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Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimisation

D5.10

Report on economic analysis of test cases

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Executive Summary

A better integration of renewable energy sources can be achieved by using the power-to-gas (PtG) technology to convert renewable electricity into synthetic natural gas (SNG) that can be injected into the natural gas infrastructure

This report deals with the economic aspects of SNG injection for different combinations of SNG plants and gas networks, as well as of optimised operation schemes for the gas networks. Next to the demo plants and the connected gas grids from within this project, combinations of several typical test grid topologies and increased plant sizes are considered in this Deliverable, when calculating costs for injecting SNG under different network operation schemes. In addition, the capacities of the gas infrastructure and the connected underground storages for long term storage of currently natural gas, in the future SNG, are shown.

The energy demand and its associated costs for injecting SNG into the gas infrastructure depend mainly on the demand of compression. The main influencing parameters for the compression are the ratio of the operating pressure (OP) of the power-to-gas (PtG) plant to the OP of the respective gas grid as well as the considered volume flow. Therefore the connection of a PtG plant with a low outlet pressure to a high pressure gas grid causes the highest energy demand and costs, whereas the connection to a low pressure distribution grid causes no or reduced demand for compression.

To optimize the injection of SNG into the gas grid, besides the selection of suitable plant concepts for the respective gas grid, the network operation schemes can be adjusted to whether increase the capacity for injecting renewable gases or to lower the energy demand for compression. The energy demand for gas compression can be reduced by lowering the OP of the grids, the installable PtG system output can be increased using the dynamic storage capacity of the grid. Both possibilities for adjustment therefore have an opposite effect on the costs for compression.

The investment costs for the injection plant depend mainly on the required compressor system, which is depending mainly on the inlet and outlet pressures, the volume flow to be compressed and the resulting drive power. Therefore, a selection of suitable plant concepts for the respective gas grid could also decrease the costs for the overall system.

The biggest advantages, when injecting SNG into the gas grid, are the opportunity to defossilize the gas sector, and the access to a huge storage capacity for especially medium and long-term storage. The storage capacity of the gas grid itself is called linepack and depends mainly on the minimum and maximum pressure of the gas grid. This can be used in particular to optimize the grid operation for larger capacities for SNG or for reduced effort for injection of SNG. For long term storage the gas grid grants access to the gas underground storages. With a planned overall gas storage capacity of about 1 300 TWh in the year 2025, a share of about 25 % of the current yearly gas consumption of EU-28 can be stored – and therefore also large quantities of SNG.

1 Introduction

A better integration of renewable energy sources can be achieved by using the power-to-gas (PtG) technology and converting surplus renewable electricity into synthetic natural gas (SNG). Besides biomethane, SNG can be injected into the natural gas infrastructure and help both decarbonising gas supplied sectors (domestic and industrial heat, gas mobility, power generation from gas fired power plants) and storing renewable energy. If injection takes place in the transmission network, due to the connected underground gas storages, large-scale and long-term energy storage becomes accessible for renewable energies.

1.1 Objective and scope of this Deliverable

Deliverable 5.10 is the last of three Deliverables of Task 5.3 “Analysis of Gas Grid Integration and Storage Opportunities” and builds on the results from

- D5.3 Report on defined test grid topologies and load cases [1]
- D5.7 Report on optimised operation schemes for gas grids in test cases [2]

It focuses on economic aspects of SNG injection for different combinations of SNG plants and gas networks, as well as of optimised operation schemes for the gas networks. Next to the demo plants and the connected gas grids from within this project, combinations of several typical test grid topologies and increased plant sizes are considered in this Deliverable, when calculating costs for injecting SNG under different network operation schemes.

2 Overview of test grids and PtG plant types

This chapter provides a short overview of the different test grids and the three methanation plants. Therefore, decisive parameters for SNG injection are introduced as minimum and maximum load, operating pressure, etc. on the side of the gas grids and SNG output and operating pressure, etc. on the demo plant.

2.1 Overview of introduced test grids

In Deliverable 5.3 – *Report on defined test grid topologies and load cases* – seven test grids have been described and analysed, including the gas grids/pipelines at the demo plants in Falkenhagen (Germany) and Solothurn (Switzerland). These grids represent all network levels reaching from large and medium sized high-pressure transmission pipelines with a large transport capacity to regional, urban and rural medium- and low-pressure gas distribution networks with lower transport capacity.

In the case of the OPAL and the Transitgas transmission pipelines, specific sections are considered for the calculations of conventional and optimised network operation with regard to SNG injection. The smaller transmission pipeline of Ontras at the demo plant Falkenhagen is part of a larger and meshed gas network. However, due to available data, only the pipeline at Falkenhagen is considered for calculations, but it must be taken into account that the potential of accommodating SNG from PtG plants would be significantly higher for the surrounding transmission network of Ontras. Due to missing data, the distribution network of Regio Energie Solothurn can only be considered for conventional network operation (status quo), but not for optimisations and therefore is not considered in this report.

The finally considered gas grids and pipeline sections are listed in Table 2-1.

Table 2-1: Sections of the chosen gas grids or pipelines
Source: DBI – own illustration, data from [3], [4], [5], [6], [7], [8]

Grid structure	Section of grid
OPAL transit pipeline	from compressor station (Radeland) to exit (Brandov)
Transitgas transmission pipeline	from entry (Wallbach) to compressor station (Ruswil)
Ontras domestic transmission pipeline	pipeline passing demo plant Falkenhagen
Regional high pressure distribution network	entire network
Urban intermediate pressure distribution network	entire network
Rural intermediate pressure distribution network	entire network

Table 2-2 shows a summarising overview of descriptive parameters with effect on SNG injection and network operation. The minimum load of a grid or pipeline basically determines the installable system output of a PtG plant for year-round injection at nominal power.

Table 2-2:Parameters of typical gas grid structure.
Source: DBI – own illustration, data from [3], [4], [5], [6], [7], [9, p. 7], [8]

Grid structure	Length [km]	DN [mm]	Pipeline volume [m³]		OP [bar]	Load [Nm³/h]
OPAL transit pipeline	236	1 400	363 294	max.	100	3 629 340
				min.	73	475 323
Transitgas transmission pipeline incl. transit to Italy	70	900	44 532	max.	68	1 105 412
				min.	50*	137 033
Ontras domestic transmission pipeline @ demo plant Falkenhagen	23	600	6 503	max.	63*	100 000
				min.	35*	10 000
Regional high pressure distribution network	3 266	250	160 319	max.	70	746 419
				min.	35	61 638
Urban intermediate pressure distribution network	23	44 – 110	166	max.	0.8	1 846
				min.	0.2	64
Rural intermediate pressure distribution network	32	26 – 110	228	max.	0.8	674
				min.	0.2	7

** assumptions*

For a better comparison of the different test grids, all loads in m³/h refer to the calorific value of Russian natural gas (11.186 kWh/m³ STP). Therefore, they slightly differ from the values of Deliverable 5.3.

2.2 Overview of the methanation plants at the demonstration plants

Within the STORE&GO project three types of methanation concepts are integrated: the Falkenhagen demo plant, the Solothurn demo plant and the Troia demo plant. Detailed information about the location, the type of methanation and the most relevant parameters of the demo plants is listed in Table 2-3.

The methanation sub-system of Falkenhagen (catalytic methanation) is a honeycomb reactor. A plant size of 1 MW electric power input and a nominal SNG output of 52.5 m³/h STP makes the Falkenhagen demo plant the largest of the three methanation systems. The nominal operation pressure of the methanation is 15 bar.

In Solothurn the PtG plant uses a biological methanation technology with an electric power input of 350 kW (about 30.5 m³/h STP of SNG production).

The objective of the Troia demo plant is the demonstration of a milli-structured methanation reactor at an equivalent 200 kW scale. The produced SNG (11.8 m³/h STP) is purified and liquefied. The hydrogen is produced at the current power-to-H_2 demo plant in Troia.

Table 2-3: Relevant parameters of the PtG demonstration plants
Source: DBI – own illustration, data from [10, p. 9], [11] an project partners

Parameter	Unit	Demo plant Falkenhagen	Demo plant Solothurn	Demo plant Troia
Location		Rural area in the North East of Germany (high wind power production, low overall electricity consumption)	Municipal area in the Alps region, CH (considerable Renewable Energy source from PV and hydro production, high overall electricity consumption)	Rural area in the Mediterranean area, IT (high PV capacities, considerable wind power, low overall electricity consumption)
Type of methanation		Catalytic	Biological	Catalytic
SNG temperature downstream	[°C]	20	25	37.5
Electric input power	[kW]	1 000	350	200
Nominal OP of methanation	[bar]	15	10	3
Calorific value H_s	[kWh/Nm³]	10.952	10.295	10.875
Nominal SNG output	[Nm³/h]	52.5 (100 %)	30.0 (100 %)	11.8 (100 %)
Nominal SNG output	kW	575	309	128

3 Analysis of necessary gas treatment systems

This chapter is based on the Deliverable 7.2 “European Legislative and Regulatory Framework on power-to-gas” [12] for the EU and Deliverable 7.3 “Legislative and Regulatory Framework for power-to-gas in Germany, Italy and Switzerland” [13]. It provides a short overview of the regulatory framework for gas quality in the EU and the three countries where the demo plants are located. The most important gas parameters are considered, which determine if a gas treatment is necessary.

3.1 European Standard on the Quality of High Calorific Gases

The standard EN 16726 executed by the Technical Committee of the European Committee for Standardization (CEN) specifies “gas quality characteristics, parameter and their limits, for gases classified as group H that are to be transmitted, injected into and from storages, distributed and utilized [14]. “H-gases” are defined in EN 437 [15]. Together they contain limit values for the gas quality parameters Gross Wobbe index, Relative density, Carbon Dioxide, Oxygen, Water dew point, Mercaptans, Total sulphur and Hydrocarbon dew point, which are listed in Table 3-1 for comparison with the national values.

At the time the regulation entered into force, hydrogen was not an issue to the gas market, for which reason admissible concentrations of hydrogen were excluded. Due to the current development of PtG-technology, the European Commission has recently remarked in an informal staff working document on energy storage that “Hydrogen can be blended in the natural gas infrastructure up to a certain percentage (between 5-20 percent by volume, as demonstrated by the EC research project NaturalHy (…) the relevant regulations on gas quality and limits of hydrogen at EU level could define safe levels of hydrogen in the natural gas infrastructure and enable the transfer of the low-carbon value of variable renewable energy sources between the electricity and the gas networks” [16].

Being aware of these developments, but unable to find consensus on a definite and uniform parameter on the volume of hydrogen in natural gas system, the Technical Committee and CEN members have adopted an informative Annex E on hydrogen to standard EN 16726. This Annex refers to a study by the European Gas Research Group (GERG) which shows that an admixture of up to 10 percent by volume of hydrogen is safe and technically possible in certain parts of the natural gas system [17]. Annex E recommends a case by case analysis depending on the local (storage) infrastructure and possible end-use. Regarding gas turbines, the Annex states that minor modifications to currently installed turbines could result in an acceptable hydrogen concentration volume of 5 percent. For new or upgraded turbines, the concentration volume could be up to 15 percent according to Annex E.

3.2 Legal Framework for gas quality in Germany, Italy and Switzerland

In Germany, hydrogen and SNG produced through power-to-gas can be classified as biogas under the Energy Industry Act (*Energiewirtschaftsgesetz* – hereafter “EnWG”) and the Gas Network Access Regulation (*Gasnetzzugangsverordnung*) – hereafter “GasNZV”) when the electricity and carbon originate predominantly from renewable sources within the meaning of Directive 2009/28/EC (the 2009 Renewable Energy Directive). Article 36(1) of the GasNZV requires that in-feeders of biogas ensure that the gas at the entry-point and during injection complies with the gas quality specifications in worksheets G 260 and G 262 of 2007 issued by the German Association for Gas and Water (Deutscher Verein des Gas- und Wasserfaches, hereafter “DVGW”).

With the Legislative Decree No. 28/2011, implementing Directive 2009/28/EC, the Italian legislation also allows SNG to be treated as renewable gas, namely as “biomethan”. Pure hydrogen, however, does not seem to be covered under this definition, as this does not have the same characteristics and usage conditions as natural gas. Article 20 of Legislative Decree No. 28/2011 requires the Italian Regulatory Authority for Electricity Gas and Water (L'Autorità di Regolazione per Energia Reti e Ambiente, or ARERA – former known as the Italian Authority for Electricity and Gas, or AEEG → AEEG/ARERA) to publish technical and economic conditions for the connection of biomethane production plants to the gas networks. The Italian standardisation organisation UNI published the UNI EN 16723-1, which transposed the European standard into an Italian standard, and the technical report UNI-TR 11537 "*Injection of biomethane in the natural gas transportation and distribution networks*". Both define the gas quality specifications for Italian gas grids.

As Switzerland is not a member of the EU, its gas market is not as regulated as that of member states such as Germany and Italy. Many explicit rules for the gas sector are established by industry agreements under Swiss private law [18]. This may change in the future due to the announced Gas Supply Act (*Gasversorgungsgesetz*), the text of which is expected to be published in 2019. It would be recommended that this Act affirms the extent that Swiss gas legislation also applies to alternative gases from a renewable source. Because at the moment the Federal Pipeline Ordinance, adopted by the Federal Council, only applies to pipelines for the transportation of liquid or gaseous fuels, hydrocarbons or hydrocarbon mixtures such as crude oil, natural gas, refinery gases, petroleum distillates or liquid residues of petroleum refining [19]. This scope is broad enough to cover hydrocarbons from a renewable origin such as SNG. But more uncertainty exists about the application of the private industry agreements to other gases than natural gas, as they merely use the term "Erdgas" (natural gas). However, there is a definition of renewable gases such as biogas or SNG, provided under Directive G13 on the "Injection of Renewable Gases" issued by the Swiss Gas and Water Industry Association (Schweizerische Verein des Gas- und Wasserfaches, hereafter "SVGW") [45]. Equally important for SNG are SVGW Directives G18 (gas quality in the natural gas grid) and G11 (Odorisation). It is possible to inject gases which are not compliant with SVGW Directives G18 and G13 by admixing these to the gas which flows through the gas network. As a minimum requirement, the injected gas must consist at least for 50% out of combustible components. Furthermore, the injected gas must be able to mix into the available gas stream so that the gas is compliant at the first exit point of a consumer. The maximum amount of renewable gas to be injected is then thus determined by the composition of the gas mixture after the entry point and before the first consumer exit point.

The specifications with which a renewable gas must comply in order to be allowed to be injected to an unlimited extent into the gas grids of each country are provided in Table 3-1.The values in the table only give an indication of certain gas quality specifications. The legal conditions for individual values may, however, be different under specific circumstances.

Table 3-1: Gas quality specifications
Source: DBI – own illustration, data from [10, p. 9], [11], [14]

Parameter	**Unit** (1)	**EU**	**Germany** (2)	**Italy** (3)	**Switzerland** (4)
Wobbe Index	MJ/Nm3	45.7 – 54.7	46.1 – 56.5	47.31 – 52.33	47.88 – 56.52
	kWh/Nm³	12.7 – 15.2	12.8 – 15.7	13.1 – 14.5	13.3 – 15.7
Calorific Value	MJ/Nm3	-	30.2 – 47.2	34.95 – 45.28	38.16 – 47.16
	kWh/Nm³	-	8.4 – 13.1	9.7 – 12.6	10.6 – 13.1
Relative Density		0.555 – 0.7	0.55 – 0.75	0.5548 – 0.8	0.5 – 0.7
Carbon Dioxide	% mol	≤ 2.5 to 4	≤5	≤ 3	<5
Methane	% mol	≥ 65	≥ 95	(5)	≥ 96
Oxygen	% mol	≤ 3	≤ 3	≤ 0.6	≤ 3
Carbon Monoxide	% mol	-	-	≤ 0.1	≤ 3
Hydrogen content	% mol	-	≤ 10 (6)	≤ 0,5	≤ 2
Hydrogen Sulphide	mg/(S/N)m3	≤ 5	≤ 5	≤ 6.6	≤ 5
Sulphur from mercaptans	mg/(S/N)m3	≤ 6	≤ 6	≤ 15.5	≤ 5
Total Sulphur without (with) odorant	mg/(S/N)m3	20 (30)	≤ 30 Avg/y	≤ 150	-
Hydrocarbon Dew Point	°C (up to 70 bar)	-2	-2	≤ 0	-
Water dew point	°C (at 70 bar)	-8	-	-	-

(1) The Italian technical rules make reference to Sm_3 (standard cubic meter), Germany and Switzerland use Nm_3 (norm cubic meter).
(2) DVGW Worksheets G260 and G262
(3) UNI EN 16723-1 and UNI/TR 11537
(4) SVGW Worksheets G13 and G18
(5) The acceptable value is intrinsically linked with the acceptable range of the Wobbe Index
(6) This is the advised maximum level. System operators are allowed to apply lower levels depending on local circumstances.

3.3 Gas quality of PtG plants and necessary gas treatment

The most important gas parameters of the demo plants are summarized in Table 3-2. Their positions in the aforementioned legal framework are shown in Figure 3-1 to Figure 3-4.

It should be noted that at the time of writing this Deliverable, the plants are not yet working at full capacity for test purposes, and that the methane concentrations can be increased by utilizing all technical possibilities.

Table 3-2: Relevant actual average gas parameters of the SNG
Source: DBI – own illustration, data from project partners

Parameter	Unit	Falkenhagen	Solothurn	Troia
CH_4 concentration	% mol	**98.6**	**90.1 ±1.09**	**97.3**
H_2 concentration	% mol	**1.2**	**9.2 ±1.06**	**2.7**
CO_2 concentration	% mol	**0.6**	**0.0**	**0.0**
Wobbe index W_S	kWh/Nm³	14.672	14.467	**14.762**
Calorific value H_S	kWh/Nm³	10.952	10.295	**10.875**
Relative density d	-	0.557	0.506	**0.543**

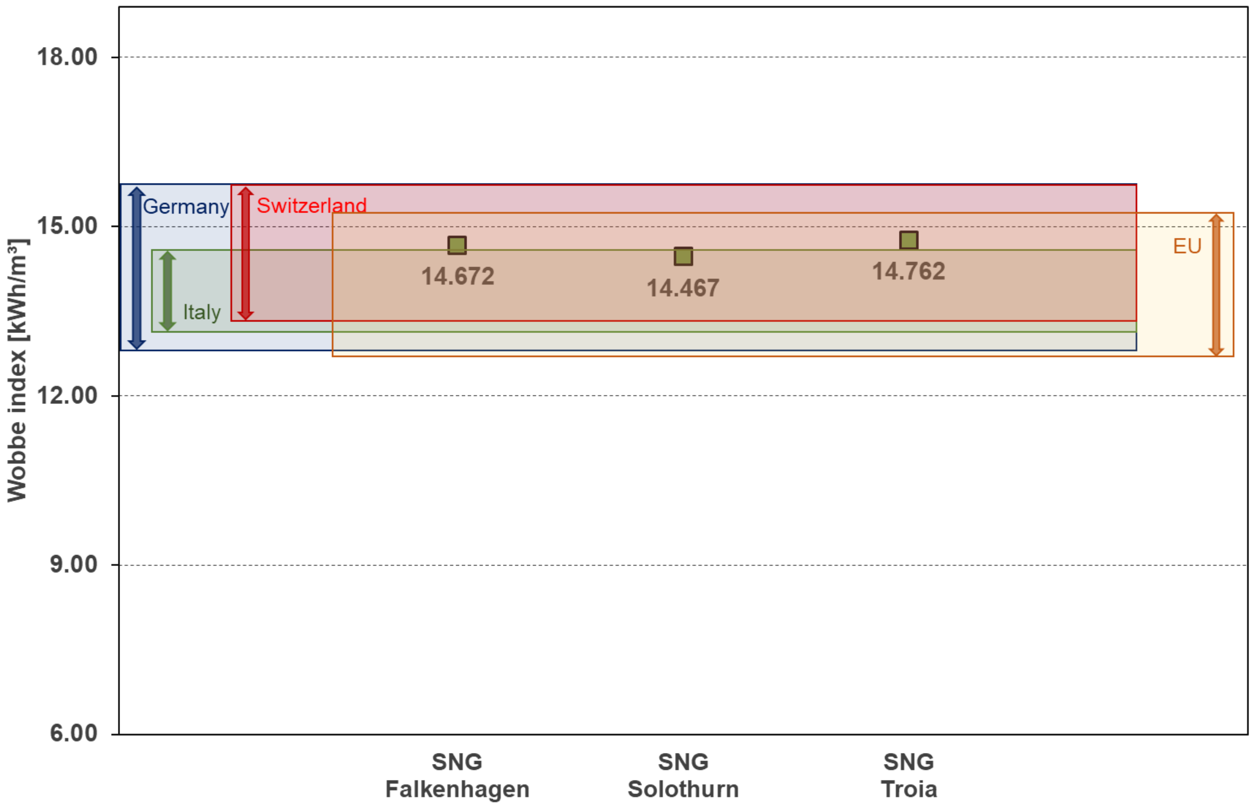

Figure 3-1: Limits of Wobbe Index
Source: DBI – own illustration, data from project partners, [10, p. 9], [11], [14]

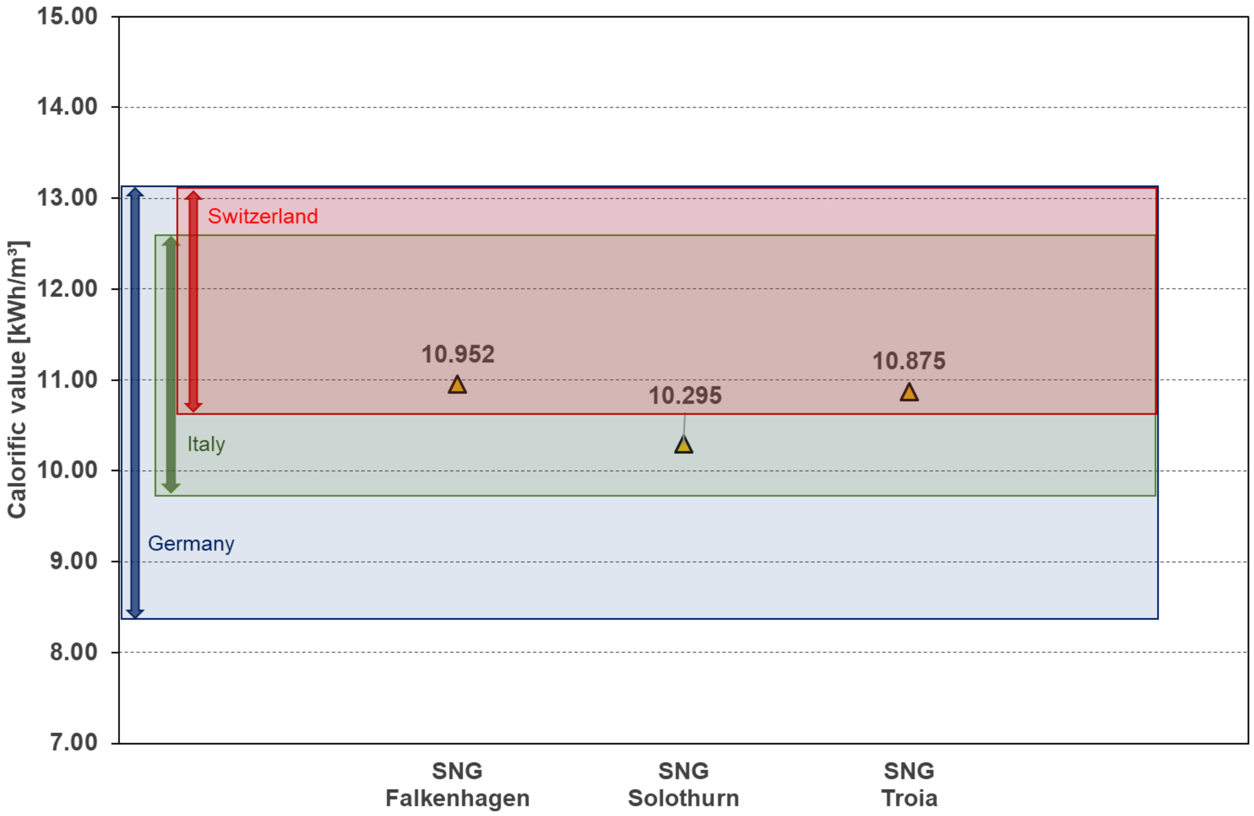

Figure 3-2: Limits of calorific value
Source: DBI – own illustration, data from project partners, [10, p. 9], [11], [14]

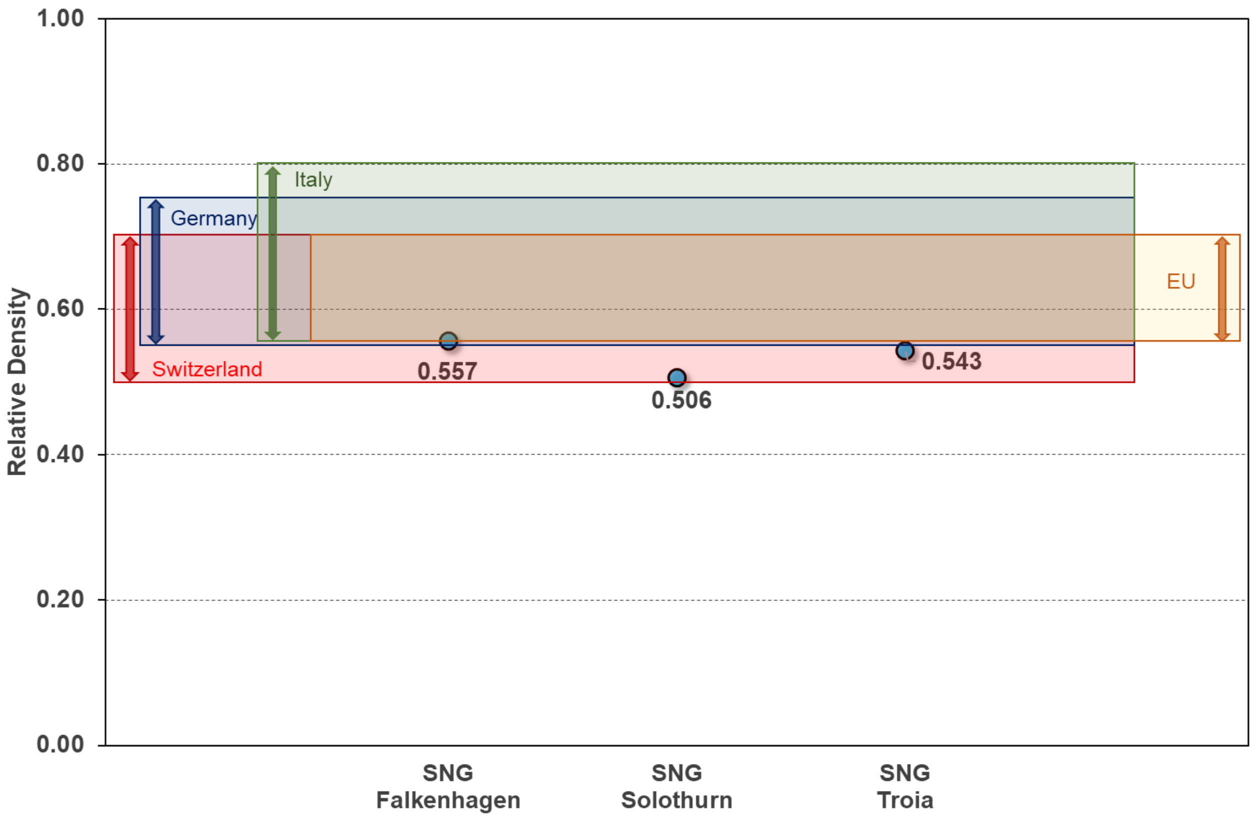

Figure 3-3: Limits of relative density
Source: DBI – own illustration, data from project partners, [10, p. 9], [11], [14]

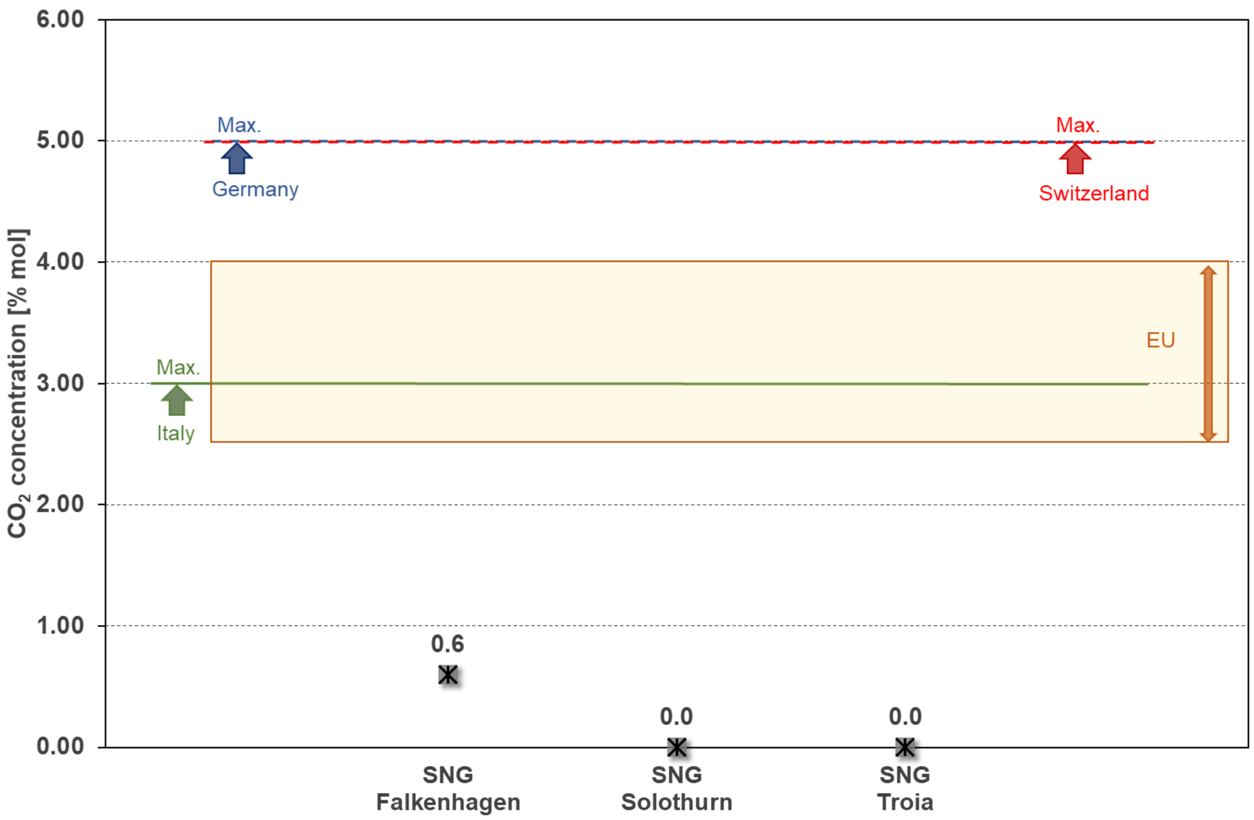

Figure 3-4: Maximum permitted CO_2 concentrations
Source: DBI – own illustration, data from project partners, [10, p. 9], [11], [14]

For the most part, the values are within the limits. As the methane concentration can be raised with all technologies used at the demo plants, no relevant demand for gas treatment is assumed for all demo plants and their economic analysis renounced with here.

4 Technical analysis of injection systems

This chapter is a summary of the results from Deliverable D5.7 and presents various ways in which grid operation of gas grids can be adapted or optimized to increase the installable power of PtG plants and reduce the energy demand of SNG compression.

The Interface of this examination is the output of the demo plants to the respective test grids.

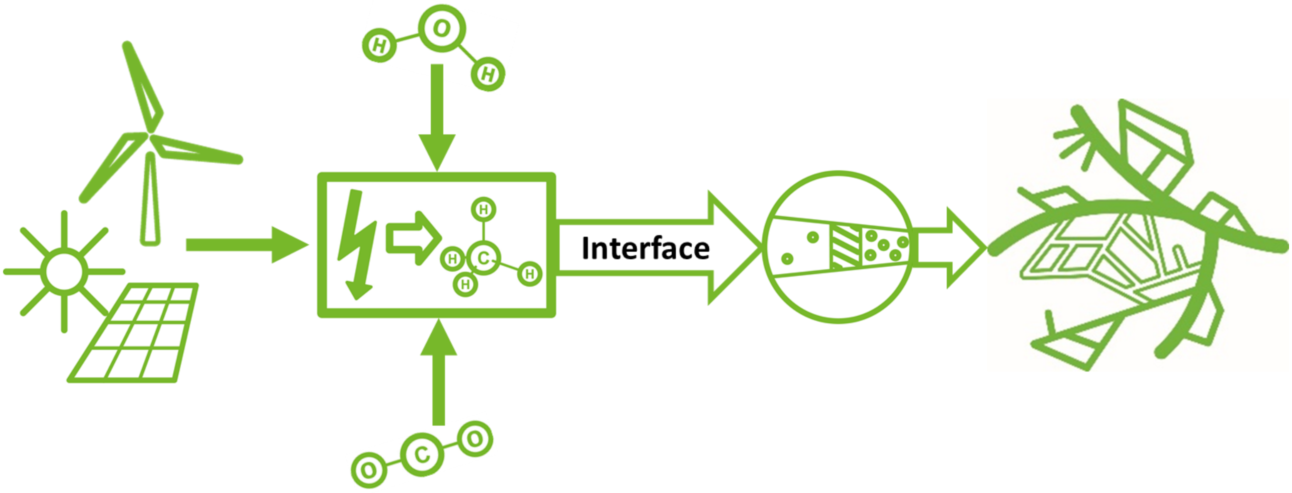

Figure 4-1: System diagram
Source: DBI – own illustration

4.1 Energy demand of SNG compression

Depending on the operating pressure of the methanation plant and the outlet pressure of the PtG plant, the produced SNG possibly will require further compression to be injected into a gas grid at its current OP. If the outlet pressure of the plant is higher or equal than the gas grid's possible operating pressures, SNG compression is not required.

The mechanical drive power P_{mech} for gas compression from the outlet pressure of the PtG plant p_1 to the current operating pressure of the gas grid p_2 can be written as follows:

$$P_{mech} = \frac{\dot{m} \cdot w_{t\,real}}{\eta_{eff}} = \frac{1}{\eta_m \cdot \eta_{is}} \cdot \dot{V}_n \cdot p_n \cdot \frac{T_1}{T_n} \cdot \frac{\kappa}{\kappa - 1} \cdot \left[\left(\frac{p_2}{p_1} \right)^{\frac{\kappa - 1}{\kappa}} - 1 \right] \cdot Z_1 \qquad (4\text{-}1)$$

P_{mech}	Mechanical drive power of compressor
$\dot{m}$	Mass flow
$w_{t\,(real)}$	(Real) specific compression work
η_{eff}	Effective efficiency of compressor
η_{is}	Isentropic efficiency of compressor
η_m	Mechanical efficiency of compressor
$\dot{V}, \dot{V}_n$	Volume flow, standard volume flow at p_n, T_n
p, p_n	Pressure, standard pressure (1.01325 bar)
T, T_n	Temperature, standard temperature (273.15 K)
T_1	Temperature before compression
κ	Isentropic exponent
p_1	Pressure before compression
p_2	Pressure after compression
Z_1	Compressibility factor of gas before compression

In this report, a constant overall efficiency of 0.78 and an isentropic gas compression (without gas cooling) is assumed for all calculations of energy demand. The volume flow and the pressure ration are the main influencing variables in this calculation. A detailed derivation can be found in [2]. Figure 4-2 shows the required mechanical power depending on the pressure ratio for exemplary volume flows.

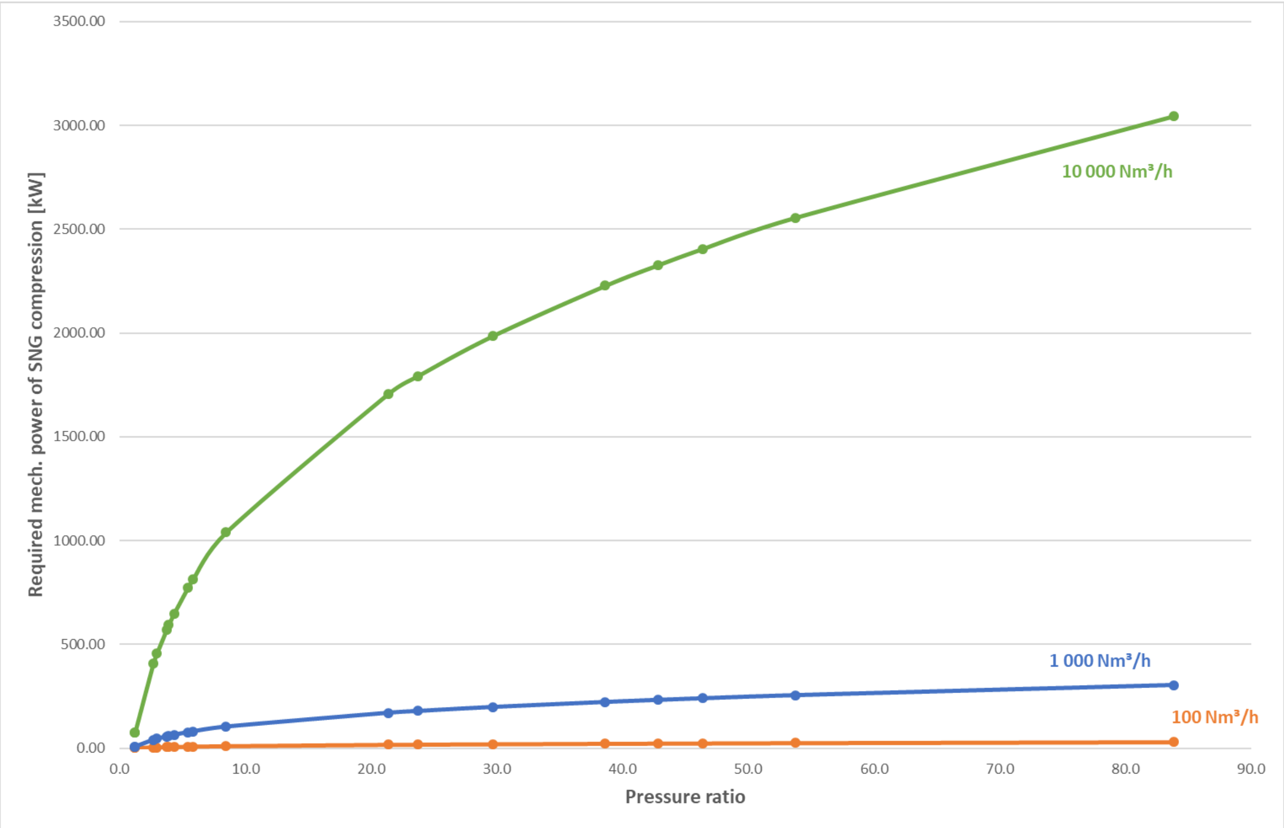

Figure 4-2: Mechanical Power of SNG compression depending on the pressure ratio
Source: DBI – own illustration

4.2 Evaluation of combinations of PtG plants and test grids for the current demonstration plant designs

A fundamental issue of the injection of renewable gases is the question whether the gas grid can accommodate the injected gas or not.

Table 4-1 shows the factor which is required to scale the PtG system output up or down in order to substitute the base load of natural gas (minimum load of the grid) at the actual plant sizes. If the nominal output of the PtG plant is less or equal than the minimum load of the respective grid, then SNG can be fed in throughout the year (scaling factor ≥ 1), otherwise the plant must operate in part load or be switched off temporarily (scaling factor < 1). The scaling factor indicates how many times the nominal SNG output of the plant can be accommodated by the minimum load of the grid.

It should be noted that the minimum loads of the test grids in Table 2-2 refer to the calorific value of Russian natural gas (11.186 kWh/Nm³). But the scaling factors were calculated using minimum loads referring to the respective calorific values of the demo plants. Therefore, they would slightly differ from the results if the values of Table 2-3 were used.

Table 4-1: Scaling factors per combination of PtG plant and grid
Source: DBI – own illustration, data from [3], [4], [5], [6], [7], [9, p. 7], [8], [10, p. 9], [11]

		Scaling factor = min. load of grid / nominal SNG output		
Grid structure	**min. load** [Nm³/h]	**Falkenhagen** (52.5 Nm³/h)	**Solothurn** (30 Nm³/h)	**Troia** (11.8 Nm³/h)
OPAL TP	475 323	9 555 ✓	16 368 ✓	41 471 ✓
Transitgas TP	137 033	2 755 ✓	4 719 ✓	11 956 ✓
Ontras TP	10 000	201 ✓	344 ✓	872 ✓
Reg. distrib. net.	61 638	636 ✓	1 089 ✓	2 760 ✓
Urban distrib. net.	34	1.3 ✓	2.2 ✓	5.6 ✓
Rural distrib. net.	7	0.1 ✗ (✓)	0.2 ✗ (✓)	0.6 ✗ (✓)

✓ = min. load ≥ SNG output, ✗ = min. load < SNG output, (✓) = part load possible

The comparison of the operating pressures of the demo plants and the different test grids is the main indicator for compression effort. Table 4-2 shows the pressure ratio. For a ratio less or equal to 1 compression is not required before injecting the SNG into the gas grid. Transmission networks typically have higher operating pressures than distribution networks, hence, the pressure ratio increases according to the network level and in dependency of the outlet pressure of the respective plant which has a significant influence.

Table 4-2: Pressure ratio between the average OP of a grid and the OP of a PtG plant
Source: DBI – own illustration, data from [3], [4], [5], [6], [7], [9, p. 7], [8]

		Pressure ratio OP_{grid} / OP_{PtG} [abs. pressures]		
Grid structure	**OP** (average)	**Falkenhagen** (15 bar)	**Solothurn** (10 bar)	**Troia** (3 bar)
OPAL TP	92.3 bar	5.8 ✓	8.5 ✓	23.3 ✓
Transitgas TP	58.8 bar	3.7 ✓	5.4 ✓	14.9 ✓
Ontras TP	46.7 bar	3.0 ✓	4.3 ✓	11.9 ✓
Reg. distrib. net.	42.0 bar	2.7 ✓	3.9 ✓	10.7 ✓
Urban distrib. net.	0.35 bar	0.1 ✓	0.1 ✓	0.3 ✓
Rural distrib. net.	0.35 bar	0.1 ✓	0.1 ✓	0.3 ✓

✓ = no compression effort, ✓ = moderate compression effort, ✓ = high compression effort

All plants do not need compression for the urban and rural distribution network because their operating pressure is above the grid pressure. For the high-pressure test grids, the Falkenhagen and Solothurn plants indicate a moderate compression effort, whereas the effort for the Troia plant is high because it has a much lower operating pressure.

4.3 Adjustment and optimisation of network operation of gas grids

To assess the effect of different network operation schemes in comparison to a status quo, the status quo is defined for PtG plant sizes (SNG output) which perfectly match the minimum load of the respective test grid. Therefore, the current system output of each plant is multiplied by the scaling factors of Table 4-1.

4.3.1 Reduction of energy demand of SNG compression

A reduction of energy demand of gas compression can be obtained by lowering the grid's operating pressure. In gas distribution networks the actual pressure is typically only known at its entry point(s) where it is equal to the constant set pressure of the gas pressure regulator station (GPRS). This applies particularly for local distribution networks. The pressure at the so-called point of lowest pressure (PLP) is unknown and its value varies in dependency of the load somewhere above the allowed minimum p_{min}.

If the information of the currently lowest occurring pressure in the grid would be made available by pressure measurements at all possible PLP, the set pressure of the GPRS could be adjusted or controlled in such a way that the pressure at the PLP remains at a minimum.

Instead of holding the outlet pressure of the GPRS constantly on the level of its set pressure (conventional network operation) while having a variable pressure at the PLP, the set pressure of the GPRS will be readjusted by adding the measured deviation from the allowed minimum pressure at the PLP to the value of the previous set pressure.

In large transmission pipelines the expected pressure reduction can account for several bar, while it reaches values of a few to some hundred millibar in local distribution networks. The effects regarding the energy demand for compression are shown in Table 4-5.

4.3.2 Capacity increasing optimisations

An increase of the installable PtG system output can be achieved by using the dynamic storage capacity of the gas grid. This can be done in two ways.

The first way is the active utilisation of the so-called linepack. Decisive for the gas content of pipelines is the geometric volume (length and inner diameter) and the operating pressure of the gas grid, which can vary between the allowed minimum and maximum operating pressure (MOP) in dependency of the load and location within a pipeline.

The linepack at standard temperature and pressure (STP) can be calculated according to Equation (4-2) by integration of the operating pressure over the length of the pipeline and multiplication with its geometric volume. The gas law deviation factor K considers real gas behaviour.

$$V_{LP} = V_{geo} \cdot \frac{T_n}{p_n \cdot K_m \cdot T \cdot l} \cdot \int_0^l p(x)dx \tag{4-2}$$

V_{LP}	Gas content of linepack
V_{geo}	Geometric pipeline volume
T, T_n	Temperature (of gas), standard temperature (273.15 K)
p, p_n	Pressure, standard pressure (1.01325 bar)
K_m	Mean gas law deviation coefficient
l	Length of pipeline
x	Position along pipeline

Summarised briefly, the ability of a gas grid or pipeline to store gas depends on its load, geometric pipeline volume and the available pressure difference between OP and MOP.

The location of the PtG plant has an influence on the pressure gradient as it effectively works like a substitution of the normal entry point in shorter distance to the exit point. This primarily becomes relevant for long pipelines wherefore the injection of the PtG plant into the test grids is located halfway between beginning and end of a pipeline or section of it (OPAL TP, Transitgas TP, Ontras TP) and centrally in the regional gas distribution network. Furthermore, utilisation of linepack is ineffective for low pressure distribution networks (20 – 100 mbar), because of the small available pressure differences.

An alternative way of making further accommodation capacities accessible or supplementing active linepack utilisation is the feedback of gas to superimposed networks or in the case of an advantageous location of the PtG plant the bidirectional injection into different network levels.

Gas can be fed back whenever the subordinate gas network reaches its capacity limit and there is free capacity in the superimposed network. In combination with active linepack utilisation the feedback plant (compressor) will be activated when the MOP of the subordinate grid is reached and can remain in operation for a maximum of time until the pressure of the superimposed network increases to MOP level.

In this case a PtG plant can be designed for SNG flows beyond the capacity limit of the respective gas grid at minimum load or at linepack utilisation. Even at higher loads the PtG plant can proceed longer supplying the subordinate grid completely with renewable gas.

To enable the feedback option a compressor / compressor station with the compression power to reach the OP or MOP of the superimposed network is required. The total installable system output of the PtG plant then depends on the sum of the accommodation capacities of both gas grids. Gas feedback in particular can be an attractive solution for distribution networks.

4.3.3 Results of the optimizations

If the optimization options mentioned above are applied individually or in combination to the different test grids, the possible SNG outputs listed in Table 4-3 result.

Table 4-3: Possible SNG outputs of different network operation schemes

Source: DBI – own illustration, data from [2]

Test grid	Operation scheme	SNG output [kW]		Test grid	Operation scheme	SNG output [kW]
OPAL TP	Typical OP (status quo)	5 317 203		Reg. distrib. net.	Typical OP (status quo)	353 918
	OP reduction	5 317 203			OP reduction	353 918
	Typical OP + LP	10 627 235			Typical OP + LP	729 434
	OP reduction + LP	20 840 464			OP reduction + LP	750 635
Transitgas TP	Typical OP (status quo)	1 532 917		Urban distrib. net.	Typical OP (status quo)	713
	OP reduction	1 532 917			OP reduction	713
	Typical OP + LP	1 619 767			Typical OP + LP	919
	OP reduction + LP	1 763 208			OP reduction + LP	975
Ontras TP	Typical OP (status quo)	111 865		Rural distrib. net.	Typical OP (status quo)	77
	OP reduction	111 865			OP reduction	77
	Typical OP + LP	251 131			Typical OP + LP	273
	OP reduction + LP	258 066			OP reduction + LP	317

The annual output of the demo plants for all operation schemes is listed in Table 4-4 and the energy demand of compression per injected m³ is shown in Table 4-5.

The values in parentheses show the relative decrease (arrow down) or increase (arrow up) of the energy demand in relation to the status quo.

Table 4-4: Annual SNG outputs of different network operation schemes
Source: DBI – own illustration, data from [2]

Grid structure	operation scheme	Effective injectable energy [TWh/a]		
		Falkenhagen	**Solothurn**	**Troia**
OPAL TP	Typical OP (status quo)	46	46	45
	OP reduction	46 (↑0.07 %)	46 (↑0.07 %)	45 (↑0.15 %)
	Typical OP + linepack	74 (↑59 %)	74 (↑59 %)	72 (↑59 %)
	OP reduction + linepack	181 (↑292 %)	181 (↑292 %)	177 (↑292 %)
Transitgas TP	Typical OP (status quo)	13	13	13
	OP reduction	13 (↑0.10 %)	13 (↑0.11 %)	13 (↑0.11 %)
	Typical OP + linepack	14 (↑7 %)	14 (↑7 %)	14 (↑7 %)
	OP reduction + linepack	17 (↑30 %)	17 (↑30 %)	17 (↑30 %)
Ontras TP	Typical OP (status quo)	1.0	1.0	1.0
	OP reduction	1.0 (↑0.04 %)	1.0 (↑0.05 %)	1.0 (↑0.08 %)
	Typical OP + linepack	2.2 **(↑124 %)**	2.2 **(↑124 %)**	2.1 **(↑124 %)**
	OP reduction + linepack	2.3 (↑131 %)	2.2 (↑131 %)	2.2 (↑131 %)
Reg. distrib. net.	Typical OP (status quo)	3.1	3.1	3.0
	OP reduction	3.1 (↑0.08 %)	3.1 (↑0.09 %)	3.0 (↑0.16 %)
	Typical OP + linepack	6.4 (↑106 %)	6.4 (↑107 %)	6.3 (107 %)
	OP reduction + linepack	6.6 (↑112 %)	6.6 (↑113 %)	6.5 (↑113 %)
			[GWh/a]	
Urban distrib. net.	Typical OP (status quo)	6.2	6.2	6.2
	OP reduction	6.2 (→0 %)	6.2 (→0 %)	6.2 (↑0.05 %)
	Typical OP + linepack	8.1 (↑29 %)	8.1 (↑29 %)	8.1 (↑30 %)
	OP reduction + linepack	8.5 (↑37 %)	8.6 (↑37 %)	8.6 (↑37 %)
Rural distrib. net.	Typical OP (status quo)	0.7	0.7	0.7
	OP reduction	0.7 (→0 %)	0.7 (→0 %)	0.7 (↑0.05 %)
	Typical OP + linepack	2.4 (↑256 %)	2.4 (↑260 %)	2.4 **(↑261 %)**
	OP reduction + linepack	2.8 (↑313 %)	2.8 (↑314 %)	2.8 (↑315 %)

When using the linepack, the annual output in the high-pressure transmission pipelines can be increased by up to 124 % and in the low-pressure gas distribution networks by up to 261 %.

At a constant calorific value, the volume flow changes in the same ratio and thus also the energy demand for compression.

Table 4-5: Energy demand of compression per injected m³
Source: DBI – own illustration, data from [2]

Grid structure	operation scheme	Energy demand of compression [Wh/m³]		
		Falkenhagen	**Solothurn**	**Troia**
OPAL TP	Typical OP (status quo)	86	112	330
	OP reduction	79 (↓8.2 %)	104 (↓7.1 %)	315 (↓4.7 %)
	Typical OP + linepack	87 (↑1.0 %)	113 (↑0.9 %)	332 (↑0.6 %)
	OP reduction + linepack	80 (↓7.6 %)	105 (↓6.6 %)	316 (↓4.4 %)
Transitgas TP	Typical OP (status quo)	63	86	280
	OP reduction	53 (↓16.5 %)	74 (↓13.7 %)	258 (↓7.9 %)
	Typical OP + linepack	63 (↑0.1 %)	86 (→0.0 %)	280 (→0.0 %)
	OP reduction + linepack	53 (↓16.4 %)	75 (↓13.6 %)	258 (↓7.8 %)
Ontras TP	Typical OP (status quo)	60	68	246
	OP reduction	55 (↓9.1 %)	63 (↓7.1 %)	238 (↓3.6 %)
	Typical OP + linepack	61 (↑0.8 %)	68 (↑0.2 %)	247 (↑0.1 %)
	OP reduction + linepack	55 (↓8.4 %)	63 (↓6.9 %)	239 (↓3.2 %)
Reg. distrib. net.	Typical OP (status quo)	42	62	236
	OP reduction	34 **(↓19.9 %)**	53 (↓15.1 %)	219 (↓7.3 %)
	Typical OP + linepack	43 (↑3.3 %)	64 (↑2.6 %)	239 (↑1.2 %)
	OP reduction + linepack	36 (↓14.4 %)	56 (↓10.8 %)	224 (↓5.2 %)
Urban distrib. net.	Typical OP (status quo)	0	0	0
	OP reduction	0	0	0
	Typical OP + linepack	0	0	0
	OP reduction + linepack	0	0	0
Rural distrib. net.	Typical OP (status quo)	0	0	0
	OP reduction	0	0	0
	Typical OP + linepack	0	0	0
	OP reduction + linepack	0	0	0

By reducing the operation pressure, the energy demand for compression can be reduced in the high-pressure transmission pipelines by up to 19.9 %.

The combination of pressure reduction and linepack has the biggest effect on an increase of the effective injectable energy as additional linepack is made available and compression energy is reduced in phases where linepack is not actively used.

5 Economic analysis of compressor systems

The basis for the economic analysis in this chapter are the results of determining the energy demand of SNG compression for the different operating schemes from D5.7.

5.1 Investment costs for compressor systems

A precise calculation of costs is difficult due to a high number of variables and less consistent sources. The costs essentially depend on the inlet and outlet pressures, the volume flow to be compressed and the resulting drive power. However, several other variables together also have a considerable influence on the costs. These include, for example, the selection of the compressor type (diaphragm compressor, piston compressor, ...), the need for redundancies, the degree of automation and the necessary measurement and control technology.

The following calculations of investment costs are based on the data of the network development plan (*Netzentwicklungsplan Gas* – hereafter "NEP") of German transmission system operators from 2018 [20]. According to the law, this plan must be drawn up by the transmission system operators every two years and includes all construction projects, such as pipelines, GPRS and compressor stations.

Figure 5-1 shows an overview of the costs for different sized compressor stations only depending on their drive power including a trend line for further considerations.

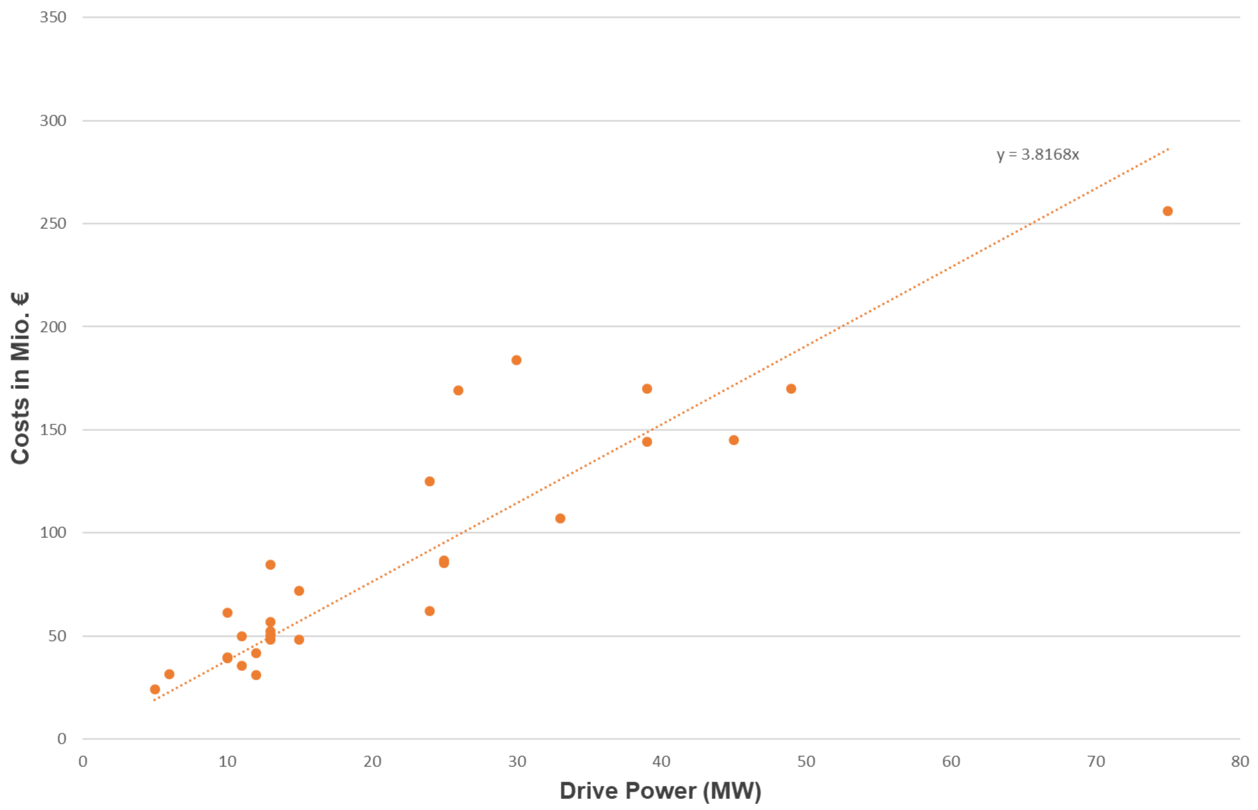

Figure 5-1: Costs of compressor stations in NEP2018
Source: DBI – own illustration, data from [20]

Usually a non-linear development of costs is expected, which implies a decrease of costs per MW with increasing plant size. A more precise database could not be obtained even after extensive research among manufacturers of compressors and planning companies. They explained that it is not possible to make generally valid statements about the price development due to the above mentioned manifold possibilities of designing compressor stations.
It is assumed that there is a cost degression with increasing plant size, but this cannot be quantified for the reasons already mentioned.

However, as such a non-linear trend is not discernible, the costs for the compressor stations for all combinations of demo plants, test grids and operating modes are determined with this linear trend based on the previously calculated energy demand for SNG compression, which is equated here with the drive power. This trend indicates a specific price of 3 816 800 €/MW.

The results regarding the compressor stations for the combinations of demo plants (scaled plant sizes, for details see Table 4-1) and different gas grids are shown in Figure 5-2 and are listed in

Table 5-1.

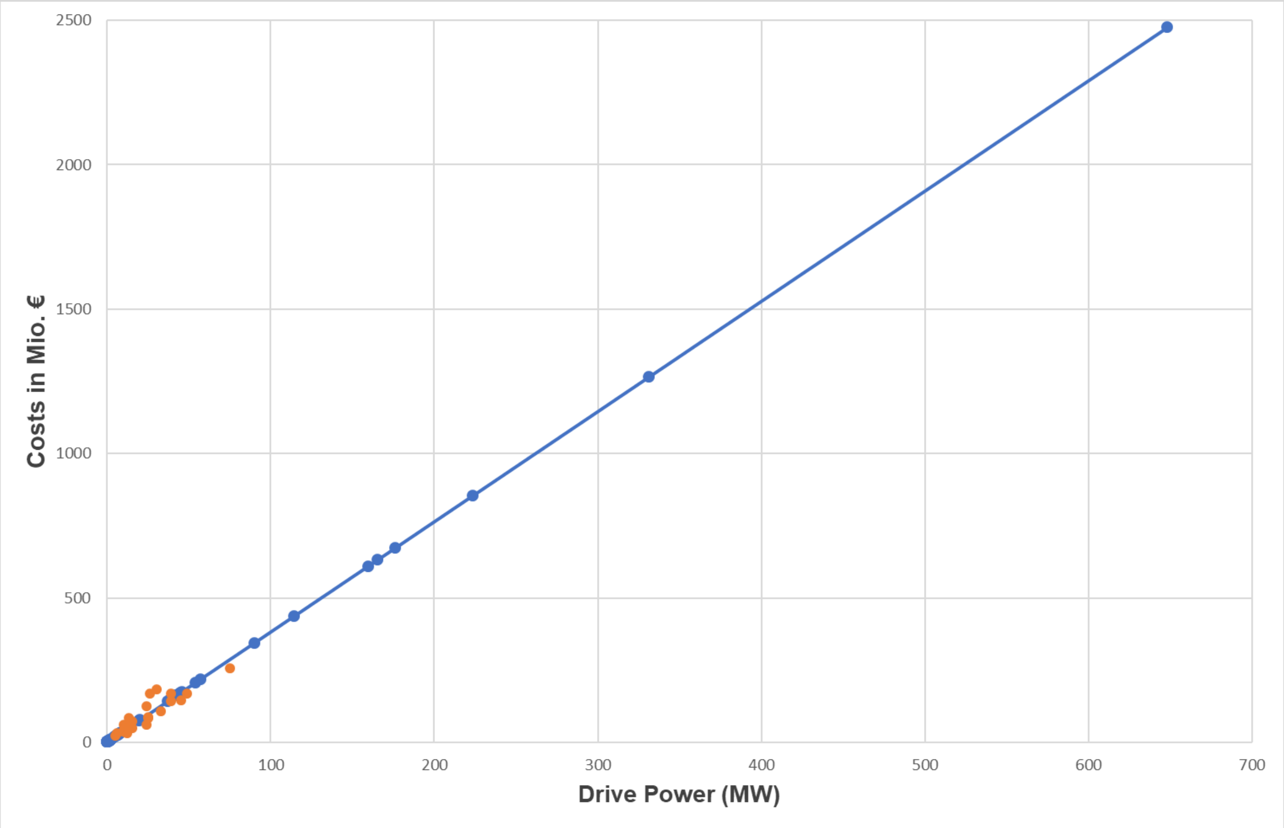

Figure 5-2: Interpolation of investment costs of compressor stations
Source: DBI – own illustration, data from [20]

Taking into account the inaccurate data situation and the assumption of a cost degression, however, a potential for cost savings can be expected here.

Table 5-1: Investment costs for injection systems
Source: DBI – own illustration, data from [2], [20]

Test grid	Operation scheme	Required mech. power of SNG compression [kW]			Investment costs of SNG compression [Mio. €]		
		Falk.	Solo.	Troia	Falk.	Solo.	Troia
OPAL TP	Typical OP (status quo)	44 914	57 032	165 293	**171**	**218**	**631**
	OP reduction	42 358	54 181	159 701	**162**	**207**	**610**
	Typical OP + LP	90 172	114 438	331 253	**344**	**437**	**1 264**
	OP reduction + LP	176 279	223 798	648 377	**673**	**854**	**2 475**
Transitgas TP	Typical OP (status quo)	8 748	11 780	38 760	**33**	**45**	**148**
	OP reduction	7 956	10 902	37 073	**30**	**42**	**142**
	Typical OP + LP	9 795	13 067	42 078	**37**	**50**	**161**
	OP reduction + LP	10 663	14 247	45 814	**41**	**54**	**175**
Ontras TP	Typical OP (status quo)	548	759	2 637	**2.1**	**2.9**	**10**
	OP reduction	505	712	2 550	**1.9**	**2.7**	**10**
	Typical OP + LP	1 478	1 979	6 430	**5.6**	**7.6**	**25**
	OP reduction + LP	1 520	2 035	6 629	**5.8**	**7.8**	**25**
Reg. distrib. net.	Typical OP (status quo)	1 405	2 040	7 679	**5.4**	**7.8**	**29**
	OP reduction	1 126	1 732	7 120	**4.3**	**6.6**	**27**
	Typical OP + LP	4 691	6 207	19 558	**18**	**24**	**75**
	OP reduction + LP	4 828	6 390	20 134	**18**	**24**	**77**
Urban distrib. net.	Typical OP (status quo)	-	-	-	-	-	-
	OP reduction	-	-	-	-	-	-
	Typical OP + LP	-	-	-	-	-	-
	OP reduction + LP	-	-	-	-	-	-
Rural distrib. net.	Typical OP (status quo)	-	-	-	-	-	-
	OP reduction	-	-	-	-	-	-
	Typical OP + LP	-	-	-	-	-	-
	OP reduction + LP	-	-	-	-	-	-

5.2 Operating costs for compressor systems

In this report, only the costs for the compression itself are considered. Costs for maintenance and servicing are not considered, as they are negligible. In addition, they are usually calculated as a percentage of the investment costs of about 1-3%. However, the investment costs are already subject to great uncertainty, such a consideration would not be appropriate.

To calculate the energy costs of SNG compression, an electricity price of 0.10 €/kWh is used in this report for the “balance of plant”.

The plants are assumed to have 8 760 operating hours per year, even if this does not correspond to real operating hours.

Table 5-2 shows the energy demand and costs of SNG compression for the typical operation scheme at actual demo plant size.

Table 5-3, on the other hand, shows the energy demand of SNG compression for scaled plant sizes by using the scaling factors of Table 4-1 and the optimised operation schemes, described in chapter 4.3, and Table 5-4 shows the associated costs.

Table 5-2: Energy demand and operating costs of SNG compression – status quo
Source: DBI – own illustration, data from [2]

Parameter	Falkenhagen	Solothurn	Troia*
Nominal OP of methanation [bar]	15	10	3
Nominal SNG output [Nm³/h]	52.5	30.0	11.8
Calorific value Hs [kWh/Nm³]	10.599	10.829	10.875
Nominal SNG output [kW]	556	325	128
Injectable quantity of SNG per year [MWh/a]	4 875	2 846	1 123
Grid structure	**Required mech. power of SNG compression [kW]**		
OPAL TP	4.7	3.5	2.1
Transitgas TP	2.6	3.3	1.7
Ontras TP	2.7	2.2	1.5
Reg. distrib. net.	2.2	1.9	1.4
Urban distrib. net.	-	-	-
Rural distrib. net.	-	-	-
	Energy demand for SNG compression [kWh/a and % of injectable quantity of SNG]		
OPAL TP	38 843 (0.8 %)	29 005 (1.0 %)	18 000 (1.6 %)
Transitgas TP	27 819 (0.6 %)	21 868 (0.8 %)	14 470 (1.3 %)
Ontras TP	21 666 (0.4 %)	17 892 (0.6 %)	12 961 (1.2 %)
Reg. distrib. net.	19 352 (0.4 %)	16 403 (0.6 %)	12 251 (1.1 %)
Urban distrib. net.	0 (0 %)	0 (0 %)	0 (0 %)
Rural distrib. net.	0 (0 %)	0 (0 %)	0 (0 %)
	Energy costs of SNG compression [€/a]		
OPAL TP	**3 884**	**2 901**	**1 800**
Transitgas TP	**2 782**	**2 187**	**1 447**
Ontras TP	**2 167**	**1 789**	**1 296**
Reg. distrib. net.	**1 935**	**1 640**	**1 225**
Urban distrib. net.	**-**	**-**	**-**
Rural distrib. net.	**-**	**-**	**-**

*simplified calculations

Table 5-3: Energy demand of SNG compression – network optimisation – plant sizes scaled
Source: DBI – own illustration, data from [2]

Test grid	Operation scheme	Injectable quantity of SNG [MWh/a]	Energy demand of SNG compression [MWh/a]			Energy demand of SNG compression [% of injectable SNG]		
			Falk.	Solo.	Troia*	Falk.	Solo.	Troia*
OPAL TP	Typical OP (status quo)	46 578 698	378 114	482 492	761 619	0.81	1.04	1.64
	OP reduction	46 578 698	347 287	448 140	792 312	0.75	0.96	1.70
	Typical OP + LP	93 094 580	778 023	976 593	1 522 210	0.84	1.05	1.64
	OP reduction + LP	182 562 468	1 369 802	1 766 017	2 978 509	0.75	0.97	1.63
Transitgas TP	Typical OP (status quo)	13 428 354	76 635	103 189	176 280	0.57	0.77	1.31
	OP reduction	13 428 354	69 693	95 503	186 098	0.52	0.71	1.39
	Typical OP + LP	14 189 157	81 612	109 817	186 267	0.58	0.77	1.31
	OP reduction + LP	15 445 706	80 771	110 794	202 869	0.52	0.72	1.31
Ontras TP	Typical OP (status quo)	979 937	4 358	6 164	11 411	0.44	0.63	1.16
	OP reduction	979 937	3 960	5 725	11 907	0.40	0.58	1.22
	Typical OP + LP	2 199 906	9 809	13 865	25 617	0.45	0.63	1.16
	OP reduction + LP	2 260 659	9 169	13 244	26 393	0.41	0.59	1.17
Reg. distrib. net.	Typical OP (status quo)	3 100 323	12 308	17 870	34 021	0.40	0.58	1.10
	OP reduction	3 100 323	9 862	15 177	37 702	0.32	0.49	1.22
	Typical OP + LP	6 389 844	26 216	37 896	70 117	0.41	0.59	1.10
	OP reduction + LP	6 575 559	22 349	33 917	72 184	0.34	0.52	1.10
Urban distrib. net.	Typical OP (status quo)	6 247	-	-	-	-	-	-
	OP reduction	6 247	-	-	-	-	-	-
	Typical OP + LP	8 053	-	-	-	-	-	-
	OP reduction + LP	8 537	-	-	-	-	-	-
Rural distrib. net.	Typical OP (status quo)	671	-	-	-	-	-	-
	OP reduction	671	-	-	-	-	-	-
	Typical OP + LP	2 388	-	-	-	-	-	-
	OP reduction + LP	2 773	-	-	-	-	-	-

*simplified calculations

Table 5-4: Operating costs of SNG compression – network optimisation – plant sizes scaled
Source: DBI – own illustration, data from [2]

Test grid	Operation scheme	Energy costs of SNG compression [Mio. €/a]			Percentage share of the assumed investment costs [%]		
		Falk.	Solo.	Troia*	Falk.	Solo.	Troia*
OPAL TP	Typical OP (status quo)	**37.81**	**48.25**	**76.16**	22	22	12
	OP reduction	**34.73**	**44.81**	**79.23**	21	22	13
	Typical OP + LP	**77.80**	**97.66**	**152.22**	23	22	12
	OP reduction + LP	**136.98**	**176.60**	**297.85**	20	21	12
Transitgas TP	Typical OP (status quo)	**7.66**	**10.32**	**17.63**	23	23	12
	OP reduction	**6.97**	**9.55**	**18.61**	23	23	13
	Typical OP + LP	**8.16**	**10.98**	**18.63**	22	22	12
	OP reduction + LP	**8.08**	**11.08**	**20.29**	20	21	12
Ontras TP	Typical OP (status quo)	**0.436**	**0.62**	**1.14**	21	21	11
	OP reduction	**0.396**	**0.572**	**1.19**	21	21	12
	Typical OP + LP	**0.981**	**1.39**	**2.56**	18	18	10
	OP reduction + LP	**0.917**	**1.32**	**2.64**	16	17	11
Reg. distrib. net.	Typical OP (status quo)	**1.23**	**1.79**	**3.40**	23	23	12
	OP reduction	**0.986**	**1.52**	**3.77**	23	23	14
	Typical OP + LP	**2.62**	**3.79**	**7.01**	15	16	9
	OP reduction + LP	**2.23**	**3.39**	**7.22**	12	14	9
Urban distrib. net.	Typical OP (status quo)	-	-	-	-	-	-
	OP reduction	-	-	-	-	-	-
	Typical OP + LP	-	-	-	-	-	-
	OP reduction + LP	-	-	-	-	-	-
Rural distrib. net.	Typical OP (status quo)	-	-	-	-	-	-
	OP reduction	-	-	-	-	-	-
	Typical OP + LP	-	-	-	-	-	-
	OP reduction + LP	-	-	-	-	-	-

*simplified calculations

The values are shown in Figure 5-3. Considering all operating schemes, a linear trend is obtained for each demo plant, from which specific costs per injected quantity of SNG can be derived (indicated in color in the diagram).

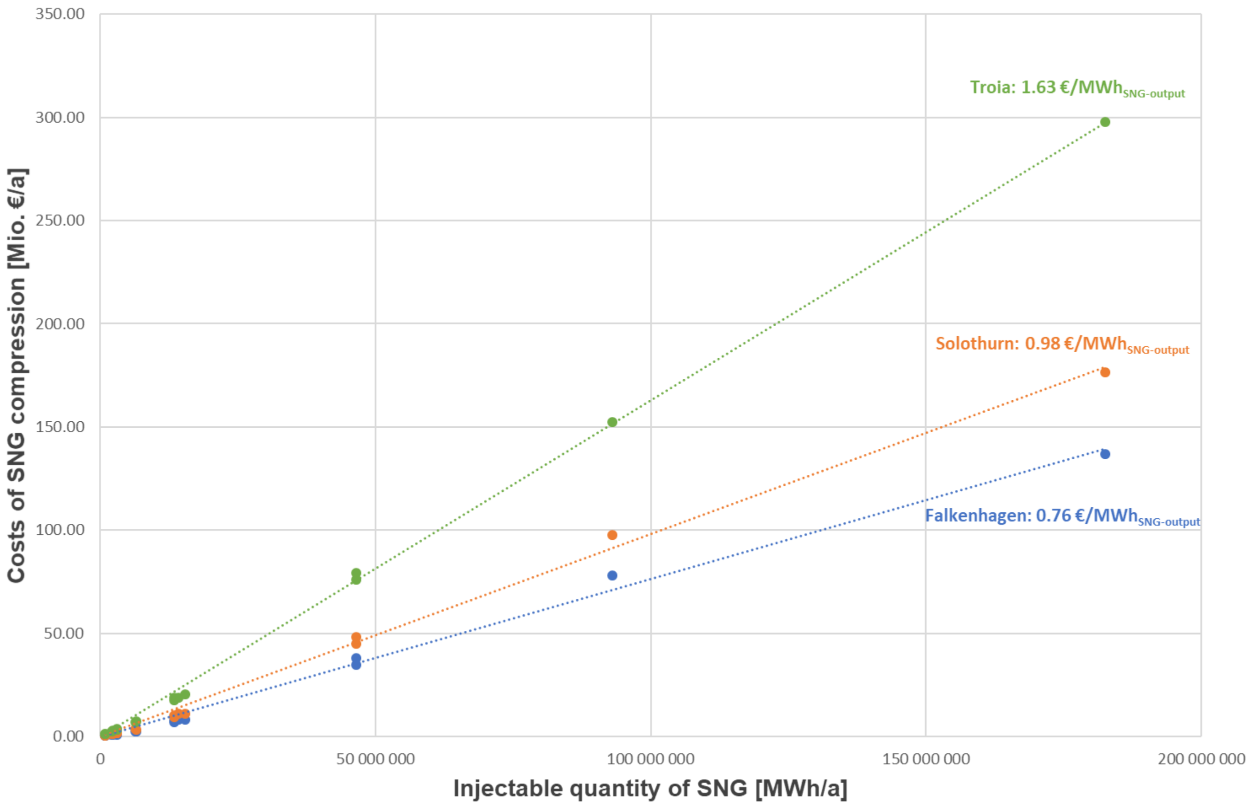

Figure 5-3: Specific operational costs for injected quantities of SNG
Source: DBI – own illustration, data from [2]

These specific costs increase as the pressure ratio increases, which is why they are highest for the Troia demo plant and lowest for the Falkenhagen demo plant.

Table 5-4 also shows the percentage share of annual operating costs in the investment costs estimated in this report. If the operating hours are assumed to be lower, the percentage is reduced accordingly. Consequently, the investment costs are the more relevant factor for a cost consideration in the construction of compressor stations. Following this project, the data situation must be improved in order to be able to make more accurate forecasts.

5.3 Required additional investments due to automation

This optimised network operation schemes require, besides pressure measurements at various points, a suitable data transmission system, an electric motor at the gas pressure regulator and a computing unit for the GPRS, which enables remote-controlled adjustments of the set pressure. It must be considered that remote-controlled gas pressure regulators or – in the case of transmission pipelines – compressor stations usually only exist in transmission or larger regional distribution networks, while GPRS in local distribution networks typically are adjusted manually and therefore would require a retrofit.

However, the investment costs will not be considered in this report due to the variety of equipment options for the GPRS.

6 Brief supplement: Technical Storage Potential at EU Level

This chapter provides a short overview of the technical storage potential of the natural gas system in Europe. SNG from PtG-/methanation-plants can be injected into the natural gas grids basically without any constraints regarding gas quality. Therefore, the storage potential of the natural gas system with its connected underground gas storages is open for transporting and storing SNG as well.

The storage capacity of the gas grid itself is called linepack and depends mainly on the minimum and maximum pressure. The effects of using the linepack for different types of gas grids are shown in chapter 4.3. As the linepack is more of an intermediate storage for hours or a few days, long term storage requires the large storage capacities of the underground gas storages.

There are basically two different groups underground storages: cavern storage facilities and porous storage facilities. The kind of storage facilities in an area depends mainly on the geological aspects. While underground storage of hydrogen is, at the present state of the art, mainly possible in cavern storage facilities, SNG can be stored in both kinds of storages. Figure 6-1 shows the partition of storage capacities among European countries with underground gas storage and planned or under construction capacities.

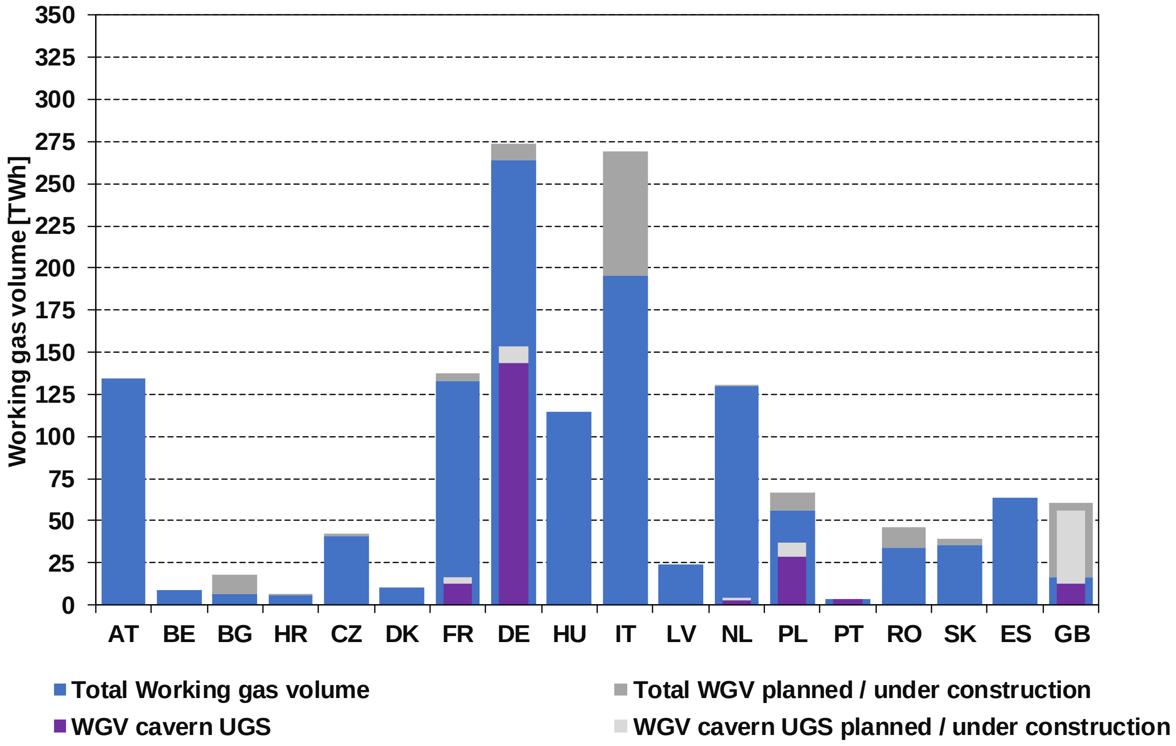

Figure 6-1: Working gas volume of gas storage in EU-28 countries
(countries without underground gas storages are not shown here)
Source: DBI – own illustration, data from [21]

The current storage capacity of the EU-28 countries is about 1 100 TWh with an injection capacity of 11 632 GWh/d and a withdrawal capacity of 20 169 GWh/d [22]. About 200 TWh of the installed capacity comes from cavern storage facilities. Most of the storage capacities are located in Germany, Great Britain and Italy are planning the largest expansion of cavern storage. According to the current plans, the total capacity of cavern storage facilities will be nearly doubled to 390 TWh until 2025, resulting in an overall gas storage capacity of about 1 300 TWh [21]. That corresponds to a share of about 25 % of the current yearly gas consumption of EU-28.

The share of available storage capacities in proportion to gas consumption differs from the European average, as shown in the following Figure 6-2.

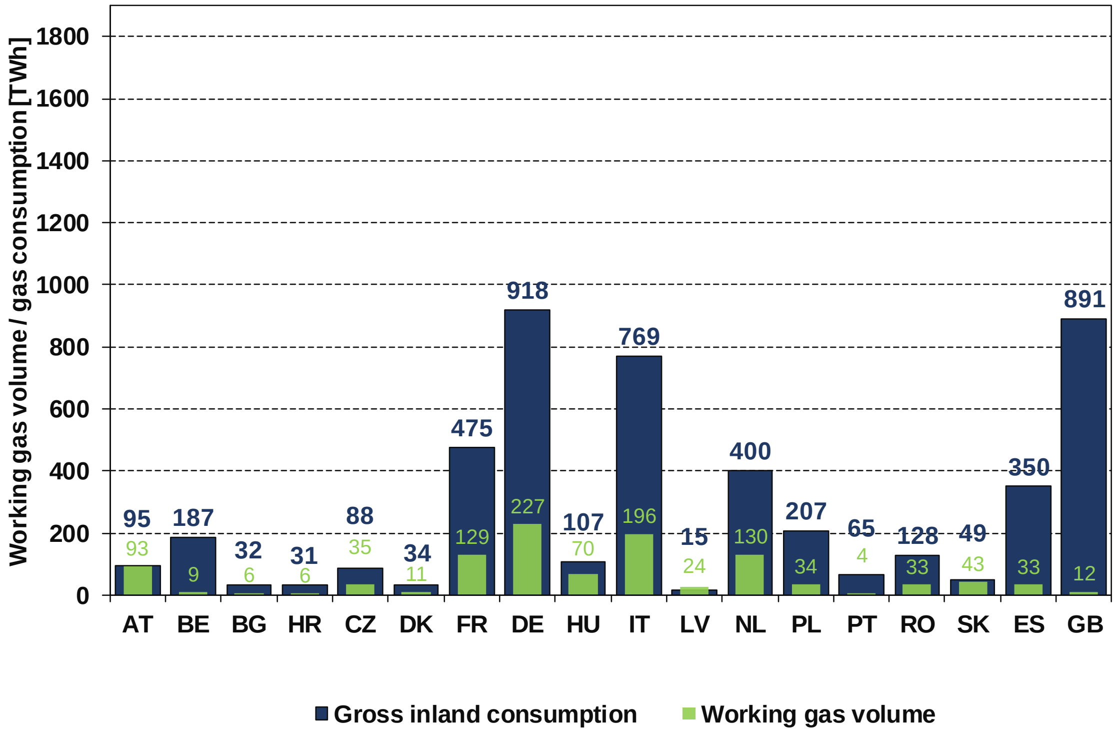

Figure 6-2: Comparison of Gross inland gas consumption and the workings gas volume (EU-28)
(countries without underground gas storages are not shown here)
Source: DBI – own illustration, data from [21], [23]

A further difference can be found when taking the transit / export of gas into account (Figure 6-3), which has a big share of the transported gas especially in countries like Germany, Belgium, Austria, Slovakia or the Netherlands. As storage capacity is used for national as well as international gas quantities, these numbers give the best impression of the flexibility, that can be provided by underground storages.

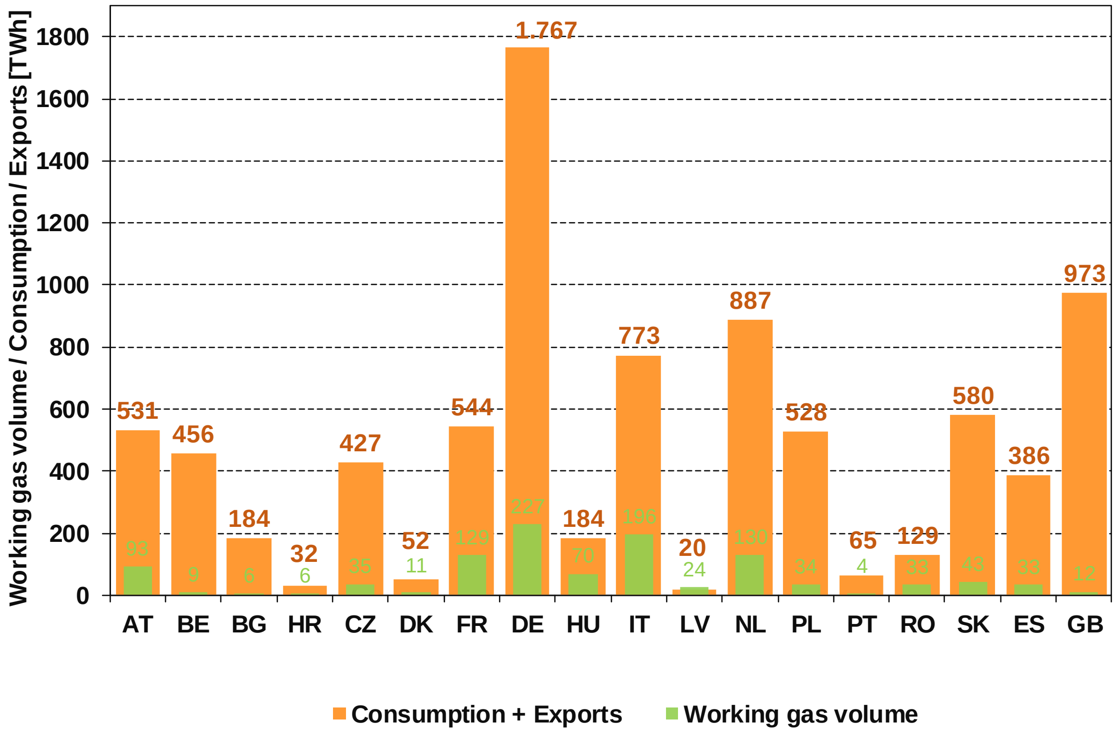

Figure 6-3: Comparison of gas consumption, exports and the workings gas volume (EU-28)
(countries without underground gas storages are not shown here)
Source: DBI – own illustration, data from [21], [23]

The underground gas storages all over Europe can provide flexibility for the energy system as well as large capacities for seasonal and long-term storage of natural gas and, in the future, SNG. In combination with the gas grids, SNG from PtG/methanation plants with sizes from several kW up to GW can be injected, transported and stored within the gas system.

The underground storages depend heavily on geological aspects as well as the availability of a gas grid with sufficient capacities. Therefore, the locations of underground storages and capacities of the gas grid should be taken into account when optimizing and developing the overall energy system.

Abbreviations

CAPEX	Capital expenditure
CH_4	Methane
CO_2	Carbon dioxide
DN	Nominal diameter
GPRS	Gas pressure regulator station
LP	Linepack
MOP	Maximum operating pressure
OP	Operating pressure
PLP	Point of lowest pressure
PtG	Power-to-gas
SNG	Synthetic natural gas
STP	Standard conditions for temperature and pressure
TP	Transmission pipeline

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