METIS Technical Note T7

METIS Gas Module Documentation

METIS Technical Notes
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1. INTRODUCTION

METIS is an on-going project[1] initiated by DG ENER for the development of an energy modelling software, with the aim to further support DG ENER's evidence-based policy making, especially in the areas of electricity and gas. The software is developed by Artelys with the support of IAEW (RWTH Aachen University), ConGas and Frontier Economics as part of Horizon 2020 and is closely followed by DG ENER.

The intention is to provide DG ENER with an in-house tool that can quickly provide insights and robust answers to complex economic and energy-related questions, focusing on the short-term operation of the energy system and markets. METIS was used, along with PRIMES, in the impact assessment of the Market Design Initiative (part of the Clean Energy for all Europeans package of policy proposals).

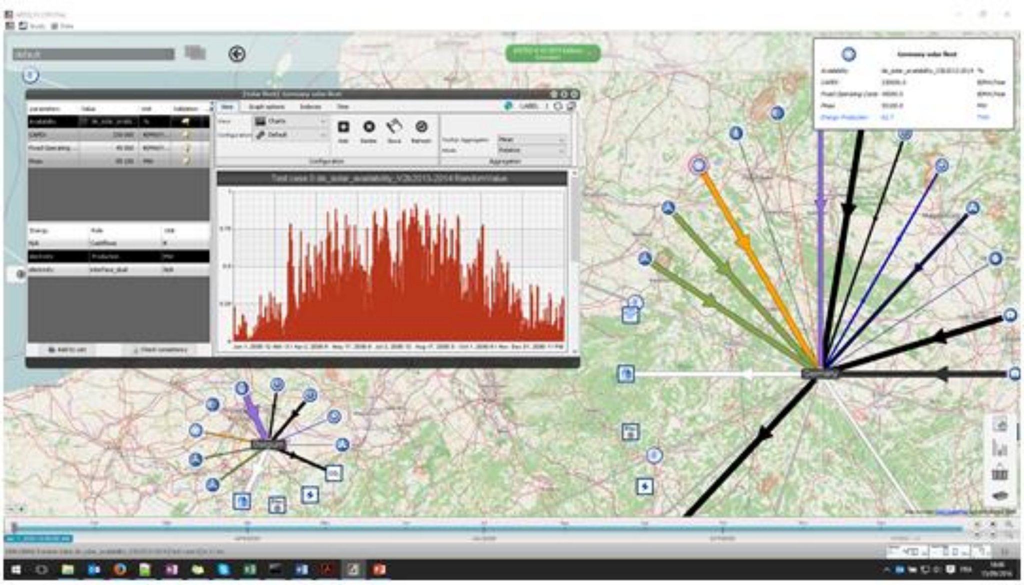

Figure 1: METIS user interface screen

The Gas Module was developed in two major phases that are described below.

First, the **Gas System Module** of METIS has been designed to address multiple gas systems problematics, following a welfare-maximization principle. It allows for the analysis of the European gas systems' dynamics, by providing production plans, gas flows, unserved energy volumes and durations, or other standard indicators which are introduced in section 5.

Such a modelling tool can be used to conduct different types of studies or quantitative analysis on gas systems, among which:

- Gas security of supply analysis
- Supply dependence analysis
- Study of the impact of infrastructure projects on security of supply

The Gas Market Module of METIS is an updated and extended version of the METIS Gas Module. Using the same modelling approach, features have been added notably to make

[1] http://ec.europa.eu/dgs/energy/tenders/doc/2014/2014s_152_272370_specifications.pdf

gas prices endogenous results of simulation, depending on the optimal supply mix and on supply routes used. Two additional scenarios (based on EUCO30 and using this enhanced market representation) have been delivered.

In addition to above-mentioned analysis on security of supply and supply dependence, the Gas Market Module update can be used to conduct analyses involving gas prices:

- Can new infrastructures give access to cheaper gas sources?
- How additional infrastructures and entry/exit fees impact import routes?
- Impact assessment on market prices and social welfare?

The present document is organised as follows:

- **Section 2** is dedicated to description of the modelling principles used in the METIS gas modules. The different elements one can include to represent gas systems are presented as well as the cost-minimizing criteria used in simulations. The respective structures of both *system models* and *market models* are also described and compared,
- **Section 3** describes datasets delivered within METIS to perform gas system studies,
- **Section 4** describes datasets delivered within METIS to perform gas market studies,
- **Section 5** describes some of the main outputs and key performance indicators METIS provides and some of the features of the interface to display them.

Note that METIS also embeds a Power System Module (enabling the modelling of the European power system and day-ahead markets) and an advanced Power Market Module (containing models for European intraday and balancing markets) which have their own specific documentation (see METIS Technical Note T2 and T3).

2. General Modelling Principles

In METIS, the gas system is represented as a network in which each node stands for a couple (geographical zone[2], energy). Geographical zones can be linked to one another with transmissions (e.g. pipelines to exchange gas). Energies represented in the gas module are gas (representing natural gas), LNG and CO2[3,4].

At each of the nodes, assets are attached. These assets represent all supply and withdrawal of energy at this node. The model aims at minimizing the overall cost of supplying the demand at each node and at each time steps.

The following section describes the list of assets available for gas system modelling in the METIS asset library. The scenarios used in METIS studies are also presented both in terms of underlying model structures and input data.

2.1. Asset Library

The METIS gas module contains a library of assets for production, consumption, storage and transmission of gas that can be attached to each node of the network.

The following assets are included:

- **Gas consumption**: demand of natural gas withdrawn from a given node,
- **Gas production**: production of natural gas injected at a given node,
- **Gas storage**: storage facilities for natural gas,
- **LNG terminal**: gasification terminals, it can withdraw and store LNG and convert it to natural gas and inject it on the network,
- **LNG imports** [System Module]: imports of LNG, injected to a node from which LNG terminals can withdraw it,
- **LNG exports** [System Module]: exports of LNG to countries out of the modelled perimeter,
- **LNG liquefaction train** [Market Module]: liquefaction train, liquefying natural gas and exporting LNG. It withdraws gas from the network to export it to the LNG global market. It is modelled as a gas transmission from a node to which a *Gas production* asset is attached to the global LNG market (virtual) node,
- **Gas imports** [System Module]: imports of natural gas from non-modelled countries through pipelines,
- **Gas exports** [System Module]: exports of natural gas to non-modelled countries through pipelines,

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2 Depending on the spatial granularity, a zone may be a subnational region, a country, a set of countries aggregated into one region, etc.

3 In scenarios delivered with the gas *market* module, LNG is not represented as an independent energy but as a parallel circuit to exchange the gas energy (see section 2.3.2).

4 Only CO_2 emissions resulting from gas consumption can be modelled.

- **Pipelines**: natural gas transmissions between modelled zones,
- **Import pipelines** [Market Module]: natural gas transmissions from external suppliers,
- **CO_2 emissions**: CO_2 emissions due to the consumption of natural gas, associated with a CO_2 price.

A detailed description of each asset's underlying mathematical model and all configurable parameters can be found in METIS library detailed documentation[5].

2.2. GRANULARITY, HORIZONS, AND OBJECTIVE FUNCTION

2.2.1. GENERAL STRUCTURE OF THE OPTIMIZATION PROBLEM

Simulations of the gas system in METIS are performed with Artelys Crystal Optimisation Engine and aim at determining a cost-minimizing production plan that ensures a supply-demand equilibrium at each node over the study period, using a daily time step. This is done by solving the following optimisation problem:

For each energy, the **supply-demand equilibrium constraint** at each node $\boldsymbol{n}$ and each time step $\boldsymbol{t}$ is the following:

$$\mathrm{Supply}_{n,t} = \mathrm{Demand}_{n,t}$$

with

$$\mathrm{Supply}_{n,t} = \sum_{\substack{\text{producers p} \\ \text{at node n}}} \mathrm{Production}_{p,t} + \sum_{\text{neighbours } n' \text{ of } n} \mathrm{Flow}_{n' \rightarrow n,t} + \mathrm{UnservedEnergy}_{n,t}$$

$$\mathrm{Consumption}_{n,t} = \sum_{\substack{\text{consumers c} \\ \text{at node n}}} \mathrm{Demand}_{c,t} + \sum_{\text{neighbours } n' \text{ of } n} \mathrm{Flow}_{n \rightarrow n',t} + \mathrm{GasFlare}_{n,t}$$

Assets corresponding to consumers at node n are:

- For natural gas: Gas consumption, Gas storage, Gas exports and LNG exports, LNG liquefaction train
- For LNG: LNG terminal
- For CO2: CO2 emissions.

Assets corresponding to producers at node n are:

- For natural gas: Gas production, Gas storage, Gas imports, LNG terminal,
- For LNG: LNG imports, LNG liquefaction train
- For CO2: Gas consumption

The objective function of the system is the total cost of the system:

$$\mathrm{TotalCost} = \sum_{\text{producers p}} \mathrm{ProductionCosts}_p + \sum_{\text{consumers p}} \mathrm{ConsumptionCosts}_p + \mathrm{UnservedEnergyPenalties} + \mathrm{GasFlarePenalties}$$

Where:

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[5] Available on METIS webpage [1]

- $\mathrm{ProductionCosts_p}$ represents the cost of supply from producer p, i.e. production and import costs.
- $\mathrm{ConsumptionCosts_p}$ represents the cost or earnings associated to energy withdrawal and consumption of consumer p. It usually includes CO2 emissions costs and export earnings.
- $\mathrm{UnservedEnergyPenalties}$ represents penalties proportional to the volume of unserved energy.
- $\mathrm{GasFlarePenalties}$ represents a virtual penalty applied on the exceeding gas volume when actual supplies exceed the overall withdrawal from the network (including storing and exports). It is usually close to 0€/MWh but one could use other values to penalise unused energy and losses.

2.2.2. HORIZONS AND OPTIMISATION PROCESS

While for power system models the horizon is broken down into smaller periods to facilitate the optimisation process (see METIS Technical Note T2), gas system models are solved in a single run, by jointly optimizing all days of the year in order to properly capture the annual management of gas storage facilities.

This implies that gas storage injections and withdrawals are planned with perfect anticipation of future needs.

2.3. MODELS STRUCTURE

2.3.1. GAS SYSTEM MODULE

As illustrated in Figure 2, in the contexts delivered within the gas system module, the European gas supply chain is structured using the following principles:

- Represented zones are linked to one another by **Pipeline** assets.
- **LNG imports** assets are attached to nodes representing geographical zones where LNG terminals exist
- **Gas imports** assets are attached to nodes representing geographical zones connected by pipeline to external (and non-explicitly represented) suppliers. Gas imports assets stand for the whole supply chain: pipeline and upstream production.
- **Gas production** assets are attached to nodes representing geographical zones which have internal gas wells.

LNG imports (asset type **LNG imports**)
Pipeline imports from non-represented suppliers (asset type **Gas imports**)
Pipeline between two represented zones (asset type **Pipeline**)
Internal gas production (asset type **Gas production**)

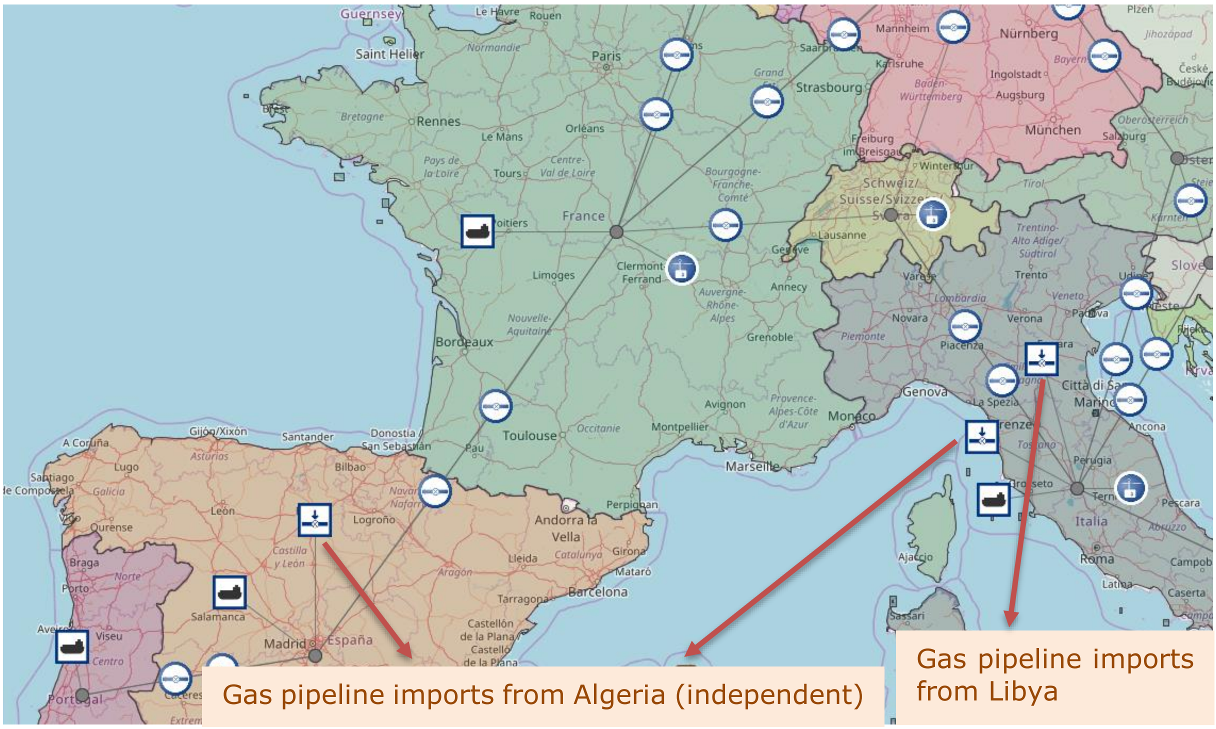


Figure 2 : METIS gas system module – supply assets structure
(LNG terminal, gas storages, demands and exports are excluded from the illustration)

Different **Gas imports** assets may represent imports from the same source supplying different destinations (e.g. imports from Algeria to Spain and from Algeria to Italy on Figure 2). In the delivered scenarios, Germany has a **Gas imports** asset that represents imports from Russia via Nordstream; Poland has a **Gas imports** asset representing imports from Russia via Belarus; Slovakia, Hungary and Romania also have respective **Gas imports** assets representing imports from Russia via Ukraine. All these imports are represented by independent variables in the underlying mathematical problem, therefore the import level from Russia to Germany would not affect prices of other imports from Russia. Consequently, the model structure is not suited to study gas prices and should be used with a fixed gas price. The objective of the gas market module is to refine the representation of gas supply by introducing supply curves that link imports from a single supplier to different destinations.

2.3.2. GAS MARKET MODULE

The contexts delivered with the gas market module involve **piecewise-linear gas production costs with respect to the production level**. Evaluating the total production of a supplier is therefore necessary to determine its marginal production costs[6]. This is done by including the main external suppliers into the modelling scope. The following principles then apply:

- Represented zones are linked to one another by **Pipeline** assets.
- All internal and external suppliers exporting to Europe are represented by **Gas production** assets (including main LNG producers that do not have pipeline access to Europe like the Middle-East, the United Arabic Emirates, Egypt, South America, North America and Western Africa)

[6] In METIS modelling, based on economic fundamentals (supply-demand equilibrium), marginal costs as used as a proxy for prices.

- A dedicated node (located on the map in Iceland for visualization purposes[7]) stands for the global LNG market. All external suppliers can supply the global LNG market using **LNG liquefaction train** assets which link suppliers' nodes to the LNG market node. **LNG terminal** assets are LNG entry points in all other nodes and can only withdraw LNG from the dedicated LNG market node.
- All external suppliers that have pipeline access to Europe have consequently two streams to supply Europe: direct pipeline flows or LNG supply (transiting through the LNG market node)

Figure 3 and Figure 4 show how pipeline imports are represented in the gas market module. By comparing pipeline imports from North Africa between Figure 2 and Figure 3, one may see that the difference lies in the import chain disaggregation: production and transmission are modelled as separated assets in the gas market module (whereas they are merged into one asset in the gas system module). Several transmissions can link the same producer to several destinations, making **all destinations co-dependent since it is the overall supply from a given source that determines the source's marginal production cost**.

 LNG liquefaction train

 LNG terminal

 Pipeline between two represented zones

 Internal gas production

[7] Iceland is not part of the METIS scope

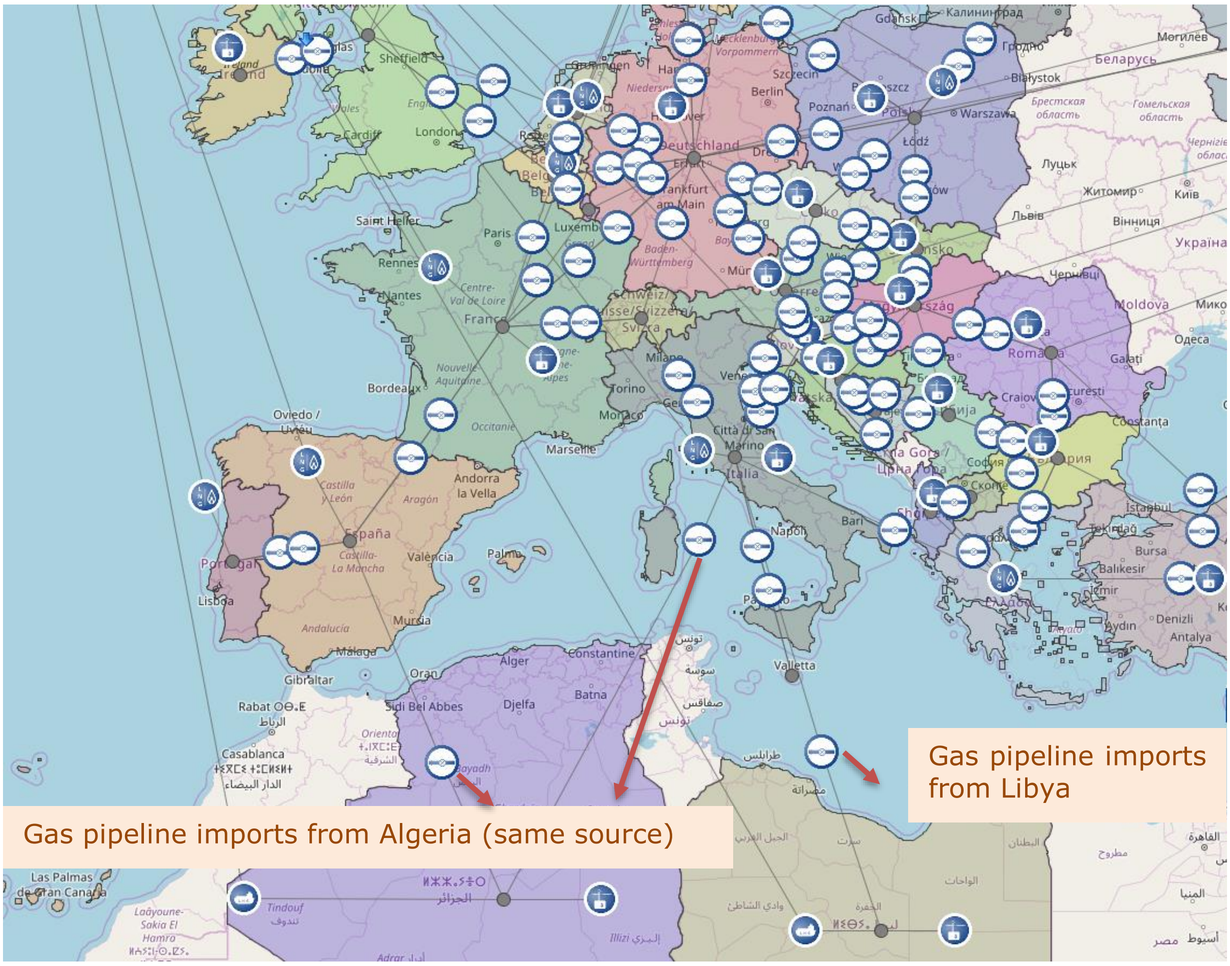


Figure 3 : METIS gas market module – supply structure from North Africa (gas storages, demands and exports are excluded from the illustration)

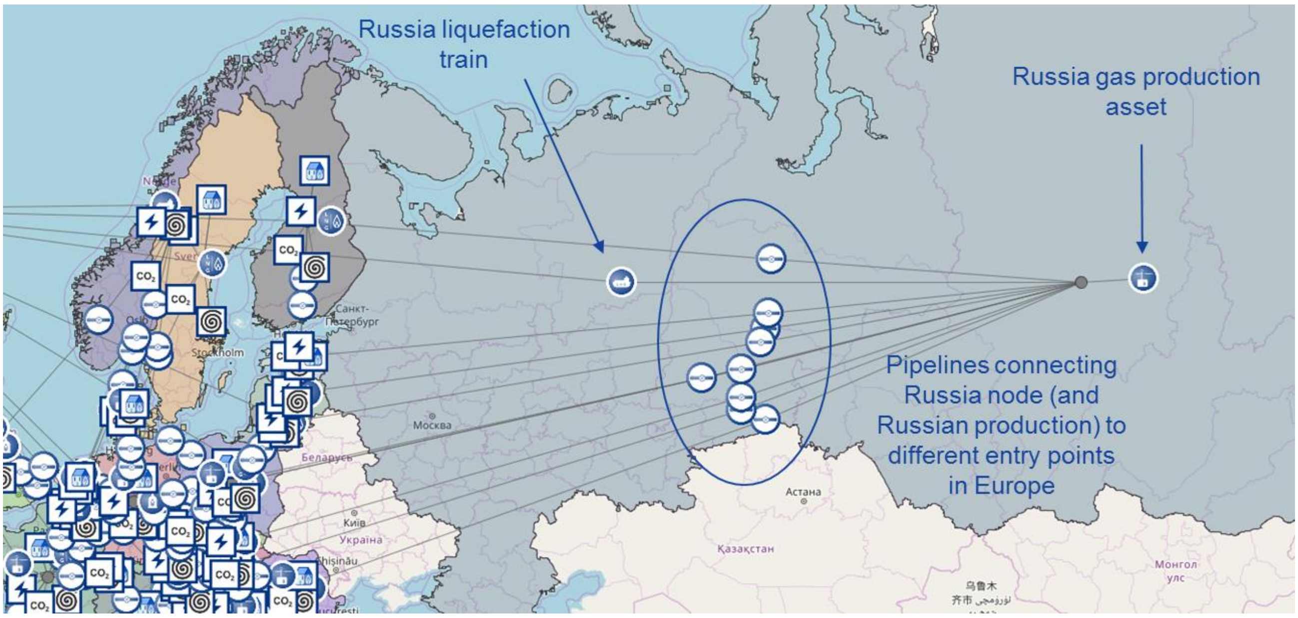


Figure 4: METIS gas market module – supply structure from Russia

The second major difference between the two models is the way the LNG circuit is modelled. Figure 5 illustrates that **all LNG supply must transit through the LNG market node (1) at which a single marginal supply cost[8]** applies to all importing zones, depending on the overall LNG supply mix. Two situations can occur:

- Producers that do not have pipeline access to Europe, like Middle-East (2), can only supply the LNG market node (1) thanks to **LNG liquefaction train** assets (3).
- Producers that have pipeline access to Europe, like Norway, can also supply the LNG market node (1) thanks to **LNG liquefaction train** assets (4) or can directly supply Europe with natural gas using the pipeline network (6)

Explicitly modelled zones, like the UK, can import LNG using **LNG terminal** assets (5) which withdraw LNG from the LNG market node and inject gas directly into the zone.

[8] Endogenously determined at each time step on the basis of a general supply-demand equilibrium

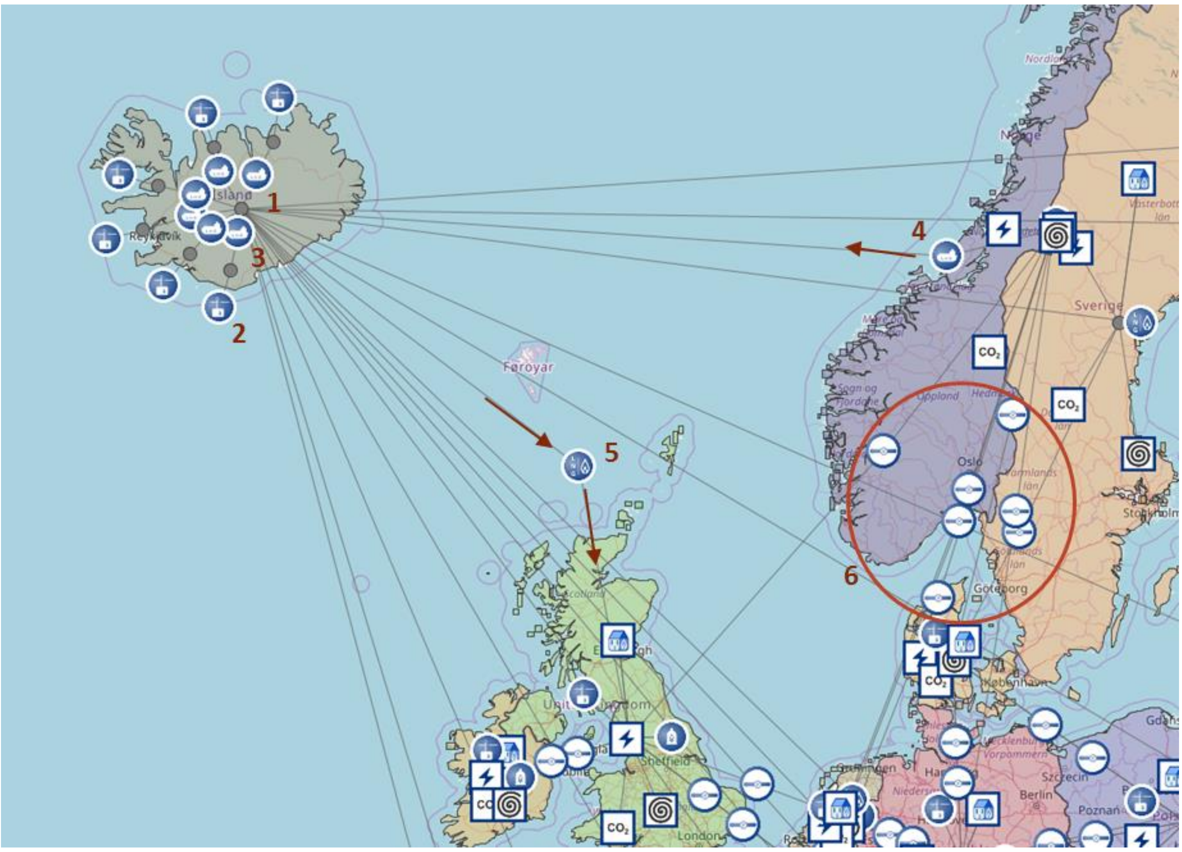


Figure 5: METIS gas market module - LNG market structure

3. Data and Scenarios used in METIS Gas System Models

3.1. Gas system Module scenarios available in METIS

In the version delivered to the European Commission[9], several scenarios have been implemented:

- ENTSOG **TYNDP2015 GREY scenario** for year 2030
    - A set of variations from this scenario have been developed for the METIS Study S5, including S5-FID scenario, S5-PCI1 scenario and S5-PCI2 scenario.
- ENTSOG **TYNDP2015 GREEN scenario** for year 2030
- European Commission **REF15 scenario** for year 2030
- European Commission **EUCO30 scenario** for year 2050

The scenarios delivered to the European Commission share the same modelling scope that is described briefly below:

- National granularity:
    - All Member States are represented in the model. In addition to countries from EU28, the following countries are explicitly modelled: Albania, Bosnia-Herzegovina, the former Yugoslav Republic of Macedonia, Montenegro, Norway, the Republic of Serbia and Switzerland.
    - Other neighbouring countries are not explicitly modelled but are be represented by a **Gas imports** asset if they export gas to modelled countries. Those include Russia, Belarus, Ukraine, Algeria, Libya and Turkey.
- Simulations over a whole year, using a daily time step. All time steps are jointly optimised (i.e. the operational and tactical horizons have a duration of 365 days)

These scenarios rely on ENTSOG, GIE and EUCO30 datasets and are complemented with other METIS datasets such as demand time-series.

3.2. Scenario-specific data

Scenario-specific data are:

- Endogenous production, i.e. annual volumes of gas production per European country
- Annual demand, i.e. annual volumes of gas demand per European country
- Infrastructure assumptions, i.e. all injection, withdrawal or storage capacities for pipelines, LNG terminals or storage plants.
- Fuel costs, i.e. nominal cost for gas and LNG imports.

Other data are mostly generic and common to all scenarios.

[9] More information at https://ec.europa.eu/energy/en/data-analysis/energy-modelling

Scenario	Years	Endogenous production	Annual demand	Infrastructure assumptions	Fuel costs
TYNDP2015 GREY	2030	ENTSOG TYNDP2015	ENTSOG TYNDP2015 GREY	Projections from ENTSOG TYNDP2015 PCI vision	IEA WEO 2012[10], Current Policies scenario
TYNDP2015 GREEN	2030	ENTSOG TYNDP2015	ENTSOG TYNDP2015 GREEN	Projections from ENTSOG TYNDP2015 PCI vision	IEA WEO 2012, 450 scenario
S5-FID	2030	ENTSOG TYNDP2015	ENTSOG TYNDP2015 GREY	2015 capacities and FID projects from ENTSOG TYNDP2015	IEA WEO 2012, Current Policies scenario
S5-PCI1	2030	ENTSOG TYNDP2015	ENTSOG TYNDP2015 GREY	2015 capacities, FID projects from ENTSOG TYNDP2015 and projects from the first list of PCI[11]	IEA WEO 2012, Current Policies scenario
S5-PCI2	2030	ENTSOG TYNDP2015	ENTSOG TYNDP2015 GREY	2015 capacities, FID projects from ENTSOG TYNDP2015 and projects from the second list of PCI	IEA WEO 2012, Current Policies scenario
REF15	2030	COM REF15	COM REF15	Projections from COM REF15	IEA WEO 2012, 450 scenario
EUCO30	2030, 2050	COM EUCO30	COM EUCO30	Projections from COM EUCO30	IEA WEO 2012, 450 scenario

3.3. DETAILED ASSUMPTIONS

The following sections describe data sources used to build the METIS gas system module scenarios. The reader may refer to METIS asset library detailed documentation[12] for further details on parameters definitions, underlying mathematical models and other possible configurations.

3.3.1. GAS PRODUCTION

Endogenous production is assumed to be constant all year long. The production capacity is then computed in order to correspond to the annual volumes assumed in the scenario (and given by the main scenario sources, as listed above) and assets are configured to produce constantly at full capacity.

[10] See [1]

[11] Only includes projects from the first list of PCI which remained in the second list.

[12] Available on METIS webpage

Parameter	Data
Production capacity (in MW)	Equal to annual production (in MWh) divided by 8760
Min load (% of Pmax)	100%
Availability (in %)	100%
Production cost (in €/MWh)	0

3.3.2. GAS STORAGE

The parameters of current infrastructure (2015), in particular injection, withdrawal and storage capacities, have been extracted from GSE published data (see [6]). For specific projects (FID projects and PCI), capacities have been extracted from ENTSOG TYNDP 2015.

For prospective scenarios, such as TYNDP2015 GREEN, TYNDP2015 GREY, REF15 and EUCO30 scenarios, where usually only withdrawal capacities are provided, injection and storage capacities have been derived from withdrawal capacities by applying the current (2015) ratios between the injection and storage capacities and the withdrawal capacities.

In order to enforce a storage management that takes into accounts winter period requirements, a *Minimal storage level* has been set to 100% on the 1st of October.

The model *withdrawal-from-storage* costs are set to 0.001 €/MWh to avoid numerical artefacts such as simultaneous withdrawals and injections.

Parameter	Data
Injection capacity (in MW)	Collected from scenario data if available. Otherwise based on the withdrawal capacity the current ratio (existing injection capacity / existing withdrawal capacity)
Withdrawal capacity (in MW)	Collected from scenario data
Storage capacity (in MWh)	Collected from scenario data if available. Otherwise based on the withdrawal capacity by applying the current ratio (existing injection capacity / existing withdrawal capacity)
Minimal storage level (in %)	100% on the 1st of October, 0% otherwise.
Withdrawal-from-storage cost (in €/MWh)	0.001

3.3.3. GAS IMPORTS

The import capacity of a given explicitly modelled zone is based on the capacities of incoming pipelines from external (non-explicitly modelled) suppliers, as given by each scenario's main sources or existing infrastructures.

A constant gas price, collected from IEA World Energy Outlook data, is used as supply cost for **Gas imports** assets. One should note that the gas system module has been designed mainly for supply source dependency and security of supply analyses and thus is not calibrated for gas prices analyses. Scenarios included in the gas market module delivery include models and data specifically designed to analyse the impact of infrastructures on gas prices and social welfare (see sections 4 and 2.3.2).

In standard scenarios, annual imports volumes are not constrained and can range from 0 to full annual capacity. However, the METIS Study S5 includes sensitivity analysis to disruption cases which are implemented by setting some **Gas imports** assets' availability to 0%.

Parameter	Data
Production capacity (in MW)	Collected from scenario data
Availability (in %)	0% in case of import disruption, else 100%.
Minimal annual volume (in MWh)	0
Maximal annual volume (in MWh)	Production capacity * 8760
Cost (in €/MWh)	25.7 €/MWh in EUCO30, REF15 and TYNDP2015 GREEN 33.4 €/MWh in S5 scenarios and TYNDP2015 GREY

3.3.4. Gas exports

Gas exports are represented in TYNDP2015 GREEN and TYNDP2015 GREY scenarios. The withdrawal-from-network capacities correspond to the maximal capacity of pipelines connecting European countries to non-European countries and are given by published capacities from ENTSOG TYNDP 2015.

Parameter	Data
Pmax (in MW)	Collected from scenario data
Availability (in %)	100%
Minimal annual volume (in MWh)	0
Maximal annual volume (in MWh)	Production capacity * 8760
Price (in €/MWh)	0 €/MWh

3.3.5. LNG Terminal

Current send-out and storage capacities (2015), have been extracted from GLE data (see [5]). For specific projects (FID projects and PCI), capacities have been extracted from ENTSOG TYNDP 2015.

For prospective scenarios (TYNDP2015 GREEN, TYNDP2015 GREY, REF15 and EUCO30), where only send-out capacities were available, storage capacities have been derived from send-out capacities by applying the current (2015) ratio between these capacities.

Gasification costs are set to 0, i.e. all LNG import costs are borne by **LNG imports** assets.

LNG terminal assets are also configured to withdraw constant daily LNG volumes from LNG imports assets during the whole simulation.

Parameter	Data
Send-out capacity (in MW)	Collected from scenario data
Storage capacity (in MWh)	Collected from scenario data if available. Otherwise base on the send-out capacity by applying the current ratio (existing storage capacity / existing send-out capacity)
Cost (in €/MWh)	0

3.3.6. LNG IMPORTS

For each node which is an LNG entry point (i.e. each node to which a **LNG terminal** asset in attached), LNG maximal and minimal imports are limited by the send-out capacity of the attached LNG terminal.

LNG imports costs are based on IEA World Energy Outlook data.

One should note that the gas system module has been designed mainly for supply source dependency and security of supply analyses and thus is not calibrated for gas prices analyses. Prices are set to define a merit order and not to represent accurately gas market prices. The price of LNG is set higher than the price of gas imports. However, except from REF15 and EUCO30 scenarios, it is cheaper to import LNG than to import gas that has to transit through another EU Member State.

Parameter	Data
Maximal Imports (in MW)	Equal to send-out capacity of attached LNG terminal
Import cost (in €/MWh)	Gas import cost + 0.01€/MWh for REF15 and EUCO30 scenarios Gas import cost + 0.001€/MWh else

3.3.7. LNG EXPORTS

A liquefaction and export terminal is modelled in Norway. It is configured so as to withdraw the annual exports volume assumed in each of the scenarios presented above (that is to say as given by REF15, EUCO30 and current export volumes), evenly spread on every time step.

The *export price* is set to 0€/MWh since it has no impacts on the simulation results, the exports being constant over the year and defined by the capacity.

Parameter	Data
Exports (in MW)	Set according to the scenario annual assumption
Export price (in €/MWh)	0

3.3.8. GAS CONSUMPTION

While annual volumes of demand are based on scenario assumptions, time series for demand are generated by Artelys. To assess the benefits of regional cooperation, it is crucial to use consistent weather data through Europe. Indeed, even though all countries must prepare to cover their peak demand, it is important to note that all peaks do not occur at the same time throughout Europe.

The following paragraphs describe the methodology which was used to build the demand time series.

The objective is to generate 50 scenarios of daily demand for each country by means of a statistical model using to the following data sources:

- **Historical daily temperature** data from years 1965 to 2014 for all countries from the European Climate Assessment & Dataset project (ECA), see [7].
- **Historical daily demand** from year 2014 from ENTSOG transparency platform, see [2].

In this regard, each demand scenario is modelled as the sum of a thermo-sensitive component and the non-thermo-sensitive one. The thermo-sensitive component is computed by using a piecewise linear model. This model is set up with one threshold and two slopes[13] and calibrated by getting recourse to a *Multivariate Adaptive Regression Splines* method[14] that involves the computation of temperature gradients (MW of demand increase per °C increase) for each country.

As depicted in the figure below for Spain, the temperature scenarios of each country drive its thermo-sensitive demand scenarios by using the country temperature gradients. Then, thermo-sensitive and non-thermo-sensitive demand scenarios are added so as to complete the generation of the country demand scenarios.

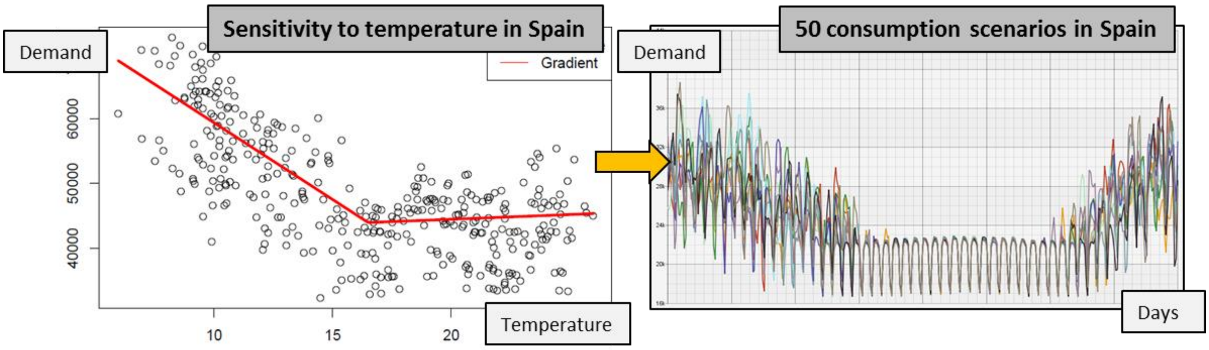


Figure 6: Two gradients accounting for heating effects on Spanish demand

[13] The use of two slopes - one slope associated to low temperatures and one slope associated to high temperatures allows for applying the same approach for each country, with the same number of parameters.

[14] See [23] for the method and [24] for its R implementation.

The fifty hourly scenarios of demand are then rescaled linearly so that the average value of demand corresponds to the average value of demand in a given scenario.

Parameter	Data
Demand (in MW)	The average value is scenario-based. 50 realizations of profiles were generated by Artelys on the basis of historical weather data.
CO2 emissions (in ton/MWh)	0.34

3.3.9. PIPELINES

The capacity of pipelines are based on scenario data for REF15, EUCO30, TYNDP2015 GREY and TYNDP GREEN. For the scenarios used in the METIS Study S5, the infrastructure from 2015 were collected from ENTSOG map and new projects were collected from ENTSOG TYNDP 2015.

Transmission costs are set to 0.001€/MWh to avoid simultaneous imports and exports.

Parameter	Data
Capacity (in MW)	Scenario-based or collected from ENTSOG map and ENTSOG TYNDP2015.
Transmission cost (in €/MWh)	0.001

4. DATA AND SCENARIOS USED IN METIS GAS MARKET MODELS

4.1. GAS MARKET MODULE SCENARIOS AVAILABLE IN METIS

The gas market module delivery includes two additional scenarios, based on EUCO30, implementing the METIS market models:

- **METIS EUCO30** scenario for year **2020**
- **METIS EUCO30** scenario for year **2030**

These scenarios share a number of common modelling choices, which are briefly described below:

- National granularity:
    - All Member States are represented in the model. In addition to countries from EU28, the following countries may be explicitly modelled: Albania, Bosnia-Herzegovina, the former Yugoslav Republic of Macedonia, Montenegro, Norway, the Republic of Serbia and Switzerland.
- Modelling of gas producers outside EU
    - Contrary to the Gas System Module, the following external gas suppliers are explicitly modelled in the METIS gas market models: Russia, Algeria, Libya Turkey, Azerbaijan, Middle East, United Arabic Emirates, Egypt, North America, South America and West Africa.
    - Each external supplier is represented as a **Gas production** asset connected to a dedicated node. These assets represent the available supply for exports to Europe only[15], installed production capacity should therefore exclude the capacity that would be used for domestic consumption and exports to the rest of the world. Exports to Europe can be realized in two ways:
        - Through **Import pipeline** assets connecting a given external supplier to European entry points, that is to say countries/zones that have direct access to the supplier. External suppliers connected to Europe through pipelines in METIS market models are Russia, Algeria, Libya, Turkey and Azerbaijan
        - Through the global LNG market. As described in section 2.3.2, the global LNG market is represented as an independent node. Any pure producer (namely all external suppliers and Norway) can supply the global LNG market through **LNG liquefaction train** connecting their respective dedicated nodes and the global LNG market node.

          A liquefaction-and-transport cost is associated to **LNG liquefaction train** assets. European demand can then be supplied by national **LNG terminal** assets, withdrawing gas from the LNG market node and injecting it (a regasification cost has to paid) on their own associated nodes.

          Suppliers that can only supply the global LNG market node (no pipeline connection to Europe) are Middle East, United Arabic Emirates, Egypt, North America, South America and West Africa.
- Simulations over a year at daily time step

[15] There is no asset connected to the corresponding nodes and standing for domestic-demand or other-exports

These scenarios rely on ENTSOG, GIE and PRIMES data as well as commercial data from Rystad and inputs from Congas regarding regulated transport tariffs. There are complemented with other METIS datasets such as demand time-series.

4.2. DETAILED ASSUMPTIONS

The following sections describe data sources used to construct METIS gas market module scenarios. The main assumptions regarding the parametrisation of the assets are presented. The reader may refer to METIS asset library detailed documentation (see [1]) for further details on parameters definitions, underlying mathematical models and other possible configurations.

4.2.1. GAS PRODUCTION

- **Production capacities**

Suppliers' production capacity is based on PRIMES EUCO30 data for 2030. The annual gas volume available to Europe is defined as the sum of exports to Europe and unused production capacity, as given by EUCO30:

$$\begin{aligned}&\mathrm{AnnualGasAvailableToEurope}_{\mathrm{external\ supplier}}\\&\qquad = \mathrm{productionCapacity}_{\mathrm{externalSupplier}} - \mathrm{annualProduction}_{\mathrm{externalSupplier}}\\&\qquad + \mathrm{exportsToEurope}_{\mathrm{externalSupplier}}\end{aligned}$$

The production capacities are then computed in such a way that using this capacity to saturation all year long would produce exactly $\mathrm{AnnualGasAvailableToEurope}_{\mathrm{external\ supplier}}$

- **Production costs**

Member States' gas production cost is set to the average supply price used in PRIMES EUCO30, which is a result of the PROMETEUS model.

Suppliers which are not MSs have been attributed piecewise-linear cost curves based on commercial data collected by Rystad. A calibration process has been applied on Rystad data to incorporate it into the METIS EUCO30 gas market scenarios, consistently with other data sources. Appendix A presents the calibration process in more detail.

Parameter	Data
Production capacity (in MW)	Results in the annual available volume for exports to Europe if used at full annual capacity
Production cost (in €/MWh)	Average gas price from EUCO30 for MS; dependent on production level for external suppliers

4.2.2. Gas storage

Injection, withdrawal and storage capacities have been extracted from GSE published data. Current and under construction infrastructures were considered and filtered on the start-up date.

In order to enforce a realistic storage management, **Gas storage** assets are forced to be at least 20% full at any time and at least 80% full on October, 1st.

Regulated tariffs (see Appendix B) have been applied on injections and withdrawal. Entry/exit tariffs of national storages have been estimated by averaging entry/exit tariffs of cross-border flows for every country[16].

Parameter	Data
Injection capacity (in MW)	Current and under construction infrastructures from GSE (2016)
Withdrawal capacity (in MW)	Current and under construction infrastructures from GSE (2016)
Storage capacity (in MWh)	Current and under construction infrastructures from GSE (2016)
Minimal storage level (in %)	80% on the 1st of October, 20% otherwise.
Maximal storage level (in %)	100%
Injection/withdrawal costs (in €/MWh)	Average of tariffs applied to cross-border flows with neighbouring countries

4.2.3. LNG Terminal

LNG withdrawal capacities have been extracted from GLE published data. Current and under construction infrastructure (the start-up date of which is planned before the considered horizon, for each scenario) assets have been considered. Storage capacities have been set to 0 as terminals were not considered to participate in the daily supply-demand balance management.

Gasification costs are provided at terminal level by the European Commission and are averaged to match the aggregated national LNG terminals.

Parameter	Data
Send-out capacity (in MW)	Current and under construction infrastructures from GLE (2016)
Storage capacity (in MW)	0
Cost (in €/MWh)	Averaged from terminal level gasification costs provided by EC

[16] Cross-border flows tariffs were provided by Congas (see Appendix B) and assessed on the basis of public data.

4.2.4. Gas consumption

While annual volumes of demand are based on PRIMES EUCO30 scenario assumptions, the demand daily time-series have been generated by Artelys. To assess the benefits of regional cooperation, it is crucial to use consistent weather patterns throughout Europe. Indeed, although all countries must be prepared to cover their peak demand, it is important to note that all peaks do not occur at the same time throughout Europe.

The same methodology was used to build the daily and weather-dependent demand profiles in all gas scenarios delivered within METIS. The reader can find a description of this methodology in section 3.3.8.

Parameter	Data
Demand (in MW)	The average value is scenario-based. Time series were generated by Artelys.
CO2 emissions (in ton/MWh)	0.34

4.2.5. CO2 Emissions

To be consistent with the METIS EUCO30 power scenarios, the price of CO2 emissions is set to 27€/tonne.

4.2.6. Pipelines

Cross-border pipeline capacities are based on PRIMES EUCO30 data. National entry/exit fees have been compiled by Congas on the basis on public data from ACER, TSOs and ENTSOG (see Appendix B).

Parameter	Data
Capacity (in MW)	PRIMES EUCO30.
Source exit fee (in €/MWh)	Based on publications from ACER, TSOs and the ENTSOG (see Appendix B).
Destination entry fee (in €/MWh)	Based on publications from ACER, TSOs and the ENTSOG (see Appendix B).

5. Main Outputs And Visualization In The Interface

5.1. Main Key Performance Indicators

METIS provides functionalities to display model inputs and results as tables, charts or geographical illustrations. An extensive list of predefined Key Performance Indicators (KPIs) was delivered within METIS. Among others, the following high-level indicators can be computed, analysed at different granularity level and displayed in various ways:

- **Demand** [input data]
- **Installed capacities** [input data in standard SIMULATION mode, result in CAPACITY_EXPANSION mode]
- **Storage capacity** [input data in standard SIMULATION mode, result in CAPACITY_EXPANSION mode]
- **Transmission capacities** [input data in standard SIMULATION mode, result in CAPACITY_EXPANSION mode]
- **Supply** [simulation results]
- **Consumption** [simulation results]
- **Capacity factor** (detailed by infrastructure type) [simulation results]
- **Expected unserved energy** [simulation results]
- **Marginal costs statistics** [simulation results]
- **Producer surplus** [simulation results]
- **Consumer surplus** [simulation results]
- **Congestion rent** [simulation results]
- **Welfare** [simulation results]

KPIs can be displayed in tables or directly on a map as shown in the following figure:

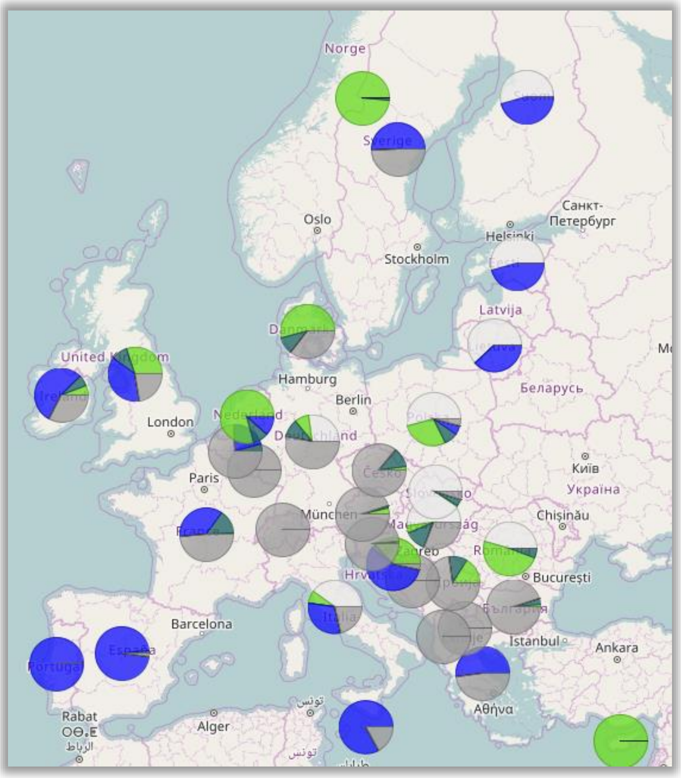


Figure 7: Supply by source and by country, displayed directly on the European map in Artelys Crystal Super Grid

The reader may refer to the detailed KPI documentation to find exact definitions of all KPIs embedded in METIS and utilization instructions.

5.2. Gas Mark-up Costs

As part of the gas market module delivery, a variant of every economic KPIs has been developed to take into account suppliers' mark-ups in gas price and partially reflect market power, including:

- Marginal costs statistics (Gas fixed markup)
- Consumer surplus (Gas fixed markup)
- Production revenue (Gas fixed markup)
- Producer surplus (Gas fixed markup)
- Congestion rent (Gas fixed markup)
- Border exchange surplus (Gas fixed markup)
- Welfare (Gas fixed markup)
- Load payment (Gas fixed markup)

All the indicators in the above list are based on marginal costs. The 'Gas fixed markup' variants use marginal costs increased by supplier-specific mark-ups (provided as inputs by the user) instead of the marginal costs as extracted from the simulations. Mark-ups are therefore applied to marginal costs as a post-treatment.

For instance, the producer surplus without markup is defined as:

$$\text{producerSurplus(supplier)} = \sum_t \text{production}_t^{\text{supplier}} \cdot (\text{marginalCost}_t^{\text{supplier}} - \text{productionCost}_t^{\text{supplier}})$$

Leading to defining the indicator 'Producer surplus (Gas fixed markup)' as:

$$\text{producerSurplus(supplier)} = \sum_t \text{production}_t^{\text{supplier}} \cdot (\text{marginalCost}_t^{\text{supplier}} + \text{markup}^{\text{supplier}} - \text{productionCost}_t^{\text{supplier}})$$

The following methodology was proposed to reflect mark-ups on the supply mix resulting from simulations in order to take into account a given supplier's market power:

1. Define a base-case scenario to be used as reference
2. Duplicate the base-case scenario and set the studied supplier's availability to 0
3. Launch the simulations on both contexts (base-case and variant excluding the studied supplier)
4. Compare marginal costs in both contexts
    a. They should be higher in the variant with one supplier being excluded
    b. The rise in marginal costs caused by a supplier's exclusion from the supply mix measures the market power of this supplier
    c. Deduce a mark-up that the supplier would be able to apply on its prices given its market power
5. Duplicate again the base-case scenario and add a **Gas Market Markup Cost** model object named "Gas Market Markup Cost"
    a. Set the mark-ups according to the previous point
6. Use the action script "Modify cost curves" on the latest context to add mark ups to the production costs used during the simulation[17]
7. Launch the simulation on the latest context
    a. The supply mix should be impacted by the increase in production costs
8. Use the KPI "Producer surplus (Gas fixed mark-up)" not to consider the mark up as a real production cost but as a margin absorbed by the supplier surplus.
    a. The standard KPI Producer surplus will use increased production costs as if it reflected real costs
    b. Part of the production cost actually corresponds to the supplier mark up and should not be deduced from its surplus
    c. The KPI variant "Producer surplus (Gas fixed mark-up)" displays results including the mark up in the supplier surplus instead of considering it as a cost paid by the supplier

5.3. OTHER DISPLAY FEATURES

In addition to annual indicators (KPIs), METIS provides view modes allowing the user to display and analyse results as time-series with different temporal aggregation features. In particular, the *Cumulative generation* curve can be very useful to analyse a given zone's supply mix since it displays it with temporal insights, that is to say at every time steps.

[17] Mark-ups parameters set in step 5.a are not used in the simulation but only in post-treatment. This is why an action script is required to modify the production cost curves actually used in the simulation by adding mark-ups

Figure 8: Cumulative generation curve for a year in Italy in 2030, simulated using METIS models and displayed in Artelys Crystal Super Grid

Appendix A - Construction of cost curves [market module]

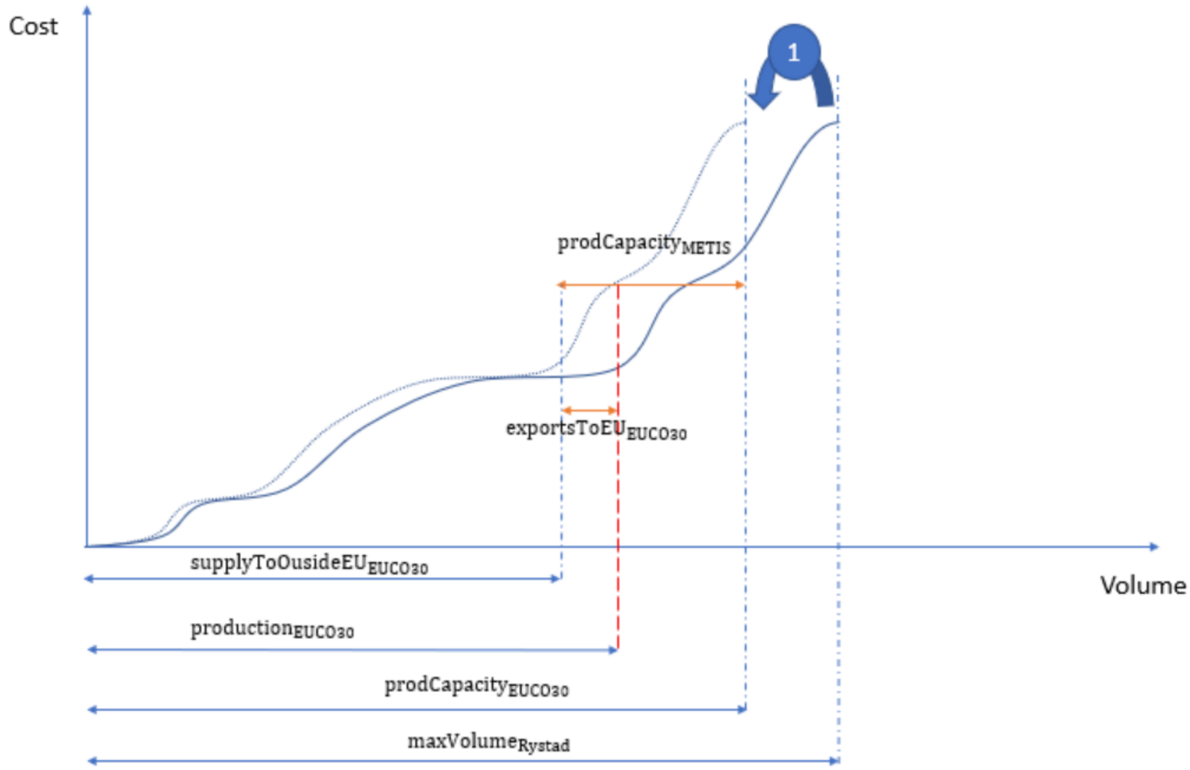
Supply curves reflecting the cost of gas production as a function of the annual production volume were provided for a number of countries by the European Commission based on Rystad data. A calibration process was undertaken to incorporate these datasets into METIS EUCO30 scenarios in a way that is consistent with the other data sources used therein.

The following points were given a particular attention as they are crucial to make Rystad supply curves consistent with METIS scope and EUCO30 input data.

1. For some suppliers, the maximum volume of each source provided by Rystad differs from the overall production capacity given by EUCO30. It can be higher or lower, depending on the suppliers.
2. Rystad data provides production costs of each source as a function of their overall annual production volume. In METIS, on the other hand, only European countries' demands are modelled, the production of external suppliers in METIS simulations hence correspond to the volume supplied to Europe only, and does not include the domestic demands of those suppliers and exports to the rest of the world. To match exports to Europe with production costs, assumptions have to be made on each external source's domestic demand and exports to the rest of the world in order to determine the overall productions by source. Based on the result of this procedure, the marginal production cost can be determined as a function of the overall import to Europe.
3. Using demands and supply mixes from EUCO30 with supply curves embedded in METIS should yield the same average gas supply price for Europe as those used in EUCO30. Indeed, in order to allow integrated gas-and-power modelling (as used in METIS study S10), the average gas supply price from METIS EUCO30 gas scenario has to be consistent with the fixed gas price used in METIS EUCO30 power scenarios, which is set to the EUCO30 assumption. Otherwise gas-to-power place in the power supply merit order may change between power-only simulations and gas-and-power simulations.

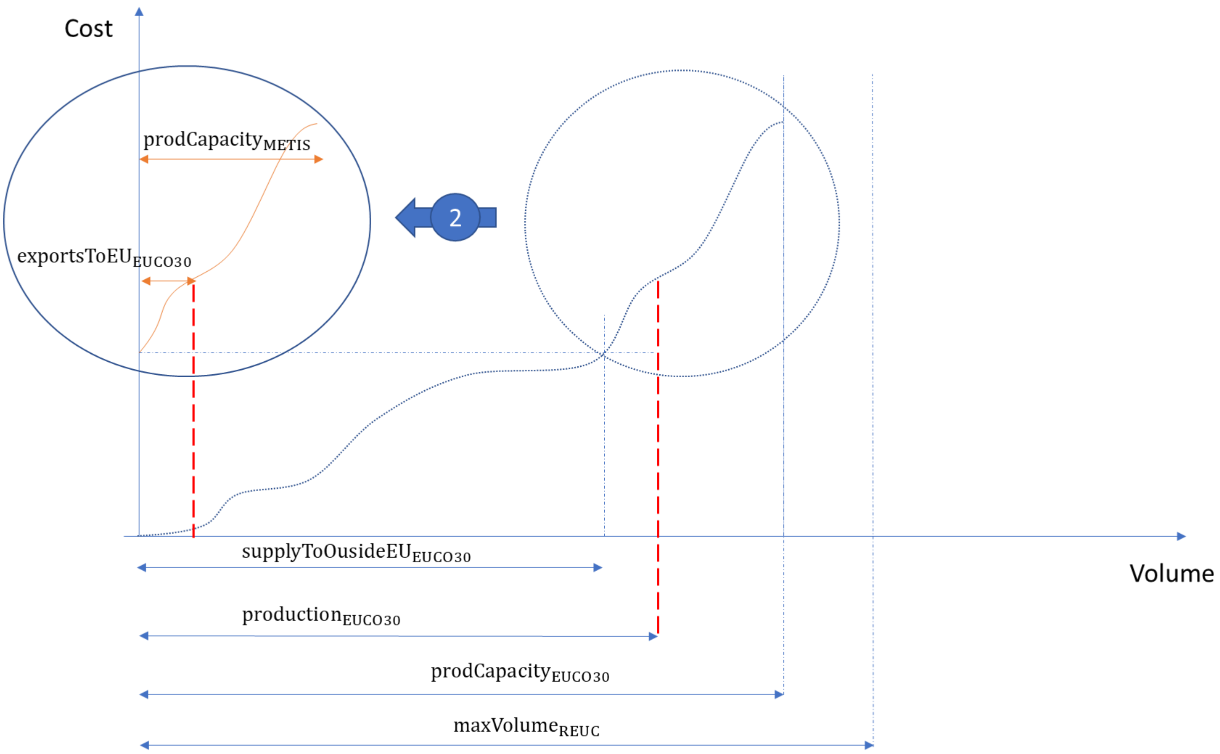
With these points in mind, the following calibration process has been developed and adopted:

1. **Producer capacity rescaling**: For each supplier, Rystad supply price curves are rescaled so that their maximum volumes match the PRIMES EUCO30 capacity.



2. **Taking into account exports to the rest of the world** (RoW)**:** External sources' domestic demand and exports to non-modelled countries (i.e. outside Europe) are assumed to be fixed to EUCO30 values. The METIS gas market module assumes that any supplier has a single bidding price (per time step), at its marginal production cost, taking into account all importers and offered to all importers. Prices are not based on bilateral agreements. Therefore, production costs of a given supplier cannot be less than the costs associated to the volume supplied to RoW (including domestic demand). The supply curves used in METIS are then restrained to production cost ranges that take into account that part of the production capacity is solicited because of supplies to RoW, whatever simulation results might be[18].

[18] Note that it does not mean that Europe would be supplied last and at the highest prices: the assumption made is that exports to outside Europe (which are not represented in METIS) are not dependent on Europe's supply mix. The marginal cost of each supplier is then bounded from below by the cost corresponding to its supply to RoW. However, offers form a source - resulting from both fixed exports to RoW and optimized European overall supply mix - would be common to every country supplied by this source.



3. **Calibration of the reference average gas price**: In order to be consistent with the EUCO30 scenario, supply curves are re-calibrated in such a way that using them to compute the average gas price associated to the PRIMES EUCO30 supply mix yields the same average European gas price than the one assumed in EUCO30. The average gas price of a supply mix can be computed as follows:

$$\mathrm{averageSupplyPrice(V)} = \frac{\sum_{\mathrm{supplier\ s}}\left(\mathrm{V_s}\cdot\lambda_{\mathrm{s}}(\mathrm{V_s}) + \mathrm{V_{liq,s}}\cdot\lambda_{\mathrm{liq}}\right)}{\sum_{\mathrm{supplier\ s}}\mathrm{V_s}}$$

Where:

- V_s is the annual gas volume supplied by supplier s, including LNG supply
- $V_{liq,s}$ is the volume of V_s supplied as LNG only
- $V = \{V_s\}_{supplier\ s}$ is the set of supply volumes by source
- $\lambda_s(V_s)$ is the marginal production cost of supplier s (depending on V_s)
- λ_{liq} is the liquefaction and transport cost of LNG

A single scaling coefficient can be computed and applied to all supply curves so that the average supply cost associated to PRIMES EUCO30 supply mix is exactly the gas price from EUCO30:

$$\mathrm{priceScalingCoefficient} = \frac{\mathrm{gasPriceAssumption^{EUCO30}}}{\mathrm{averageSupplyPrice(V^{PRIMES\ EUCO30})}}$$

Appendix B - Network entry/exit fees [market module]

Based on ACER and TSOs publications, the following tariffs data was compiled by Congas and included in METIS EUCO30 scenarios for 2020 and 2030.

Origin	Destination	Exit (EUR/MWh/day/year)	Entry (EUR/MWh/day/year)	Data source	Comments	
AL	**IT**	105	104	transport cost calculation	Trans Adriatic Pipeline (TAP)	TYNDP 2017 Project TRA-F-051
AT	**DE**	175	110	[1]	compared to TSO data, ok	
AT	**HU**	80	225	[1]	TSO data not found	
AT	**IT**	219	217	[1]	TSO data indicates lower tariff	
AT	**SI**	173	106	[1]	TSO data not found	
AT	**SK**	48	91	[1]	TSO data not found	
AT	**CZ**	49	162,5	ACER Market Monitoring Report 2015 same value as CZ->AT	Bidirectional Austrian Czech Interconnectio n (BACI), planned start in 2020	TYNDP 2017 Project TRA-N-021
BE	**DE**	130	96	[1]	TSO data indicates higher tariff	
BE	**FR**	74	114	[1]	compared to TSO data, ok	
BE	**UK**	289	346	[1]	TSO data indicates lower tariff, Exit BE = Exit + Interconnector	
BE	**LU**	0	0	no tariff in ACER/CEER	BE & LU are integrated	
BE	**NL**	87	78	[1]	compared to TSO data, ok	
BG	**GR**	161,5	173	[1]	TSO data not found	
BG	**MK**	161,5	258,5	[1]	entsog: Bulgartransgaz firm exit to MK 19.73 BGN / $1000m^3$ (~ 420€/MWh/day)	
BG	**RO**	161,5	270	[1]	used mean values from ACER/CEER, missing technical data for project estimation	TYNDP 2017 Project TRA-N-379
BY	**LT**	708,1	32	[1]	BY exit = entry fee UA (ewi eucers 2016) + estimation for 575km RU + BY (cwpe1051.pdf)	

BY	**PL**	208,05	131	[1]; Options for Gas Supply Diversificatio n for the EU and Germany in the next Two Decades (ewi eucers 2016); cwpe1051.pdf	BY exit = entry fee UA (ewi eucers 2016) + estimation for 575km RU + BY (cwpe1051.pdf)	
CH	**IT**	219,5	172	[1]	TSO data not found	
CZ	**DE**	224,5	136,5	[1]		
CZ	**PL**	224	254	[1]		
CZ	**SK**	200	114	[1]		
CZ	**AT**	162,5	49	ACER Market Monitoring Report 2015	Poštorná - Reintal border point, data source not ACER map	
DE	**AT**	96	60	[1]		
DE	**BE**	200	37	[1]		
DE	**CH**	96	219,5	[1]		
DE	**CZ**	82	28	[1]		
DE	**DK**	147,5	69	[1]		
DE	**FR**	123	114	[1]		
DE	**LU**	131,552083	174	firm tariff data from entsog platform	OGE firm exit in Remich = 0.00865 EUR/(kWh/h)/d	
DE	**NL**	119	36	[1]		
DE	**PL**	116	159	[1]		
DK	**DE**	168	141	[1]		
DK	**SE**	182	0	[1]	SE is downstream, commodity and postage stamp tariff?	
DK	**PL**	76	174	transport cost calculation	PCI baltic pipe, start of operation in 2022 possible	
DZ	**ES**	0	132	[1]		
DZ	**IT**	0	446	[1]		
EE	**LV**	274	0	[1]	note: actual RU import and short transit via EE	
ES	**FR**	244	114	[1]		
ES	**PT**	244	201	[1]		
FR	**BE**	45	74	[1]		
FR	**CH**	399	219,5	[1]		

FR	**ES**	497	132	[1]		
FR	**LU**	0	0	no tariff in ACER/CEER	not found in ENTSOG IC table	
FR	**DE**	114	123	[1]	Reverse capacity from France to Germany at Obergailbach	TYNDP 2017 Project TRA-N-047
UK	**BE**	171	196	[1]		
UK	**IE**	171	58	[1]		
GR	**BG**	173	161,5	[1]	Interconnector Greece-Bulgaria (IGB Project)	TYNDP 2017 Project TRA-F-378
GR	**AL**	241	105	transport cost calculation	Trans Adriatic Pipeline (TAP)	TYNDP 2017 Project TRA-F-051
HR	**HU**	456	234	[1]	reverse flow capacity HR->HU is limited, downstream system	
HU	**HR**	234	456	[1]		
HU	**RO**	225	245	[1]		
HU	**SI**	116	105	transport cost calculation	Slovenian-Hungarian interconnector, planned comissioning in 2020	TYNDP 2017 Project TRA-N-325 Project
HU	**SK**	237	122	[1]	used same values as SK->HU, note: reverse flow capacity is limited	
HU	**RS**	234	456	no tariff information in ACER/CEER or entsog tp	used HU->BA values	
IE	**UK**	72	213	no tariff information in ACER/CEER or entsog tp	used UK->IE values, note: reverse flow capacity is limited	
IT	**AT**	63	23	[1]	note: reverse flow capacity is limited	
IT	**CH**	160	219,5	[1]		
IT	**SI**	142	80	[1]		
IT	**MT**	0	0	no tariff information in ACER/CEER or entsog tp	no network - Malta has a floating LNG vessel, regas for power generation	
LT	**LV**	38	32,899	[1]	Entry Kemenai from 2017 conexus tariffs	

LT	**PL**	134	268	transport cost calculation	Gas Interconnection Poland-Lithuania (GIPL)	TYNDP 2017 Project TRA-N-341
LV	**EE**	33,0148	274	[1]	Exit Karksi from 2017 conexus tariffs	
LV	**LT**	33,0148	32	[1]	Exit Kemenai from 2017 conexus tariffs	
LY	**IT**	0	415	[1]		
MK	**AL**	0	0	no tariff information in ACER/CEER or entsog tp	MK is supplied via Bulgaria, no reverse flow	
MT	**IT**	0	0	no tariff information in ACER/CEER or entsog tp	no network - Malta has a floating LNG vessel, regas for power generation	
NL	**BE**	89	39	[1]		
NL	**DE**	50	120	[1]		
NL	**UK**	381	346	[1]		
NO	**BE**	336	31	[1]		
NO	**DE**	345	140	[1]		
NO	**FR**	342	114	[1]		
NO	**UK**	393	339	[1]		
NO	**NL**	322	36	[1]		
NO	**DK**	340	76	transport cost calculation; NO import mean value	Gassled - Danish upstream system	TYNDP 2017 Project TRA-N-394
PL	**CZ**	141	28	[1]		
PL	**DE**	131	112	[1]		
PL	**DK**	174	152	transport cost calculation	Poland - Denmark interconnection (Baltic Pipe), note: physical flow will be mainly NO->PL	TYNDP 2017 Project TRA-N-271
PL	**LT**	378	189	transport cost calculation	Gas Interconnection Poland-Lithuania (GIPL)	TYNDP 2017 Project TRA-N-341
PL	**SK**	37	38	transport cost calculation	Poland - Slovakia interconnection	TYNDP 2017 Project TRA-N-275

PL	**UA**	141	0	[1]	reverse flow PL-UA is limited	
PT	**ES**	0	132	[1]		
RO	**BG**	0	161,5	[1]	exit tariff RO tu BG is unknown, transit system	note: Bulgaria has commodity price only (postage stamp tariff system)
RO	**HU**	904	255	[1]	Romanian-Hungarian reverse flow Hungarian section 2nd stage	TYNDP 2017 Project TRA-N-377
RS	**BA**	0	0	no tariff information in ACER/CEER or entsog tp	downstream supply of Bosnia via Zvornik, commodity price (postage stamp tariff)	
RS	**BG**	394	165,5	transport cost calculation	the Bulgaria-Serbia Interconnector shall be in operation in 2020, reverse flow RS->BG maybe limited	
RU	**DE**	883,3	197	[1]; Nord Stream AG IFRS report 2015	Entry DE from ACER/CEER, calculation of transport costs for Nord Stream 1 at 80% utilization in 2015/2016	
RU	**EE**	0	274	[1]		
RU	**FI**	0	0	no tariff information in ACER/CEER or entsog tp		
RU	**LV**	0	0			
SI	**HR**	92	356	[1]		
SI	**IT**	88	164	[1]		
SI	**HU**	105	116	transport cost calculation	Slovenian-Hungarian interconnector, planned comissioning in 2020	TYNDP 2017 Project TRA-N-325 Project
SK	**AT**	258	39	[1]		
SK	**CZ**	236	28	[1]		
SK	**HU**	122	237	[1]		
SK	**PL**	46	45	transport cost calculation	Poland - Slovakia interconnection	TYNDP 2017 Project TRA-N-275
SK	**UA**	274	0	[1]	reverse flow to UA	

TR	**GR**	777	241	[1]; transport cost calculation	Trans Adriatic Pipeline (TAP)	TYNDP 2017 Project TRA-F-051
TR	**BG**	0	161,5	[1]	note: reverse flow TR->BG maybe limited	
UA	**HU**	900	255	[1]		
UA	**PL**	747	254	[1]		
UA	**RO**	665	295	[1]		
UA	**SK**	943	204	[1]		

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