CONCEPT STUDY AND FINANCIAL MODEL

LNG-to-Power Solutions

JENBACHER
INNIO

List of abbreviations

ASEAN	Association of Southeast Asian Nations
APAC	Asia Pacific region
CAGR	Compound annual growth rate
CO_2	Carbon dioxide
COD	Commercial operating date
CAPEX	Capital expenditure
DCF	Discounted cash flow
DSCR	Debt-service coverage ratio
EPC	Engineering, procurement, and construction
FDI	Foreign direct investment
FOM	Fixed operation and maintenance costs
FSA	Fuel supply agreement
FSRU	Floating storage and regasification unit
GTCC	Gas turbine combined cycle
HFO	Heavy fuel oil
HHV	Higher heating value
IDC	Interest during construction
IC	Internal combustion engine
IEA	International Energy Agency
IGU	International Gas Union
IPP	Independent power producer
IRR	Internal rate of return
ISO	International Organization for Standardization
LHV	Lower heating value
LNG	Liquefied natural gas
LTSA	Long-term service agreement
NTP	Notice to proceed
NO_x	Nitrogen oxides
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
OP	Operating profit
OPEX	Operational expenditures
O&M	Operating and maintenance
PPA	Power purchase agreement
SI	Spark ignited (engine according to the Otto cycle)
SO_x	Sulphur oxide
SPV	Special purpose vehicle (as company structure for power and LNG projects)
TBD	To be detailed
VOM	Variable operation and maintenance costs
WACC	Weighted average cost of capital

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All data provided in this document is non-binding. This data is for information only and is not guaranteed in any way. Depending on the subsequent specific individual projects, the relevant data may be subject to changes and will be assessed and determined individually for each project. This will depend on the particular characteristics of each individual project, especially specific site and operational conditions.

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LNG-TO-POWER

A huge opportunity for INNIO's customers to secure stable profits if gas prices are managed

Basic Scope

The global small-scale LNG market is expected to grow from $2.3 billion US in 2020 to $2.6 billion US by 2025, at a CAGR of 2.6% during the forecast period.[1]

Within this market, the power industry takes a huge portion, in addition to the transportation sector.

The market is expected to grow from 12 GW over the next four years, at about 3 GW annually.

Under a CAPEX estimation of €1,300/kW, this would be a market volume of approximately €3.9 billion per year up to 2025.

The strongest markets are expected in Asia and the Americas, where the largest consumption as well as the largest economic development is taking place.

What exactly is defined as small-scale LNG?[2]

Small-scale LNG refers in general to LNG-related facilities, receiving terminals, storage units, vessels, etc., of similar characteristics but with a lower magnitude than conventional large-scale LNG infrastructure.

Since LNG is an industry driven by economies of scale, there are few small-scale LNG facilities.

Moreover, then, no strict classification of scale has been made so far and there is not a commonly accepted and clear definition or classification for small-scale LNG.

The growing interest in small-scale LNG has led to different definitions. For example:

Klimczak[3] uses 2 million metric tons per annum (mtpa) as the standard for classifying liquefaction capacity as large-scale LNG.

Brown[4], on the other hand, distinguishes LNG-related facilities with a liquefaction capacity of more than 1 million metric tons per annum as "large-scale" and those with less as "small-scale."

The accounting and consulting firm PwC uses less than 500,000 metric tons per annum as a standard for small-scale liquefaction facilities.

Furthermore, GOC and Linde have identified small-scale LNG infrastructure mainly based on the scale of their storage capacity and have adopted 10,000 cubic meters as their criteria.

The International Gas Union (IGU) shows a nearly "median value" of these various definitions. The IGU has established the following criteria for each small-scale LNG value chain: liquefaction, regasification, import: 0.05–1 mtpa, transportation of LNG in wholesale: maximum 60,000 cubic meters (carrier capacity).

At INNIO, we have linked this to our expected and most economical scale of an LNG-to-power project in the 20 MW and 50 MW range. Under today's and tomorrow's market outlook, this size offers the best return for investors, with expectations of at least a project IRR larger than 12%.

[1] Global Forecast to 2025 Markets and Markets™, June 2020.
[2] https://www.apec.org/docs/default-source/Publications/2019/9/Small-scale-LNG-in-Asia-Pacific/219_EWG_Small-scale-LNG-in-Asia-Pacific.pdf
[3] Renee F. Klimczak, "Small-to-Mid Scale LNG's Ship is Sailing," Paper presented to LNG 18 (April 2016, Perth, Australia)
[4] James Brown, "Development of Small-Scale LNG Value Chains and Infrastructure in South East Asia," Paper presented to LNG 18 (April 2016, Perth, Australia)

Times of uncertainty for future gas prices – Affecting all sectors alongside the natural gas value stream

Uncertainty lies in the future development and demand hubs for LNG and natural gas, mainly driven by stronger LNG import volumes shifting from Asia to Europe, which must replace pipeline gas from Russia.

Capacity and infrastructure are lacking. Liquefaction and large regasification capacity take time to build and currently are in planning or under development, with COD dates at the earliest in 2023 and 2024 on main larger projects in the EU (non-FSRUs) and in countries such as Vietnam.

Price development – Entering a new era of gas prices, who can protect a local economy from stranded assets?

Countries with their own large natural gas resources such as Australia, the U.S., Qatar, Malaysia, and parts of Indonesia are the winners of the gas run.

So, too, are countries that can make use of large mainly government-supported bargaining power and order large cargoes at attractive prices on the global market. All indications show a strong switch from a large buyer's market to a newly strong supplier's market, as new infrastructure projects are not yet completed.

What's ahead?

Various economies are likely to use more cheap coal and develop more new nuclear projects. The EU, for example, clearly plans to invest in more nuclear power and natural gas (EU taxonomy for sustainable activities, regulation 2020/852) to keep energy prices low within their economies.

What to expect on the spot price and mid-to long-term prices for natural gas and LNG

Times of $2 US/MMBTU and lower at the Henry Hub and LNG cargoes signed for $7-$10 US/MMBTU most likely are gone for the next several years.

Up to August 2020, Asia LNG prices were ranging between $7-$12 US/MMBTU, which means on an energy price level $24-$41 US/MWh (€20-€35 /MWh), close to prices contracted at the EEX and Nord Pool for piped natural gas.

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Supply and demand between pipeline gas at the EEX and Nord Pool to LNG Asia prices was balanced

Post-COVID logistics challenges and ongoing initiatives to reduce dependence on Russian gas caused extreme gas price volatility as the EU competes with Asia for LNG cargoes. Speculative and volatile gas spot prices make little economic sense, resulting in questionable economics for every new gas-fired project relying on gas spot contracts. As of July 2022, Reuters analysts of expect an LNG spot price as forward contract August 2022 in Asia of $39 US/MMBTU or $133 US/MWh (€112/MWh[5]).

On the mid- to long-term for signed contracts, analysts expect a recovery back to levels of approximately $12 US/MMBTU, especially in Asia and the Americas.

A long-term consensus forecast published by Bloomberg expects the price of benchmark Japan-Korea Marker (JKM) to reach a level of $10.2 US/MMBTU by 2024. This forecast anticipates a 22% increase in the U.S. LNG supply in 2024, compared to year-end 2021, as new projects come online[6] . Among other countries offering increased LNG supply to the market are Australia, Nigeria, Norway, Canada, Mozambique, and Qatar.

The high price scenario anticipates an average price of $12 US/MMBTU by 2024, a forecast by INNIO based on values of the JKM forward curve[7] adjusted by an average ratio between cost of imported LNG for Japanese utilities and spot prices since January 2021.

Producing sustainable power and secure stable returns and cash flows for investors.

To cover the high impact of variable gas prices on the cost of generating electricity, every investor should seek the most efficient technology to convert gas molecules into electrons. Also, CAPEX and OPEX factors are the main drivers to securing stable and profitable revenue streams of the entire life cycle of an investment.

For small-scale LNG-to-power solutions, under baseload, the preferred technology is the internal combustion engine. For two business cases covering an output of 20 MW and 50 MW, we have chosen the highest efficiency Jenbacher gas engines, with an output of 4.4 MW for the J624 MW and 10 MW for the J920. Both engines are best in class with regard to electrical efficiency and environmental footprint. These output sizes are part of the financial model for highly efficient gas-to-power solutions powered with LNG.

Concept proof and robustness of the business case: Life cycle cost analysis and financial modeling

Based on the above-mentioned power output, the following chapters will analyze the robustness of the business model, covering the main success criteria for an EPC LNG-to-Power project for 20 MW and 50 MW. They are:

- The EPC pricing
- Capital invested, including equity cost
- Operational cost
- Generating cost per MWh
- Cash flows
- IRR

[5] https://www.reuters.com/markets/europe/asia-spot-prices-jump-amid-stronger-demand-concerns-over-russia-2022-07-01/
[6] "Global LNG Market Outlook 2022-26," Bloomberg NEF, June 16, 2022
[7] JKM LNG forward curve as of July 4, 2022; Japanese utilities cost data is from Bloomberg NEF and is representative of long-term LNG contracts

FRAMING THE BUSINESS CASE

for 20 MW and 50 MW baseload with highly efficient Jenbacher engines

Project key data	Unit	20 MW baseload LNG to power	50 MW baseload LNG to power
Gas Engine Type		J624 two-staged turbocharged (1,500 rpm, 50 Hz)	J920 two-staged turbocharged (1,000 rpm, 50 Hz)
Installed Power Gross	MWel	22.0	51.8
Electrical output plant net to grid at step-up	MW	21.1	49.7
Full load operational hours per year	h/a	8,500	8,500
Capacity factor	%	95%	95%
Electricity generating per year (net)	MWh/a	168.8	397.6
LNG consumption & storage for the sites			
LNG consumption per year (Hi)	m³/a	55,263	132,289
LNG consumption per day (Hi)	m³/d	151	362
LNG consumption per hour (Hi)	m³/h	31	16
Bunkering interval to site 14 days			
Storage capacity at site	m³	2,120	5,074
Truck supply to LNG facility			
Truck delivery per day 14t per truck; 6 days per week / 1h for off-loading	Trucks/day	2	6
Truck delivery per week	Trucks/week	17	41
Truck delivery per month	Trucks/month	77	184

ELECTRICITY GENERATING COST

Life-cycle cost analysis for 20 MW and 50 MW

On wholesale and competitive electricity markets, the production cost of electricity per MWh is the leading measure for the profitability of a power-generating asset.

Available generating technologies will be requested on wholesale markets according to a merit order system. The merit order system is a way of ranking available sources of electricity-generating assets, based on ascending order of price. It reflects the order of their short-run marginal/variable cost of production – the so-called clearing price – together with the amount of energy that will be generated.

On a liberalized and transparent wholesale energy market, the ranking is such that those power plants with the lowest marginal cost are the first to be brought online to meet demand, and the plants with the highest marginal cost are the last to be brought online.

An electricity production price below the clearing price of an electricity market is the most important measure for every investor. Literally, the gap between the sales price of electricity and the production costs needs to fulfill the financial expectations of an investor and cover the debt service as part of an up-front and operational investment.

The main performance indicators for a power plant solution, in this case the LNG-to-Power setup, are:

Technology

- Net efficiency, net heat rate under ISO and under at-site conditions covering derating aspects
- Emissions, preliminary CO_2, and NOX linked to efficiency and fuel type

Project finance

- EPC price
- Owners cost, including infrastructure work, project development, and permitting process
- Construction time for the asset from NTP to COD Determine the IDC
- Capital and investment structure / equity vs. loan structure
- Local tax rate
- WACC
- Annuities

Operational

- Expected full-load hours under PPA
- Dispatchable or non-dispatchable technology ("additional grid services for an additional revenue")
- Operational expenses including insurances (e.g., break down insurance)

INPUT PARAMETERS

for the life-cycle cost calculation for 20 MW and 50 MW

Parameters	Comment	20 MW site J624	50 MW site J920
Plant net output (50 Hz)	Net electrical power available for delivering electricity under the PPA	21.1 MWel	49.7 MWel
Plant net heat rate / electrical efficiency	Covering own consumption of the power plant and the efficiency of the high voltage step up transformer. 5% tolerance for project specific adjustments	9,323 kJ/kWh; 38,6%	8,658 kJ/kWh; 41.6%
EPC investment costs for the power plant plus LNG-related installation (without site costs)	Power plant investment based on project experiences in APAC. LNG covers under an EPC: related vacuum-insulated tanks plus regasification system and truck unloading. Suitable for 14 days of storage	€922/kW	€1,145/kW
IDC	Typically, construction time from notice to proceed to start commercial operating date is between 12 and 18 months, depending on the complexity. Site preparation work and, for example, costs for HV connection not implemented within this concept study	€0.64 Mio.	€2.3 Mio.
Capital costs/annuities based on 8.3%	Are included for a 25-year lifetime of the asset	€2.02 Mio.	€5.9 Mio.
WACC	Included based on 30% equity (12% equity costs) and 70% debt financed with 5% loan costs	8.4%	8.4%
Tax rate	We assume no tax holiday / income taxes due to the local market mechanism. Income tax for an SPV / operating power plant, estimated	15%	15%
Fixed operating and maintenance costs[8]	Included the people who operate the power plant in a three-shift model – one cost basis for white collar/ blue collar salary €40,000/a	5 people	7 people
Insurances and other services	Not included		
Variable maintenance costs	Included costs per periodic maintenance services with spare parts and supervisor assistance	5.0 €/MWh	4.5 €/MWh
Lube oil	Included as consumable for the power plant	€1.2/MWh	€1.2/MWh
LNG price in €/MWh at site	- $10.2 US/MMBTU in the best-case scenario: $34 US/MWh / €29.4/MWh (see footnote 6 and corresponding analysis on page 5) - $12 US/MMBTU in the high-price scenario: (see footnote 6) $40 US/MWh / €34.7/MWh	€29.4/MWh Plus, high-price scenario €34.7/kW	€29.4/MWh Plus, high-price scenario €34.7/kW
Fuel costs under full load	Fuel costs in correlation to the net efficiency of the power plant in simple cycle without use of waste heat[9]	€88.8/MWh	€83.5/MWh
Emission regulation	TBD / here not adjusted / NOX reduction would add approximately €0.8/MWh on CAPEX and operating (Urea)		
COD	Starting after 8 months for the J624 project and 12 months for the J920 project as NTP	2023	2023
Annual operating hours	Baseload operating – basis for financial model	8,500	8,500

[8] Escalation rate for costs 2.5%/a

[9] Depending on the vaporization process, engine cooling water and exhaust gas energy can be used. With this waste heat use, the total fuel efficiency (caloric heat input) can be optimized above 70%. "LNG CHP process"

ELECTRICITY GENERATING COST

for 21.1 MW net output at the J624 site and 49.7 MW at the J920 site

Scenario 1: Gas price: **€29.5/MWh** "Business as usual" / **Scenario 2:** Price increase to **€34.7/MWh** "High gas price"

	Annual operating hours	Unit	5x J624 Basic scenario LNG to €29.5/MWh	5x J624 Price increase LNG to €34.7/MWh	5x J920 Basic scenario LNG to €29.5/MWh	5x J920 Price increase LNG to €34.7/MWh
Variable costs in €/MWh			**82.4**	**95.7**	**77.8**	**90.3**
Fixed costs in €/kWa			106.1	106.1	127.4	127.4
	250	€/MWh	507	520	587	600
	500	€/MWh	294.6	308.0	332.5	345.0
	1000	€/MWh	188.5	201.9	205.1	217.6
	1500	€/MWh	153.2	166.5	162.7	175.2
	2000	€/MWh	135.5	148.8	141.4	153.9
	2500	€/MWh	124.9	138.2	128.7	141.2
	3000	€/MWh	117.8	131.1	120.2	132.7
	3500	€/MWh	112.7	126.1	114.1	126.6
	4000	€/MWh	108.9	122.3	109.6	122.1
	4500	€/MWh	106.0	119.3	106.1	118.6
	5000	€/MWh	103.6	117.0	103.2	115.7
	5500	€/MWh	101.7	115.0	100.9	113.4
	6000	€/MWh	100.1	113.4	99.0	111.5
	6500	€/MWh	98.7	112.1	97.3	109.9
	7000	€/MWh	97.6	110.9	95.9	108.5
	7500	€/MWh	96.6	109.9	94.7	107.2
	8000	€/MWh	95.7	109.0	93.7	106.2
	8500	€/MWh	94.9	108.2	92.7	105.2

FINANCIAL MODELING

for the LNG-to-Power solution

Discounted cash flow – time value of money

The model for profitability is based on the DCF using a project-specific WACC, including a 15% corporate tax rate.

All project cash flows are linked to an energy-market scenario with sales prices for electricity as well as expenses for fuel and other consumables and services.

On a liberalized and transparent wholesale energy market, the ranking is such that those power plants with the lowest marginal cost are the first to be brought online to meet demand, and the plants with the highest marginal cost are the last to be brought online.

The inputs are:

Variable operation and maintenance costs (VOM) including periodic maintenance lube oil and start-up costs. Full O&M management not considered.

Fixed operation and maintenance costs (FOM) for running the power plant, including costs for operating staff and local tax rate.

Financing parameters covering construction time with the important allocation of the IDC, equity ratio, and costs.

Capital costs that are reflecting the annuities linked to the operating lifetime of the power plant.

The results for the decision makers are:

- **Cash flows**
- **The discounted and net operating profit** available for shareholders and investors
- **The internal project IRR** for the capital invested as the benchmark for the profitability of the project
- **The payback time in years** linked to the first positive discounted cash flow
- **The DSCR**

SUCCESS CRITERIA AND INDICATION

of financial profitability

The leading financial indicators were calculated under two scenarios within this concept study. Scenario one is the "business as usual" scenario. In the second scenario, which is linked to a price increase for the LNG/natural gas up to €34.7/MWh, we take "ceteris paribus" for any other external condition such as market development, CAPEX, or equipment changes.

Scenario 1: "Business as usual"

LNG price at COD	**€29.5/MWh** $10.2 US/MMBTU
Sales price of electricity under PPA	€120/MWh[10]
Power plant annual operating hours under 100% load	8,500 annual operating hours under 100% load
Years of commercial operation (project lifetime)	25
WACC	8.4%
Tax rate (corporate tax rate for SPV)	15%

Results for the "Business as usual" scenario

Parameters	20 MW site with J624	50 MW site with J920
Operating profit, accumulated before tax over lifetime	€160 Mio.	€496 Mio.
Discounted cash flow over project lifetime before taxload	€43 Mio.	€138 Mio.
Operating profit on average / annum before tax	€6 Mio.	€20 Mio
IRR (Internal project rate of return) over the project lifetime	24.3%	26.2%
DSCR on average over 20 years	0.4	1.4
Payback time *First positive cumulative positive cash flow	4 years	3 years

Result: Overall good and strong project IRR above WACC (8.4%) for both projects due to high electrical efficiency. Solid operating profit and cash flows, especially with the large 50 MW project, as well as good DSCR performance. Payback time very attractive for the IPPs and utility business investors. Gas prices must be linked to a solid PPA to secure stable cash flows over the project lifetime.

[10] Average power price in Japan and Korea in 2021; source: BloombergNEF, JPEX, KEPCO

Scenario 2: "Higher gas prices under ceteris paribus"

LNG price at COD	**€34.7/MWh** $12 US/MMBTU
Sales price of electricity under PPA	€120/MWh[11]
Power plant load	8,500 annual operating hours under 100% load
Years of commercial operation (project lifetime)	25
WACC	8.4%
Tax rate (corporate tax rate for SPV)	15%

Results for the "Higher gas prices under ceteris paribus" scenario

Parameters	20 MW site with J624	50 MW site with J920
Operating profit, accumulated before tax over lifetime	€75.2 Mio.	€315 Mio.
Discounted cash flow over project lifetime before taxload	€8 Mio.	€64 Mio.
Operating profit on average / annum before tax	€3 Mio.	€13 Mio.
IRR (Internal project rate of return) over the project lifetime	11.9%	17.4%
DSCR on average over 20 years	0.2	0.9
Payback time *First positive cumulative positive cash flow	5 years	4 years

Result: Higher gas prices and higher variable costs have clear impacts. Electrical efficiency is the main criterion to secure an overall solid financial performance. IRR still above WACC (8.4%) for both projects. Solid operating profit and cash flows. Payback time attractive for all kinds of investors within the power sector. Gas prices must be as strong as possible hedged/secured to avoid further price increases and eliminate the risk of a stranded asset. DSCR as measure of the cash flow available to pay current debt obligations is below 1 and must be controlled with some improvements on gas prices and cost reduction for operating, but overall, still in an acceptable range.

[11] Average power price in Japan and Korea in 2021; source: BloombergNEF, JPEX, KEPCO

RESULT DISCUSSION

supporting decarbonization with clean gas and small-scale LNG to replace oil- and coal-based power generation

A well-matched link between PPA and gas prices is needed to support and promote investment into the LNG-to-power infrastructure. Too high gas prices will lead gas projects to quickly become stranded assets.

Small power projects in the range of 20 MW to 50 MW have a huge chance of quickly decarbonizing the often oil- and coal-based energy landscape, especially in developing countries in Asia, Latin America, and Africa.

For that to happen, foreign direct investments must be attracted. An important hurdle for investors is an IRR above the WACC. A higher WACC typically means higher financing costs and higher risks.

Financial performance of the business cases

- The overall financial performance is very attractive as long as the gas price is in a range of $10 to $12 US/MMBTU[12]. High efficiency, a good PPA structure, and high annual operating hours pay off and deliver IRR numbers above the WACC.
- Short construction time ("sunset date") between 8 to 12 months from NTP to COD secures an early commercial start-up and first positive cash flow.
- Operational cash flows linked to power plant sizes are strong and deliver especially in the business-as-usual scenario good overall debt-service cover ratios (e.g., bond rating, according to S&P).

Success criteria

- The LNG price of $10 US/MMBTU is the leading benchmark for an excellent operational performance and must be secured (e.g., via a hedging or supporting instrument that is linked to the PPA).
- Convoy concept for optimized CAPEX and permitting process is needed. EPC responsibility for the power plant and the LNG infrastructure must be aligned.
- High technical and commercial availability of the entire asset must be secured via the responsible EPC / operating company.
- Commercial alignment of main project stakeholders as part of the SPV secures an optimized construction and operating phase.

[12] $10.2 US/MMBTU: $24 US/MWh or €29.5/MWh. $12 US/MMBTU: $40 US/MWh or €34.7/MWh

Risk prevention

- Secure a flexible PPA linked to the gas price at site.
- Pass-through clause for the gas price should be included in the upcoming negotiations with the grid operator/electricity off-taker.
- LNG supply contract is based on take-and-pay.
- Second LNG supplier strategy must be evaluated.
- Secure multiple off-take of the LNG plant to ensure various revenue streams.
- Hedging of LNG supply should be considered.
- Optimize the IDC phase with a separate credit line to keep main capital costs low.

Outlook

- Supplying more than baseload power to the local market is optimal. Ancillary services, spinning reserve, non-spinning reserve, and frequency control can be key components. Expand the business model toward more flexibility. The engines are offering a very flexible operating regime. The benefit could increase with additional income streams on the company's balance sheet. Normally, in energy markets with a high number of fluctuating renewable sources, these new markets will be promoted by the grid operators to secure stable grid frequency.
- Making use of the hydrogen business and including synthetic gases (by mixing) in the operation of the power plant merits consideration. In particular, Europe, Japan, and Korea are currently very strong in developing hydrogen strategies for the power, industry, and mobility sectors.

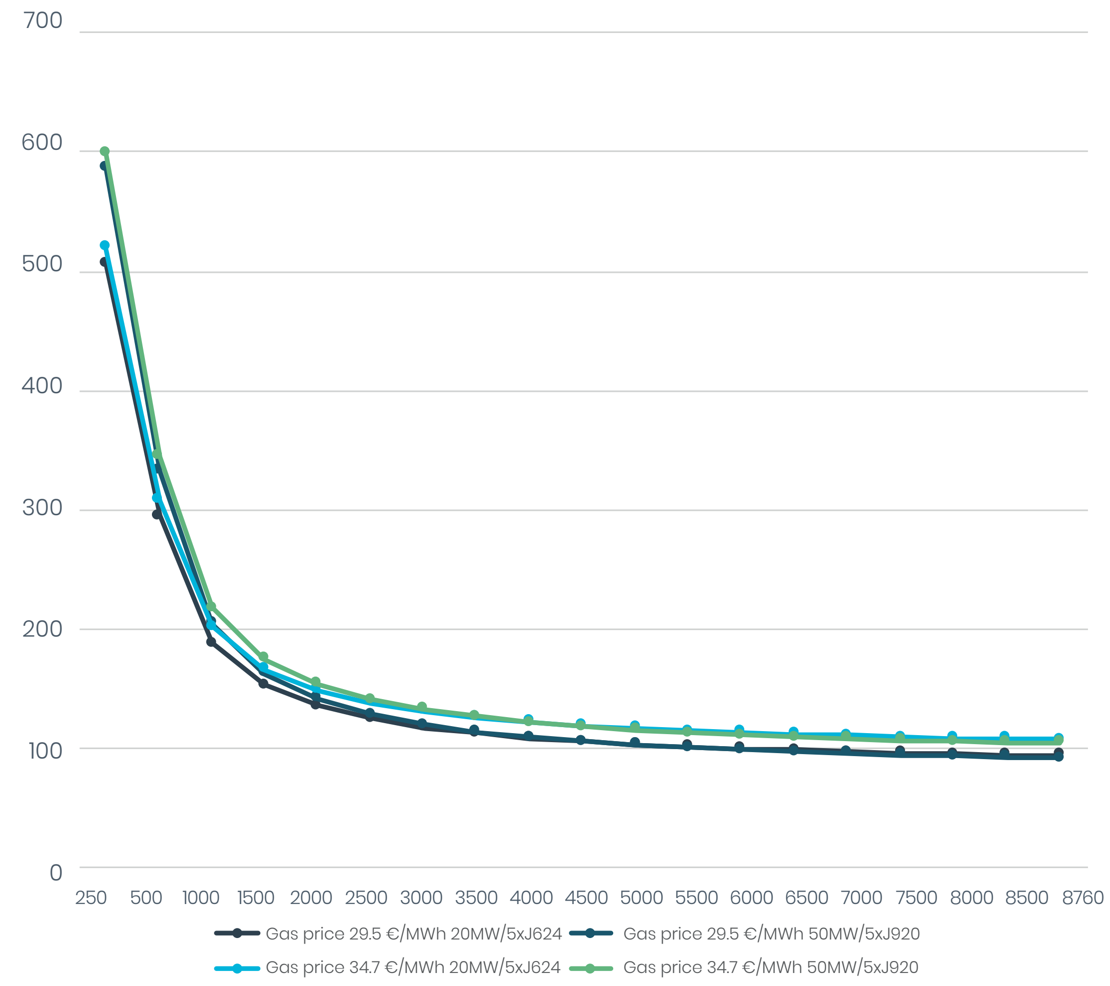

Figure 1: Electricity Generating Costs in €/MWh over annual operating hours for both scenarios

APPENDIX

Conversions

Currency	€0.90 = $US 1.04	As of July 03, 2022	
LNG			
1	MWh	3.41	MMBTU
1	MMBTU	0.293	MWh

EPC prices based on own experiences and international surveys

Gas price developments

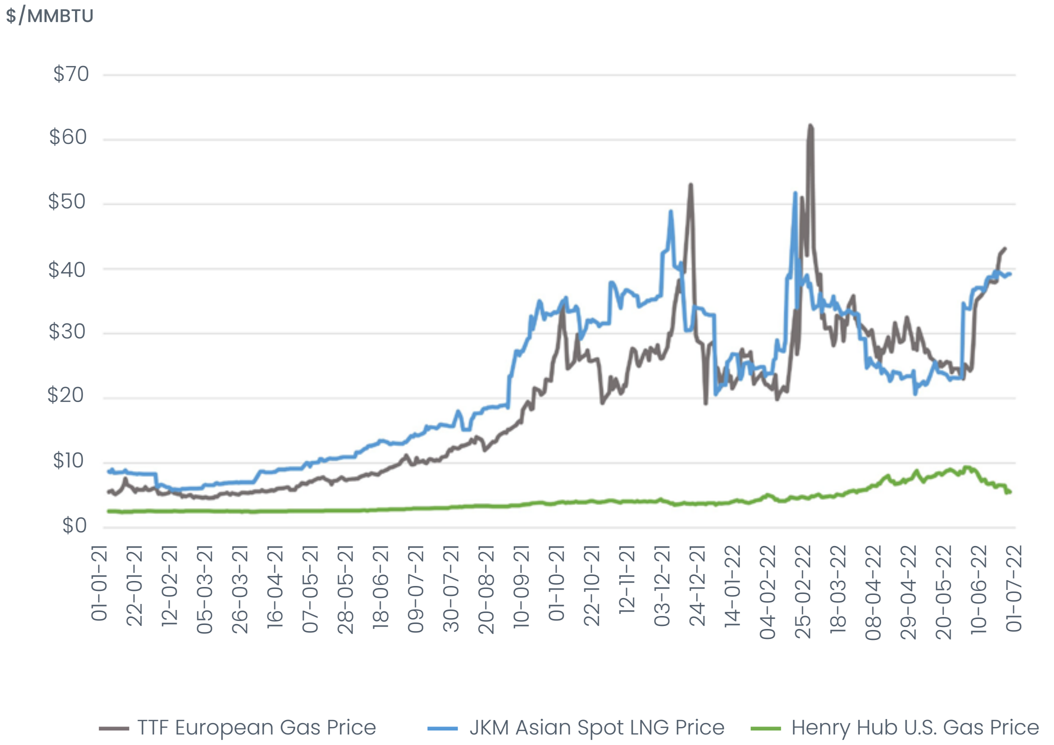

Figure 2: Henry Hub, TTF and Asian Spot LNG price developments as of July 03, 2022; source: BloombergNEF

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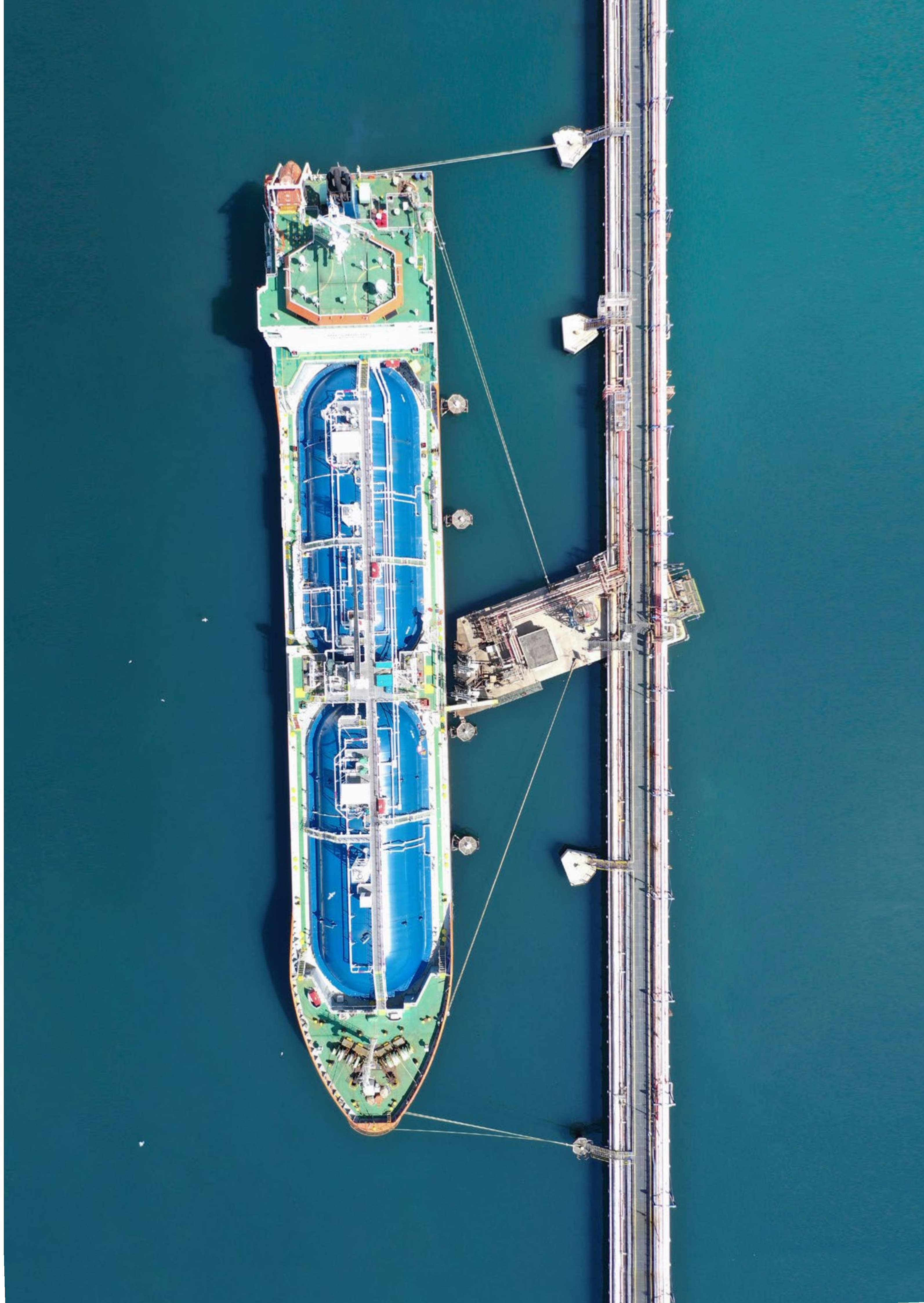

INNIO is a leading energy solution and service provider that empowers industries and communities to make sustainable energy work today. With our product brands Jenbacher and Waukesha and our digital platform myPlant, INNIO offers innovative solutions for the power generation and compression segments that help industries and communities generate and manage energy sustainably while navigating the fast-changing landscape of traditional and green energy sources. We are individual in scope, but global in scale. With our flexible, scalable, and resilient energy solutions and services, we are enabling our customers to manage the energy transition along the energy value chain wherever they are in their transition journey.

INNIO is headquartered in Jenbach (Austria), with other primary operations in Waukesha (Wisconsin, U.S.) and Welland (Ontario, Canada). A team of more than 3,500 experts provides life-cycle support to the more than 54,000 delivered engines globally through a service network in more than 80 countries.

INNIO's ESG Risk Rating places it number one of more than 500 worldwide companies in the machinery industry assessed by Sustainalytics.

For more information, visit INNIO's website at **www.innio.com.**

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