa of LNG (+15%), including 120 mtpa in Asia. The effect is much less pronounced in Europe, as the market price is already mostly discovered via gas-to-gas competition, and cheap piped gas is abundant to compete with LNG.

Market integration clearly increases as LNG supply grows, with “Asian premium” basically disappearing after 2030 as the market is liberalized.

#### Figure 2. LNG projected prices in case of oversupply, $/mmbtu

xource: GECF Secretariat based on data from GECF GGM

The results show more market integration also with respect to the benchmarking. Isolated Latin American market price actually could increase given more integration, as gas trade contracts in the region are dominantly oil-indexed.

#### Figure 3. LNG projected prices in case of oversupply vs. Ref Case, $/mmbtu

|  |  |
| --- | --- |
|  |  |
|  |

The effect of full price liberalization is twofold – it increases traded volumes, expanding the markets by estimated 15% relative to case with simple LNG oversupply, but the price levels in this scenario guarantee almost no new investment coming in the gas supply infrastructure after announced projects are fulfilled (according to the schedule).

The NPV for the new projects stays negative under any plausible assumptions from 2025 to 2040. The net global effect for the LNG exporters is close to zero for LNG oversupply case, and negative in case both price liberalization and LNG oversupply take the effect. However, the regional structure of exports matters: exporting LNG to Asian and Latin American markets stays marginally profitable even after full price liberalization, while European LNG supplies do not, that is probably why volumes almost do not change.

# Conclusions and policy implications

There are three main outtakes from the modelling. First, gas market design and pricing mechanisms matter, especially in how the Asian customers behave. By 2025, some of them will have access to the piped gas from Russia, as well as to an increasing indigenous production of natural gas. Secondly, the impact of “LNG glut” for Latin American and European markets is often overlooked, as those markets are price-sensitive and could absorb up to extra 40 mtpa annually, even as the pipeline gas consumption is flat or growing. Thirdly, the policy drivers of natural gas demand should not be overlooked. The gas use in China as per Chinese 13th Five-year plan was undercut in 2017-2018 by the lack of infrastructure and affordability challenges vis-à-vis coal, but the demand is also price-elastic and might ramp up quickly (Wanga and Xue, 2017).

The results of modelling contest that the “LNG glut” and “LNG revolution” would be absorbed by the growing markets in full with no effect, as the LNG price effect of such competition is visible. While there is a significant increase in volumes, it is not beneficial for the exporters, as it challenges the business model they use. The latest IEA Outlook features the special topic on gas exporter strategies in case of oversupply, and the main outtake is in line with the modelling results. As it is, the LNG (and natural gas) oversupply is not beneficial for exporters, but natural gas emerges as a market for different term supplies, where short-term and long-term, firm and flexible supply forms of the same commodity coexist. If such changes in market structure would allow the equitable risk sharing between exporters and importers, there is enough gas demand to support it.

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# Annex

**Abbreviations and Acronyms**

|  |  |
| --- | --- |
| GECF | Gas Exporting Countries Forum |
| OPEC | Organization Of Petroleum Exporting Countries |
| IEA | International Energy Agency  |
| RCS | Reference Case Scenario |
| CMS | Carbon Mitigation Scenario (GECF) |
| TAS | Technology Advancement Scenario (GECF) |
| NPS | New Policies Scenario (IEA) |
| SDS | Sustainable Development Scenario (SDS) |
| IEF | International Energy Forum  |
| MENA | Middle East and North Africa |
| OECD | Organisation for Economic Co-Operation and Development |
| GDP | Gross Domestic Product |
| GGM | Global Gas Model (GECF) |
| UN | United Nations |
| IMP | International Monetary Fund |
| GGO | Global Gas Outlook (GGO) |
| EU ETS | European Union Emissions Trading System |
| CAAGR | Compound Average Annual Growth Rate  |
| WEO | World Energy Outlook (IEA) |
| WOO | World Oil Outlook (OPEC)  |
| UNSD | United Nation’s Statistical Division |
| ORB | OPEC Reference Basket |
| mmbtu | Million Tons of Oil Equivalent |
| mboe/d | Million Barrels of Oil Equivalent per Day |
| bbl | Barrel  |
| NDCs | Nationally Determined Contributions |
| Mtoe | Million Tonnes of Oil Equivalent  |
| GHG | Greenhouse Gas |
| bcm | Billion Cubic Metres  |