

# H<sub>2</sub>DLAT Reference Document

## H<sub>2</sub>DLAT Introduction

The **Hydrogen Delivered Lifecycle Analysis Tool (H<sub>2</sub>DLAT)** is a webtool that analyzes the lifecycle greenhouse gas (GHG) emissions of producing and transporting hydrogen. For the production emissions, users can choose between two hydrogen production pathways (natural gas pathways and electrolysis), each of which includes different technologies and different inputs (natural gas source, electrolyzer efficiency etc.). For the transportation emissions, users can select amongst four different pathways. Each pathway likewise has a variety of inputs such as the energy source for converting and reconverting hydrogen to/from the hydrogen carrier as well as the transportation distance.

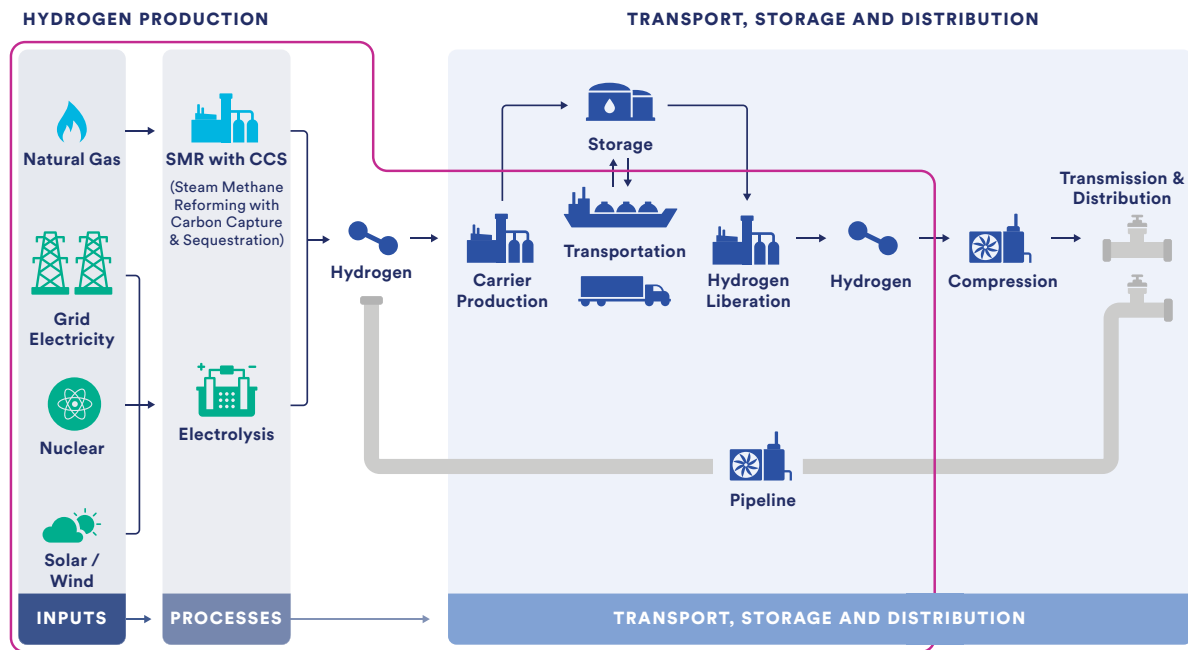
## H<sub>2</sub>DLAT Boundaries

H<sub>2</sub>DLAT provides an estimate of the life cycle emissions of hydrogen delivered, and thus, includes not only hydrogen production but also hydrogen transport. The emissions associated with transporting hydrogen are generally overlooked in international hydrogen certification schemes and emerging hydrogen regulations. This is a major oversight considering that depending on transport choices, these emissions could be as high or even higher than those from producing hydrogen and can potentially outweigh the benefits from using clean hydrogen. The system boundary of the webtool aims to cover the main emission sources throughout the lifecycle of the delivered hydrogen, with a few exceptions. Generally, emissions from the construction, manufacturing, and decommissioning of equipment are not included as they are considered to be relatively small compared to other sources, with the exception of those from renewable energy. Upstream emissions from renewable energy sources have been considered since these are the only emissions component of these energy sources and generally not negligible in magnitude compared to the upstream emissions for the methane reformer/POX, which have longer lifetimes. Manufacturing emissions data from other equipment may be included in future updates of this webtool. Emissions from hydrogen storage and hydrogen distribution to the final user were also not considered in the webtool.

The H<sub>2</sub>DLAT is based on a more comprehensive hydrogen LCA tool developed by Cerulogy on behalf of CATF. The comprehensive tool allows for greater customization of some parameters, assumptions, and input data. To obtain more information about the comprehensive tool, please contact Rocio Gonzalez ([rgonzalez@catf.us](mailto:rgonzalez@catf.us)).

Figure 1: Scope of the H<sub>2</sub>DLAT

Source: CATF



Emission sources covered (see Figure 1):

- **Inputs:** emissions from feedstock and energy sources, including upstream emissions of renewable energy and natural gas.
- **Processes:** emissions associated with the processes to generate hydrogen, including the carbon dioxide (CO<sub>2</sub>) produced from the feedstock in natural gas pathways and emissions from the energy sources to run both the methane reformer/POX and the carbon capture and storage (CCS) unit.
- **Transport:** emissions from conversion and reconversion to/from the hydrogen carrier (heat and electricity); emissions from shipping, trucking, and pipeline transport; hydrogen leakages from conversion/reconversion and from transportation.

## Input Data

The input data used in the webtool can be found in “data\_inputs.xls”, which contains data on:

- Electricity generation GHG intensity
- Heat generation GHG intensity
- Natural gas sources
- Electrolyzers characterization
- Natural gas pathways technologies (reformers)
- Carbon capture characterization
- Hydrogen transport (energy use and losses)
- Other data

## Natural Gas Pathways (SMR, ATR and POX)

The web tool includes three different natural gas pathways: Steam Methane Reforming (SMR), Autothermal Reforming (ATR) and Partial Oxidation (POX).

### Natural gas sources and upstream emissions considerations

The source of natural gas impacts the lifecycle emissions associated with producing hydrogen due to variations in [methane](#)<sup>1</sup> and CO<sub>2</sub> emissions from producing, processing, and transporting natural gas.

Methane leakages occur along the natural gas supply chain (i.e.: production, processing, and transportation). Natural gas sourced from different countries/basins and with different transportation pathways can have significantly different [upstream methane emissions](#)<sup>2</sup>. These emissions fall into three main categories:

- **Leaks/fugitive emissions:** these are a significant portion of GHG emissions from oil and gas production. Leaks are a broad category that includes any loss of containment. Smaller leaks include gas escaping past a failing seal, through a crack, or across corroded material on a vessel, and fugitive emissions when transferring methane from one vessel to another. Leaks can also include larger “super-emitters” that stem from operational errors such as valves that are stuck open, hatches that are left open, and flares that are unlit. Leaks can be reduced through leak detection and repair (LDAR) programs, in which operators are required to inspect facilities for leaks at regular intervals and repair leaking components.
- **Vent:** these emissions come from equipment in the oil and gas industry that vent gas to the atmosphere as part of normal operations. Equipment includes pneumatic controllers and pumps, compressors, tanks, well completions and workovers, and dehydrators. Venting emissions can be reduced by retrofitting facilities with lower or zero emitting equipment or by capturing gas that would otherwise be vented.
- **Flares/combustion:** these emissions are also known as “methane slip”. This is the small amount of methane that does not combust and instead leaks into the atmosphere when natural gas is flared and combusted at oil and gas sites. Routine flaring can be reduced through advanced planning while methane slip emissions can be reduced through the use of more efficient flares and eliminated if sites are electrified.

CO<sub>2</sub> emissions also occur along the natural gas supply chain (i.e.: production, processing, and transportation). Natural gas sourced from different countries/basins and with different transportation pathways can have significantly different upstream CO<sub>2</sub> emissions. These emissions are primarily caused by flaring and combusting natural gas (and sometimes other fuels) in engines and turbines at oil and gas sites. In some production basins with high levels of CO<sub>2</sub> in the produced gas, venting of CO<sub>2</sub> as a result of acid gas removal must also be accounted for. For pathways involving liquefied natural gas (LNG), CO<sub>2</sub> emissions associated with liquefying and transporting gas can also be significant.

CATF recommends using emissions data from [Alvarez et al. \(2018\)](#)<sup>3</sup> to estimate emissions from hydrogen production via natural gas pathways in the US. This article is a recent comprehensive study of methane leakages in the US based on direct emissions measurements from thousands of sites, which estimated a 2.3% leak rate from US oil and gas operations. This leak rate is significantly higher than that reported by the official US Greenhouse Gas Inventory (also provided as an option in the webtool). However, even [Alvarez et al. \(2018\)](#) likely underestimates the average US leak rate because the study did not include measurements from the Permian basin, which is known to have very high emissions. Methane emissions in the US clearly and substantially vary between production regions. Measured emissions are as low as 0.4 – 0.75% for some high-productivity regions in Pennsylvania, and as high as

---

<sup>1</sup> <https://www.catf.us/2023/02/guide-monitoring-quantifying-methane-emissions-oil-gas-sector/>

<sup>2</sup> <https://www.catf.us/methane/mitigation-program/>

<sup>3</sup> <https://www.science.org/doi/10.1126/science.aar7204>

<sup>4</sup> <https://acp.copernicus.org/articles/17/13941/2017/>

<sup>5</sup> <https://pubs.acs.org/doi/10.1021/acs.est.1c06458>

<sup>6</sup> <https://www.researchsquare.com/article/rs-2406848/v1>

9.6% and 5.7% in the Permian and Uinta basins, respectively ([Barkley et al. \(2017\)](#),<sup>4</sup> [Chen et al. \(2022\)](#),<sup>5</sup> [Sherwin et al. \(2023\)](#).<sup>6</sup> For natural gas production in the Permian basin, an option from [Sherwin et al. \(2023\)](#) is provided in the webtool. The emissions associated with the US cases also include an estimate of methane and CO<sub>2</sub> emissions associated with LNG liquefaction and transport from the US to the EU (also provided as options in the webtool if the user is interested in evaluating these cases). Several points in the LNG value chain have potentially large methane emissions, and these emissions are far less studied than emissions associated with domestic natural gas use, so LNG adds significant emissions and uncertainty to overall value-chain emissions. Global averages from [Schwietzke et al \(2014\)](#)<sup>7</sup> and [Chen et al. \(2023\)](#) are also provided. The emission details of all the natural gas sources provided in the webtool can be found in “data\_inputs.xls”.

For the EU, six natural gas sources are provided based on the natural gas pathways from the [EU JEC WTW v5](#)<sup>8</sup> (carried out by the JRC, EUCAR and Concauwe). In addition to the GHG emissions from energy use for gas extraction and processing, the [EU JEC WTW v5](#) natural gas pathways include 1% volume venting as CO<sub>2</sub> and 0.4% volume of methane losses. Leakages during transportation are also included, accounting for a loss of 0.13% of the transported natural gas per 1000 km. While this case reflects official inventories, it may be an underestimate of true emissions because it is not based on top-down methane measurements.

## Carbon capture considerations

For SMR, carbon capture can be applied in several different configurations (Figure 2). In pre-combustion capture configurations, CO<sub>2</sub> is separated from the process stream prior to combustion. This can be carried out on the process stream either before or after the pressure swing adsorber (PSA) that separates the pure hydrogen product. Existing large-scale CCS projects typically adopt one of these configurations. For example, the [Quest project](#)<sup>9</sup> at the Scotford Upgrader in Canada captures 80% of the CO<sub>2</sub> from the PSA tail gas (Option 2). The [Air Products project in Port Arthur](#)<sup>10</sup> (Texas, USA) adopts Option 1 in the figure, capturing at least 90% of the CO<sub>2</sub> in the process stream. These pre-combustion configurations do not capture the CO<sub>2</sub> produced from the natural gas combustion that supplies heat to the reformer, leaving up to around a third of the total CO<sub>2</sub> unabated. However, process modifications such as firing the reformer with H<sub>2</sub>-rich syngas could allow for over 90% capture using pre-combustion capture.

The post-combustion configuration (Option 3 in Figure 2) allows for higher capture rates as it addresses the CO<sub>2</sub> from both reforming natural gas and from combusting fuel to heat the reformer. Post-combustion capture on SMRs is also technically mature and has been demonstrated at [several commercial facilities in Asia](#) for fertilizer production<sup>11</sup>. The SMR modelling in the webtool is based on the [IEAGHG Technical Report 2022-07](#), and therefore, is based on the post-combustion configuration. The IEAGHG report provides data of an SMR without CCS and with CCS (90% capture rate). The energy demand (heat and power) for the SMR+CCS system in the webtool has been estimated based on both sets of data, assuming a linear relationship between the energy use for CCS and the CO<sub>2</sub> captured. This simplification allows the user to select a different capture rate other than 90%. In principle, there is no technical barrier to raising post-combustion capture on SMR to 100% effective capture (i.e., 100% of fossil CO<sub>2</sub> is captured). A techno-economic analysis of this case is presented in [Mullen et al. \(2022\)](#).<sup>12</sup>

There are currently several plans to equip existing SMRs with CCS, including projects associated with chemical and refinery complexes in the Port of Antwerp and the Port of Rotterdam, as well as Linde’s initiative to apply CCS to its hydrogen production facilities on the Texas Gulf Coast.

---

<sup>7</sup> <https://pubs.acs.org/doi/abs/10.1021/es501204c>

<sup>8</sup> <https://publications.jrc.ec.europa.eu/repository/handle/JRC121213>

<sup>9</sup> [https://www.shell.ca/en\\_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html](https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html)

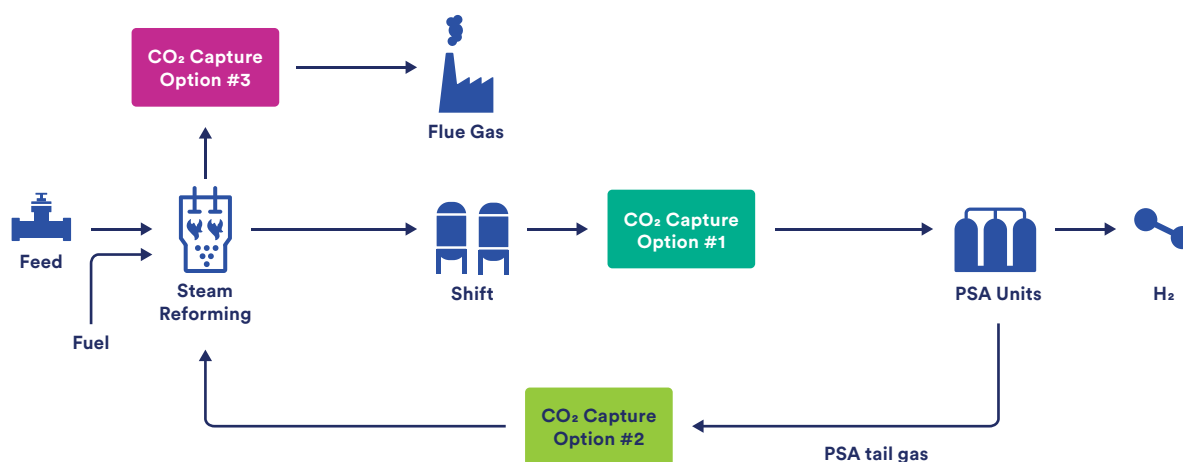
<sup>10</sup> <https://www.airproducts.com/company/innovation/carbon-capture>

<sup>11</sup> <https://www.co2conference.net/wp-content/uploads/2021/01/JThomas-CO2-Conference-forweb.pdf>

<sup>12</sup> <https://www.sciencedirect.com/science/article/pii/S1750583623000749>

**Figure 2: Possible carbon capture configurations for SMR**

Source: [IEAGHG Technical Report 2022-07](#)



ATR is of particular interest for CCS as the CO<sub>2</sub> is produced in a single stream at relatively high partial pressure, and no 'post-combustion' step on low-pressure flue gases is required. Both of these are important given that CCS costs increase as the partial pressure decreases and the number of point sources increase. The heat for the steam reformation reaction is generated in the reactor using the exothermic partial oxidation of methane. The H<sub>2</sub>DLAT webtool is based on the ATR-CCS configuration used in the IEAGHG report, which is based on Johnson Matthey's low-carbon hydrogen (LCH™) process. Shifted syngas from the ATR is fed to a CO<sub>2</sub> absorber using the commercial amine-based solvent activated methyl diethanolamine (aMDEA) and the solvent is regenerated in a stripper column, producing pure CO<sub>2</sub>. As the IEAGHG report only examines one case of ATR with 94% capture rate and does not document the additional energy required to operate the carbon capture unit, data from [Oni et al. \(2022\)](#)<sup>13</sup>, which includes two ATR cases without carbon capture and one with carbon capture (91%), has been used to complete the energy demand modelling in the webtool.

There are many active proposals to construct new ATR units integrated with CCS, typically aiming for capture rates of at least 95%. Notable examples include the [HyNet project](#)<sup>14</sup> at the Stanlow refinery (UK), BP's H<sub>2</sub>Teesside project (UK), H-Vision project in Rotterdam (Netherlands), H<sub>2</sub>BE (Belgium), and a large project planned by Air Products for the Louisiana Clean Energy Complex (USA).

In POX, the feedstock is gasified in the presence of oxygen without steam. POX is usually used in refineries to produce the hydrogen needed as this technology is able to process heavy hydrocarbons (in the current version of the webtool this option is not considered). Similar to its review of ATR technology, the IEAGHG report does not document the additional energy required to operate the CCS unit for a POX plant and includes only a case with 100% capture rate. To allow for different capture rates and due to lack of other data sources, the same energy ratios obtained for ATR from [Oni et al. \(2022\)](#) have been applied to the POX data in the IEAGHG report.

<sup>13</sup> <https://www.sciencedirect.com/science/article/pii/S0196890422000413>

<sup>14</sup> [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/866401/HS384\\_-\\_Progressive\\_Energy\\_-\\_HyNet\\_hydrogen.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866401/HS384_-_Progressive_Energy_-_HyNet_hydrogen.pdf)

## Assumptions for natural gas pathways

The assumptions used in the webtool for natural gas pathways are summarized below. The sources for these assumptions can be found in “data\_inputs.xls”.

- Heat source: natural gas boiler (75.1 gCO<sub>2</sub>/MJ).
- Manufacturing emissions for the natural gas reformer/POX are not included.
- For SMR pathways, a “post-combustion” configuration is applied, allowing for capture of the CO<sub>2</sub> from both reforming natural gas and combusting fuel to heat the reformer. CO<sub>2</sub> from electricity is not considered for capture since it is assumed to be produced offsite.
- Water supply: municipal water supply (5 MJ/t water).
- Electricity source for the natural gas reformer/POX and water supply: EU 2020 grid (73.6 gCO<sub>2</sub>/MJ).
- Electricity transmission losses: assumed medium voltage grid connection (3.5% losses).
- No coproduct credit considered.

## Electrolysis (low temperature and high temperature)

### Electrolysis considerations

There are four main electrolyzer types available on the market today: polymer electrolyte membrane (PEM), anion exchange membrane (AEM), Alkaline, and solid oxide electrolyzer cell (SOEC). AEM was omitted from this tool due to the limited deployment available as of this time. A comparison of typical electrolyzer stack efficiencies and a sample electrolyzer system efficiency are listed in the table below.

**Table 1: Comparison of electrolyzer stack efficiencies by technology.**

Alkaline and PEM values are from *Fraunhofer 2022*.<sup>15</sup> SOEC values are from *ISPT 2023*.<sup>16</sup> The system specific energy consumption for sample plants of different technologies are also shown for illustration purposes. The actual energy consumption of a system will depend on the energy consumed by auxiliary equipment (Electric heating, compression etc.) and steam generation (if required).

Technology	Specific Energy Consumption (kWh/kg)	Efficiency (%)
Alkaline Stack (DC)	47-65	52-71
PEM Stack (DC)	50-76	44-67
SOEC Stack (DC)	34-35	96-97
Sample 100 MW Alkaline System	55	60
Sample 100 MW Alkaline System	53	62
Sample 500 MW SOEC System (excludes energy for steam generation)	39	86
Sample 500 MW SOEC System (includes energy for steam generation)	47	70

<sup>15</sup> <https://www.ise.fraunhofer.de/en/press-media/press-releases/2022/towards-a-gw-industry-fraunhofer-ise-provides-a-deep-in-cost-analysis-for-water-electrolysis-systems.html>

<sup>16</sup> <https://ispt.eu/media/20230508-FINAL-SOE-public-report-ISPT.pdf>



Of the three technologies modeled, PEM and Alkaline are available for low temperature electrolysis given their operating temperature ranges: 50-80 °C for the former and 70-90 °C for the latter. SOEC's can operate between 500-900 °C and are suitable for high temperature electrolysis. For high temperature electrolysis, an external heat source can be used to evaporate the water. This effectively relieves the electrolyzer stack from having to provide the latent heat of evaporation, reducing the electrolyzer's electricity consumption, and thus, enables a step change increase in efficiency when measured as hydrogen out per unit of electricity consumed. The ability to make use of an external heat source is particularly relevant to industrial processes, where large amounts of steam are often discarded in the condensate system. The additional heat source does however introduce another potential source of emissions that must be factored into the LCA. Two efficiencies for SOEC systems are shown in Table 1: one that includes the heat required for steam generation (lower value of 70%, as it considers the electricity and heat needed for the process) and the other that excludes it (higher value of 86%, as it accounts only for the electricity needed for the process, which is lower when external heat is introduced).

The default efficiencies used in the webtool are 60% for PEM, 62% for Alkaline and 86% for SOEC (excluding energy for steam generation). The user can also decrease or increase the efficiency within the webtool. The electrolyzer efficiencies in the webtool are all only based on electricity consumption. For SOEC, the heat consumption is applied separately, and thus, when SOEC efficiency is increased or decreased, it is relative to the default 86%.

## Assumptions for electrolysis pathways

The assumption used in the webtool for electrolysis pathways are summarized below. The sources for these assumptions can be found in "data\_inputs.xls".

- Electricity transmission losses: assumed medium voltage grid connection (3.5% losses)
- Water supply: municipal water supply (5 MJ/t<sub>water</sub>).
- Manufacturing emissions for the electrolyzer were not included.
- No coproduct credit considered.

## Hydrogen transport

### Hydrogen transport considerations and assumptions

Four hydrogen transportation pathways are considered in the webtool: compressed hydrogen, liquified hydrogen, liquified ammonia, and liquid organic hydrogen carriers (LOHC). Details on the inputs, sources and assumptions can be found in "data\_inputs.xls".

The transport block consists of three phases:

- **Conversion:** accounts for the energy used to convert the hydrogen to the carrier.
- **Reconversion:** accounts for the energy used to reconvert the carrier to hydrogen (for pipeline transport, no energy use is considered for reconversion as it is assumed that hydrogen is compressed using the electricity source at origin [conversion]).
- **Transport modes (shipping, trucking and pipeline):** accounts for the energy used to transport the carrier via the transport mode selected (assumed heavy fuel oil for shipping, diesel fuel for trucking, and electricity for pipeline). For pipeline transport, the electricity source at destination is used to calculate emissions from "pipeline" in the webtool (i.e.: the carbon intensity of the electricity source selected is multiplied by the distance travelled and by the energy intensity of pipeline transport [3.3 MJ/tkm]).

The following options of “carrier-transport mode” are provided in the webtool:

- Compressed hydrogen via pipeline
- LOHC, liquified ammonia and liquified hydrogen via ship or truck

## Hydrogen losses

The climate impact of hydrogen losses to the air is represented in the “H<sub>2</sub> fugitives” results. While the IPCC has not yet published a Global Warming Potential (GWP) for hydrogen, CATF considers it important to include the climate impact of hydrogen as an option in the webtool. GWP values from different sources are offered to the user, including the option of not accounting for this impact.

Data on the hydrogen losses/leakages during transport are still very limited and the range of results of the existing data is very large. Thus, a number of assumptions had to be made (see details in “data\_inputs.xls”) to factor in this variable into the LCA. The tool considers hydrogen losses during conversion, reconversion and transport (shipping, trucking and pipeline). A summary of the hydrogen losses used in the webtool via pipeline, trucking and shipping is provided in the table below (detailed information of the sources and assumptions for each case can be found in “data\_inputs.xls”).

**Table 2: Hydrogen transport losses considered in the webtool for different hydrogen carriers and transport modes**

	Compressed	LH <sub>2</sub>	LOHC	Ammonia
Pipeline	0.44%	n/a	n/a	n/a
Ship	n/a	3.34%/1000km	0.01%/1000km	0.01%/1000km
Truck	n/a	1.67%/1000km	0.01%/1000km	0.01%/1000km