# On the climate benefit of a coal-to-gas shift in Germany's electric power sector

**SUPPLEMENT**

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22 pages, 5 Figures, 6 Tables

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# 1 Statistical "Fleet –conversion" modelling

We modeled the GHG radiative forcing effect of fuel-switching scenario from coal to natural gas in Germany's power sector. This scenario is based on supply chain and in-use $CO_2$ emissions from the coal and natural gas sector and methane emissions from the coal sector for year 2018. Fuel-specific emissions from the individual supply countries and domestic sources are considered (Table S1). Break-even methane emission rates from natural gas usage are determined by the modeling. Natural, geological and technological variability of the key input parameters were accounted for using Monte Carlo simulations. Truncated distributions were applied for several parameters to achieve physically reasonable simulations.

Few, well constrained parameters (supply chain $CO_2$ emission for coal and gas, country shares for coal) were modelled with fixed values. Most parameters were presumed to be uncorrelated. The only exception is the efficiency of gas power plants, which has a direct effect on the amount of methane needed for generating a certain amount of energy (e.g., 1 MWh). For these parameters a correlation with r ~ -0.8 was modelled using a Gaussian copula.

The simulations were performed using the software packages Scilab,[1] R[2] and Julia[3]. 100,000 runs were computed for the Monte Carlo simulations. The results are given in Table S2 and selected input parameter distributions are shown (Figures S1- S5)

**Table S1**: Modelling input parameters. Netherlands (NL), Norway (NOR), Russia (RU), Colombia (CO), Poland (PL), South Africa (ZA), Germany (DE)

| Parameter | unit | distribution | mean | standard dev. | truncation min. | truncation max. | remark |
|---|---|---|---|---|---|---|---|
| CO2 in-use, gas, NL | kg/MWh | truncated normal | 200.8 | 0.5/1.282*(max-min) | 200.3 | 201.2 | truncation at P10 and P90 |
| CO2 in-use, gas, NOR | kg/MWh | truncated normal | 202.9 | 0.5/1.282*(max-min) | 202.0 | 203.8 | truncation at P10 and P90 |
| CO2 in-use, gas, RU | kg/MWh | truncated normal | 198.9 | 0.5/1.282*(max-min) | 198.6 | 199.1 | truncation at P10 and P90 |
| CO2 in-use, gas, others | kg/MWh | truncated normal | 200.7 | 0.5/1.282*(max-min) | 200.1 | 201.2 | truncation at P10 and P90 |
| CO2 in-use, gas, DE | kg/MWh | truncated normal | 200.1 | 0.5/1.282*(max-min) | 199.5 | 200.7 | truncation at P10 and P90 |
| CO2 supply chain, gas, NL | kg/MWh | fixed value | 3.9 | | | | |
| CO2 supply chain, gas, NOR | kg/MWh | fixed value | 12.4 | | | | |
| CO2 supply chain, gas, RU | kg/MWh | fixed value | 46.1 | | | | |
| CO2 supply chain, gas, others | kg/MWh | fixed value | 28.2 | | | | |
| CO2 supply chain, gas, DE | kg/MWh | fixed value | 18.5 | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| share gas, NL | % | uniform | 22.1 | | mean - 10 | mean + 10 | |
| share gas, NOR | % | uniform | 25.8 | | mean - 10 | mean + 10 | |
| share gas, RU | % | uniform | 38.6 | | mean - 10 | mean + 10 | |
| share gas, others | % | uniform | 5.5 | | 0 | 11 | |
| share gas, DE | % | none, fixed value | 8 | | | | |
| Mass methane per quantum electricity | kg/MWh | truncated normal | 122.3 | 4.5 | 0.9 * mean | 1.1 * mean | correlated with "Gas … efficiency", r = -0.8 |
| Gas power plant, efficiency | % | truncated normal | 55 | mean/15 | 0.9 * mean | 1.1 * mean | correlated with "Mass methane …", r = -0.8 |
| hard coal power plant, efficiency | % | truncated normal | 44 | mean/15 | 0.9 * mean | 1.1 * mean | |
| lignite power plant, efficiency | % | truncated normal | 39 | mean/15 | 0.9 * mean | 1.1 * mean | |
| Coal share hard-coal: | % | fixed value | 36.2 | | | | |
| Coal share lignite | % | fixed value | 63.8 | | | | |
| share, hard coal, PL | % | fixed value | 0.66 | | | | |
| share, hard coal, CO | % | fixed value | 10.81 | | | | |
| share, hard coal, RU | % | fixed value | 49.57 | | | | |
| share, hard coal, ZA | % | fixed value | 2.5 | | | | |
| share, hard coal, USA | % | fixed value | 18.02 | | | | |
| share, hard coal, DE | % | fixed value | 9.93 | | | | |
| share, hard coal, others | % | fixed value | 8.5 | | | | |
| share, lignite, DE-Lusatia | % | fixed value | 38.4 | | | | |
| share, lignite, DE-Rhineland | % | fixed value | 50.1 | | | | |
| share, lignite, DE-Central Germany | % | fixed value | 11.5 | | | | |
| $CO_2$, in-use, hard coal, PL | kg/MWh | truncated normal | 349.7 | 0.5/1.282*(max-min) | 342.9 | 356.4 | truncation at P10 and P90 |
| $CO_2$, in-use, hard coal, CO | kg/MWh | truncated normal | 358.9 | 0.5/1.282*(max-min) | 339.5 | 378.3 | truncation at P10 and P90 |
| $CO_2$, in-use, hard coal, RU | kg/MWh | truncated normal | 350.0 | 0.5/1.282*(max-min) | 343.9 | 356.0 | truncation at P10 and P90 |
| $CO_2$, in-use, hard coal, ZA | kg/MWh | truncated normal | 351.4 | 0.5/1.282*(max-min) | 340.7 | 362.0 | truncation at P10 and P90 |
| $CO_2$, in-use, hard coal, USA | kg/MWh | truncated normal | 325.4 | 0.5/1.282*(max-min) | 319.7 | 331.0 | truncation at P10 and P90 |
| $CO_2$, in-use, hard coal, DE | kg/MWh | truncated normal | 331.0 | 0.5/1.282*(max-min) | 320.1 | 341.9 | truncation at P10 and P90 |
| $CO_2$, in-use, hard coal, others | kg/MWh | truncated normal | 349.0 | 0.5/1.282*(max-min) | 319.7 | 378.3 | truncation at P10 and P90 |
| $CO_2$, in-use, lignite, DE-Lusatia | kg/MWh | truncated normal | 399.4 | | min(data) - 0.5*s | max(data) + 0.5*s | |
| $CO_2$, in-use, lignite, DE-Rhineland | kg/MWh | truncated normal | 403.5 | | min(data) - 0.5*s | max(data) + 0.5*s | |
| $CO_2$, in-use, lignite, DE-Central Germany | kg/MWh | truncated normal | 373.3 | | min(data) - 0.5*s | max(data) + 0.5*s | |
| $CO_2$, supply chain, hard coal, PO | kg/MWh | fixed value | 9.6 | | | | |
| $CO_2$, supply chain, hard coal, CO | kg/MWh | fixed value | 9.98 | | | | |
| $CO_2$, supply chain, hard coal, RU | kg/MWh | fixed value | 13.34 | | | | |
| $CO_2$, supply chain, hard coal, ZA | kg/MWh | fixed value | 12.65 | | | | |
| $CO_2$, supply chain, hard coal, USA | kg/MWh | fixed value | 15.94 | | | | |
| $CO_2$, supply chain, hard coal, DE | kg/MWh | fixed value | 7.89 | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CO2, supply chain, hard coal, others | kg/MWh | fixed value | 11.57 | | | | |
| CO2, supply chain, lignite, DE | kg/MWh | fixed value | 10.19 | | | | |
| CH4, hard coal, PL | kg/MWh | truncated normal | 1.091 | 0.5/1.282*(max-min) | 0.9871 | 1.195 | truncation at P10 and P90 |
| CH4, hard coal, CO | kg/MWh | truncated normal | 0.739 | 0.5/1.282*(max-min) | 0.4971 | 0.981 | truncation at P10 and P90 |
| CH4, hard coal, RU | kg/MWh | truncated normal | 0.880 | 0.5/1.282*(max-min) | 0.1861 | 1.574 | truncation at P10 and P90 |
| CH4, hard coal, ZA | kg/MWh | truncated normal | 0.277 | 0.5/1.282*(max-min) | 0.2582 | 0.297 | truncation at P10 and P90 |
| CH4, hard coal, USA | kg/MWh | truncated normal | 0.333 | 0.5/1.282*(max-min) | 0.1757 | 0.491 | truncation at P10 and P90 |
| CH4, hard coal, DE | kg/MWh | truncated normal | 0.636 | 0.5/1.282*(max-min) | 0.3774 | 0.895 | truncation at P10 and P90 |
| CH4, hard coal, others | kg/MWh | truncated normal | 0.659 | 0.5/1.282*(max-min) | 0.4136 | 0.905 | truncation at P10 and P90 |
| CH4, lignite, DE | kg/MWh | truncated normal | 0.013 | 0.5/1.282*(max-min) | 0.005 | 0.020 | truncation at P10 and P90 |

**Table S2**: Monte Carlo simulation GHG emission modelling results for a scenario of German power sector fuel switch from coal to natural gas[a]

| Parameter | unit | s | p05 | p50 | p90 |
|---|---|---|---|---|---|
| CO2 in-use, gas, NL | kg/MWh | 0.3 | 200.3 | 200.8 | 201.2 |
| CO2 in-use, gas, NOR | kg/MWh | 0.5 | 202.2 | 202.9 | 203.7 |
| CO2 in-use, gas, RU | kg/MWh | 0.1 | 198.6 | 198.9 | 199.1 |
| CO2 in-use, gas, others | kg/MWh | 0.3 | 200.2 | 200.7 | 201.1 |
| CO2 in-use, gas, DE | kg/MWh | 0.3 | 199.6 | 200.1 | 200.6 |
| share, gas, NL | % | 4.9 | 14.2 | 22.1 | 30.0 |
| share, gas, NOR | % | 4.9 | 17.9 | 25.8 | 33.8 |
| share, gas, RU | % | 5.1 | 30.7 | 38.6 | 47.5 |
| share, gas, others | % | 3.1 | 0.6 | 5.5 | 10.3 |
| share, gas, DE | % | 0.0 | 8.0 | 8.0 | 8.0 |
| CO2 supply chain+in-use, gas MIX | kg/MWh | 0.2 | 200.2 | 200.5 | 200.9 |
| Gas, power plant efficiency | % | 2.7 | 50.5 | 55.0 | 59.5 |
| CH4, hard coal, CO | kg/MWh | 0.12 | 0.54 | 0.74 | 0.94 |
| CH4, hard coal, DE | kg/MWh | 0.13 | 0.42 | 0.64 | 0.85 |
| CH4, hard coal, others | kg/MWh | 0.13 | 0.45 | 0.66 | 0.87 |
| CH4, hard coal, PL | kg/MWh | 0.05 | 1.00 | 1.09 | 1.18 |
| CH4, hard coal, RU | kg/MWh | 0.36 | 0.30 | 0.88 | 1.47 |
| CH4, hard coal, ZA | kg/MWh | 0.01 | 0.26 | 0.28 | 0.29 |
| CH4, hard coal, USA | kg/MWh | 0.08 | 0.20 | 0.33 | 0.47 |
| CH4, lignite, DE-Lusatia | kg/MWh | 0.004 | 0.006 | 0.012 | 0.019 |
| CH4, lignite, DE-Central Germany | kg/MWh | 0.004 | 0.006 | 0.012 | 0.019 |
| CH4, lignite, DE-Rhineland | kg/MWh | 0.004 | 0.006 | 0.013 | 0.019 |
| CO2 in-use, hard coal, CO | kg/MWh | 10.0 | 342.6 | 359.0 | 375.2 |
| CO2 in-use, hard coal, DE | kg/MWh | 5.6 | 321.8 | 331.0 | 340.2 |
| CO2 in-use, hard coal, others | kg/MWh | 15.2 | 324.2 | 349.0 | 373.8 |
| CO2 in-use, hard coal, PL | kg/MWh | 3.5 | 344.0 | 349.6 | 355.3 |
| CO2 in-use, hard coal, RU | kg/MWh | 3.1 | 344.8 | 349.9 | 355.1 |
| CO2 in-use, hard coal, ZA | kg/MWh | 5.5 | 342.4 | 351.4 | 360.3 |
| CO2 in-use, hard coal, USA | kg/MWh | 2.9 | 320.6 | 325.3 | 330.1 |
| CO2 in-use, lignite, DE-Lusatia | kg/MWh | 2.7 | 395.0 | 399.4 | 403.8 |
| CO2 in-use, lignite, DE-Central Germany | kg/MWh | 4.6 | 365.4 | 373.4 | 380.6 |
| CO2 in-use, lignite, DE-Rhineland | kg/MWh | 8.3 | 389.8 | 403.5 | 417.6 |
| CO2 supply chain+in-use, coal MIX | kg/MWh | 2.9 | 385.3 | 390.0 | 394.9 |
| CH4 supply-chain, coal MIX | kg/MWh | 0.07 | 0.16 | 0.27 | 0.37 |
| CH4 supply-chain eff. coal MIX | kg/MWh | 0.15 | 0.36 | 0.60 | 0.85 |
| hard coal, power plant efficiency | % | 2.2 | 40.4 | 44.0 | 47.6 |
| lignite, power plant efficiency | % | 1.9 | 35.8 | 39.0 | 42.2 |
| CO2 eff. hard coal | kg/MWh | 40.9 | 750.3 | 812.1 | 884.7 |

| | | | | | |
|---|---|---|---|---|---|
| CO2 eff. lignite | kg/MWh | 53.5 | 967.4 | 1047.6 | 1142.3 |
| Normalization of natural gas efficiency | kg/MWh | 4.4 | 115.0 | 122.3 | 129.6 |
| CO2 emission, gas MIX | kg/MWh | 20.6 | 377.9 | 409.3 | 445.6 |
| CO2 emission, coal MIX | kg/MWh | 37.3 | 905.9 | 963.3 | 1027.9 |
| leakage t=1 | % | 0.39 | 3.55 | 4.17 | 4.85 |
| leakage t=20 | % | 0.46 | 4.17 | 4.89 | 5.69 |
| leakage t=100 | % | 0.93 | 8.37 | 9.83 | 11.44 |

[a]The mean column shows arithmetic mean results and s denotes the standard deviation. pXX: are percentiles (i.e. p05 means that 5 % of the results are smaller than this value). Netherlands (NL), Norway (NOR), Russian Federation (RU), Germany (DE), Colombia (CO), Poland (PL), South Africa (ZA). Time [years] is indicated as t.

Country-specific distributions of CO2 emissions from natural gas and from coal are shown in Figures S1 and S2. The distributions for methane emissions from coal from the different import countries and Germany are shown in Figure S3. The variance in power plant efficiencies is shown in Figure S4. The overall $CO_2$ emissions of the gas and coal mix, respectively in 2018 in Germany are shown in Figure S5.

It should be noted that about one seventh of the coals declared as steam coal imports were used in the steel industry, mainly as PCI (pulverized coal injection) coals. As no information is available on a corresponding quantity breakdown per country, the percentage ratios by supplier country could not be adapted.

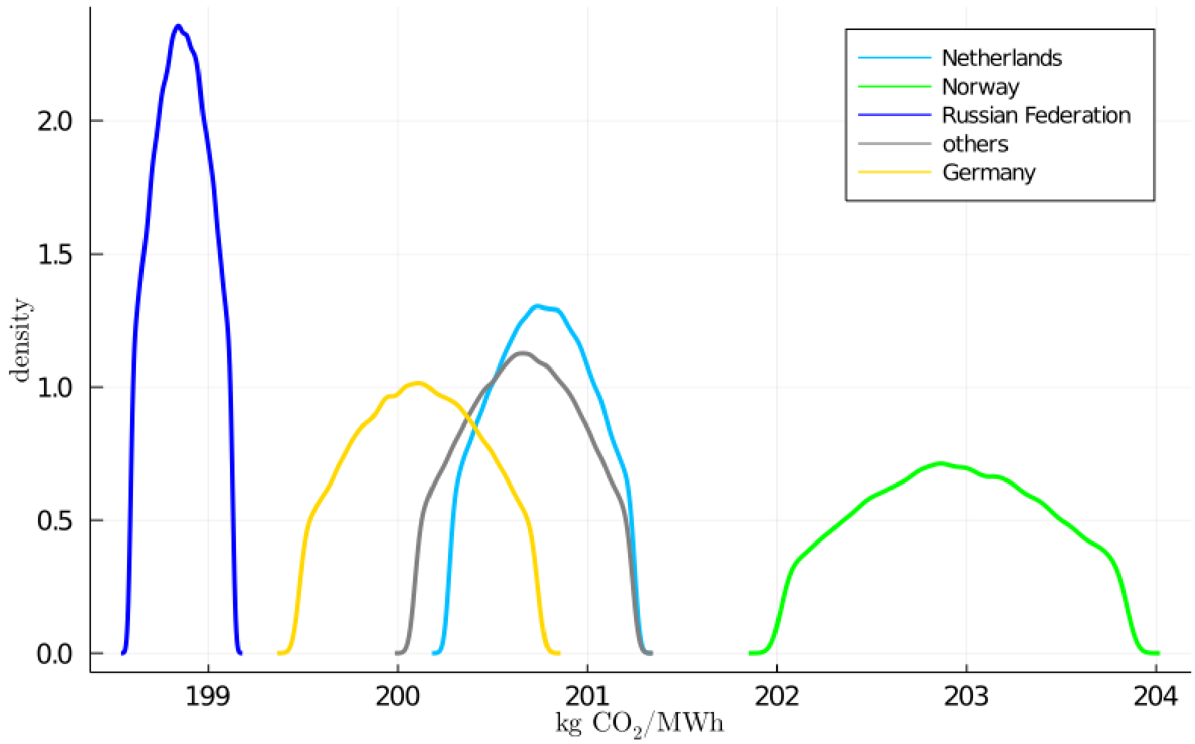


**Figure S1**: Input distributions for $CO_2$ emissions from natural gas (by country of origin); NL – Netherlands; NOR – Norway; RU – Russian Federation; DE – Germany, for Monte Carlo simulation.

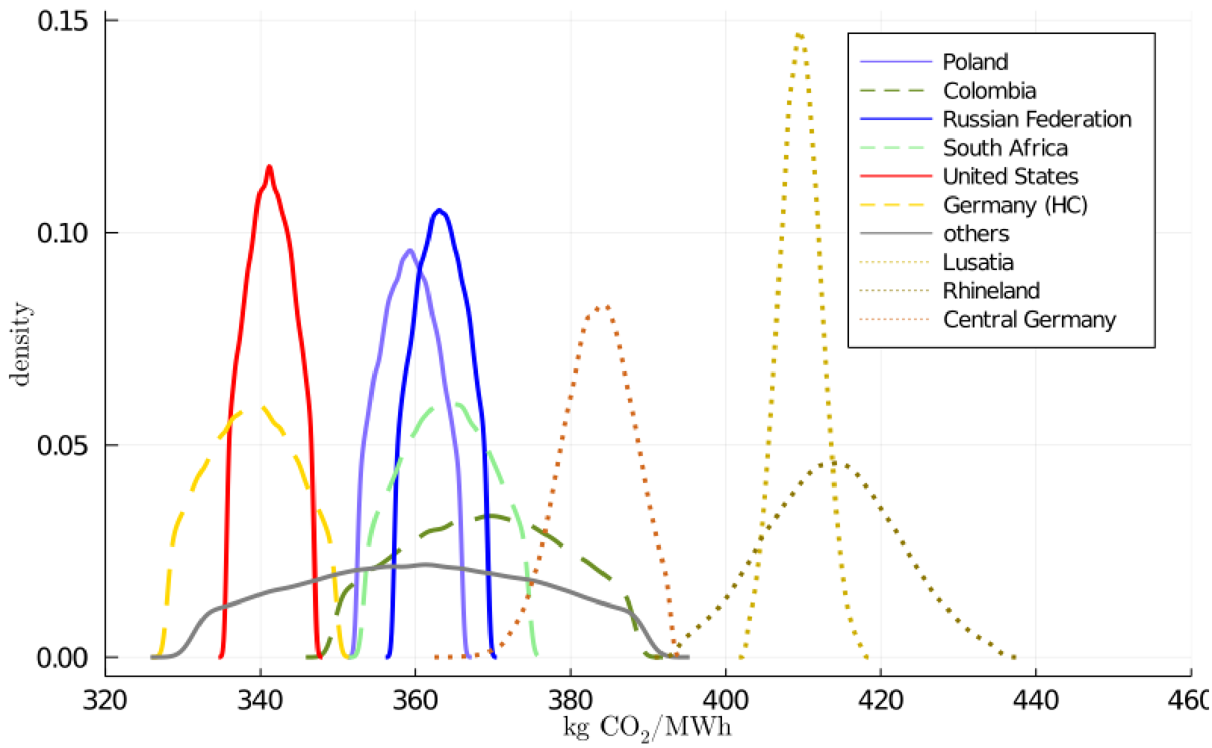


**Figure S2**: Input distributions for $CO_2$ emissions from coal (HC - hard coal, imported into Germany and lignite produced in Germany, respectively), for Monte Carlo simulation. Dotted lines indicate lignite.

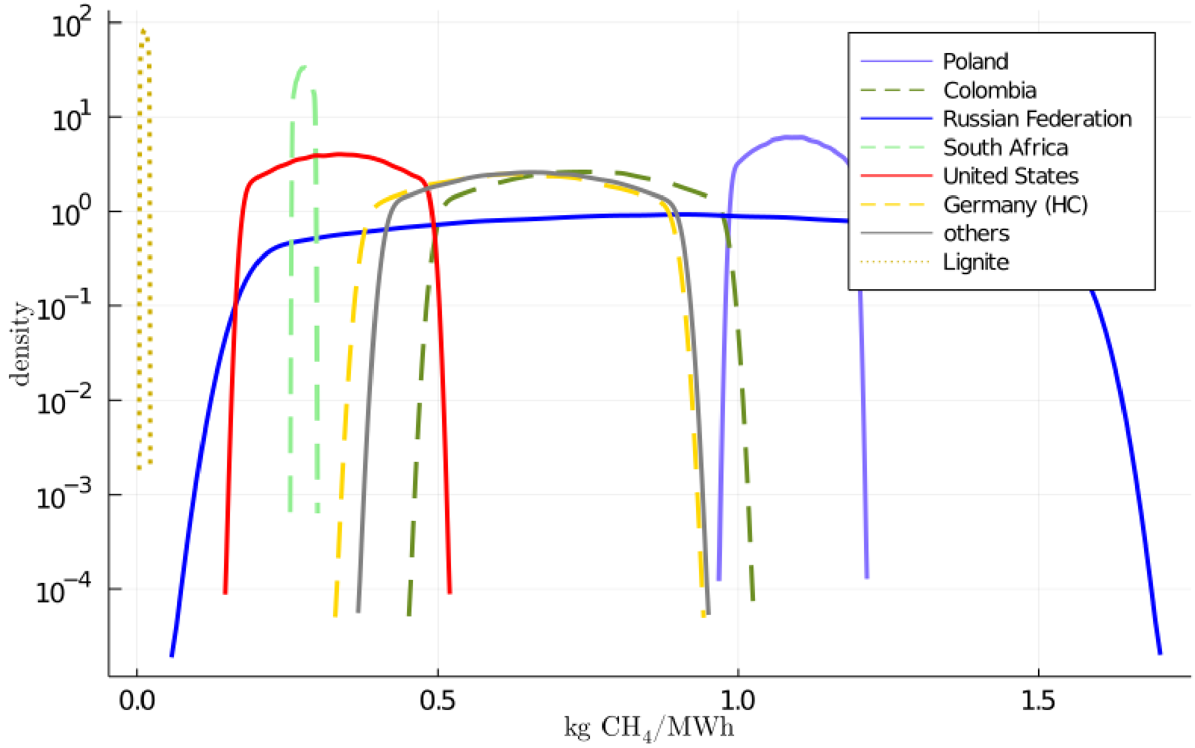


**Figure S3**: Input distributions for methane emissions from coal (HC - hard coal, imported into Germany and lignite produced in Germany, respectively), for Monte Carlo simulation.

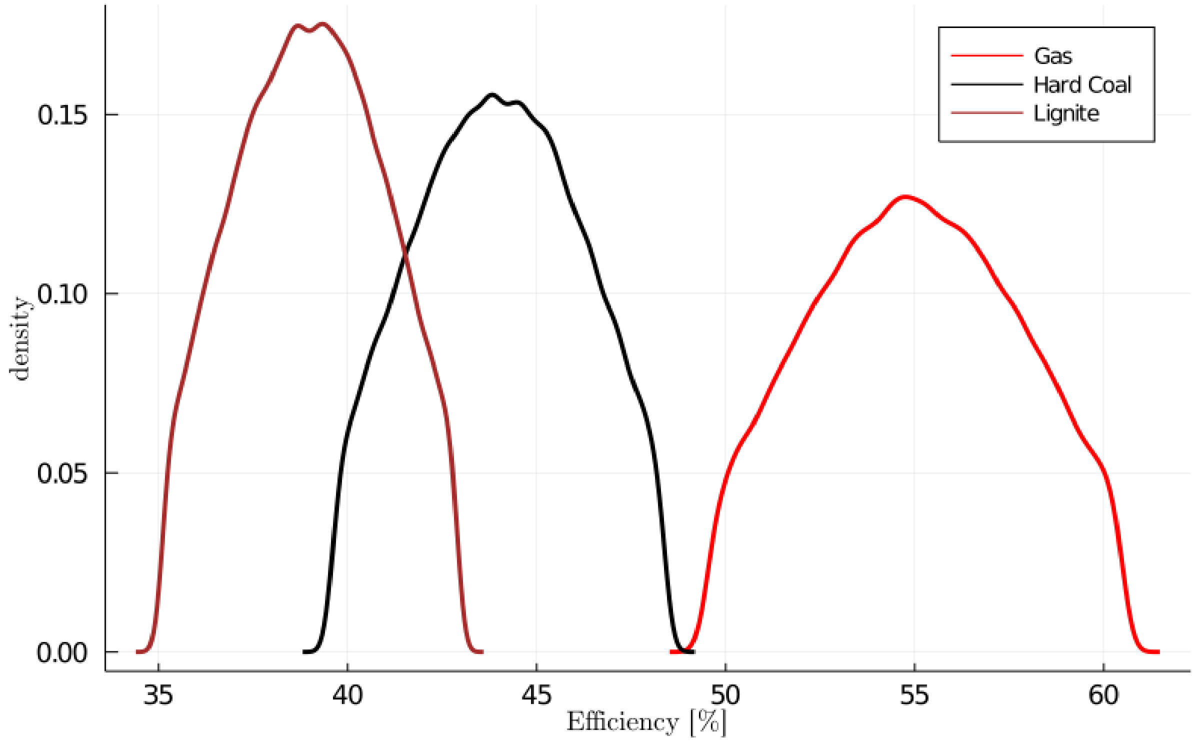


**Figure S4**: Input distributions for power plant efficiencies by fuel, for Monte Carlo simulation.

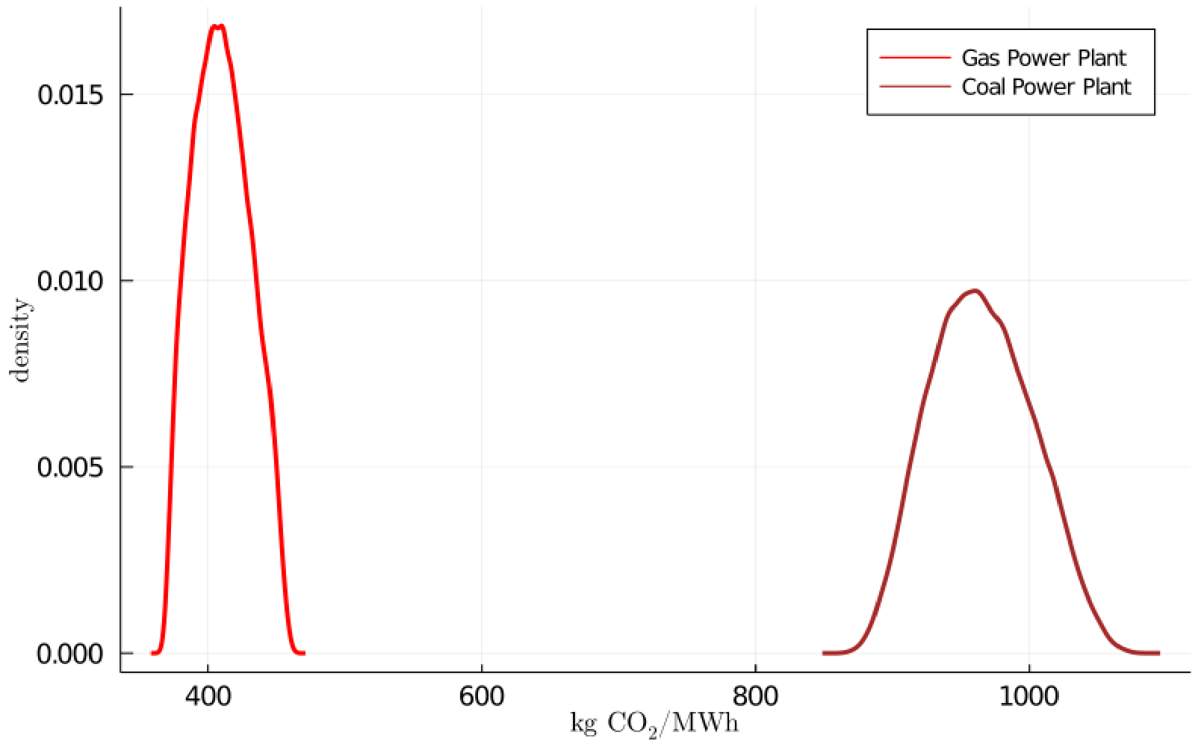


**Figure S5**: Comparison of input distributions for $CO_2$ emissions from natural gas and coal (hard coal and lignite) for Germany-specific power plant fuel mixes (including supply-chain and in-use emissions and considering power plant efficiencies, for Monte Carlo simulation.

# 2 Compilation of natural gas supply chain methane emission data

## 2.1 Methane emission data for natural gas imported to Germany

*Russian Federation*

Russian natural gas exported to Europe is primarily produced from fields in West Siberia, as well as from the recently developed fields of the Arctic Yamal Peninsula, where also a modern processing hub has been constructed.

According to the LCA studies[4-6] methane leakage rates for production of natural gas exported to Germany amount to 0.0092 %.[6] This has been reevaluated to 0.016 % based onDBI[5] and – considerably higher to 0.5 % by EXERGIA S.A. et al.[4] (Table S3). The NIR for 2012 reports leakage rates for the production/processing category of 0.54 %,[7] which is in a similar range as reported for the same year by others if applying current efficiencies of German natural gas power plants.[8] Since 2015 the NIR uses a considerably smaller emission factor resulting in a leakage rate of 0.032 %.[9]

The Russian Federation operates a high pressure, long distance trans-continental pipeline infrastructure comprising three export routes, each about 4,000 km long, into Central Europe. Methane leakages along these routes are reported by DBI[5] as a distance weighted mean of 0.26 % of the injected volume. Similar leakage rates are reported in the “thinkstep study”, except 0.17 % for the northern route. This route utilizes the 1,200 km long North Stream pipeline through the Baltic Sea. Under water and without any further compressor facilities this pipeline is considered as a closed system, without any natural gas leakages into the atmosphere.[6]

Already in 2003 – before completion of the North Stream pipeline – a field campaign to study the natural gas leakage rates along the long distance export pipeline routes was conducted by Lechtenböhmer et al.[10]. They assessed leakage rates between 0.5–1.5 %, with a mean of 0.6 %, slightly less than a previous assessment by Dedikov et al.[11], which is based on a more restricted dataset from prior the breakdown of former USSR. Mitigation measures since then led to reductions in natural gas leakages.[12] Overall, according to recent studies, “bottom up” methane leakage rates for Russian pipeline gas to Germany and the EU, respectively, are in the order of 0.3 %. Bearing this in mind and considering that further leakage reduction mitigation measures have since been implemented as well as that the first North Stream pipeline has gone in operation, it appears that gas leakage rates of 1 %[4] for Russian pipeline transport are probably rather high.

**Table S3**: Compilation of natural gas leakage rates reported for the Russian Federation, Norway, Netherlands and Germany

| Report/ Study | Data reference year | $CH_4$ leakage rate [%] | | | |
|---|---|---|---|---|---|
| | | Production | Processing | Long distance transport | Sum supply chain |
| **Russian Federation** | | | | | |
| EXERGIA S.A. et al.[4] | 2012 | 0.5000 | n.s.[a] | 1 | 1.500 |
| DBI[5] | 2014 | 0.0160 | n.s.[a] | 0.26 | 0.276 |
| thinkstep AG[6 b] | 2015 | 0.0092 | n.s.[a] | 0.3[c] | 0.309 |
| Höglund-Isaakson [8] | 2012 | 0.65 | - | - | - |
| Lechtenböhmer et al.[12d] | 2003 | n.s. | n.s. | 0.6 | n.s. |
| NIR 2020 [9] | 2018 | 0.032 | 0 [a] | (1.0) [e+f] | (1.032) |
| **Norway** | | | | | |
| EXERGIA S.A. et al.[4] | 2012 | 0.00500 | 0.005 | 0.00028 | 0.010 |
| DBI[5] | 2014 | 0.00800 | 0.0080 | 0 | 0.016 |
| thinkstep AG[6] | 2015 | 0.00458 | 0.0042 | 0 | 0.009 |
| NIR 2020 [13] | 2018 | 0 | 0 | 0 [e] | 0.003 |
| **Netherlands** | | | | | |
| EXERGIA S.A. et al.[4] | 2012 | 0.03 | 0 | 0.00028 | 0.030 |
| DBI[5] | 2014 | 0.026 | 0 | 0.000114 | 0.026 |
| thinkstep AG[6] | 2014 | 0.026 | 0.0017 | 0.000114 | 0.028 |
| NIR 2020 [14] | 2018 | 0 | 0 | 0.019[g] | 0.019 |
| **Germany (domestic)** | | | | | |
| DBI[5] | 2014 | 0.0189 | 0.016 | 0.001618[g] | 0.036518[h] |
| NIR 2020 [15] | 2018 | 0.008 [i] | n.s.[a] | n/a | 0.246 [k] |
| **GasMix to Germany** [l] | | | | | |
| UBA 2017 [16] | 2016 | | | | 0.71 [m] |

[a]: processing not reported separately, either included in production or transport net; [b]: primarily based on DBI values; [c]: unweighted, global mean deduced from reported individual transport route values; [d]: duplications from further publications based on the same dataset i.e Lechtenböhmer et al.[10,] Lelieveld et al.[17] are not listed here; [e]: leakage rate resembles rubric 1.B.2.B.iv (transmission) of the NIR, [f]: comprises emission of the intra Russian distribution network, not representative for high-pressure long distance pipelines. [g]: intra German distribution and transport; [h]: sum intra German supply chain; [i]: leakage rate domestic production Germany; [k]: leakage rate normalized to sum of consumed and transmitted in Germany. [l]: GasMix from different import countries to Germany. [m]: calculated from 0.48 g $CH_4$/kWh considering 67.3 g $CH_4$ to generate 1 kWh in a natural gas plant in Germany. Reports in this table other than "NIR" are taken as basis for calculating leak rates for the "Other Reports" scenario in Figure. 4; n.s.: not specified.

*Norway*

Norway's natural gas resources are located offshore on the Norwegian continental shelf. Natural gas is primarily found and produced as associated gas from oil fields. Notable exceptions are the Troll Field (North Sea) and Snøhvit (Barents Sea), which predominantly produce dry natural gas. In general, the natural gas is processed offshore and injected into the North Sea offshore pipeline network, directly transporting natural gas to the EU customers. In case of Snøhvit, however, natural gas is exported via LNG.

Methane leakage rates for offshore production and processing, respectively have been reported before 2014 unanimously in various studies around or less than 0.006 % (Table S3). Updated data since 2014 led to an order of magnitude reduced rates of approx. 0.0004 %.[5, 6] Similarily, the Norwegian Environment Agency (NEA) observed that methane emissions are considerably lower than previously assessed.[18]

Underwater pipelines are considered a closed system, which generally inhibits atmospheric methane emissions.[5, 6] The NEA, however, uses the emission factor of 0.0003 % for the pipeline transport network, following the IPCC 2006 protocol,[19] corresponding to another report.[4]

Overall, methane leakage rates for natural gas from offshore Norway to Germany are reported to be less than 0.02 %.

*Netherlands*

Natural gas from the Netherlands supplied to Germany comes primarily from the Groningen gas field, west of the German-Dutch border. For production and processing, leakage rates of approx. 0.03 % are reported (Table S3). Due to the short distance, leakage rates for transport are less than 0.0001 %.[4-6] Updates of the methane emission factors have led to lower transport leakage rates in the more recent studies. Overall, methane leakage rates for natural gas from the Netherlands to Germany are reported to be less than 0.03 %.

Yacovitch et al.[20] performed measurements on methane emissions from the natural gas supply chain for a region in the Netherlands, including the Groningen natural gas field. Although the methane emissions determined were low when compared to production sector emissions in the U.S., the authors report that $CH_4$ emissions exceed the Netherlands NIR data. Uncertainties in their measurements are, however, large and the resulting error range includes the current NIR value of 0.03 %.[14]

Nevertheless, even assuming a factor 10 higher emission rate for the Groningen field would still yield an overall low emission rate compared to other suppliers for natural gas to Germany and EU, respectively.

*Germany*

Domestic production of natural gas is mainly concentrated in the North of Germany (Federal State of Lower Saxony). According to the published DBI report methane leakage rates for domestic gas are low (0.04 % for 2014[5]). The most recent National Inventory Report reported 10 fold higher values, but this also includes transmitted gas through Germany (Table S3).[15] A recent exemplary study on methane losses in the local natural gas distribution network of Hamburg, Germany found loss rates of 0.04 – 0.07 % of total annual natural gas consumption of Hamburg.[21]

## 2.2 Compilation of U.S. nationwide and global methane emission studies

**Table S4**: Published methane leakage rates (global and U.S. estimates) [a]

| Source | Scope/ region/ comment | Reference year | $CH_4$ emissions in the natural gas supply chain | | |
|---|---|---|---|---|---|
| | | | Shale gas | Conventional gas | Total |
| **Global** | | | | | |
| Hayhoe et al. (2002)[22] | Global summary. (according to GRI (1997)) | probably 1997 | | | 0.5 % production + 2.5 % distribution and usage (0.76 kg/GJ) |
| Schwietzke et al. (2016)[23] | Global estimate based on atmospheric $\delta^{13}$C-methane | 2013 | | | 2.2 % |
| World Energy Outlook (2017)[24] | Global estimate (data source unpublished) | 2015 | | | 1.7 % |
| **USA wide** | | | | | |
| Howarth et al. (2011)[25] | Shale gas, conventional natural gas USA (questioned by e.g.[26]) | 2007 | 3.6–7.9 % | 1.7–6 % | |
| Hultman et al. (2011)[27] | Shale gas, tight gas, CBM USA | 2007 | 2.8 % production + 0.9 % downstream | 1.3 % production + 0.9 % downstream | |
| Burnham et al. (2012)[28] | USA | 2009 | 2.01% (0.71–5.23 %) | 2.75 % (0.92–5.47 %) | |
| Cathles et al. (2012)[26] | USA; numbers are based on EPA 2009 and calculations (no measurements) | 2008 | 1.1 % (0.2 % production + 0.9 % distribution and processing) | | 0.9–2.2 % |
| Littlefield et al. (2017)[29] | USA | 2012 | | | 1.7 % (1.3–2.2 % at 95 % confidence) |
| EPA (2017)[30] | USA | 2015 | | | 1.4 % (*) |
| Alvarez et al. (2018)[31] | Based on measure-ments in ~30% of natural gas production regions in the USA | 2015 | | | 2.3 % (1.9–2.6%) |
| Omara et al. (2018)[32] | USA natural gas production. (Downstream from[31]) | 2016 | | | 1.5 % (non-parametric model) and 0.59 % (regression model) natural gas production without 1 % downstream emissions |
| EPA (2020)[33] | USA (calculated using production numbers from [34]) | 2018 | | | 1.1 (1.3) % |

[a]calculated based on a production of 523 x $10^6$ t($CH_4$)/yr (90 % methane out of 581 x $10^6$ t natural gas production) in 2018. https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm; bracketed values include $CH_4$ emissions from oil production.

## 2.3 Compilation of regional or basin wide methane emission studies in the U.S.

**Table S5**: Overview of published methane leakage studies of selected U.S. basins

| Reference | Region/comment | Year | $CH_4$ loss rates | | |
|---|---|---|---|---|---|
| USA (basin /well pads) | | | Shale gas | Conventional gas | Total |
| Peischl et al. (2015)[35] | Marcellus Shale (Pennsylvania + W Virginia) | 2013 | 0.18–0.41 % | | |
| Omara et al. (2016)[36] | Marcellus Shale (Pennsylvania + W Virginia) | 2014/ 2015 | 0.13 % (0.01–1.2%) | 10.5 % (0.35–91%) | |
| Omara et al. (2018)[32] | Marcellus Shale (Pennsylvania + W Virginia) | 2016 | | | Production: 0.27 % |
| Ren et al. (2019)[37] | Marcellus Shale (Pennsylvania + W Virginia) | 2015 | 1.1 % (0–3.5%) | | |
| Peischl et al. (2015)[35] | Haynesville (Arkansas, Louisiana, East Texas) | 2013 | 1.0–2.1% | | |
| Peischl et al. (2018)[38] | Haynesville (Arkansas, Louisiana, East Texas) | 2015 | 1.0 % | | |
| Karion et al. (2015)[39] | Barnett Shale (Texas) | 2013 | 1.3–1.9 % | | |
| Lyon et al. (2015)[40] | Barnett Shale (Texas) | 2013 | 1.1 % (1.0–1.3 %) (4% oil production not considered) | | |
| Zavala-Araiza et al. (2015)[41] | Barnett Shale (Texas) | 2013 | 1.2–1.9 % | | |
| Peischl et al. (2018)[38] | Barnett Shale (Texas) | 2015 | 1.5 % | | |
| Omara et al. (2018)[32] | Barnett Shale (Texas) | 2016 | | | Production: 0.65 % |
| Schneising et al. (2014)[42] | Bakken (North Dakota etc.) | 2006-2008 (a) 2009-2011 (b) | a) 10.1 % (± 7.3 %) 9.1 % (± 6.2 %) | | |
| Peischl et al. (2016)[43] | Bakken (North Dakota etc.) | 2014 | 4.2–8.4 % | | |
| Peischl et al. (2018)[38] | Bakken (North Dakota etc.) | 2015 | 5.4 % | | |
| Peischl et al. (2018)[38] | Eagle Ford East | 2015 | 3.2 % | | |
| Peischl et al. (2018)[38] | Eagle Ford West | 2015 | 2.0 % | | |
| Peischl et al. (2015)[35] | Fayetteville Region | 2013 | 1.0–2.8 % | | |
| Robertson et al. (2017)[44] | Fayetteville (Arkansas) | 2015 | | | Production: 0.09 % (0.05−0.15 %) |
| Omara et al. (2018)[32] | Fayetteville (Arkansas) | 2016 | | | Production: 0.5 % |
| Pétron et al. (2014)[45] | Denver-Julesburg (Colorado) | 2012 | 4% (± 1.5 %) | | |
| Omara et al. (2018)[32] | Denver-Julesburg (Colorado) | 2016 | | | Production: 1.6 % |
| Robertson et al. (2017)[44] | Denver-Julesburg (Colorado) | 2014 | | | Production: 2.1 % (1.1−3.9%) |
| Peischl et al. (2018)[38] | Denver Basin | 2015 | 2.1 % | | |
| Karion et al. (2013)[46] | Uintah County, (Utah) | 2012 | | | 8.9 % (6.2–11.7 %) |
| Robertson et al. (2017)[44] | Uintah County, (Utah) | 2015 | | | Production: 2.8 % (1.0−8.6%) |
| Omara et al. (2018)[32] | Uintah County, (Utah) | 2016 | | | Production: 3.5 % |

| | | | | |
|---|---|---|---|---|
| Robertson et al. (2017)[44] | Upper Green River (Wyoming) | 2014 | | Production: 0.18 % (0.12−0.29%) |
| Omara et al. (2018)[32] | Upper Green River (Wyoming) | 2016 | | Production: 0.5 % |
| Omara et al. (2018)[32] | Pinedale (Wyoming) | 2016 | | Production: 0.65 % |
| Peischl et al. (2015)[35] | W. Arkoma (Arkansas) | 2013 | 6–20 % | |
| Zhang et al. (2020)[47] | Permian Basin (Texas & SE New Mexico) | 2018/ 2019 | | Production: 3.7 % |

# 3 Potential LNG import to Germany - supply chain- emissions

Liquefaction, ocean transport and regasification are all energy-consuming processes, further adding $CO_2$ and $CH_4$ emissions to the natural gas supply chain for a potential future LNG supply of natural gas from the U.S. or other countries to Germany. Energy demand depends among other factors on the liquefaction process, scaling of the plant, composition of natural gas, ambient temperatures and tanker size. Shipment distances and vessel efficiency are main factors for the energy demand. In total, energy demand for LNG, including liquefaction, transport and regasification, lies between 6 % and 20 % of the gross natural gas amount transported.[48] When considering the entire life cycle of natural gas used for electricity generation, emissions from LNG specific operations are less than 11 % of the overall GHG emissions.[49, 50] Using electricity from renewables and waste heat recovery can reduce these emissions considerably.[48-51]

Additionally, methane slip adds to GHG emissions during transport with ocean going LNG carriers equipped with gas-fired engines. Mallapragada et al.[50] suggested a value of 2 g $CH_4$ emitted/kg (0.2 %) LNG fuel and calculated a contribution of shipping of 2 % to total GHG emissions of generated electricity. Abrahams et al.[49] calculated the same range (1-3 %).

Overall methane loss rates by LNG specific steps add about 0.2 – 0.4 % to the natural gas supply chain emissions (Table S6).[52] However, a part of this leakage is counterbalanced by excluding emissions from the downstream national distribution grids, which are not utilized when transporting gas to the LNG export terminals. For the U.S. this is in the order of magnitude of ~0.1 % local distribution and ~0.3 % transmission and storage of annually produced gas in 2018.[34]

**Table S6**: LNG import to Europe: overview of reported GHG emissions*

| Study | GHG emissions (g $CO_2$eq/kWh) | $CH_4$ leakage rate (%) |
|---|---|---|
| Thinkstep (2017), AR4 (25) [a 6] | 13.4–53.6 | 0.23–<<0.86[f] |
| Thinkstep (2019), AR5 (30) [53] | 44.6 | |
| Mallapragada et al. (2018), AR5 (30) [b 50] | 36 | 0.04–0.58 |
| Balcombe et al. (2016), AR5 (34)[c 52] | 14-73.1 (median 32.1) | 0.2–0.4 |
| Abrahams et al (2015), AR5 (36) [49] | 33[e] | |
| Umweltbundesamt (2019)[d], AR4 (25) [54] | 31.7 | |
| NETL (2019)[55], AR5 (36) | 69.8 | |

*Study name and GWPs are given in the first column. GHG emissions for the LNG supply chain, i.e. liquefaction, ocean transport and regasification. Methane leakage rates of produced gas attributed to the LNG supply chain. [a]: „EU-28 Natural Gas Consumption Mix 2015“ (without USA) import to EU North; wide range of values includes natural gas production; [b]: Marcellus Shale to EU (UK, Spain); [c]: comprehensive compilation of estimated CO2 and methane emissions with a focus on the U.S.; [d]: LNG from the U.S. [e]: Median values from Figure S2 in Abrahams et al. (2015); [f]: Includes natural gas production, processing, ocean transport and liquefaction.

Based on the available literature (Table S6) the range of possible methane loss rates of the U.S. supply chain including the LNG supply-chain to Europe appears to be between 1.3 % and 2.5 %. The lower limit corresponds to estimates of EPA[56] and the upper limited to estimations by Alvarez et al.[31], excluding national distribution, but adding the approximate median value for losses reported from the LNG supply chain.[52] Thus, transportation related methane loss rates of potential U.S. LNG transported to Germany on one side and for long distance pipeline gas transport e.g. from Russia on the other side, may both add up to less than 0.4 % leakage rate (Tables S3 and S4). Considering also carbon dioxide emissions for the energy intense LNG or long-distance pipeline transport, does not change the magnitudes of emissions. While the LNG supply chain emissions (liquefaction, ocean transport, regasification) from the U.S. are on average about 36 g $CO_2$eq/kWh (13.4-73.1 g $CO_2$eq/kWh, Table S6), pipeline transport from Russia to Germany are about 32-47 g $CO_2$eq/kWh.[5, 57]

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